PETROLEUM REVIEW

October 1990 Volume 44 Number 525 £4.50

Subscription (inland) £40.00 (overseas) £50.00

PUBLISHERS

Published Monthly by
THE INSTITUTE OF PETROLEUM

Director General: *Ted Williams*

Membership Services Director: *Brian Raggett*

Honorary Editor: *Peter Ellis Jones*

61 New Cavendish Street,
London W1M 8AR
Telephone: 071-636 1004. Telex: 264380
Fax: 071-255 1472

For details of membership, including Petroleum Review at no extra cost, please apply to the Membership Department.

Printed by Eyre & Spottiswoode Ltd, London and Margate.

Contents

Cover photo of a drilling crew engaged in exploration research at Conoco's borehole testing facility near Newkirk, Oklahoma. (See Newsdesk).

ISSN 0020-3076

If you're spending more than £250,000 a year on electricity, allow us to turn on the light.

This sort of expenditure suggests you're what we call a one megawatt user.

Which means you should no longer be in the dark about major changes in the electricity supply industry.

Because instead of having to buy from your regional electricity company, you may have the opportunity to go direct to the biggest manufacturer of electricity in England and Wales, National Power PLC.

We can discuss flexible contracts to suit your specific needs.

Arrangements for billing can be designed to suit the way you want to pay. Prices can be indexed to provide predictability on longer term contracts.

And aggregated terms for multiple sites become a possibility. You may find there are opportunities for co-generation and joint ventures in energy.

To start the dialogue, and to obtain your free copy of the **Energy Direct** brochure simply telephone us now on 0800 444 284 or complete and return the coupon below.

National Power
The Heart of the Country.

To: Peter Hare, Sales Manager, National Power, **Energy Direct,**
Sales Branch, Centre Court, 1301 Stratford Rd., Hall Green, Birmingham B28 9HH.

Name_____ Position_____

Company_____ Nature of business_____

Address_____ Post Code_____

Telephone No:_____ Monthly energy spend: £20-30K_____ ☐ £30K+_____ ☐

S006 PR/A1

. . . news in brief

10 August

Oil production from the Scott field is to be exported by BP's Forties pipeline system.

Oil workers in the North Sea are to be electronically tagged by BP as part of safety trials.

Petrobras has suspended its contract to purchase 160,000 b/d of oil from Iraq.

Chevron is offering to sell its four asphalt terminals in Ohio, Pennsylvania and Kentucky.

The US Environmental Protection Agency will require an 80 percent cut of sulphur in diesel by October 1993.

13 August

Fuel prices in the United Kingdom could rise by about 300 percent if a carbon tax is introduced on oil and coal without offsetting measures, according to a study carried out for the EC Commission.

Ultramar has placed an order worth $212m for three oil tankers to secure long term transport requirements to its refinery in Quebec. Each tanker will be ice-strengthened and double-skinned and will be capable of carrying 1m barrels of oil.

India asked Malaysia and Indonesia for crude to offset the loss of supplies from Iraq and Kuwait.

14 August

BP has lined up a further ten agreements to supply gas to industrial customers direct from the Welland field.

The Danish Underground Consortium has made a new natural gas find near the North Sea Dan field.

Nippon Oil Co Ltd will build a residue fluid catalytic cracker at its Negishi refinery to cope with rising demand for light products.

15 August

ICI Plc has sold its entire 24.9 percent stake in Enterprise Oil Plc to Warburg Securities, in conjunction with Cazenove and Co for a total of £679.6m.

16 August

BP Exploration has purchased a new system, known as Zermag, designed to stop problems associated with the creation of magnetic fields during welding operations.

Amoco Chemical Co have signed a letter of intent with a major Indonesian group to conduct a feasibility study for 250,000 ton per year purified terephthalic acid plant in Java.

17 August

Kingston Oil and Gas has moved to expand its activities in the United Kingdom with the £4.5m proposed acquisition of Orcol Fuels, which specialises in the recovery and distribution of fuel oil.

The US 587m barrels Strategic Petroleum Reserve has been put on a 'Phase Two' alert as it prepares for the possibility of a near-term draw on stocks.

20 August

The United Kingdom is likely to be a net importer of oil in September and October as offshore maintenance programmes hit oil production.

Total Petroleum Canada Ltd has bought $11m worth of assets from Amoco Canada Petroleum Co Ltd.

Mitsubishi Oil Co Ltd will import 25,000 tonnes of synthetic gasoline from Petroleum Corp of New Zealand after gasoline prices surged, following the imposition of sanctions against imports from Iraq and Kuwait.

BHP has signed a production-sharing contract with the government of Malta to explore, survey and drill, off the north coast of the island.

The US President signed legis-lation which establishes clean up procedures for oil spills and requires all tankers calling at US ports to be fitted with double bottoms.

21 August

Chinese Petroleum Corp has signed a three-year contract with a unit of Union Pacific Corp to jointly explore for oil in Argentina.

British Petroleum have invited bids for BP Exploratie. The move is part of its plan to sell off smaller businesses and of a continuing review of its asset portfolio.

Statoil have discovered oil and natural gas with an exploratory well drilled north of the Heidrun field in the Haltenbanken oil province.

22 August

PDVSA may supply crude to Czechoslovakia in exchange for industrial equipment.

Norway's share of natural gas exports to West Germany will more than double to 35 percent of overall supply by the year 2000, according to the vice-president of gas purchasing in Rhurgas.

The government of Thailand is setting up a new entity to take over the operations of two state petroleum agencies, the Petroleum Authority of Thailand and Bangchak Petroleum.

23 August

Iran has struck natural gas under the Caspian seabed at Bandar Anzali for the first time confirming prospects of substantial oil and gas reserves.

24 August

The UK government plans to float PowerGen on the stock market in February 1991, after announcing that it has ended negotiations aimed at selling the company to Hanson.

Yorkshire Water and Yorkshire Electricity announced that they were jointly planning to build 25–35 wind turbines on Ovenden Moor in the Pennines.

The major US oil companies have been summoned to the US Justice Department to discuss whether the sharp increases in oil and gasoline/petrol prices have reflected collusion and anti-competitive practices.

Mobil Corp will restructure the operations of its 16 European marketing and refining affiliates to improve efficiency and take advantage of the opportunities associated with single European Community market.

28 August

Shell reported that its Nigerian subsidiary has found an oil field near Yenagoa, with estimated oil reserves of 400m barrels and more than 500 trillion cubic feet of gas.

Bechtel Group Inc has been awarded a contract to design and build a $140m petroleum coke/sulphur recovery facility at Conoco Inc's Billings, Montana, refinery.

29 August

BP and Statoil announced plans for a series of joint ventures in international oil and gas production and gas marketing.

According to the director of gas purchases for Gaz de France, Norway's share of the French gas market could grow to between 20 and 25 percent by the year 2000.

Greece will allow foreign com-panies to prospect for oil in a bid to reduce its dependence on Middle Eastern supply.

30 August

The Seychelles Islands and Ultramar Plc have signed an agreement for oil exploration.

Chevron International Oil Co is decentralising its crude oil and product trading operations to improve its market focus and its ability to react to changes in the world market.

31 August

Ranger Oil Ltd expects to spend about Can$400m to bring North Sea properties into production by 1997.

Ireland is to reopen the Whiddy terminal in Bantry Bay closed since a French tanker blew up there in 1979.

Saga Petroleum is in talks with Statoil over a proposal to store gas from the Snorre field in the Statfjord reservoir.

3 September

The California legislature has passed a bill that would make it the first US state with a plan for responding to offshore oil spills.

4 September

Algeria has decided to move ahead with plans to expand a pipeline which carries its natural gas exports across the Mediterranean to Italy.

5 September

Texaco Inc has sunk its first well in southern Tanzania.

Atlantic Richfield Co has launched a reformulated gasoline designed to reduce toxic emissions from cars.

The European chemical industry faces extra costs of about £2.66bn a year as a result of the rise in naphtha prices since the start of the Gulf crisis.

6 September

Esso AG hope to open 250 to 350 service stations in East Germany in the next eight to ten years.

Esso Malaysia Bhd has struck oil at a promising new field offshore of the Malaysian Peninsula.

7 September

Saudi Arabia has virtually doubled its exports of crude to over 7m b/d in a short term move to fill the supply gap created by the international embargo against Iraq.

Plans for an offshore oil terminal in the Gulf of Mexico are being revived by Phillips Petroleum Co and seventeen other US oil companies.

10 September

UK government approval has been sought for the development of the East Brae oil and gas field by a group of oil companies lead by Marathon Oil.

British Petroleum Co Plc has transferred its oil exploration and development rights in Ecuador to Oryx Energy Co.

How to get a piece of British Gas pipeline.

British Gas has produced a revised brochure giving details of its gas transportation services.

With simple guidelines, it explains how independent gas suppliers can utilise the British Gas national pipeline network.

The brochure lists the charges which take effect from 1st October, 1990.

For a copy of the brochure, or more information, phone 071-821 1444 or write to Gas Transportation Services Department, British Gas plc, 100 Rochester Row, London SW1P 1JP.

British Gas

Gulf crisis traps IP members

ONLY one person out of the Institute of Petroleum's 20 odd strong membership in Kuwait has been confirmed as having escaped from the occupied country since the 2 August invasion by Iraq.

The member, who does not want to be named, dodged Iraqi patrols by taking the desert route across the border between Kuwait and Saudi Arabia three and a half weeks ago.

The other members, 13 Kuwaiti nationals and seven expatriates, have not been heard of since the invasion, although some of them could have been out of the country on holiday or on leave when the Iraqis took over.

Foreign Office sources have confirmed that they have knowledge of four expats members still trapped inside the annexed country.

The situation is extremely dangerous for trapped expats because if they are caught by Iraqi patrols whilst in Kuwait, they could be forced to become part of the Iraqi President, Saddam Hussein's 'human shield'.

As hostages they could be taken to sites of strategic importance where Hussein thinks their presence will act as a 'shield' to discourage air attacks.

More immediately, all the members still in Kuwait will face the problem of dwindling food supplies as the UN embargo of Iraq and, ironically Kuwait, begins to take effect.

Since the invasion there has been a mass exodus of expats working in Kuwait. The number of British citizens in Kuwait has been reduced from about 4,500 to around 1,000 of which approximately 100 are thought to be women and children.

Statoil-BP plan joint ventures

PLANS for significant collaboration in international exploration, gas supply and technical research were announced by Statoil and BP at the Offshore Northern Seas Conference.

The deal signed by the two companies last August will seek to explore the scope for commercial cooperation in three specific fields, which add up to a major step in internationalising Statoil.

Cooperation will mainly be carried out through the use of existing and new North Sea infrastructure to carry both countries' gas to markets in the UK and Europe, and joint marketing of gas in Britain.

A joint technical research programme to support the international exploration and development, drive is also on the agenda.

This part of the scheme could involve spending some $20 million a year split equally between the two partners, Statoil and BP announced.

Statoil and BP also aim to pursue joint oil and gas ventures in West Africa, offshore China and Vietnam, and the USSR.

Horizontal drilling raises yield

A prediction has been made by the Chairman of Oryx Energy Co that there will be a big increase in horizontal drilling of onshore wells in the United States during the next 10 years.

Robert Hauptfuhrer says that his company has so far drilled 15 horizontal wells in the United States — more than any other company and all the 12 horizontal holes completed in the Austin chalk of South Texas are still producing more than 1,000b/d, which is in contrast to rapidly depleting vertical holes in the chalk.

Oryx expects to drill about 105 horizontal wells in the United States in 1990, 30 of them wildcats. Eighty-five will be in the Austin chalk area.

Oryx's first horizontal holes cost as much as three times the cost of conventional vertical holes. The costs in the chalk are now 50 percent more than a vertical well but achieves three to five or more times the daily production and reserves. Flow rates have also gone up and drilling costs have come down.

Mr Hauptfuhrer said success with horizontal drilling is due more to experience through trial and error than to developments in hardware, although it could not have occurred without developments in things such as downhole motors, well measurement and seismic data during the last decade.

AGAS/ ARCO gas deal

AN agreement signed by AGAS and ARCO British Limited means that, for the first time, an independent wholesaler will contract gas for sale directly into the UK market. AGAS will purchase ARCO's share of the 10 per cent of gas reserves from the Welland fields which are not being sold to British Gas.

Production from the ARCO-operated Welland field is scheduled to start at the beginning of October 1990 and AGAS will re-sell ARCO's share of the direct sales gas to satisfy part of the substantial demand from the industrial and commercial sectors. AGAS is currently finalising sales agreements with several customers.

This deal is a key to implementing AGAS' strategy to purchase and market gas in the UK. Alan Marshall, Managing Director of AGAS, said: 'We are delighted to sign this agreement with ARCO because it emphasises the independence of AGAS and puts us into business. Customers now have a new alternative to purchasing from British Gas or other producers.'

Bruce plan approved

BP Exploration announced that the £1,500 million Bruce Field development plan has been approved by the Department of Energy.

The Bruce Field lies in 120 metres water depth, some 400 kilometres north east of Aberdeen, spanning three northern North Sea blocks, 9/8A, 9/9A, and 9/9B.

The field contains an estimated 2·6 trillion cubic feet of natural gas and 220 million barrels of liquids (condensate and oil).

Soviet agreement

TEXACO Inc has announced that its subsidiary, Texaco Petroleum Development Company, has signed an agreement on Principles of Co-operation with the Ministry of Geology of the Soviet Union for proposed joint participation in the exploration, development and production of hydrocarbons — including development of areas of identified and established oil reserves — in onshore Soviet Union.

Texaco anticipates beginning a feasibility study this summer, focused on some areas of the Timan-Pechora region, located in the Northern European part of the Soviet Union, which could lead to the development of oil and gas fields with reserves estimated to be well in excess of five billion barrels of oil.

Labour MP calls for co-operation

MR FRANK DORAN MP, Labour's Shadow Spokesman on oil and gas, has called for offshore employers to assist in a ballot to help stop the 'wildcat' strikes by North Sea contract workers.

He said there was no good reason why the employers should not accept the result of a ballot organised by seven unions representing some of the 4,000 offshore workers.

Mr Doran said the way to solve an industrial relations problem is with better management and a vital part of any good system of management is the ability to motivate the workforce.

Speaking last month in London, Mr Doran said: 'The continuing refusal of all offshore employers to assist in a ballot smacks of fear of the outcome. There is no good reason why the views of the workforce offshore should not be tested. A ballot would confirm one way or another what the workforce wants.'

Mr Doran also called for the operators to examine the reasons for the dispute. 'Not in a defensive or confrontational way, but in a genuine attempt to understand how it is that so many of the workforce have reached the stage where the only option which they see is industrial action.'

The unofficial stoppages began at the end of July when workers called for union recognition and for the transfer of responsibility for offshore safety from the Department of Energy to the Health and Safety Executive.

Because of the stoppages some operators have been forced to abandon a number of the £750 million maintenance programmes needed to meet new government safety regulations.

Flotta flows

OCCIDENTAL Petroleum (Caledonia) Ltd confirmed that the successful repair of the Claymore/Flotta pipeline has enabled seven North Sea oilfields to resume oil production at the initial rate of 40,000 barrels per day (b/d). The throughput of oil into the Flotta pipeline system will increase gradually over the next few days to the normal average of 200,000 b/d, equivalent to 11 percent of UK oil output.

Production was halted for eight days to allow the replacement of a four-mile section of pipe following an "intelligent pig" survey of the 112-mile pipeline.

Conoco research

SINCE early July, scores of domestic and international geologists, petroleum engineers and other oil field experts have been working around the clock staffing two drilling rigs three miles east of Newkirk, Oklahoma. But they're not interested in finding oil!

Conoco have brought together one of the largest international group of oil companies, oilfield-service companies, institutes and universities ever assembled to enhance research in geological formation evaluation and drilling through the sharing of ideas, information and resources. Don Whitfill, director of Conoco's reservoir and recovery research division said: 'After several months of discussion, planning and organising of a joint-industry project, we began this month a 40-day, $1.5 million project that will allow 52 participants to do research in areas of mutual interest.'

Shell merger

SHELL have amalgamated their two bulk LPG operations — Shell Gas and Britannia Gas into one company, with Immingham as its Head Office.

Positive outlook for UK

NEW energy minister Colin Moynihan said he had confidence in the potential of the North Sea to ensure that Britain remains a major force among world oil producers for many years.

Speaking during a visit to ONS in August, he commented on just how good the prospects are for the UK offshore supplies industry.

'We expect 1990 to be a record year for exploration drilling,' he said. 'So far this year, there have been 15 significant discoveries announced.

IEA announcement

THE International Energy Agency (IEA) said that it expects world commercial oil stocks to suffer a 'large' drawdown in September, before a recently agreed increase in Organisation of Petroleum Exporting Countries (OPEC) oil output becomes significant.

It added that, while higher OPEC output would be generally evident in October, the IEA expects that a further commercial stock draw will be necessary to balance the market in that month.

The IEA also forecast that the world oil market will become 'increasingly tighter' during the winter months, which are historically peak oil demand months, despite higher OPEC output, stock draws, and a drop in demand.

The agency pointed out that the crude likely to be produced to make up for the shortfall in Iraqi and Kuwaiti oil will be slightly heavier and of a slightly lower sulphur content than the crudes they will replace.

Survival centre

A NEW survival training facility for North Sea oil workers is to be built in Dundee. The RGIT Survival Centre which, at its Aberdeen headquarters, trains up to 15,000 offshore personnel in the UK sector of the North Sea each year, is to operate Britain's first freefall lifeboat training system.

The £700,000 project will be situated at the Centre's existing facility at the Tidal Basin near the mouth of the River Tay.

Repsol invest

REPSOL SA, along with its newly formed subsidiary Repsol (UK) Ltd, have announced that they are to make their first major capital investment in the UK following the acquisition of Carless Refining & Marketing Ltd and Carless Petroleum Ltd in August, 1989. The major part of the £5m expenditure will be devoted to a new three column vacuum distillation unit in Harwich, capable of handling a range of feedstocks from 30°C to 550°C.

Jimmy Hay talks to *Petroleum Review*

'We are not even halfway through the lifespan of the North Sea'

The future of North Sea exploration and production looks a lot rosier thanks to the latest advances in oilfield technology. Improved seismic techniques, better drilling practices and the introduction of lighter, better designed platforms could greatly enhance the chances of finding new deposits of oil and gas in the UKCS.

Safety offshore is another area of paramount importance, especially with the imminent publication of the Cullen report on Piper Alpha and the recent 'wildcat' strikes by offshore workers.

In an interview with the *Petroleum Review* in September, Mr JTC Hay, General Manager, UK Operations, BP Exploration, talked about the major changes his company faces in the North Sea and his confidence in meeting the challenges of the future.

Carol Reader: Have the recent 'wildcat' strikes by contract workers interrupted production in the North Sea?

Mr Hay: Well, I can obviously only answer for BP but when the 'wildcat' action started we had two platforms shutdown for various maintenance and safety related work. We managed to get those back up — one without any delay and the other with only a few days delay. So there was no significant loss in production. As far as other operators are concerned I am not sure what the situation has been but, as far as I am aware, there has been no major interruption in UK production.

Will the strike affect your maintenance schedules? Will they delay the installation of emergency shutdown valves, required by the Government to be in place by the end of December? What will happen if BP, or any other company, does not meet that deadline?

Taking those as three separate questions. First of all our normal maintenance schedules are basically unaffected by the strikes because most of our regular contract workers on platforms, including the long term maintenance people, have been working quite normally.

As far as the installation of emergency valves is concerned we have been making good progress on most of the installations, but we may have one or two platforms where we may possibly face problems meeting the end of year deadline. Much depends on the construction workers quickly resuming normal working.

There have been continued and continuing claims from the workers that they are taking action over improved safety, but without being specific at all. We have had no mention of any specific safety related work they would wish to see done. It is ironic that it is safety related work which is being primarily affected by this action. If we get to the situation where we are not going to be able to complete the work within the period, then obviously we will need to have discussions with the Department of Energy. However, I could not in any way prejudge what the Department of Energy might say as a result of those discussions.

Is an official strike a possibility now?

It appears that the trade unions are proposing to take a ballot of some unspecified work force. I would have thought that the most likely outcome will eventually be some form of discussion between the employers and trade unions, but only time will tell.

What is the immediate effect of recent events in the Middle East on BP's North Sea operations? What policy changes might follow?

From the point of view from our actual activity, it has had no effect at all. As regards what policy changes might follow in the present circumstances I could not foresee any significant changes. However, should the situation deteriorate the government might possibly wish to examine what could be done to enhance North Sea production. But that is a matter for government to decide.

The oil business has been described as the high technology industry — what do you consider to be the most significant technological development in recent years?

I have considered this for sometime and I have thought long and hard as to what really significant individual technology has developed to make significant changes and I come down to

three main areas of development.

Firstly, there have been tremendous advances in recent years in the detail that can be obtained from seismic — that is 3D seismic. You really can see detail now that we would never have thought possible a few years ago.

Another area where there has been tremendous development is in drilling. We have been able to use a variety of improved technologies to enhance our drilling performance — downhole drilling motors, improved metallurgy, improved equipment, improved technology in the guiding and steering of wells, improved qualities of mud — we have introduced a technology with a broad capability that really is tremendous. We are now able to drill huge distances away from platforms, drill horizontal wells over quite significant lengths getting on for half a mile horizontally. We have seen wells drilled to angles and to distances from the platform we never thought possible. I am talking about three miles away from platforms not being anything untoward. This means, for example, in some of the fields that were developed with three or four platforms in the early stages of the North Sea, could now be developed with one or two platforms.

The final area of technology I think has improved quite considerably is in processing fluids. We are finding better ways of processing fluids without the same bulk of equipment which we needed in the early days. In this way we can now produce fields with half the topside weight we might have considered at one point — an enormous saving. The other major development offshore is the introduction of heavy lift vessels. Nowadays you can complete the module, hook it up and actually commission much of the module onshore before it goes offshore, saving an enormous amount of time and effort.

How about unmanned platforms?

Yes, we have, as you are aware, developed the Amethyst gas field with unmanned platforms, the intention being that we look at future developments in the oil producing area again for unmanned platforms. That is our stated intent, one we are going to pursue quite hard. The problems in dealing with oil as opposed to dealing with gas are much greater, a more complicated process is required to produce it and there are more systems needed to control that whole process. Our aim would be to have unmanned stand-alone oil installations offshore

Mr JTC Hay

within this decade. We would still need to visit and still need to maintain them, but at least we would not have people on some of our installations permanently. I do not know whether that can be done in all cases or not but I would hope that we can do it in some.

The other thing we are looking at is the ability to continue producing at quite low rates both for individual wells and as a field. Say a field has to be shutdown at 12,000 barrels a day because of present operating costs — if we could halve the operating costs we would be able to produce at a level of 6,000 barrels a day. This might be another two or even three years of production and that would all be incremental recovery. So these are a few examples of a whole range of things that we are tackling. The terrible fact is that for all the oil in place in a reservoir rock in the North Sea, I would think that on average across all the fields, we will probably only recover around a third, maybe 40 percent. So there is all that oil still sitting down there and it is a tremendous challenge to win more oil from these reservoirs.

What steps has BP taken to improve safety offshore since Piper Alpha?

Well, immediately following the Piper Alpha tragedy we instituted a major incident prevention and containment study. A team of experts with the necessary knowledge of engineering, safety and offshore operations visited all our installations in the UK and Norwegian sectors and looked very thoroughly at them, examining equipment, operational techniques and how people operated. They made a number of recommendations — some we picked up on, have subsequently come through from the Department of Energy. One of the key areas we identified was the relocation of valves. We also identified the need to install fire protection in some places. An enormous amount of work was done on the whole issue of safety and that has brought about changes, both mechanical and procedural, to ensure that we have an even more fail safe system than we thought we had. We are also looking to improve training. So there is a whole plethora of things that we are doing to further improve safety. It is a fundamental aspect of how we operate, everything we do must be done safely and we must continue to strive to improve our performance in this important area.

Do you believe that the UK government is soon going to require the fitting of subsea isolation valves?

There has been some discussion about the fitting of subsea isolation valves. We, as a company, were asked by government on one of the reports following the Piper Alpha incident to look at all our pipelines and the interfaces between those pipelines and the platforms, to assess which of those interfaces would need or would be improved by having subsea isolation valves. We found, after having looked at all our pipeline/platform interfaces, that a number could benefit from fitting these valves. In other instances we have found that approaches other than SSIV's are equally effective. Using techniques such as Quantitative Risk Assessment (QRA) we looked at the broad aspects of improving the safety of people on our installations. After all it is people we are concerned about. What the government may do is unclear and we must wait to see Lord Cullen's recommendations.

'It is ironic that it is safety related work which is being primarily affected by this action.'

The new frontier areas in the area west of Shetland look set to present a formidable challenge. How is BP equipped to take on the challenge and

does the company intend to take a leading role? Is *Ocean Alliance* the only deep-sea rig that BP has available?

I shall take the second part first — yes, we intend to take a leading role. As far as the challenge goes — the challenge is not so much to make discoveries but to produce. We already have the technology to go out and explore in water depths in that environment. We have *Ocean Alliance* which with its dynamic positioning system can hold station in water depths of up to 6,000 feet without the use of anchors. We have another rig, on contract, the Santa Fe 140, currently drilling in over 2,000 feet of water. So we have the capability to go out and explore the seas off the west of Shetland.

We need, of course, to produce the oil once we find it. There, we have been looking at means of producing oil without having to have fixed installations. We have the SWOPS vessel *Seillean,* that is currently producing from the Cyrus field. Currently that vessel would not be able to operate in very deep water because of the limitations of the riser. But that type of technology could possibly be applied. We have also been progressing with the DISPS type technology. This is a diverless subsea production system which we envisage being able to install and operate in very deep water certainly to 2,000 feet. So, yes, we believe we can do the drilling and exploration, the testing and we believe we can develop the systems in order to produce the hydrocarbons we find.

A recent UKOOA report indicated that activity on the UKCS is only halfway through its lifespan. One area that seemed to present scope for upstream companies was the use of new technology to improve oil recovery. What new methods does BP envisage?

I would agree with the UKOOA report but I would modify it slightly. I would say that we are not even half way through the lifespan of the North Sea. We have been going now for only 25 years and we will certainly see that and probably as much again. As to the use of new technology to improve oil recovery. There is a lot of work going on in our research centre at Sunbury looking at the physical process of oil flowing from the reservoir through into a well bore, however, that is an area which will be looked at in the future.

Currently recovery can be improved in a number of ways. By improving the rate at which oil or gas or formation fluid will flow from the reservoir rock into the well bore. We have been very successful at fracturing the Ravenspurn South reservoir and expanding the channels that allow gas to flow into the well bore and we have put a lot of effort into that. Once we get the fluid to the well bore there are mechanical methods we can use to get it to the surface. Gas lift is one route that we are adopting. In the Forties, Thistle and Clyde fields we are installing gas lift equipment. We also have a lot of experience of using electrical submersible pumps to produce and recover oil from the Beatrice field. We also have pumps on the unattended Forties Echo platform as well, and we would look to install those pumps in other fields. This allows us to continue to produce the reservoir below the pressure at which it would flow naturally and therefore we can continue producing.

'We have the capability to go on and explore the seas off the west of Shetland.'

A comprehensive rationalisation of BP's assets in the North Sea is taking place, but BP's exploration activities in the North Sea are said to be at record levels. Is this true?

Yes, this year we will have drilled more exploration wells, both as operator and as non-operator than we, as a company, or as BP/Britoil, combined. The total number of spuds both operated and non-operated during 1990 is just something under 90 wells. As operator we have spudded some 40 odd wells. I am not aware of the whole North Sea programme but references from government figures show there may be 200 wells spudded in 1990. We will have participated in between 40 and 50 percent of all the wells drilled.

Is BP's first priority now to concentrate on developing and expanding its gas interests in the North Sea rather than oil?

No, obviously, we believe that there are enormous opportunities in the gas market, but oil will remain an important part of our business.

How is your company aiming to 'clean up' its offshore operations — in an environmental sense? What about cuttings — is onshore disposal prohibitively expensive?

We intend moving to a situation where we are not putting oil contaminated cuttings onto the seabed at any exploration location. The possibilities we are looking at to deal with this include: the development of new muds, looking at improving ways of cleaning cuttings offshore and the possibility of subsurface disposal. Bringing cuttings back to shore within the North Sea is hazardous business, loading and unloading at any platform is not easy. Another area we are pursuing is the alternatives to oil based mud. We are also pursuing the cleaning option but our intent is that we shall not put oil contaminated cuttings into the sea. Another area where we intend to improve our environmental performance is in the use of halons. Halon is used as a fire and explosion suppressant on certain of the modules on offshore platforms. It is very efficient, very effective but unfortunately appears to cause problems in the upper atmosphere. Because of that we are looking at alternatives.

The Miller and Bruce fields will be brought on stream in 1992 and 1993. I understand that the construction stage will have an operational input. What is the purpose of this? Does it mean that precommissioning work is done in the yard?

Yes, I mentioned earlier that large modules and heavy-lift cranes allow a lot of precommissioning in the yards. But what we are looking to do in Miller and Bruce and all future fields is improve our operations experience input to those new fields. We have experience of operating existing fields and we are trying to improve the feedback from that experience into new fields. I think we are now becoming quite successful at that. It is important that when we bring a new field on that it is easy to operate and operates in a cost effective and safe manner. We don't want to acquire from our projects group facilities which are too complex, or difficult to operate. So our input helps not only them, but we can, to a degree, make our operation more cost effective. ■

The economic consequences of higher oil prices

By Brian Pearce, Chief Economist, Ernst & Young ITEM Club

Iraq's invasion of Kuwait and the subsequent threat to the world's oil supplies has taken the price of Brent crude over $30 a barrel, a rise of 80 percent over the $17 a barrel which had been the average since 1986. This represents a sharp blow to the OECD and non-oil developing economies, not to mention the newly-emerging Eastern bloc but it should be seen in perspective. The 1979 shock when the Shah of Iran was deposed, which tipped the world into recession, took oil prices up by 275 percent.

Higher oil prices act like a tax on the oil importing economies, transferring income to the oil exporters. Spending will be cut in the oil importing economies but if the oil exporters increase their demand for overseas goods, then output and employment may not fall in the OECD. Prices will be raised by higher energy costs but the extent to which this leads to an inflationary spiral depends on the response of the world's monetary authorities.

Oil importers — less vulnerable

Most oil importers are now much less vulnerable to oil price shocks than they were in the 1970s. The massive rises in oil prices have led to the development of substitutes and more energy efficient capital goods. The largest improvements have been in the United Kingdom, where energy intensity (oil used per unit of GNP) has fallen 44 percent since 1973. Most of this improvement is due to efficiency gains, although some may be due to the shrinkage of heavy manufacturing in the severe 1980–81 recession. Japan has reduced its energy intensity by 37 percent after suffering very badly in the previous oil price shocks and now uses only half the oil used in the United States to produce a unit of GNP. Within continental Europe the biggest improvements have been made in Italy, West Germany and France. Spain has actually increased the oil it uses to produce a unit of GNP as it rapidly expands its industrial base since joining the EC.

So clearly the demand for oil is responsive, or elastic in economists' jargon, to changes in the price of oil over a period of years. Once this occurs OPEC and other oil exporters lose the extra revenue they sought by raising prices. Saudi Arabia is very aware of this and acts as swing producer to try to maximise revenues in the long term by keeping prices low enough to discourage substitutes and efficiency gains.

The responsiveness of oil demand to price increases has risen in recent years, it is possible for the generation of a certain amount of electricity to be switched quickly from oil powered to coal or nuclear powered stations. But it is not possible to switch quickly to more energy efficient equipment in manufacturing. Nor is it possible for households to switch quickly from oil central-heating or to gas-powered cars. So in the short term the demand for oil is relatively fixed and oil consumers pay a larger proportion of their budgets for their oil needs.

Inflationary consequences vary with energy intensity . . .

A measure of the extent to which the increased oil bill will affect an economy's costs and price inflation is given by its energy intensity. Despite increases in efficiency in the last 15 years, the most vulnerable OECD economy is Canada which uses 25 percent more energy per unit of output than the United States, because of its relatively cold climate and concentration of heavy industries. The United States itself is also relatively inefficient in its use of energy and vulnerable to the oil price shock. Japan uses less than half the energy used to produce a unit of output in the United States, which belies the popular belief that Japan is worst affected by oil price rises. The United Kingdom and continental Europe have similar energy intensities, and therefore similar cost rises, to Japan with the exception of Spain and some of the southern economies, which are developing their manufacturing industries in an effort to catch up with northern Europe.

The first and most direct effect of higher oil prices is to increase the cost of living and retail prices through higher petrol prices. In most OECD economies petrol accounts for 3–5 percent of a typical households budget. So, in the case of the United Kingdom, where petrol prices have risen 16 percent from £1.99 a gallon to £2.30,

households will find their budgets available for buying other goods and services cut by 0.5 percent. Higher costs for domestic fuels will double this erosion of purchasing power, more so in colder regions such as Canada.

A second impact on inflation is for higher oil prices to put up the costs of commerce and industry, particularly in manufacturing which is an intensive energy user. In the United Kingdom, Japan and continental Europe, manufacturing industry typically faces an oil bill representing 5 percent of total costs. A 20 percent increase in industry's fuel costs would raise total costs by 1 percent. The extent to which this can be passed onto final consumers will depend upon the state of the market and level of capacity utilisation. It is more likely to be passed on fully in a booming home market like West Germany than a depressed market like the United Kingdom, where increased costs are more likely to be absorbed by reducing profit margins. So after some delay, and to varying degrees, the cost of living and retail prices will be boosted further by higher factory-gate prices of manufactured goods.

There may then be the problem in many economies that employees will seek to restore their eroded real incomes by asking for higher wages. This is what happened after the first oil price rise in 1973 and contributed to a long and damaging period of high inflation in the OECD. The problem is that employees in oil importing economies cannot restore the real income loss caused by the rise in oil prices, because the income has been transferred overseas to OPEC and the oil exporters. If companies pay the higher wage demands this will only lead either to higher prices, or lower profits and job losses. In both cases the employee's real income is not fully restored as higher wages are offset by higher prices or unemployment. Even if the company accepts lower profits and does not cut back its workforce, it will cut back non-viable investment, reducing employment in the capital goods industries. Both households and companies will suffer losses to their incomes and profits. The distribution of the loss being dependent upon the extent to which employees gain higher wages and the extent to which companies can pass on cost increases.

. . . and the monetary authorities' response

Of course there is the serious danger that this could all lead to a damaging wage-price spiral, of the kind experienced in the mid-1970s. After the first oil price shock in 1973, the OECD governments and monetary authorities sought to offset the recessionary consequences by expanding budget deficits and money supplies. This accommodation of cost pressures, accentuated by a wage push, led to the damaging period of high inflation. By the time of the 1979 oil price rise, the authorities had changed their priorities and immediately tightened economic policies, rather than loosen them, in order to prevent an inflationary spiral. The cost of which was recession.

Brian Pearce

The overriding economic policy aim in the OECD is still to reduce inflation, and the monetary authorities will undoubtedly react to the current rise in oil prices by increasing interest rates. The exception may be in the United States which is close to recession already. In general the reaction of the authorities will be crucial to limiting the rise in inflation in the OECD economies. The constraints on the Federal Reserve will mean that inflation will rise further in the United States than in Europe or Japan.

One influence on the distribution of the inflationary shock within the OECD economies will be the movement of exchange rates. The rise in oil prices has already led international investors to push up the exchange rates of Canada and the United Kingdom, both oil exporters, and Australia, an energy exporter. The US dollar and the Spanish and Italian currencies have all been weak, being particularly vulnerable to higher oil prices, or not perceived to be willing to raise interest rates. The higher a country's exchange rate, the smaller will be the inflationary impact of higher $ oil prices, as non-oil import prices will be reduced and there will be some offset in the domestic currency price of oil. Where the exchange rate is weakened, such as in the United States, Spain and Italy, the inflationary impact will be accentuated by higher prices for both oil and non-oil imports.

Economic growth will fall

The impact of GNP and unemployment within the OECD economies will depend on a number of factors. First of all, there is an income loss in the oil importing economies affecting households and companies to varying degrees as already discussed above. Households may in the first instance draw on savings or increase borrowing to maintain consumption, but fairly quickly consumer spending will be cut as real income losses are perceived to be permanent. Similarly, companies will initially maintain investment plans and their workforce by borrowing to cover their larger financial deficit. However, they will also reduce their expenditure on investment, inventories, dividends and

	Oil balance 1989 % of GNP	Energy consumption 1989 US = 100	Energy consumption % change 1973–89	Oil as % of energy consumption 1989	Exports to OPEC as % of total 1989
Net oil exporters					
Canada	+0.3	125	−21	31	1.1
United Kingdom	+0.1	46	−44	40	4.7
Net oil importers					
Australia	−0.3	80	−8	34	3.6
Japan	−1.1	48	−37	56	3.5
France	−1.1	45	−26	44	3.4
West Germany	−1.1	48	−31	41	2.1
United States	−0.9	100	−26	40	3.3
Spain	−1.6	63	+9	54	3.3
Italy	−1.4	50	−35	61	3.3

Table 1

Source: The Economist

	OECD	US	Japan	W Germany	UK
Economic growth					
1989	3.4	2.5	4.9	4.0	2.1
1990 (f)	2.5	1.0	4.8	4.1	1.6
1991 (f)	2.2	1.3	3.5	2.7	2.4
Inflation					
1989	4.6	4.9	2.3	2.8	7.8
1990 (f)	4.8	5.1	2.6	2.7	9.2
1991 (f)	4.3	4.9	2.3	2.3	5.5

Table 2 Source: Ernst & Young ITEM Club

employment after a period of time. Clearly output is going to be lower and unemployment higher.

The extent to which growth is reduced within the OECD will vary according to how dependent each economy is on oil imports. Economies like Spain and Italy are relatively large oil importers (over 1.5 percent of GDP) and so will suffer the largest transfer of income to OPEC and the largest losses to GDP. Although the United States uses twice as much oil per unit of GNP as Japan or northern Europe, it can partially supply its needs from domestic supplies and so imports a similar amount of oil to Japan and northern Europe (all between 0.9–1.1 percent of GNP). These economies will all suffer a similar income loss. A different case again is presented by Canada and the United Kingdom who are both net oil exporters. These two economies suffer no income loss overall and in fact are small net gainers. Because of the tax systems, particularly in the United Kingdom, the government are the main income beneficiaries. In principle the government could offset the income losses suffered by households and companies by cutting taxes or increasing grants. In which case GDP would not fall and unemployment would not rise.

The actions of the government and monetary authorities are also crucial for the GNP consequences of higher oil prices as they are for the inflation consequences. Although the governments of the United Kingdom and Canada could prevent unemployment rising by relaxing fiscal policy, this is not likely. The overriding consideration will be to reduce the inflationary impact which will generally involve higher interest rates. The exception may be in the United States where the economy is very close already to recession. The Federal Reserve is widely expected to cut interest rates to prevent the economy slipping into recession, in which case the rise in oil prices may not lead to lower GNP in the United States, although inflation will be higher. The Canadian economy is also very weak and the monetary authorities may choose to delay any interest rate cuts they were planning until next year. However, the economies of Japan and continental Europe are booming and interest rates will go sharply higher. In these economies the reduction to GDP and the rise in unemployment caused by higher oil prices will be much greater, as interest-sensitive spending such as fixed investment is discouraged.

OPEC winners

So far we have only considered the reactions of the oil price losers. The winners in OPEC will benefit from a large income gain at least in the short term. This can either be saved by placing it in financial assets or it could be spend on imports. After the first oil price shock in 1973, the OPEC economies, with small populations and undeveloped economies, were in no position to be able to spend their windfall income gain, and so there was a sharp fall in world trade as the oil money was placed on deposit in London and elsewhere. Since then the OPEC economies have industrialised and hugely increased their ability to spend. So some of the loss of output in the OECD from lower domestic spending will be offset by higher OPEC demand for OECD goods. Best placed to gain from this will be the United Kingdom which exported 5 percent of its goods to OPEC in 1989. Less fortunate is Canada who only sold 1 percent of its goods to OPEC.

To summarise, the inflationary consequences of higher oil prices vary with energy intensity — Canada, the United States, Australia and Spain lose out. The inflationary consequences also vary according to the response of the monetary authorities in which case the United States, Canada and the United Kingdom suffer. With the likelihood of a wage price spiral, Spain and Italy are vulnerable. The output and unemployment consequences of higher oil prices are dependent on the size of net oil imports — Canada and the United Kingdom benefit, while the United States, Japan, Germany and France lose equally and Spain and Italy are worse off. They are also dependent on the response of the monetary authorities where the United States benefits, Canada and the United Kingdom do not suffer and where Japan and continental Europe suffer further losses; and finally on the exposure to higher OPEC imports, where the United Kingdom gains and Canada is badly placed. The overall impact is to move the OECD close to recession. This may well occur in the United States and the United Kingdom but Japan and continental Europe will remain buoyant.

The US Strategic Petroleum Reserve: politics prevail

By Judith Gurney

The current Middle East crisis has clearly demonstrated that it is easier to mandate the building of government stockpiles of oil than to decide to draw them down. Despite the widespread conviction that there is not enough spare production capacity to compensate for the loss of 4.3m b/d of Iraqi and Kuwaiti oil in the coming winter months, internal US political factors far outweigh market forces in determining not only when and if the US Strategic Petroleum Reserve (SPR) is used but also, to a large extent, who will benefit. Although the SPR was established to "fulfil US obligations under the international energy programme," according to the Department of Energy, SPR crude cannot be exported from the United States. Apparently the only way that the United States could contribute to the International Energy Agency emergency allocation programme would be to turn away crude cargoes destined for the United States and designate them for alleviating shortfalls elsewhere. It is difficult to imagine that the government would, or could, exercise the amount of control in commercial oil dealings needed to effect this type of manoeuvre.

Building the SPR

The creation of a government oil reserve was authorised by Congress in 1975, following the 1973–74 oil embargo. Although a one-billion barrel SPR was originally planned, its size was subsequently downgraded to 750 million barrels, largely because of costs. Funding the SPR requires annual appropriations, and to date these have totalled more than $19 billion, an expenditure which has been the subject of recurrent heated discussions in budget debates.

Although the first government purchases of crude occurred in 1977, filling the SPR did not begin in earnest until the early 1980s. The fill rate since then has been erratic, reflecting, to some extent, the price of oil which, it is believed, reflects the danger of supply shortages. During 1981, when oil prices were high, the average daily fill rate was 336,000 b/d. In 1985 the fill rate was 199,000 b/d, and in 1989, 56,000 b/d. Although much of the oil was purchased on the spot market, a considerable quantity was bought on contract from Mexico as part of a financial rescue package. By the end of 1989, the SPR contained 580 million barrels of oil, of which some 388 million barrels were sour, largely Mexican, crude.

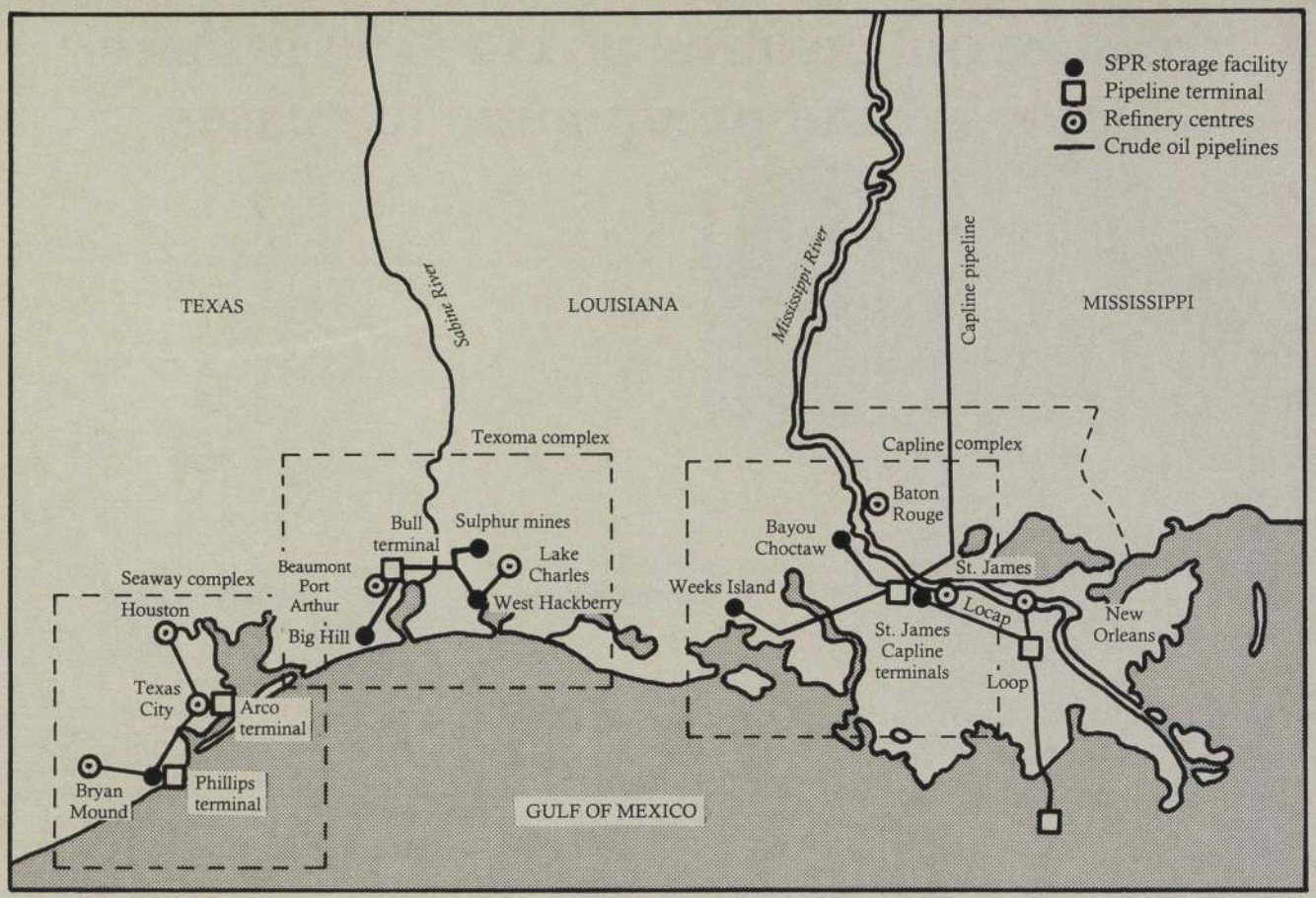
The SPR is stored in salt dome caverns, each typically about 200 feet in diameter and 2,000 feet high, constructed by piping in fresh water to dissolve the salt contained therein. The stockpile, maintained by a private company under government contract, is held in six locations in Texas and Louisiana, along the Gulf Coast. The storage facilities include:

- Big Hill, Texas, currently under expansion, which will contain 14 caverns.
- Bryan Mound, Texas, with 20 caverns.
- Bayou Choctaw, Louisiana, with six caverns.
- West Hackberry, Louisiana, with 22 caverns.
- Weeks Island, Louisiana, a previously existing salt mine.
- Sulphur Mines, Louisiana, with three brine caverns. It is planned to decommission this facility in 1992, due to the instability of its structure.

Three distribution systems connect these storage facilities, via government-owned pipelines, to commercial crude oil pipeline networks, as well as to commercial and government-owned marine terminal distribution facilities.

Drawdown and distribution

The plans for extracting oil from the salt dome caverns involve pumping water through pipe systems at the bottom of the caverns to force the oil to the top where it can be pumped out. The Department of Energy's projected drawdown capacity is currently 3.5 mb/d. Many experts, however, even within government circles, dispute this figure, noting that there has been only one major test of drawdown and distribution since the inception of the SPR. They argue that the salt caverns cannot be treated as normal petroleum storage tanks, and point out that the



Source: U.S. Department of Energy, "Strategic Petroleum Reserve, Annual/Quarterly Report"

Figure 1. Strategic Petroleum Reserve complexes and associated pipelines and terminals

system has been dogged by technical problems, notably corrosion. There is general agreement that there is a limit to the number of times that caverns can be filled and emptied and that the drawdown rate will decrease rapidly as inventories become depleted. Security is also a concern for successful drawdown because of the remoteness and geographic dispersion of the SPR storage facilities and the commercial nature of the privately owned marine terminals in the distribution system.

By law, only the President can authorise a SPR drawdown of stocks to be sold by auction, although the Department of Energy can decide on the number of auctions to be held over the course of a drawdown. It is anticipated that a Notice of Sale, specifying the type and location of crude being offered in an auction, can be issued within 24 to 48 hours of a Presidential Decree, and that the Notice will allow seven days for the submission of bids. The winner will be notified by the 16th day after the Notice of Sale, and delivery is expected to require at least another 15 days. Non-US companies are effectively discouraged from bidding by the Jones Act, which mandates that only American-flag tankers can move oil between American ports.

'By law, only the President can authorise a SPR drawdown of stocks to be sold by auction.'

Timing will be crucial

The government cannot wait until the last minute to decide on a drawdown because delays in the auction process, and technical problems in drawdown and distribution, could reduce the effectiveness of the SPR in meeting a sudden shortfall. To some extent, the effect of such delays could be overcome by government allocation of some of the reserve. By law, the government can forgo the auction process and directly allocate the distribution of up to 10 percent of the SPR holdings. To do so, however, could have serious political repercussions if it appeared that any given oil company was receiving government favour.

In addition, a large drawdown over a short period of time could face long delays in reaching the product market due to bottlenecks in the refining process. More than 100 US refineries have closed for economic and environmental reasons in the past decade, reducing the national refinery capacity to 15.5 mb/d from 18 mb/d. As a result, existing refineries are now operating somewhere around 96 percent of capacity. Moreover, many refineries in the Mid West, unlike those in the Gulf, would not be able to handle large quantities of sour crude. The danger of a refinery bottleneck has been recognised by the Department of Energy which is currently trying to get legislation passed allowing it to swap some SPR crude for products in the Caribbean market.

The United States is not alone in hesitating to use its reserves. Of the other countries holding government reserves, only Korea has come to a decision to use them on a case-specific basis for refineries which were heavily tied to Iraqi oil. Japan, with its substantial reserves, Germany with its relatively small reserves, and Sweden with its very small reserves, are all waiting and weighing the consequences of drawdown decisions. ■

Pressure on gasoline production is main factor behind pump price increases

Four factors (two positive and two negative) have contributed to the recent UK petrol pump price increases:

- A sharp rise in the crude oil price
- An even higher rise in price of petrol vs. crude oil
- A strengthening in the pound/dollar exchange rate
- A reduction in the inland distribution and retailing margin made by oil companies

Figure 1 shows the contribution of these factors since tension started to mount and Iraq invaded Kuwait on 2 August.

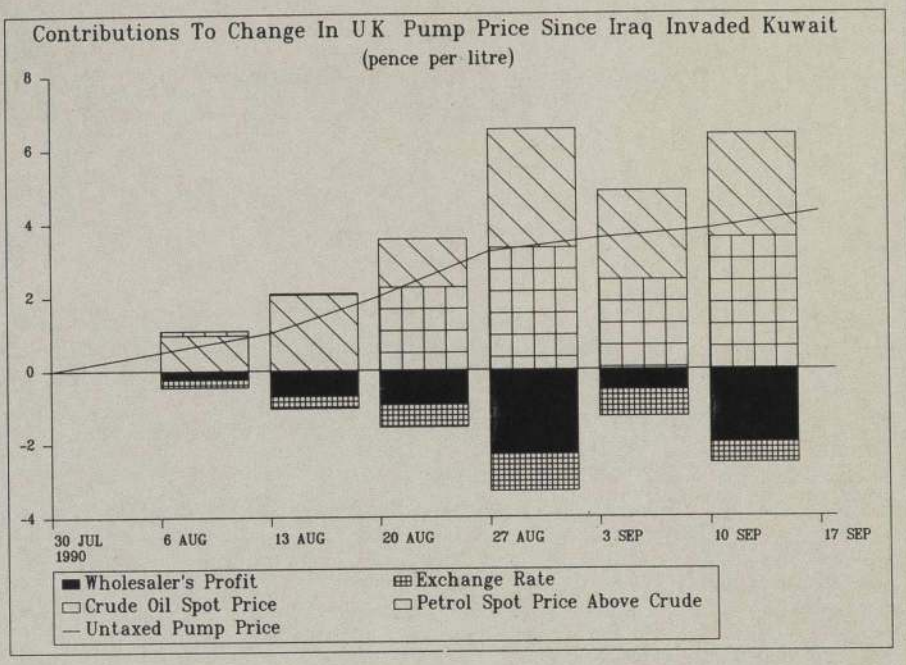


Figure 1

Rise in crude oil price

As the graph of the Brent price (a marker for crude oil prices) shows in **Figure 2**, the price of crude oil has risen significantly. This is a consequence of real fears and some panic over the supply of crude oil. We believe this has added 3.58 pence per litre to the pump price.

Strong increase in the gasoline spot price minus Brent crude price

On the Rotterdam spot market, the traded price of petrol has risen further than the traded price of Brent — see **Figure 3**. This is a consequence of several factors.

First, petrol supply and demand in the North Atlantic are finely balanced, and refiners run their petrol-making plants flat out to meet normal demand. They are rightly concerned that if crude oil were to stop flowing from the Middle East for a few weeks, they would not be able to make up the lost production, because they simply do not have the capacity. So the refiners are stock-building.

Second, many of the gasoline-making plants in Europe are scheduled to be shut down for maintenance in the next few weeks. This has aggravated supply concerns.

Third, supplies of petrol from the

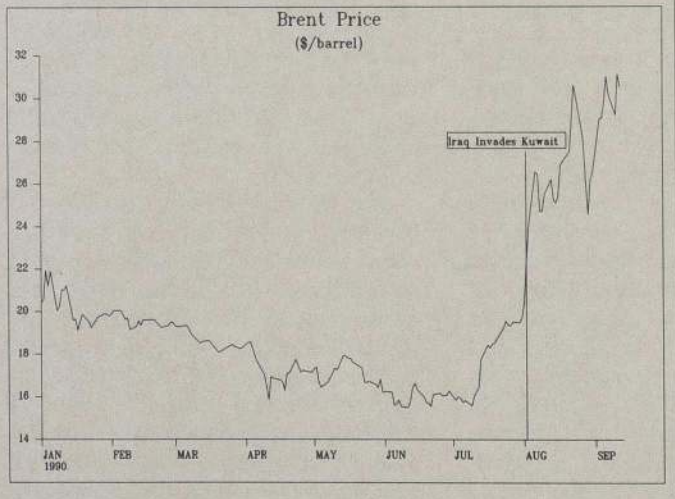


Figure 2

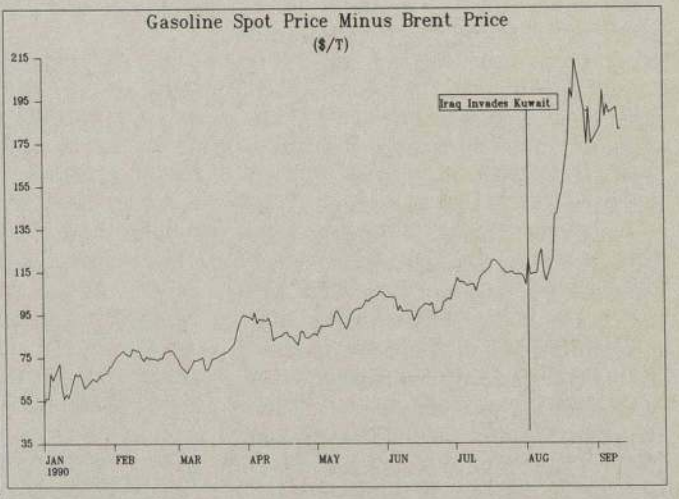


Figure 3

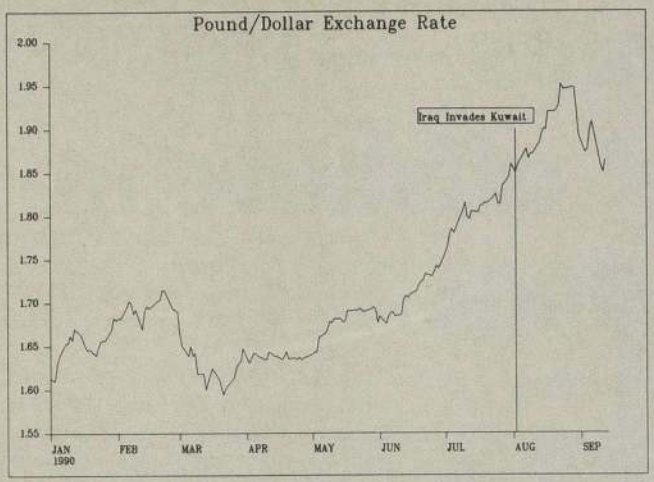


Figure 4

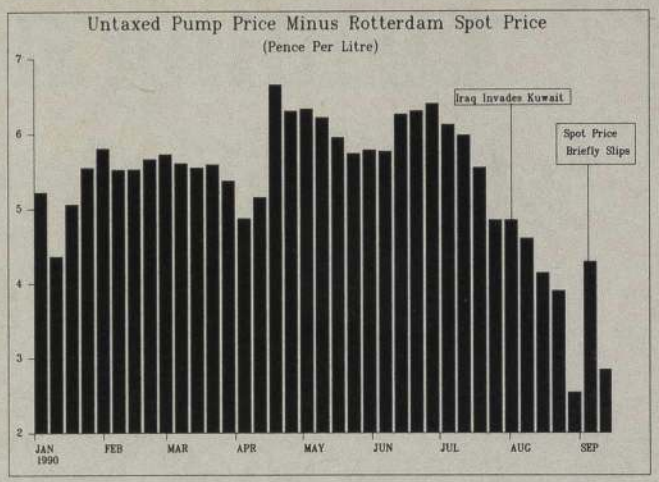


Figure 5

Middle East have been sharply reduced, as the embargo against Kuwait and Iraq bites, and the Saudis stockpile fuel for the military build-up. We believe the increase in the spot price of petrol above that of crude oil has added 2.79 pence per litre to the pump price of petrol.

The Rotterdam spot market is a free market which responds to supply and demand. When supply is restricted, prices will rise until the demand comes down or supply recovers. Unfortunately, motorists tend not to reduce their petrol consumption by much when the price goes up, so price is extremely sensitive to supply disruption.

Pound rises sharply against dollar

Offsetting these increases, the pound has risen sharply against the dollar, as shown in **Figure 4**. Oil is purchased in dollars and this movement in the money markets has helped the British motorist by 0.55 pence per litre.

Oil companies' inland margins cut

The last component is the profit the oil company takes to cover its storage, distribution and marketing costs. The graph shows that this has fallen sharply by 2.0 pence per litre (see **Figure 5**), contrary to conventional expectations. In fact this is quite normal when the spot price of gasoline increases. ■

Acknowledgement to the monthly report 'European Refining Activity' produced by WEFA Ltd, London.

Drilling fluids — the 'state of play' offshore in the 1990s

By Mark Scruton

Increased concern about the environment looks set to transform the way drilling fluids are used in the North Sea. The UK government is soon to bring in legislative measures which will further reduce the amount of oil allowed on cuttings currently discharged offshore.

These moves will be stepped up in 1994 by which time the government, in line with EC guidelines, intends to prohibit the discharge of all oil contaminated cuttings from single wells. Because of the planned measures the mud companies will have to come up with solutions to meet the 'green' challenge and so help to protect the environment of the North Sea.

Specifically the government intends to lower the limit of oil on cuttings to 100 grams/kilogram by 1992 from its present level of 150 g/kg and to reduce discharges from exploration and appraisal wells to zero by 1994.

Already these moves have brought about a flurry of research and development by drilling fluid companies to develop innovative mud systems which will meet the new requirements without affecting the drilling performance.

The green challenge

This is not the first time that mud companies have had to face the 'green' challenge. In 1988, a government directive to reduce oil on cuttings discharges to 150 g/kg resulted in a move from the average 80/20 oil to water ratio in muds to almost a 50/50 O/W ratio.

Chris Higgins of BW Mud, said: 'It is only five years ago that diesel was no longer used in oil-based muds. The change over to the more environmentally friendly "low toxic" base oils meant a major research push to develop new emulsifier packages to work in these oils. Base oils differ considerably in their ability to activate emulsifiers and other mud products and build a mud system.'

He added: 'Certain products which would emulsify in a "Brand X" base oil would not work in a "Brand Y" base oil. This has meant that not all systems are interchangeable in the way diesel muds were.'

However the driving force to reduce oil in muds has come from government legislation and mud companies have had to do a lot of research to find ways of eliminating the need to use oil in muds and are experimenting with different solvents or specially formulated water-based muds.

Oil-based muds (OBMs) are used specifically to suit particular drilling environments because of an interrelated mix of engineering, economic and safety reasons.

Non-aqueous fluid

The main reason for using an invert or oil based fluid is the maximum bore hole stability that can be achieved, in conjunction with proper pressure control through mud density. The additional stability may be crucial for highly deviated wells where the rock stresses are larger and more difficult to control with fluid density and the time period of open hole has to be extended because of extended drilling and greater drilled depths. Other advantages are apparent. The inert environment prevents the cuttings from hydrating and dispersing so they can be effectively removed by the solids removal equipment. Thus, good gauge holes are obtained and the need to dilute the fluid because of contamination by drilled solids is almost eliminated. The fluid, the high levels of surfactants and a stable hole tend to combine to give a high level of lubricity which reduces torque, and improves drilling conditions generally.

The non-polar nature of the fluid ensures that the system is generally insensitive to the chemical contaminations that affect water based systems such as salt, anhydrite, cement, carbon dioxide and hydrogen sulphide.

Another area where the inert nature of the fluid has advantages is in the drilling in stage and coring of oil producing zones, completion and work over situations. The fluids can be formulated such that the emulsions are extremely stable even to extremes of temperature. This property together with the lubricity and shale stability often makes invert oil fluids the system of choice.

The main problem with WBMS is that it can cause clays and shales to expand. Chris Higgins said: 'The end result for the operator is that a 16 inch hole can become only 8 inches in diameter and the cuttings can also expand and pack off in the hole, leading to possible stuck pipe.'

He added that to prevent stuck pipe the driller has to 'wipe' or pull the whole bottom hole assembly up and down to try to keep the hole in gauge.

'This obviously takes time and as the rig day costs are usually high, this wasted time increases the drilling cost of the well.'

Because oil does not react with clays and shales the chances of preventing sloughing and cavings are much improved, so ultimately saving the operator money.

Rig cost savings

Mud consultant Nick Cherbanich estimates that operators using OBM can make up to 15 to 20 percent savings on drilling time and so produce corresponding savings on rig costs.

But cost is not the only reason operators specify OBMs. The systems play a great part in overcoming engineering problems encountered downhole. By their very nature OBMs have a high degree of lubricity. This can enable operators to drill long highly deviated wells (70 degrees plus) including, most recently, production wells with 2–3,000 feet horizontal sections.

Chris Higgins said: 'This kind of well would be extremely difficult to complete successfully if a water-based mud had been employed.'

OBMs also improve the rate of penetration achieved during the drilling of a well, again primarily because of their ability to lubricate the hole and the bit.

They are also considered safer than water-based muds because of the inherent stability of the OBM system. The systems have proved to have a high tolerance to contamination, whether due to the influx of formation fluid or to the high solids content in heavy weight muds.

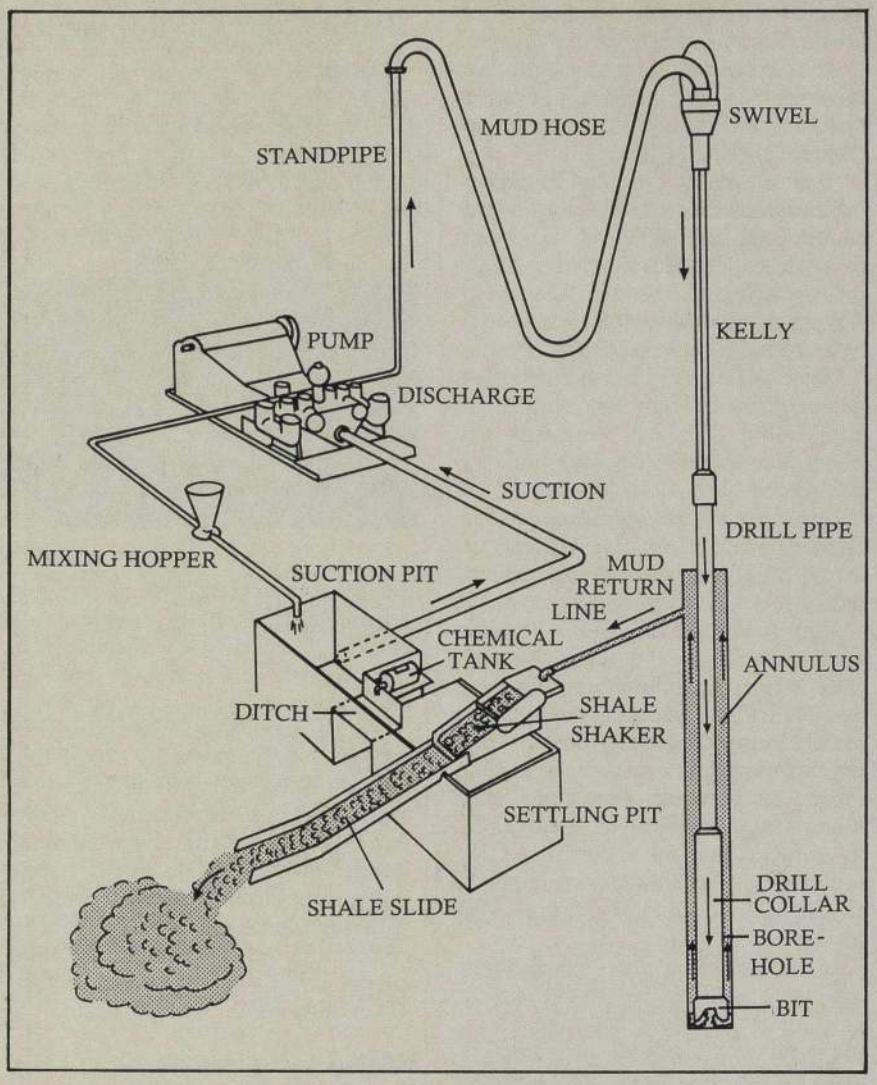
This tolerance has the advantage of removing the uncertainty of performance often exhibited by water-based muds which can make normal drilling operations, especially in high pressure areas like the North Sea, fraught with danger.

But OBM is not the 'be all and end all' as Iain Whyte of Aker Drilling Fluids points out: 'Some operators do opt for OBM in situations where water-based systems could do the job well. In many cases this stems from a lack of confidence in and understanding of the vastly improved WBMs available in the current drilling environment, while drilling practices and rig equipment are far superior than they were years ago. It is therefore the prerogative of the mud companies to increase operator confidence levels in the new range of water-based muds.'

Reduced oil levels

Since the introduction of the 150 g/kg rule in 1988, there has been a definite move to use less oil in their systems. Most companies seem to use the 50/50 systems in a bid to reduce oil retention figures on cuttings dumped into the sea.

However, circumstances vary. Tim Barr of International Drilling Fluids said: 'Where possible operators specify 50/50 oil/water ratio muds, but 40/60 systems are also being run on occasions. An estimate of the number of 50/50 muds (now being used in the UKCS) would be in the order of 60 to 70 percent of all OBMs.'



Components of a Fluid Circulating System

Chris Higgins added: 'The term 50/50 muds is now somewhat misleading. My company will design a mud system optimising the oil/water ratio within the constraints of the conditions expected in an individual well. This means the oil/water ratio may be as low as 40/60 or as high as 90/10. The oil/water ratio is not a fixed parameter. You may start drilling with a 50/50 ratio and alter to 60/40 as the well encounters changing conditions.'

Significantly all the companies which were consulted agreed that although the new systems had resulted in reduced overall discharges of oil to the environment, there was very little impact on costs. In fact, because of the lower oil content in the mud, they claimed it should be less expensive.

Alan Corbett of Milpark Drilling Fluids, said: 'By lowering the percentage oil in the fluid, you should affect the oil retention figures but it must be borne in mind that other factors combine to affect these results.

'Costwise the product selling price of the formulated mud should be less. However, as the fluid's limitations are reached, there is effectively an incremental increased cost to be applied from the need to use higher levels of emulsifiers.'

Safety margins

Additional costs have also been incurred because 50/50 systems are more difficult to run than 80/20 systems because of smaller margins of safety.

Malcolm Ellice, of Baroid, said: 'Maintenance and reconditioning requirements are similar to conventional oil muds but more experienced engineers are necessary to run 50/50 systems properly.'

He said that although he considered Baroid's system was very safe, 50/50 muds were susceptible if polyhalite sections with highly variable pore pressures were encountered.

Tim Barr said: 'The reliability of any

system is directly related to the skill of the mud company. This skill manifests itself in the appropriate application of systems, the skill in choosing the right system for the right formation and engineering skill offshore.

'It is true to say that mud engineering and the ability to choose systems to suit the project are skills that have been devalued with the advent of oil muds in the North Sea. Their stability has led to a sense of security by being a virtual panacea for all mud problems.

'The mud industry in the North Sea will have to relearn the skills of system application. This will be easier for international companies who market a plethora of systems worldwide.'

Chris Higgins was confident that 50/50 muds could be treated just the same as the 80/20 oil water ratio mix systems.

When asked if 50/50 muds were more susceptible to 'flipping' (a situation where the influx of fluids and gases downhole cause the mud system to fail), he said: 'This is a fallacy, 50/50 muds are not more susceptible to flipping. The very fact that water is a much larger component in a 50/50 mud means that the water/brine contamination has less effect on these systems than it would have on an 80/20 mud.

'Also the emulsifiers which these systems employ are far superior to the emulsifiers of five years ago. Well planning comes into this argument. If you expect to meet overpressures which will require mud weights of 15 to 16 pounds per gallon (ppg), you will not start drilling that interval with a 50/50 mud. If you did enter a situation where you are drilling with a 50/50 system and need to weight up the mud from say 11 to 16 ppg, the mud system is not going to fall apart. The rheology will increase significantly and once the well is under control you will have to adjust the oil/water ratio upwards to achieve a plastic viscosity and yield point to enable drilling to continue. But the other parameters such as high temperature, high pressure, fluid loss and emulsion stability are not going to "crater".'

Tim Barr claims the important factor was the amount of 'free' emulsifier available: 'Susceptibility to flipping is related to the amount of free emulsifier available in the system to cope with influxes of water. Assuming equal quantities of free emulsifier, an 80/20 system will be more "rheologically" stable for an equal volume influx of water when compared with a 50/50.'

Iain Whyte took the view that 50/50 muds were safe enough for normal applications. He said: '50/50 muds are safe enough in certain formations and where good drilling practices are employed. But they are unsuitable for high temperature and high pressure exploration wells.'

Alan Corbett said: 'No system can ever be described as being 100 percent safe in drilling terms if applied in the wrong drilling environment. Each system type can in turn carry the same level of risk if applied in the wrong drilling environment. Very broadly speaking there will be less impact by contamination or sudden formation changes with a higher oil content mud given other factors being the same.'

History of environmental changes

1988 150 g/Kg oil on cuttings

1992 100 g/Kg oil on cuttings

1994 'Zero' discharge on Exploration and Appraisal wells

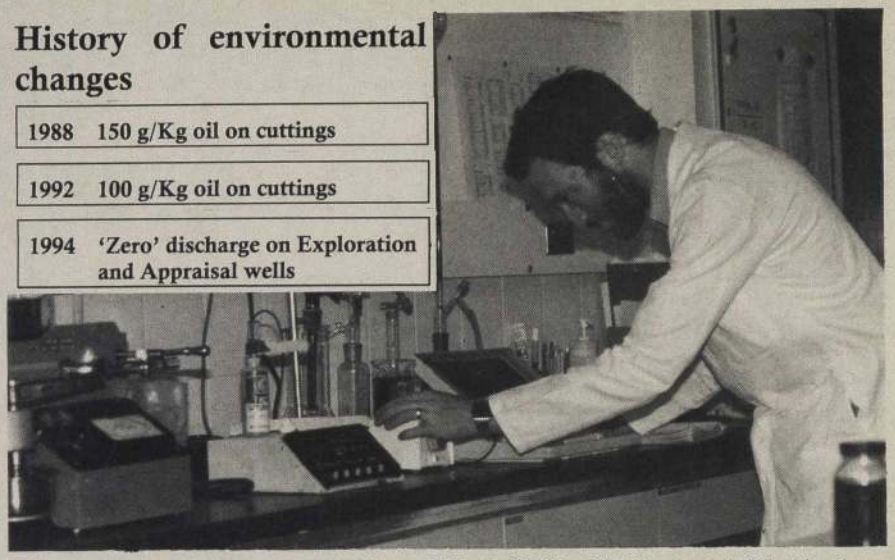


Photo: Milpark Drilling Fluids research lab, Aberdeen

Other methods

Reducing the amount of oil is not the only avenue that mud companies are exploring in their bid to meet the new challenge. The most likely methods without reducing the amount of oil is to use more advanced solids control equipment, cuttings cleaning systems and multiple centrifuging.

Solids control systems, improved by better design of equipment coupled with increased vigilance by offshore workers to make sure the systems work efficiently, could help to prevent oil being discharged.

But better shale shakers are not the only solution. Mud companies and mud control experts have also mooted other systems: the use of cuttings cleaning systems, where the cuttings are either burned, vacuum distilled, or washed and disposed of on the mainland.

Some mud companies are wary of washing cuttings on offshore installations because they say it could create more safety hazards in an already dangerous workplace. The present system of washing cuttings relies either on detergents or solvents. Not only do both these create potential environmental problems but the use of solvents could be a possible extra fire risk.

Other companies have looked into solving the oil on cuttings problem by suggesting either incinerating and literally burning off the oil or using a vacuum distillation system.

However, both methods are expensive and the combustion method is not looked upon favourably because of the high energy use.

Land disposal

Finally, cuttings could be disposed of onshore. At present mud companies are not keen on disposing of cuttings onshore, because of the vast amount of cuttings generated by rigs in the North Sea, the possibility of an accident in bad weather, the sheer logistics and cost of moving the cuttings and the problem of finding suitable sites onshore.

Tim Barr explained: 'The use of cuttings cleaning equipment or disposal on land is only "moving the environmental problem to another place" or creating a different source of pollution, ie cuttings wash effluent. Cuttings wash technology is generally cumbersome and expensive. If the industry is to solve the major problem of environmental impact by mud, it must invest in those mud companies conducting R&D and not in sort-term cost-cutting.'

Drilling contractors Sedco/Forex take the view that all areas of research have to be covered to meet the government's directives.

Alan Mckee said: 'From the drilling contractors' viewpoint, this is not part of our main business activity. However, we are keeping abreast of the technology in this field and looking at ways to accommodate new processing and cuttings handling designs on our rigs, especially new designs.

'We are also considering the implications of green (zero discharge) rigs, as systems to provide zero discharges may become the rate determining step in the drilling process.'

The equipment, however, is very expensive and the majority of mud companies have spent their time and effort concentrating on more traditional mud product development methods to deal with the new legislation.

Non oil-based systems

Most mud companies have developed innovative water-based systems to replace oil-based muds or have done a lot of research into the mechanisms of how oil is held onto the cuttings.

BW Mud, for instance, have been able to introduce new emulsifiers which optimise the contrasting requirements of emulsification, oil wettability and low oil on cuttings requirements.

The company claims that its new products can offer a 10 to 20 percent reduction on Cuttings Oil Retention (COR) values when compared with an identical parameter mud system.

Both Baroid and Aker Drilling Fluids have developed non-toxic biodegradable invert emulsion systems to obtain a 'zero-rated' category with respect to discharge.

Baroid's PETROFREE uses an ester instead of oil in the formulation of a mud system which had just been tested on BP's SE Ula field, while Aker's AQUAMUL uses ether as the continuous phase and will shortly be tested on Phillips' Ekofisk field.

There is a lot of research underway at the moment using a variety of new polymer and existing highly inhibitive polymer water-based systems, such as Baroid's new lubricant and shale stabilizer TORQ TRIM 22, a cationic polymer system BARACAT, Aker's cationic polymer WBM's ANCOQUAT system and IDF's HF-PLUS system.

IDF's HF-PLUS system is a water-based mud that derives its inhibitive properties from the use of a mixture of glycerols and polyglycerols and a synthetic inhibitor IDCAP. The company has also developed a highly inhibitive water-based mud called SAFEDRILL, which it claims offers a realistic and economic alternative to OBMs in environmentally sensitive areas.

BW Mud have already used water-based fluids incorporating a polyglyceride/polyglycerol blend for lubricity and inhibition in a number of wells. In addition the company has also developed an aqueous cationic polymer system and an alternative to oil-based muds, based around a truly biodegradable organic liquid.

Currently Milpark are completing extensive lab tests on an ester based system and are hopeful of running their first test well before the year end.

In addition Milpark have completed some 10 wells using their MDF 1402 polyglycol system the results of which indicate ROP and torque figures very comparable to OBM with PDC bits.

Research is also being carried out by other companies on systems based around vegetable oils, glycerol and glycol products and surfactant-based systems.

The bottom line for the mud companies is that more and more operators may specify the need to use water-based muds. In fact some companies report that some operators already specify only water-based muds on single wells except in extreme circumstances.

R&D funding

Funding for the research and development of new mud systems does not come cheap, but unless they gain sponsorship from the operators, mud companies normally have to pick up the tab themselves.

Certainly research and development of new muds can prove expensive in terms of time and money. For instance Malcolm Ellice of Baroid, said it took five years of research and a $2 million investment just to develop PETROFREE.

Notification scheme

The mud companies seem to have mixed feeling about the government's implementation of a 'notification scheme' for all chemicals and materials used offshore to be first approved on the mainland.

Iain Whyte said: 'The scheme is restrictive and by and large unfair since the operators and contractors offshore have already got far superior quality assurance/quality control safety policies and safety equipment in place — compared to many industries on the mainland. Personnel are also trained to a far higher level offshore in the main.'

On the other hand, Baroid and BW Mud liked the system. Malcolm Ellice said: 'It is a fair and sensible system.'

Tim Barr said: 'IDF would like to see the UK Chemical Notification Scheme widely adopted. It is a useful tool as it provides an independent assessment and categorisation of products on toxicity grounds.'

Mud toxicity

Ironically, as mud systems become more 'environmentally friendly', the toxicity of emulsifiers and other chemicals becomes more significant.

Chris Higgins said: 'Emulsifiers and chemicals account for 5 to 10 percent of the volume of our INVERKLEEN systems. However, to ensure that a minimal amount of toxic chemicals are introduced into the system, these emulsifiers are supplied in refined mineral oil carrier fluids.'

Tim Barr said: 'While the toxicity of individual emulsifiers is a concern, the main concern is the overall toxicity of the mud systems as measured by the toxicity tests.'

Iain Whyte said: 'The "environmental friendliness" of each individual component in the system has to be addressed. Furthermore the toxicity of the products of biodegradation has to be established along with the biological oxygen demand (BOD) in the degradation process.'

He added that certain of the low toxic OBM alternatives can be formulated using reduced concentrations of emulsifiers (surfactants) which also makes the system less harmful to the environment.

Conclusion

The 1990s look set to produce a shift away from using oil-based muds for environmental reasons. The main thrust of the mud companies' R&D programmes appears to be towards the use of new water-based muds which will be able to cope with the overpressured formations encountered in the North Sea and the alternative use of a biodegradable continuous phase instead of oil.

Because of the concern to reduce pollution control of drilling fluid discharge appears to become more crucial necessitating that both mud engineers and drilling contractors work together more closely to prevent 'leaks' into the environment. This can be partly achieved with the help of greatly improved solids control equipment on the drilling rig to provide 'drier' discharges and better housekeeping and fluid management techniques.

Other methods which might prove effective in removing OBMs from cuttings such as incineration, vacuum distillation and multiple centrifuging were thought to be too expensive. But at the time of going to press, the oil price has increased from $15 to around $30 a barrel, so these systems may now be affordable. ■

Acknowledgement:
Thanks to Nick Cherbanich of NMC Consultants for help in drafting this article.

Oryx Energy — a transformed company

By Robert Keiser, President and Chief Executive Officer of Oryx UK Energy Company

Although Oryx is only a year and a half old, we are in fact a company with over 89 years' experience. We can trace our roots all the way back to Spindletop in 1901 when we were part of Sun Oil Company, later Sun Company. In November 1988, we were spun off from Sun Company as a totally independent E&P company.

On 1 November 1988, there was a share for share distribution of the stock to the shareholders of the Sun Company and an independent US domestic E&P company was formed called at that time Sun Exploration and Production Company. When the company was spun off, we started trading on the New York Stock Exchange as an independent company. Both companies have about 105 million shares of stock outstanding and, as they trade every day, the mix of shareholders between the two companies changes.

Why would a company do this?

Well, Sun Company took this action in order to maximise shareholder value. They believed that the financial markets would place a larger value on the pieces rather than on the whole. Furthermore, the actions that Sun took basically allowed both companies to go their separate ways and focus on their separate industries. Oryx was able as an independent E&P company to have a single business focus. We could concentrate on our reserves, we could concentrate on our production, we could concentrate on cash flow and the things we need to do to make our performance better. Again, we have no relationships with our former parent — we are financially and operationally independent. We have no common board members and again the shares are traded independently.

When the company was first spun off, Oryx put together some very simple operational goals which are all directed towards our performance. We wanted to improve our reserve replacement which meant that we did not want to allow the basic fundamentals of our business — the reserves and the production — to decline. We wanted to do this at a very competitive FD&A (finding, development and acquisition) cost. We wanted also to make sure that we continued a process of cost control that had been started several years earlier.

To accomplish our objectives we depend on keeping our pipeline full of good exploration and development projects. In our divestment programme which we are doing annually, and have been doing for at least seven years, we go through and look at our portfolio and we divest those assets that are not performing or do not fit our current goals and strategies. We have been working extremely hard to reduce our operating expenses, especially through the use of technology and operating efficiencies.

New strategies

To keep people focused on what we were going to do, we developed three basic strategies. The first one was technology. Basically, we are counting on our technology to carry us, to be the driver in accomplishing our goals. If we can specifically apply technology, we believe that we can reduce our cost of finding and development (F&D) and we can also lower our expenses.

Our second strategy is to pursue natural gas in the United States. Like most oil and gas participants, we believe that the US gas bubble is now gone on an annual basis. It is now a matter of seasonal timing. We decided to draw on the increasing gas values in the United States. Operationally gas is easier to produce; therefore, it has lower operating expenses (one of the goals) and it is easier to find resulting in lower F&D costs (another one of our goals). Accordingly, we intend to move our US reserve position from 40 percent being gas and 60 percent being liquids to something more in the 50/50 range over the next several years.

The last strategy was to actively pursue international opportunities. We set a goal for ourselves back in 1988 to look at foreign investment to achieve all of those aforementioned goals of lower cost, lower operating expenses, etc. We have basically accomplished this — we got into the international arena. We will expand on this base.

As soon as this first goal was reached, my boss turned around and said, 'OK, now you have a new goal, we want to have 50 percent of our reserves outside the US by the end of the century.' So basically what we are saying is that we have made that first step — going international, and we are in the international arena as a long-term player.

Let us look a little more closely at how we are trying to accomplish our three strategies. We have in Dallas, Texas what we think is a state-of-the-art technology centre. It houses our

'Cray' computer, our 'Vax' system, and our seismic and geophysical processing stations. We are at the point where every geologist and geophysicist has the availability of a work station. We also have reservoir simulation, core analysis, log analysis. We have a complete well completion and stimulation section. We have a complete production service lab for things like cathodic protection, oil treatment, etc. We also direct our horizontal drilling technology out of Dallas.

We have found — and this is just one example of the technology — that it is far, far better to make mistakes on a computer — and much cheaper. So if we can apply this technology and increase our success ratios, we believe that we are going to be a lot more efficient, especially in the area of finding and development costs. So we have turned to physical experimentation, through the use of computer-based technologies, to improve success ratios.

New technologies

Probably the technology we get more press coverage on in the United States than anything else is horizontal drilling. Horizontal drilling involves taking a well bore straight down and then turning either on a short or long radius in order to take the well bore horizontally through the reservoir. Basically, what you are trying to do is to establish the location of oilfield fractures or porosity zones, where if you drill vertically you might not even make a well, or you might make a well that will not produce economically.

One of the interesting areas is the Austin Chalk in south Texas. In the Austin Chalk, we have drilled wells in excess of a 4,000 foot lateral displacement and we have had test and production rates coming out of these wells in excess of 6,000 barrels a day. When you compare this with a normal well that is vertically drilled through these sections, you might be looking at 30 or 40 barrels a day. We have increased our ability to prevent a hit and miss attitude with this technology as well as to be able to have a more economical well bore.

When you get into new technologies, you have to make sure that you are also taking care of the other side of the business — the cost end of it. When we first started out with horizontal drilling, we were marginally successful from an economic standpoint. But by refining the technology, not only in the drilling of a well but also in the completion of it, we have reduced the cost by almost three-

Robert Keiser

fold. Again, we were interested in making sure that we got more productivity out of these wells but also we were trying to reduce costs at the same time.

We now have about 20 wells on production in the Austin Chalk. When we first started out, we had production of only around 160 barrels a day. We now have in excess of 11,000 barrels a day — and it continues to go up. So costs are down and production is up. We have produced in excess of 1,400,000 barrels of crude out of the Austin Chalk in this time frame and we have one well that has produced over 200,000 barrels. In the Austin Chalk area, a normal well would produce about 60,000 barrels vertically drilled.

Moving to our gas strategy, we are using 3D seismic in the Gulf of Mexico. We are looking to the Gulf of Mexico to satisfy our gas strategy, although we are in the other areas and plays in the United States. By using the 3D and the work stations we have been able to increase our success ratio on rank wildcats from basically a one in seven to a one in four — and this means a lowering in those F&D costs.

Gulf of Mexico

We are a relatively large player in the Gulf of Mexico. We have interests in about 230 blocks. We operate 91 of those blocks and 56 have producing facilities of some kind on them. In the 1989 programme we basically had 12 discoveries. Also during that year we made decisions to go ahead with eight proposed developments. On High Island A-370, we will put down Oryx's first subsea completion. As you know, there are a lot of subsea completions worldwide but in the Gulf of Mexico there are only 50 or so. This is technology that we picked up in our previous existence in the United Kingdom and introduced to our Gulf of Mexico developments. The Viosca Knoll 826 well that we drilled last year flowed about 1,400 barrels a day and about seven million cubic feet of gas. We have also announced a platform on South Timbalier 198 and have drilled another exploration well and it tested in excess of 15 million cubic feet a day.

When you look at our Gulf of Mexico development activity, we have a series of developments that are going to be put on production with start-up dates as early as June of this year and going on through the first part of 1991. Basically percentages of interest range from 18–100 percent. The 241 million cubic feet per day of gross gas production equates to approximately 80 million net production. Our total production from the Gulf of Mexico net to Oryx in 1989 was 140 million cubic feet per day, so we are talking about more than a 50 percent increase in that production.

International assets

Our international assets were acquired from BP. We purchased approximately 264 million equivalent barrels of proved reserves at $4.24 a barrel. We acquired interests in the United Kingdom, Indonesia, Ecuador, Gabon, and Italy. Although we are in five countries, approximately 85 percent of the value is in the UK North Sea.

We decided that we would go international because we felt that was where we could improve on our reserve replacement and meet the kind of standards that we want to have as far as our operating performance as a company is concerned. It gives us a very balanced portfolio. We acquired not only production but development projects and in excess of two million acres of exploration potential. This gives us the platform from which we think we can take ourselves from a 75 percent domestic/25 percent foreign reserves base company to the 50/50 balance we desire.

We announced the acquisition in September of 1989. The bid was about $1.31 billion. We estimated that at that time there was about 283 million equivalents. We were preempted on about $191 million, so we ended up with a $1.1 billion package at the $4.24 per barrel level. Everything became

effective 1 January 1990, so we went from zero outside the United States on 31 December to a relatively major operation on 1 January.

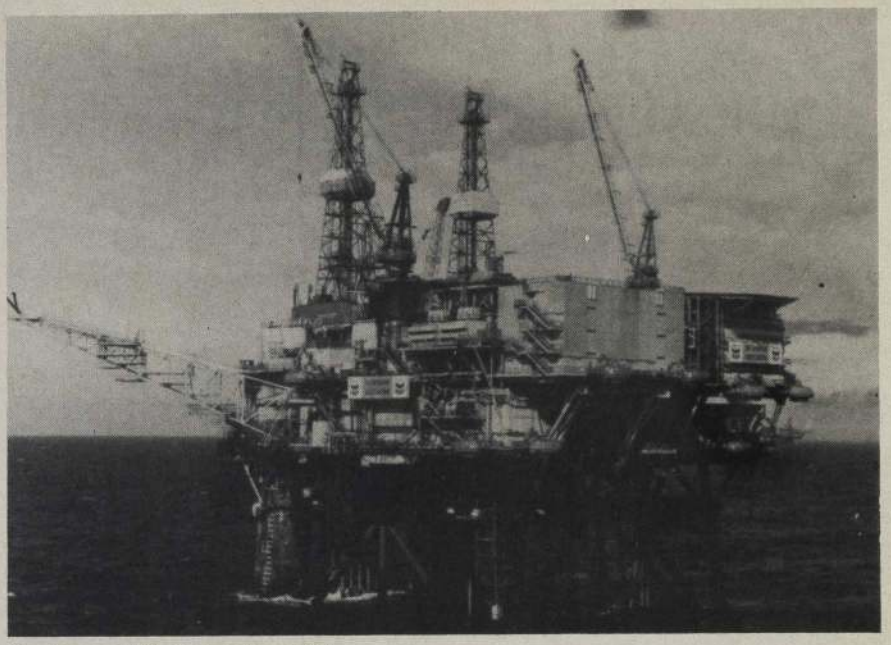
In Indonesia, we acquired an interest in three production sharing contracts. In the Kakap Field, which presently has the KF field development underway, we own almost 20 percent. The southeast Sumatra area is where Maxus, the operator, had a lot of press in 1986 with the Widuri and Intan fields. They are being put on production today. And in the Malacca Straits, operated by Lasmo, we have a 21.5 percent interest.

When you look at the United Kingdom, we acquired interests in 41 different blocks, of which five are currently producing. We have seven future developments at various stages and again 41 exploratory tracts. In the Ninian field, we are the number one holder of interests at 21.4 percent. We have a 14 percent interest in Dunlin operated by Shell, 22 percent in Hutton operated by Conoco, and 25.9 percent in Murchison, operated by Conoco. Our interest in the Audrey gas field will be determined through future redeterminations that are presently ongoing — right now we have 17.5 percent interest.

Also, in the United Kingdom we have some very nice developments. The Audrey phase II development is under completion right now. Strathspey, Lyell, the Colomba tracks, Galleon, Alba and Kilda are other developments that we acquired. They are in various stages of investigation. Probably the largest two are the last two — the Alba and Kilda fields both on Block 16/26. These are Eocene and the Cretaceous discoveries which have received a lot of press. Several of the other developments are satellites. Since as a manager I have to report on results, I like satellites because they tend to be inexpensive in terms of development costs. And they tend to make the platforms that support them have lower operating expenses per barrel produced. So from that aspect of it, we expect to get a nice return on our investment on those properties.

Capital programme

As far as US exploration and development expenditures go, they will continue this year at about the same level as in 1989. Internationally, we have plans to spend about $100 million in development and $25 million or so in exploration. Since acquisitions are opportunity driven, we don't budget for these kind of expenditures; however this does not mean that we will not have some activity in this area.



Southern platform, Ninian field

We have been working very hard at utilising technology, consolidating various and sundry operations, divesting properties, etc. Basically, we cut about $120 million of expense between 1988 and our 1989 performance, and we worked very, very hard to get that. We did fairly well on all of our expense categories with the exception of one — administrative expenses.

What makes up the $11 million extra administrative expense? In our attempts to get operating expense and administration down, we incurred about $7 million that is related to a complete overhaul of our financial computer systems, as well as some costs incurred when we became an independent company — we now have to put out an annual report for example. And also because we had such a good year last year, we passed out a nice little bonus to everyone!

When you look at our first quarter results and compare 1989 with 1990, you can see the effect of having a good oil price. It is also nice to have the volumes from the international arena for the first part of the year. We had an increase in liquids volumes from 117,000 barrels per day to 176,000, gas volumes were up, income was up, cash was up, oil price was up significantly and gas price up slightly.

We are proud of our accomplishments over the past several years in reserve replacement and FD&A costs. Our reserve replacement has been virtually 100 percent the last two years and FD&A costs in 1989 were only $5.07 per equivalent barrel. Since 1986 that is in excess of a 50 percent increase in reserve replacement and almost a 60 percent decrease in FD&A costs. I will point out that our goal isn't over because we still want to drive the FD&A costs down and we want to further increase the replacement rate of our reserves.

I'd like to summarise what we have accomplished in our relatively brief existence as an independent company. We said we wanted to shift to natural gas in the Gulf of Mexico. We've got eight new facilities that are coming on that are gas producers. We wanted to reduce our expenses which we did. We wanted to improve our reserve replacement and we have done that over the last four years. We wanted to reduce our FD&A costs and we have pulled those down consistently over the last four years. From an exploitation of our technology standpoint, we wanted to exploit horizontal drilling. We have got 23 wells drilled, we are physically running seven rigs and completing with another seven wells. We will drill by the end of the year in the Austin Chalk some 85 wells. We wanted to establish a strong international presence — we have done it.

And we wanted to get our share price up. Shareholders like to have the price of their equity go up. When we spun off, the combined share price of both companies at that point in time was $55 a share. Oryx was spun off at $26 a share. The present Oryx price, depending on what day it is, runs somewhere right now between $44 and $49 a share. So in one and a half years, we have increased the share price substantially. ■

Mr Keiser was a guest speaker at a joint Energy Economics Group and Exploration and Production Discussion Group meeting on 10 May, 1990.

3-D seismic — a powerful exploration tool

By Mark Scruton

Three-dimensional seismic technology has come of age thanks to the tremendous advances made in the electronics and computer industries during the past 20 years. For not only have the new computer workstations been used to revolutionise how the immense amount of data generated is analysed, but they have also helped engineers interpret seismic information, and reduce most of the guesswork about where best to accurately position development wells.

By using the sharper, clearer images of the underground rock structures generated by the 'number-crunching' super computers, geoscientists now have a powerful tool literally at their fingertips, which can help improve their exploration drilling success rate.

This tool becomes even more crucial as the trend for exploration work, especially in the North Sea, is shifting towards the analysis of marginal fields, which are smaller and much more complex than the large reservoirs discovered in the 1970s.

Interestingly the technology required to cope with 3-D seismic can also be used in conjunction with logging and geological data to 'fine tune' the mapping of the structure.

Integrating data

By integrating static seismic and logging data with dynamic testing data, the new workstations can improve reservoir characterisation with the result that fewer wells are required to develop a field.

Speaking at the 9th International Offshore Northern Seas Conference in Stavanger recently, Mr Victor Grijalva, Executive Vice President of Schlumberger's Wireline Testing and Seismic Division, said: 'Finding smaller fields requires high resolution seismics and vast amounts of data from newer and more sophisticated multisource, multistreamer and multivessel techniques.'

He added: 'Data integration is required to evaluate the discovery more fully since the information available from a single exploration well may be limited. Sensitivity analysis should be performed to determine which assumptions most influence the decision to develop a small field.'

'Powerful workstations and interactive interpretation software serve both to perform the sensitivity analysis and to enable geoscientists and engineers to utilise more data to create more accurate reservoir models.'

Increased use

The technology to create these sharper images of subsea strata has come a long way since the first commercial 3-D survey was shot in the Gulf of Mexico in 1975. Since then more than 1,000 3-D surveys have been conducted throughout the world, currently amounting to about 60 percent of all marine seismic work undertaken, and that percentage looks set to increase.

In conventional 2-D offshore surveys, geophysical data is collected by a survey ship, towing a streamer about 3,000 metres long. Directly behind the boat is a set of compressed airguns, which fire every few seconds, sending shockwaves through the water to the sea-bed and down into the rock structure.

Hydrophones — special listening devices spaced along the streamer — pick up sound waves reflected from the different rock layer interfaces and record the elapsed time taken from the explosion until the reflected wave returns.

During the survey, the ship sails back and forth across the specified area in a grid pattern, leaving a one to two kilometre gap between each pass. Each hydrophone records the strength of the reflected sound — weak or strong — hundreds of times a second.

As there are typically 120 sets of hydrophones in a streamer, the amount of data obtained from these reflections, particularly their strength, or amplitude, and their arrival times, is enormous.

The data is recorded on magnetic tape and returned to shore for processing. Complex computer programmes are then used to unravel the data and the final displays are shown as vertical cross sections through the earth, showing the reflections from rock layers down to six seconds beneath the sea — up to depths of about 20,000 feet.

Like slicing bread

Conoco's North Sea chief geologist John Adams explains: 'Each vertical cross-section gives us an indication of the rock structure at one or two kilometre intervals across the survey area — it's rather like slicing up a loaf of bread.'

'The interpretation geophysicist's task is to use the displays to build up a complete picture of the rock layers in an area and use his or her geological knowledge to predict the structure in the areas between the survey lines. The most usual way to present the results is as a contour map of the reflection time to the top of the reservoir.'

2-D surveys can be interpreted by tracing rock layer reflections printed

on paper strips using coloured pencils and then measuring off the travel times.

Mr Adams said that once the layers had been mapped in time, the critical next step was to convert the map to show the depth of the layers. This process used to be very time-consuming but has been considerably speeded up and made more accurate by using a computer workstation.

'We can usually calculate the depth of a particular rock formation in the North Sea to within 50 feet either way. That's not bad for an invisible layer of rock two or three miles beneath the sea-bed — but it could still be the difference between a discovery and a dry hole,' he said.

Data analysis

Once the geophysicist has analysed the area's faults, domes and troughs indicated by the map, any promising structures are assessed to see if they fulfil the criteria vital for oil accumulation.

This normally means using available data from surrounding wells, if any, a good porous reservoir rock to hold the oil and gas and an overlying cap rock to seal it in. If all the factors are favourable, a well location is selected. This whole process could take as long as a year.

2-D surveys give a reasonable first impression of the underlying structure, but because of the one to two kilometre spacing between each pass of the survey ship, geoscientists need to interpolate what is happening to the structure between the seismic lines. As the search for new reservoirs extends into increasingly complex geological areas, localised folds and faults, which could have a significant bearing on the potential of the whole structure, these could go unnoticed in conventional surveys.

Victor Grijalva said: '3-D seismic exploration is a key technique to explore areas offsetting developed fields.'

3-D seismology

3-D seismology is a more sophisticated version of 2-D, developed to fill in the gaps in such complex areas. Instead of a vertical section, the final image resembles a cube.

But because a 3-D survey generates so much information than a 2-D survey of the same area, it is much more expensive to acquire. This has meant that 3-D is only used, at present, in "mature" zones which have already been surveyed by 2-D seismic. So geophysicists must be convinced that a promising structure exists before authorising the technique.

A typical workstation

3-D surveys are shot in a similar way to 2-D but the line spacing for vessels is reduced from one kilometre to no more than 25–30 metres. Specially equipped ships are fitted with two airgun arrays and two or more streamers each carrying anything between 120 to 480 hydrophones.

'We divide the survey area into tiny cubes, called "Bins",' explained Mr Adams. 'Each bin must receive a certain number of sound reflections, so that an accurate image of the area can be built up. Since the streamers are so long, they tend to drift sideways in the ocean currents and tides. So the hydrophones tend to pick up sound emissions from a large number of bins across the area.' He added the accurate positioning of the vessel and the geometry of the airgun to the streamer is crucial. 'Most boats are now equipped with sophisticated computers which indicate the exact position of the end of the streamer. Each streamer usually carries 12 compasses, which relay back to the computer their position in relation to the boat.'

Because of the volume of data in 3-D surveys, the geophysicist uses a sophisticated workstation to display the information and speed up the interpretation of the data. These workstations are at the forefront of computer technology in image processing and data storage. Since they are being developed at a rapid pace, it is common practice to rent a system during the interpretation phase.

'Using these workstations we can cut across virtually any plane to obtain a vertical, horizontal or diagonal section of the area,' said Mr Adams. 'It can even be a zig-zag section across the survey area — between wells, for example. This is useful for incorporating geological data to fine-tune the mapping of a structure.'

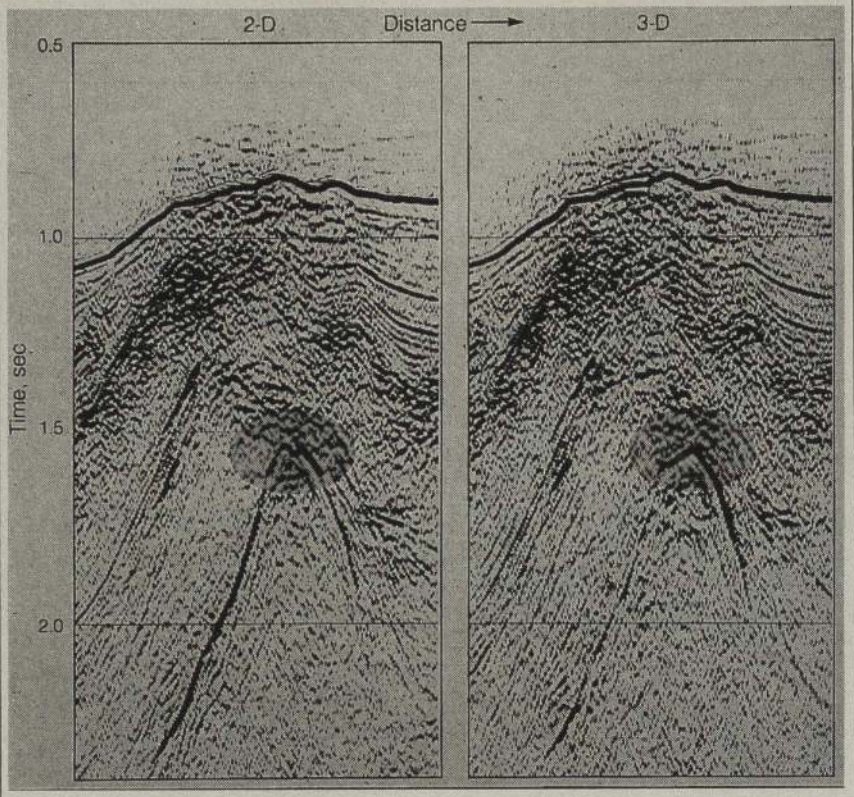
Reservoir simulation

With this detailed map of an area, reservoir engineers and exploration geophysicists can plot the position of development wells so that they tap the reservoir in the most efficient way.

Mr Grijalva said: 'The term structural imaging is used today to describe the integration of model-based seismic processing, proper analysis of seismic velocities and sophisticated migration algorithms. Migration algorithms are applied to seismic data to "reverse" the propagation of the seismic wavelength. Through this process, artefacts are removed and a clear picture of the structure results.'

He added that geological and geophysical maps of marginal accumulations are refined with data from borehole seismic measurements — check shots and Vertical Seismic Profiles (VSP) — which define structural anomalies crossing the well.

'Accurate evaluation of the potential of marginal accumulations for commercial production requires a detailed



Improved resolution of 3-D sections over 2-D seismic of a dome and a fault. Note the different dome structure. **Courtesy: Geco**

image of the reservoir. Formation characterisation techniques have recently evolved from a gross approximation of petrophysical parameters to high resolution measurements of individual layers that yield images of the subsurface.'

Added bonus

As an added bonus, the data collected by 3-D seismic can be linked to new logging technology by the data processing techniques now available on the new workstations.

These new sensors, developed to have higher sampling rates, have been applied to resistivity, nuclear and geochemical measurements to obtain such reservoir characteristics as porosity, saturation and permeability values in complex environments and thin beds.

'Resolution has improved from traditional ranges of two feet to 10 feet, down to 0.2 inches to two inches. Beds as thin as 1 cm can be detected and formations as thin as 15 cm can be evaluated quantitatively.'

To improve borehole imaging techniques, his company has developed a new wireline acquisition system to improve wellsite efficiency and the success of offshore exploration efforts using the higher downhole telemetry rates and the additional processing capabilities of the new workstations.

The surface unit of the new system features a downhole telemetry rate of 500 kilobits per second, a five-fold increase over existing systems.

Furthermore a new generation of logging tools has been developed. One of the first tools to be introduced was a multi-receiver sonic tool that combines dipole and monopole technology to measure compressional and shear waves in all formations. Previous sonic tools could not measure shear waves effectively in soft formations. Besides determining porosity, the tool can be used to correlate with surface seismic, determine the formation breakdown and create images of near-borehole structural features. The latter technique is being developed to determine bed boundaries in horizontal wells.

New testing tools

Even well testing techniques have also been improved to take advantage of the impressive new interpretation technology.

Mr Grijalva said: 'An array of new testing tools is being introduced into North Sea operations; a very stable, highly accurate quartz gauge, a multipurpose downhole recording system that stores data downhole or transmits data to surface on demand and a highly versatile system of downhole valve actuation that allows innovative and cost-effective testing sequences.

Thanks to the ability of the workstations to cope with the input of data from both seismic and well testing sources, the geophysicists, geologists and reservoir engineers have a much clearer idea of the potential reservoir structure and hence its feasibility as a producer.

'Smaller, more complex fields are being developed with fewer wells, but with more data recorded to evaluate the reservoirs. In exploration wells testing is extensive and is used not only to define the well and reservoir parameters, but also to describe the limits that fully characterise the reservoir.'

Mr Grijalva added that characterising the reservoir's dynamic response around the well with wireline formation testers and well testing and integrating the response with high resolution logs, are critical for the efficient appraisal of small fields.

'Managing and interpreting the increasing amounts of static seismic and logging measurements and dynamic test data can no longer be done by hand. Workstations with imaging capabilities for reservoir characterisation are being used to process and interpret the data. Workstations provide geoscientists with an integrated, interactive environment for building a reservoir model that is used as a 3-D multiphase reservoir simulator.

'The model is a set of related interpretation elements from surface and borehole seismic, logs, core analysis and test data describing geometry and physical properties of the reservoir. 'The geoscientist may use various modelling relationships to constrain the way in which the 3-D model is produced. Petrophysical, geological and reservoir modelling application packages are used by the interpreter to reflect and better define the image of the reservoir.'

Talking about the 3-D surface surveys John Adams summed up his view of the new processes: 'Although 3-D surveys are expensive and take considerably longer to acquire and process, they are essential for accurately locating production wells to ensure the maximum amount of oil is recovered. If a single dry hole can be avoided by using 3-D technology, the survey will have paid for itself several times over.' ■

NOW OUR PRICES LOOK EVEN BETTER.

Customers already know us for our low priced quality petrol, and that's not about to change. What we are changing, is our look. We're aiming to attract a whole new group of customers with a brand new image.

From forecourt price-poles to petrol pumps, the bright new look better reflects the needs of today's motorist, yet remains unmistakably Jet.

A unique combination of price and look, designed to get even more customers on the forecourt, and give you even better profits. The refurbishment begins in March 1990 and will roll out over the next two years.

If you own your own filling station and would like to be part of our bright new future, call us now JET on 071-408 6112 or 071-408 6211. You won't look back.


JET
4 star
Litre
37·3
4 star
Gallon
169·6
Unleaded
Litre
35·1

FORTHCOMING EVENTS

October

6th-12th
New Delhi: 'ChemTech '90'. Details: ChemTech Secretariat, Taj Building, 3rd Floor, 210 Dr DN Road, Bombay 400 001, India. Tel: 2042044.

7th-19th
Oxford: Course on 'Management of Shipping Costs and Revenues with Computer Applications'. Details: Mrs Jeanette Soper, Drewry Shipping Consultants Limited, 11 Heron Quay, London E14 9YP. Tel: (071) 538 0191. Fax: (071) 987 9396.

8th-12th
Harwell: Course on 'Reservoir Simulation'. Details: Dr NA Bailey, AEA Petroleum Services, Winfrith, Dorchester, Dorset DT2 8DH. Tel: (0305) 202074. Fax: (0305) 203424.

8th-12th
Southampton: Course on 'Refinery Technology for New Graduates'. Details: The Conference Section, Institution of Chemical Engineers, Davis Building, 165–171 Railway Terrace, Rugby CV21 3HQ. Tel: (0788) 78214. Fax: (0788) 60833.

9th
London: Conference on 'Information Support for the Energy Industries — An Evaluative Approach'. Details: Caroline Little, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR. Tel: (071) 636 1004. Fax: (071) 255 1472.

9th-10th
Sheffield: Course on 'The Update of the COSHH Regulations'. Details: Mrs KW Wainwright, The Centre for Continuing Vocational Education, The University of Sheffield, 65 Wilkinson Street, Sheffield S10 2GJ. Tel: (0742) 768653.

9th-10th
London: Conference — 'Hydrocarbons 90'. Details: Hydrocarbons 90 International Conference, Themedia Ltd, PO Box 2, Chipping Norton OX7 5QX. Tel: (060884) 700/888. Fax: (060884) 796.

9th-10th
Buxton: Conference on 'Carriage/Storage of Dangerous Goods'. Details: Dr E. Rhodes, Marylebone Press Ltd (Conferences), Lloyds House, 18 Lloyd Street, Manchester M2 5WA. Tel: (061) 832 4607. Fax: (061) 832 8129.

12th
London: 'UK Oil and Gas Fields — The Results of 25 years of Offshore Exploration'. Details: Heidie Gould, Petroleum Group, The Geological Society, Burlington House, Piccadilly, London W1V 0JU. Tel: (071) 434 9944. Fax: (071) 439 8975.

15th
London: Conference on 'The Greening of Business'. Details: Katie Townsend, Public Policy Consultants, 50 Rochester Row, London SW1P 1JU. Tel: (071) 828 6088. Fax: (071) 828 7217.

16th-17th
London: Course on 'Oil and Loss Control'. Details: Amanda Stuart, IBC Technical Services Ltd, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

16th-19th
Birmingham: Conference 'Maintenance '90'. Details: Conference Communication, Monks Hill, Tilford, Farnham, Surrey GU10 2AJ. Tel: (02518) 3111. Fax: (02518) 3143.

17th
Guildford: Conference on 'Energy Demand: Evidence and Expectations'. Details: Mrs E Blakeway, Department of Economics, University of Surrey, Guildford, Surrey GU2 5XH. Tel: (0483) 509171. Fax: (0483) 300803.

17th
Sheffield: Course on 'Safe Storage of Hazardous Chemicals'. Details: Mrs Kathleen Wainwright, The University of Sheffield, CCVE, 65 Wilkinson Street, Sheffield S10 2GJ. Tel: (0742) 768653.

17th
London: Conference on 'Joint Operating Agreements'. Details: Jenny Jones, Conference Organiser, European Study Conferences Limited, Douglas House, Queen's Square, Corby, Northants, NN17 1PL. Tel: (0563) 204224. Fax: (0563) 204218.

18th
London: Conference on 'Oil Mists'. Details: Caroline Little, The Institute of Petroleum.

18th-19th
London: Conference on 'Oil and Money'. Details: Brenda Hagerty, International Herald Tribune, 63 Long Acre, London WC2E 9JH. Tel: (071) 836 4802. Fax: (071) 836 0717.

22nd-24th
Brighton: Association for Geographic Information's Second National Conference and Exhibition. Details: Westrade Fairs Limited, 28 Church Street, Rickmansworth, Herts WD3 1DD. Tel: (0923) 778311. Fax: (0923) 776820.

23rd-24th
Chislehurst: Course on 'Safety of Electrical Equipment in Potentially Explosive Atmospheres'. Details: Sira Communications Ltd, South Hill, Chislehurst, Kent BR7 5EH. Tel: (081) 467 2636. Fax: (081) 467 7258.

25th
London: Course on 'Flammable and Toxic Gas Detection'. Details: Sira Communications Ltd, South Hill, Chislehurst, Kent BR7 5EH. Tel: (081) 467 2636. Fax: (081) 467 7258.

25th
London: Course on 'Successful Contracting'. Details: European Study Conferences Limited, Douglas House, Queen's Square, Corby, Northants NN17 1PL.

28th-2nd November
Moreton-in-Marsh: Course on 'Handling Emergencies in the Oil Industry'. Details: Mr R Ayres, Petroleum Training Federation, Room 326, 162–168 Regent Street, London W1R 5TB. Tel: (071) 439 2632. Fax: (071) 287 5483.

29th
London: Conference on 'Emergency Planning'. Details: Liz Hide, IBC Technical Services Ltd, Bath House (3rd Floor), 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

29th-31st
Esher: 'UK Corrosion '90'. Details; Jean Pritchard, Society for Underwater Technology, 76 Mark Lane, London EC3N 7JN. Tel: (071) 481 0750. Fax: (071) 481 4001.

29th-2nd November
Sheffield: Course on 'Safe Handling of Industrial Chemicals'. Details: The Conference Section, Institution of Chemical Engineers, Davis Building,

FORTHCOMING EVENTS

165-171 Railway Terrace, Rugby CV21 3HQ. Tel: (0788) 78214. Fax: (0788) 78214.

30th
London: Conference on 'Ignition Hazard from Electrical Equipment in Flammable Areas'. Details: Katie Lye, IBC Technical Services Ltd, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

31st
London: Conference on 'Electricity from Gas'. Details: Judith Higgins, The Institute of Energy, 18 Devonshire Street, London W1N 2AU. Tel: (071) 580 0008. Fax: (071) 580 4420.

31st-2nd November
Amsterdam: Tenth International Symposium on 'Jet Cutting Technology'. Details: Symposium Organiser, Tenth Jet Cutting, BHR Group Limited, Cranfield, Bedford MK43 0AJ. Tel: (0234) 750422. Fax: (0234) 750074.

November

5th-6th
Edinburgh: Conference on 'Oil and Gas European Export Technology — worldwide opportunities for industry'. Details: Natalie Cox, IBC Technical Services Limited, Bath House (3rd Floor), 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

5th-7th
New York: Course on 'Tanker Ownership, Chartering and Operations — Tactical and Strategic Decision Making'. Details: The College of Petroleum Studies, Sun Alliance House, New Inn Hall Street, Oxford OX1 2QD. Tel: (0865) 250521. Fax (0865) 791474.

6th
London: Conference on 'Safe Road Transport in the Petroleum Industry — The Way Ahead'. Details: Caroline Little, The Institute of Petroleum.

6th
London: Conference on 'The Transportation of Hazardous Substances by Sea'. Details: Linda McKay, Legal Studies & Services Limited, 3rd Floor, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

7th-14th
Alfriston: 'Environmental Policy and Management: an international forum'. Details: Courses Department, The British Council, 65 Davies Street, London W1Y 2AA. Tel: (071) 389 7817.

8th
London: Conference on 'Environmentally Induced Weld Failures'. Details: The Meetings Department, The Welding Institute, Abington Hall, Abington CB1 6AL. Tel: (0223) 891162. Fax: (0223) 892588.

8th-9th
London: Conference on 'Environmental Assessment: Theory and Practice'. Details: Liz Hyde, IBC Technical Services Ltd, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

12th-14th
Bahrain: Conference on 'New Developments in the Oil Industry'. Details: Conference Section, The Institute of Chemical Engineers, 165-171 Railway Terrace, Rugby CV21 3HQ. Tel: (0788) 78214. Fax: (0788) 60833.

12th-16th
Winfrith: Course on 'The Basics of Improved Oil Recovery'. Details: Dr NA Bailey, AEA Petroleum Services, Winfrith, Dorchester, Dorset DT2 8DH. Tel: (0305) 202074. Fax: (0305) 203424.

13th
London: Lecture on 'Engineering a Greener Pipeline — A Practical Approach' by M Hadley, Trident Consultants Ltd. Details: Mr A Reed, Secretary, The Pipeline Industries Guild, 17 Grosvenor Crescent, London SW1X 7ES. Tel: (071) 235 7938.

13th
Aberdeen: Conference on 'Maintenance for the Offshore Industry'. Details: Sue Klarfeld, Customer Services Manager, The Industrial Division, IIR Ltd, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel (071) 412 0142. Fax: (071) 412 0144.

13th-14th
Geneva: Conference on 'The Automotive Industry and the Environment'. Details: Helen Conry, Environmental Matters, 43 Manchester Street, London W1M 5PE. Tel: (071) 224 1876. Fax: (071) 224 4961.

13th-14th
London: Course on 'Desert Sediments and the Rotliegend'. Details: JAPEC Secretary, c/o The Geological Society, Burlington House, Piccadilly, London W1V 0JU. Tel: (071) 434 9944. Fax: (071) 439 8975.

14th
Aberdeen: Course on 'Quality Improvement for the Offshore Industry'. Details: Sue Klarfeld, Customer Services Manager, The Industrial Division, IIR Limited, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel: (071) 412 0142. Fax: (071) 412 0144.

15th
London: Conference on 'Major Performance Related Clauses for Offshore Oil Construction and Supply Contracts'. Details: Joanna Hulbert, Legal Studies and Services Limited, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

16th
London: Conference on 'Futures and Forward Markets — Swaps and Options — Which Way Forward?'. Details: Caroline Little, The Institute of Petroleum.

19th-20th
Egham: Course on 'Modern Developments in Airport Fuelling Operations'. Details: Dr EM Goodger, Route SouthWest Ltd, 78 Church Road, Woburn Sands, Milton Keynes, MK17 8TA. Tel: (0908) 582120. Fax: (0784) 435383.

20th
London: Conference on 'Procurement for the 1990s'. Details: European Study Conferences Limited, Douglas House, Queen's Square, Corby, Northants NN17 1PL.

20th-21st
Manchester: Conference on 'The Human Factor in Safety: Implications for the chemical, process and offshore oil and gas industries'. Details: Katie Lye, IBC Technical Services Ltd, Bath House, 56 Holborn Viaduct, London EC1A 2EX. Tel: (071) 236 4080. Fax: (071) 489 0849.

22nd
London: Conference on 'Offshore Safety — The Way Ahead'. Details: Caroline Little, The Insitute of Petroleum.

FORTHCOMING EVENTS

22nd-24th
Perth, Australia: 'Petroleum Technology Australia 90'. Details: Energy House 103 Scarborough Beach Road, Mt Hawthorn, Western Australia 60616. Tel: (09) 443 3400. Fax: (09) 242 1811.

25th-28th
Singapore: 'The Far East Maritime and Offshore Services Show'. Details: Hilal Asian Exhibitions, 50 Jalan Sultan, 20-06 Jalan Sultan Centre, Singapore 0512. Tel: 2939233. Fax: 2970862.

26th-28th
London: Conference on 'Welded Structures '90'. Details: The Meetings Department, The Welding Institute, Abington Hall, Abington, Cambridge CB1 6AL. Tel: (0223) 891162. Fax: (0223) 892588.

27th
London: Lecture on 'Gas Based Chemicals and Fuels — A Technical and Commercial Overview' by Chris Peacock, Principal, Chem Systems Ltd. Details: Mr E Hudson, Chem Systems, 28 St James's Square, London SW1Y 4JH. Tel: (071) 839 4652.

27th-29th
Birmingham: Course on 'Understanding Heat Treatment'. Course Administrator, Wolfson Heat Treatment Centre, Aston University, Aston Triangle, Birmingham B4 7ET. Tel: (021) 359 3611. Fax: (021) 359 6470.

28th-29th
London: Conference on 'Environmental Forces on Offshore Structures and their Prediction'. Details: Society for Underwater Technology, 76 Mark Lane, London ECR3 7JN. Tel: (071) 481 0750. Fax: (071) 481 4001.

December

3rd-4th
London: Conference on 'Energy and the New Europe'. Details: The Energy Conference Organiser, The Royal Institute of International Affairs, 10 St James's Square, London SW1Y 4LE. Tel: (071) 930 2233.

4th
London: Workshop on 'Crude and Petroleum Product Shipments: Problems encountered during Independent Inspection'. Details: Caroline Little, The Institute of Petroleum.

6th
London: Conference on 'Accident Prevention in the Chemical Industries: Using People in the Organisation'. Details: Conference Secretariat, SCI 14/15 Belgrave Square, London SW1X 8PS.

9th-14th
Moreton-in-Marsh: Course on 'Handling Emergencies in the Oil Industry'. Details: Mr R Ayres, Petroleum Training Federation, Room 326, 162-168 Regent Street, London W1R 5TB. Tel: (071) 439 2632. Fax: (071) 287 5483.

12th
London: Evening meeting on 'Geological aspects of safety during drilling of deep wells in the Central Graben'. Details: Heidie Gould, Petroleum Group, The Geological Society, Burlington House, Piccadilly, London W1V 0JU. Tel: (071) 434 9944. Fax: (071) 439 8975.

IP WORKSHOP

Crude and Petroleum Product Shipments: problems encountered during independent inspection

To be held at
The Institute of Petroleum

Tuesday 4 December 1990
(10.00–15.00)

Topics to be covered include:

The Meaning of 'Independent'
Commercial Pressures on the Inspector
Interpretation of Analytical Results
Functions Expected of the Inspector
Can Those Functions Be Met?

There will be presentations on these topics, each followed by an informal discussion.

Registration Fees: £85.00 plus VAT for IP Members
£120.00 plus VAT for Non-Members

For further information, and a copy of the registration form, please contact **Caroline Little, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR. Telephone: 071-636 1004. Telex: 264380. Fax: 071-255 1472.**

Information Evening

Proposed North Eastern Branch Institute of Petroleum

From an approximate membership of 400, the Yorkshire Branch of the Institute of Petroleum has almost 200 members living in the north eastern area.

With monthly meetings held during the winter season at the Mansion Hotel, Roundhay, Leeds, the distance and time involved understandably discourages most members from this area from attending.

The Yorkshire Branch committee feels the opportunity to start a North Eastern Branch should be offered and to this end an Information Evening is proposed to set the ball rolling.

A meeting has therefore been arranged on Thursday, 25 October, 1990 at Swallow Hotel, St. John Walker Square, Stockton-on-Tees at 7.30 for 8.00 pm.

For more details please contact Mr Richard Hey, Millers Oils Ltd, Hillside Oil Works, Brighouse HD6 3DP. Tel: (0484) 713201.

Australia's urgent need for more oil

By William Scholes

The Iraqi crisis highlights the increasing vulnerability of Australia, in fact the whole Asia-Pacific region, where demand for oil has been growing by more than 4.5 percent a year since 1987. This has meant that regional demand for oil has risen by 1.5 million barrels a day (b/d) during the past three years to boost to about 12 million b/d and now constitutes about 18 percent of world demand. Consumption rates are expected to soar during the 1990s in the fastest growing region in the world.

Australia is better off than most in the region and is now about 82 percent self-sufficient, with the potential to remain virtually self-sufficient in oil for another 20 to 30 years, and can avoid becoming dependent on increasing levels of imports from the Middle East.

An ongoing Bureau of Mineral Resources research programme covering Australia's continental margin has suggested that the deepwater areas should contain at least as much oil as the estimated 7 billion barrels that will be recovered from the continental shelf.

A big question mark hangs over the level of future self-sufficiency, mainly because the present exploration effort on the continental shelf is inadequate. Little recognition is given to the fact that it would require 10 to 15 discoveries of the size of Woodside Petroleum Ltd's Wanaea field — the best find in more than a decade — to replace Bass Strait reserves.

The dangers of a rising dependence on imports have persisted because inadequacies in the country's tax regime have held back exploration, even though many billions of barrels of oil remain to be discovered.

1990–91 budget

However, that has all been changed in the 1990/91 budget, delivered in August. The Federal Government scrapped the Bass Strait oil excise and royalty system and introduced a newly designed Resource Rent Tax (RRT) in the most dramatic shakeup of the oil industry tax base since the Bass Strait fields came into production more than 20 years ago. The sweeping alterations to the oil industry's tax base backdated to 1 July include the introduction of tax deductibility for oil exploration in all areas in which the RRT applies. In addition, oil companies will now be able to use as a tax deduction the cost of oil production platform removal, also effective from 1 July.

The Federal Government's RRT system will not be applied to the North West Shelf project where the existing excise and royalty arrangements will be retained.

The package centres on a redesigned RRT which encourages exploration in high risk frontier fields. The package contains nearly every tax reform that the oil industry has lobbied for during the last few years.

North west coast

The north-west coast of Australia, covering more than 2,100 kilometres from Carnarvon to Darwin, is undoubtedly shaping up as the most prospective oil area in the Asia Pacific region. Oil companies are expected to spend more than $A500 million over the next two years on exploration and development in the region. Explorers are targeting the Carnarvon Basin, the Exmouth Plateau, Browse Basin, Timor Sea, Bonaparte Gulf and Arafura Sea.

In that entire area fewer than 200 oil exploration wells have been drilled. The exploration permits surrounding the North West Shelf Liquified Natural Gas project, combined with the permits surrounding the Timor Sea exploration area, together cover more than four times the entire UK sector of the North Sea oilfields. In the UK North Sea more than 2,000 exploration wells have been sunk. Simple mathematics suggest that much more oil will be found in this vast stretch of coastline. The major problem will be the cost of exploration and the limited volume of funds available to Australian companies.

The significance of the north-west coast of Australia and highly prospective Papua New Guinea region is being recognised by many international oil companies.

British Petroleum has declared that Papua New Guinea (PNG) and the north-west coast of Australia will be the company's major exploration focus for up to five years, with more funds committed to those two areas than any other area of the world. PNG holds the attention of the wc ld in the lead-up to the development of the Kutubu oil project in the Southern Highlands which will incorporate production from the Iagifu/Hedinia/Agogo/Usano oilfields. But while the industry generally expects large oil discoveries from the PNG Highlands recent discoveries in the Exmouth Plateau and Carnarvon Basin in Australian waters have outweighed the most optimistic PNG forecasts.

Woodside Petroleum's Wanaea discovery in Western Australian waters could contain 200 million barrels of recoverable oil, easily eclipsing the largest of the known fields in PNG. Nearby the Cossack and Echo fields could contain 80 million barrels and 50 million barrels of liquids respectively.

Further north in the Timor Sea BHP's Jabiru field, which was developed on the basis of 11 million barrels of recoverable reserves, is steadily being revised. The latest published figure for reserves is around 82 million barrels but is most likely to be in-

creased to around 100 million barrels.

The adjacent Challis field, which came into production late last year, has reserves of around 50 million barrels. In all, the north-west coast of Australia now produces oil at a rate of around 400,000 barrels a day from 13 separate oilfields.

At least another six fields are earmarked for development over the next five years. But many more are likely to be discovered, with the potential existing for a field up to the billion barrel size to be discovered. BHP is developing Skua field, its third oil producer in the Timor Sea, at a cost of $A175 million. Skua has estimated reserves of 45 million barrels.

Deepwater potential

The new confidence about the size of Australia's total oil resource base has been provided by a big continental margins research programme — water depths of up to 2000 metres — by the Bureau of Mineral Resources (BMR). The virtual doubling in the estimates of potential Australian reserves, to about 15 billion barrels, means that the country can maintain extremely high levels of self-sufficiency well into the 21st century.

The first insight into the deepwater offshore potential for oil was provided by a number of BMR geoscientists in a joint paper delivered at the recent annual conference of the Australian Petroleum Exploration Association (APEA). They noted that oil and condensate reserves identified in Australia's 1.7 million sq km continental shelf area, excluding the Great Barrier Reef Marine Park, total 5.2 billion barrels. At a 50 percent level of probability a further 2.5 billion barrels remain to be discovered in these areas.

In his paper Dr David Falvey, acting associate director of the BMR, said: 'The continental margin immediately adjacent to the Australian shelf has an area of about 3 million sq km. This area is virtually unexplored and formal estimates of undiscovered petroleum are limited to north-east Australia and Triassic reefs. On balance, it is hard to see that the undiscovered resources of the deepwater Australian margin are not at least comparable to those beneath the shelf.'

Interest in deepwater exploration offshore Australia is expected to be revitalised during the next few years as prospective offshore blocks are put up for bidding. Bids are now being called for a number of exploration leases in the Great Australian Bight, including three deepwater leases in the Ceduna Terraces and two in the Duntroon Basin, west of Kangaroo Island.

BHP Petroleum's Challis-2A well

In the early 1980s, three different consortia carried out exploration in the deepwater areas of the Exmouth Plateau, which was then touted as the most likely area to provide discoveries on the scale of Bass Strait.

However, the search was eventually abandoned after a total expenditure of about $A200 million on 15 wells drilled mainly in water depths of between 800 metres and 1700 metres.

The only significant discovery was Esso Australia Ltd's giant Scarborough gas field, which is uneconomic. A Bureau of Mineral Resources geoscientist, Dr Neville Exon, said a second round of drilling was likely in the Exmouth Plateau within the next 10 years.

Bright outlook

Woodside Petroleum is expected to be one of the most active companies in the offshore developments. Crucial aspects of the brighter outlook include:

Oil production of up to 60,000 b/d in 1992 from the newly discovered Cossack field, with output possibly rising threefold by about 1995 when the bigger adjoining Wanaea field begins production. Recent reassessments of Cossack indicate that recoverable oil reserves are likely to be twice as large as the earlier expected 30 million barrels, while the latest Wanaea well has raised confidence that it would contain 200 million barrels.

Domestic natural gas supply would rise by almost 40 percent by 1995 if the West Australian government accepts a recent Woodside proposal for additional gas supplies for a new 600 megawatt power station.

Condensate production, when Goodwyn comes on stream, is now forecast to rise to 100,000 b/d which, at present prices, would be worth about $A1 billion a year, from the present output of about 20,000 b/d.

Incremental tonnages for LNG sales are being considered amid strengthening Japanese demand and plant performance at 10–15 percent above design capacity. Output could possibly be raised to more than seven million tonnes a year by relatively inexpensive plant alterations and Woodside is already considering the use of an eighth LNG tanker at a cost of $A220 million for additional sales after 1993.

A fourth cryogenic tanker, in which methane gas is kept liquid at minus 163° Celsius, was due to be delivered to the joint venture in September. The prospects for an additional tanker, and even greater cash flows than expected, look good.

An additional five cargoes sailed to Japan after the inaugural shipment in July last year, taking deliveries in the Japanese fiscal year ending March this year to 25. Fifty shipments are scheduled this year to the eight Japanese utilities, with an additional four also likely, raising revenues from a projected $A600 million to about $A650 million.

A computerised control room is at the hub of all this activity on the North Rankin A platform, the world's largest capacity gas platform which is 135 km off the coast from Dampier in Western Australia's north-west.

The tendering process for the $A2.7 billion Goodwyn third phase of the North West Shelf liquified natural gas (LNG) project will be completed with the awarding of a mechanical erection contract worth more than $A100 million.

Exploration activity

Offshore petroleum exploration activity continued at a high level in the second quarter and is expected to be sustained through at least the remainder of 1990, according to the Canberra-based Bureau of Mineral Resources. Thirteen of the 15 offshore exploration wells drilled were new field wildcats aimed at testing previously undrilled prospects. Seven of these were drilled off the north-west coast of Australia and six in the Gippsland basin of south-eastern Australia.

The BMR long held the view that Australia's best chances of finding major new oil resources lie offshore. Recent oil and gas discoveries and appraisal drilling, particularly off north-western Australia support this view.

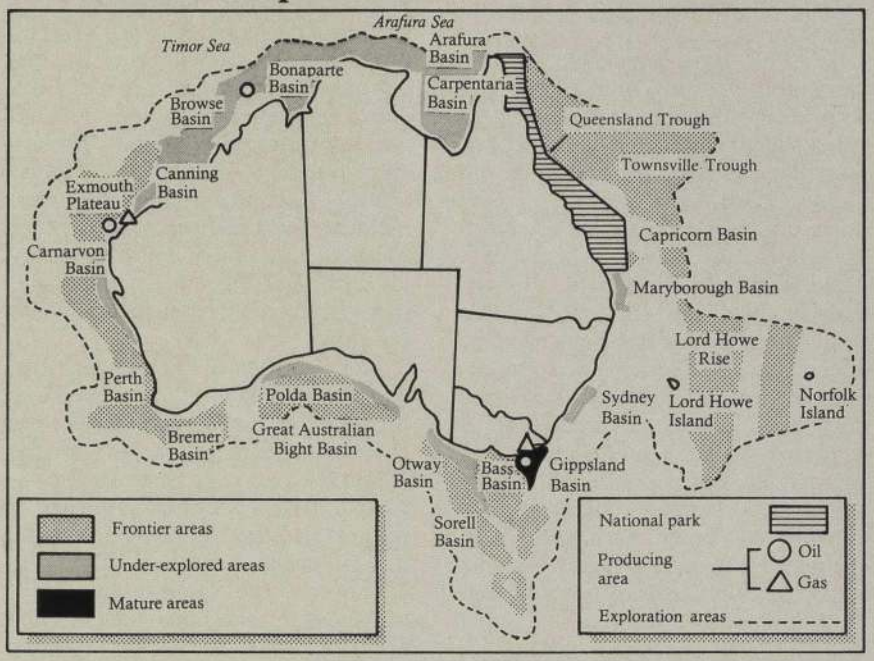
The prospect of sustained offshore exploration activity during the next six months is supported, according to the BMR figures, by the fact that the highest number of offshore seismic line kilometres (26992) were shot during a quarter. In addition, BMR collected a further 2115 kilometres of offshore scientific seismic data off north-western Australia aimed at frontier areas of the Australian continental margin. As seismic work is required to identify future drilling targets, seismic activity of this magnitude is seen as an encouraging indication of future levels of exploration drilling. The continuing increased level of activity reflects the strong interest of both local and overseas exploration companies in offshore exploration acreage.

The WAPET consortium has been a significant player in Western Australia for 20 years. Now, with Western Mining Corp, it has posted a second significant success on the Roller oilfield with a 5,925 b/d oil flow from the Flacourt formation. The well, Roller 4, follows the Roller 1 discovery in January which in turn led to the finding of the new oilfield in permit TP3-1, just south-west of the Saladin oilfield. The Flacourt sandstone was perforated over the interval 912 to 915.5 metres and flowed 29 degree API oil at a stabilised rate of 5,925 barrels of oil a day accompanied by 1.044 million cubic feet of gas a day at a wellhead pressure of 420 psi. The well has been temporarily suspended pending completion as an oil producer. The well partners now plan a 3D seismic survey over the entire Roller structure. Conceptual engineering studies of field development options are already under way.

The WAPET consortium, which controls 90 percent of the permit, is owned by Chevron Asiatic Oil Company (25.7 percent), Texaco Oil Development Company (25.7 percent), Ampol Exploration Limited (12.9 percent) and Shell Development (Australia) Pty Ltd (25.7 percent), while WMC owns the remaining 10 percent.

The partners said the Roller 4 success confirmed WAPET's interpreted north-easterly extent of the Roller oil reservoir. The field could now poten-

Australia offshore petroleum



Courtesy of Department of Primary Industries and Energy

Table 1
Successful offshore exploration wells completed – 1989

Well name	Operator	Depth (m)	Title	Result
Chervil 4	WMC	1618	TP7	Oil/Gas
Challis 8	BHP	1540	ACL3	Oil
Saladin 6B	WAPET	1875	TP3	Oil
Wanaea 1	Woodside	3011	WA28P	Oil
Chinook 1	BHP	3400	WA210P	Oil/Gas
Blackback 1	Esso	4401	VICP24	Oil/Gas
Chervil 5	WMC	1909	TP7	Oil
Jabiru 11	BHP	1840	ACL1	Oil
Talbot 1	Santos	1784	ACP12	Oil
Cowle 1	WAPET	1174	TP3	Susp/Oil

Table 2
Successful offshore exploration wells completed during 1990 to date

Well name	Operator	Depth (m)	Title	Result
Cossack 1	Woodside	3030	WA28P	Susp/Oil
Maple 1	BHP	4230	ACP2	Gas/Cond
Roller 1	WAPET	1332	TP3	Susp/Oil
Griffin 1	BHP	3400	WA210P	Susp/Oil
Wanaea 2	Woodside	3000	WA28P	Susp/Oil
Archer 1	Petrofina	4050	VICP20	Gas/Oil
Sinbad 1	Hadson	2898	TP008	Susp/Gas
Terakihi 1	Esso	3040	VICP24	Susp/Oil
Angel 4	Woodside	2825	WA3L	Gas/Cond
Challis 9	BHP	1700	ACL3	Oil

tially approach the size of the Saladin oilfield in which WAPET also has interests.

WAPET has announced plans to develop the tiny Yammaderry and Cowle oilfields adjacent to the Saladin oil facility in production permit TL4 in Western Australia. The two fields will be developed using a single-leg platform on each structure with production lines tied back to the Saladin facilities on Thevenard Island. Development costs of $A30 million include one directional well drilled on each structure to be used as a production well from the Flacourt sandstone formation. Crude oil production is expected to begin in February next year at an initial combined rate of about 6,500 barrels a day. The oil is light 49° API crude. Each field has an estimated life of four years with an expected cumulative recovery of four million barrels.

Timor Gap problems

Companies planning to explore for oil in the Timor Gap, with the implementation of the recently signed treaty between Indonesia and Australia now face problems.

Portugal still claims sovereignty over East Timor. Shortly after the signing of the treaty, it lodged a formal protest with Australia against its signing. One Portuguese minister described the treaty as a 'flagrant violation of international law and the UN charter.' Portugal could commence action against Australia before the International Court of Justice. While Australia has accepted the compulsory jurisdiction of this court, Indonesia has not, so the outcome of such an action is uncertain.

These unresolved international legal questions would need to be taken into account by petroleum exploration companies contemplating activities within the area covered by the treaty. An exploration permit covering part of the area had been granted by Portugal to a US company in the 1970s. There are also possible claims by three Australian-led consortiums which spent $A50 million in the 1970s exploring the area before it came under dispute.

Existing permit holders, including BHP, Chevron, Petroz, Santos, Shell and Woodside, have been told their expertise will be taken into account when it comes to releasing exploration permits. Industry sources expect permits to be let in the Australian-administered part of the treaty zone by November.

Some oil companies realise there may be legal problems in searching for oil in the 61,000 sq km area of the Timor Gap zone. Dave McDonald, managing director of Lasmo Oil (Aust) Ltd, agreed there were provisions in the treaty and associated rulings which, in his view, were unclear or could be amended to make the situation more workable.

Keith Orchison, executive director of the Australian Petroleum Exploration Association Ltd, said Australian companies 'already involved and those interested in the [treaty area] are very conscious of the legal complexities' of the treaty arrangements and would be looking at the terms of the permit contracts 'very carefully.' He said companies would approach the region with caution for a variety of reasons, including the legal aspects.

BHP Petroleum's floating production facility *'Iabiru Venture'.*

More gas

A multi-billion dollar project is being planned to tap the huge natural gas deposits discovered off the western coast of Western Australia. When given the go-ahead, the project will be at least equal in size to the $A12 billion North West Shelf development — and have the potential to earn Australia more than $A1.5 billion a year in export revenue.

The decision to conduct detailed studies was announced by the Western Australian government. The gas plan will tap the deposits of the Gorgon gas field, 130 km off the coast and about 60 km south of the North West Shelf's giant North Rankin platform. The Gorgon field is in far deeper water — up to 250 m deep — and the platform will have to be twice as large as that on North Rankin, already the world's largest.

Gorgon is owned by WAPET, two of whose major shareholders, Shell and Chevron, are both part owners of the North West Shelf project. 'The current view of this venture is a 6 milllion tonne-a-year liquid natural gas project of the same scale as the current Woodside venturers development,' said Western Australian government officials.

The gas could be piped ashore near Karratha and treated at the existing processing plant built by Woodside. Other alternatives would see a new plant built on an adjoining site — or a plant built on Barrow Island. The Gorgon venturers are looking to have their first export sales shortly after the year 2000.

Exploration in Timor Sea

BHP Petroleum Pty Ltd (BHPP) has been the most active explorer in the Timor Sea since 1983 when its first offshore wildcat well, Jabiru 1, struck oil.

In the early years BHPP spent about $A40 million a year on exploration in northern Australia. This rose to a peak of $A150 million last year, when four offshore rigs were used. Exploration expenditure in 1990–91 will fall to about $A120 million.

The expenditure still represents a drop in the bucket since the company's total area covers almost 100,000 sq km in the Timor Sea, Arafura Basin, Carnarvon Basin and the Bonaparte Basin. In the past 17 years, BHPP has spent $A450 million in these areas, most of it going into the Timor Sea where oil production from Jabiru and Challis has averaged 100,000 barrels of oil a day since February.

During this period, 44 exploration and 23 appraisal wells have been drilled, including 13 that have been tied into the production facilities at Jabiru and Challis. It is not widely recognised either by the public or the Federal government that the reserves so far discovered in the Timor Sea will run out in about five years.

The French-owned Elf Aquitaine, one of the pioneers in the search for oil in the Timor Sea, spent tens of millions of dollars with its only successes being the discovery of the Petrel and Tern gas fields. Last year, Elf Aquitaine cut loose by selling off these interests to the Adelaide-based Santos Ltd at prices that reflect the non-commercial nature of the offshore gas deposits.

Competition to develop the next oil field in the Timor Sea is intensifying.

Santos Ltd and its partners have decided to accelerate the exploration programme in ACP12, where it struck oil with its first well last December. The Santos joint venture, which gained a flow of 5000 barrels a day from Talbot 1, decided to drill a follow-up well, Talbot 2, which has been equally successful. Each well costs between $A7 million and $A8 million to drill.

Sumitomo Corp is considering plans to join Australian producers in a LNG project aimed at shipping up to four million metric tons of LNG a year to Japan for 20 years. The Japanese company is conducting a feasibility study into establishing a plant at Darwin, using natural gas from the offshore Bonaparte Gulf fields.

Sumitomo estimates the plant would cost between $A900 million and $A1.6 billion to build, excluding ships to transport the LNG. Exports could start in 1998, according to a report by Sumitomo. The Japanese company plans further discussions in the next two months with Australian companies and government officials.

Santos Ltd is the major shareholder in the Bonaparte Gulf's Petrel and Tern gas fields and is conducting estimates of gas reserves and will not make any decisions on the future of the fields until results are known. Sumitomo said in its report on the project that 'demand for LNG as a clean fuel in Japan and in other Asian countries is expected to increase. This project has several advantages over other grass-roots LNG projects in the Pacific Rim, such as transportation costs and the reliability of the host country.'

The Sumitomo spokesman said the project is dependent on signing up long-term customers in Japan. The company has talked with potential buyers there and believes other Asian nations also might be interested. Demand for LNG in Japan, South Korea and Taiwan is expected to rise to about 56.2 million tons a year by the turn of the century, Sumitomo said. Contracts have been arranged to supply 38.2 million tons by the year 2000, which leaves a shortfall of 18 million tons, the report said. ■

Modular rigs reduce topside weight

By Ian Shearer, Smedvig Ltd

As the UK offshore oil and gas industry enters the decade of the 1990s, the recent relatively steady oil price has not only created a return to near record drilling activity but, importantly, the stability to enable oil companies to plan for future field developments. The heady days of the 1970s have slipped into the distant past when announcements of large North Sea oil and gas strikes would lead inevitably to the placement of orders for steel or concrete platforms to exploit these new found riches. Undoubtedly further oil and gas reserves will be discovered which will economically merit the construction of platforms bearing full drilling and production packages.

The major challenge for the industry in the 1990s will be the economic exploitation of oil and gas from marginal fields. Reservoirs which lie in close proximity to existing platforms can be developed successfully with current sub-sea technology, it is the smaller fields which 'stand-alone' that present the greater challenge and will demand an innovative solution to their needs.

Recent platform designs have seen a trend towards lighter-weight (and thus reduced cost) jackets and top-side facilities. In the shallower waters of the southern North Sea, platform drilling facilities can be dispensed with in favour of cantilever jack-up drilling rigs. The emergence of Friede & Goldman Universe Class, Marathon le Tourneau 116-C and MSC CJ-62 harsh environment, deepwater jack-up rigs in the early 1990s will push this methodology into the central North Sea in water depths of around 350 feet. However, with expected high jack-up utilisation and high capital investment such rigs will command premium day rates.

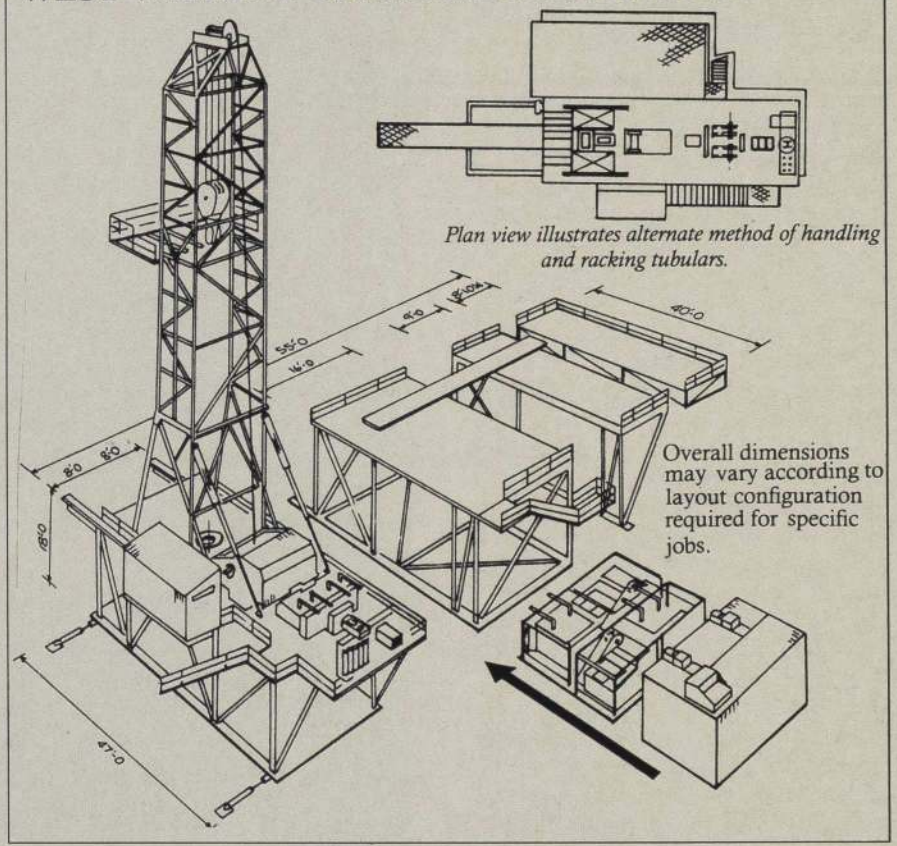
An alternative approach, which has been successfully employed in both the southern North Sea and the Gulf of Mexico is the use of modular drilling and workover rigs.

Modular rigs

Modular rigs have a proven history both in the southern North Sea and the Gulf of Mexico. To date, modular rig utilisation in the North Sea has been limited to cased hole workovers — running and pulling production tubing, drilling out plugs, milling packers and well killing operations with drilling experience so far restricted to the Gulf of Mexico.

Modular rigs used in UK offshore waters have exclusively been of the 'space saver' type. These rigs have been designed to operate on the smallest of platform deck space and carry minimal mud tank capacity (400 bbls). Drilling rigs operating in the North Sea will require mud capacities of at least 2,000 bbls with drawworks power of 1,500 hp to give a drilling depth of 16,000 feet. Modular drilling rigs and compact modular workover

WEST VALIANT OFFSHORE RIG PROFILE



rigs may share common operating philosophy but the drilling rig, for obvious reasons, cannot operate within the same space and weight constraints.

Nevertheless, modular drilling rigs not only offer cost, weight and space savings over conventional platform drilling packages but after completing a drilling programme they can be rigged down and shipped to another platform to undertake a further programme of drilling or workover operations.

Assembly and transportation

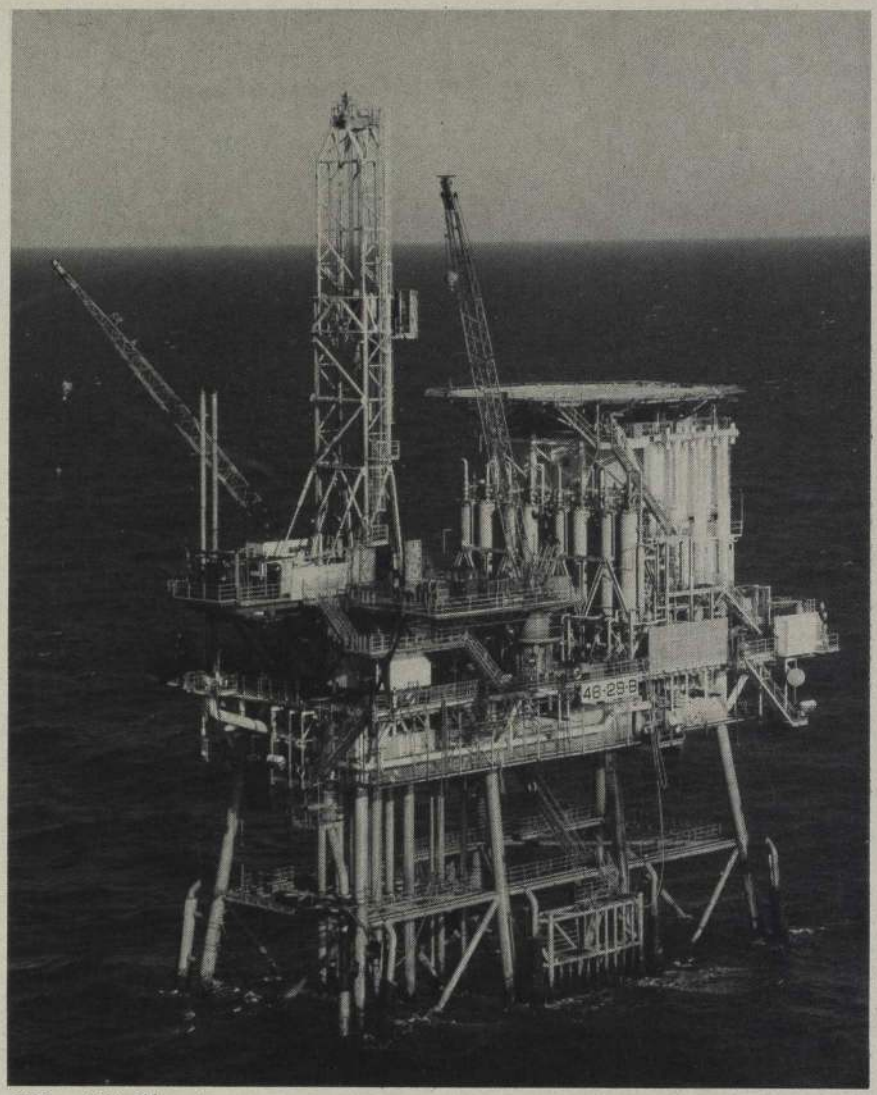
Modular rigs are transported and assembled as a series of units or components. The size and weight of each unit is determined by the lift capacity of the platform crane. Thus the units can be pre-assembled onshore to complement individual platform crane ratings. The heaviest lift for the West Valiant compact modular workover rig is 10.5 tonnes, however, operators have indicated component lifts of around 30 tonnes in the concept designs of modular drilling rigs. Alternatively the rig can be shipped and loaded on to the platform using a crane barge.

The modules forming the rig structure are normally pinned together allowing the supporting I-beam framework sections to be assembled quickly and efficiently.

The substructure which supports the drill floor and mast is assembled over skid beams which are arranged to transfer the weight of the rig to the load-bearing capping beams of the platform jacket structure. The skid beams also provide a means by which the rig can be repositioned over adjacent well slots using hydraulic jacks. Rotary table power is supplied via the drawworks, the table is normally mounted on the drawworks skid to eliminate the need for re-alignment after rig moves. The modular framework which houses the mud pumps, mud tanks and ancillaries supports the pipedeck and can be either pinned to skid with the substructure on the skid beams or remains on the skid deck depending upon the operation or the availability of platform space.

The mast is free-standing and does not require the use of guy-lines. The design permits horizontal or vertical (if platform space is limited) mast assembly and includes travelling block guide rails to offset wind induced motion of the hook/block.

Traditionally modular workover



West Valiant

Summary of rig weights

DESCRIPTION	*WEIGHT (LBS)*
Mast, Substructure, Pipe Racks, Mud Tanks and Jacks	695,230#
Drawworks and Accessories	83,240#
Mud and Kill Pumps for Well Servicing	49,000#
Mud Cleaning Equipment	52,885#
SCR System	55,000#
Blowout Preventers	232,790#
BOP Control System	21,500#
Rotary and Travelling Equipment	61,000#
Top Drive System	54,760#
Instrumentation	3,000#
Rig Air System	8,000#
Electrical	10,500#
Coke and Kill Manifold	30,000#
Auxiliary Equipment	156,400#
Halliburton Equipment	76,880#
Standby Generator	6,120#
Iron Roughneck	12,100#
1600 hp Mud Pumps	170,190#
Additional Modules	303,250#
Rig Up, Piping, Test and Rig Down	80,000#
Cuttings Cleaning Equipment	18,790#
ESTIMATED TOTAL WEIGHT	2,180,635#

A weight reduction of approximately 50 percent can be achieved, without down-rating hoisting capacity, for workover operations, rigging up with conventional rotary drilling equipment and well service pumps.

rigs were furnished with mechanical prime movers to power the rig drawworks and mud pumps. AC electrical power for lighting and centrifugal pumps was supplied directly from the platform or from a diesel driven electrical generator. Today the emphasis is on SCR rigs with DC motors taking favour over the diesel engine mechanical drives. The SCR modular rig may be furnished with dedicated diesel driven generator sets or alternatively powered from the platform through a drag chain connection. In either case it is prudent to incorporate a diesel driven cement or mud/kill pump within the rig package for the purpose of well control in the event of complete electrical failure.

There is nothing new about modular rigs, essentially they are specialised 'land rigs' designed for offshore use. However, they do present an interesting and worthy solution to reducing platform weight and are currently being given careful consideration by a major North Sea operator.

Modular rig

Concept studies have been undertaken for several operators into modular rig configurations, they range from large workover rigs through to sophisticated drilling rigs. To highlight the flexibility of these rigs a large modular rig was proposed for a full platform drilling programme. After completing the programme the rig can either be 'down-rated' to workover status by rigging down most of the drilling equipment or shipped to another platform to undertake drilling or workover operations with a similar or reduced drilling equipment inventory. ■

Summary of offshore modular rigs

Compact modular workover rig

The West Valiant CMWR owned and operated by Smedvig Ltd from its Great Yarmouth base is typical of a space saver mechanical rig.

Rig equipment and specification

WORKOVER DEPTH	20 000′
MAST	DRECO 10216-T Vertically Telescoping, free-standing. 102′ × 16′.
MAXIMUM HOOK LOAD	Gross Nominal Capacity 500,000 lbs Ten Lines 357,000 lbs
RACKING CAPACITY	10 000′, 4½″ Drill Pipe.
SUBSTRUCTURE	Height 21′, length 47′, width 17′ Capacity: 450,000# table; 225,000# set back.
DRAWWORKS	SUPERIOR 700 hp Powered by (2) GM 8V-92 diesel engines 375 hp each.
ROTARY TABLE	Gardner Denver 17½″ opening.
MUD PITS	Total Capacity 400 bbls.
MUD PUMPS	National JWS 400 (2) driven by GM 12V-71N (2), 456 hp each.
MUD MIX PUMPS	5 × 6 Mission (50 hp) 4 × 5 Mission (50 hp)
BLOWOUT PREVENTER	11″, 5000 psi Annular Ram 11″, 5000 psi Single Ram 11″, 5000 psi Double Ram
BOP HANDLING SYSTEM	Two, 5 ton hoists mounted on track and dollies.
CHOKE MANIFOLD	5000/10000 psi, H2S trim.
HYDRAULIC SKID RAMS	Two, 100 ton double acting rams on substructure base. Two, 50 ton double acting rams on drill floor skid beams.

ACKNOWLEDGEMENT
Smedvig Limited wish to acknowledge the help and co-operation of Dreco Inc, Houston, in the compilation of conceptual modular rig designs.

Advances in automated drilling

By JF Croxford, Strachan & Henshaw Ltd

A number of automated drilling projects are under way around the world as a result of the drilling industry's greater interest in automation. Drillers see automation as offering them smaller, lighter rigs with lower manning levels which can reduce the risks of injury and at the same time, reduce platform size and cost. Drilling rig designers see that automated rigs are now more practical as a result of better and more reliable components. There have been improvements in the elements of automated drilling systems from the sensors and computers needed to control them to the automatic torque wrenches and power swivels which manipulate the drill string. One approach to the integrated automated drilling rig is a system being developed in Britain by Strachan & Henshaw's offshore division, in collaboration with three British and one Norwegian oil companies' the Department of Energy's Offshore Supplies Office and the CEC. Strachan & Henshaw is building a prototype rig known as RA-D or Rig Automation-Drilling to prove the concept of versatile, automated pipe handling for drilling wells down to 20,000 feet.

The automated pipe handling will greatly reduce the need for roughnecks to handle pipe, casing, collar, stabilisers and other bottom hole assembly (BHA) pieces on the drill floor. This will not only improve safety on offshore rigs but will reduce manning levels and the size and operating cost of accommodation. The drilling rig is a fast singles rig and can be skidded using a lighter support structure, so further reducing platform cost.

This concept includes an integrated pipe handling system, capable of handling all diameters from 3½" drill pipe to 20" casing and 26" stabilisers and all lengths from 600mm crossovers to 14.8m joints of casing.

The pipe handling system is an integrated system under the control of a Programmable Logic Controller. The system comprises two major subsystems whose actions are interconnected.

The pipe handling and storage subsystem is composed of one or two carriages which move strongbacks, stackable pallets full of pipe joints or BHA parts and offer them up to a boom, which can pick each piece off its strongback, lift it and move it onto the well centreline. See **Figure 1.**

The drilling derrick and drill floor sub-system comprises four major units:

- A hydraulically powered swivel raised and lowered by a hydraulic winch.
- A hydraulically operated elevator attached to the power swivel and used to pick up pieces delivered to it by the pipe boom.
- A hydraulically powered pipe wrench, which automatically makes up and breaks out the joints between drill pipe, BHA pieces and/or casing.
- A set of automated slips to hold the drillstring while pieces are being added or removed.

In order to adapt to various sizes and styles of components, the handling system has the following special features.

Drill pipe strongbacks

The drilling rig, being a singles rig, will generally use range three (14.7m) grade S135,5" drill pipe. For workovers, range 2 grade G105,3½" drill pipe will be used and for hole depths around 6,000 metres, 6½" drill pipe may be needed.

All drill pipe including heavyweight drill pipe (HWDP) will be stored close packed on the strongbacks (13 joints of 5" drill pipe will fit on each strongback).

For all drill pipe and HWDP the strongbacks will carry less than 9 tonnes of pipe and their contents will be limited by the space available rather than the lifting capacity of the strongback carriage.

Collar strongbacks

The standard collar sizes which we have already provided for are 4¾", 6½", 8" and 9½". To make it easy to handle loaded strongbacks, we have limited the maximum weight to 15 tonnes. For this reason, strongbacks loaded with collar will not be filled up.

BHA pieces

The RA-D system is designed to minimise manual intervention when making up BHA assemblies. It is able to handle stabilisers, non-magnetic collar, drilling jars, crossovers etc. This is achieved by the flexibility of the grab and strongback system, which is able to position the strongbacks and grabs to retrieve any specified piece from a strongback and transfer it automatically to the derrick.

Where two strongback carriages are available, the system is made faster and more effective by storing the component pieces of the drillstring in both strongback stacks, so the boom can be picking one or more pieces out of the left strongback while the right strongback carriage is putting one strongback on a stack and collecting another from a different stack.

Figure 3 shows proposed left and right arrangements for a 3955m TMD hole similar to a deviated hole drilled in the northern North Sea in 1988.

The arrangement of BHA pieces has been optimised for this hole so that the strongbacks stay in place in the carriage as long as possible and are changed least often.

Picking up drill pipe

The pieces of drill pipe are stored in standard strongbacks, packed closely. 5″ S135 drill pipe has $6\frac{5}{8}$″ O/D joints; 13 joints can be stacked at 169mm centres on one strongback. In order to pick these up, the grabs are rotated on the boom to pick up the pipe piece nearest the edge of the strongback, the grabs are extended to strongback height and the strongback carriage is moved to bring the piece between the jaws before closing the jaws.

The same method is used for grooved collars and casing; the computer memorises the different sizes and pitches so that the grabs and the strongback move to the correct positions for each size of piece.

Picking up other BHA pieces

Whereas drill pipe, casing and grooved collars are stored wholesale and delivered wholesale, slick collars, stabilisers and crossovers must be delivered retail. They are therefore stored differently so that any one piece on a strongback can be picked out without disturbing the pieces on either side.

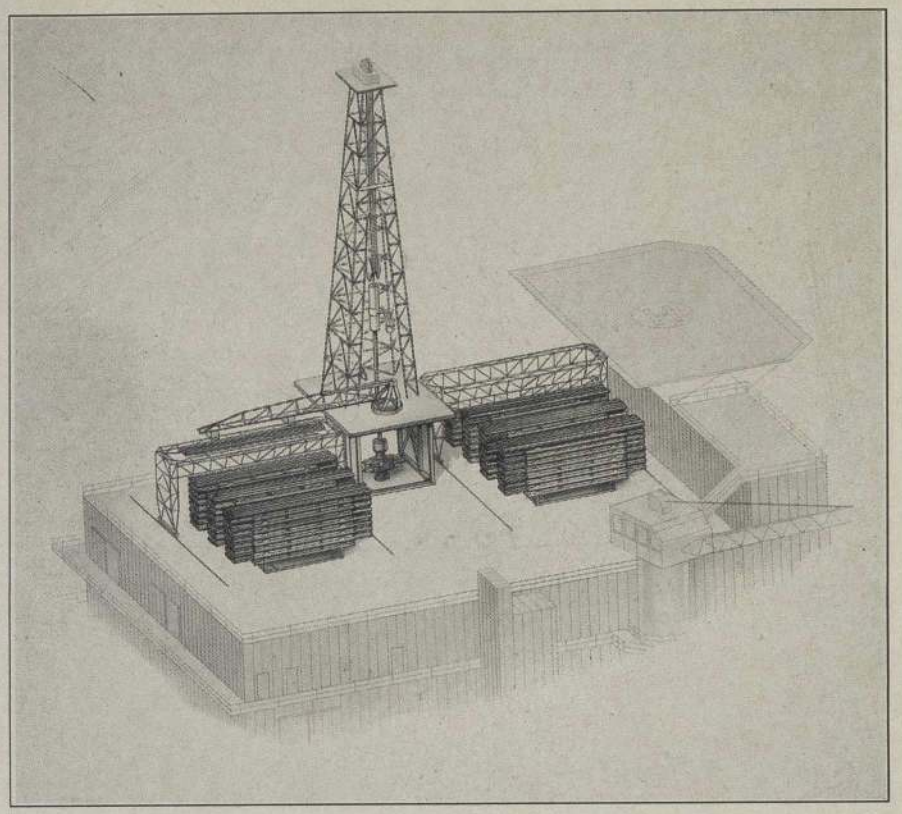
Boom and grabs

The boom is literally the central part of the RA-D system. It has been designed to be both versatile and fast operating.

All movements are hydraulically controlled with non-contact electronic sensors to provide reliable measurement of positions of all movements.

The boom has the following motions.

- **Luff** from the horizontal strongback storage to vertical for the derrick. This motion is hydraulically driven via a crank and rocker mechanism to provide smooth movement from horizontal to vertical in 16 seconds or less, carrying pieces weighing up to 3 tonnes.
- **Slew** from facing either strongback carriage to facing the derrick. This motion is driven by a hydraulic motor with proportional control to ramp down the speed as it approaches the stopping point.
- **Move grabs along the boom**
  The two grabs can move independently, driven by hydraulic motors. The position of each grab is sensed by encoders attached to the hydraulic motors which drive gears meshing with a rack.
  The grabs move lengthwise to adapt to different sizes and positions of pipe pieces. For example, the lower grab has one standard



Rig automated drilling station

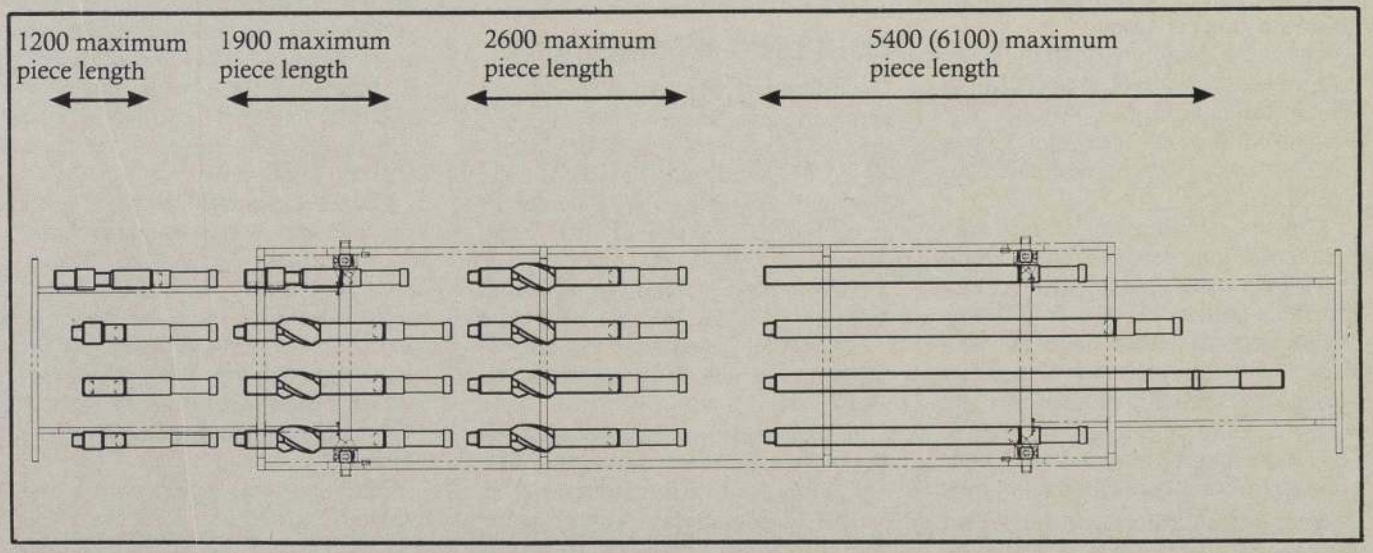


Figure 1: Plan view of strongback with miscellaneous parts

pickup position in the strongback for all range 3 joints of pipe or casing and another standard pickup position for all range 2 joints of pipe or casing.

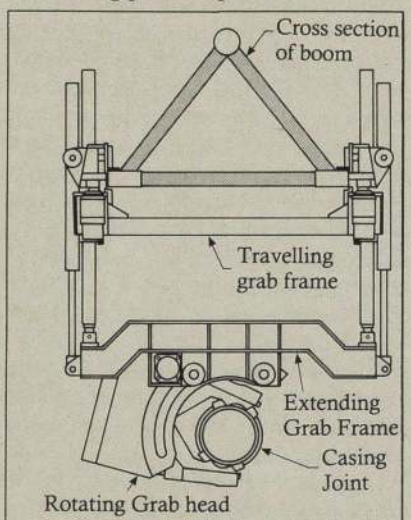
There will be several other positions for picking up miscellaneous pieces such as short collars, stabilisers and subs.

After the piece has been picked up, the grabs move it along to the index plate when a switch on the index plate stops the long travel motors. The piece is now in a known position for the elevator to grip on it eliminating the uncertainty of positioning in the strongback or the relative position of boom and strongback.

- **Extend grabs and index plate**

The extension and retraction is powered by hydraulic cylinders, one on the index plate and two on each grab. These cylinders have continuous linear position transducers which enable the computer to synchronise their movement.

Each grab has to move about 1 metre in and out. The fully extended position is just beyond the drill centreline in the derrick. The fully retracted position clears the derrick V-door for slewing the boom and clears the strongbacks and carriages when the boom is lowered. The extension at pickup depends on the size of the piece being picked up.



Cross section: Grab rotated and extended to pick up casing

Above is a cross section showing the rotating grab head picking up a casing joint with the grab fine extended. Once picked up the joint can be returned and fully retracted 1 metre to clear the derrick V-door for slewing the boom.

Figure 2

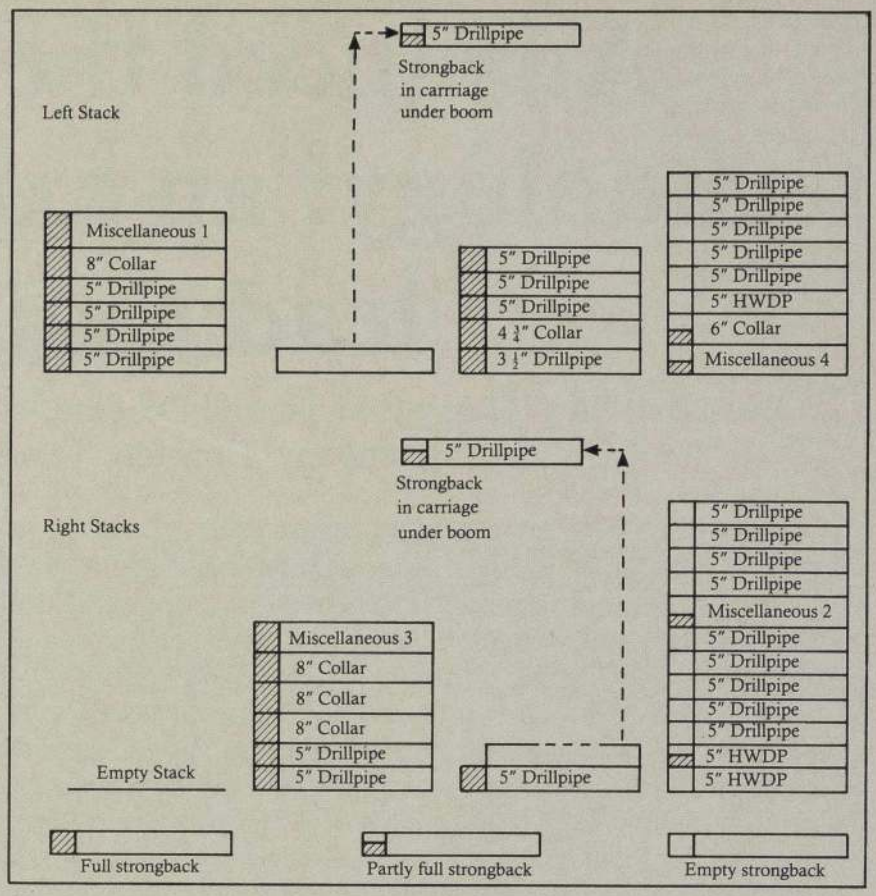


Figure 3: 'Parking' arrangements of strongback positions while tripping a 4000m coring string (Last piece of drill pipe being inserted when the coring bit is at the bottom of the hole)

The index plate has only two positions, extended to the well centreline and fully retracted, but it moves in synchronisation with the grabs, so a piece held in the grabs and moving with the index plate will not slip on the index plate.

- **Rotate grabs**

The rotation of each grab is powered by a hydraulic motor, which turns the grab through 70° so that it can pick up a joint of drill pipe, casing or collar.

Sensors on each end of the travel tell the computer when the rotation is complete.

- **Open and close grab jaws**

The grab jaws can be opened or closed to fit any piece from 3½" to 20" diameter.

In order to adapt to the larger diameters, a pair of jaws designed for pieces over 7" diameter can be moved into position to grip the larger joints of collar and casing.

All jaw movements are powered by slow speed hydraulic motors driving lead screws and the open positions are determined by proximity switches.

When the jaws close on a joint, the pressure in the hydraulic oil is used to sense that the piece has been gripped.

Conclusion

We have described the versatility of the automated storage and handling system for Rig Automation-Drilling. This versatility is achieved by using modern hydraulic systems controlled by Programmable Logic Controllers and non-contract sensors. This system is able to pick up and transfer to the drillstring all the pieces between the drilling bit itself and the powered swivel which drives the drillstring.

The same principles of automation have been applied to the power swivel, the automated slips, the automated pipe wrench and the draw works, so that they can work as an integrated system under the control of the driller. The driller can also intervene in the automatic sequence to add special pieces, or adjust any piece to be inserted. ■

Advanced thermal technology: an exploration lead tool

By A Earl Swift, Terry E Swift, and Leonard A Aucoin, Swift Energy Company, Houston, Texas

Iraq's invasion of Kuwait demonstrated once again, if it was not already obvious, the dangers inherent in relying too heavily on imported Middle East petroleum to meet the US domestic energy needs. The present crisis has focused attention on these dangers, with the global price of crude climbing to over $30 per barrel. At the same time, public debate in the United States has begun to centre on alternatives to imports and as a result, the exploration of domestic oil and gas reserves has received renewed interest.

The short-term price swings triggered by political upheavals in the Middle East were not entirely unexpected. A resurgence of US domestic exploration was even more predictable since rising global demand for crude oil had devoured a major portion of the world's total production capacity even before the current crisis took place.

Swift Energy Company, an independent US oil and gas producer located in Houston, realised several years ago that crude oil and natural gas price cycles would bring about major increases in product prices during the first half of the 1990s. Accordingly, it began to develop expertise in new exploration technologies that could provide a competitive advantage in the discovery and development of US oil and gas reserves. Technologies for horizontal drilling and the advanced processing of seismic data received a considerable amount of attention. In addition, Swift began to develop a proprietary technology under a licensing agreement with Lloyd Fons Exploration, Inc., which could be used as a lead tool to concentrate exploration efforts on those areas where hydrocarbon accumulations are most likely to reside. This lead tool is called Advanced Thermal Technology (ATT) because it is based upon the thermal insulating characteristics of crude oil and natural gas reservoirs.

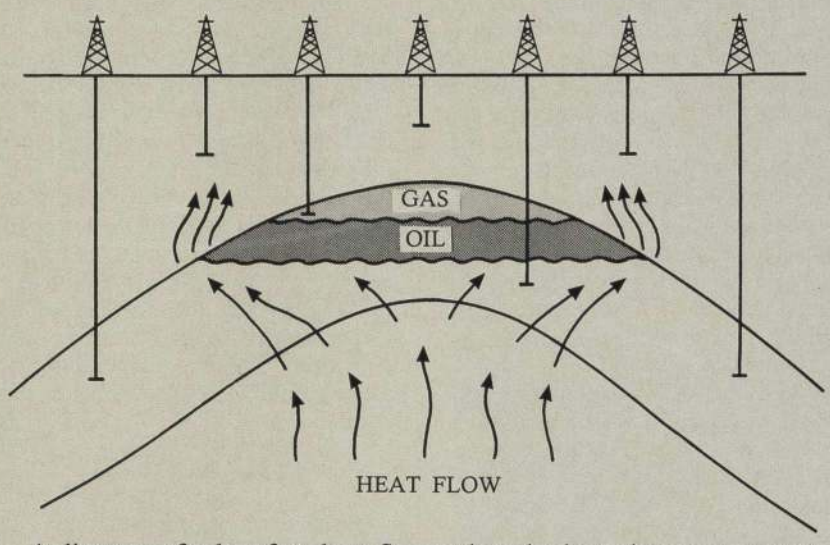
Theory of advanced thermal technology

The insulating characteristics of oil and gas create both vertical and horizontal temperature anomalies surrounding hydrocarbon deposits. Vertically, heat flowing from the centre of the earth tends to cause areas below a pool of hydrocarbons to be abnormally warm while the areas directly above are abnormally cool. Horizontally, areas adjacent to a reservoir at the same horizon should be warmer than their surroundings as heat flows around the reservoir toward the surface (see **Figure 1**). Because oil and gas are insulators, subsurface temperature abnormalities can be used to infer the presence of hydrocarbons. The thermal conductivities of oil, gas (CH_4), and water at one atmosphere and 20°C are 0.150W/m-°C, 0.063W/m-°C, and 0.602W/m-°C,[1] respectively. When these fluids are present in porous media, the thermal conductivity of the media is dependent on the relative quantity of the fluids.

Investigation of the thermal characteristics of subsurface materials was concentrated on heat flow by conduction, rather than convection or radiation, since the varying conductivities of the materials provides the primary mechanism for subsurface temperature anomalies. In porous formations, the thermal conductivity of the fluid filling the rock has the dominant effect upon the thermal conductivity of the system as a whole.[2] Both crude oil and natural gas have significantly lower thermal conductivities than salt water. Consequently, the presence or absence of hydrocarbons has a profound effect upon the thermal conductivity of materials within a particular geologic formation. Using a simulation technique, Swift analysed the relationship between the radius of pore space and normalised apparent conductivity for a quartz-gas model and found that increasing pore radius had a profound effect on the conductivity of the system as a whole (see **Figure 2**). The computer simulation suggests that as hydrocarbon pore volume increases, the conductivity of the gas begins to predominate.

Once the expected conductivities of the subsurface materials are determined, information about actual temperature differences below the surface can be combined with these conductivities to develop a picture of subsurface anomalies that might be caused by the presence of hydrocarbons. The required temperature information was obtained primarily through the use of bottomhole temperatures, which provided an attractive source of data because of their widespread avail-

Figure 1



A diagram of subsurface heat flows where hydrocarbons are present.

ability. A potential drawback of bottomhole temperatures is the inaccuracies that can be caused by the circulation of drilling fluids during the drilling process. If one is concerned with relative differences between many wells, however, inaccuracies caused by the drilling process tend to cancel each other out, and where applicable, the company employs a correction method to adjust bottomhole temperatures for some of these effects.

Development of thermal technology

The company has created a large digital database of measured temperatures for various areas of interest that it is investigating as part of its exploratory effort. It has established normal temperature gradients and identified areas where temperatures deviate from the norm. The initial product developed through the application of this process includes maps showing heat flux at different depth horizons where $Q = k(dT/dx)$ (Q representing the heat flux in $^3BTU/day\text{-}ft^2$, k representing thermal conductivity in BTU/day-ft- °F, and dT/dx representing the temperature differential in °F divided by the distance between the datums in feet). Areas with low flux rates can be indicators of the presence of hydrocarbons at deeper horizons while areas with high flux rates can suggest adjacent hydrocarbon accumulations at the same horizon. In addition to using heat flux maps to identify possible hydrocarbon deposits, vertical cross-sections have been developed showing areas where heat flows deviate from the norm.

The usefulness of those thermal lead tools were verified by undertaking a three-pronged investigation of the technology. This three-pronged approach included statistical studies, field studies and individual well studies.

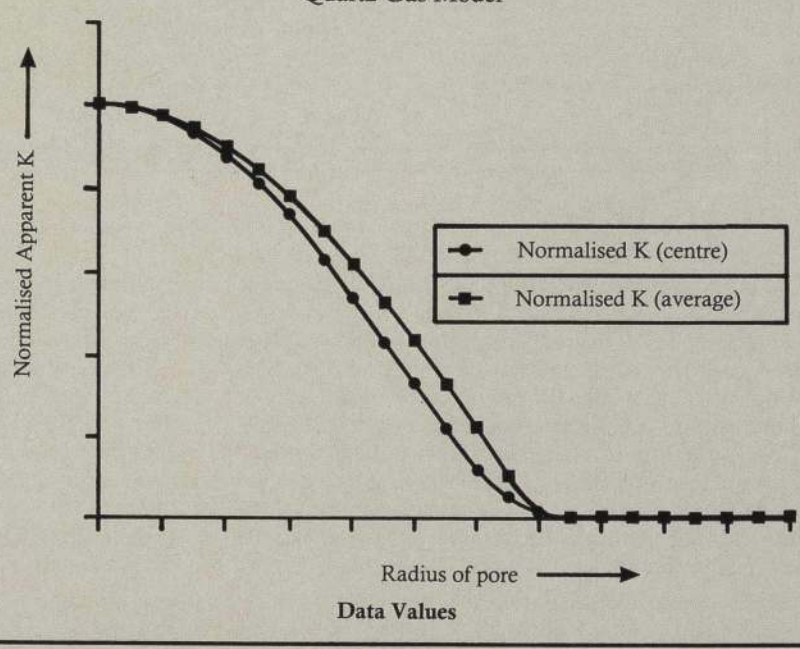
Initially, Swift looked at the effectiveness of the ATT process versus conventional technology for a portion of the Gulf Coast Basin. Subsequent drilling success rates in areas that, according to the company's thermal database, would have been thermal leads were compared to overall success rates for the study area as a whole. The success rates for wells drilled in ATT leads were more than double industy rates using traditional technology alone. The geo-thermal information was clearly correlated to the existence of hydrocarbon deposits. The correlation was not duplicated by geo-pressure data.

Next, information was obtained about the eight major fields in Texas, Louisiana, Kansas and Missouri, which compared the field location with the locations of associated temperature anomalies.[4] These fields were primarily associated with stratigraphic or combination traps. In every case but one, the entire field was located within the temperature anomaly. In the one exception, the majority of the field resided within what would have been a thermal lead.

Finally, the geoscientists looked at temperature versus depth profiles for particular wells in the Gulf Coast Basin. In the area in question, temperature increases with depth at an average of 1.6 degrees per 100 feet. The temperature gradient in any given area is directly proportional to the heat flux and inversely proportional to the conductivity of the system. One would expect that, because oil and gas are insulators, the temperature gradient across the pay zone of producing wells

Figure 2

Normalised Apparent Conductivity vs Pore Radius
Quartz-Gas Model



would be much greater than average. This was indeed the case for the wells investigated. For example, the temperature gradient across pay zones varied from 5 to 8 degrees per 100 feet.

Thus, the individual well studies reinforced the findings of the field studies and the statistical investigation. The results of the three-pronged approach indicated that Advanced Thermal Technology can identify new exploratory leads or build confidence in existing exploratory prospects.

Application

This thermal technology is used early in the exploration process to focus more traditional exploratory techniques, as well as advanced seismic processing, on areas that have a higher than average probability of yielding hydrocarbons. As soon as a structural area of interest is identified, the heat flow maps of the appropriate horizons are examined and evaluated. If thermal technology suggests that the area looks promising, additional geologic control is developed and, if necessary, additional seismic data are shot or reprocessed. Because seismic investigations, leasehold acquisitions, and exploratory drilling make up the vast majority of the finding costs associated with the discovery of oil and gas, the development of relatively inexpensive thermal leads has the potential of greatly reducing the cost of exploration. The more expensive elements of the exploratory process can be focused on areas where hydrocarbons are more likely to reside.

By lowering finding costs, thermal technology may also open up new areas of exploration that were previously uneconomical. For example, thermal leads may prove particularly useful for exploring stratigraphic traps. Because stratigraphic traps are caused by gradual changes in the permeability or deposition of sedimentary layers rather than abrupt shifts or deformations in structure, they have historically proved more subtle and difficult to identify than other trapping mechanisms. This suggests that a significant potential exists for the future discovery of oil and gas resources in stratigraphic areas because the difficulty in identifying these traps means that many of them remain unexplored. By indicating the presence of hydrocarbons, thermal technology may facilitate the discovery of oil and gas accumulations in stratigraphic traps, making new resources available for economical exploration.

While the ATT exploration tool provides the prospecting process with a direct hydrocarbon indicator and can open up new areas to economical exploration, Advanced Thermal Technology is not a panacea. Organic shales, salt domes, granite basement features, and other geologic conditions also alter thermal signatures. These complications could potentially confuse the explorationist; however, the proper integration of the ATT tool with state-of-the-art seismic methods should improve the quality of the exploratory prospect and lower overall prospecting costs.

Conclusion

Swift Energy believes that thermal technology has wide applicability in a variety of geologic environments. This lead tool provides an inexpensive means of focusing exploratory investigations on areas that have a significantly higher probability of containing oil and gas than areas identified using conventional technology alone. The company expects that Advanced Thermal Technology will play an important role, along with other innovative exploration technologies, in implementing its strategy of using technological advances to lower the finding costs associated with the discovery of new oil and gas resources in the United States. The economical exploration and development of domestic reserves is crucial to the security of not only of the United States but of all of the major oil consuming nations. Given the dangers inherent in reliance on imports from the Middle East, all of the technological tools available to lower the cost of exploration should be devoted to finding new oil and gas resources in the United States and other parts of the world. Swift Energy believes that Advanced Thermal Technology can make a significant contribution to that effort. ■

References

[1] Rohsenow, WM; and Hartnett, JP; *Handbook of Heat Transfer*, New York: McGraw-Hill Book Company, 1973.

[2] Somerton, WH; Keese, JA; Chu, SL: "Thermal Behavior of Unconsolidated Oil Sands", *Soc. Pet. Eng. J.* (October 1974) pp. 513–21 and, Anand, J; Somerton, WH; Gomaa, E: "Predicting Thermal Conductivities of Formations From Other Known Properties", *Soc. Pet. Eng. J.*, (October 1973) pp. 267–73.

[3] Bennett, CO; and Myers, JE: *Momentum, Heat, and Mass Transfer*, New York: McGraw-Hill Book Company, 1974 p. 246.

[4] Ball, Stanton, M: "Exploration Application of Temperatures Recorded on Log Headings – An Up-The-Odds Method of Hydrocarbon-Charged Porosities Prediction", *The American Association of Petroleum Geologists Bulletin*, Vol. 66, No. 8, (August 1982) pp. 1108–23.

Acknowledgement

Swift Energy Company wishes to express its appreciation to Lloyd Fons for his valuable contribution and participation in bringing this project to fruition.

Letter to the Editor

Dear Sir

You published my article on Reformulated Gasolines in the September 1990 issue of *Petroleum Review* and I was dismayed to see that a number of changes had been made to the text without any reference to me. In some cases the changes incorrectly modified the emphasis and in others they were very misleading.

As one example, in the section on unleaded reformulated gasoline, where I was referring to the need for protection against valve recession by the use of non-lead-containing additives, part of this sentence has been changed; it should have read 'Valve recession on unleaded reformulated gasoline could be a severe problem for vehicles with non-hardened valve seats unless some form of protection is included.'

I have already listed to you the other changes in an earlier letter and so will not repeat them here. I would like to make the point, however, that a reputable journal should not make changes to a text which modify the technical sense, without first consulting the author.

Yours faithfully,
Keith Owen

Editor: *Petroleum Review* tried to consult Mr Owen on several occasions but failed to make contact.

IP Information Service News

Journals merger

In 1991, ***International Petroleum Abstracts*** and ***Offshore Abstracts,*** two highly valued oil industry abstracting journals, will merge to provide a new and essential reference source, together with database facilities.

The new journal encompasses both upstream and downstream aspects of oil and gas technology, from a worldwide coverage of scientific and technical journals, conference papers, research reports, standards, and patents.

Online access to the database is available via the Pergamon Orbit host.

The selective compilation includes material which relates specifically to the offshore engineer such as welding, maintenance, diving, underwater equipment, metallurgical research, turbines, structural engineering, vibration, batteries and many other relevant subjects. This is in addition to sections on oilfield exploration and development, transport, refining, petroleum products, economics, safety, training, and pollution.

Informative, but concise abstracts are presented together with complete bibliographical details, and annual subject and author indices.

The joint publication is under the editorship of Gretchen E. Taylor, who has published and edited ***Offshore Abstracts*** since its inception in 1974 and who is currently editor of ***International Petroleum Abstracts.***

New educational booklet

A new booklet on ***Petrochemicals*** has recently been added to our 'Know more about oil' series. This popular series of publications is designed to give background information on the oil industry to students, schoolchildren, teachers and those entering the industry. This latest addition provides concise information on petrochemical processes and products, the economics and the market. Further details of all these booklets may be obtained by contacting the Information Department on (071) 636 1004.

A selection of new additions to the library

Arab economies: structure and outlook.
ARAB BANKING CORPORATION ABC.
3rd revised edition.
[U.K.] ARAB BANKING CORPORATION, 1990. Class Number: 900

Directory of Soviet engineering.
Moscow/London, Vneshtorgizdat/Flegon Press, 1990. Class Number: 080R REF/DIRECTORIES

Energy information for 1992.
INSTITUTE OF PETROLEUM IP. Edited by: ETHERTON, J.
London, IP, 1990. Class Number: 130 Pamphlet

European auto diesel challenge.
INSTITUTE OF PETROLEUM IP. Edited by: CLUER, A.
London, IP, 1990. Class Number: 817 Pamphlet

An evaluation of energy related greenhouse gas emissions and measures to ameliorate them. UK country study for the intergovernmental panel on climate change response strategies working group energy and industry sub group.
DEPARTMENT OF ENERGY
Energy paper series, Energy paper number 58.
London, HMSO, 1990. Class Number: 769.1 Pamphlet

Fuels, lubricants and associated products; Defence standard 01–5.
MINISTRY OF DEFENCE.
Issue 8 edition.
London, Ministry of Defence, 1989. Class Number: 810

Hydrocarbon technology international 1989/1990.
Edited by: HARRISON, Peter.
London, Sterling, 1990. Class Number: 720

Instrument engineers yearbook 1990 Annual manufacturers'/users' guide to instrumentation and control.
INSTITUTE OF MEASUREMENT & CONTROL IMC.
2nd edition.
London, IMC, 1990. Class Number: 080R REF/DIRECTORIES

International Petroleum Encyclopedia 1990.
Tulsa, PennWell, 1990. Class Number: 000R REF/DIRECTORIES

Man environment energy: The future.
ENTE NAZIONALE IDROCARBURI ENI. Edited by: QUILICI, F.
Rome, ENI, 1989. Class Number: 769 Oversize

The new energy markets of the Soviet Union and East Europe.
FINANCIAL TIMES BUSINESS INFORMATION. By: LYONS, P. K.
London, Financial Times Business Information, 1990. Class Number: 131

North sea field development guide 1990.
OILFIELD PUBLICATIONS LTD OPL.
3rd edition.
Ledbury, OPL, 1990. Class Number: 138R REF/DIRECTORIES

Pipeline Management 90—symposium papers 13–14 June 1990.
PIPELINE INDUSTRIES GUILD.
London, 1990. Class Number: 615

Rapid methods for diagnosis of microbial problems in the petroleum industry.
INSTITUTE OF PETROLEUM IP. Edited by: WATKINSON, Dr R. J.
London, IP, 1990. Class Number: 295

IP Technical Report

Exploration and Production

Comments on the first draft of the Code of Practice for 'Well Control during Drilling and Testing of High Pressure Wells' have been received. The more specific aspects of high temperature and high pressure well control and well testing will be given greater emphasis in the second draft. The extent to which the Code relates to provinces other than UKCS is under review.

The IP/SPE Offshore Safety Conference on 22 November has attracted considerable interest in view of the imminent publication of the Cullen report.

A decision will be taken at the month-end by the ISO Technical Board on the status of selected API standards in international use.

Refining and Marketing

A Marketing panel has been formed to deal with all vapour recovery issues.

The Institute proposal that the HSE/IP design code for tankers conveying flammable liquid should be submitted for adoption as a European standard has resulted in the setting-up of a British Standard committee. SMMT are expanding the code to a manufacturing specification. Agreement has been reached within CEN for discussions to start in 1991.

The Conveyance Panel is meeting the HSE Hazardous Installations and Transport of Dangerous Substances National Interest Group to discuss periodic examinations of road tankers and the testing of P/V and fire engulfment relief valves.

The HSE have requested discussions on the possibility of an anti-static additive being made a requirement in middle distillate as a precaution against static ignition during switch loading of road and rail tankers. The meeting has been scheduled following an internal debate among companies.

Having completed a survey of safety related plant, equipment and procedures at member companies' road loading facilities, the Marketing Sub-Committee is now engaged in identifying compatibility issues affecting distribution terminals, transport and customer premises.

A meeting with HSE, CIA, ITSA and CBI has resulted in numerous changes in the HSE's draft guidance document on the storage of flammable liquids in fixed tanks above 10,000m^3 total capacity to conform more closely with IP codes and oil industry practices.

The Aviation Hydrant Pit Systems Code has now been published in its revised form covering both new facilities and the replacement of obsolete valves in small pit boxes.

The first meeting of the Fire Safety Precautions Working Group has been held. A programme of work to draft a Fire Precaution Code for the Oil Industry was agreed and is now underway. The anticipated completion date is end-1991.

The Institute has proposed to UKPIA the formation of a joint Working Group to consider comments on the IP draft Users' Guide to Potential Safety Hazards of Hydrogen Sulphide in Heavy Fuel Oil. UKPIA nominations are awaited.

The Code of Practice on Area Classification has been published by John Wiley.

The Chairman of the Engineering Committee, Mr MJ Salter, is conducting an appraisal of the activities covered by the Engineering Committee. This review will include identification of the longer-term objectives which the oil industry requires of the Institute.

Petroleum Measurement

The following measurement papers are ready for submission to the publishers:

- Recommended UK Practice for Proving Gantry Meters fitted with Electronic Heads
- Code of Practice for the Proving of Loading Gantry Meters.

Panel PM-A-1, Tank Calibration, has been reconvened. The agreed work programme includes an assessment of the status of new technology calibration systems, while work has commenced on revision of the fundamental method of calibrating tanks using manual methods (Petroleum Measurement Manual, Part II, Section 1, Tank Calibration, published 1969).

Concern has been expressed to the National Weights and Measures Laboratory, BSI and the International Standards Organisation, ISO, about the possible adoption by the EC of blanket OIML Recommendations in the measurement field.

Standardization

The ASTM sent a delegation of 14 led by Dr Ed White to the biennial IP/ASTM meeting held in London. At this meeting many topics relating to test methods and their production were discussed together with the problems associated with producing technically up-to-date ISO test methods.

IP members represented BSI at the ISO TC 28 Meeting held in Budapest. Among the many test methods discussed was the determination of knock characteristics (Research and Motor Methods). The problems associated with the changes proposed by the ASTM were not resolved and will be further discussed at the ASTM meeting in December.

This meeting also saw the adoption of the new ISO Directives which allow the appointment of project leaders.

Health and Environment

An update of the Professor Grasso study on the carcinogenicity of automotive emissions has been received. The original Grasso study and update formed the major part of the Institute's submission to the Royal Commission on Environmental Pollution study on Emission from Heavy Duty Diesel Vehicles.

A scoping study is planned on soil and groundwater contamination by hydrocarbons with the objective of standardising procedures for the measurement of contamination on petroleum sites.

A conference on 'Oil Mists — Occupational Health Risks' has been organised for 18 October.

The IP sponsored research project to investigate bacterial growth in biofilms has been successfully completed. The final report is in the course of preparation. Following on from this work a further year has been proposed and is at the final approval stage. The objective is more effectively to reflect biofilm properties in an industrial environment.

J Hayes, Technical Director

Around the Branches

Aberdeen
9 October: 'The Gannet Project', by John Carter, Project Manager, Gannet Project, Shell UK Exploration and Production.
13 November: 'What is the environmental cost of offshore oil?', by Dr John Davies of the Marine Laboratory, Department of Agriculture and Fisheries for Scotland.
23 November: Annual Dinner — Principal speaker Mr John Browne, Managing Director and Chief Executive Officer, BP Exploration.

Edinburgh and South East Scotland
1 November: 'Advances in power generation' by Mr JC Waterton, Scottish Power.
22 November: 'Applications of advanced computing in the petroleum industry' by Dr N Carmichael, Shell Expro at Herriot Watt University, Riccarton.

Essex
10 October: 'Environmental legislation in the oil industry — current and future' by Mr P Sloan, Assistant Director of United Kingdom Petroleum Industry Association.
28 November: Ladies Evening — 'Christmas Shopping at Sainsbury's' by Mrs C Gillett, Home Economist of J Sainsbury plc.

Irish
Date to be announced: 'Offshore Exploration' by Mr Duane Deines, Marathon Petroleum (I) Limited.

Humber
26 October: Annual Dinner Dance, Beachcomber, Humberston.
22 November: 'Oil spill response' by a speaker from the Oil Spill Service Centre, Southampton.

London
25 October: 'Minimising Potential HS&E exposures in petroleum shipping operations' by Mr M Hind, BP Shipping.
15 November: 'Never a dull moment — 36 years in petroleum engineering' by Basil Butler, OBE, The British Petroleum Company Plc.

Midlands
17 October: The Green Bill and environmental developments in the 90s' by Mr David Nott, Leigh Environmental.
14 November: 'The use of SPC in pursuit of continuous improvement in quality' by Mr A Leslie, Ford Motor Company Ltd.

Northern
16 October: 'Electrical oils' — a video by Carless Refining and Marketing.
13 November: 'EMPROX and synthetic metal working fluids' a talk by ICI.
23 November: Annual Dinner Dance, Belfrey Hotel, Handforth. Guest speaker Mr Brian Goodland, of Texaco.

Shetland
9 October: 'Attitudes of Banks to financing oil supplies and services in far flung places' by Mr Tom Borthwick, Bank of Scotland.
2 November: Annual Dinner — guest speaker Basil Butler OBE, Director, British Petroleum and President of the Institute of Petroleum.

Southern
14 October: Treasure Hunt.
26 October: 'The rusting of the Iron Curtain' by Julian Critchley, MP at Exxon Chemical Diner, Fawley.

South Wales
18 October: 'Improve your driving' by Superintendent MV Gage, Powis Constabulary, at Amoco Refinery, Milford.
22 November: 'The Severn barrage project' by Dr TL Shaw, at BP Oil Llandarcy.

Stanlow
30 October: 'Alternatives to CFC's' by Dr Hugo Steven, ICI.
8 November: 'Sea transportation' by Mr Andrew Jones, Jo Tankers.
30 November: 'Golden Jubilee' Dinner Dance.

West of Scotland
23 October: Celebrity Lecture.

Yorkshire
13 November: 'Automotive trends' by Mr J Moore, Eythel Corporation.

Deaths

We report with much regret the deaths of the following members:

	Born
Henry J Bezer, Altrincham, Cheshire	1925
John Ladd, Rickmansworth	1922
William G Peacock, Streetly, West Midlands	1906
Michael Swiss, Sherwood, Nottingham	1920
Anthony T Wray, Iver, Bucks	1916

Deliveries into Consumption

UK deliveries into inland consumption of major petroleum products —Tonnes

Products	*July 1989†*	*July 1990**	*Jan–Jul 1989†*	*Jan–Jul 1990**	*% change*
Naphtha/LDF	205,780	248,610	1,830,140	1,740,600	−4.9
ATF—Kerosine	678,000	647,510	3,731,810	3,835,500	2.8
Motor Spirit	2,018,900	2,119,600	13,791,910	14,205,440	3.0
of which unleaded	454,220	718,680	1,923,502	4,094,150	112.8
Super unleaded	n/a	84,710	n/a	509,200	
Premium unleaded	n/a	633,970	n/a	3,584,950	
Burning Oil	68,350	127,030	1,055,290	1,168,770	10.8
Derv Fuel	819,910	912,000	5,776,030	6,214,440	7.6
Gas/Diesel Oil	557,100	639,600	4,910,960	4,778,140	−2.7
Fuel Oil	640,270	1,165,680	5,707,490	8,109,590	42.1
Lubricating Oil	72,420	71,340	519,800	484,620	−6.8
Other Products	535,600	590,210	3,796,750	4,010,690	5.6
Total above	5,596,330	6,521,580	41,120,180	44,324,430	7.8
Refinery Consumption	485,710	494,420	3,374,560	3,441,910	2.0
Total all products	6,082,040	7,016,000	44,494,740	47,766,340	7.4

†Revised *Preliminary n/a not available

Institute News

New Fellows

Dr Peter Miles joined ICI Dyestuffs Division as a laboratory technician in 1953. While there, he embarked on a London external degree by part-time study, which he completed while working on synthesised lubricants with the Geigy Company, which he joined in 1956.

After gaining his doctorate, Dr Miles continued his research, moving from ester technology to phosphorus chemistry on becoming a Group Leader in 1968. His researches led to the large-scale production of anti-wear additives for engine oils and several scale control additives for desalination plants in the Middle East.

Dr Miles is currently Head of the Ciba-Geigy Oil Chemicals Application Laboratory, where one of his duties is to formulate the biodegradable ester basestocks he made during his research. These fluids are now used as transformer oils, chain lubricants and compressor oils. He is also responsible for testing of new corrosion inhibitors, metal deactivators and extreme pressure additives for both water and oil systems.

He has served on several IP Committees, both as Chairman and Secretary, as well as attending meetings of the German Standards Committee (DIN) and taking part in International Round Robin testing. An active committee member of the IP Northern Branch; he served as Honorary Secretary for five years before his election as Chairman in 1989.

Mr Christopher Willy read law at Oxford and international law at Cornell University, becoming a barrister in 1955.

Following National Service, he spent five years at the Foreign Office, where he learned Arabic, and served in Lebanon and the Sudan. He joined BP in 1960 as Company Representative in Abu Dhabi and Libya and as Secretary of the Iranian Consortium in Teheran, serving also as Alternate Director of the Iraq Petroleum group.

He headed BP's Concessions Group for four years, seeking new exploration and production acreage on a worldwide basis and in the mid-1970s became Co-ordinator in London for BP's UK and North Sea exploration and production operations.

In1982 he transferred to UKOOA, where he was Director – External Affairs, until his retirement this year.

While in UKOOA, Mr Willy became involved in Institute activities and has been a member of the IP Energy Economics Group Committee for eight years and the Publications and Information Services Committee for four years. He is a founder member and currently Chairman of the IP Exploration and Production Discussion Group.

Mr Graham Weale is Manager, WEFA Energy, a division of The WEFA Group, an international consulting firm which he founded in 1987. He specialises in the European downstream oil and natural gas markets and has written several major reports on these subjects. He has acted as a consultant to the Continental Gas Buying Consortium and as arbitrator in respect of oil price disputes for North Sea pipeline companies.

Mr Weale's main industrial experience was gained in Esso Petroleum Co., where he held a variety of positions in the supply and refining divisions which entailed responsibility for production, distribution and long-term planning.

Mr Weale has a science degree from Oxford University and an MBA from Cranfield School of Managment. He is a committee member of the Institute of Petroleum Energy Economics Group and an associate of the Chartered Institute of Arbitrators.

Dr Stephen Maxwell worked as Consultant Microbiologist for a firm of oilfield corrosion engineers in Aberdeen after gaining a doctoral degree in Petroleum Microbiology from Aberdeen University in 1984, sponsored by Shell Expro. In 1986, he became Senior Partner of Media Supplies, a firm which specialised in the manufacture of test kits for monitoring microbial contamination in industrial plant. Dr Maxwell was appointed Managing Director of Oilfield Microbiology Services Limited in 1988, which offers consultancy and analytical services in industrial microbiology.

Dr Maxwell was the first recipient of the Institute of Petroleum Paul Rumsey Prize in 1986.

PETROLEUM RETAILING AFTER THE MONOPOLIES REPORT
The challenges of the 1990s

The publication of the Monopolies and Mergers Commission report brought to an end a year of uncertainty for petroleum retailers. Management can now concentrate on the major challenges to be faced in the 1990s in securing an acceptable return on the major investment made in this highly competitive sector of the market. The events of the past year have shown, however, that one such challenge lies in an unsatisfactory public image and media relations.

The Energy Economics Group's retail conference for 1990 looked at these challenges through the eyes of three oil companies of differing sizes and attitudes. The opportunities in product quality and the environment, forecourt automation and merchandising and improved communication over the decade ahead were also covered.

UK £18.00 Overseas £21.00

Please send remittance with order.

This publication is available from the Library, The Institute of Petroleum.

New Members

Axiak, V, Head, Dept of Biology, University of Malta, MSIDA, Malta
Al-Ghamdi, U, PO Box 13122, Jeddah 21493, Saudi Arabia
Ball, DJ, Conoco Ltd, Conoco House, 230 Blackfriars Road, London SE1 8NR
Brown, RW, PO Box 1029, Al Jubail 31951, Saudi Arabia
Christie, AG, Villa de Rohan, Triq il Keffa, Swieqi, Malta
Clark, AR, Grange Farm, Grange Road, Leconfield, North Humberside HU17 7NG
Couch, MJ, Overrock, Woodcroft, Chepstow, Gwent NP6 7PZ
Chwialkowski, J, c/o Beck (Meters) Ltd, 1 Greenlea Park, Prince George's Road, Colliers Wood, London SW19 2JD
Davies, AW, 24 Kiln Lane, Ley Hill, Bucks HP5 3QS
Davison, P, Clyde Petroleum Plc, Coddington Court, Coddington, Ledbury, Herefordshire HR8 1JL
Dean, J, Shell UK Oil, c/o UOCS/2, Shell Mex House, Strand, London WC2R 0DX
Duncan, AJ, Abela Management Services S.A., 4/6 Savile Row, London W1X 1AF
Ebejer, E, Medina Offshore Services Ltd, 12 Barriera Wharf, Valletta, Malta
Essien, GE, PO Box 70480, Victoria Island, Lagos, Nigeria
Fenty, MJ, Laser Graphic Design, Laser House, Rutland Street, Grimsby, South Humberside DN31 3AF
Fox, PM, 12 Spenlow Drive, Chelmsford, Essex CM1 4UR
Gatt, JA, Villa Gerald, L-Ikliw Road, Naxxar, Malta
Graham, PS, 89 Castlesteads Drive, Sandsfield Park, Carlisle, Cumbria CA2 7XD
Grima, JF, Kenn Taghna, Triq Il-Qannes, San Gwann, Malta
Harding, JF, 11 Stirling Way, Christchurch, Dorset BH23 4JJ
Ihre, HT, Wayne Europe, Box 30049, 20061 Marmo, Sweden
Jones, GA, 44 Chestnut Drive, Pinner, Middlesex HA5 1LY
Knight, J, Asst Director, County Natwest Ltd, 9th Floor, 135 Bishopsgate, London EC2M 3UR

Koko, IT, Port Harcourt Refinery Company, PO Box 585, Port Harcourt, Rivers State, Nigeria
Kulasinghe, UE, 18B Pitmedden Crescent, Aberdeen AB1 7HQ
Lanham, PI, 2 Princes Road, Ruakaka, Northland 0253, New Zealand
Lill, GF, 35 Marsden Lane, Aylestone, Leicester LE2 8LS
Malloy, M, 20 Barbour Grove, Milesmark, Dunfermline KY12 9YB
Maycott, RR, 3225 Gallows Road, Fairfax, Virginia 22037-0001, USA
Mclean, BS, 2 Court Close, Little Dewchurch, Hereford HR2 6PT
Mills, A, Petrovend (Europe) Ltd, 41 Business Park, South Park Way, Wakefield, West Yorks WF2 0XJ
Milton, J, 11 Deben Court, Braintree, Essex CM7 6XQ
Moss, CM, Brookes Bell & Co, Oriel Chambers, 5 Covent Garden, Liverpool L2 8UD
Ockenden, PME, 71A Klea Avenue, London SW4 9HZ
Pearce, HA, South Western Tar Distilleries Ltd
High Street, Totton, Southampton SO4 4TN
Pritchard, CD, Clyde Petroleum, Coddington Court, Coddington, Ledbury, Herefordshire HR8 1JL
Rendell-Lea, NJ, Enterprise Oil Plc, 5 The Strand, London WC2N 5HU
Ridings, J, Clyde Petroleum Plc, Coddington Court, Coddington, Ledbury, Herefordshire HR8 1JL
Robotham, CS, Heathcote, Guildford Road, Westcott, Dorking, Surrey RH4 3QE
Sakai, T, c/o Japan Oil Development Co Ltd, 65/66 Queen Street, London EC4R 1EB
Sharp, JC, Meteorological Office, Aberdeen Weather Centre, Seaforth Centre Lime Street, Aberdeen AB2 1BJ
Snaith, HN, 1 Kings Walk, Leicester Forest East, Leicester LE3 3JP
Srinivasan, S, Chairman & Managing Director, Mobil Trading & Supply Ltd, Mobil Court, 3 Clement's Inn, London WC2A 2EB
Stock, JD, 5 Tudor Gardens, Hedge End, Southampton, Hampshire SO3 4AT
Taniguchi, S, c/o Japan Oil Development Co, London Office, 65/66 Queen Street, London EC4R 1EB
Thomas, NA, Mobil Oil Co Ltd, Coryton Terminal, The Manorway, Stanford-le-Hope, Essex SS17 9LQ
Tierney, WJ, Managing Director, Manufacturing & Marketing, Texaco Ltd, 1 Knightsbridge Green, London SW1X 7QJ
Wegner, H, Flat 35 Kappara Court, Triq il-Buqrajq, St Julians, Malta
Wilkinson, P, Treramleon, Triq Hal Drasu, Bidnija Mosta, Malta
Wood, KW, 15 Ballingham Close, Tile Hill, Coventry

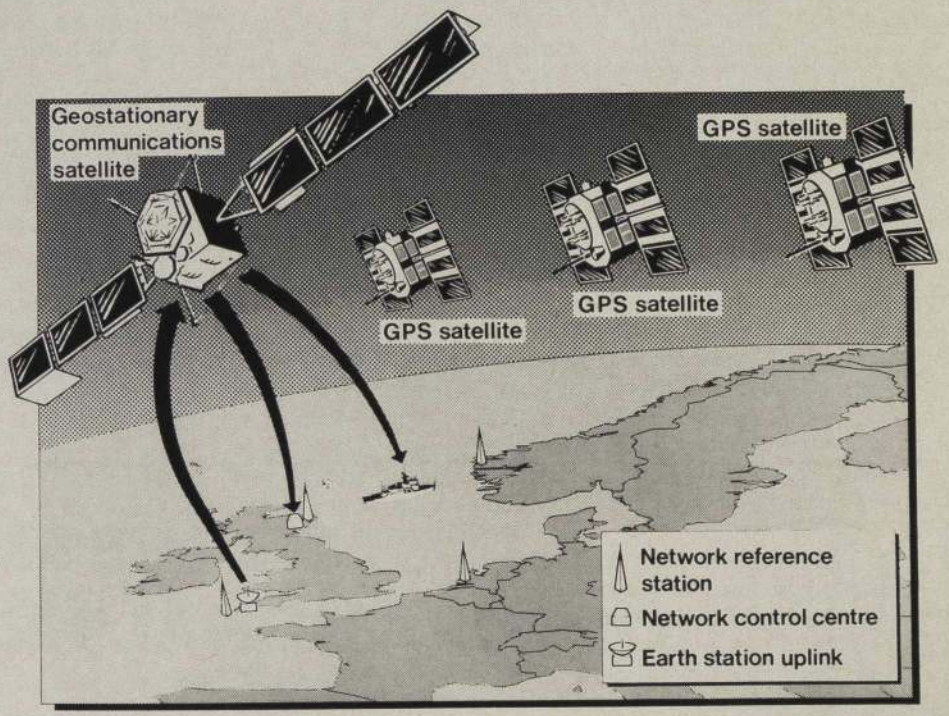
Racal survey launches Skyfix

RACAL Survey has introduced the first network differential GPS (Global Positioning System) service using the Inmarsat Atlantic Ocean region satellite for the datalink.

Called SkyFix, the new satellite-based system has significant advantages over a terrestrial link including wide area coverage, low data error rates and high message update rates.

Racal Survey's fully-networked Skyfix system has GPS reference stations in Norway, Holland and two in the UK, providing excellent coverage for the North West Europe Continental Shelf. Data from the reference stations is gathered together in a Network Control Centre in Aberdeen, where it is integrity-checked prior to being formatted into a single composite message for broadcast by the British Telecom earth station at Goonhilly Downs in Cornwall.

The differential GPS system works by broadcasting corrections (to observed GPS pseudo ranges) from a shore-based reference station. The corrections for each satellite, as determined by the specialised software, are transmitted via SkyFix. A purpose-designed unit decodes the data which is then applied to the onboard GPS equipment. The differentially-corrected GPS position of the vessel is then interfaced to the survey computer.



Bug tester

BIOMET Laboratories Ltd have developed two products which have the unique property of being able to conveniently detect aerobic bacteria (Microstrip BT) and yeasts/moulds/fungi (Microstrip Fm) in 100 percent hydrocarbon materials by a simple test.

The test consists of a firm plastic strip to which is affixed a dehydrated test pad containing nutrients ('food') to support microbial growth and indicators which show yeast/mould/fungal colonies in black and bacterial colonies in red.

•Microstrip are supplied 25 tests per kit and all you have to do to test a 100 percent hydrocarbon material is rehydrate the test area with water, dip test area into the hydrocarbon or 'water-bottom' and place into the sterile incubation pouch supplied. Incubate for about 24/36 hours at 25° to 30°C for bacteria or 72 hours for yeasts/moulds/fungi — and then simply read off the results from the conversion chart.

On the move

Barge cranes offload a distillation tower at the North Sea Petrochemicals plant in Antwerp, Belgium. The tower, the biggest ever made in one piece in Europe, is more than 356 feet long, 21 feet in diameter and weighs more than 2 million pounds. It is part of a (US) $250 million complex being built by North Sea. MW Kellogg Limited, London, is providing the engineering, procurement and construction management for the plant.

Subsea solution for oily cuttings

DRILL cuttings from oil-based fluids are contaminated by the oil and must be cleaned before disposal. Existing cleaning methods are expensive and will not meet the more stringent restrictions being drafted by several North Sea nations for implementation in the near future. Norwegian Contractors is developing a new system for offshore cleaning, degradation and deposition of drilling waste contaminated by oil.

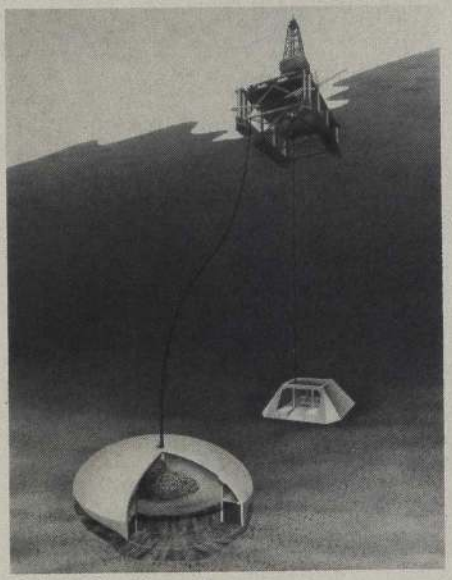
The basic idea of the concept is to confine drilling waste in a subsea concrete structure and so keep it separate from the ocean environment until the oil is removed during a natural cleaning and degradation process. Thereafter the waste can be either safely released into the environment or removed from the site for dumping elsewhere.

During drilling, the waste (cuttings and drain water) is transported into a watertight structure — the SCU — for separation, deposition, cleaning and natural degradation.

After drilling is completed and diffusion has decreased to an acceptable rate, the SCU is opened for a slow, natural exchange of water by a flow of fresh seawater into the SCU induced by natural flow gradients. The purpose of the water exchange is to supply oxygen to the SCU in order to enhance biodegradation of oil particles and remove produced gases dissolved in water.

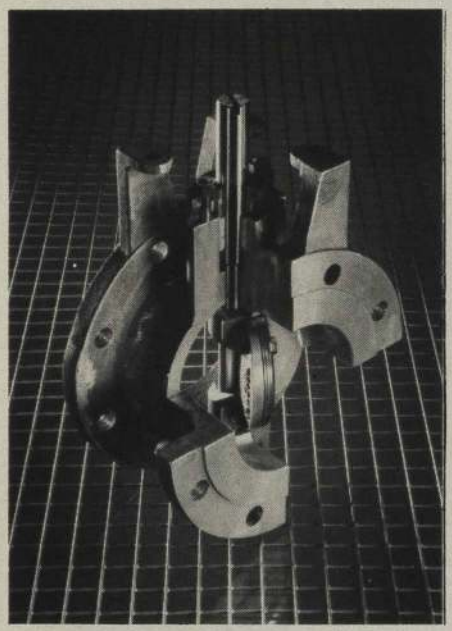
The rate of the cleaning and stabilisation process, and the degree of exposure of waste to the ocean environment, differ in the two distinct phases: active and passive.

At any time during either phase, it is possible to evacuate oil retained by oil traps by connecting a hose from a vessel and pumping out the entrapped liquid.



Subsea cleaning unit.

Vanessa valves



KEYSTONE offer a quarter-turn valve range for isolation and control through a wide range of temperatures and pressures.

The 30,000 series Vanessa universal valves have an innovative metal seal with bi-directional zero-leakage to API 6 D. This metal seal has the advantage of being relatively unaffected by temperature, having been designed to provide resilient sealing from temperatures as low as −253°C — suitable for cryogenic applications, to temperatures of 650°C, or beyond depending upon the application.

Biwater treatment

BIWATER Treatment Limited have delivered a packaged reverse osmosis plant for the new Shell/Esso Gannet oil and gas production platform.

The plant produces 20 tonne/day potable water, at a quality less than 500 Mg/l TDS. This is produced from water at between 4–11°C through three 8" filmtec membranes. The plant is designed to give a recovery rate of 15 percent which alleviates the need for chemical dosing. The sandfilters which pre-treat the feed water are cleaned via a PLC controlled backwash sequence.

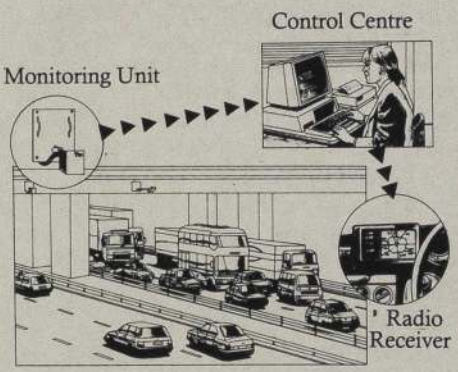
Pipeline taped

MIDDLESEX-based firm Elliot Tape and Printing company has come up with a unique method of clearly marking pipelines in refineries, terminals, authorised distribution locations, service stations and on ocean-going tankers.

By means of a printed self-adhesive tape, the company claims thay can provide an inexpensive safety product which ensures the permanent and visible identification of pipelines at all times.

Guaranteed for twenty years against deterioration or fading even under extreme weather conditions, Elliots also offer a superior grade resistant to 300 degrees celcius.

Traffic beater



The network

GENERAL Logistics plc have developed a high technology solution to today's motorway traffic problems. The Luton-based company has come up with a dashboard-mounted driver information system which will help drivers avoid traffic jams.

The system, called Trafficmaster, keeps a constant watch on the major roads around London by a network of specially developed sensors mounted on bridges above the motorway relays signals back to a control room as slow-moving or stationary traffic is detected.

Operating all year round the control centre monitors the network and inputs traffic data regularly every few minutes.

At a glance the Trafficmaster can show where the difficulty is developing, the average speed of the traffic, the direction affected and whether the tail-back is growing.

New tech at Offshore Northern Seas

AMONGST the new products displayed at the recent ONS exhibition in Stavanger were: New environmentally friendly muds from Aker Drilling Fluids called Anco Aquamul and Anco-Quat.

The first of these systems represents a direct replacement for invert emulsion oil-based muds, but is based on a low toxicity organic liquid which biodegrades much faster than conventional mineral oils.

As an aqueous system, however, Anco-Quat marks a substantial improvement on current water-based muds.

Alfa-Laval Industries exhibited its Leo-Light Equipment Offshore-centrifugal separation system which offers a dual-purpose solution for crude oil dehydration and/or deoiling of produced water.

Among **Baker Oil Tools** new products was its EM-SCSSV system, an electromagnetically controlled subsurface safety valve designed to eliminate control umbilicals for such valves and so enhance system life and reliability.

Baker also showed its new PSI system which is used for perforating, stimulating and isolating multiple zones in horizontal well bores, significantly reducing fluid losses, completion time and costs compared with conventional methods.

Cooper Oil Tools had its Camsmart system of intelligent running tools for subsea drilling and completion equipment on show. The system uses acoustical two-way communication between the subsea wellhead and the surface.

Eastman Christensen exhibited its Mosaic diamond cutter made of one-third carat thermally stable product (TSP) bonded into a single cutting element the approximate size and shape of a PDC.

Hitec had its new Star pipe-racking system which it developed to reduce manpower in drilling derricks and masts.

Norwegian Contractors displayed its plans for a concrete-hulled tension-leg platform (TLP) for sub-Arctic regions like the Northern Barents Sea. The TLP is capable of resisting drifting icebergs up to 500,000 tonnes in 500 metres of water.

Petrobras International had a BUP system representing a new deepwater drilling guide for GLL wellhead applications, eliminating the need for temporary or permanent guide bases.

Scanrotor A/S has come up with a completely new method of cold cutting for casing, making platform abandonment operations quicker and easier.

Finally **Weatherford** was demonstrating its wide range of thread lubricants which can be precisely distributed onto tubular box threads using the Accukote thread lubricant applicator developed in conjunction with Statoil.

Hydrant dispenser

SIMON Gloster Saro, the Gloucester-based manufacturer of specialist Crash Fire Rescue (CFR) and Refuelling Vehicles for airports, showed off its new Hydrant Dispenser refuelling vehicle at Farnborough '90.

The vehicle on display was the first in an order for 6 vehicles which will be delivered to Aircraft Service Ltd, a company managed by Aircraft Service International Inc of the USA.

Commenting on the contract, Jim Millar, Sales Director at SGS, said; 'This is an important order for SGS. Aircraft Service are already market leaders in North America, and our Hydrant Dispensers will be part of a critical move by that company into the European market.

'The trend at airports worldwide is towards under-apron fuelling systems, bringing important improvements in turn-round times and safety. The Hydrant Dispenser perfectly matches this trend, and is capable of delivering fuel to any commercial aircraft at 3,870 litres per minute.'

Powerlance

DUTCH-based Partek Butterworth has introduced a new and unique tube bundle cleaning system to the European market called the Powerlance. The Powerlance is a patented machine that cleans the tube side of heat exchangers, reactors, surface condensors, and reboilers. Utilising the volume and pressures of an existing water-blaster, the Powerlance can erode, extrude or shatter all fouling materials easier, safer and always faster than previous methods. It has successfully removed materials that could not be drilled out.

Gas register

Lloyd's Register is analysing the emissions from 50 ships of different types, sizes and trades, with purpose designed portable instrumentation monitors in order to gain a full picture of the gases emitted into the atmosphere by the world's merchant fleets.

Oil probe

CANADIAN company CBR international has developed an exploration tool which uses bacteria to hunt for oil.

The company claims its new 'oil probe' can detect the presence of hydrocarbons by using biotechnological methods to find specific types of bacteria in soil samples.

A 48-hour analysis is based on an Enzyme Linked Immuno Sorbent Assay (ELISA) which shows up the hydrocarbon-loving bugs.

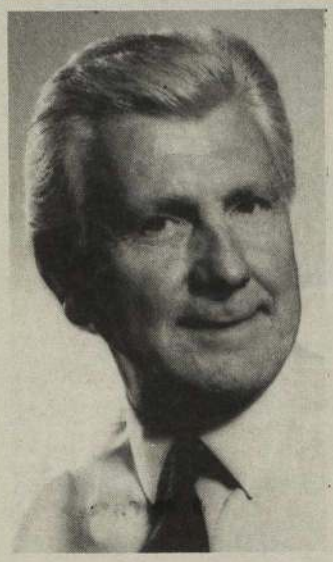
The company claims if the assay is positive it could indicate the presence of hydrocarbons seeping into sediment or soil samples from underlying oil deposits.

High temp alkaline cell

SUVICON Ltd, a member of the Steatite group of companies, makes a high temperature alkaline cell suitable for powering downhole instrumentation at up to +125°C.

This 'C' size oilwell battery has a nominal open circuit voltage of 1.55v and will provide 190 hours of continuous operation at +115°C under a 100 ohm load to an end point voltage of 0.8v.

. . . people



Big Inch Marine Systems Ltd, the Aberdeen based sub-sea pipeline connector company, has appointed **Mr Tony Moore,** above, as Senior Sales Executive, with Sales and Marketing responsibilities in the Eastern Hemisphere.

Mr Ian Wallace has been appointed Safety Manager by Sovereign Oil and Gas. Currently Chairman of the UKOOA Safety Committee, he joins Sovereign from Conoco, where he was Safety Services Manager. Mr Wallace will be responsible for safety matters on all Sovereign fields, reporting directly to the Managing Director, **Dr David Biggins.**

Ginge-Kerr AS, the Danish supplier of fire fighting equipment and systems to the marine, offshore and industrial markets, have appointed **Mr Roger McKay,** below, as Managing Director of its subsidiary based at St Helens, Merseyside.

Mr Andy Branch has recently been promoted to the position of Engineering Manager for Moore Products Co (UK) Ltd — the process instrumentation and control equipment company.

Lloyd's Register have appointed **Mr Tony Sanders** as Head of its Offshore Division and **Mr John Stansfield** as Head of the Safety Technology Department.

International drilling company Smedvig Limited has appointed **Mr John Ramsay** as Personnel Manager of their Aberdeen based management group, which is responsible for operations in the UK and Danish sectors of the North Sea and the Adriatic.

Mr David Moorhouse has been appointed Managing Director of John Brown Engineers & Constructors Limited, London Operations. He is responsible for the continued development of business in the oil and gas, transportation, nuclear and defence industries. Mr Moorhouse has been with John Brown for 15 years and was Sales and Marketing Director for John Brown's offshore structures business, before becoming Sales and Marketing Director for John Brown Engineers and Constructors in 1985.

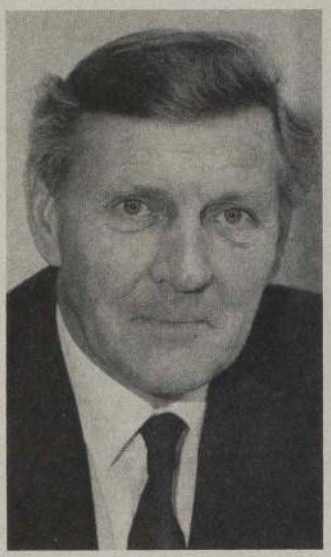
Topas, the distribution and logistics management computer software house have appointed **Mr Paul Garner** as TOP/AS Support Manager.

Mr Jack Harcus, above left, Highland and Islands Airports' Manager at Sumburgh, has succeeded **Mr Arthur Laurenson**, as Chairman of the Shetland Oil Industries Group. The new Vice Chairman is **Mr John Groat**, above right, General Manager of S and JD Robertson Offshore. **Mr Allan Wishart**, Assistant General Manager of Lerwick Harbour Trust, continues as Secretary.

Mr Roy Rumbold, previously manager of the Upper Thames depot of Tankfreight Ltd, the bulk distribution company, has been promoted to Regional Director South East — Petroleum. It is a new position which reflects the scale of Tankfreight's petroleum distribution operations on behalf of Texaco and Gulf Oil in the region. **Mr Cliff Walker** has been appointed to the new position of Regional Director for Scotland and Northern Ireland. He is responsible for all bulk haulage operations including dedicated petroleum distribution on behalf of Texaco and Gulf Oil, at Tankfreight's Leith, Grangemouth, Port Dundas and Carrickfergus depots.

Aberdeen-based Solus Schall, providers of engineering and inspection services to the oil and gas industries, have appointed **Mr Adrian Goodwin** as Managing Director. Mr Goodwin has an engineering background and was Staff Engineer with Occidental and Middle East Area Manager with SGS before joining Solus Schall as Commercial Director last year.

Hamilton Brothers Oil and Gas Limited have appointed **Mr Robert Sears** as Division Drilling Manager in Aberdeen. A graduate of Texas A&M University, Mr Sears has more than 30 years' experience of the oil industry in the United States.



Wesumut GmbH of Augsburg, the West German producers and distributors of vehicle washing and water reclamation equipment have announced the appointment of **Mr Don Phillips,** above, as Managing Director of Wesumat Car Wash Equipment Ltd. Mr Phillips is well-known in garage business circles, having recently moved from another car wash equipment company where he was Marketing Director, and before which he held several senior retail appointments in Shell and BP.

Mr Gordon Sambrook has been appointed as Chairman of The Steel Construction Institute Council. Mr Sambrook was formerly Chairman of British Steel's General Steels Division.

Ernst and Young have appointed **Mr Jim Marshall,** below, as partner in charge of the firm's national Oil and Gas Tax practice. Mr Marshall was previously Ernst and Young's lead oil tax partner in Scotland. He has over 10 years experience in the oil and gas industry and was previously Head of Tax at Britoil Plc.