PETROLEUM REVIEW

IP THE INSTITUTE OF PETROLEUM

February 1996

Russia
New law on production sharing agreements

The final frontier in Russia's Far East

Loss Control
An analysis of marine loss statistics

Southeast Asia
Status of refinery expansion plans

Algeria
Successes follow arrival of foreign oil companies

IFEG

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9th Oil Price Seminar

Managing the Long-term Risk

Tuesday 20 February

To be held at the Cavendish Conference Centre, London

Many billions of dollars can be committed to major oil projects, be they the exploitation of a reservoir in deep water, the instatement of a continental pipeline or the upgrade of a refinery to meet new environmental requirements. Such projects take years to plan and execute but the price of oil, on which the return on this investment ultimately depends, can not even be predicted reliably a few months in advance.

This seminar will look at the means available to investors to handle the risk associated with long-term uncertainties in the revenue from their projects. Firstly we will hear from an integrated oil company how it copes with the risk exposure of different parts of its business. Then an investment banker will look at the problems currently facing the refineries sector, which traditionally has not looked very far ahead in hedging. Finally the approach available to governments will be analysed, including planning and strategy and how to overcome administrative and political inertia.

IFEG is indebted to NYMEX for its long-standing support of the Oil Price Seminar

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- Applied Trading Systems
- Bechtel Ltd
- Dow Jones Telerate
- Knight-Ridder Financial
- Nymex
- Petroleum Argus
- Saladin
- SHL Systemhouse Corporation
- Teknekron

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IP

THE INSTITUTE OF PETROLEUM

Luncheon

Guest of Honour and Speaker

Sir David Simon CBE,

Chairman, The British Petroleum Co plc

'A time of change ... and a time to change'

Tuesday 20 February

To be held at the Dorchester Hotel, London

Over the last century the oil industry has survived and prospered despite dramatic technical and political changes, as well as significant shifts in patterns of supply, demand and trade. The industry has demonstrated its ability to adapt – avoiding rigidity and responding with speed and confidence to each successive challenge.

The 1990s are a period of further rapid change. Energy demand is growing in line with population and the spread of prosperity and within the total geographical and sectoral pattern the demand for oil and gas is also changing. Political change is gradually providing access to areas previously closed to international investment, and is altering the relationship between the public and private sector on an international scale. Political change is also reshaping the climate in which the industry operates – placing a higher premium on the ability to balance commercial objectives with the maintenance of the required environmental standards.

Beyond the issues specific to the energy sector, technical change and shifts in patterns of management and organisation are affecting all large organisations.

The speech will discuss these challenges and the ways in which our ability to change in response will impact on the culture and performance of individual enterprises and the industry as a whole in the years ahead.

For a copy of the ticket application form, please contact Conference Department,
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COVER PHOTO
Singapore refinery
Photo courtesy of British Petroleum

News in Brief

11 December

A consortium led by investment company Candover and including the current management team of Mainline Freight is to bid for the three trainload freight companies - Mainline, Loadhaul and Transrail - as part of the UK rail privatisation programme. Other partners include Associated British Ports Holdings and a number of financial institutions.

12 December

Chevron has announced that it is to restructure its US gasoline marketing business by combining regional offices and consolidating support functions in order to 're-focus on service and sales growth'. The reorganisation is scheduled to be completed this coming summer and will create a new company, Chevron Retail Marketing.

14 December

Occidental Petroleum Corporation and Canadian Occidental Petroleum Ltd have reached an agreement with Petroecuador to increase exploration and development activities on block 15 in the Oriente Basin in eastern Ecuador. Six oilfields have been found in the basin to date, four of which have been developed and are producing some 24,000 b/d.

Caltex Petroleum Corporation, Shantou Ocean Enterprises (Group) Petroleum and Petrochemical Co have set up a joint venture company, Caltex Ocean Gas and Energy Co, to build southern China's biggest LPG terminal to date. Located in Shantou in the Guangdong province, the terminal is scheduled to become operational in mid-1998 and will have an initial storage capacity of some 100,000 tonnes - triple China's current storage capacity for imported LPG.

15 December

The construction contract for the Nigeria Liquefied Natural Gas Project, in which Shell is a 25.6 percent shareholder, has been signed (see *Petroleum Review*, December 1995).

A subsidiary of Oceaneering International Inc has purchased the crude oil tanker *MT Swift* from Mobil Shipping and Transportation Company for conversion to a floating production, storage and offloading system. Renamed *Zafiro Producer*, the FPSO is to be installed at Mobil's Zafiro field offshore Equatorial Guinea by mid-August in 1996.

18 December

Stork Protech has been awarded a Dfl 6.5m contract for the design of NAM's L9-FF-01 offshore gas production complex. The facility will be capable of handling some 16 million Nm^3 /day - the largest capacity of any gas production complex currently operating on the Dutch Continental Shelf.

Amoco Corporation and Israel's Paz Group have signed an agreement jointly to pursue opportunities in the emerging Israeli natural gas industry.

Texaco and Calor plan to enter the UK domestic and small industrial consumer gas market, a British Gas monopoly until April 1996, through a new joint venture company Texaco & Calor Gas Ltd which will trade under the name of CalorTex.

Ecopetrol has signed a $566m loan with a group of foreign banks to help finance the construction of a 500,000 b/d pipeline linking the Cusiana and Cupiagua oilfields in eastern Colombia with a port on the Caribbean coast.

19 December

Amerada Hess and its co-venturers have received consent from the Secretary of State for Trade and Industry for the subsea development of the Telford field straddling blocks 15/21 and 15/22 in the UK North Sea. Recoverable reserves are estimated at 48m barrels of oil and 74 bn cu ft of gas. First oil is scheduled for early 1997 with production expected to peak at 30,000 b/d.

Kvaerner has failed in its £360m hostile bid for Amec.

A United Arab Emirates trad-ing group has set up a petroleum gas joint venture near Tangshan city in north China, reports the Xinhua news agency. Some $22m has been invested in Tangshan International Petroleum Gas Co, $4.4m of which came from Tangshan's Jingtang Port office, with UAE providing the balance.

Ampolex, the Australian oil and gas group, is to sell its interest in the Lufeng oilfield in the South China Sea to Statoil. The sale, which does not include the field's *Santa Ynez* floating production vessel, will provide Statoil with a 75 percent stake in the field, China's CNOOC holding the remaining 25 percent. First production is expected in 1997.

A European consortium is to build a $1bn joint venture Israeli-Egyptian oil refinery in Alexandria in Egypt reports the *Financial Times*. The European Investment Bank has finalised a $300m loan for the 100,000 b/d plant which will produce 'environmentally friendly' fuels for the Israeli, Egyptian and eastern Mediterranean markets. Operations are scheduled to begin in 1999.

Barmac, the Brown & Root and J Ray McDermott joint venture company, is to spend up to £8m on upgrading facilities at its Nigg construction yard in the north of Scotland in order to create a custom-built decommissioning facility.

20 December

BHP Petroleum's Hamilton North field, part of the Liverpool Bay development, has produced first gas. Initial output is being used to commission systems and pipelines offshore and onshore, and subsequently PowerGen's new power station at Connah's Quay, before full contract deliveries start in mid-1996.

Rockwater has secured a £40m contract from Amerada Hess for the engineering, procurement, installation and commissioning of all the subsea facilities associated with the oil company's Telford development.

A recent study by Gemini Consulting has shown that five oil/energy companies together control some 22 percent of total sales by the top 100 foreign firms in Japan. The five companies are Exxon (ranked third), Mobil (fourth), Shell (fifth), Caltex (sixth) and Pertamina (45th).

Enterprise Oil has made a significant oil discovery on block 5604/20 in the Danish sector of the North Sea. The Siri-1 well tested hydrocarbons at a maximum rate of 5,988 b/d together with associated gas. Preliminary estimates indicate that this may be the biggest Danish oil find since the Skjold field in 1977.

21 December

A catastrophic pressure release during pressure testing of pipework on an oil rig which was being commissioned at AMEC Process & Energy Ltd's yard in North Shields, Tyneside before being taken out to sea has killed three workers and injured four others.

Coflexip Stena Offshore Norway has won a $58m contract from Norsk Hydro to engineer, manufacture and install over 10 miles of flexible pipes, flowlines, risers, integrated service umbilicals and a power cable for the Njord field.

Neste Oy has announced that it is to complete its pull out of the UK oil and gas sector with the sale of its 50 percent stake in upstream gas venture Sovereign Northgas, a subsidiary of UK regional electricity company Northern Electric. The Finnish company plans to focus activities on the Middle East, Norway and Russia.

A crack in the No 1 port wing tank of the 23-year old tanker *Alandia Wave* is reported to have caused a two to three tonne oil spill at the Sullom Voe terminal. While some oil reached the beach on Sulla Ness, transfer of the 71,000 tonne cargo within the vessel minimised pollution.

News in Brief

22 December

Mobil Oil Australia has purchased the Amgas service station and wholesale distributor business in Western Australia. Amgas owns 46 service stations and six wholesale distributors and currently holds 8 percent of Perth's gasoline market, approximately 0.5 percent of the total Australian petroleum fuels market.

The Abbot Group has launched an £8.25m takeover bid for oilfield and energy industry inspection firm OIS.

23 December

Korea Petroleum Development Corporation (Pedco) plans to enter into North Sea oil production with the acquisition of a 15 percent interest in Texaco's Captain field for $210m. Due to enter production in 1996, the field is estimated to have recoverable oil reserves of over 300m barrels. Texaco hopes that the strategic alliance will help it break into Far East markets in the future.

26 December

Peru is reported to have extended until February the deadline for talks with a consortium led by Royal Dutch Shell Group to develop the Camisea natural gas fields.

30 December

Dana Petroleum is seeking a London listing and hopes to raise some £16m to fund investment in Russia through a share placing and offering.

American International Petroleum Corporation is to farm-in to an undivided 49 percent working interest in the Lapangan Pamanukan Seltan areas of West Java in Indonesia under an agreement with PT Pelangi Niaga Mitra International.

1 January

Saudi Arabia's King Fahd handed over the running of the government to his half-brother, Crown Prince Abdullah. The transfer of power is only a temporary measure while King Fahd recuperates from a mild stroke.

2 January

Vietnam has invited three foreign partners to join a £1.2bn, 130,000 b/d oil refinery project at a remote site on its central coast, reports *Lloyd's List*. Conoco, South Korea's LG Group and Petronas are to replace Total which withdrew from the project last year. The other two partners are Taiwan's Chinese Petroleum Corp and Chinese Investment and Development Corp.

SHV Calor Brazil has purchased 49 percent of the combined common and preference shares in Supergasbras Distribuidora de Gas, Brazil's fourth largest distributor of liquefied petroleum gas, for $62m.

3 January

Pogo Producing Company reports that four drill-stem tests in a second exploratory well on the large Benchamas seismic structure on block B8/32 in the Gulf of Thailand have yielded cumulative daily flow rates of 33.3 mn cu ft of natural gas and 7,575 barrels of oil or condensate per day.

BHP Australia plans to invest some A$300m in an expansion programme that will increase capacity at its Kwinana refinery in Western Australia from 120,000 to 140,000 b/d.

8 January

Enterprise Oil is acquiring licence interests in four blocks located close to its Nelson field in the central region of the UK North Sea.

North Sea Cables has secured a 5-year contract for the exclusive supply of power, control and instrumentation cables to BP Exploration.

9 January

Russian authorities have stated that an oil pipeline spill into the Balaya river in the southern Urals is on a 'completely different scale' to the 100 tonnes originally reported by the pipeline owner. Clean-up teams are still battling to control the leak.

Clyde Petroleum and Novus Petroleum have signed heads of agreement with Marathon International Oil Company in relation to the Marathon-operated Kakap Production Sharing Contract which covers four oilfields in the Natuna Sea offshore Indonesia. Once negotiations are complete, Clyde will hold a 31.25 percent interest in the Kapak PSC and will assume the operatorship, while Novus, which already holds an 18.75 percent interest, will acquire a further 6.25 percent.

The parliament of Yemen has ratified the LNG project agreement signed last September between the Republic of Yemen and Total of France. The contract gives Total a 70 percent interest in the project with General Gas Corporation of Yemen holding the remaining 30 percent. Other partners may join the project later on. Costing some $3bn, the project is expected to produce some 5 mn tonnes/year over a 25-year period beginning in 2001.

10 January

Repsol Exploración's appraisal well, Tut Deep, has produced 62 mn cu ft of gas, 1,337 barrels of condensate and 4,800 bopd during three production tests in the Khalda concession, Egypt.

ABB has won a $470m contract from Anonima Petroli Italiana to build a 260 megawatt low-emission integrated gasification combined-cycle power plant in Falconara. It will be the first plant in Italy to produce electrical power from oil refinery residues.

Victoria Petroleum, Sun Resources and Capital Energy have formed a consortium which has been awarded a 330km^2 exploration block W94-11 in the offshore Carnarvon Basin of Western Australia.

Pogo Producing Company has discovered hydrocarbons on its South Pass Block 78 field offshore Louisiana.

A consortium comprising ABB, Aker and the Maritime Group is to supply the world's largest oil floating production, storage and offshore installation for Statoil's Asgard development. The FPSO will have an oil production capacity of 200,000 b/d, a storage capacity of some 150,000 cu m of oil and a gas processing capacity of 15-16 mn cu m/d.

12 January

Agip and Enterprise Oil have successfully tested the first horizontal well in the Monte Alpi oilfield in the Southern Apennines area of Italy. The well tested 3,600 bopd, a figure expected to rise to 8,000 bopd when the well is connected to the permanent production facilities.

15 January

The Spanish government is to sell a further 11 percent stake in Repsol later this month.

The Kvaerner Stolt Alliance, a joint venture between Kvaerner Installasjon and Stolt Comex Seaway, has been awarded a NKr95m contract for the abandonment and removal of installations on Norway's North East Frigg field by Elf Norway. The structures are to be recycled rather than dumped at sea.

The UK Department of Trade and Industry has given consent for the start of the £1.6bn development of the Eastern Trough Area Project (ETAP), a group of seven offshore accumulations 150 miles east of Aberdeen.

17 January

British Gas has halted production from its Miskar field offshore Tunisia following problems at the Hannibal onshore gas processing plant.

18 January

British Gas has acquired the oil and gas interests of Fiat Rimi for £20m. The deal involves some 50 exploration and production licences in Italy's Southern Apennines.

Vanguard Petroleum has announced that its 50.3 percent Russian subsidiary Magma Oil has been granted a full production licence over the Orekhovskoye oilfield in Western Siberia.

Newsdesk

British Gas tests the waters of the Caspian Sea

Since the breakup of the Soviet Union, the Caspian region has emerged as one of the most promising new hydrocarbon provinces.

The Caspian Sea Consortium was set up by the government of Kazakhstan to carry out an Exploration Research Study (ERS) of the entire offshore region to define its hydrocarbon prospectivity. The study is operated by Kazakhstan-CaspiShelf (KCS), while foreign participants are British Gas, Agip, BP/Statoil Alliance, Mobil, Shell and Total. The activity of the consortium is governed by the Consortium Agreement which became effective on 1 February 1994.

The major part of the ERS is the acquisition, processing and interpretation of regional and infill seismic grids over the entire Kazakhstan offshore. Over 18,000 km of seismic data has been acquired to date.

The data is being acquired in two phases - an initial regional phase followed by detailed infill grids to define individual prospects. Phase 1 is now finished and Phase 2 is scheduled for completion later this year. The whole study is expected to be completed by July 1997.

The current seismic survey covers three operational environments with most of the work conducted by conventional deep marine vessels. In the northern area, two additional seismic crews are acquiring data using an ocean bottom cable in shallow water and transition zones.

KCS is running the seismic survey from the city of Atyrau which lies on the Ural river at the northern end of the Caspian Sea, while the overall exploration programme is being directed from the main office in Almaty. The western oil companies have seconded staff into the operator's organisation and British Gas is providing seismic acquisition supervision for the shallow zone using its experience in the shallow, environmentally sensitive waters offshore Tunisia. The company is also providing legal, contract and procurement, geological and accounting expertise through its secondees in Almaty, where it has also established medical cover for the consortium.

In return for undertaking the seismic survey, the foreign partners will choose a total of 12 blocks to explore under a production sharing agreement.

More than 70 oil and gas fields have been developed since oil was first extracted onshore in the Atyrau region in 1911. The largest of these is the Tengiz field which is thought to have recoverable reserves of five billion barrels of oil. The Caspian Sea Consortium hopes to find a similar sized field in the northern Caspian Sea since the geological trend on which Tengiz lies extends offshore into this region.

Gaz de France and Gazprom set up joint venture

At the end of last year, French state gas utility Gaz de France (GdF) set up a 50:50 joint venture company with the Russian company, Gazprom.

The joint venture will specialise in providing a range of services to Russian firms, including expertise on energy conservation, production quality and pollution control. 'The agreement is the culmination of co-operation over the past four years between the two groups,' a GdF spokesman said.

In addition to the creation of a joint venture company, GdF Chairman Loik Le Floch-Prigent, expressed his support for a cross-shareholding agreement between GdF and Gazprom. 'It is important that Gazprom takes an interest in order to avoid creating a parallel distribution structure in France as is the case in Germany and Italy,' Mr Le Floch-Prigent commented.

He said the simplest way of doing this was for Gazprom to take a capital stake in GdF and vice versa. However, this would be a long-term objective as it would necessitate changing GdF's status as a publicly owned utility.

Gazprom is awaiting the results of studies, undertaken by management consultants Price Waterhouse to determine the operator's market value before selling off 9 percent of its capital to international investors. Mr Le Floch-Prigent added that negotiations with Gazprom also centred on increasing French gas supplies from Russia, purchase prices and industrial co-operation between the two groups.

At the end of last year, Électricité de France (EdF), France's state-owned electricity utility, and Elf Aquitaine announced the setting up of a 50:50 joint venture company specialising in developing projects for electricity production from hydrocarbons.

'By combining their assets and expertise through the agreement, EdF and Elf will become a recognised competitive player in an expanding market where there are many promising opportunities,' commented Elf Chief Executive Officer, Philippe Jaffre.

Elf's chemical subsidiary, Elf Atochem, is one of EdF's biggest customers, since its chlorine production plants are big consumers of electricity.

Under the terms of the agreement, Elf Atochem is to acquire, for approximately FFr2 billion, the rights to use EdF's electricity capacities, on a cost price basis, corresponding to a third of its overall requirements. In return, EdF will take a 2 percent stake in Elf, costing around FFr1.7 billion, with the utility group's General Manager, Francois Ailleret, appointed to the French oil giant's board.

BP reshapes worldwide refining system

British Petroleum plans to rationalise its international refining business in a bid to 'create a global network of plants that are all among the most efficient and profitable in their regions'.

The company says that it intends to sell its wholly-owned refineries at Lima, Ohio, and at Lavera in the south of France and to close the Pernis section of the Nerefco refinery complex at Rotterdam in which BP has a 65 percent stake.

Including the sale of Marcus Hook in the United States, announced last November, the new moves will cut BP's existing refinery capacity from two million to 1.4 million barrels per day, leaving the company with 11 principal refineries worldwide and bringing its refining-to-marketing ratio more into line with that of its major competitors, most of whom refine less than they sell.

BP Chief Executive John Browne said that the company is determined that it should contain only assets that, in regional terms, are among the top 25 percent in efficiency and profitability. He also stated that following a $1.3 billion investment programme over the past three years, six of BP's refineries are already in this category and that 'modest, carefully-targeted investment' would bring the remaining five facilities in-line.

'BP's marketing operations will not be affected by these moves,' commented Mr Browne. 'We have excellent marketing business in the areas concerned and we intend to keep it that way.'

The various rationalisation actions are expected to give rise to an exceptional charge of $1,075 million after tax, comprising losses on sale and closure of $610 million and provisions for environmental remediation and other costs of $465 million. This exceptional charge would be included in BP's fourth quarter results, due later this month.

Newsdesk

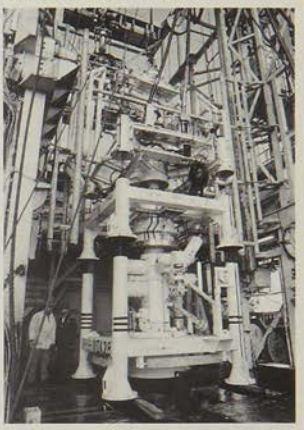
World first operation completed on Ivanhoe

Amerada Hess and a Coflexip Stena Offshore/Camco joint venture recently replaced a subsea christmas tree on the IK28 production well in the Ivanhoe field using a dynamically positioned monohull vessel. It is believed to be the first time such an operation has been undertaken anywhere in the world.

The multipurpose support vessel (MSV) *Stena Seawell* was used for the planned well intervention. Plugs were set and the well killed prior to disconnection and recovery of the original tree, which was being removed for maintenance and refurbishment, and before installation and hooking up of the replacement. After production logging and reperforating, mechanical and cement plugs were set to isolate water-bearing zones of the reservoir and the well was returned to production.

'This is a significant step forward in the servicing of subsea wells and is of particular value to Amerada Hess and its partners who operate a high proportion of subsea wells on our field developments,' said Tony Ward, Amerada's Production Director. 'The utilisation of a dynamically positioned monohull vessel produces considerable benefits in both time and cost over more traditional methods which require the deployment of a conventional mobile drilling rig.'

Amerada and Coflexip Stena Offshore/ Camco also worked on a subsea wireline intervention on a 10,000 psi rated well on the Scott field last December.



Ivanhoe's replacement subsea christmas tree

Norsk Hydro unveils new plans for Oseberg

Norsk Hydro has submitted a revised plan for the development and operation of the Oseberg field to the Norwegian Ministry of Industry and Energy.

The proposal calls for an expansion of the development's existing oil production facilities in anticipation of additional gas export in the year 2000.

A new steel platform with gas processing and export equipment will be linked to the Oseberg field centre, while a new gas pipeline will tie in to the existing pipeline system in the Heimdal area. Some NOK2.5 billion is to be invested in expanding field installations and a further NOK1.1 billion on the new pipeline.

Oil production from the Oseberg field, begun in 1988, now amounts to 500,000 barrels per day. Recoverable gas reserves are estimated at 115 billion cubic metres. Initially it is planned to export some 4 billion cubic metres of gas annually, rising to 10 billion cubic metres per year after 2010.

Repsol joins Trinidadian LNG project

Repsol has acquired a 20 percent stake in Atlantic LNG, the consortium established last July to construct a liquefied natural gas plant in Trinidad (see *Petroleum Review*, January 1996).

Strategically located at Point Fortin on Trinidad's southeast coast, the new plant will serve the needs of both the European and American gas markets. It will handle approximately three million tonnes of natural gas per annum from the East Mayaro and South South East Galeota offshore fields some 80 and 60 km southeast of Trinidad, respectively.

Total investment in the project is estimated at $1 billion and start-up is scheduled for March 1999.

Contracts signed between Atlantic LNG, Cabot LNG and Enagas provide for the sale of all the plant's production.

Some 60 percent of output is destined for Cabot LNG markets in the northeast of the United States, while Enagas will market the remaining 40 percent in Spain. Accounting for between 15 and 20 percent of Spain's total natural gas requirements, the Trinidad LNG will help offset the country's current heavy reliance on Algerian gas.

Offers for turnkey realisation of the plant's construction, and possible project financing through a banking syndicate are currently under study.

Repsol states that its interest in the Trinidadian LNG project strengthens its upstream integration and underlines the growing importance of the company's natural gas activities.

Repsol has a 43 percent stake in Gas Natural SDG capital equity, the main distributing company in Spain which, in turn, owns 91 percent of Enagas.

Other shareholders in Atlantic LNG are Amoco Trinidad LNG Company (34 percent), British Gas Trinidad LNG Limited (26 percent), Cabot Trinidad LNG (10 percent) and NGC Trinidad & Tobago LNG Ltd (10 percent).

Chevron signs Venezuelan oil alliance

Chevron and Maraven have formed a multi-faceted alliance to develop Venezuela's Boscan oilfield and provide supplies of heavy crude oil to Chevron in the United States. The alliance covers an initial period of 20 years with a 10-year extension option.

Under the terms of an operating service agreement, Chevron will be responsible for operations and production in the Boscan field, which contains 1.6 billion barrels of proven reserves. Maraven, a subsidiary of Venezuelan state oil company PdVSA, will be responsible for marketing.

Chevron expects to invest some $2 billion in developing the field over the 20 to 30 year period and plans to increase production from 80,000 barrels per day to 115,000 barrels per day during the next three years. It is the first time since 1975 that an international oil company has been responsible for such a high level of production in Venezuela.

Maraven is also to act as Chevron's joint venture partner in a West Coast asphalt business, Chevron Ven Asphalt Alliance, that will supply crude oil feedstock to Chevron's refinery at Pascagoula in Mississippi and asphalt plants in Perth Amboy (New Jersey), Portland (Oregon) and Richmond Beach (Washington).

Last minute hitch for UK gas industry

The date for issue of licences for new public gas shippers and suppliers in the United Kingdom has been postponed by one month to 1 March following a recent meeting between the UK Department of Trade and Industry, Ofgas and the industry.

It is also possible that the opening-up of the domestic gas market in the southwest may be delayed from the planned start on 1 April because the computer systems and arrangements for handling multiple suppliers may not be ready in time.

Newsdesk

Dutch gas field hat-trick for Clyde Petroleum

Clyde Petroleum Exploratie BV has gained approval for the simultaneous development of three satellite gas fields in blocks P2a and P6 offshore the Netherlands. Each of the three fields will be developed using a new generation of low-cost, unmanned, fully re-usable jack-up production platforms tied back to the P6-A processing facilities where the gas will be treated prior to export. Total base reserves for the three developments are estimated at 112 billion cubic feet gross with 25 billion cubic feet net.

Block P2a contains two Rotliegend gas fields, P2-NE and P2-SE, discovered in 1982 and 1985. The development plan comprises one vertical and one new horizontal production well on the P2-NE field with gas exported by a 10.7 km, 10-inch diameter pipeline to P2-SE. The new pipeline will also provide the opportunity for further satellite developments in an area currently devoid of infrastructure. Two new horizontal production wells are planned for P2-SE.

Gas from both fields will be combined and transported by a 27.5 km, 10-inch pipeline to the P6-A processing facilities, from where it will be transported via the existing P6 export pipeline to L10-A and subsequently into the Noordgastransport pipeline to landfall at Uithuizen.

Both P2a unmanned platforms will have minimum process facilities and will be controlled from the manned P6-A platform.

First gas from P2-NE is scheduled for early 1997 and from P2-SE in mid-1997. Total project cost is estimated at Dfl165 million.

The development plan for the P6-South gas field, discovered in 1990, comprises re-entry and dual recompletion of two reservoirs in the P6-8 discovery well with produced gas exported by a flexible 6-inch, 6.6 km pipeline to the existing unmanned P6-B satellite platform.

Gas from P6-South will be commingled with main field production from P6-B and transported to the manned P6-A facilities for processing to sales specifications. The subsequent export route will be the same as for existing P6 production and as planned for P2a gas. Total project cost is estimated at Dfl40 million with first gas expected by the end of this year.

Greek licensing round

Foreign firms were invited to bid for three onshore and three offshore blocks in western Greece at the end of last year. This is the first international licensing round in this region.

The offshore areas on offer comprise acreage in Paxi-Parga (2,000 km²) , the Gulf of Patraikos (2,100km²) and Katakolon (1,900km²) in the Ionian Sea. The three onshore blocks are located in the northwest Peloponnesos (2,050km²), Aitoloakar-nania (3,650km²) and Ioannina (4,200km²), close to the border with Albania.

This acreage were offered under a new petroleum law passed last year which brings Greece into line with the European Union Hydrocarbon Licensing Directive.

Under the arrangements, state-owned Public Petroleum Corporation of Greece, Exploration and Exploitation of Hydrocarbons (DEP-EKY) will take a 12 percent stake in each licence, the remainder being available to foreign oil companies and private Greek investors.

No date has yet been given for licence awards.

Sweden's strategic oil storage depots up for sale

The Swedish government has announced that it is to sell off what has up until now been a closely guarded state secret – its strategic oil reserves.

Stored in vast underground caverns blasted into the bedrock, no fewer than 45 depots have been used to store oil reserves earmarked for use in national emergencies. However, following the fall of the Soviet Union, the resulting independence of Baltic States and Sweden's recent membership of the European Union, the Swedish government feels the time is now right to sell off the depots.

According to the National Oil Stockpile Agency (NOSA), which will administer the sale, the strategic position of the depots in the rapidly expanding Baltic region means that there should be no shortage of prospective buyers.

The 45 underground storage sites are to be sold off in a phased programme which is scheduled for completion by 30 June 1999. Four depots are to be sold in the first phase:

Norrköping Located on Sweden's Baltic coast, to the west of Estonia, this large subterranean chamber has a capacity of over 100,000 cubic metres. Existing infrastructure comprises a local authority-owned deep-water harbour and pipeline.

Oskarshamn On Sweden's Baltic coast to the west of Latvia, this facility comprises seven separate subterranean chambers with a collective capacity of some 100,000 cubic metres. This site too has a local authority-owned deep-water harbour and pipeline.

Kappelshamn Located on the island of Gotland in the middle of the Baltic, Kappelshamn has its own quayside and comprises four separate underground chambers with a total capacity of some 40,000 cubic metres. It also has two above-ground storage tanks, each of 5,000 cubic metres capacity.

Strömstad On Sweden's west coast, close to the Norwegian border, this depot has four separate subterranean chambers with a collective capacity of 50,000 cubic metres. Existing infrastructure includes its own quayside as part of a deepwater port.

NOSA reports that while the sites are currently being used to store oil products, they can easily be modified to store crude oil.

New Years Honours list

Professor Sir Donald Iain MacKay, Chairman, Scottish Enterprise

R E Mabro CBE, M Inst Pet, Director, Oxford Institute for Energy Studies (below)

R C Paul CBE, Chief Executive, Albright and Wilson

A F Roberts CBE, former Chief Executive, Health and Safety Laboratory

J G Speirs CBE, Managing Director, Norsk Hydro (UK)

R A James OBE, Senior Gas Engineer, Sarajevo

B G S Taylor OBE, M Inst Pet, Director-Technical Affairs, UKOOA

R S Allison CB, Chief Executive, Offshore Safety Division, HSE

J F Shaw CB, UK Department of Health

D H Slater CB, former Head of HMIP and now to be Environment Agency Director responsible for pollution control and regulation in England and Wales

K W Bell MBE, Regional Treasurer, Yorkshire and Humberside Energy Management Groups

R Cook MBE, former Regional Manager, Esso

C R Hawker MBE, Director, Safety and Environment, Exploration and Production, British Gas

Newsdesk

Oil companies and supermarkets battle it out in petrol pump price war

The UK petrol pump price war hotted up last month as some of the major retailers dropped fuel prices by as much as 4.4 pence per litre – following Esso's announcement that it proposed to extend its 'Pricewatch' scheme nationwide.

The national roll-out of the scheme, trialled in northeast England and Scotland last year, was accompanied by a blaze of publicity. However, much of the media coverage appeared to have misinterpreted the national campaign, quoting Esso as having given 'a guarantee (to the consumer) to meet the lowest prices' in a given catchment area.

Although this was indeed the case in the earlier trials – petrol prices at each of the 52 participating service stations guaranteed to be the lowest within a two-mile radius – the nationwide version of Pricewatch, in fact, only promises that petrol prices will 'be amongst the lowest available.' The catchment area in which prices are sampled in the nationwide scheme also differs from the northeast trial, increased to a three-mile radius for supermarkets while other competitor service stations are monitored within a one-mile radius. As in the northeast trial, Esso has withdrawn its Tiger Token promotion for the nationwide launch.

According to Esso, average pump prices at its 2,100 sites across the United Kingdom on 18 January were:

Unleaded 95	54.4p/litre
Unleaded 98	59.3p/litre
4 star	60.1p/litre
Diesel	55.5p/litre

Shell was one of the first to hit back at Pricewatch, cutting 4.4 pence/litre off the recommended pump price of Shell Advanced 4 star petrol. The recommended pump price of Shell Advanced unleaded also fell from 58.9p/litre to 56.9p/litre, while the price of Shell Advanced diesel dropped from 59.9p/litre to 58.9p/litre.

The company was quick to point out, however, that cuts had not been made at the expense of product quality and customer service.

Indeed, this theme was addressed by Shell UK Downstream's Managing Director Colin Harvey at the IP East Anglia branch meeting on 18 January. Discussing the historical oversupply in the downstream sector and petrol retail competition, he stated that, 'Oil companies must choose between alternative responses – to invest in taking the retail battle to the customers by offering higher quality and value for money, or to retreat into becoming suppliers of an unbranded commodity to third parties at marginal costs. Those with confidence in their own strengths are taking the former course. The latter cannot be a sound, sustainable long-term strategy....'

BP, Texaco and Gulf also followed Esso and Shell, dropping their fuel prices and adding that they planned to maintain competitive pricing policies.

The supermarket chains, which today account for around one in every four litres of petrol sold in the United Kingdom, also stated that they plan to match competitors' prices.

Indeed, even after the oil company cuts, both Tesco's and Sainsbury's prices remained amongst the lowest to be found in the United Kingdom last month – Tesco's pump prices averaging 53.78p/litre for unleaded petrol, 60.02p/litre for 4 star, 54.98p/litre for diesel, 56.78p/litre for low benzene fuel and 58.60p/litre for super unleaded, while Sainsbury's unleaded petrol averaged 54.2p/litre, diesel 55.2p/litre, 4 star 59.4p/litre and super unleaded 58.3p/litre.

While the motorist admittedly benefits, it is the smaller independent petrol retailer who is likely to suffer from this kind of petrol price war.

According to the Petrol Retailers Association (PRA), its members reported up to a two-thirds drop in sales during the Pricewatch trial in the northeast of England. 'The results of the Esso northeast experiment indicates that if Pricewatch were to be rolled out nationally in the same way, up to 6,000 independent and about 1,000 oil company owned service stations would leave the business within a two-year period,' forecast a PRA spokesman.

Although the nationwide Pricewatch scheme does differ slightly from the northeast trial, it does seem likely that if Esso and the other oil companies continue to cut prices in a bid to win customers, dropping prices to below cost in some cases, this gloomy forecast from the PRA might be substantiated.

Grant first for Scottish service station upgrade

Caithness and Sutherland Enterprise (CASE), a Scots local enterprise council, has awarded a £50,000 grant to Assynt Trading Company's service station in Lochinver in northwest Sutherland.

The grant will be used to upgrade the site, which is situated on the Vestey estate in a remote area of northern Scotland, and bring the facility in line with the recommendations of HS(G)41 - '*Petrol Filling Stations: Construction and Operation Guidance Note*'.

Two new storage tanks will replace the site's five existing tanks, three of which are 30 years old, increasing overall storage capacity from 36,000 to 90,000 litres. The forecourt's petrol pumps, too, are to be replaced as they are nearing the end of their working lives.

According to CASE, the high capital cost coupled with relatively low annual sales at the Lochinver service station did not make the upgrade an attractive investment for business. 'If CASE did not assist there is a real risk that the petrol station would close,' stated a company spokesperson. 'This would have had a severe adverse effect on the local community as there is no alternative local source.'

CASE say that this is the first time such an award has been granted to a service station. If there were another service station in the vicinity, the grant would not have been made.

An increasing number of smaller rural, and urban, service stations are closing as the result of the financial burden of meeting increasingly stringent UK and European Union safety and environmental legislation whilst trying to compete with the larger players in the market. Competition, exacerbated by petrol price wars, continues to compound the problem.

It will be interesting to see if the successful application of the Lochinver service station for a grant to fund an upgrade programme has set a precedent and results in a spate of similar applications from other low-volume service stations which are struggling to compete in today's petrol retailing market-place.

New guidelines are now replacing HS(G)41. An updated risk assessment guidance - 'HS(G)146, *Dispensing Petrol: Assessing and controlling the risk of fire and explosion at sites where petrol is stored and dispensed as a fuel*' has just been published by the HSE (see next month's issue of *Petroleum Review* for a detailed account of the document's recommendations).

Guidance on the technical solutions to address the results of such risk assessments is being prepared by industry and will be published jointly by the Institute of Petroleum and the Association for Petroleum and Explosives Administration later this year.

Russian law - production sharing agreements

By Chris Ferguson, Senior Lawyer, Clifford Chance

The new Russian law 'On Production Sharing Agreements' became operative on 30 December 1995 when it was signed by President Boris Yeltsin. Reaction so far has been unenthusiastic. Some western oil companies have said that while they are prepared to work with it they believe a good law has been rendered impotent by the addition of last minute amendments to placate the newly strengthened conservative faction. Others believe it is a step backwards and sections of the press have described it as viciously anti-western.

However, seasoned Russia hands have been here before. The Russian statute books are full of, on the one hand, pieces of apparently draconian legislation which are, in reality, implemented leniently and, on the other hand, supposedly pro-foreign investment measures which are later ignored. The new law (referred to here as the 'Law') deserves a second, more respectful, glance.

A short article cannot deliver an in-depth analysis of such an important and complex piece of legislation. However it can attempt to apply it to the crudest possible test for foreign investment – does the law enable an investor (the term used in the Law) to secure exploitation rights, protect its interests during the life of the project and get the profits out?

Getting in

The government of the Russian Federation has been given until the end of March to submit to the legislature for approval (in the form of a federal law) a list (the 'List') of all surface areas which will be permitted to be the subject of production sharing agreements (an 'Agreement'). The List is said to be confined to areas of climatic or geological difficulty which, it is supposed, cannot be exploited without foreign capital. The purpose of this section, however, is not to create a block system allowing for the rational exploitation of resources via selective licence offering by the state: there is no prohibition on exploitation of areas outside the List (albeit without the benefit of the tax breaks available via an Agreement).

While it was publicly claimed that the late amendments were added to placate conservative elements opposed to Russia's strategic resources falling into the hands of rapacious foreigners, it is likely the real reason behind the amendments was to enable the legislature to wrest control of the process from unaccountable civil servants. In a country known for its corruption, where none of the normal constitutional checks and balances are in place, the legislature felt the need to oversee the agencies negotiating the Agreements.

There is obvious potential for confusion in the compilation of the List. The problem of the selection of the criteria of 'difficult' areas and the effect on production in those areas not included on the List, and thus denied tax breaks, has not been sufficiently considered.

In any event, particularly for companies already deeply involved in negotiations, it will be crucial to ensure prospective licence areas are listed by the end of March. Time limits in Russian legislation are rarely complied with and it is difficult to imagine that this List is final.

The right to enter into negotiations for an Agreement will be dependent on winning a competitive auction or tender (a 'Competition'). Under the, still valid, licensing regulations it is permissible to restrict a Competition to Russian entities, subject to this limitation – any person (individual, legal person, Russian or foreign) or any partnership or unincorporated joint venture wishing to explore, prospect or produce natural resources under an underground resources licence (a 'Licence') may enter into an Agreement.

The reference to consortia is an improvement on the previous situation, which did not easily accommodate the use of unincorporated joint ventures or unregistered partnerships. There is now specific provision for joint and several liability in these circumstances and the issue of a Licence to one party on behalf of others (whose identities are noted on the licence). The Agreement may not vary the terms of the Competition.

There are certain investors who may be, by decision of the state, exempted from the need to enter a Competition. These include:

- Investors who find themselves the only applicant for an announced Competition;
- Investors who are considered to be the only acceptable option for an area noted on the List as one with national defence and security interests;
- Investors who are either existing licensees or part of a legal entity or a consortium of which the existing licensee is a member;

- Investors who are (with the agreement of the government and the Republic) already in negotiation over a proposed Agreement.

While the last of these explanations is obviously vital to the major western companies currently engaged in high profile discussions, for some their troubles do not end there.

Any Agreement reached with an exempted investor must be presented to the legislature for examination and approval in the form of a federal law. This requirement also applies to any Agreement related to an offshore area or an area of 'special state strategic interest', whether or not the Investor is the winner of a Competition.

The inclusion of the legislature's right to examine an Agreement concerning an area of 'special state strategic interest', again a late amendment, has been the subject of much speculation. Given that the provision already catches all offshore Agreements and those resulting from existing negotiations, who did the legislature have in mind? The wording differs from that describing the areas of 'national defence and security' (which must be determined as such by both the government and the Republic and indicated on the List). As with the other amendments, it is probable that there was no particular target and that the legislature merely wished to give itself the right to examine publicly any agreement without, even, the need to refer the reasonableness of their decision to another authority.

All the rights permitted to an Investor under the Law must be included in the Agreement. The most basic of these, the exclusive right to explore, prospect for and extract on the Licence area, is granted in the Agreement. Following signing, and if necessary legislative approval, the state licensing authority is obliged to issue a Licence within 30 days. The Licence merely confirms the contractual right of use of the sub-soil plot. The term of the Agreement is fixed but may be extended by the Investor to cover the full commercial life of the area. No maximum time limit is stated but the existing Licence regulations allow for a combined exploration and production Licence of 25 years within unlimited extensions of five years each. If the Agreement is extended, the licensing authority is required to re-issue the Licence for the same term. The Law permits regulation of a very wide range of exploitation activities in the Agreement including transportation, processing and disposal.

'The legislature felt the need to oversee the agencies negotiating the Agreements'

Agreements for onshore areas must be signed by both the Government of the Russian Federation and the executive agency of the federal sub-division (generally a Republic) on which the area is situated (unless either authorises the other to sign on its behalf). Offshore Agreements require only the signature of the Federal Government but must be 'co-ordinated' with the Republic.

Preserving its interests

Title to production: the first slice of production goes to the Investor in the form of compensation production equal to the costs of production. Next, an amount equal to the royalties is deducted and paid to the state. The remainder is divided between the state and the Investor in the proportions stated in the Agreement. The state may elect delivery in cash or kind. The accounting principles used for computation of these amounts are to be the subject of further subordinate legislation. The Agreement grants the Investor full title to both the compensation production and its own production share. It also has title to all property created or acquired by it during the term of the Agreement (other than the rights to the initial data, which remain with the state).

'Time limits in Russsian legislation are rarely complied with and it is difficult to imagine the List is final'

Tax regime: the primary purpose of any production sharing arrangement is to offer a stable, attractive tax regime fixed for the full term of the Agreement and operating outside the normal legislative framework in return for a share of production. The Law exempts an Investor from all taxes, duties and charges (including VAT) levied by any level of competent authority, apart from royalties (the amount of which must be fixed in the Agreement), production and/or signing bonuses (fixed in the Agreement), area specific annual rentals (fixed in the Agreement), surface rentals (agreed with the surface owner) and Profit Tax (corporate tax). The position of customs duties is unclear. They are not expressly excluded but at the same time cannot come within the express reference to the limited number of taxes and charges which can be levied. The same privileges apply to the operator and all other contractors including carriers. The taxable base for Profit Tax can be reduced by deduction of interest payments on loans, lump sum royalties and any other unreimbursed expense. Again, secondary legislation on computation of these figures will be introduced. Deductions may be rolled over. The Law appears to prohibit the Investor from benefiting from any other universally applied Profit Tax exemption. Given the poor drafting of the latter provision, Profit Tax arrangements should be specified in the Agreement in detail.

The Investor's tax position is protected by provisions enabling the Investor to deduct from the state's production share, together with interest, all unrecovered VAT and any tax, duty or other payment made in response to a demand contravening the Agreement.

Stability: in addition to the protections in the event of tax changes, the law envisages two situations in which subsequent legislative changes may adversely affect the Investor's position. First, changes which cause the Investor's commercial results to worsen. Secondly, changes which limit rights granted to the Investor under the Agreement. In

the former case, the Law requires the Agreement to be amended in order to restore the position of the Investor. In the latter case, the Investor is given a state guarantee of immunity from such legislation. It should be noted that in the case of both types of change, the immunity does not extend to legislative changes connected with health, the environment and safety. In addition, there is no immunity from public and state security measures for changes of the second type.

Amendments: a great deal of press comment has centred on the right of either party (although concern rests with the government's exercise of this right) to amend unilaterally the terms of the agreement. However this right is expressly subject to the provisions of the Civil Code. The language describing the unilateral variation is directly lifted from Chapter 29 (*Modifications and Termination of a Contract*) of the Civil Code. This chapter deals at some length solely with *force majeure* situations and requires, in the absence of the agreement of the parties, a court order for amendment or termination. Given that under most legal systems some form of *force majeure* provision would be implied where none was expressed and that disputes under the Agreement, including the order for amendment or termination, can be referred to international arbitration, while the impact of the *force majeure* legislation on any particular project should be carefully assessed, I would suggest that the provision does not merit the alarm it has raised.

Dispute resolution: the governing law of the Agreement is required to be Russian but disputes can be referred to international arbitration. Care should be taken to select a forum, the judgements of which are enforceable in Russia. Much attention has been paid to the provision which gives the state the option of not waiving its immunity. However, if it does choose not to waive its immunity, it must do so in the Agreement. Thus, it would appear that an agreed waiver of immunity cannot be withdrawn on the steps of the court. It should be noted that the waiver of immunity only applies to contracts with foreign entities.

'The more impenetrable the legislation, the more detailed the Agreement'

Getting out

Transportation: the Law purports to grant the investor the right to contract 'to freely access ... pipeline transport as well as the right to freely use ... pipeline and other transport ... storage and processing facilities without any discriminatory restrictions'. Given that this only restates the present right to enter into a commercial contract for carriage it does not appear to grant any added benefit. The clause following it grants full title to any such facility constructed by the Investor.

Quite what this means in the context of the current problems surrounding the pipeline system and difficulties some of the larger projects have had over common carrier status is difficult to assess. Again, the advice must be the more impenetrable the legislation, the more detailed the Agreement.

Export: the Investor has freedom of export for all production to which it has full title ie the Compensation Production and its production share. However, the freedom is limited to the imposition of 'quantitative' restrictions and the right is subject to the law *'On State Regulation of Foreign Trade'*.

This is a recent, comprehensive piece of legislation which does not expressly refer to hydrocarbons other than those exported in fulfilment of the country's international obligations. However, it is broadly drafted and the express reference to it in the law clearly indicates that the legislature believes the Investor's production is caught by its terms. It gives the federal executive wide powers to impose trade restrictions including customs tariffs, quotas and licensing. It allows quantitative restrictions to be imposed by the government on the grounds of national security, fulfilment of its international obligations (taking into account the state of the internal commodity market) and protection of the internal market. The state is permitted to hold competitions for quota rights but is not obliged to do so. It also permits the state to impose an export monopoly by way of licensed state export organisations which are required to act in a non-discriminatory manner.

It is significant that one of the final amendments to the text of the Law on production sharing was to delete both the grant of a right to freedom from export licensing and the requirement to sell through a specified commercial or non-commercial organisation. The investment protections contained in the law, and referred to below, purport to maintain the position of the Investor during the life of the project. However, by making the Agreement expressly subject to *'On State Regulation of Foreign Trade'*, the export right is considerably weakened. I would suggest that, subject to official clarification, based on the history of export problems that the petroleum industry has experienced in Russia, this provision has the potential to cause greater difficulties than many of those which have received press attention.

Currency control: compared with the export of raw materials, the repatriation of realised profits would appear to be reasonably unproblematic. The investor is entitled to maintain domestic Rouble and hard currency accounts and offshore hard currency accounts (without the need for a Central Bank licence in the case of Russian entities). These must be used exclusively for Agreement activities. Hard currency from both the domestic and foreign accounts can be freely disposed of; there is no need either to repatriate export profits or to comply with the regulations on mandatory sale of hard currency. One point to note in the context of unincorporated ventures is that these rights extend only to the Investor, who will be acting on behalf of the consortium. Care should therefore be taken over access rights to the accounts.

Diary Dates

London Branch

'Interrelationship between Fuel Quality, Engine Design and Air Quality — Outcome of the European Auto-Oil Research Programme'

Tuesday 20 February 1996, tea at 17.15 for 18.00

By Mr F H Palmer

Before recently taking up his post with CEC as Technical Director, Frank Palmer was the consultant co-ordinating production of the final EPEFE report on behalf of both motor and oil industries as input to the Auto-Oil Programme. The EPEFE programme, initiated in 1993 and completed in 1995, is a major part of the technical basis behind the drafting of European legislation to limit vehicle emissions from the year 2000. Mr Palmer will trace the history of EPEFE and show how its results fit in with the Auto-Oil Programme on which the Draft Fuels and Emission Directives are based.

Light refreshments will be available afterwards. IP contact: Mike Wood or Mrs E Walker, Hon Secretary, London Branch. Tel : 01926 404768

Energy Economics Group

'Vertical integration of oil companies – is this necessarily the recipe for success?'

Wednesday 28 February, tea at 17.00 for 17.30, until 19.00

Dr Fernando Barrera-Rey of the Oxford Institute for Energy Studies will discuss the conclusions of his recent work on the advantages and disadvantages of vertical integration for the economic performance and technical efficiency of American oil companies, offering some explanation of the widely differing integration strategies adopted within the industry

IP contact: Jenny Sandrock

Joint E&P/EEG Discussion Group Meeting

'The Future of the Norwegian Shelf'

Tuesday 5 March 1996, tea at 17.00 for 17.30

By Dr Knut Åm, Senior Vice President, Exploration and Production, Phillips Petroleum

Wine and cheese after the meeting sponsored by Offshore Northern Seas

Numbers may have to be limited

IP contact: S F Schuyleman

Joint meeting:
Environment and Energy Economics Groups

'Global Warming Update'

Wednesday 13 March, tea at 17.00 for 17.30 until 19.00

By Dr Mike Kelly, Climate Research Unit, University of East Anglia

Dr David Maddison, Centre for Social & Economic Research into the Global Environment

and

Dr Jack Barratt, Imperial College

A lively debate is guaranteed

IP contact: Jenny Sandrock

All meetings are held at the Institute of Petroleum
Please tell the IP contact if you plan to attend any of these free meetings
Tel: 0171 467 7100 Fax: 0171 255 1472

Petroleum and the environment in Western Siberia: challenge and opportunity

By Andrew Whitney

Last autumn a US Trade Mission visited Western Siberia to assess the market for Western oilfield and environmental technologies. It provided an opportunity to witness first-hand the level of environmental degradation in and around one of Western Siberia's oil centres – Nizhnevartovsk – and the notorious Samotlor oilfield.

While the extent of the degradation cannot be denied, there are considerable grounds for optimism. Drawing on a series of interviews, from the federal and local ministerial levels down to the oilfield crews, the author found that there is indeed widespread acceptance of the environment as a serious priority in the Russian petroleum industry. This also manifests itself in the development of the appropriate legislative and punitive frameworks, the expansion of budgets for state-of-the-art equipment and the development of dedicated organisational groups and structures geared towards optimising oilfield operations *vis-a-vis* the environment. In addition to being a positive development for local communities, and the wider population of the Russian Federation, this trend represents an excellent opportunity for western manufacturers of oilfield equipment and services.

Snapshot: Nizhnevartovsk

Located 1,500 miles northeast of Moscow in the Khanty-Mansisk autonomous region, Nizhnevartovsk is one of Western Siberia's largest cities, with a population of 243,000. Oilfields within 500 miles of the city account for 75 percent of Russian oil output and 67 percent of the entire Former Soviet Union output. Perhaps most significantly, as Mayor Yuri Timoshkov was quick to attest, Nizhnevartovsk regional production accounts for 60 percent of the hard currency income of the oil industry.

The city was established some 25 years ago following major oil discoveries around Lake Samotlor in the early 1960s. The village of Nizhnevartovskoye had been located on the banks of the Ob river as early as the turn of the century but in 1940 its population numbered only 500. The oil discoveries changed things considerably.

The Soviet oil industry effectively picked the low-hanging fruit, and did so in a very inefficient and often haphazard manner. Now, as a consequence of under-investment in technological improvements, the upper fruit is proving difficult to reach and the existing infrastructure is failing with alarming regularity because of poor design and lack of maintenance.

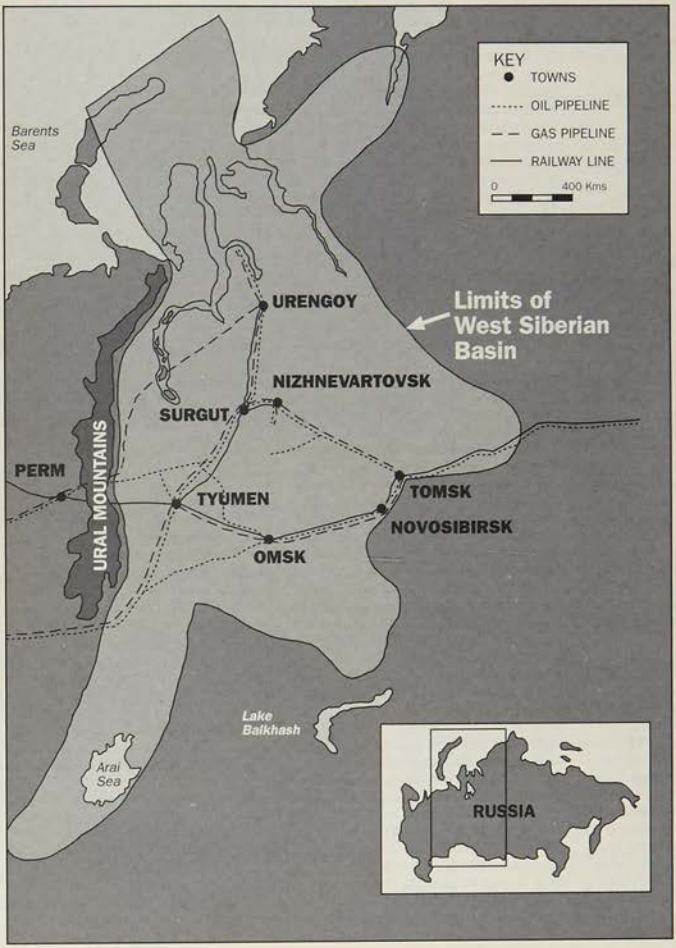
Environmental damage

Flying over the Nizhnevartovsk and Samotlor regions, one can see the extent of the resulting environmental damage. Even narrow pipelines are clearly visible as a consequence of significant leakage along their course, abandoned wells and slime pits are a frequent feature of the terrain, irresponsibly discarded oilfield equipment lies scattered around what were obviously Soviet-era production sites. The extent of pollution of the groundwater is evident from the acres of blackened and dead forestry around polluted water courses, pipelines and other visible leakages.

Most of the abuses were systemic, and therefore the demise of the USSR was positive in a way. One senior official with the US Agency for International Development commented that 'the consequent collapse of industry has reduced pollution and waste to a great extent.'

Mr Viktor Danylev-Danilyan, Russian Minister for Protection of the Environment and Natural Resources, was the first to acknowledge the fact that oil and gas 'is the primary source of environmental pollution in the Russian Federation.' According to officials at the Ministry of Fuel and Energy, fuel and energy are responsible for 48 percent of all pollutants.

There is often a tendency among



West Siberian Basin

commentators to focus on the scale of spills, rather than the actual consequences and how they manifest themselves. This type of assessment can prove difficult to arrive at but, according to figures recently released by the Nature Development Institute, a scientific and technical institute based in Tyumen, the rate of pollution has had obvious and alarming consequences on the health of people in the city of Nizhnevartovsk.

An unhealthy city

Nizhnevartovsk is among the most unhealthy cities in Russia, according to the study, with the number of abnormal pregnancies exceeding 75 percent and a 'very high' rate of spontaneous abortions and premature births. Adult rheumatism is 10 times the Russian national average, the incidence of endocrinal diseases in children and adults is twice the average, while there are three times as many malignant tumours in the 15-49 age group. The report attributes these startling figures to the 'occurrence of persistent oil products in drinking water and a stable concentration of all pollutants,' which have carcinogenic, mutative and embryothropic properties. Air pollution in Nizhnevartovsk, for example, far exceeds the national average, with some hydrocarbons occurring at nine times accept-

able limits.

Alexander G. Khurshudov, Director of Technical Sciences at the Tyumen-based Nature Development Institute (NDI), attributes the principal sources of environmental pollution associated with the petroleum industry to:

- irrational location of production facilities
- pipe breakages
- oil and water leaks from wells and slime pits
- gas flaring.

Pipelines

The widely-reported spillage at Komi last year was a chilling testimony to the present condition of the Russian pipeline infrastructure. In fact, according to a US Environmental Protection Agency spokesman in Moscow, 'Komi was not an isolated incident. In fact, it is somewhat run of the mill.' The high failure rate of Russian pipelines is largely due to poor design, construction and maintenance. After initially using low-quality metals and manufacturing pipeline sections with poor production tolerances that did not always fit together properly, the Soviets compounded their mistakes by failing to use adequate internal or external protective measures. In some cases, pipelines were not even raised above the ground. Consequently, the majority are now suffering from serious internal and external corrosion. Yevgeny Minaev, Chief of the Main Administration of Ecology and Nature Management at the Ministry of Fuel and Energy, finds that 'Some 75 percent of the pipelines in our oil producing areas need to be replaced, in addition to 60 percent of the trunk lines, at a cost of billions of dollars.'

The Russian production associations have begun to respond by injecting corrosion inhibitors, purchasing glass-fibre internal protection 'sleeves' and external pipeline coatings. This is generating business opportunities for Western companies, as is the bioremediation and other treatment of sludges and soils associated with spillages. Vladimir Fidumen, Nature Protection Director of Tomskneft, dramatically summarised the rate of loss, 'We have between 400 and 7,000 oil spills in the region every year.'

Nikolai Krupinin, Chairman of the Nizhnevartovsk District Environmental Committee of the Russian Ministry of Environment and Natural Resources, calculated that the average spill releases 2.8 tonnes of oil. In other words, between 12,000 and 196,000 tonnes of oil are spilled regionally every year.

There is also the problem of measuring and the systematic under-reporting of spills, with oil companies providing figures which, when checked by ministry officials, represent inaccuracies 'of the order of thousands of tonnes,' according to Mr Krupinin.

Legislative and punitive issues

To address the problem of drilling muds and pits, West Siberian oil companies, such as Chernogorneft and Megionneftegaz, are adopting closed-loop systems. Such systems obviously require substantial initial outlay but in a statement which testified to the growing awareness of the concept of defrayed costs, the Chief of Megionneftegaz's Foreign Economic Relations Department, Yevgeny Khanis, said, 'We consider that the cost is not an over-riding issue because it is compensated for very quickly; it pays for itself because we do not attract fines.'

The company's closed-loop cycle leads to the manufacture of certified construction bricks and will be used in future to heat facilities in the field, as associated gas is trapped and processed rather than burnt.

The disincentive system therefore appears to work in practice but this depends to a great extent on the polluting entity's ability to pay. Recalling the Komi disaster, Mr Danylov-Danilyan said, 'This incident showed quite clearly the type of threats we face, and I hope that our oil producing and transportation companies can now appreciate the consequences. Komineft, for example, was presented with a bill for $400 million, since it was responsible for the spill,' before adding that '...it may not be in a position to pay this for some time.'

Mr Krupinin also described an incident in which Yuganneftegaz was fined R8 billion for water pollution. Aside from the difficulty of extracting payment from the company, his committee also faced a great deal of hostility at federal level. 'These companies cannot afford to pay taxes if they pay us. So then Moscow calls me to complain that I'm taking away all their tax revenue.'

Confirmation of another difficulty that is faced in the collection of fines came from one senior official when I enquired as to the possibility of the ministry being paid in oil. He said, 'In principle it is possible, but we try to avoid it: where there is oil trade, there is Mafia.'

Ultimately, Mr Krupinin's ministry is therefore faced with a choice between allowing offenders to go unpunished or putting production companies out of business. The latter course, he acknowledged, was hugely controversial on account of the enormous social consequences.

'It is possible to pronounce these companies bankrupt and to throw people out onto the streets but this is just too dangerous,' he said. 'We are sitting on a powder keg and we have to make compromises.'

Raise the double standard?

It is these 'compromises', however, which constitute another bone of contention. Some would describe them as double standards.

Western joint ventures find themselves facing environmental stipulations which in some cases exceed requirements in other countries. They believe that ministry officials' zeal in applying fines stems, in a large part, from the knowledge that Western entities will always pay. The system, they argue, seems in practice to be less to do with deterring polluters and more a matter of policing according to the means to pay. This is serious since disputes over liability for pre-existing environmental conditions and contracts established on the fragile Russian legislative base are always open to some interpretation.

Among some Western joint venture participants there is a related concern about recent Okrug legislation which

grants the ministry the right to revoke the licences of those deemed to contravene the project provisions on the use of resources. At least one Western joint venture has already been threatened in this way. Given Mr Krupinin's previous comments, it seems unlikely that Russian entities would be closed down under such legislation. 'At the very least,' argued a senior representative of another Western oil company, 'it is difficult to be competitive under such double standards.'

When questioned about the issue of apparent double standards, ministry officials only reiterated the precarious nature of their predicament and argued that making an example of someone was more effective than policing no-one. It is likely that these circumstances will remain a feature of the industry as long as it is beset by the non-payments crisis* and until privatisation establishes a meaningful divide between government and the production associations. Until then, Russian entities will receive preferential treatment, while the legislative and enforcement frameworks continue to develop. These, in time, will provide the legal springboard for future environmental compliance efforts.

Growing budgets

Perhaps the most compelling evidence of the on-going Russian reappraisal of environmental policy is the growth of budgets for the purchase of environmental products and services and the development of organisational structures to oversee the matter. Both dynamics reflect the growing awareness and internalisation of environmental penalties into calculations of resource use costs. In purchasing advanced technology, Russian production associations realise that they will make long-term gains from efficiency improvements as well as penalty avoidance.

Surgutgazprom, for example, was forecasting a payment of R1.5 billion in fines for last year and this is clearly influencing its decision-making on resource exploitation and equipment procurement, according to the statement of a senior official from their environmental department. He said, 'We have incorporated environmental fines into calculations of the cost of using natural resources and are now seeking to purchase equipment to help us avoid large-scale fines.'

Every major production entity in Russia now has an environmental department of some description and their roles may include anything from conducting primary analysis to evaluating equipment, or company policy. Most importantly, they usually have direct control over increasingly significant budgets, or at least form the basis of any procurement decision. They are therefore an excellent target for Western companies anxious to enter the market.

Megionneftegaz, one of Russia's largest oil producing companies (1993 output: 17.7 million tonnes), with its eye on the long run intends to spend 'a substantial amount' in order to purchase 'technology rather than equipment.'

Yuganskneftegaz (1993 output: 32.2 million tonnes) spent R4.5 million in 1994, and R16.5 billion in the first six months of 1995. This was used to purchase equipment to eliminate leakages from oil collectors to a plant for producing pipeline sections with internal linings.

Chernogorneft has set aside an environmental budget of R70bn for 1996, which will include repair and replacement of 158 kilometres of pipeline sections, since this is one of their key stated objectives. The estimated cost of the operation is approximately $11.5 million, and in 1994 R32 billion was spent replacing 212 km of pipe. They expect a 50-year life from the new pipeline sections, to be achieved through the use of polymer liners.

Meanwhile at Lukoil-Kogalymneft, the environmental budget is simply described by one senior official as 'quite sufficient to buy all the necessary equipment.' With 1993 oil production of 25.2 million tonnes, it is unlikely that Kogalymneft is spending insignificant amounts.

Everybody wins

Western companies are now in a strong position to do business in the Russian Federation, and the wider CIS, where they can capitalise on the pre-existing internalisation and enable the Russians to optimise the benefits to be derived from their resources. Reducing leaks and wastage has to benefit Russian production entities, both in terms of the value of lost product and the fines that such practice incurs. This convergence of interests represents a great opportunity for western products and services.

The International Monetary Fund, European Bank for Reconstruction and Development and the World Bank now make environmental impact analyses critical prerequisites to any decision to commit funds to projects. This further underscores the need for environmental solutions to be incorporated into business strategies, which in turn generates sales opportunities for environmental products and services. Meanwhile, on the medium-term horizon is the prospect of the long-awaited Production Sharing Legislation (PSL) and a suitable set of accompanying normative acts which could bring as much as $50 billion of investment into the Russian Federation. One senior US embassy official said, 'It does not take a rocket scientist to appreciate the level of procurement these projects will generate.'

'Ultimately, avoiding fines isn't our main objective. Our main objective is protecting the environment,' said Yury P Nisshetenko, Surgutgasprom.

This is perhaps the best sign of all: a genuinely positive attitude, not one born entirely of coercion or a disincentives structure. And it is a very widespread one. In general, from the top to the bottom of the Russian energy sector, industry members appreciate the need to protect the environment. This is healthy for Russia, as well as the global atmosphere, and it offers great opportunities for Western business. Everybody wins.

References/notes

* According to US embassy sources in Moscow, 'In 1996, unpaid bills among oil industry participants will reach $1 trillion.'

Andrew Whitney is studying for a PhD degree at Cambridge University. He is the current holder of the Paul Frankel Award.

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Russia's Far East - the final frontier

By Stephen O'Sullivan, Oil and Gas Analyst, MC Securities Ltd

Russia's Far East region had been one of the least-known to western observers prior to the break-up of the Soviet Union in 1991. The region has an eight-hour time difference with Moscow and is 11 hours flying time from the capital. Even in Soviet times it was an area which attracted little attention from the more populous western regions of Russia. The port city of Vladivostok was the base for Russia's Pacific Fleet and much of the rest of the Far East was dominated by heavily fortified military installations. In many ways it was a region distinctly separate from the mainstream of Russian life.

While in some respects this remains true – winter lasts from September until May and temperatures fall to -50°C, major cities rely on internal air services and summer season shipping for communication with the outside world - in many other ways the Russian Far East (RFE) has rapidly become the scene of intense western interest. After the break-up of the Soviet Union, foreign interest focused on Western Siberia and the Central Asian states, particularly Kazakhstan. There was a gradual realisation that the resource potential of the Far East was so large that it could not be ignored.

The RFE can be divided into nine territories. One of the territories (the Republic of Sakha) has greater autonomy while two of them (Jewish Autonomous Oblast and Chukotka Autonomous Okrug) have become territories only relatively recently. Within it are found oil and gas reserves, two refineries, numerous marketing companies and pipeline networks, none of them physically connected with the rest of Russia, reinforcing the region's isolation from the rest of the country.

Overview

Despite the large reserves of hydrocarbons that lie within it, the RFE is a net importer of energy from the rest of the Commonwealth of Independent States (CIS). The region's two refineries are supplied mainly from the Siberian oilfields, although the Komsomolsk refinery is linked to Sakhalin Island by a pipeline. The nearest pipeline link is in Irkutsk and the crude completes its journey by rail tank car, an increasingly unreliable and expensive supply option. Product supply is also predominantly imported and the logistics of distribution within the region are complex, with a small population - some 8 million people - scattered over an enormous area.

The RFE is therefore a region with tremendous long-term resource potential allied with serious short-term problems. The challenge for both companies and governments is to ensure that the long-term benefits are realised, while resolving the more serious short-term problems which the region faces.

Oil reserves and production

Interest in the oil sector has focused on Sakhalin Island, the large island in the Pacific Ocean off the eastern coast of Russia and north of the Japanese island of Hokkaido. Oil was found here over a century ago but even today production remains relatively low. 1995 production levels are likely to be in the region of 30,000 barrels per day (bpd). The real interest from foreign investors lies not in existing production but in the enormous untapped reserves which lie offshore on the Sakhalin Shelf. Proven reserves are estimated to be in the region of 3.5 billion barrels of oil and over 1 trillion cubic metres (tcm) of gas while potential reserves are estimated by the Russians at 17.5 billion barrels of oil and 5.5 tcm of gas. There is always some doubt over Russian reserve estimates because their evaluation does not take account of economic factors (such as the oil price and the cost of production) and therefore generally overstate them. However, these figures indicate that the likely reserves are very significant, even for the largest companies. Exxon, one of the largest players in the region, has total worldwide proved reserves of 6.1 billion barrels of oil and 1.2 tcm of gas.

It may be worth noting that Sakhalin is merely the highest profile region within the RFE as far as oil and gas reserves are concerned. In fact there are considerable reserves in the Autonomous Republic of Sakha (formerly known as Yakutia). Some geologists' estimates have suggested that recoverable oil reserves in Sakha may be five times as large as those found on Sakhalin. However, the logistical difficulties of transporting oil from the region (absence of infrastructure) should not be underestimated and the Sakhalin developments are likely to

proceed first before there are any moves to develop oil in these remote inland regions of the RFE.

Three consortia are currently developing projects offshore Sakhalin, although no significant work will begin until the adoption of an acceptable production-sharing law by the Russian government. A draft has recently been sent to President Yeltsin for his signature, although its provisions are unlikely to be completely welcome to western oil companies operating in Russia and it is possible that he may veto it, thereby delaying the projects further.

Two of the consortia have signed production-sharing contracts and, following the passage of legislation, work on the projects may begin this year. The Sakhalin-1 consortium consists of Japan's SODECO (largely government-owned) and Exxon and is developing three fields with recoverable reserves of 2.4 billion barrels of oil and 400 bcm of gas. This has been the most drawn-out negotiation, being based on an original 1975 agreement under which SODECO had discovered two of the fields. Political problems over the Soviet invasion of Afghanistan meant that the Japanese found it difficult to proceed. The Gulf War, with its threat to Japan's supply security, coincided with the break-up of the Soviet Union and prompted a fresh set of negotiations. The third field - Arkutun-Daginskoye - was added to the project in order to enhance its viability and Exxon joined as a partner.

The production-sharing agreement was signed in the middle of last year. The western partners have 60 percent of the project, with Rosneft and Sakhalinmorneftegaz holding 17 percent and 23 percent respectively. Production is, however, unlikely to commence until the 21st century. There is a five-year evaluation period built into the contract (during which more studies will be carried out) after the production-sharing legislation is passed by the government and $10 billion must be found by the partners before development can be completed.

Sakhalin-2 covers two fields - Lunskoye and Piltun-Astokhskoye - with recoverable reserves of some 750 million barrels of oil and 450 bcm of gas. The development consortium - 4MS - consists of Marathon, McDermott, Mitsui, Mitsubishi and Shell but contains no Russian partner (although the Russian side will receive revenues from the production-sharing agreement). The project's origins date from a time when Sakhalin-1 was stalled as a result of the 1986 oil price fall and the United States decided to assist the Soviets' development of their offshore fields. A production-sharing agreement was signed in 1994 and had been awaiting the passage of production-sharing legislation through the government before substantial operations commenced.

Both Sakhalin -1 and -2 plan to export crude oil to markets in the Far East, which has long been an importer from the Middle East and Australia. Natural gas will also be exported as LNG from terminals on the south of the island to markets such as Japan, Korea and Taiwan. A pipeline link to Japan is a possibility, although the main demand centres around Tokyo are probably too far away from Hokkaido to justify a pipeline link.

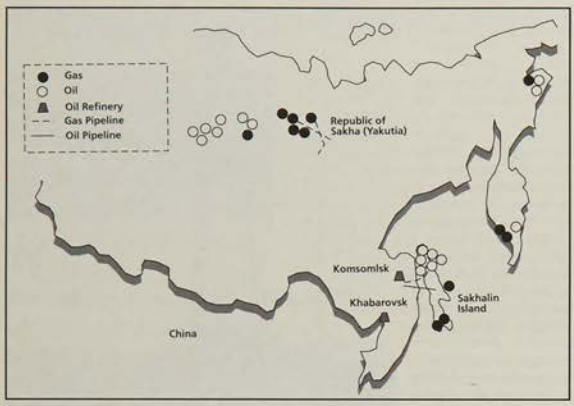
Sakhalin-3 is the other project on Sakhalin Island. Exxon won the East Odoptu and Ayashsky blocks, while a consortium of Mobil and Texaco won the Kirinsky block. The agreement has yet to be formally signed because we understand that the contract's effective date is not when an acceptable legislative framework is in place (as is the case with the other contracts) but the date of signature. In the absence of the PSA law, signature is therefore unlikely. Reserves in Sakhalin-3 are estimated to be 350 million barrels of oil and 175 bcm of gas.

Drilling rig in Sakhalin

These three projects are not the end of the story. A tender was held recently for Sakhalin-4. It elicited only one bid - from Exxon, which appears to be making Sakhalin a very strong area of focus for its operations in the CIS given its existing involvement in Sakhalin-1 and -3. The Exxon bid, which was for only one of the three blocks on offer, was apparently rejected. There are divisions within the Russian bodies responsible for attracting investment as to whether the right course of action is to slow down the bidding process to assess the results to date or to speed it up in the hope of developing a critical mass of investment which will spur other developments.

There is no doubt that the Sakhalin Shelf is very prospective. On the other hand, the region is an inhospitable and high-cost area where substantial investments will be required before the companies involved can generate the returns that they are seeking. The

Russian Far East



absence of an acceptable legal framework for production sharing and an acceptance by the Russian side of the need to remunerate the risks taken by the companies will together prevent much of the investment taking place and thereby delay the development of these large projects which can only enhance the RFE's economic prospects.

Natural gas reserves and production

Natural gas is one of the RFE's most underrated resources. While much has been written about Sakhalin's oil reserves, gas is also a major element of the Sakhalin projects, with recoverable reserves estimated at over 1 tcm and potential reserves of 5.5 tcm. Production volumes, like those of oil, are relatively low. Last year's production is likely to be in the region of 1.5 bcm. Full-scale development of the Sakhalin projects is likely to mean production of at least 15 bcm a year.

The Republic of Sakha (Yakutia) also has approximately 1 tcm of reserves, with current production levels around 1.5 bcm a year. Future forecasts of production from the Ministry of Fuel & Energy as well as independent forecasters suggest that production over the next decade could rise to between five and ten times its current level. With domestic demand growing at a lower rate, the impact on exports from the region will be proportionately much greater.

It is interesting to note that Gazprom has no involvement in gas production in the RFE. This is in marked contrast to the situation elsewhere in Russia, where Gazprom has a stranglehold on the Russian gas industry. Given the potential importance of gas in the RFE energy balance, it would not be surprising if Gazprom attempted to move into the region. It has already been involved in the early stages of negotiations surrounding some of the Sakhalin developments through its connections with the Moscow government.

The development of the RFE's gas reserves depends entirely on secure markets being found for the gas. LNG is the preferred option for at least two of the three Sakhalin projects and the market for LNG will be the critical factor in determining whether the projects become reality or not. The major markets in the region are currently Japan, Korea and Taiwan, all of which import LNG from Indonesia, Australia and the Middle East.

Sakhalin LNG is well-placed to compete with these other suppliers on location grounds. One of the main drives behind these projects is security of supply. The three countries noted above are highly dependent on imported energy, particularly from the Middle East, and a source of supply effectively on their doorstep represents an attractive alternative. In addition, China has grown to become the world's second-largest energy economy after the United States and is becoming a net energy importer. There must be considerable prospect for gas exports to China, whether by pipeline or as LNG (although the necessary pipelines or LNG import facilities would need to be constructed).

Sakha gas is less attractive for these markets because of the high production costs that such a remote location imposes. However, China remains a potential market for pipeline gas and it may be feasible in due course for Sakha gas to flow southwards to China's growing energy market in the north-east of the country. It has also been suggested that South Korea may be a market for pipeline gas; we think this unlikely given the present state of political relations between North and South Korea - South Korea is unlikely to put all its gas eggs in a basket which is controlled by its northern neighbour.

Conclusion

The RFE has tremendous natural resource wealth and it is situated close to the major energy consuming countries of Japan, Korea and Taiwan. The political and economic situation in Russia may not actively encourage investment at the moment. However, the logic of stronger links between the RFE region and its southern neighbours is likely to ensure that western investment (which is essential for the projects to succeed) is focused on projects which will strengthen these links. The emergence of China as a major regional power and an increasingly energy-intensive consumer can only mean that further integration is inevitable, for both strategic and commercial reasons.

New company targets opportunities onshore Sakhalin Island

By Kim Jackson

Sakhalin Petroleum, an independent oil company formed three months ago by a group of UK and Australian oilfield professionals and investors, has acquired a 50 percent interest in two onshore exploration and production licences on Sakhalin Island in the Russian Far East.

The two interests were purchased from Australian companies Hardman Resources, Key Petroleum and Border Petroleum for a consideration of £300,000 in Sakhalin Petroleum ordinary and preference shares. The interests on both licences are held through Sakhalin Petroleum (Cyprus) Limited, a subsidiary set up in order to take advantage of the double taxation treaty between Cyprus and Russia. The remaining 50 percent interest in each licence is held by Russian companies, including Vostokgeologiya, the former state exploration association for the whole of the Russian Far East.

Prizalivnaya The Prizalivnaya licence covers exploration and production rights in a 167km2 block on the eastern coast of the island, close to the offshore Lunskoye field. The area contains four prospective structures including the Mezhdurechenskaya oil discovery which is ready for appraisal and fast-track development. The discovery well flowed 38° API oil at rates of up to 1,610 barrels per day in an open hole test.

Preliminary recoverable reserve estimates are in the range of 100 to 200 million barrels and an appraisal well is planned for later this year. Sakhalin Petroleum began operations in January in order to mobilise a Russian drilling rig to the selected well location during the winter season. Despite the cold weather, transportation is facilitated during winter by the frozen ground. Following completion of the appraisal well, early production is expected in 1997 and for full development in 1998.

Kholmsk The Kholmsk licence covers exploration and production rights for a 1,000km^2 block in southwest Sakhalin. The block has many prospective anticlinal structures, the largest of which is Kostromskaya with estimated possible reserves in excess of 100 million barrels.

A seismic acquisition programme is planned for later this year with the first exploratory well expected to be drilled next year.

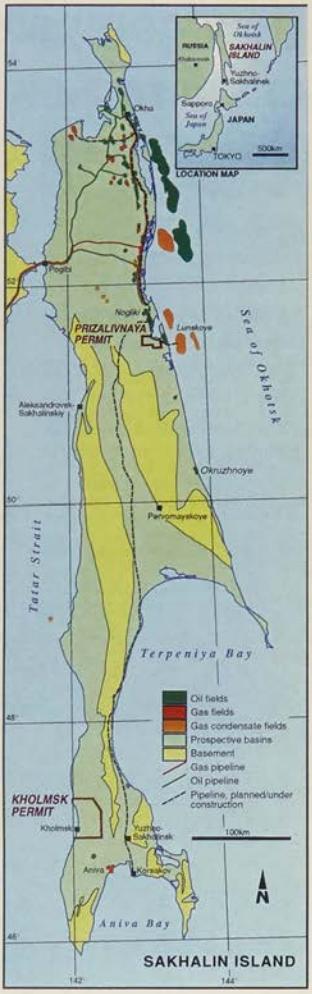
Sakhalin Petroleum is mobilising a Russian drilling rig to drill its first well in Prizalivnaya licence area.

Sakhalin potential

'Sakhalin Island still has good opportunities to acquire and develop low risk oil reserves which are close to the existing infrastructure and export routes to the major petroleum markets of Japan, China, South Korea and Taiwan,' says Mark Young, Chairman and Chief Executive, Sakhalin Petroleum.

Both the Prizalivnaya and Kholmsk licence areas are conveniently located in relation to Sakhalin Island's road and rail network, which will enable early production to be transported to the local domestic market. Meanwhile, as far as exports are concerned, Prizalivnaya is within 20km of the existing pipeline network operated by the

Drilling ops on Sakhalin Island



local production association Sakhalinmorneftegaz. Oil can be piped west to a refinery on the Russian mainland or north to a smaller tanker loading terminal. 'We are also considering the possibility of building our own terminal to allow exports directly by sea from Prizalivnaya,' says Mr Young. 'However, this will be some years down the line once sufficient reserves are developed to support such a financial commitment.' For the Kholmsk licence there is also the future possibility of direct export by small tankers to China or South Korea.

Prizalivnaya may also benefit from new infrastructure developing around the large oil and gas fields located offshore the northeast coast of the Island, including the Lunskoye gas condensate field directly to the east of Prizalivnaya. Development of these offshore fields, however, awaits further legislation to provide an acceptable framework in which the consortia will operate (see page 60).

Future prospects

'With the right local partners there are excellent prospects for a high return from these underdeveloped and undervalued assets offshore Sakhalin,' says Mr Young. 'Strong partnerships with our Russian counterparts will also provide other attractive opportunities elsewhere on Sakhalin and the Russian mainland,' he added.

Indeed, Sakhalin Petroleum already has an agreement with Vostokgeologiya and Sakhalinmorneftegaz to form a bidding group for an additional onshore licence. A further development is that Sakhalin Petroleum (Cyprus) Limited is purchasing a 10 percent stake in Vostokgeologiya. Its privatisation process was completed with an auction last December but foreign companies were not permitted to participate. 'We have moved quickly to buy these shares from two of the successful Russian bidders as we consider that Vostokgeologiya's assets are significantly discounted,' Mr Young commented. This holding gives Sakhalin Petroleum an indirectly increased stake in the Prizalivnaya and Kholmsk licences and an interest in assets which include 15 deep drilling rigs and other exploration licences.

Forthcoming Events

February

5th-6th
London: 'Successful Market Development for Utilities'. Details: AIC Conferences Ltd, 2nd Floor, 100 Hatton Gardens, London EC1N 8NX.
Tel: 0171 242 2324
Fax: 0171 242 2320

7th-8th
London: 'Managing the Cycle for Maximum Life'. Details: Margaret Clinton, Chem Systems Ltd, 28 St James's Square, London, SW1Y 4JH.
Tel: 0171 839 4652
Fax: 0171 930 1504

13th-14th
Houston: 'Global Energy Strategies: Looking Over the Horizon'. Details: Cambridge Energy Research Associates, 20 University Road, Cambridge, MA 02138, USA
Tel: 1 617 497 6446
Fax: 1 617 497 0423

13th-15th
France: 'The Bitumen Business'. Details: Ms Josée Foucault, ENSPM FI, Economie et Gestion, 232 avenue Napoléon Bonaparte, BP 311, 92506 Rueil-Malmaison Cédex, France.
Tel: 33 1 47 52 72 93
Fax: 33 1 47 52 70 66

14th
London: 'Safety and Environmental Hazards'. Details: IBC Technical Services, 57-61 Mortimer Street, London W1N 8JX.
Tel: 0171 637 4383
Fax: 0171 631 3214

14th-15th
Aberdeen:
'International ROV Forum '96'. Details: Shirley McDowell, The Conference Partnership Ltd, Eastlands, 2 London Road, Basingstoke RG21 4AW.
Tel: 01256 330315
Fax: 01256 811500

15th-16th
Amsterdam: 'Offshore Pipeline Technology'. Details: Helen Smith, The Bookings Department, IBC Technical Services, 57-61 Mortimer Street, London W1N 8JX.
Tel: 0171 453 2128
Fax: 0171 631 3214

19th
London: 'Oil and Gas in the Global Economy: The Outlook to the Millennium'. Details: Caroline Little, The Institute of Petroleum.

20th
London: 'IFEG 9th Oil Price Seminar'. Details: Catherine Cosgrove, The Institute of Petroleum.

21st
London: 'Microemulsions and Predispersed Solvent Extraction'. Details: SCI Conference Secretariat, 14/15 Belgrave Square, London, SW1X 8PS.
Tel: 0171 235 3681
Fax: 0171 823 1698

22nd
London: 'Minimising the Impact of Decommissioning'. Details: Caroline Little, The Institute of Petroleum.

25th-29th
Tehran: '1st Oil, Gas and Petrochemical Fair'. Details: Andy Maclean, Orient Exhibitions, Unit A9, Chaucer Business Park, Kemsing, Sevenoaks, Kent TN15 6PW.
Tel: 01732 763344
Fax: 01732 763606

26th-27th
London: 'Worldwide Deep Water Technologies'. Details: The Bookings Department, IBC Technical Services, 57-61 Mortimer Street, London W1N 8JX.
Tel: 0171 637 4383
Fax: 0171 631 3214

27th
London: 'Non-Operatorship – The Issues'. Details: Langham Oil Conferences Ltd, 37 Main Street, Queniborough, Leicester LE7 3DB
Tel: 01509 881022
Fax: 01509 881576

27th-28th
Dallas: 'The Latin Energy Finance Conference '96'. Details: Conference ConnectionAdministrator, 151a Goldhill Centre, Thomson Road, Singapore.
Tel: 65 356 0960
Fax: 65-356 0962

27th-29th
Myanmar: 'Myanmar (Burma) Oil and Gas Expo '96'. Details: CP Exhibition, Rm 2801, Tung Wai Commercial Building, 109 Gloucester Road, Wanchai, Hong Kong.
Tel: 2511-7427
Fax: 2511-9692
Telex: 76270 CHOCH HX

March

4th-7th
Amsterdam: 'Corrosion in the Oil & Gas Industry'. Details: C F Britton.
Tel/Fax: 01635 202329

4th-7th
France: 'Investment Profitability Studies in the Petroleum Industry'. Details: Ms Josée Foucault, ENSPM FI, Economie et Gestion, 232 avenue Napoleon Bonaparte, BP 311, 92506 Rueil-Malmaison Cédex, France.
Tel: 33 1 47 52 72 93
Fax: 33 1 47 52 70 66

6th-8th
Vietnam: 'Vietnam Oil & Gas Expo '96 (Upstream and Downstream). Details: CP Exhibition, 2801 Tung Wai Commercial Building, 109 Gloucester Road, Wanchai, Hong Kong.
Tel: 852 2511 7427
Fax: 852 2511 9692
Telex: 76270 CHOCH HX

12th
London: 'Microbes in Ships: Effects on Operations and Safety'. Details: The IMarE Conference Department, The Institute of Marine Engineers, The Memorial Building, 76 Mark Lane, London EC3R 7JN.
Tel: 0171 481 8493
Tel: 0171 488 1854

12th-13th
Ukraine: 'Investing in Ukraine'. Details: Claudia Stokes, EuroForum, 45 Beech Street, London EC2Y 8AD.
Tel: 0171 878 6888
Fax: 0171 878 6999

13th-14th
Turkmenistan: '11st Turkmenistan International Oil & Gas '96 Projects Conference'. Details: International Trade and Exhibitions J/V Ltd, Byron House, 112A Shirland Road, London W9 2EQ.
Tel: 0171 286 9720
Fax: 0171 286 0177

18th-19th
London: 'Offshore Platform Design & Construction'. Details: Claudia Stokes, EuroForum, 45 Beech Street, London, EC2Y 8AD.
Tel: 0171 878 6888
Fax: 0171 878 6999

25th-26th
London: 'Petroleum Trading and Cargo Shortages'. Details: Abacus International, 214 Inchbonnie Road, South Woodham Ferrers, Essex CM3 5WU.
Tel: 01245 328340
Fax: 01245 323429

27th-28th
London: 'Petroleum Trading and International Law'. Details: Abacus International, 214 Inchbonnie Road, South Woodham Ferrers, Essex CM3 5WU.
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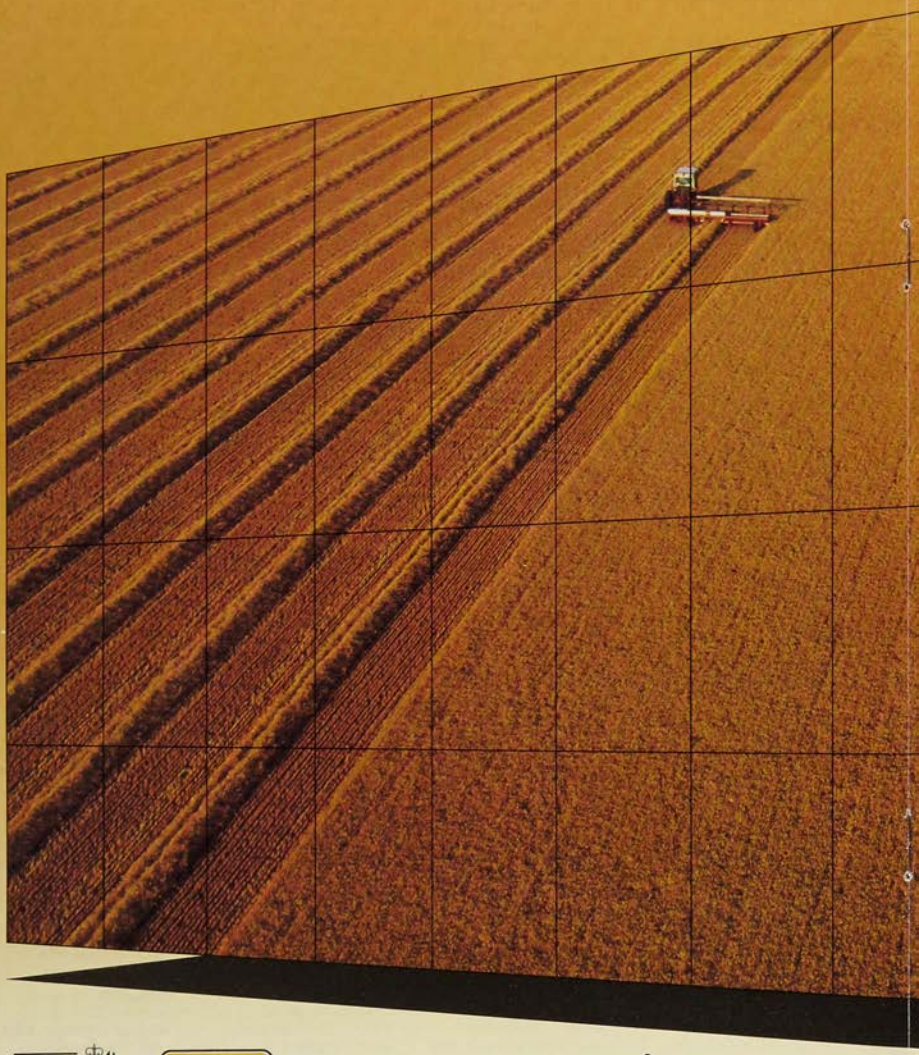

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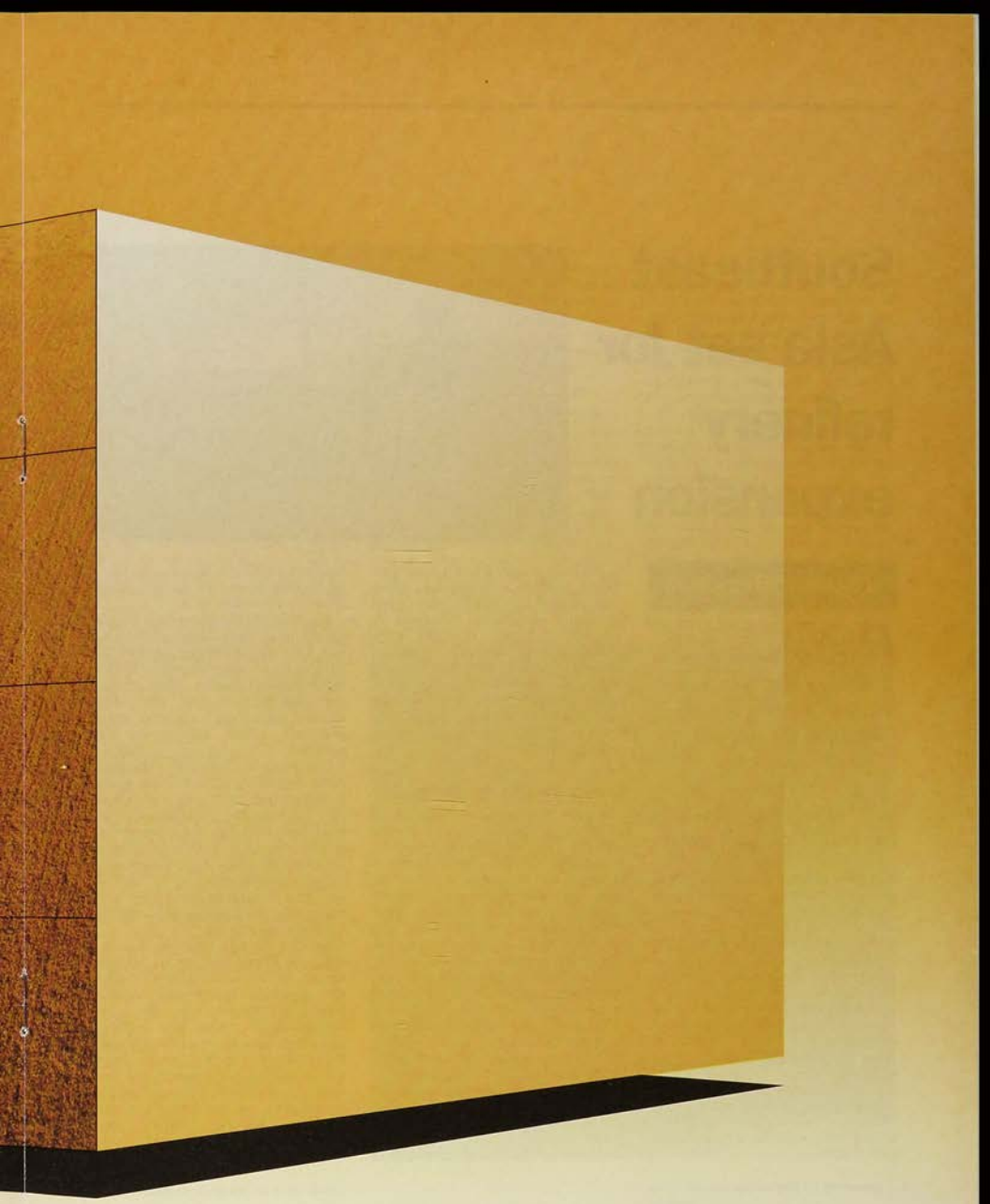

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Southeast Asia set for refinery expansion

By David Buckman

Refinery capacity in the Asia/Southeast Asian area looks set for big expansion into the next century. Indications are that if planned projects are brought on stream in the next few years capacity will be raised about 25 percent.

A number of countries – notably China and India – face serious product shortages, because they do not have enough refinery capacity to meet demand, even though they would prefer to avoid costly imports. Other states see an opportunity to meet their needs by building export-oriented complexes.

Regional economies are growing fast enough, anyway, to ensure that much new capacity will probably have to cater for domestic demand. The Institute of Energy Economics (IEE) in Japan predicts that consumption in the Asia-Pacific region will expand from 14.2 million barrels a day (mbd) in 1993 to 18.47 mbd in the year 2000 and 21.63 mbd in 2005.

This expansionary mood is in contrast to the situation a decade ago, when overcapacity and inefficiency were prevalent worldwide. Refineries in advanced European countries were operating on an average at under 60 percent of capacity. Since then rationalisation has taken place and in recent years utilisation has been over 90 percent of rated capacity, approaching the 95 percent which is reckoned to be the practical limit.

China –hungry for products

The situation in products-hungry China remains very different. It has 20 percent of the world's population but less than 4 percent of its refining capacity. Although stated capacity is around 3.6 mbd, until recently around 25 percent of that has not been usable (in 1994 Chinese refineries processed about 2.55 mbd of crude). It is forecast that utilisation in around two years will reach 80 percent, then 85 percent by the year 2000 but meanwhile imports have grown alarmingly.

Earlier this year the East-West Center in Honolulu said that by 2005 China, which became self-sufficient in oil after developing the Daqing field in the late 1950s and early 1960s, would see imports of about 250,000 bd in 1994 rise to about 2 mbd in 2005, 38 percent of its consumption. In 1993 China became a net importer of oil, crude and products combined. Whereas in 1992-94 demand soared 18 percent, crude production rose very little.

According to DRI International Energy Consulting of Paris, China will need to add 6.9 mbd of refinery capacity by 2015 to match demand and to ensure better regional balance. Much of present capacity is in areas with weak demand, while there is a shortfall in the southeast where consumption is strongest.

DRI reckons that new refineries need upgrading units to yield more transport fuels. Just over a year ago He Guangyuan, Minister of Machinery, said that the government would provide incentives to private car buyers to support the automotive industry. At present, of 1.2 million cars only 5 percent are owned privately. The implications of a private car boom are obvious.

Refinery funding could be a problem, so China has been looking abroad. In 1991 Total became the first firm to sign an agreement to build a refinery in northern China, calling for investment of almost $450 million. Since then others such as Shell, Mobil, the Japanese and the Koreans have shown interest but progress has not always been smooth. Elf has just abandoned plans for involvement in the Shanghai Pudong refinery. The Chinese are keen for new refiners to target the revenue-earning export

Above: BP's oil refinery in Singapore

market as well as the easier local one.

Crude-rich Middle East states are obvious candidates to establish new complexes. East-West Center says that the Middle East supplied 40 percent of China's crude imports in 1994; this could more than double by 2005.

India – expansion planned

Another big country that can ill afford a heavy products imports bill is India. During the year to end-March 1995 refinery capacity was around 1.15 mbd but in addition almost 280,000 bd of imports were needed.

India has done well to raise its crude production. In fiscal 1994-95 this was 640,000 bd, trimming crude imports 50,000 bd on 1993-94 to 550,000 bd. It is anticipated that oil output in the current fiscal year may rise another 100,000 bd.

But domestic refining capacity seems likely to continue lagging behind products demand, for in 1995-96 consumption is predicted by the petroleum ministry to average 1.6 mbd, up 300,000 bd on the previous year. During the eighth economic plan period demand for products is estimated to increase by 6.8 percent annually. By 2001-02
India will require about 2.04 mbd of products.

There is no shortage of plans for new refineries. In mid-1993, for example, government assented to the construction of nine complexes, with a total capacity of 320,000 bd. Even so, the decision early in the 1990s by state and private companies to invest Rupees 500 billion in expanding existing and building new refineries has had its critics. They contend that if too many proceed India could be left with surplus capacity.

The Petroleum Ministry seeks to reform the industry, which "will begin upstream and work its way down," according to its Secretary, Dr Vijay Kelkar. One reform aims to bring domestic product prices in line with the world market. As it will take two to three years to implement the changes and as it takes three to four to get a refinery off the ground, quick action is crucial.

There is renewed interest from major international companies in downstream India. In 1994 Mobil, Shell and Esso all made deals that enable them to return in some form. In addition, Kuwait Petroleum Corp is working with Indian Oil Corp on a grassroots refinery plan.

Pakistan – refining plans

India's neighbour Pakistan has also seen refinery capacity lag. Pakistan's indigenous oil output has risen in recent years to about 70,000 bd but the country requires up to 280,000 bd, while refinery capacity is only half that. Its three refineries are in need of considerable repairs and modernisation. Meanwhile, annual oil imports cost up to $2 billion, about a sixth of Pakistan's total import bill.

Government is hoping that by the end of the decade it will get an injection of almost $2 billion for new refinery capacity from private investors. A handful of projects has been in mind for some time but in Pakistan matters move slowly.

Early this year Crescent Petroleum of the United Arab Emirates and Pakistani firm Perac began building a $360 million hydrocracker, due on stream in 1998. It is designed to convert 32,000 bd of residual fuel from Karachi's two refineries to lighter products.

Shortly before this, Hyundai engineering and construction group and Pakistan Oil began choosing consultants for a $800 million, 90,000-bd refinery they plan.

Pak-Arab Refinery, a joint venture of Pakistan and Abu Dhabi, has lately finalised details for a $756 million, 100,000-bd refinery, due to be completed by early 1999, to meet the needs of Punjab and the North-West Frontier Province, representing 60 percent of the country's total demand. Mid-1999 is the target date for start-up

India: Vacuum heater with air pre-heater system

of a 120,000-bd refinery on the Baluchistan coast planned by Kuwait Petroleum and Pakistan State Oil. Recently, National Iranian Oil Co and Pakistan's State Petroleum Refining & Petrochemicals Corp invited contractors to apply for basic design of another 120,000-bd complex at Khalifa Point, again in Baluchistan, to use Iranian oil.

Vietnam– refining requirement

Another burgeoning oil producer needing refinery capacity is Vietnam. Its offshore oil output is now around 140,000 bd, far in excess of its 85,000 bd of products demand. By the end of the decade Vietnam hopes to produce 400,000 bd, and more in later years.

With products demand seen likely to double over the next five years, it is essential that Vietnam, which has to export all its crude and import its product needs, creates a refining industry. In the long term, if refineries are established and output continues to grow Vietnam could become a products exporter (see Petroleum Review, May 1995).

A first $1.2 billion, 130,000-bd complex is expected to be on stream in 1999 but by then products demand will probably have outstripped such capacity. Therefore, over a year ago Vietnam began taking bids for a second complex. This would cost at least $1 billion, have a throughput of some 100,000 bd and might be built along the northern coast, coming on stream about two years after the first.

Vietnam has been keen to decentralise industry. The authorities want to site the first refinery at Dung Quat, in the poor, central Quant Ngai province, rather than in the more prosperous south, near Vung Tau oil port. Total, which insisted that the southern location was better, lately exited from the developing group as it reckoned the project uneconomic. South Korean firms Daewoo, Hyundai and the LG group have now shown interest. Taiwan's China Investment & Development Co and Petrovietnam, the state firm, are the remaining partners.

Philippines

The Philippines have a growing import bill for products. In 1987 imports comprised 13 percent of total sales at 23,500 bd, which by 1993 has risen to 65,000 bd. The problem has been that the four established refineries – one a lube plant – were built between 1954 and 1974. Shell has now added a new 110,000-bd plant at its Tabangao site but despite this and planned expansion of Caltex's refinery at Batangas to 150,000 bd in the second half of 1997, with a possible further expansion to 260,000 bd by 2000, a study by Royal Dutch/Shell around mid-1995 saw a shortfall of almost 100,000 bd of products during the period to end-century.

The Philippines is a country planning to liberalise regulations to encourage new companies to become involved downstream. Liberalisation was set for the end of last year but tax structure changes have set this back to mid-1997.

Meanwhile, several firms are eyeing refineries in the Philippines. Proposals by Asian Dragon Oil Refinery, Kabigan Holdings, Amtron and Petroleum Authority of Thailand and Petron have all been drawn up which could include the export of products. Energy Secretary Francisco Viray is keen to see Iran get involved in the refining sector, with the promise of a regular crude supply to support minimal indigenous output.

South Korea

South Korea already has substantial domestic refining capacity and a burgeoning petrochemical industry, although there is no local oil or gas production to support them. Products demand was over 1.8 mbd in 1994. Liberalisation of the heavily controlled oil sector has been promised. Foreign investors will be able to freely own and operate refineries and filling stations from 1999 .

Meanwhile, a handful of expansions of existing plants has been announced to add around 350,000 bd of capacity. Most of that has lately been deferred – 220,000 bd at Honam Oil's Yocheon complex – to the second half of this year as the result of tighter environmental regulations.

Thailand – downstream plans

Thailand's huge gas industry and modest liquids production are fostering big downstream expansion. Shell- and Caltex-led groups are building two new refineries as part of this. They will add 275,000 bd to the existing three refineries' just-over 345,000 bd of crude distillation capacity, and other complexes are fitting assorted processing units. Earlier this year Esso Thailand Chairman David Ledlie was quoted as believing that existing and new capacity will be able to cope with domestic needs to the year 2000. Several proposed new projects, amounting to 750,000 bd, were 'ill-founded', he contended, even though they were termed export refineries.

Iran might become involved in a Thai refinery. Its ambassador to Thailand recently offered an oil-for-rice deal as an option.

Taiwan

Taiwan's demand for oil has soared from 350,000 bd in 1984 to 610,000 bd in 1994 but it has minimal domestic hydrocarbons production. Chinese Petroleum Corp, the state firm, has two refineries with a total crude capacity of just over 540,000 bd and, in common with others, is planning more in connection with huge expansions, so there should be no shortage of products processing hardware.

Taiwanese refiners, however, face a shortage of land and environmental constraints. Overseas sites are therefore being examined.

Malaysia

Malaysia, Indonesia and Singapore should all be in a position to cater for the products export market in varying degrees. Malaysia has been producing about 600,000 bd of oil, although its productive capacity is about 75,000 bd above that, and it exports roughly half its production.

Late in 1993 Malaysia disclosed seven new refinery schemes with substantial export capacity in a bid to compete with Singapore as the hub of Southeast Asian refining. Eng Ku Ainon, a senior Petronas

executive, said that the government had approved four refinery capacity expansions, totalling 450,000 bd, spearheaded by multinational groups. In addition, the state firm planned two 100,000 bd refineries at Malacca and was studying expansion of its Kertih refinery by a further 10,000-40,000 bd. Combined, the plans would cost up to $10 billion and would boost Malaysia's refinery capacity to 915,000 bd by 2000, existing expansions taking it to almost 345,000 bd by mid-1994. Malaysia's own products demand was expected to rise to 325,000 bd last year and 440,000 bd in 2000.

Indonesia

Indonesia has been producing around 1.6 mbd of crude but fast rising domestic demand threatens to turn the archipelago into a net oil importer within a decade. Home consumption is undermining Indonesia's hopes of becoming a significant added-value exporter of products to its Southeast Asian neighbours. In 1990 Pertamina planned four export refineries, designed to add 500,000 bd of capacity but in 1993, apart from a new plant at Balongan that started production in 1994, new refineries were scrapped in favour of expansions, because of shortage of funds. Balongan added 125,000 bd of capacity that was originally designed entirely for export but home demand has trimmed exports to half that.

Prior to Balongan, Indonesia's six refineries had a capacity of 850,000 bd, with consumption around 800,000 bd. Jakarta is now reviewing its refinery law, to make it more flexible. There is much interest from overseas groups, seven new refineries have been approved by government and substantial new export capacity is foreseen in the next few years.

Singapore – export centre

Singapore must be the model in Southeast Asia for a successful refiner catering for export markets while having no indigenous oil production. The first refinery, Shell's at Pulau Bukom, went on stream in 1961. Mobil, BP, Esso and Singapore Refining Co (SRC) also established operations, so that Singapore became the world's third largest refinery centre after Houston and Rotterdam, with capacity at end-1994 of 1.1 mbd, local demand being only 450,000 bd.

Within the last year or so, however, there have been gloomy warnings, as competition increases and costs rise. Traders have been reluctant to renew third-party processing deals because of poor profit margins after buying crude, shipping it to Singapore, paying the refining fee, then finding it hard to sell products competitively. They might even face a loss. On their side, refiners have seen their margins slashed from $4/barrel a few years ago to around half that. BP closed its Pasir Panjang 28,000-bd plant recently; it is due to hand back its site to the government in 1999, when it will be developed as a port terminal.

Land shortage is a problem in Singapore. However, an area around seven islands in the south is to be reclaimed for petrochemical development, tripling acreage available, and independent storage companies are being urged to build on the Riau Islands, Indonesian territory to the south.

Within these constraints, Singapore's refining sector is expanding. A massive roughly $430 million revamp of Shell's Pulau Bukom refinery has turned it into the group's biggest, in capacity, in the world. SRC, in which BP has a stake, has lately been completing a major expansion, adding 60,000 bd of crude distillation and a 33,000-bd residual catalytic cracker; Esso has been working on a new aromatics complex; and Mobil is working towards an 8,000-bd lube plant by late 1997. The company, which might – it is reported – eventually boost Jurong's crude capacity from 260,000 bd to 300,000 bd by end-decade, tells Petroleum Review that expansion of the aromatics complex is 'under consideration', and if approval is given, 'We aim for streaming possibly some time in 1998.' In addition, Gadgil Western Group of India earlier last year was talking with the government of Singapore about a new $120 million, 20,000-bd refinery on an unnamed island.

Long residue Catalytic Cracking Unit, and Iso-Propyl Alcohol Plant on Pulau Ular, Singapore

Concrete for the Congo

This month the completed 100,000-tonne concrete-hulled production barge for Elf's Nkossa development, 60 kilometres off the coast of the Congo, will be towed out by Smit tugs from Fos in southern France. It will take 45 days for this, the largest prestressed concrete barge in the world, to reach the field. There will then be six weeks commissioning involving some 50,000 man-hours, with the field due to come on-stream in May, with plateau production of 120,000 b/d.

By Neil Potter

Recoverable reserves are put at 400 million barrels. The water depths range from 150 metres in the east to 300 metres in the west where the continental shelf drops away suddenly. This will be the deepest water development undertaken in the Gulf of Guinea.

The field was discovered in 1984 but as the reservoir seemed too small and full of gas, it was left for five years. Then between 1989 and 1991 two appraisal wells were drilled and a 2-D seismic survey shot which proved the field to be much bigger than originally thought.

The development decision was taken in December 1992. Innovation has been the keynote for Elf in this FFr9.4 billion development – the use of the concrete barge, offshore separation of butane and propane from the associated gas before reinjection, use of an LPG storage/offloading vessel with a storage capacity of 80,000 cu m.

The crude oil to be produced will be sold at a premium over the Brent benchmark because of its high quality, which is why the oil will not be transported and treated at the existing shore facilities at Djeno.

Instead the crude oil will go through a 16-inch line to an FSO tanker with a storage capacity of 270,000 tonnes. The 273,268 dwt crude carrier *Stena Contender*, now owned by SBM, Monte Carlo, is being converted by Dubai Drydocks. It is understood a Maersk vessel will become the LPG storage unit.

Technip/TPG carried out basic and detailed engineering studies for all the production units and feasibility studies for the NKP barge.

The production barge is the central part of the overall field development, which comprises two 11,500-tonne steel drilling/wellhead platforms, NKF1 and NKF2, comprising 41 surface wellheads of which 24 will be producing wells, 12 water injection wells and five gas injection wells. The unmanned platforms, in 170-metre water depth, will be remotely controlled from the barge, which will be located close to NKF2.

The NKF jacket, the piles and drilling decks for both platforms were fabricated by McDermott-ETPM at Jebel Ali in Dubai, while the NKF2 jacket was built by Bouygues subsidiary Boscongo in the Congo, the largest ever built in the Gulf of Guinea.

Elf went out to international tender for a steel hull for the production barge but bidders were allowed to propose a concrete-based alternative. In 1993 the contract for the design and construction was awarded to the Bouygues Offshore-Bouygues joint venture.

Bernard Astier, Elf's Project Manager, says that one of the decisive factors for

Elf's Nkossa production barge

Elf's Nkossa production barge

Elf in going for pre-stressed concrete was its excellent durability and good fatigue resistance – the barge is expected to operate on station for 30 years without interruption. 'Using concrete', he added, 'is about 15 percent cheaper than a steel-hulled vessel. We have saved around FFr1 billion on project costs by using a barge and virtually completing hook-up and commissioning inshore. In addition, the selection of the barge solution, and its length, has enabled the living quarters to be located at the maximum distance from the process and gas compression facilities thereby enhancing personnel safety.'

The 70,000-tonne hull of the barge is rectangular in shape, 220 metres long, 46 metres wide and 16 metres high. Watertight bulkheads divide the hull into 35 dry compartments and four ballastable units. The barge is permanently anchored by 12 4.5-inch chains in groups of three at each corner.

The barge accounts for 47 percent of the budget, with drilling and completion accounting for 27 percent and the fixed platforms 18 percent. The cost of the barge is around the same as a platform but it provides a weight carrying capacity almost 12 times that of one platform.

The 'barge' concept had other advantages – assembly of modules and their integration onto the hull could be performed inshore thus minimising offshore work.

All the production facilities as well as living quarters for 160 people are housed on the barge. It will provide:

- oil treatment-separation and desalination (116,000 b/d).
- production of LPG (1,300 t/d).
- electric power generation and distribution (3 x 25 MW).
- dehydration and condensate extraction (13 MMcu m/d)
- gas reinjection (390 MMcf/d at 6,100 psi).
- water injection (113,000 b/d at 3,550 psi).

The reservoir, around 3,000 metres below the seabed, has an elliptical shape, 7 km long and 4 km wide.

Reservoir pressure will be maintained at a constant level by injecting water into the lower part of the reservoir and re-injecting the methane and ethane fractions contained in the associated gas into the top of the reservoir.

Water injection at a pressure of 240 bars will be 18,000 cu m/d.Three Nuovo Pignone turbo-compressor sets have been installed and gas injection will be at 11 million cu m/d and is compressed at 420 bars.

The surface temperatures and pressures of the liquids have necessitated the use of flexible pipes, jumpers and risers from Coflexip in France.

Elf has awarded GTM of Marseilles an incentive-based contract for the maintenance of the barge once it is on location.

Two semi-submersibles, Sedco Forex's *Sedco 700* and *Sedneth 701* were transferred from the North Sea in the second half of 1993 to begin predrilling wells. Before leaving for West Africa they underwent intensive modifications at the Verolme yard in Rotterdam, including adding new modules to the living quarters increasing the capabilities of the mud systems, upgrading the drilling equipment and preparing them for their tender-assisted drilling capability.

The rigs drilled the first wells in the conventional mode through two 310 tonnes subsea templates, fabricated by Boscongo and installed in September 1993. After the installation of the jackets, the rigs operated in the TAP mode. By May, when production starts it is planned to have 14 wells completed and the drilling programme is expected to last for another two years.

IEA studies Middle East

By John Roberts

Oil production policy in most of the major producing countries of the Middle East looks likely to change as a result of financial constraints and pressures on demand. This - implicitly rather than explicitly - is perhaps the main conclusion to be drawn from the International Energy Agency's (IEA) magisterial study on Middle East oil and gas, in which the production capacities, energy development policies and the structural economic problems of six major oil and gas producers in the region are examined.

The study details both the individual and collective importance of Saudi Arabia, Iran, Iraq, Kuwait, the United Arab Emirates and Qatar in world oil and gas production. They control almost two-thirds of the world's oil reserves and almost one-third of the world's gas reserves. Collectively, their importance can be summed up as follows. At 1995 production levels - and in rough accordance with their Opec quotas - the six countries are producing at a rate of some 16.9 million barrels of crude oil per day (mb/d), of which, judging by performance in recent years, around 85 percent is routinely available for export: in other words, 14.4 -14.7 mb/d.

Since the IEA report estimates an increase in the global demand for oil from around 68 mb/d in 1994 to between 85 and 105 mb/d in 2010, the ability of these six countries to raise output is clearly crucial. Indeed, the IEA foresees an increased call on crude from these countries of as much as 20 mb/d between 1994 and 2010.

The IEA considers that their current production capacity actually totals some 22.9 mb/d and that plans for capacity increases will take this total to 28.2 mb/d in the year 2000. In other words, it considers that in five years time the six countries would, if necessary, be able to produce at a rate some 11.3 mb/d higher than at present.

Financial constraints

Whilst this is as far as anyone can project increased capacity based on specific current plans for such increases, it is at least consistent with an ability to reach an output level of around 37 mb/d over the next 15 years or so. But there are several jokers in the pack. The costs of such expansion programmes are likely to prove very heavy, forcing most producer countries to re-evaluate their oil strategies in the light of their own financial constraints. Secondly, there are geographical imbalances.

In addition, much will depend on non-Opec output levels, not least because other IEA studies have noted that areas such as the North Sea are showing an increasing ability to sustain and even increase high output levels, so that it is hard, even in a medium five-year framework, to forecast just how much Middle East crude will be needed to satisfy global oil demand. And of course, if the Middle East countries should feel that there was little reason for short-term investment, then consequences for long-term investment could prove severe. But on the assumption of the IEA's latest study, Middle East producers would be required to meet a considerable proportion of global increase of perhaps as much as 9 mb/d over the next five years or so.

The 11.3 mb/d gap between current output and projected year 2000 capacity provides a reasonable safety cushion but it should be noted that the biggest single element in this comes from unused current Iraqi capacity and projected increases in Iraqi capacity. Any prolongation of sanctions is bound to impact on such scenarios considerably. It should be noted that the IEA study was based on an assumption that sanctions against Iraq would be lifted this year. While it looks quite conceivable that Iraq may be changing its policy with regard to limited sales under UN supervision, unless President Saddam Hussein actually falls from power, there is no realistic prospect that such key players as the United States and Kuwait will give serious consideration to a full-scale lifting of sanctions until they have completed their general and presidential elections towards the end of this year.

Amongst the study's general conclusions is a comment that 'Middle East Six governments are caught between flat revenues and increasing expenditures. They are dependent on oil, yet face steadily rising spending requirements, between military commitments and rapidly growing populations demand-

ing more services to maintain the current quality of life. At the same time, the governments have developed chronic budget deficits, which they have financed by drawing down their foreign assets and borrowing.' It adds that with the exception of Qatar and the United Arab Emirates, the other Gulf states have fewer foreign assets earning less income and greater debt loads and debt service than in previous years. At the same time, oil prices have tended to decline.

Investment needs vary

It is against this background that governments will have to raise approximately $100 billion to pay for oil and gas development plans. Of this, an estimated $50 billion is required to take oil production capacity to the 28.2 mb/d level. For several countries - indeed, for perhaps all of them except Saudi Arabia - this is likely to mean a swing towards greater reliance on production sharing agreements, which means in the case of Iraq and Kuwait, a return to a policy bitterly rejected and opposed in the past.

The IEA argues that the six governments are increasingly aware of making their state-owned energy companies more cost efficient and are currently seeking to develop energy projects in a cost-conscious perspective. It therefore notes the role that international oil companies can play in view of their advanced technology, managerial expertise and capital. But while it clearly believes that this is a probable development, it does not state that this is the likely solution.

However, while making it clear that it believes that production sharing, or hybrid arrangements (which would reduce the political impact of declared production sharing agreements) would be more widely used, the IEA report also notes that national oil companies can still borrow to help finance energy projects. The report observes that 'There are probably fewer potential problems associated with borrowing for upstream oil sector development projects because of the widely liquid international market for crude oil.' However, it notes that natural gas expansion plans are more likely to be constrained by the need to ensure repayments are tied to sales, thus requiring buyer commitments.

Overall, the main conclusions are, to a certain extent, predictable. Middle East energy production costs are still considerably lower than anywhere else in the world. Work by the Centre for Global Energy Studies is quoted to show how while average costs for adding a barrel of capacity for these six states amounts to around $3,500 in 1993-95, those for other Opec countries amount to an average $9,900. Moreover, these costs are escalating – to $4,833 and $11,333 respectively – for estimated additional capacity costs between 1996 and 2000.

There are, however, considerable differences between the various countries. Iraqi costs to increase sustainable capacity in the short run (because what is required is repair rather than wholly new development) are put at just $1,000 per barrel, while Kuwait costs are $3,000 per barrel, Saudi costs $4,000 and Qatari costs $6,000 per barrel. The UAE costs are put at $7,000 and those of Iran at $8,000. Overall, the IEA study estimates that the six countries will have to spend $53 billion both to maintain and increase their capacity over the period 1993 to 2000, whilst other Opec countries will have to spend $39.4 billion in this regard.

Working on the basis of announced plans for the continuation of existing projects, the study foresees a very different future for each of the six countries. Iraqi capacity, put at 1.5 mb/d for 1993, is seen as rising to 5 mb/d in 2000, whilst at the other end of the scale, Iranian output merely changes from 3.8 to 4.5 mb/d. Kuwaiti capacity jumps from 2.25 to 3.25 mb/d, Qatar's from 0.475 to 0.6 mb/d, the United Arab Emirates' from 2.75 to 3.75 mb/d, and Saudi Arabia's from 9.725 to 11.130 mb/d.

The strength of the report is its summary of the energy and energy-development plans of each of the six countries, and the financial environment within which such plans will have to operate. Some of its individual conclusions are as follows:

Iraq

The study cites Iraqi aspirations to take capacity to 6 mb/d by 2003 at an estimated cost of $25 billion. It comments that 'Obtaining adequate access to export routes will be a challenge,' a reflection of the prevailing but possibly mistaken view that Iraq faces constraints not only at its Gulf terminals of Mena al-Bakr and Khor al-Amaya but also on the Turkish pipeline. *Petroleum Review* has been informed by engineers engaged in the project that there are now no serious blockages on the Turkish lines as a result of Turkey supplying the Iraqis with a replacement pumping set for equipment damaged at the northernmost Iraqi pumping station on the Iraq-Turkey line.

Clearly, development of actual capacity will largely have to wait for an end to sanctions but the IEA notes that 'Large parts of the country are inadequately explored, in part because Iraq has spent nine of the last 14 years at war'. It cites industrial sources' support for Iraqi assertions that proven oil reserves now total 112 billion barrels and adds that 'There is also good potential for the discovery of additional reserves beneath fields now in production.' Cash constraints make production sharing arrangements the logical choice.

Kuwait

With Kuwaiti oil officials now very conscious of the need to adopt full cycle accounting for oil development plans, the IEA study notes an interest in possible production sharing arrangements with international companies but does not come to any significant conclusion as to whether Kuwait will indeed do more than examine the possibility of such companies developing the Ratga field in the north.

Saudi Arabia

The question of how much capacity the Kingdom is prepared to add is tangentially addressed. The IEA study includes

the pre-Gulf War proposals for increasing crude oil production capacity to 12 mb/d, whilst also acknowledging more recent comments that development plans for new fields, such as Shaybah, are intended as much to improve the quality of output as to increase capacity. Hence its calculation of 11.13 mb/d as a likely capacity level for the year 2000.

United Arab Emirates

The United Arab Emirates, like Kuwait, has a quite definite programme of increasing capacity by around 50 percent by the year 2003. While Abu Dhabi will obviously provide the bulk of this increase, the survey notes that enhanced recovery could boost Dubai's sustainable crude oil capacity to 0.4 mb/d, whilst output from the other Emirates is projected at around 0.1 mb/d. However, like Qatar, the UAE focus is primarily on gas, with Abu Dhabi seeking to double output of natural gas between 1998 and 2003. In part, this is to boost LNG sales, whilst domestic use is expected to expand considerably. In addition, there will be increased gas re-injection into the oilfields.

Qatar

With two major LNG projects currently under development, a third under consideration and active plans for gas pipeline exports, oil not unnaturally takes second place in current Qatari energy strategy. Yet Qatar is clearly seeking to maximise the return on its still substantial oil reserves and QGPC is thus seeking wider participation by international oil companies. The report was written before Qatar concluded an alliance agreement with Brown & Root and other companies to share both the risks and rewards inherent in a programme aimed at boosting output from the Dukhan field. However, the emirate's adoption of more liberal terms to attract foreign investors into exploration ventures and production or secondary recovery opportunities is noted.

Iran

In 1994, Iranian crude production totalled some 3.61 mb/d. But a mystery continues to hang over its actual capacity. In theory, this totalled 4.19 mb/d in mid-1994 and was projected to rise to 4.5 mb/d by the end of last year. However, the IEA report cites industry observers (as of mid-1995) as suggesting that 'Actual sustainable production capacity is not much more than present production levels.' The fields which Iran requires to have in full operation to achieve its 4.5 mb/d capacity are listed, together with detailed tables concerning the pipeline network, domestic usage and export availabilities.

***Middle East Oil and Gas* is available from the IEA/OECD Publications Service.**

Algerian hydrocarbon magnet

By Kim Jackson

Algeria is the world's seventh largest gas producer and currently boasts one of the biggest gas fields - Hassi R'Mel - discovered to date. Recording the highest number of oil and gas discoveries anywhere in the world in 1994, the country is proving to be a magnet for foreign oil companies despite its continued political instability and the security risks posed by Islamic fundamentalists. Some 40,000 lives have been lost since Islamic militants began fighting the government in 1992, including a number of foreign journalists and two foreign pipeline workers.

Oil and gas revenues account for some 95 percent of Algeria's total foreign earnings. State-owned Sonatrach has been the sole gas producer in the country for the past 30 years, producing some 50 billion cubic metres of gas annually, 30 billion cubic metres of which is currently exported via the Transmed pipeline to Italy and by ship to Spain, Belgium, Turkey, France and the United States. The company also produces 1.3 million barrels of oil and condensate per day, 75 percent of which is exported.

Keen to boost exports to Europe, Sonatrach has already secured contracts that will increase gas exports to some 60 billion cubic metres annually by the year 2000. A new gas pipeline linking Hassi R'Mel to Spain and Portugal is under construction and scheduled for completion later this year.

BP and Sonatrach first

In order to meet future increases in demand from European gas consumers and cut costs, Sonatrach signed an agreement with BP at the close of 1995 to explore for and produce gas in the Sahara Desert which the two companies will market jointly in Europe. BP believes it is the first foreign international oil company to achieve such production sharing and joint venture links with Sonatrach and hopes that the deal will increase the company's worldwide gas production by some 30 percent.

The deal, which requires the approval of the European Union and ratification by the Algerian authorities, will initially allow BP to appraise seven known gas discoveries and to explore for additional gas reserves in a 25,000km^2 block in the In Salah region of District 3, a remote desert province some 1,200 kilometres south of the capital city of Algiers. BP's acreage is believed to be capable of producing some 10 billion cubic metres of gas per year by the early part of the next decade.

A three-year programme of exploration and appraisal is due to begin shortly, with nine appraisal and exploration wells planned. It is expected that BP's technology for producing 3-D seismic images of underground rock formations will help to overcome some of the technical problems involved in tapping reserves identified in the region's 'difficult' geology. It is understood that the agreement will allow BP to withdraw if there is not sufficient gas to merit exploitation.

However, if the scheme goes ahead, a new 48-inch diameter pipeline extending some 580km north to Hassi R'Mel, Algeria's gas hub, would be required to link into the newly constructed export pipeline to Spain where it will be jointly marketed by a new company owned 50:50 by BP and Sonatrach. This would fulfil Algeria's plans to open up markets for its gas throughout southern Europe.

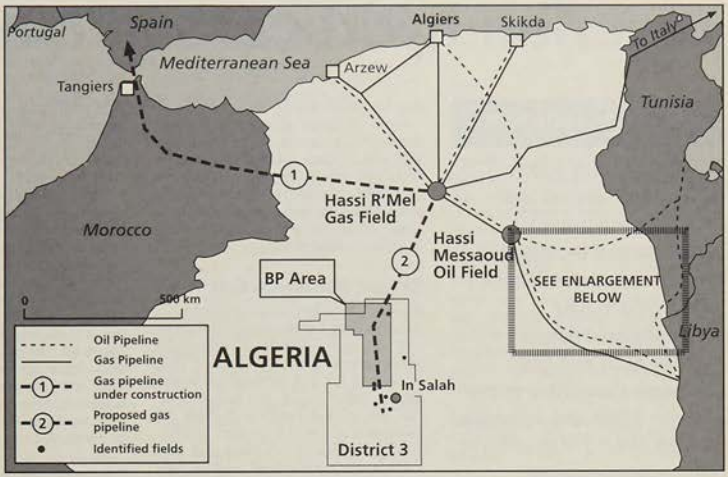
The full cost of the project is estimated at some $3.5 billion over a five-year period, 65 percent of which will be provided by BP, the remainder by Sonatrach. BP will take about 30 percent of the net profits of the development after payment of royalties and taxes in order to recoup the high level of expenditure during the initial stage of the project.

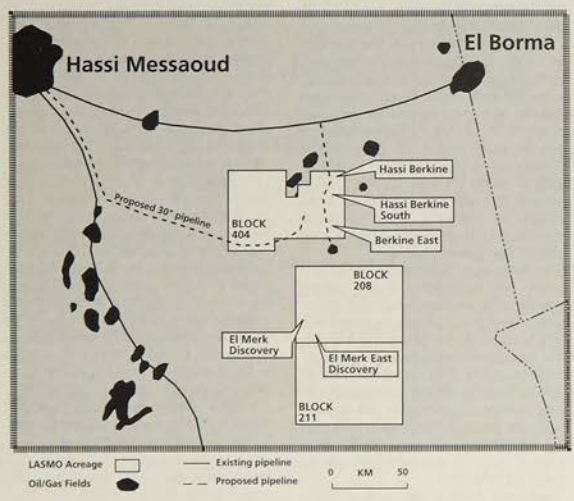
State of security

Algerian government officials are reported to be hoping that the BP/Sonatrach deal will act as an example to other projects and encourage other foreign companies to overcome their reservations about the security situation in Algeria. Indeed, the government cordoned off vast areas of the desert in April last year in anticipation of such future oil and gas exploration.

BP reports that it 'fully investigated' the potential security threat from Algeria's political unrest and has 'prepared plans for safeguarding employees'. These may well draw on the company's experiences of exploring for oil in other countries such as Colombia and Vietnam. It is thought, however, that the risks are relatively small as most of the violence to date has been confined to a region further north of the remote In Salah province, focusing in particular on Algiers itself.

Indeed, some observers suggest that political stability may be a step closer following former General Liamine Zeroual winning the country's first democratic presidential poll last November. This remains to be seen, however.





Developments under way

A number of other western companies are already active in Algeria. Agip, for example, has interests in parts of the huge Hassi Messaoud oilfield while Atlantic Richfield Company (ARCO) has interests in two concessions - Guerrara to the northwest of Hassi Messaoud and Hassi Bir Rekiz to the northeast of Hassi Messaoud, respectively.

ARCO has completed some 5,000km and 1,700km of seismics acquisition in Guerrara and Hassi Bir Rekiz, respectively, and plans to use a single rig for a back-to-back drilling programme this year. The first well, in Guarrara, is already near completion. This will be followed by the drilling of two wells in the Hassi Bir Rekiz prospect and then a further two wells in Guerrara.

Lasmo, too, has made discoveries to the east of the Saharan desert which are estimated by the operator Anadarko to have reserves of some 1.5 billion barrels of oil. Entering Algeria at the start of 1990 with partners Maersk and Anadarko, Lasmo has a 25 percent working interest in four exploration blocks in the Saharan desert region.

Development of Lasmo oilfields will take place in two stages

Seven wildcat wells have been drilled to date and five discoveries made - three oilfields (Hassi Berkine, Hassi Berkine South and Berkine East) and two gas/condensate fields (El Merk and El Merk East). The oilfields contain light sweet crude and are located in block 404, relatively close to existing infrastructure. Wells are said to have flowed 'prolifically', producing over 13,000 barrels of oil per day. The partners have no economic rights to any gas finds.

Lasmo, along with its partners and Sonatrach, plans to develop the discoveries in stages. The first phase will provide first oil by 1997 from the HBN and HBNS fields in block 404 at a rate of approximately 40,000 barrels per day (gross). A new pipeline going north to join the existing El Bourma to Haoud-El-Hamra pipeline is planned. Development facilities will cost some $210 million.

The second phase includes the full development of the discoveries made on block 404. A new 30-inch pipeline is to be built by Sonatrach to connect to the main oil terminal facility at Haoud El Hamra. This stage of the development programme is expected to cost approximately $1 billion.

Lasmo states that the oilfield's operating costs are relatively low - the operating cost per barrel is less than $2.25, according to Anadarko.

The partners are currently drilling appraisal wells on the Hassi Berkine South discovery and a wildcat well is planned on the southernmost block (block 245) early this year. Two drilling rigs will undertake a continuous and extensive exploration, appraisal and development drilling programme on the acreage throughout the course of this year.

Meanwhile, commercial discussions are ongoing regarding the Hassi Berkine and Hassi Berkine South developments and applications for exploitation licences are expected to be submitted some time later this year.

Contracts in the pipeline

Algeria is said to be negotiating contracts with a number of other foreign companies. Reports mention a possible natural gas deal with Exxon, a $1 billion-plus oil contract with Atlantic Richfield and a wet gas project with Total. No information confirming these reports had been received when *Petroleum Review* went to press.

Survey confirms continuing reduction in crude oil marine losses

By Paul S Harrison, Consultant to PM-L-4A

The following discussion covers the main findings from the 1994 data collected by PM-L-4A and presents detailed results for the crude oils which appear most frequently in the data base. Development of the overall loss situation is also discussed. It should be noted that the convention used in this paper is to express losses as negative values and gains as positive.

Sets of data analysed from more than 4,000 individual voyages in 1994 with a total volume in excess of 2.2 billion barrels. This represents some 23 percent of worldwide crude movements by sea.

Overall loss comparison

In order to compare overall results from one year with those from other years, a standard representative 'basket' involving some 60 crudes has been established based on world production and the areas covered by the member companies. This is used to weight net losses by crude type each year to arrive at an overall comparative figure. The weighting is in accordance with the fraction of each crude oil within the crude oil basket. The data published in 1992[1] is not directly comparable with that below since the earlier data was unweighted.

Over the last six years differences between the Bill of Lading and outturn quantities, expressed as Net Standard Volumes (NSV), have been calculated in **Table 1** as follows:

Table 1

Year	NSV Loss
1989	- 0.34%
1990	-0.32%
1991	-0.30%
1992	-0.30%
1993	-0.29%
1994	-0.25%

Clearly losses continue to reduce.

It should be emphasised that these loss figures, although termed 'NSV losses' do not for the most part represent real losses of crude oil. Instead, they are largely the result of differences in measurements between load and discharge ports. However, such differences or 'apparent losses' have an important financial impact.

The steady reduction in the overall NSV loss figures is the result of improved measurement practices at terminals and in particular wider acceptance of API/IP measurement standards. This includes adoption of the 1980 Petroleum Measurement Tables for volume correction and improvements in sampling and analytical methods for water and sediment measurement, all of which have played a significant part in the improvements.

Sediment and water loss (S&W Loss) which equals the water and sediment value measured at load port minus that at discharge, has reduced as indicated in **Table 2** (unweighted mean values).

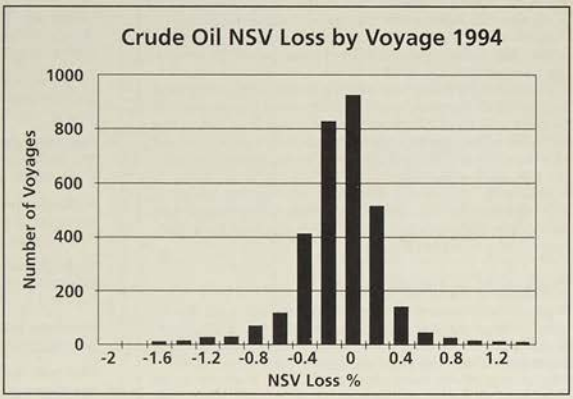


Figure 1

Table 2

Year	S&W Loss	
	Mean	Standard Deviation
1986/7	- 0.13%	0.26
1988	- 0.11%	0.24
1989	- 0.10%	0.24
1990	- 0.12%	0.24
1991	- 0.09%	0.23
1992	- 0.09%	0.22
1993	- 0.07%	0.21
1994	- 0.06%	0.21

Loss distribution

The frequency distribution of losses for individual voyages is sufficiently close to the theoretical 'normal distribution' to allow detailed statistical analyses and comparison of the results to be performed with a high level of confidence. The NSV loss distribution for 1994 is shown in **Figure 1**. The mean NSV loss was - 0.20 percent and the standard deviation was 0.34 percent. Note that these are unweighted figures.

The standard deviation defines the 'spread' of the results in that 95 percent of all losses can be expected to fall within ±2 standard deviations of the mean. In this example, 95 percent of losses lie within the range -0.88 percent to +0.48 percent.

Loss comparison for individual crude oils

Losses or measurement differences are found to correlate strongly with crude type, load port and discharge port. The data base analysis therefore includes calculations based on grouping voyages under these headings.

Table 3 gives mean NSV loss and standard deviation for shipments of the most popular crudes in the data base. The mean of the reported API gravity is also given together with the overall percentage loss based on total barrels shipped.

The graph in **Figure 2** compares the loss distribution of a typical North Sea

Crude Oil Marine Loss Data Base Panel

The Crude Oil Marine Loss Data Base Panel (PM-L-4A) was established after the first IP conference on loss control in 1984. The panel collects and analyses worldwide crude oil shipping data with the general aim of improving loss control through a better understanding of loss patterns and trends.

Panel members submit their company data for confidential analysis by an independent consultant retained by the panel. An annual report is issued individually to all members. This report includes analysis of the individual company data together with an overall analysis of the entire annual data set. A synopsis of the results is also published from time to time in *Petroleum Review*.

In addition to overall analysis of the data, consideration has been given over the years to assessment of differences relating to the use of 'old' and 'new' Petroleum Measurement Tables, water analysis methods and crude oil vapour pressure.

Membership of PM-L-4A is open to companies involved in the export and import of crude oil. In 1994 data was submitted by:

AGIP Petroli
BP Oil
Chevron International
Conoco
Elf France
Elf International
Esso
Marathon
Mobil
Petrofina SA
PMI Pemex
Phillips
Repsol Petroleo
Shell
Statoil
Sun Oil Company
Total

The value of the information carried out by the panel depends heavily on the amount of data submitted. New members are therefore very welcome and companies interested in joining the panel should contact the chairman of PM-L-4A via the Institute of Petroleum.

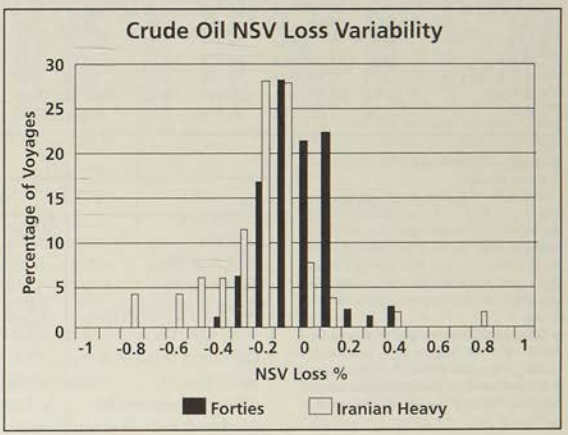


Figure 2

Table 3

Analysis by Crude Oil Type

Crude Type	API Gravity	Overall Volumes (NSV)			Calculation by Voyage		
		Total Barrels	Barrels Loss	Barrels Loss %	NSV Loss % Mean	St.Dev.	No.
Alaskan North Slope	29.33	228,379,546	-210,733	-0.09	-0.08	0.17	311
Amna	37.20	19,540,437	-16,855	-0.09	-0.10	0.25	34
Arab Heavy	27.89	32323666	-45,445	-0.14	-0.16	0.24	56
Arab Light	32.58	94,042,779	-183,220	-0.19	-0.17	0.28	129
Arab Medium	30.93	29,180,574	-93,808	-0.32	-0.22	0.32	39
Belayim	27.89	35,271,977	-84,067	-0.24	-0.24	0.29	65
Bonny Light	35.53	19,472,448	-73,736	-0.38	-0.34	0.41	25
Bouri	26.07	18,330,009	-63,178	-0.34	-0.35	0.46	31
Brent	38.27	70,590,994	-25,746	-0.04	-0.04	0.22	90
Bu Attifel	40.53	31,973,510	-84,457	-0.26	-0.26	0.49	52
Cabinda	32.75	32,287,820	-59,330	-0.18	-0.19	0.33	36
Djeno	26.96	16,866,716	-14,124	-0.08	-0.07	0.20	21
Ekofisk	39.89	47,644,053	-42,367	-0.09	-0.09	0.13	75
Escravos	36.00	63,531,633	-159,901	-0.25	-0.25	0.58	65
Flotta	36.37	30,521,742	-100,089	-0.33	-0.32	0.21	50
Forcados	29.52	29,108,390	-3,464	-0.01	0.01	0.33	32
Forties	39.61	60,331,963	-74,087	-0.12	-0.11	0.18	86
Fulmar	40.54	20,596,619	-11,784	-0.06	-0.05	0.21	29
Gullfaks	32.26	181,804,745	-360,601	-0.20	-0.20	0.19	226
Iranian Heavy	30.58	51,212,515	-150,422	-0.29	-0.28	0.31	56
Iranian Light	33.75	25,631,701	-118,335	-0.46	-0.32	0.33	25
Kuwait	31.64	29,385,563	-91,216	-0.31	-0.24	0.34	23
Maya	21.93	78,180,851	-82,285	-0.11	0.13	0.38	96
Olmeca	38.97	24,134,175	-75,825	-0.31	-0.32	0.25	47
Oseberg	36.10	37,055,838	-76,322	-0.21	-0.19	0.20	58
Qua Iboe	36.16	31,821,002	-66,454	-0.21	-0.17	0.49	29
Sahara Blend	45.38	34,387,554	-69,225	-0.20	-0.20	0.25	57
Sarir	37.42	20,475,594	-71,238	-0.35	-0.35	0.32	34
Sirtica	40.05	12,119,614	-24,677	-0.20	-0.19	0.21	22
Souedie	23.98	17,071,483	-34,430	-0.20	-0.19	0.28	37
Soviet Export Blend	32.54	75,951,047	-118,175	-0.16	-0.16	0.33	136
Statfjord	38.48	162,560,948	-527,141	-0.32	-0.32	0.16	194
Syrian	36.22	32,950,614	-65,175	-0.20	-0.20	0.30	58

crude (Forties) with a Middle East crude (Iranian Heavy).

Not only do the mean losses vary (Forties - 0.11; Iranian Heavy - 0.28) but the increased spread of losses represented by the increased standard deviation for the Iranian crude (0.31 percent) when compared with the Forties (0.18 percent) is clearly shown.

By establishing means and standard deviations for losses associated with crudes, load ports and discharge ports it is possible to use statistical methods to determine the probability of any particular loss occurring for a single voyage or group of voyages. This allows panel members to target investigations on those voyages which really do fall outside established limits.

Detailed loss analysis

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

Overall results for each of the main measurement differences are as follows (see also Table 4), comparing unweighted figures for 1994 with those for 1986/87:

- NSV and TCV (Total Calculated Volume) losses are simple comparisons between bill of lading and outturn figures.
- Load difference is the difference between ship and shore TCV quantities on loading.
- Discharge difference is the difference between ship and shore TCV quantities on discharge.
- Ship loss or 'transit difference' is the difference between ship TCV measurements at the load port before sailing and at the discharge port on arrival.

	1994		1986/87	
	Mean	Std. Dev.	Mean	Std. Dev.
NSV loss %	-0.20	0.34	-0.29	0.48
TCV loss %	-0.14	0.32	-0.18	0.46
Load difference%	+0.16	0.43	+0.20	0.44
Ship loss %	+0.01	0.22	+0.02	0.42
Discharge difference %	-0.31	0.43	-0.39	0.52
S&W loss %	-0.06	0.21	-0.13	0.26
ROB differences %	+0.03	0.17	+0.002	0.20

Table 4

- S&W loss is the difference between water and sediment measured at load and that measured at discharge.
- ROB difference is the difference between the TCV measured on the ship prior to loading (OBQ) and that remaining after discharge (ROB).

In addition to a reduction in mean losses since the data base was established, there has been a clear reduction in the standard deviation of the losses in each category. This is an indication of steady improvements in methods and controls throughout the measurement sequence (eg increased use of autosamplers, increased use of electronic dip tapes, better water analysis methods).

Vessel data

A fully laden ship is a very repeatable measurement device. Vessel data isparticularly useful in monitoring losses as vessels form the link between load and discharge ports. Vessel data is particularly useful in monitoring port performance where data is available for a number of different vessels using the same port.

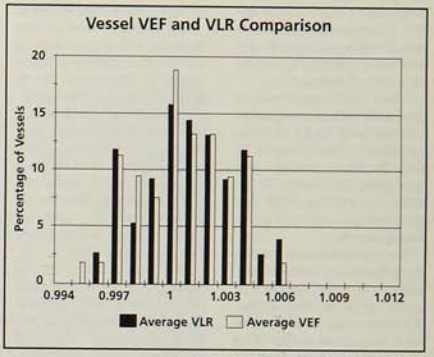
The data base therefore contains performance information relating to individual vessels together with the crude and port information discussed above. Vessel Load Ratios (VLR) are calculated and stored together with reported Vessel Experience Factors (VEF).

The VLR is simply the ratio of the TCV received by the vessel as calculated from the vessel tank measurements and the TCV delivered from shore, normally calculated from loading meter readings. As the calibration tables for the vessels' tanks are normally derived from engineering drawings, there are often fixed errors in the vessel measurements. These errors are reflected in the VLRs together with any errors in the load port measurement. In order to correct systematic errors in the vessel measurements VEFs are used. VEFs are derived by averaging VLRs which satisfy prescribed criteria. Voyages following dry docking are excluded, independent Bill of Lading figures must be used and all VLRs used must be within ± 0.003 of the mean of voyages used for the VEF calculation. VEFs are calculated on a 'rolling average' basis.

In general it is found that a simple average of a number of VLRs provides a value which can he used in calculations where true VEFs are not available.

Figure 3 compares average VLRs and VEFs for all vessels in the data base with 10 or more entries.

Figure 3



The distributions for average VLR and VEF are very similar and no values fall outside the range 0.994 - 1.006. The overall average is 0.99998 for VEFs and 1.0004 for VLRs, ie essentially unity for both average factors.

In a previous report[2], it was pointed out that the full data base average VLR (and VEF) was of the order of 1.002. This still holds true when all vessels are considered, rather than only those with 10 or more voyages, as this selection includes a high proportion of larger vessels. Average VEF is found to vary with vessel size as follows:

Vessel Size '000 bbls	Average VEF
<250	1.0026
250-750	1.001
750-1250	1.001
>1250	1.0008

This variation in **Table 5** above is thought to be due to the larger vessels having a greater number of evenly shaped tanks which can be more accurately calibrated from drawings.

Conclusions

Analysis of 1994 data shows continued reductions in losses across a wide sample of voyages. Weighted average NSV loss stands at -0.25 percent compared with -0.34 percent in 1989.

Loss reduction has been achieved at all stages in the measurement chain with reduction in losses due to water measurement being particularly noticeable. This is the result of wider use of improved methods for sampling and analysis.

The variability of losses has also reduced significantly indicating better control of measurement methods and systems.

Vessel measurements continue to provide a valuable analysis tool. Full use can only be made of such measurements if reliable vessel experience factors are available. Reported VEFs are stored in the data base but an average of a sufficient number of vessel load ratios can provide a useful alternative where VEFs are not available.

References

1. Crude oil shipments - update of marine loss statistics, *Petroleum Review*, April 1992.
2. Shipping Survey Shows Continuing Loss Reduction, *Petroleum Review*, December 1990.

Any questions or comments on the content of this paper or any other aspects of the activities of the panel should be addressed to the chairman of Panel PM-L-4A at the Institute of Petroleum.

Technology News

A breath of fresh air in potentially explosive atmospheres

Kemira Safety has augmented its range of Autoflow respirators with 'Autoflow Ex', a powered respirator specifically designed for use in potentially explosive atmospheres.

The new respirator is powered by a rechargeable battery pack and has been certified to the EEx ib IIC T4 classification under the European standards EN 50 014 and EN 50 0202 for explosive-atmosphere equipment.

The manufacturer states that special electronic circuitry in the respirator power pack limits the electrical currents used in the unit to a level below that required to cause ignition in order to ensure that the system is 'intrinsically safe'. Furthermore, the design also saves energy, allowing the power pack to be used for much longer periods between each recharge than with conventional respiratory protective devices.

Autoflow Ex also incorporates a fast recharging device that provides eight hours of operation from just 2.5 hours recharging.

As with other designs in the Autoflow respirator range, Autoflow Ex's built-in electronics automatically regulate the volume of filtered air supplied to the user by adapting to the breathing response rate.

The unit also offers a steady, optimised rate of air flow throughout the day, even if the filters become clogged with airborne contaminants or particles. An LED display in the power pack provides the user with a warning if minimum air flow cannot be maintained.

The Autoflow Ex respirator

High accuracy level gauge simplifies tank monitoring

A new, high accuracy MTS magnetostrictive level transmitter has been developed by Allison Engineering of Basildon in Essex to provide an easily engineered solution to the problem of tank monitoring in a small/medium sized tank farm or combination of vessels.

Equipped with a tank contents supervisory system comprising programmable intelligent plant interface hardware and configurable SCADA software, the new MTS tank level gauge enables continuous monitoring of the contents of up to 48 tanks at any one time. Information on tank content levels, specific gravity of product etc are displayed via a user-friendly operator interface.

The unit is programmed to handle a wide range of tank shapes up to 8 metres in height and is claimed to be accurate to within ±1mm.

Fully certified to Cenelec Exi requirements, the MTS intrinsically safe level transmitter is suitable for use in Zone 1 and Zone 2 hazardous areas.

The new design is currently being offered to interested parties for trial purposes.

The MTS level transmitter

Ball valve with integral instrument tappings targets UK market

Inte-S has introduced a new ball valve concept to the UK market that is capable of accommodating up to three instrument tappings for the monitoring of fluid parameters such as temperature, pressure, pH and flow.

Closure of the valve isolates instrument connections from both upstream and downstream fluids, thereby enabling on-line removal and replacement of instruments when required.

This design not only eliminates many of the fittings and extra block valves usually required for instrument isolation but also offers a substantial saving in related fabrication and installation costs, according to the manufacturer.

The valves are available in 1/2-inch to 6-inch nominal bore models.

Based in Germany, Inte-S holds the worldwide patent to this design of ball valve. The unit has already proved popular in its domestic market and the company is now looking to export the technology.

Rhodia Sorb cleans up

Rhône-Poulenc's 'Rhodia Sorb' range of non-woven, spill clean-up products is now available in the United Kingdom and Eire through White Stone in Pulborough, West Sussex.

Manufactured from polypropylene, Rhodia Sorb offers high levels of absorption of oil and organic liquid spills while being weather resistant, water repellent and dust free.

Rhodia Sorb products are also safe to dispose of, breaking down to carbon dioxide and water on incineration without emitting any toxic gases.

Technology News

Emergency call-out service mops up spills

All organisations have a duty of care to provide an adequate level of spillage control on site in order to comply with UK legislation. However, with budgets usually tight and spillages often escalating beyond the capabilities of on-site spillage control stocks, additional clean-up and containment products are frequently required as back-up.

With this in mind, Leicester-based spillage control specialist Fosse Spilkleen and fluid handling company Dunlop Hiflex last month launched a new 24-hour emergency call-out service for tackling oil and chemical spillages.

The 'Reflex' service provides members with suitable materials for absorbing and containing spillages less than four hours after placing their call. 'This eliminates the need for members to carry large stocks of products at their own expense just in case an incident occurs,' says Mark East of Spilkleen.

Initially covering the industrialised areas of Greater Manchester, Cheshire, Lancashire, Humberside and Yorkshire, the call-out service is scheduled to go nationwide in the next few months.

Included in membership is a risk assessment site survey which assesses potential spillage hazards and advises on the minimum stocks of spillage control products required for day-to-day use.

ST&C setting new standards

Sira Test & Certification has introduced a two-tier service for differential pressure measurement enabling customers to tailor costs for different requirements.

While both services are carried out on identical rigs, the measurement procedures have been revised to deliver two levels of accuracy. Customers can choose either a fast, low-cost calibration for routine situations, or an alternative 'national best' standard for high accuracy.

Calibrations meet DTI requirements for fiscal metering and can be carried out at line pressures of up to 200 bar. The benchmark for the new service will be either up to or better than 0.6 ppm of line pressure, 30 ppm of differential pressure and 8 Pa, giving for example ±0.03 percent at 500 mbar differential and 100 bar line pressure.

Sonardyne system measures marine riser angles

During drilling the wellhead and BOP assembly differential angle must be minimised. If it deviates by more than a few degrees from zero the drillstring will come into contact with internal components of the wellhead, flex joint and BOP stack. Unless quickly detected, the resultant 'key seat' wear can cause so much damage that the well has to be abandoned.

Bearing this problem in mind, Sonardyne Ltd has developed a new 'Marine Riser Angle Monitoring System' (MRAMS) that allows mobile drilling rigs to measure marine riser angles more accurately and maintain the critical position over the wellhead and BOP assembley.

The system integrates ultra-short-baseline (USBL) positioning technology, acoustic telemetry, Compatt transponders and high resolution inclinometers to provide rig operators with instant information about riser, BOP or differential angles and rig position relative to the wellhead.

Position and angle data are presented on a clear display in both graphic and numeric form so that there is no misunderstanding about which direction the rig should be moved to reduce the differential angle.

MRAMS can also be integrated with dynamic positioning reference sytems.

The system can be easily retrofitted and has already been installed on Houston-based Arethusa Drilling's *Worker, Neptune* and *Whittington* mobile drilling rigs.

New seismics data processing technique

A powerful new seismics multiple suppression technique has been unveiled by Ensign Geophysics.

The company has been able to commercialise the new technique, which is based on a new algorithm derived by Dr Eric Verschuur of Delft University of Technology, for the attenuation of surface-related multiples of any periodicity, through its participation in the DELPHI programme. A number of algorithms have been developed for geophysical purposes at the university through the DELPHI programme, a project which is sponsored by some of the major oil companies, Ensign Geophysics and Western Geophysical.

Incorporated into a software package known as MARS (Multiple Attenuation Related to Surface), the algorithm utilises the general wave equation boundary condition to relate the multiple-contaminated recorded seismics data to the multiple-free case.

The solution makes no assumptions regarding wave behaviour in the earth and, therefore, requires no prior model or knowledge of the subsurface, in contrast with other wave equation-based techniques. The cost of the new technique is said to be comparable to standard multi-channel multiple suppression methods.

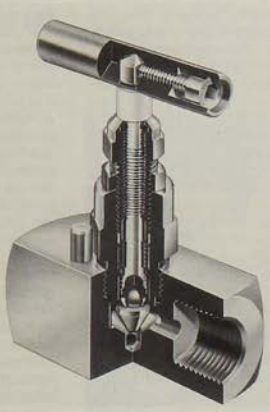
Logging advice

The Logic Group's Well Log Advisor programs are now available on a 3/5" diskette that can be viewed on any IBM-PC compatible computer having EGA or VGA graphics.

It contains four example analyses, one each from SSA (Shaly Sand Advisor), CBA (Carbonate Advisor), DSA (Devonian Shale Advisor) and OEA (Old Electric Log Advisor). Each example takes the viewer through a well log interpretation using the programs, showing screens and offering explanations.

Technology News

Klinger gets the needle



Richard Klinger has developed a range of compact needle pattern instrument valves that is based upon one standard design for all process industry applications. Traditionally, the majority of needle valves have been offered in a mix and match variety of configurations and alternative valve tips and bodies depending upon the service media and operating pressures.

Suitable for sour gas service and process industry requirements ranging from cryogenic applications up to 400°C, the valves are supplied in carbon or stainless steel, or in more exotic materials if required. They are offered with a full range of direct mounted and remote manifolds and are suitable for top or bottom process connections for gas or liquid applications as standard.

The new design centres on a valve stem assembly with a swaged, self-centring but non-rotating, hard stem point. This eliminates product leakage by ensuring perfect alignment of the valve spindle assembly and positive seat closure under all conditions.

The unit's bonnet is screwed hard down onto an annular, annealed stainless steel joint located in the valve body to form an effective seal which protects the valve's rolled threads from the process media. The stem threads are also protected by a fully adjustable sandwich of alternate hard and soft rings of PTFE and a totally encapsulated internal dust cap.

In the event of excess torque being applied to the handle, the valve assembly is protected by an in-built break feature. This consists of an annular recess machined into the top of the stem which fails safely, leaving an exposed portion of the stem to which a Stilson can be applied to operate the valve.

Whessoe acquires Italian expertise

Whessoe has augmented its range of Ex-category safety instrumentation products with the acquisition of Italy's EN Engineering which will be incorporated into Whessoe's Elcon Instruments intrinsic safety division.

'EN's products and skills are strategic in helping Elcon exploit new markets for distributed instrumentation being opened up by fieldbus networking,' states Elcon Instruments' Managing Director, Dr Gerald Wilson. 'The full Ex capability will provide us with the ability to build low-cost hazardous area nodes which can be sited remotely.'

EN Engineering's product portfolio includes flame/explosion-proof (Exd) enclosures, cable glands and micro switches, increased safety (Exe) enclosure, cable glands and LED indicator lamps and a range of intrinsic safety (Exi) products as well as a pressurised apparatus (Exp) enclosure design and manufacturing service.

Fisher-Rosemount and SAP to develop integrated products

Fisher-Rosemount System and SAP AG of Germany are to develop products to integrate Fisher-Rosemount's process and field automation systems with SAP's business management software.

The integration products will achieve certification from SAP prior to their release as fully-supported Fisher-Rosemount System products to ensure complete compatibility for users.

Fisher-Rosemount expects that the integrated products will enable process industry manufacturers to 'achieve greater manufacturing efficiency, flexibility and process uptime while keeping costs under control.'

New features for Hawke cable transits

Hawke Cable Glands Ltd has incorporated improved cable block colour coding and optional pre-lubrication of blocks in its cable transits in order to enhance the safety of transit installation and simplify inspections at a later date.

Transit safety and security have also been improved through the use of welded frames without intruding flashing or overgrinding.

Available in a number of standard sizes, the frames can be tailored to suit individual requirements. Two installation methods – integral block compression or separate compression tool – are also offered.

Cable transits

Contacts

Kemira Safety	01527 579990
Allison Engineering	01268 526161
Inte-S	01276 21723
White Stone	01798 831359
Fosse Spilkleen	0116 247 7907
Ensign Geophysics	01932 857433
The Logic Group	00 1 512 451 5707
Sira Test & Certification	0181 467 2636
Sonardyne	01252 624955
Richard Klinger	0181 300 7777
Elcon Intrinsic Safety	01325 314455
Hawke Cable Glands	0161 308 3611
Rosemount Ltd	01243 863121

People

Ed Gallagher has been appointed Chief Executive for the Environment Agency for England and Wales. The Agency will commence operations on 1 April. It will incorporate the existing NRA, HMIP, Waste Regulation Authorities (WRAs), and some central branches of the Department of the Environment. Further directorial appointments include: **Jan Pentreath,** Environmental Strategy; **Nigel Reader,** Finance; **Archie Robertson,** Operations; **Giles Duncan,** Personnel; **David Slater,** Pollution Prevention and Control; **Geoff Mance,** Water Management.

Mr John Battle has been appointed UK Labour Party's shadow energy spokesman in place of **Mr Martin O'Neill.**

The 1996 Executive Officers have been announced by UK Offshore Operators Association (UKOOA). The president will be **Dr George Watkins,** Chairman and Managing Director, Conoco (UK) Ltd. Further appointments include: Vice-Presidents: **Mr Heinz Rothermund,** Managing Director, Shell UK Exploration and Production, **Mr Lance Johnson,** President, Mobil North Sea Ltd; Honorary Secretary: **Mr Ray Harlow,** Chairman and Managing Director, Sun Oil Britain Ltd; and Honorary Treasurer: **Mr Peter Schweinhage,** Managing Director, Deminex UK Oil and Gas Ltd.

Rockwater Ltd has announced changes to its management team. As a result of General Manager **Mr Abdul Kassam** joining Brown & Root in West Africa, the responsibility for the management of Rockwater in the United Kingdom will now be undertaken jointly by Operations Manager **Mr Paul Alexander** and Commercial Manager **Mr Mark Duncan.**

Mr Pierre Gadonneix has replaced **Mr Loik Le Floch-Prigent** as the chairman of Gaz de France (GdF). Mr Gadonneix has been GdF General Manager since July 1987. Mr Le Floch-Prigent, formerly head of Elf Aquitaine, has taken up the post of chairman at French state railways, SNCF.

British Petroleum has named *Fred Phaswana* as Chairman of BP Oil Africa and Chairman and Chief Executive of BP Southern Africa. He became President of BP Netherlands and Belgium in 1992 after working for many years at BP Southern Africa.

Mr François Cornélis, Chief Executive Officer and Managing Director of PetroFina, has been unanimously elected President of the European Petroleum Industry Association. Mr Cornélis has succeeded **Mr H. Ivor Berresford,** Vice President, Supply, Trading and Planning for Shell Europe, who served as President of EUROPIA since September 1993. Mr Cornélis took up his position on 1 December 1995.

Mr John Lander, former Managing Director of Pict Petroleum, which merged with Premier Oil last year, has left to join British-Borneo Petroleum as Executive Director UK. **Mr Rick Haythornthwaite** will take over his responsibilities for managing Premier's North West Europe portfolio.

Canadian Petroleum UK Ltd (formerly CanadianOxy North Sea Petroleum Ltd) has appointed **Mr James L Stretch** and **Mr Gordon N Marriott** as Non-Executive Directors and has announced the resignation of **Mr John E Brading** as Non-Executive Director.

Mr Timothy Messman has resigned as Managing Director of Dominion Energy but will remain a Non-Executive Director. His successor is **Mr James LaPorte,** while **Mr Nicholas Marden-Taylor** becomes Finance Director.

***Dr Keith H Taylor* takes over as President of the Institution of Chemical Engineers (IChemE) following the death of *Mr John Collier,* Chairman of Nuclear Electric. He was appointed to his current position as Chairman and Chief Executive of Esso UK in 1993 and is based in London. He is currently a member of the IP Council, having served as Vice-President.**

Chevron Asiatic has appointed **Mr John Gass** Managing Director following the appointment of **Mr Ray Wilcox** to Vice-President and General Manager of Operations at Chevron Shipping Co. Mr Gass will take up his appointment on 1 April.

Mr John Cox has relinquished his position as Director General of the Chemical Industries Association to take up the position of Chief Executive with London First Centre. His successor to the post of Director General is **Dr E G Finer** whose previous position was Head of the Chemicals and Biotechnology Division at the DTI.

The International Petroleum Exchange (IPE) has elected **Mr Richard Reinert** as Chairman. He succeeds **Mr Phil Lynch** who has served as Chairman for the last five years. **Mr Colin Bryce** was also elected as Deputy Chairman.

Inspectorate has announced the appointment of a new Northern Europe Chief Executive to be based in the Netherlands. He is **Mr Chris Fisher,** former Chairman of the IP Netherlands Branch.

General Patricio Lopez has been named President of state oil company Petro-ecuador by the government. General Lopez takes over from **Mr Federico Veintimilla** who was forced to step down after allegations of mismanagement.

Former IP President *Dr Pierre Jungels* has been appointed Managing Director, Exploration and Production, British Gas. Dr Jungels was previously a main Board Director of Petrofina SA which he joined in 1974. He became President of the Institute of Petroleum in 1986 and was awarded an Honorary CBE as a result of his work for the Institute.

Membership News

NEW MEMBERS

Mr F Al-Hajri, Esso Petroleum Company Limited, Building 1093, Wessex Road, Heathrow Airport, Hounslow, Middlesex, TW6 2PZ.
Mr P Allen, Eastern Refinery Ltd, North Road, Ellesmere Port, L65 1AJ.
Mr M R Bain, 205/16 Thonglor Square, Soi Thonglor, Sukhumvit 55 Klongtoey, Bangkok 10110, Thailand.
Mr G L Batchelor, 43 Cranbrook Court, Fleet, Hants, GU13 8PY.
Mr J Beeby, 2 Broadmeadow Lane, Stratford-upon-Avon, Warwickshire, CV37 9FD.
Mr R J Bettinson, Powell Duffryn Terminals Limited, Powell Duffryn House, London Road, Purfleet, Essex, RM19 1PR.
Mr G D Bourne, BP Exploration & Operating Co, Farburn Industrial Estate, Dyce, Aberdeen, AB2 0PB.
Mr P L Bowden, Bowden Ward & Co, 28 Park Crescent, Oadby, Leicester, LE2 5YH.
Mr D M Brown, Powell Duffryn Terminals Limited, Powell Duffryn House, London Road, Purfleet, Essex, RM19 1PR.
Mr J Cameron, 11 Hawthorn Gardens, Nairn, Inverness, IV12 4TN.
Mr P J Carroll, 52 Doods Park Road, Reigate, Surrey, RH2 0QD.
Mr D P Corthorn, 71 Waverley Crescent, Wickford, Essex, SS11 7LS.
Mr M W Covil, 26 Ridge Way, Edenbridge, Kent, TN8 6AR.
Mr S J Cridland, 12 The Springs, Witney, Oxon, OX8 7AJ.
Dr R Davidson, 31 Ferndale Avenue, Chertsey, Surrey, KT16 9RB.
Mr R L De Zilwa, Kuwait Aviation Fuelling Co, PO Box 1654 Safat, 13017 Kuwait.
Mr M Dyke, 34 Coventry Road, Coleshill, Birmingham, B46 3EE.
Mr M El-Chaib, 3 Beechworth, 179 Willesden Lane, London, NW6 7YZ.
Mr A Fedotov, 11 Talbot Square, London, W2 1TR.
Mr J R Fernandez-Arribas, Repsol (UK) Limited, Kensington Centre, 66 Hammersmith Road, London, W14 8UD.
Mr S Fowle, 40 Vale Road, Sutton, Surrey, SM1 1QH.
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Mr E Gardiner, 15 Selwyn Close, Kings Stanley, Stonehouse, Glos, GL10 3LH.
Ms B Hambrook, Robson Rhodes, The Galleria, Station Road, Crawley, West Sussex, RH10 1HY.
Mr V B Hughes, 16 Grasmere Road, Frodsham, Cheshire, WA6 7LW.
Mr N M Humphrey, 19 Farm Close, Southport, Lancashire, PR9 7QB.
Mr O S Imoukhuede, Nigerian National Petroleum Corp, Pipeline & Tank Construction Div, Plot 308, Adeola Odeku Street, Victoria Island, Lagos, Nigeria.
Mr K M Jimmison, 17 Larch Road, Cleethorpes, South Humberside, DN35 0RW.
Dr F Lauterbach, Faudi Filtersystems GmbH, Scharnhorststrasse 7, 35260 Stadtallendorf, Germany.
Mr A D Leigh, National Valve & Engineering Co Pty, 33 Wedgewood Road, Hallam, Melbourne, Victoria 3803, Australia.
Mr A McDonald, 8 Larnacol Road, London, W6 9NT.
Mr R Macdonald, Symbio Scotland, Southlea, New Fowlis, Crieff, Perthshire, PH7 4NH.
Dr J McCaul , National Power plc, Occupational Health Unit H&S Dept, Windmill Hill Business Park, Whitehill Way, Swindon, Wilts, SN5 6PB.
Mr S Mctigue, Tactical Supply Wing, RAF Stafford, Beaconside, Stafford, ST18 0AQ.
Mr J Miller, Mobil Oil Company Ltd, RTSL, Coryton, Stanford-le-Hope, Essex, SS17 9LL.
Sqn Ldr A J Morgan, 19 Beamish Drive, Bushey Heath, Watford, Herts, WD2 1HJ.
Mr K Overman, Tracer Research Corporation, 3755 North Business Center Drive, Tucson, Arizona 85705, USA.
Mr K Ovreas, Christiania Bank, Lloyds Chambers, 6th Floor, 1 Portsoken Street, London, E1 8RU.
Mr G T Pearce, 17 Mountview Gardens, Aberdeen, AB2 4RT.
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Mr A J Rettie, 16 Ullswater Road, London, SW13 9PJ.
Mr C A Reynolds, Lochinver, Little Shurdington, Cheltenham, Glos, GL51 5TY.
Mr K Saleh, Arab Petroleum Pipelines Company, 431 Al-Geish Avenue, Loran, Alexandria, Egypt.
Mr P Schweinhage, Deminex UK Oil & Gas Ltd, Bowater House, 114 Knightsbridge, London SW1X 7LD.
Mr J Sherrard-Smith, BP Oil Llandarcy Refinery Ltd, Britannic House, Llandarcy, Neath, West Glamorgan, SA10 6HJ.
Dr D J Stephens, Streams Consulting, The Town House, Wharf Lane, Bourne End, Bucks, SL8 5RR.
Mr M R Trees, Talisman Energy (UK) Ltd, Belmont House, 1 Berry Street, Aberdeen, AB1 1DL.
Mr R E F Twist, 22 Bluebell Meadow, Sherwood Grange, Winnersh, Wokingham, RG41 5UW.
Mr A Velez Torres, San Salvador No 104, Plaza San Buenaventura, 50110 Toluca, Mexico.
Dr I Vince, 14 Scotts Avenue, Shortlands, Bromley, Kent, BR2 0LQ.
Mr G Wand, 9 Highview, Pinner, Middx, HA5 3NZ.
Mr F R Weston, 29 Hamesmoor Way, Mytchett, Camberley, Surrey, GU16 6JG.
Mr V Wierzbicki, Petrotest Instruments GmbH & Co KG, Symeonstr. 2a, 12279 Berlin, Germany.
Mr M K Wilson, 47 Fleetgate, Barton on Humber, South Humberside, DN18 5RA.
Mr T A Youssef, Arab Petroleum Pipelines Company, 431 Al-Geish Avenue, Loran, Alexandria, Egypt.

STUDENTS

Mr A A Adenle, Centre for Petroleum & Mineral Law & Policy, University of Dundee, Dundee DD1 4HN.
Mr D McFadden, 6 Winifred Road, Merton Park, London SW19 3AS.
Mr S W Onuosa, Flat 1, 28 Perth Road, Dundee DD1 4LN.
Miss O Oladapo, 17 Springfield Perth Road, Dundee DD1 4HT.
Mr J Rettie, 16 Ullswater Road, London SW13 9PJ.
Mr A J Tozer, 3A Elphinstone Road, Aberden AB2 3EF.
Mr B Wilfred Flat 82, Taymills, 23 Brown Street, Dundee DD1 5EF.
Mr I L Worika, Flat 1, 28 Perth Road, Dundee DD1 4LN.

NEW COLLECTIVE

Harpur Oil Industry Services,
47 Boulevard d'Alsace,
06400 Cannes,
France

Representative: **Mr Carl Clump**
Harpur Oil Industry Services provides services specifically to the oil industry.

Harpur Forecourt Services offers back-office software and integrated accounting and management information services for retailers.

Harpur Card Services provides corporate fleet card processing worldwide.

IP List of Consultants

Consultants who are also IP members or fellows are entitled to a free standard entry in the IP List of Consultants, published annually. This directory is supported by a search and listing service now provided by the IP Information Department.

If any consultant, not already included, would like to have an entry in the 1996-7 edition to be published in September, please contact Tracey Connellan in Membership Department

Membership News

DEATHS

We regret to announce the following members have died:-

	Born
Mr M J Baines	1931
Mr C Beynon	1939
Mr G R Bright	1923
Mr H T Conroy	1928
Mr J C G Cree	1916
Mr J D Graham	1912
Mr H Kaye	1917
Mr J A Parry	1927
Mr K V Rainey	1925
Mr J A Rudkin	1943
Capt E G Stout	1947
Mr E T Wadsworth	1915
Mr A J P Walsh	1910

CORRECTION
One of the small number of long-standing members who have recently completed 50 years in IP membership is Mr AS Curlet FInstPet.
Due to incorrect information supplied a misspelt version of his name appeared last month. The IP offers its sincere apologies to Mr Curlet.

IP VICE-PRESIDENTS

At the meeting of the IP Council, held last December, two new vice-presidents were appointed. They are:
Left: **Mr J M Banfield**, Chairman, Mobil Oil Co Ltd
Right: **Mr M J Pink,** Managing Director, Enterprise Oil plc

Bob Hooks (left), Chairman of the IP Analysis Sub-committee, presents Dave Mealor with an IP Certificate of Appreciation. Dave, formally of BP Research Sunbury-on-Thames, was Chairman of the Inorganic Analysis Panel from 1986 and the Diesel Particulates Analysis Inorganic Panel from 1992 until his retirement in 1993.

Les Mehew, Chairman of the IP Motor and Aviation Fuels Experimental and Operators Panel, presents Phil Grix with an IP Certificate of Appreciation and the ASTM's Certificate of Appreciation. Phil, formerly of Conoco, Humber Refinery, was a member of the Panel for some 10 years and chaired the Diesel Section from 1990 until his retirement in 1995.

AROUND THE BRANCHES

ABERDEEN
13 February: AGM, Shell UK Offshore Co-ordination Centre, Altens Farm Road, Aberdeen.
12 March: *Impact of Innovation on Future Prospects for the Norwegian Sector*
Dr Arild Nystad, Director Petroleum Resource Management Division, Norwegian Petroleum Directorate.

EDINBURGH & SOUTH EAST SCOTLAND
8 February: Annual Student Lecture
The Role of Technology Licensing in a Major Company
Martin Howard, General Manager, Licensing Business, BP Chemicals.

ESSEX
14 February: *Automotive Fuels for the Future*
Andrew Harrison, Shellhaven Oil Refinery, Shell UK Ltd, Downstream Oil.

HUMBER
1 February: Visit to Grimsby Evening Telegraph
1 March: Annual Dinner, Beachcomber Club, Humberston.

MIDLANDS
21 February: AGM - details to be circulated

NORTH EAST
6 March: *Wind Energy*
Dr G Jenkins, Northern Energy Associates.

NORTHERN
13th February: AGM, followed by *Metalworking fluids*
Castrol representative. 6.30 pm at Belfry Hotel, Handforth

SOUTH WALES
23 February: AGM and Flower Pressing, Mrs Enid Wade, Savoy Country Inn, St Clears

STANLOW
6th March: *Developments in Fuel/Fuel Additive Technology*
David Blackmore, Shell Research at the Queen Hotel, Chester

WEST OF SCOTLAND
28 March: Petroleum Dinner (by ticket), Hospitality Inn, Glasgow (not 7 March, as previously advertised)

YORKSHIRE
13 February: AGM/Hot Pot Supper followed by *Sporting Moments*. Guest speaker John Morgan, Sports Journalist and Broadcaster

UK Deliveries into Consumption (tonnes)

Products	†Nov 1994	*Nov 1995	†Jan-Nov1994	*Jan-Nov1995	% Change
Naphtha/LDF	277,935	300,620	2,569,815	2,652,146	3
ATF – Kerosene	541,496	609,327	6,753,929	7,066,230	5
Petrol	2,087,923	1,961,177	21,003,347	20,051,643	-5
of which unleaded	1,236,837	1,254,742	12,068,452	12,622,105	5
of which Super unleaded	94,927	84,514	1,268,755	880,661	-31
Premium unleaded	1,141,910	1,170,228	10,799,697	11,741,444	9
Burning Oil	233,245	262,830	2,346,949	2,374,360	1
Derv Fuel	1,326,166	1,317,517	11,918,235	12,396,723	4
Gas/Diesel Oil	621,614	628,169	6,902,522	6,592,110	-4
Fuel Oil	689,934	732,316	8,362,722	7,360,803	-12
Lubricating Oil	70,220	79,215	738,271	830,372	12
Other Products	776,603	714,307	8,005,996	8,194,048	2
Total above	6,625,136	6,605,478	68,601,786	67,518,435	-2
Refinery Consumption	517,021	552,270	5,683,078	5,886,406	4
Total all products	7,142,157	7,157,748	74,284,864	73,404,841	-1

† Revised with adjustments *preliminary NB: The 1995 figures for lubricating oil are significantly higher than those reported in 1994. This is the result of the introduction of a new reporting format, which aims to achieve greater accuracy.

IP
THE INSTITUTE OF PETROLEUM

Minimising the Impact of Decommissioning

Thursday 22 February 1996

To be held at the Cavendish Conference Centre, London

This IP conference is jointly sponsored by The Offshore Engineering Society and The Centre for Petroleum and Mineral Law at Dundee University.

Decommissioning has become an emotive and contentious public issue with governments and the industry at a critical stage in a programme to prevent international bodies like the London Convention, the OSPAR Commission or the EU from agreeing a total ban or moratorium on disposal at sea.

Public concern for the environmental issue has become paramount but how can this be balanced against the competing factors of safety and cost? What advances in technology are required to provide acceptable solutions? This conference will concentrate on the key technical issues affecting the decommissioning of offshore installations presented by renowned speakers from government, the industry and academia who will cover the topics of greatest interest. These issues will be discussed in their global perspective in order to achieve the desired balance.

The programme also includes two case studies which illustrate the detailed work that has been carried out by the operators to prepare for responsible disposal of redundant structures. The conference will again bring together a unique team of experts and delegates who will be able to debate openly the issues involved. The 'bottom line' will have an impact on everyone. Early registration for this popular conference is advised.

For a copy of the registration form, please contact the Conference Department, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR UK Telephone: 0171 467 7100 Fax: 0171 255 1472

IP
THE INSTITUTE OF PETROLEUM

Oil and Gas in the Global Economy

The Outlook to the Millennium

Monday 19 February 1996

To be held at the Cavendish Conference Centre, London

The conference will provide an authoritative view of the vital global, political, economic and environmental issues, forming the background to the business and investment decisions that need to be taken, determining the shape of the industry to the year 2000 and beyond.

Topics on the following subjects will be presented:

- An overview from a major player
- The North American perspective
- The role of an emerging giant
- Financing the future
- Environmental factors – the European Union posture
- Stabilising in the Middle East
- Prospects in the Asia Pacific Region
- Making it flow – a trader's vision

For a copy of the registration form, please contact the Conference Department, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR UK Telephone: 0171 467 7100 Fax: 0171 255 1472

EXPLORE POTENTIAL

Power

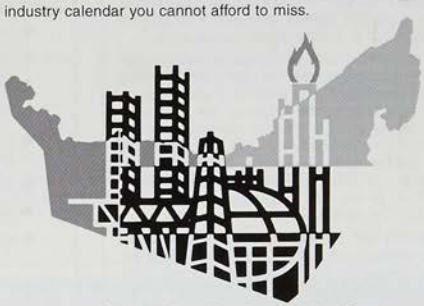
1994 was an important year for ADIPEC. It brought together 495 local and international oil related companies, representing 30 countries. That strong international representation indicates that ADIPEC'96 will be more distinguished and successful.

The 7th ADIPEC Exhibition and Conference in Abu Dhabi promises to be bigger and better than ever. It is a showcase of one of the most important oil and gas centres and a vital meeting place for oil industry people and businessmen from all over the world. The Exhibition will highlight the latest technological innovations and products for oil and gas exploration both onshore and offshore.

The 7th ADIPEC is an event in the oil industry calendar you cannot afford to miss.

13-16 October 1996

ABU DHABI INTERNATIONAL EXHIBITION CENTRE



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