Oil Trading Manual

David Long,
Editor

WOODHEAD PUBLISHING LIMITED

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Formerly edited by David Long

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Contributors

David Long

David Long is a freelance consultant and writer specialising in the oil market. He writes two monthly newsletters commenting on trends in the oil market, *Argus Fundamentals*, published by Petroleum Argus Limited and the *Monthly Oil Report*, published by the Centre for Global Energy Studies (CGES) in London. He is also a regular contributor to the weekly *Argus Global Markets* and to the bimonthly CGES *Global Oil Report*. His interests include the development and application of new trading techniques in the oil industry and he has been involved in the preparation of training material on swaps and options and the development of computer software for analysing oil price behaviour.

David began his career with BP in 1977, where he worked in Corporate Planning and Supply Departments. He then spent two years on secondment at the Oxford Institute for Energy Studies, studying the development of forward paper markets in oil, before joining the Institute as a Research Fellow from 1986 to 1989. While at the Institute he took part in research on the oil export policies of the former Soviet Union, the development of the European refining industry, and the behaviour of prices in the physical, forward and futures markets for gasoil in Europe.

Julian Lee

Julian Lee is an oil analyst at the Centre for Global Energy Studies in London. The CGES is an independent energy research centre founded in 1990 by Sheikh Yamani, former oil minister of Saudi Arabia. Julian writes research articles on a wide variety of subjects for the CGES' publications, and appears regularly on the radio and television. He is particularly interested in developments in the former Soviet Union and is the author of several reports on the subject.

Before joining the CGES in 1990, Julian worked for Zambia Consolidated Copper Mines, where he was involved in work to improve the operations of all areas of the company's business from extracting ore to exporting refined copper. He has a first class honours degree in Mathematics from the University of Warwick and an MSc in Operational Research from the London School of Economics and Political Science.

Hugh Quick

Hugh Quick is an independent consultant on oil refining and supply. He previously worked for Shell from 1956 to 1987, mainly in the Netherlands and the Far East, where he gained extensive experience of refinery operations and all aspects of refining and supply economics, in particular the planning and development of major projects, the management of the interface between refining and marketing, and refinery performance evaluation.

Since leaving Shell, Hugh has worked as an independent consultant and his main activities have included the evaluation of refineries and sites for owners and potential investors, advice to lenders on major investment projects, and advice on the supply and refining aspects of insurance claims. He studied Chemistry at Oxford University and attended the Harvard Business School.

Catherine Jago (formerly Hamer)

Catherine is a freelance consultant specialising in oil markets and oil trading. She has lectured on oil trading techniques and pricing all over the world and has acted as an oil expert, working with many of the top London firms of solicitors and barristers. Her recent work also includes studies on a variety of oil industry projects for consultants Arthur D. Little, MRC Oxford, Energy Listener and ICIS-LOR.

Catherine has been involved in the international oil industry since 1982. She began her career with BP Oil International in their Trade and Supply Department, where she worked first on forecasting and economic analysis and subsequently on pricing and operations for BP's Antwerp and Rotterdam refineries. She then moved to London Oil Reports (now part of the ICIS-LOR group) where she set up a new European Products report and also spent time in Houston studying the US crude and oil products markets. After this she joined Poten and Partners in London, working as a broker in the European and trans-Atlantic oil markets until 1989 when she became a freelance consultant.

Petroleum Argus

Petroleum Argus is one of the leading primary sources of price information on the oil market. Founded in 1970 as Europ-Oil Prices, Argus published the first ever daily crude market wire in 1979 and Argus price reports now cover all the major markets for crude and refined products and are widely used in the oil industry. Petroleum Argus also publishes a wide range of energy market newsletters, including *Weekly Petroleum Argus*, *Argus Global Markets* and *Argus Fundamentals* which explore the wider forces driving the oil market. The front page editorials in *Weekly Petroleum Argus* and *Argus Global Markets* have built up a reputation for clear and insightful analysis of industry issues, frequently challenging the conventional wisdom.

Argus was founded by Jan Nasmyth and is published by Adrian Binks. *Weekly Petroleum Argus* is edited by Nick Black and *Argus Global Markets* is edited by Alan Kennington. The Argus contribution to the *Oil Trading Manual* was prepared by various members of staff, both past and present. The chapter on crude oil markets involved contributions from Isabella Kurek, Marie-Anne Gries, William Harwood, Daniel Massey, Alan McNee, Tim Mingee, Natasha Norton, Scott Nelson, David Pike, Mark Smedley and Emma Wenban-Smith.

Sally Clubley

Sally Clubley is an independent oil consultant specialising in price risk management in the energy industries. She is a faculty member of Invincible Energy, an international training and consultancy company, with whom she is involved in developing and presenting public courses and in-house seminars on all aspects of business risk in the oil, gas and electricity markets. She is the author of *Trading in Oil Futures and Options*.

David Knox

David Knox is a director of Nations Bank-CRT and is based at their London office. He is actively involved in the options market and specialises in developing new applications for OTC options and swaps.

Frédéric Barnaud

Frédéric Barnaud was responsible for risk management and derivatives research and development for Elf Trading SA in Geneva from 1992 to 1994. He previously spent fifteen months on secondment to the Oxford Institute for Energy Studies, where he conducted research on oil economics, and to the London University City Business School, where he studied financial and commodity markets.

Frédéric qualified as an Ingénieur at the École Nationale des Ponts et Chaussées, Paris where he specialised in civil engineering, applied mathematics and finance.

Philippe Lautard

Philippe Lautard is in charge of energy derivatives marketing for Elf Trading SA in Geneva and deputy manager of Elf Trading's Hedging and Derivatives Department. He joined Elf Trading in 1988 as a futures and options trader and helped to start up Elf Trading's OTC activities.

Philippe graduated in Civil Engineering from the École Nationale des Ponts et Chaussées, Paris and Oil Economics from the Institut Français des Pétroles.

Robin Burley

Robin Burley is the founder of Kennet Oil Logistics, an independent consultancy engaged in advising companies on operational procedures and strategy.

Robin has extensive experience of the oil industry, including ten years with British Petroleum and ten years with Gulf Oil. During this time he held various management posts with reponsibilities for supply economics, oil production joint ventures, supply, trading and operations, ship management, chartering and fleet planning, and logistics, storage and trans-shipment. He has worked abroad in Europe, the US and the Middle East, and has been involved in negotiating supply and logistics arrangements worldwide.

Hanif Barma

Hanif Barma is a Director at PricewaterhouseCoopers in their Global Energy and Mining practice. Hanif's clients have included many upstream and downstream oil companies, and his work has encompassed their oil trading activities. His work has included audit work, client training and advising clients on a range of due diligence, acquisition and privatisation assignments. Hanif is also responsible for energy industry training at PricewaterhouseCoopers.

Hanif joined Price Waterhouse in 1983 and has specialised in accounting aspects of the oil and gas industry since 1986. Hanif was educated at the City University, London and graduated with First Class Honours in 1983. He qualified as Chartered Accountant in 1986.

Rachel Leigh

Rachel Leigh is a senior manager in the Market Risk business advisory service within the PricewaterhouseCoopers Banking and Capital Markets group. She is closely involved with the capital markets division of the group and has specialised knowledge of derivatives and financial instrument accounting. This knowledge has been applied actively to energy and commodities clients' trading portfolios for a number of years.

Rachel joined PricewaterhouseCoopers in 1993 and has specialised in the capital markets division from that date. Rachel studied geography at Bristol University and graduated in 1993. She qualified as a Chartered Accountant in 1996.

Matthew Price

Matthew Price is a manager in the PricewaterhouseCoopers Banking and Capital Markets group. He is closely involved with the capital markets division of the group and has specialised knowledge of derivatives and financial instrument accounting. This knowledge has been applied actively to investment banking and energy clients' trading portfolios for a number of years.

Matthew joined PricewaterhouseCoopers in 1995 and has specialised in the capital markets division from that date. Matthew studied mathematics at Warwick University and graduated in 1995. He qualified as a Chartered Accountant in 1998.

Philip Greatrex

Phil Greatrex is managing director and a senior consultant at CW Energy Tax Consultants Limited. He speaks regularly at conferences on oil and gas tax matters and frequently contributes articles on oil taxation to various journals. He is author of the taxation section of the United Kingdom Oil and Gas Law publication and has been secretary to the Brindex Tax subcommittee for many years.

Phil qualified as a Chartered Accountant with Arthur Young in 1980 and transferred to their corporate tax department two years later. Since then he has specialised in oil tax matters for a variety of clients, both UK and international. In 1990 he left the merged firm of Ernst and Young to form, along with a number of colleagues, CW Energy Tax Consultants Limited.

David Zimmerman & John S. Levin

David Zimmerman is a Member of, and John S. Levin is Counsel to, the Washington D.C. law firm of Miller & Chevalier, Chartered. They and their colleagues have advised a number of large and small firms in the oil industry and related energy fields and represented them before the Inland Revenue Service and various courts with special emphasis on United States taxation.

Alain Ahkong

Alain Ahkong formed Pioneer Associates in 1990. He was formerly the Singapore managing director of the international accountancy firm, Arthur Young. His previous career spanned sixteen years, of which six were spent in London specialising in tax in the oil and oil services industry and in the financial services sector.

Blanche Sas

Blanche Sas is head of Denton Hall's Moscow office. She specialises in energy law, in particular: international and comparative law in relation to upstream petroleum regimes; downstream energy law – especially oil trading; energy sales contracts; pipeline law; privatisation and regulation of electricity and gas industries; and, in her current job, energy legislation in Eastern Europe and the former Soviet Union. She is also the Editor of *Oil and Gas Law and Taxation Review* and the author of numerous publications on energy law.

Blanche joined Denton Hall in 1991 and was previously Lecturer in Petroleum Law at the University of Dundee from 1985. She is a graduate of Dalhousie University (Canada) and the University of Dundee. She is a member of the International Bar Association.

Françoise Deshusses

Françoise Deshusses is head of commodity controlling for energy and base metals markets at the Union Bank of Switzerland (UBS) in Zurich. She has been involved in the development of reporting and control systems for the energy derivatives market since it first began trading in the late 1980s. She studied economics at the University of Geneva and started her career in the oil industry with Elf Trading. After leaving Elf, she worked in the crude oil department at Rhein Oel before joining UBS in 1993. At UBS she has been responsible for setting up and co-ordinating back-office systems for energy and base metals markets. In her current post, she is responsible for evaluating the global risk exposure of UBS' energy and base metals trading activities.

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Abbreviations

AAA	American Arbitration Association
ADP	alternative delivery procedure
AFBD	Association of Futures Brokers and Dealers
ANS	Alaskan north slope crude
AOT	Approved Oil Traders (Singapore)
API	American Petroleum Institute
APPI	Asian Petroleum Price Index
APO	average price options
ARA	Antwerp-Rotterdam-Amsterdam area
ARCH	auto-regressive conditional heteroscedastic
ASTM	American Society for Testing Methods
bl (or bbl)	barrel (42 US gallons)
bpcd	barrels per calendar day
bpsd	barrels per stream day
b/d	barrels per day
b/l	bill of lading
C&F	cost and freight (*see CFR*)
CAA	Clean Air Act (US)
CARB	California Air Resources Board
CBOE	Chicago Board Options Exchange
CBOT	Chicago Board of Trade
CCR	continuous catalyst regeneration
CCU	catalytic cracking unit
CEA	Commodity Exchange Act (US)
CFD	contract for differences
CFPP	cold filter plugging point
CFR	cost and freight (*see C&F*)
CFTC	Commodity Futures Trading Commission (US)
CIF (or cif)	cost, insurance and freight
CIP	carriage and insurance paid to
CISG	Contracts for the International Sale of Goods
COW	crude oil washing
CP	charter-party document
CPI	consumer price index
CPT	carriage paid to
Cristal	Contract Regarding an Interim Supplement to Tanker Liability for Oil Pollution
DAF	delivered at frontier
DDP	delivered duty paid
DDU	delivered duty unpaid
DEQ	delivered ex-quay

DES	delivered ex-ship
DIN	Deutsche Industrie Normal
DPK	dual purpose kerosine
E&P	exploration and production
EdF	Electricité de France
EdP	Electricidade de Portugal
EEC	European Economic Community (now EU)
EFP	exchange of futures for physical
EFS	exchange of futures for swaps
ETA	estimated time of arrival
ETS	Energy Trading System (IPE)
EU	European Union
EXW	ex-works
FAS	free alongside ship
FBP	final boiling point
FCA	free carrier
FCCU	fluid catalytic cracking unit
FCPA	Foreign Corrupt Practices Act (US)
FIP (or fip)	free in pipeline
FOB (or fob)	free on board
FOD	fuel oil doméstique
FSA	Financial Services Act (UK)
FSU	former Soviet Union
FTA	Futures Trading Act (Singapore)
FTC	Federal Trade Commission (US)
GATT	General Agreement on Tariffs and Trade
GAAP	Generally Accepted Accounting Principles
GOM	gas oil moteur
GRM	gross refinery margin
HSFO	high sulphur fuel oil
IBP	initial boiling point
ICC	International Chamber of Commerce
ICP	Indonesian crude price
ICSID	International Centre for Settlement of Investment Disputes
IEA	International Energy Agency
IGS	inert gas system
IOC	Indian Oil Company
IP	Institute of Petroleum (UK)
IPE	International Petroleum Exchange (London)
ISDA	International Swaps and Derivatives Association
LC	letter of credit
Libor	London inter-bank offered rate
LOI	letter of indemnity

LOOP	Louisiana Off-shore Oil Port
LOR	London Oil Reports
LPG	liquefied petroleum gas
LSFO	low sulphur fuel oil
LSSR	low sulphur straight run
LSWR	low sulphur waxy residue
MMBTU	million British Thermal Units
MON	motor octane number
MPT	modern portfolio theory
MTBE	methyl-tertiary-butyl-ether
N+A	naphthenes and aromatics
NGL	natural gas liquid
NOR	notice of readiness
NWE	north-west Europe
NYH	New York Harbor
Nymex	New York Mercantile Exchange
OGLTR	Oil and Gas Law and Taxation Review
Opec	Organisation of Petroleum Exporting Countries
O/S	open-specification
OSP	official government selling price
OTC	over-the-counter
OTO	Office of Oil Taxation (UK)
Pb	lead
PONA	paraffins, olefins, naphthenes, and aromatics
PPI	producer price index
ppm	parts per million
PRT	Petroleum Revenue Tax (UK)
PTIA	Protection of Trading Interests Act (UK)
RFG	reformulated gasoline
RON	research octane number
RVP	Reid vapour pressure
S&P	Standard & Poor
SFA	Securities and Futures Association (UK)
SFPP	Santa Fe Pacific Pipeline
SG	specific gravity
SIA	Sovereign Immunity Act (US)
SIB	Securities and Investments Board (UK)
Simex	Singapore International Monetary Exchange
SRFO	straight run fuel oil
TEL	tetra-ethyl lead
TML	tetra-methyl lead
TOVALOP	Tanker Owner's Voluntary Agreement concerning Liability for Oil Pollution
UAE	United Arab Emirates

UCC	Uniform Commercial Code (US)
UCP	Uniform Customs and Practice for Documentary Credits
UCTA	Unfair Contract Terms Act (UK)
UKCS	United Kingdom continental shelf
ULCC	ultra-large crude carrier
UNCITRAL	United Nations Commission on International Trade Law
UPEI	Union Pétrolière Européenne Indépendante
USC	United States Code
VAR	value at risk
VGO	vacuum gas oil
VLCC	very large crude carrier
WTI	west Texas intermediate crude
WTS	west Texas sour crude
WS	Worldscale

Introduction

The oil market is unique in its complexity and diversity. The scale is international and the trading instruments range from the physical to the financial. As a result, the oil market has attracted the broadest possible set of participants: not only oil companies, but also banks, commodity traders, government agencies, financial engineers, fund managers, ship owners, airlines, electricity utilities, chemical producers, and industrial conglomerates are all involved in the business of trading oil. And they, in turn, require the support of accountants, lawyers, tax experts, operations specialists, business consultants and computer programmers. The *Oil Trading Manual* is intended for them all.

There are already many specialist books on individual subjects such as futures trading or financial derivatives, but these do not necessarily focus on oil. And there are others on accounting, taxation, contracts and regulation, but these rarely use oil as an example. At the same time, new participants in the oil market, such as bankers or fund managers, need to find out about the operation of the physical oil market or discover what a refinery does without serving an apprenticeship in the oil industry. Or, those who are already in the oil business, may want to learn about new trading instruments such as options or swaps, or need to know what implications new oil trading techniques might have for accounting or taxation. The *Oil Trading Manual* therefore sets out to provide in one volume a common source of basic information on all aspects of oil trading that is accessible to everyone involved.

The *Manual* is divided into three complementary parts. The first, Characteristics, is an introduction to oil and oil trading, and includes material on the nature of oil as a commodity, refinery processes and the different ways in which oil is priced. The second, Instruments and Markets, deals with the oil market itself taking each segment in turn and explaining how the various trading instruments work and describing the markets that have evolved to trade them. It starts with the physical oil market, moving on to forward and futures markets, followed by options and swaps. The third, Administration, covers the essential "back-room" activities without which oil trading could not continue. It includes practical material on operations and logistics, credit control, accounting, taxation, contracts and regulation, providing a unique guide to the subject. Like all the Woodhead Publishing commodity handbooks it will be updated regularly. I hope you find it useful.

David Long
Editor

Acknowledgements

Any book of this size must ultimately become a labour of love and the *Oil Trading Manual* is no exception. Like many large projects it has also taken longer than expected to get from the initial idea to the finished product. I would therefore like to thank those who have supported me throughout. Particular thanks go to my fellow contributors who have not only provided me with excellent material, but also updated it while waiting patiently for the *Manual* to be completed. And to Neil Wenborn, Martin Woodhead and Amanda Thomas at Woodhead Publishing who have been a constant source of enthusiasm.

I would also like to thank those individuals and organisations that have generously provided me with advice and resources: Paul Newman and Tony Dukes at Intercapital Commodity Brokers; Adrian Binks and the staff of Petroleum Argus; Nigel Harris, and Mary Jackson and Hugh Hagan at Saladin Computer Systems who kindly lent me a PAWS system to ease the task of preparing the graphs. Also Julian Lee, who helped with the final stages of production and has agreed to act as Associate Editor for future editions, and James Wood, who did the index at short notice. And finally, my family, who have put up with the long hours required to finish the job.

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1 The trading of oil

David Long

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1.1 Why oil is traded

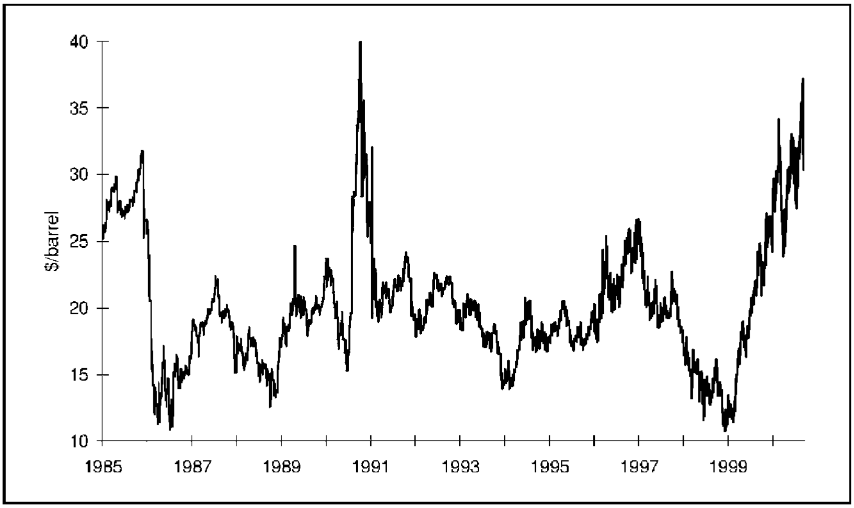
Over the last twenty years oil has become the biggest commodity market in the world. During this period, oil trading has evolved from a primarily physical activity into a sophisticated financial market. In the process it has attracted the interest of a wide range of participants who now include banks and fund managers as well as the traditional oil majors, independents and physical oil traders.

As well as being the largest commodity market in the world, oil is also the most complicated. The physical oil market trades many different types of crude oil and refined products, and the relative values of each grade are continually shifting in response to changes in supply and demand on both a global and a local scale. The industry has therefore developed a complex set of interlocking markets not only to establish prices across the entire spectrum of crude and product qualities, but also to enable buyers and sellers to accommodate changes in relative prices wherever they might occur.

The initial momentum for the expansion of the oil market came from the changing structure of the oil industry. Prior to 1973, oil trading was a marginal activity for most companies who only used the market to resolve any imbalances in supply and demand that might emerge. Trading volumes were typically small and usually spot, and prices were much less transparent than they are today. And the industry was dominated by large integrated oil companies that had little use for external markets either as a means of obtaining supplies or as a basis for setting prices.

However, the structure of the oil industry changed irreversibly in the 1970s with the nationalisation of the upstream interests of the major oil companies in the Middle East and elsewhere, and trading became an essential component of any oil company's supply and marketing operations. Having lost access to large volumes of equity oil, the major oil companies were forced to buy at arm's length from their former host governments and the physical base of the international oil market expanded rapidly. With more oil being traded, external markets began to set the price for internal transfers as well as third-party sales and companies started to buy and sell oil if better opportunities existed outside their own supply network, fuelling the growth of the market.

But the driving force behind the rapid growth in oil trading is the huge variability in the price of oil (see Fig. 1.1). Daily price movements of \$1/barrel are not uncommon and prices frequently change by up to 50 cents/barrel. Since there is no obvious upper or lower bound to oil prices, the value of a barrel of oil can double or



Source: Nymex

Figure 1.1 Crude oil prices, Nymex nearby WTI daily close

halve within the space of a few months. As a result, everyone involved in the industry is exposed to the risk of very large changes in the value of any oil that they are producing, transporting, refining or purchasing, and a range of new markets have evolved in order to provide effective hedging instruments against the elaborate combination of absolute and relative price risks that characterise the oil business. This has not only generated a very large volume of activity in its own right, but also attracted liquidity from other financial and commodity markets.

1.2 Trading characteristics of oil

Many of the characteristic features of the oil market are derived from the nature of oil itself. Despite the introduction of highly standardised paper trading instruments, oil remains a physical commodity. Like other primary commodity markets, the oil market is ultimately concerned with the transportation, processing and storage of an essential raw material as it travels from producer to consumer. However, this is a slow process, since crude oil may take several months to move from the well-head through the refinery to the sales pump. As a result, prices often change because the right oil is not in the right place at the right time. This is very different from the financial markets, where assets can be moved instantaneously from one location to another if required.

1.2.1 Transportation, processing and storage

One of the most important characteristics of oil is that it is a liquid (see Chapter 2). As a liquid, it requires specialised handling facilities for transportation, processing and storage. And it is these elements that provide the basic building blocks for the physical oil market.

Transportation

Oil is transported either in ships or pipelines. In the international market, oil moves almost exclusively in ships and it is therefore the size of the ship that forms the basic trading unit. In the case of crude oil, quantities are typically large and usually depend on the capacity of the loading and discharge terminals, the length of the voyage and the relative cost of shipping. In the North Sea, which is the most active waterborne crude market in the world, 500,000 barrel cargoes are the norm. But for longer-haul crudes from West Africa or the Middle East, oil often moves in very large crude carriers (VLCCs) which can take up to 2 million barrels at a time. As a result, the scale of financial exposure associated with crude oil trading can be very large indeed.

Refined products, however, are usually traded in much smaller quantities. Long distance movements may involve shipments as large as 60,000 tonnes (about 500,000 barrels, depending on the type of product), but most of the international trade is conducted in smaller vessels holding 20–30,000 tonnes. And many of the most active product markets deal in much smaller, barge-sized quantities, of between 1,000 and 5,000 tonnes. Since products are usually traded ex-refinery and often sold to wholesale distributors who may not have the capacity to receive or store very large quantities, the basic trading unit needs to be much smaller than in the international crude market.

As well as fixing the size of trading unit, the method of transport often determines the terms of trade. Crude oil is usually sold close to the point of production and title is transferred as the oil flows from the loading terminal into the ship. Once loaded, however, the oil can either be traded on the water or at the point of discharge. As a result, the same cargo of oil may be priced differently depending on the point of sale. Refined products are traded on a variety of terms depending on local circumstances, but it is important to realise that several markets can co-exist for the same product at the same location with prices that reflect different delivery arrangements or parcel sizes.

Oil is also transported and traded via pipelines. The most important pipeline markets are in the US where access is guaranteed in law to those who want to use them. In most cases oil is traded on a rateable basis – a specified number of barrels per day over an agreed period such as a fortnight or a month – and the oil is sold free-in-pipeline (fip) at designated locations. But in the case of West Texas Intermediate, which forms the basis of the Nymex Light Sweet Crude futures contract, oil is also sold in multiples of 1,000 barrels available from or delivered into storage facilities at Cushing, Oklahoma.

Processing

Oil is not normally used in its raw state. Crude oil must be processed through a refinery in order to turn it into a marketable product such as gasoline, heating oil or fuel oil. The only exception is low sulphur crude oil which is sometimes burnt directly in power stations. Oil is therefore traded twice, first as a refinery feedstock, and secondly as a finished product. Although crude and product markets have rather different characteristics, they are inextricably linked by the technology and economics of refinery processes.

Crude oil markets operate between the producer and the refiner. The characteristics and behaviour of the crude oil market therefore depend on the preferences and needs of the refiner as well as the composition and nature of the supply. Because there are many different types of crude oil, their relative value depends on the mix of products that can be obtained from them. In general, crudes that yield a higher proportion of the more valuable light products such as gasoline, naphtha, kerosine and heating oil can command a higher price than those which have a high yield of residual fuel oil. But there is no objective method of assessing the price of a given crude since every refinery has a different configuration and its market value will depend on who is bidding at the time. And refiners in different regions may have very different views about the price they are prepared to pay.

Product markets operate between the refiner and the blender or wholesaler. They are usually much more localised than crude oil markets, since most refineries are positioned close to the end-user, and their process facilities are tailored to the needs of the local consumer. As a result, refined product prices can differ significantly from one market to another, reflecting the local structure of demand for the various petroleum products, the configuration of the refineries, and the regional product quality specifications.

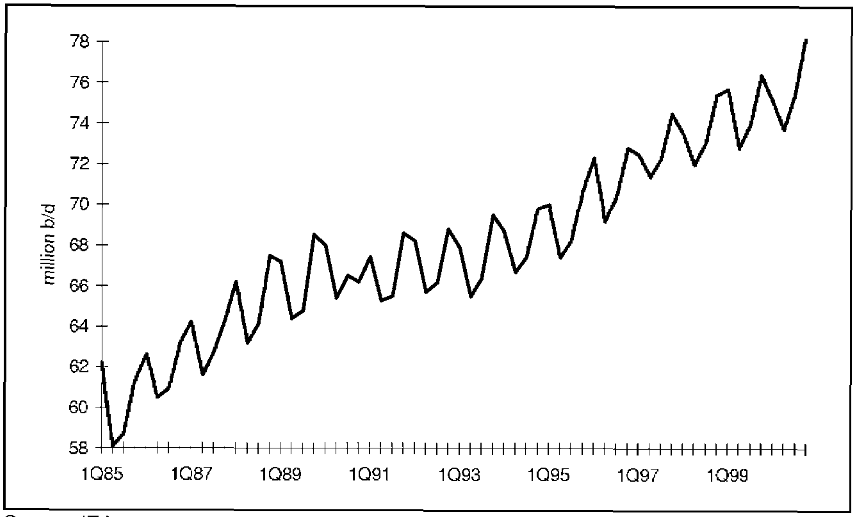
Storage

Oil must also be stored on its journey from the well-head to the pump. As oil is a liquid, this requires the construction of specialised storage tanks at every stage in the supply chain. Stocks are necessary in any business that produces, manufactures and markets a physical commodity such as oil, and fluctuations in the level of stocks held at different points along the supply chain play an important role in determining the behaviour of prices in the oil market. But holding stocks is also costly since it ties up cash and storage facilities are expensive to rent or build. Oil companies therefore try to keep their stocks as near to the minimum operating level as circumstances allow.

A surprisingly large amount of oil is required simply to fill the supply chain from well-head to customer. In addition, stocks are needed to keep the system flowing since deliveries are usually made in discrete quantities and stocks are run down in the intervening period. Also, companies need to hold extra stocks as an insurance policy against unexpected interruptions in supply or increases in demand from their customers. And finally, companies often build up (or run down) stocks for purely speculative reasons either to profit from an upward price trend or to minimise the losses from a downward price trend.

1.2.2 Demand, supply and stocks

The behaviour of prices in any primary commodity market is strongly influenced by the fundamental forces of demand and supply. Although prices frequently change for other more



Source: IEA

Figure 1.2 Seasonality of world oil demand

ephemeral reasons, especially now that trading screens and on-line news services play such an important role in the day-to-day operation of the oil market, the role of fundamentals in shaping the course of prices should not be forgotten.

Demand

The demand for oil, like other primary commodities, depends mainly on the state of the global economy. Despite improvements in energy efficiency as a result of the price increases of the 1970s and early 1980s, oil demand remains closely linked to the growth in economic activity. Over the past five years, world oil consumption has grown at an average annual rate of just under 2 per cent, adding about 1.3 million b/d to global demand each year.

Oil demand is growing fastest in the newly industrialising countries of the Asia-Pacific rim where the economies have been expanding very rapidly indeed, but the pace of growth slowed dramatically in 1998 as a result of the financial crisis before bouncing back in 1999. From 1993 to 1997, the average annual rate of oil demand growth in Asia (excluding China) was just over 7 per cent. By contrast, oil demand in the industrialised countries of the OECD has grown more slowly, averaging only 1.5 per cent over the same period, as some countries emerged from recession. And oil demand in the former Soviet Union has continued to fall as the economy contracts and the old, energy-intensive industries are no longer viable. However, the OECD countries still consume more than half the world's oil and it is in these countries that the oil markets are most developed and least constrained by government controls.

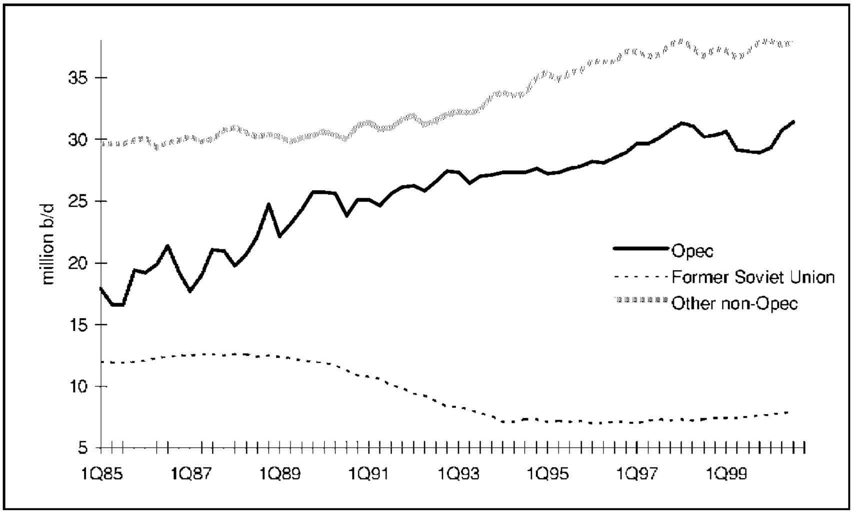
Oil demand is also highly seasonal (see Fig. 1.2). Peak demand for heating fuels such as kerosine, gas oil and residual fuel oil obviously comes in the winter, while peak demand for transport fuels such as gasoline and diesel comes in the summer. In addition, other products such as bitumen, which is used for road building also display a clear seasonal pattern that can also affect oil price behaviour at certain times of the year. Although the steady shift towards a greater share of transport fuels in the global demand barrel has reduced the annual variation in world oil consumption, there is still a difference of 3 to 4 million b/d between the winter peak and the summer trough in demand.

Prices play an ambivalent role in determining oil demand. In the short-term, they appear to have very little impact on the level of oil consumption, except in those markets such as electricity generation where there is direct competition with other fuels. In most markets, oil consumers cannot easily react to price increases because this requires investment, either in a new car or new boiler. As a result, the impact of higher prices may take years to filter through. But in the longer-term, there is no doubt that prices have a significant impact on the level of oil consumption.

The effect of prices on demand is clearly demonstrated by comparing the impact of consumer government taxes on the amount of oil consumed per head of the population in countries with similar levels of economic development. For example, the US, which still imposes very low taxes on oil products, consumes nearly twice as much oil per capita as the UK and France, which impose much higher taxes. And the fact oil products are either not taxed, or even subsidised, in many developing countries helps to explain the very high rates of growth of oil demand achieved in recent years, although this is gradually changing.

Supply

Matching oil supply to demand has become much more difficult since the oil industry ceased to be properly integrated. Most oil producers simply maximise their output, subject to the technical constraints of the field, in order to get a quick return on the very large amounts of money they have invested in developing the oil field in the first place. And because their operating costs are typically much lower than the sunk capital costs, they will continue to produce until oil prices reach very low levels.



Source: IEA

Figure 1.3 Composition of world oil supply (inc NGLs)

In the North Sea, for example, most of the fields have operating costs of less than $5/barrel and are unlikely to be shut in unless prices fall below this level. As a result, the responsibility for restraining production below capacity lies with the eleven remaining members of the Organisation of Petroleum Exporting Countries (Opec), who are committed to maintaining prices above their marginal cost of production in order to extract what they regard as a fair economic rent for oil. So far, they have succeeded, although competition for market share between Opec members has frequently forced prices down until falling revenues have eventually restored a sense of discipline to the Organisation. Opec was particularly successful during the first half of the 1980s when Saudi Arabia was prepared to play the role of swing producer alone, but it became more difficult to balance the market after the Saudis refused to continue cutting production at the end of 1985. However, Opec re-discovered the benefits of collective action in 1999 when low prices persuaded Saudi Arabia, Venezuela and non-Opec Mexico to co-operate over output cuts in order to bring the market back into balance and reduce high stocks.

Two factors have made Opec's self-appointed task more difficult. First, there is the continued expansion of oil production outside Opec (see Fig. 1.3). Although lower oil prices were initially expected to slow down the development of non-Opec oil fields, this has not proved to be the case. By encouraging technological developments and forcing companies to cut costs, lower oil prices actually made it easier to develop new oil fields outside the Opec countries. As a result, the call on Opec crude continues to grow more slowly than Opec would like to see despite rising oil consumption.

Secondly, there is the inherent seasonality of oil demand. As the residual supplier to the world oil market, Opec potentially faces large fluctuations in the level of production required by refiners at different times of the year. This not only makes it difficult to keep track of the underlying level of demand, but is also difficult to administer since Opec members find it very hard to agree on how to allocate production between themselves. The problem was temporarily "solved" in November 1993 by setting a fixed production quota over a much longer period of time, thus leaving the market to handle the seasonal variation in the demand for crude.

But growing demand made the fixed quota seem increasingly irrelevant and Opec found it difficult to restrain production after investment by foreign companies in some Opec countries boosted output and Iraq was allowed to export limited volumes of oil for humanitarian purposes. As a result, global stocks reached record levels following the Asian economic crisis and crude prices fell close to $10/bbl. Faced with the prospect of even lower prices if production was not cut, Opec negotiated new output targets which have succeeded in eliminating the stock surplus, pushing prices back over $30/bbl. Now Opec faces a new challenge: how to raise output by enough to rebuild stocks and reduce prices without precipitating another price collapse. So far, attempts to create an automatic adjustment mechanism in response to price changes have failed to garner wider support within the Organisation.

Stocks

The level of stocks held by the world oil industry has fallen since the early 1980s and was probably close to a minimum acceptable level in both 1996 and late 1999 and early 2000 (see Fig. 1.4). The reduction is partly due to the transfer of responsibility for strategic stocks from the oil companies to their governments, partly due to changes in the structure of oil demand, and partly due to improvements in the efficiency of company operations. And with renewed demand growth in recent years, the forward cover* provided by OECD industry stocks has been sharply reduced.

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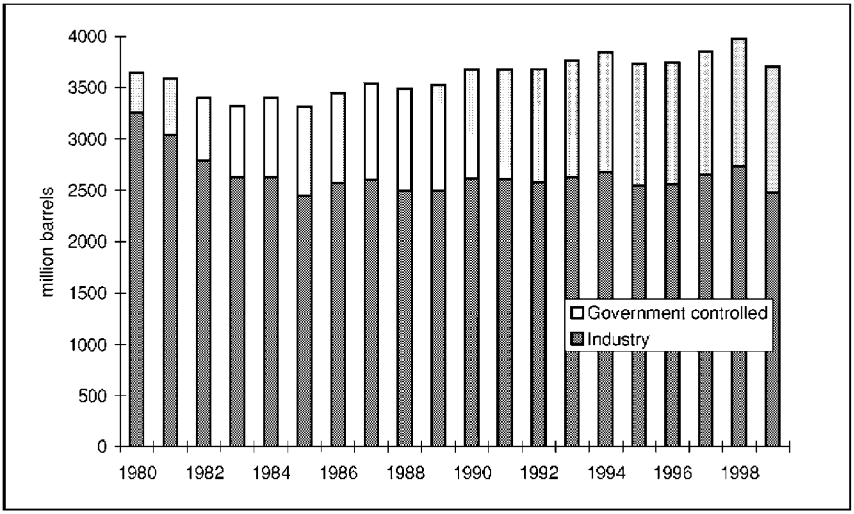
* Forward cover is calculated by dividing stocks at the end of a given period by consumption in the following period. The result is expressed in days.



Source: IEA

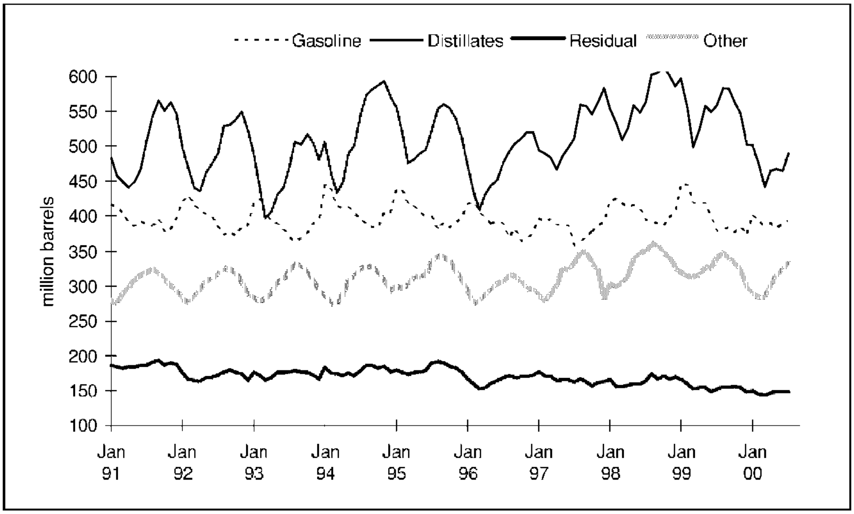
Figure 1.4 Total stocks held in OECD countries, end year

From the end of 1994, the seasonally-adjusted level of OECD industry stocks fell sharply as companies reduced their operating stocks after introducing "just-in-time" stock management policies. But demand continued to grow and the forward cover provided by total OECD industry stocks fell to only 54 days at the end of December 1995 — just below the historical minimum operating stock level of 55 days. As a result, prices rose sharply in 1996 as cold weather boosted demand and supply lagged behind expectations due to problems with new non-Opec fields and delays to the Iraqi "oil-for-aid" deal.

However, oil prices fell in 1997 with the resumption of Iraqi exports, growing competition between Opec members for market share and the aftermath of the Asian economic crisis, and industry stocks rose again, reaching 58 days of forward cover in the first half of 1999. Since then industry stocks have fallen sharply after Opec reined in production, falling to a new low of only 53 days of forward cover at the end of the second quarter of 2000.

A detailed study of the US oil industry published by Exxon[**], showed that the US held a total of 89 days of oil stocks at the start of 1981 measured in terms of forward consumption. Out of this total, 7 days' worth were held by the government in the Strategic Petroleum Reserve (SPR), and 82 days' worth was held by companies. According to Exxon 58 of the 82 days' worth of company

[**] Exxon, *World Oil Inventories*, Exxon Background Series, August 1981



Source: IEA

Figure 1.5 OECD industry product stocks, end month

stocks were minimum operating stocks. More than a third of the minimum operating stocks (20 days' worth) occupied the pipelines and tankers that transport the oil, filled the refineries that process it, and provided the "tank bottoms" for the storage facilities. The remaining 38 days' worth of stocks represented the oil in transit through the system, of which a quarter (10 days' worth) was in the form of crude oil and three quarters (28 days' worth) was in the form of refined products.

Companies need to hold more stocks in the form of products than crude for two reasons. First, the different types of refined product need to be kept separate from each other and move along their own distribution channels, which simply increases the amount of oil tied up in the supply chain once it has passed through the refinery. And, secondly, refineries are not sufficiently flexible to vary their product yields in line with the seasonal variation in demand. For this reason, refiners are obliged to accumulate unwanted stocks of heating oil and residual fuel oil when they increase runs to meet peak gasoline demand during the summer, while the reverse occurs during the winter (see Fig. 1.5). It is this involuntary stock build by refiners that creates the characteristic seasonal pattern in the level of stocks held by the oil industry and influences the behaviour of prices in the forward and futures markets (see Chapter 7).

1.2.3 Not just another commodity

It can be seen that oil has a number of important trading characteristics that also help to distinguish it from other commodities. First, there are many different types of crude oil and refined products and the relative value of each of these is constantly changing. As a result, the oil market suffers from considerable relative price volatility as well as absolute price volatility. Although other commodity markets also cover a range of grades or qualities, the scale of the price risks involved is typically much smaller.

Secondly, oil products are manufactured jointly in a refinery and, although refiners have some flexibility to vary the yield of each product derived from a barrel of crude oil, they cannot always match supply to demand across the entire spectrum of products. As a result, the price of any one type of refined product cannot be determined independently of the rest of the market since changes in the supply or demand for other products must also be taken into account. While joint production is not unique to the oil market, the factors determining the price relationships between the different refinery products are potentially much more complicated.

Thirdly, neither demand nor supply are particularly responsive to changes in price in the short-run. On the demand side, consumers cannot easily switch to some other source of energy if the price of oil rises since this usually requires investment in new equipment. In addition, there are some uses, such as transportation, for which oil still has no effective substitute. While, on the supply side, the operating costs of existing capacity are substantially lower than the capital costs of installing new capacity. As a result, oil prices can fall to quite low levels without shutting in production. In the longer run, it is a different story since both consumers and producers will eventually respond to price changes, but this happens on a much slower time scale.

Finally, oil is a highly political commodity. It still provides 40 per cent of the world's primary energy consumption and is essential to the functioning of any developed economy. However, two-thirds of the world's oil reserves and a third of the world's oil production is in the Middle East, which remains a potentially unstable area. With most of the world's largest consuming countries heavily dependent on imports for their source of supply, the threat of supply disruption remains very real and political events often play a significant role in the oil market.

1.3 Structure of the oil market

Successful markets need standardised trading instruments in order to generate liquidity and improve price transparency, and oil is no exception. But, since oil is an inherently non-standard commodity, the industry has chosen a small number of "reference" or "marker" grades of crude oil and refined products to provide the physical basis for a much larger "paper" market which trades derivative instruments such as forward and futures contracts. Although the choice is often arbitrary and problems can arise due to unforeseen changes in the underlying physical market, the industry has invariably found ways of adapting the contracts since the rest of the market now depends on their continued existence.

The most important derivative trading instrument is the New York Mercantile Exchange's Light Sweet Crude contract. It is usually known as "WTI" since West Texas Intermediate crude still effectively underpins the market despite the introduction of alternative delivery grades in recent years. Nymex WTI is the most actively traded oil market in the world and not only provides a key price marker for the industry as a whole, but also supports a wide range of other, more sophisticated, derivative instruments such as options and swaps.

1.3.1 Spectrum of instruments

The oil market now offers an almost bewildering array of "paper" trading instruments that can be used to reduce the price risks incurred by companies buying and selling physical oil. These include:

- **futures contracts**, which enable companies to buy and sell oil of an agreed standardised quality, quantity and delivery terms for future delivery within the institutional framework of a *futures exchange*. The purpose of the exchange is to provide a trading forum that matches buyers and sellers, acts as a counter-party to all purchases and sales so as to guarantee performance, publishes prices as deals are done, and organises and monitors the physical delivery of the oil if required. Most futures contracts do not result in physical delivery but are cancelled by taking an offsetting position on the futures market at a later date.

- **forward contracts**, which enable companies to buy and sell oil privately between themselves for future delivery *outside* the institutional framework of a *futures exchange*. Although some forward paper contracts, like 15-day Brent, are highly standardised and actively traded in much the same way as a futures contract, forward contracts are more risky to use than futures as positions are more difficult to liquidate and the contract is not administered or guaranteed by a clearing organisation. Unlike futures, forward contracts normally require physical delivery unless the counter-parties agree otherwise, but the oil delivered can pass through many hands before it reaches someone who actually wants to lift a physical cargo.

- **price swaps**, which enable companies to exchange price risk without involving the physical delivery of any oil. Like forward contracts, swaps are agreed directly between two parties and are not guaranteed or otherwise organised within any institutional framework. Simple price swaps involve two back-to-back contracts, one at a fixed price and one at a floating price so as to avoid any obligation for physical delivery. Swaps do not need to be standardised in the same way as futures or forward paper contracts as any mutually acceptable price index can be used in the contract. Swaps are also usually based on *average prices* for a future delivery period and are less vulnerable to short term price fluctuations that can undermine the usefulness of a futures or forward contract.

- **options**, which enable companies to lock in a maximum or minimum price for the purchase or sale of oil at a future date in exchange for a fixed non-refundable "insurance" *premium*. Options can be traded either within the institutional framework of a futures market, in which case the option confers the right (but not the obligation) to buy futures contracts at an agreed fixed price at an agreed date in the future, or privately between companies on the "*over-the-counter*" or *OTC* market, in which case the option can be *exercised* into any mutually acceptable trading instrument, either futures, forward or swaps.

Taken together, these derivative trading instruments have transformed the structure and operation of the oil market over the past fifteen years, giving companies much more control over prices and bringing new participants into the market, such as banks and financial trading houses, who are prepared to take on some of the risks created by oil price volatility.

1.3.2 Trading horizons

The most important change to the oil market has been the gradual extension of trading horizons further and further into the future. Before the introduction of forward and futures contracts, oil companies had no effective means of setting prices for future delivery. As a result, the spot market was forced to bear the brunt of trading decisions that might relate to time periods ranging anywhere from a day to a year ahead, which could only have added to price volatility. Given that refiners loading oil in the Arab Gulf are exposed to the risk of price changes over a period of 60 to 90 days as the crude is transported, refined and delivered to the consumer, it is clearly important to have markets with longer trading horizons.

The first step towards longer trading horizons was provided by the forward and futures markets, which initially provided contracts trading up to a year ahead. As the main users were the middle-men who handle the oil as it passes down the supply-chain, rather than the producers and consumers who constitute the two ends of the chain, the markets were most active over a relatively short time horizon of up to three months ahead.

Over the past few years, however, the time horizon of the oil market has been extended much further forward (see Fig. 1.6). The most active futures contracts, such as Nymex Light Crude Oil, now trade for delivery up to seven years ahead and the industry has acquired a new set of trading instruments that enable participants

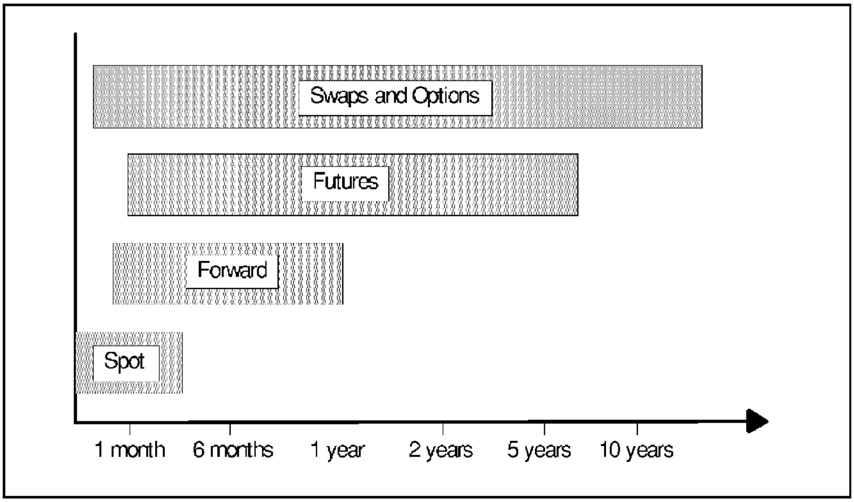


Figure 1.6 Oil market trading horizons

to establish prices even further into the future. Instead of being limited to a time horizon of only a few months, prices can now be reliably obtained for periods from one to ten years ahead. This has been made possible by the introduction of financial instruments such as price swaps and OTC options, which have created a liquid market that enables companies to trade the price of oil over a time frame that is appropriate for producers investing in new oil fields, or for consumers building new power stations.

1.3.3 Interlocking markets

The market structure that has evolved is largely unplanned and highly complex since it now covers the entire spectrum of possible trading instruments (see Fig. 1.7). Formal futures markets operate alongside sophisticated forward paper markets. Over-the-counter (OTC) swap and option markets provide a tailor-made service that complements highly liquid and standardised futures and options contracts. And physical traders frequently use financial instruments to fix prices independently of delivery. As a result, it is impossible to say where the price of oil is actually determined, since every segment of the market plays a role.

The high profile of the reference markets such as Nymex WTI or 15-day Brent has led some commentators to complain that the

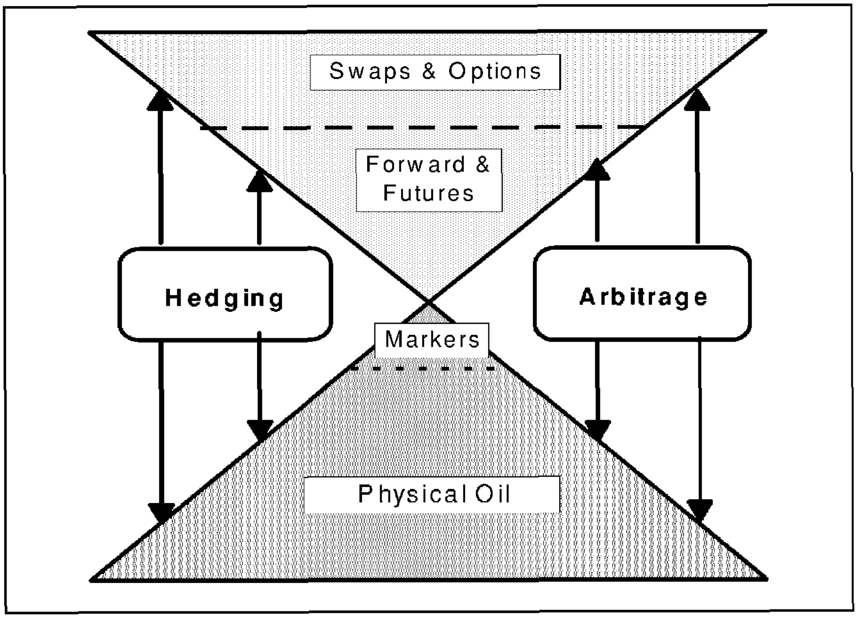


Figure 1.7 Structure of the oil market

paper "tail" is now wagging the physical "dog", and that derivative trading instruments have an influence that is disproportionate to their significance. In addition, the fact that the majority of oil trading is concerned with price differentials between grades, locations, markets, and delivery periods, suggests that absolute price levels are no longer important to the oil industry. But these criticisms are unjustified, since they miss the real point about the current structure of the oil market.

Although the structure appears to be potentially unstable because it funnels a large volume of activity through a small number of standardised trading instruments, this is necessary in order to improve liquidity in what would otherwise be a highly unstandardised and illiquid market. But the scale of trading in the derivative markets does not necessarily mean that the transactions have no underlying physical motivation. In order to come to terms with the difficult trading characteristics of oil, companies need to use a combination of techniques and instruments to protect themselves from both absolute and relative price risk, and it is the strong relationships between these interlocking markets created by hedging and arbitrage that ensure a stable structure for the oil market.

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2 Physical characteristics and refining

Hugh Quick

2.1 Introduction

The purpose of this section is to outline the physical characteristics of crude oils and products which are important for users and traders. It will also describe oil refining briefly so as to provide some understanding of its capabilities and limitations in changing the properties of oil products.

The section is included for those who trade crude oil and products, or use them, but who do not have first hand technical knowledge of the industry. It is beyond the scope of this manual to give more than a brief introduction to the topics raised and on some of them the trader will need more comprehensive knowledge. A list of suggestions for further reading is given in Appendix 2.6 which may complement the knowledge gained by experience.

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2.2 Uses of oil products

Paul Frankel* pointed out that the most important characteristic of oil is that it is liquid. Its liquid state determines the way oil is produced, transported, refined, distributed and used. It is tempting to abbreviate that list of activities by saying 'handled' but that is just the point, it cannot be handled in the literal sense.

Because of its chemical nature and liquid state oil is a very compact source of energy and, given the right equipment, can be transported and controlled easily. That is why oil products are so widely used as a source of energy.

Everyone is familiar with the main groups of oil products which, in descending order of volatility, are:

- Liquefied petroleum gases (LPGs),
- Gasolines/naphthas, which include motor gasoline or 'petrol',
- Kerosines, including most aviation fuel,
- Gasoils/diesels, used mainly for home heating and for small and medium sized diesel engines,
- Fuel oils, used in furnaces, boilers and in large diesel engines.

Liquefied petroleum gases are propane, butane or mixtures of the two, familiar to most as 'Calor Gas' or 'Camping Gaz' but also used industrially. Bitumen or asphalt should perhaps be added to the bottom of the list but, while significant volumes are used, it is a non-energy product and the trade usually follows a rather special route. There are other non-energy uses for oil products. The largest volume non-energy use is petrochemical feedstock but others, such as lubricating oils, solvents and waxes, are probably more widely known.

The characteristics of these oil products are described below but, before coming to these, it is worth considering in more general terms how the above product groupings arose. As has been said the underlying value of oil products comes from their physical and chemical nature but individual products have evolved through the combination of developments in many different fields.

The first use of petroleum was for lighting. Oil lamps had previously used vegetable or animal oils. Crude oil was no use for lamps as it was too volatile, causing risks of explosion in use, was thick, black and messy and burnt with a very smoky flame. Since millions of oil lamps existed the onus was on the oil industry to

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**Essentials of Petroleum*, Paul Frankel, Chapman & Hall, London (1946); 2nd Edition, Frank Cass & Co. Ltd, London (1969).

produce a usable product. This was done by distilling the crude oil into fractions of different and controlled volatility. By this means kerosine was produced which was clean, had enough volatility to burn in lamps but not so much as to be unacceptably dangerous, and was less smoky than previous oils. Moreover, kerosine could be produced at a cost that was competitive with the animal and vegetable alternatives.

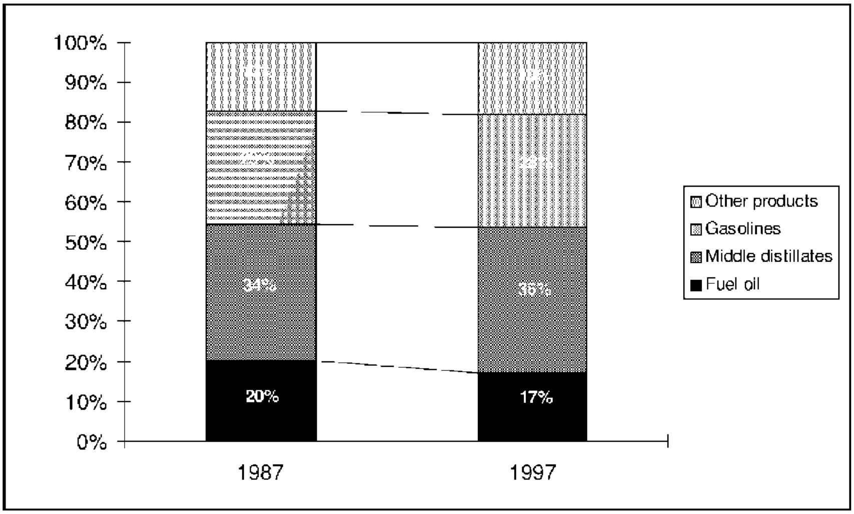
Distillation of crude oil is still the basic process of oil refining. It separates oil into fractions according to their volatility and molecular size ranges and this is the reason why the main product groups are differentiated by volatility. Many other properties of oil fractions, such as specific gravity (density) and viscosity, are largely determined by molecular size: fuel oils, for instance, will always have a higher specific gravity and viscosity than kerosine.

Kerosine suitable for lamps constituted only a small proportion of the crude oil, typically 15 per cent, so something had to be done with the rest. The heavier, less volatile fractions, which were reasonably safe to store and transport could be burnt in boilers and furnaces once suitable designs had been developed. Here the onus was largely on the boiler and furnace makers to adapt to a new economic fuel which could compete very effectively with coal.

Initially there was little use for the more volatile, gasoline fractions, and most were wasted. However, the internal combustion engine was being developed, initially quite independently of the availability of oil fractions, but it was soon realised that gasoline and gasoils were very suitable fuels. As a result, this quickly became the principal use of oil in the USA, the home of the oil industry, and the development of engines, petroleum fuels and lubricants has gone hand in hand ever since.

The purpose of recounting this well known history is to illustrate the diversity of influences on the development of oil products, not least the need for safety and, nowadays, concern for the environment. The development of oil products is of course still continuing and, as was hinted at in the history, remains a compromise between the ideal product and one that can be produced economically. For instance, iso-octane would be an excellent motor fuel, failing the ideal perhaps only because its exhaust gas contains carbon dioxide, but it cannot be produced in the volume required at an acceptable cost, although it is interesting to note how widely ideas on an acceptable cost can vary in time and place.

Mention of the volume of product required leads to another general point. Because oil is a very large volume business, over three billion tonnes per year world-wide, major changes require time. The introduction of unleaded gasoline is a good example.



Source: BP Statistical Review of World Energy, 1998

Figure 2.1 Changing shape of the world demand barrel*

Although it would now be the first choice of most motorists, it cannot be used by older cars without modifications that many owners will not make and it takes something like seven years to turn over the stock of cars in use. Refineries also need new plant to produce unleaded gasoline in volume and large refinery process units have a building time of three to four years or longer from initiation to full production.

Lastly, the possibility to use other fuels instead of oil products is worth noting. Fuel oil used in furnaces and boilers for power generation is easily substituted by coal on a short term basis and nuclear, hydro- and other power generation methods on a more permanent basis. This has indeed happened which, as will be seen, is why much effort has been devoted in the refining industry to turning fuel oil components into lighter products (see Fig. 2.1). Likewise gas oil for home heating can and is being substituted by natural gas wherever this latter is available. However, transport fuels such as motor gasoline, aviation fuels, diesel fuel and fuel for ships, or 'bunkers' as they are still called, have virtually no substitute nor any prospect of one on a significant scale in the near future.

* OECD and emerging market economies only.

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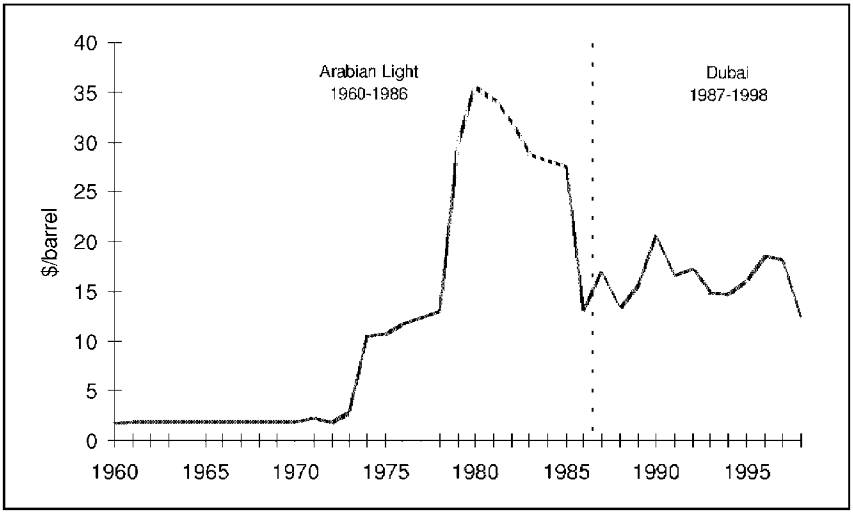
2.3 Pricing

The pricing of crude oil and main product groups needs some general comment. When not controlled by governments, oil prices respond, like other commodities, in the longer term to supply and demand and in the shorter term to perceptions of supply and demand. A look at the behaviour of oil prices during the several Gulf crises since 1973 and the price of fuel oil during the UK miners' strike illustrates the point (see Fig. 2.2). In 1973 and 1979/80 prices rose rapidly in response to a restriction of supply. In 1986 they fell rapidly as a result of Saudi Arabia's increase in production. In all these cases the price response to the supply changes was exaggerated by perceptions or expectations, and some reversal was required. On the smaller scale of day to day price changes, the importance of expectations is clear and constant and quite sharp fluctuations are evidence of exaggerated response.

The response of prices to the start of the Gulf War was much more muted, probably because fears were calmed by previous experience. Also, during the UK miners' strike the price of fuel oil relative to other products rose substantially, but not wildly, as a result of the restraint of coal production. The strike was seen as having a limited impact and accordingly the price movement was moderate.

There is now a genuinely free (but not perfect) market in oil

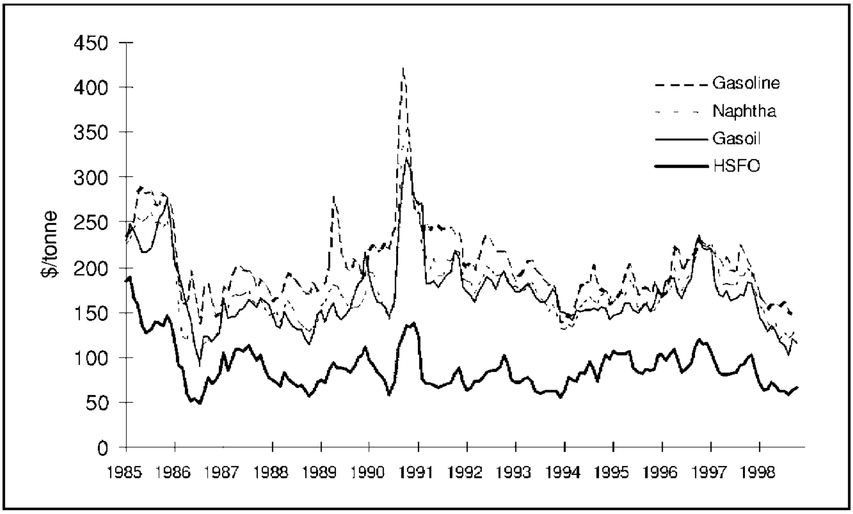


Source: BP Statistical Review of World Energy, 1998 & Petroleum Argus

Figure 2.2 Crude oil price history, annual average 1960-1998 and pricing is the mechanism by which physical supply and demand are brought into balance. However, it would be a mistake to think that the wilder fluctuations of price that occurred on previous occasions could not happen again, particularly when expectations lose touch with reality.

The general comment above applies to both crude oil and products. However, the relationship between crude and product prices also needs comment. The main products of refining crude oil are necessarily co-produced. The analogy almost invariably used is that of a butcher carving a carcass into different cuts. Therefore, although product prices may, and do, fluctuate widely relative to each other, they must together be related to crude oil price because refineries will not continue to operate long on negative margins and competition will set a ceiling to high margins. It may seem an academic point but it is perhaps worth noting that crude oil prices reflect product prices, not the other way round, as supply and demand factors act, in the first instance, on products.

Although the product prices do fluctuate relative to each other there is nevertheless a pattern (see Fig. 2.3). Generally speaking the lighter products are priced higher than heavier products. Fuel oils and LPG face competition from coal, natural gas and other energy sources and this certainly limits their prices. LPG therefore does not usually enjoy the premium associated with being the lightest product. Transport fuels have no real substitutes, at least within current price ranges. Their relative prices reflect their own supply and demand factors but there is also an underlying



Source: Petroleum Argus

Figure 2.3 Relative product prices, cargoes cif NW Europe structure based on technical and cost considerations.

For example, motor gasolines usually cost more to produce than diesel fuels and are generally priced higher. Jet fuel has a higher price than diesel, partly because, as a lighter product it has greater value* and partly because the special care required in its storage and transport is more costly. Two warnings are necessary here. First, prices may be distorted by taxes; taxes on motor gasoline more than double prices at the pump in Europe. Secondly, bulk prices are often quoted in dollars per ton but actually sold at cents per gallon or per litre. For example, on 12 November 1991 premium gasoline was quoted at $238 per tonne and gasoil at $217 per tonne in Rotterdam. On a volume basis these prices would be roughly 17.4 cents per litre and 18.4 cents per litre respectively.

Most petroleum measurements are still made in volume — usually tank contents or meter readings. Consequently, sales contracts will usually include an adjustment for specific gravity so that pricing is effectively volume based. There are some exceptions such as road or rail tanker vehicle loads of bitumen and fuel oils which can be measured directly by weight. Also new meters that measure mass directly are coming into use but are only common for LPG at present. Apart from these examples, most final sales to the end consumer are measured in volume; retail sales of gasoline and diesel at the pump, for example, are always sold on a volume basis. This means that the trader, who is further back down the supply line, must also be concerned with volume (rather than weight) since profits will ultimately depend on the *volume* of product sold.

Since oil expands and contracts with temperature, volumes are adjusted to a standard temperature, usually 15ºC or 60ºF — although it should be noted that these temperatures are not exactly the same: 60ºF is equivalent to 15.6ºC.

Example

Suppose a trader has agreed to buy 20,000 metric tons of gasoil at $200/tonne. The contract will define the quality specifications of the product including its specific gravity (see Section 2.4.2 below). Suppose the agreed specific gravity at 15ºC was 0.845, but when the cargo was loaded the inspector's report indicated that the

*Jet fuel, or kerosine, provides an explanation of why lighter products usually have higher value. As will be seen later, part of the kerosine fraction can be made into gasoline whereas diesel cannot. Also kerosine, having a lower viscosity than diesel is a better fuel oil cutter stock.

specific gravity was 0.847. Although a specific gravity of 0.847 is within acceptable limits for the quality of the cargo, there is still a price adjustment to take account of the reduced volume.

A cargo of 20,000 tonnes of gasoil with a specific gravity of 0.845 is equivalent to 23,669 cubic metres at 15ºC, i.e. a price of $169/m^3. But 20,000 tonnes of gasoil with a specific gravity of 0.847 is equivalent to only 23,613 cubic metres at 15ºC, i.e. a price of $199.53/m^3. Although it looks like a small difference, it is worth more than $9000 on the deal.

The thermal expansion of petroleum fuels is not large. If the gasoil cargo in the example above had been loaded at an ambient temperature of 20ºC it would have occupied approximately 23,707 cubic metres compared with 23,613 cubic metres at 15ºC. However, volumes are always corrected back to the standard temperature of 15ºC for the purposes of any price adjustment.

The relative prices of specific products within a group are generally cost related though still subject to variations of supply and demand. For instance, super premium unleaded gasoline is priced higher than unleaded premium or Eurograde because it costs more to produce; the lower the sulphur and cold properties of diesel the higher its price; and in fuel oils lower viscosity and lower sulphur fuels are higher priced than heavier and higher sulphur fuels. These quality premium relationships, though variable in extent, are directionally stable.

2.4 Properties of oil products

2.4.1 Product specifications

Within the main product groups described briefly in the last section are hundreds of individual products, each tailored for a specific use or climate or environmental regulation or price or a combination of these factors. The quality of each individual product is defined by a 'product specification'. A product specification is a list of properties which the product must possess to be acceptable to the customer or regulatory authority under which he works. For the most part these properties are defined as a maximum result, or a minimum result, or a range of results from certain specific tests to which the product must be subjected. However, more general requirements may be included, for example, 'clear and bright' or 'water white', or 'acceptable odour'. The test methods and their accuracy are very closely defined, usually by independent bodies, such as the Institute of Petroleum (IP) or the American Society for Testing Methods (ASTM). A buyer or a seller may use his own method, but it will be of little value unless it is accepted by the other party.

Many test methods have been developed to simulate conditions under which a product is used and require special and sometimes complex equipment; the tests for octane number of gasolines are examples. Some typical product specifications are shown in Appendix 2.1.

Product specifications are part of the agreement between buyer and seller and, in principle, may be freely negotiated between them, as they often are between traders. However, the trader should be aware that his oil will ultimately be used in a product for which the specification is not normally negotiable, either because part or all of it may be a legal requirement of the area in which the product is used, transported or stored, or because the final user is unwilling to change it. Where large numbers of customers are involved, such as in retail sales, changing specifications can be a very difficult and lengthy process.

2.4.2 General properties

In this manual it is not possible to describe in detail the product properties nor the tests used to measure them as normally defined by specifications, only the most important items can be mentioned. The important properties and tests for most products are:

- **Specific gravity (SG)**
  The specific gravity of a product is its density at 60°F divided by the density of water at the same temperature. It is often written as 'SG 60/60°F'. Oil products range from less than 0.50 for LPGs to over 1.00 for bitumen. It can be an extremely important property because it reflects the volume to weight ratio of the product, i.e. the number of barrels, gallons or cubic metres per tonne. Very large volumes of oil products are sold on a volume basis, e.g. all retail automotive fuels except perhaps LPG, yet these products or their components are often previously traded on a weight basis (see Section 2.3).

  Beware that the density of oil at 15°C is sometimes divided by the density of water at 4°C and the result can also be called specific gravity (or sometimes density, though this latter is incorrect). This specific gravity is often written as 'SG 15/4°C'. The difference between SGs 60/60°F and 15/4°C is small but can be significant when converting from volume to weight or vice versa.

  Specific gravity can also be important for other reasons, for instance in marine bunkers. Ships often separate traces of water from the fuel by centrifuge which depends on the difference in density between water and oil. An SG greater than 0.9910 is not usually acceptable because the centrifugal separation of oil and water is poor.

- **Colour**
  The colour of oil products varies from completely colourless and clear for gasolines and kerosines to straw coloured for gasoils and black opaque for most fuel oils. (Dyes are sometimes added to gasolines and kerosines.) There are several variations of the test for colour but most compare the sample with a set of standards that are numbered. The significance of colour is mainly as warning of contamination. A very small quantity of residual (fuel oil type) component will darken a light product significantly, hence the need to use separate transport and storage with cheaper freights applying to 'black oils' than to 'white oils'. A black oil ship or tank can usually be cleaned for white oil use, but it is a rather laborious process.

  Appearance is another much used specification, the requirement is often given as 'clear and bright'. Interpretation is somewhat subjective but a dark or hazy oil will not pass.

- **Flash point**

  Flash point measures the ease with which a product can be ignited by applying a flame to its surface. The test involves heating a sample of the product and applying a flame to it. The lowest temperature at which the liquid ignites is its flash point. There are several varieties of this test. Flash point is, of course, closely related to volatility and is intended as an indication of how safe it is to store and use a product. Gasolines have flash points below ambient temperature but minimum values are specified for kerosines, gasoils and fuel oils.

  There are often legal requirements for flash points and codes regulating tank storage construction lay down different requirements for high flash and low flash product tanks.

- **Volatility**

  Most specifications include tests to define the volatility of the product. The most universal is ASTM distillation. Nearly all oil products are a mixture of a large number of different hydrocarbons (refer also to Section 2.5.1) and therefore boil over a range of temperatures, not at a single temperature like water. The ASTM distillation test is a simple laboratory distillation of a measured sample and the temperature at which set percentages of the sample are recovered after condensation are recorded. The temperature of the first recovery is called the initial boiling point (IBP) and the temperature of the last is the final boiling point (FBP). (Specifications may be in terms of 'per cent evaporated'. Per cent evaporated is calculated from per cent recovered by adding the loss.) In addition to loss there is often some undistilled residue left in the flask and a maximum is sometimes specified.

  The vapour pressure of the lighter more volatile products such as gasolines is usually specified because it gives a more sensitive measure of the tendency to cause pumping difficulties, excessive vapour discharge in shipping and storing and carburettor vapour lock etc. The most widely used test is Reid vapour pressure (RVP).

- **Water content**

  The solubility of water in oil is very small and though there are tests to measure the amount of water dissolved in oil they are only of importance in refining processes and some special products such as transformer oils. However, small droplets of water can be suspended in oil and this situation is controlled by specifying either appearance (for the clear oils such as gasoline or kerosine) or water content or both. Suspended water can normally be separated from oil simply by settling and draining in a tank but traders should be aware that in some cases this can be a difficult and long drawn out process.

- **Sulphur content**
  Many oil products contain small amounts of sulphur. (Refer also to Sections 2.5.1 and 2.6.2.) Sulphur can be harmful for several reasons: it can cause an obnoxious smell, it can be corrosive and, when the oil is burnt, it produces sulphur oxides which, with moisture, are most definitely corrosive. The most common specification is simply a maximum sulphur content and there are several test methods depending on the sulphur level expected and the type of oil. However, the Doctor test, copper strip and silver strip tests are also related to sulphur content.

2.4.3 Gasolines and naphthas

These are the lightest oil products that can be stored at ambient temperatures and pressures. (LPGs have to be stored either at increased pressure, e.g. the familiar calor gas bottle, or refrigerated.) Their IBP is usually between 40°C and 100°C and their FBP less than 200°C. They have two main uses which require different properties.

Firstly, they are used to make motor gasoline. (Motor gasoline is almost invariably a blend of several components.) For this purpose they have tight specifications on volatility, appearance and sulphur content but they also have other specifications, of which octane number is the most important. Octane number measures the tendency of the gasoline to 'knock' in engines; the higher the octane number the lower the knocking tendency. There are two octane number tests for motor gasolines: the F1 or 'Research Method' and the F2 or 'Motor Method'. The F1 test gives a higher result than the F2 and the difference between them is referred to as the 'sensitivity' of the gasoline. It is common to find both methods specified for motor gasolines, for instance the premium unleaded grade, or Eurograde, has a minimum F1 specification of 95 and a minimum F2 of 85. The octane number of the more volatile part of gasoline, the 'front end' octane number, may also be specified. In the United States (F1+F2)/2 is often used for octane number specifications.

The lead compounds tetra-ethyl and tetra-methyl lead (TEL and TML) are very effective octane improvers but they are poisonous to most forms of life and lead in the exhaust gases of motor vehicles poisons the catalysts used in 'converters' to reduce atmospheric pollution. For most countries in Europe the maximum lead in leaded grades is 0.15 gm Pb/litre; for unleaded Eurograde gasoline the maximum is 0.013 gm Pb/litre. Lead is not the only octane improver used in gasoline, oxygenated compounds such as methyl tertiary butyl ether (MTBE) are also used; maximum and minimum levels may be specified. It should be noted that oxygenated compounds improve octane number as blending components rather than as additives and much larger proportions are used, e.g. up to 10 or 15 per cent (see Section 2.6.6).

Benzene is a component of most gasolines with excellent octane number but it is more toxic than other components and a maximum percentage, usually between three and five per cent, is often specified, but this has been reduced to one per cent volume in some areas in the United States.

Secondly, gasolines or naphthas are used as feedstocks for oil refineries and petrochemical complexes. For this purpose the important property, in addition to the general properties described, is the chemical composition. The relative proportions of four types of hydrocarbons are measured: these are, paraffins, olefins, naphthenes and aromatics. The test is, therefore, known as the PONA. Petrochemical users look for a high paraffin content, oil refiners look for high naphthene and aromatic contents. The other important property for either application is total absence of lead contamination, so that gasoline for these purposes cannot be shipped or stored in vessels that have previously been used for leaded gasoline.

2.4.4 Kerosines

The next group of products in decreasing order of volatility are kerosines with ASTM boiling ranges between 150°C and 250°C. They have to meet a flash point specification usually set at 38°C or 100°F. Their principle use in Europe now is as aviation turbine fuel (ATF), commonly called Jet A1. There are several different grades of these fuels but all have a large number of tightly specified properties and it is only possible to mention some of the most important ones.

Jet A1 is subjected to very low temperatures in the tanks of aircraft at high altitude, therefore the fuel must remain entirely liquid without the formation of any solid crystals, which could plug filters, down to a temperature of about –50°C. This property is the freezing point.

Jet A1 is then subjected to high temperatures in the engines before it is burnt and is therefore tested for thermal stability. It is also important that the fuel burns well with little smoke so a smoke point may be specified possibly combined with a naphthalene or aromatics content.

Apart from tight specifications the procedures for sampling, testing and delivering Jet A1 are carefully controlled to ensure that no contamination can occur.

Kerosine is still used as a lighting and cooking fuel, in many parts of Asia on a large scale. For this use smoke point is the most important specific test. The test is done in a specially designed lamp and the height of flame achieved without smoking is measured. A common smoke point specification is 25 mm minimum, although lower specifications are used in the Indian subcontinent and Indonesia. This is a higher specification than is usually required for aviation fuel but lighting kerosine does not have to meet the very low freezing point and thermal stability tests of Jet A1. Dual purpose kerosine (DPK) — which meets the specifications of both products — is sometimes required or supplied, usually to save on duplicate storage and delivery systems.

2.4.5 Gasoils

Gasoil is the generic term used for products with a minimum flash point of 66°C (150°F) and, usually, a maximum FBP between 320°C and 370°C. Their original use was for making gas , hence the name, but they are now chiefly used as diesel engine fuels or for home heating. There is also a secondary but significant use as petrochemical feedstock.

For both the main uses stability in cold weather is important. At low temperatures the heavier components of a gasoil tend to crystallise and cause filters to plug. Unusually severe spells of winter weather sometimes result in stranded vehicles because their fuel has frozen. There are several tests, all of which are designed to detect the formation of crystals. Pour point actually checks the temperature at which the oil ceases to flow freely. Cloud point detects the first formation of crystals but cold filter plugging point (CFPP) is now more commonly used. Flow improving additives are sometimes used to inhibit crystal formation. Though usually not in the specifications it may be wise for traders to know whether such additives have been used.

The fuel also has to burn well without sooty deposits. For this purpose a maximum 90 per cent or 95 per cent recovery temperature or an FBP in the ASTM distillation test may be specified to limit the heavy components. CFPP maximum may also have a similar effect.

As a diesel fuel, gasoils have to ignite at the right moment in the engine. This property is measured by cetane number a minimum of 50 being a common specification. Cetane number is measured in a test engine, as is octane number, and is an inconvenient test. Cetane index is therefore commonly used as a substitute because it can be calculated from more easily measured properties. Additives are available which improve cetane number but they do not affect cetane index.

The sulphur content of diesel fuels is becoming increasingly important and, in Europe, maxima have descended rapidly from 0.5 per cent to 0.3 per cent to 0.15 per cent and 0.05 per cent will become general by 1996. The purpose of these reductions is to lower sulphur dioxide and particulate emissions from the exhaust gases for environmental reasons (see Section 2.7).

2.4.6 Fuel oils

Fuel oils usually contain a large proportion of residual components, i.e. components which are left unvaporised in the distillation of crude oil. They therefore contain all the largest and heaviest molecules, are usually black and often nearly solid at ambient temperature.

Easy pumping and clean burning are essential for fuel oils. To achieve this the viscosity of the oil must be right. A maximum (and sometimes a minimum) viscosity is always specified and grades of fuel oil are normally distinguished by their maximum viscosities, e.g. 180 centistokes at 50°C or 280 centistokes. The actual viscosity of an oil is highly dependent on its temperature; the more viscous fuel can therefore still be used but it has to be stored and used at a higher temperature and is therefore usually cheaper.

Clean burning depends largely on the atomisation of the oil in the burning device, be it a boiler burner or a diesel injector. That is why viscosity is so important. But burning quality can also be impaired by very heavy components called asphaltenes. Tests related to the presence of these components are also used. The commonest are Conradsen carbon residues and Ramsbottom residues and maximum values are specified.

As described in Section 2.5.1, crude oils do contain very small quantities of non-volatile inorganic compounds, usually metal compounds. These are concentrated in the residues and therefore in fuel oils. When fuel oil is burnt these inorganic compounds remain as ash and even the best atomisation will not prevent ash formation. Consequently, there is usually a maximum ash content specified, typically 0.20 per cent weight. Some metals, particularly vanadium, attack the refractory material of furnaces and there may be a metals specification.

Sulphur content is also important for environmental reasons; 3.5 per cent weight is a normal high sulphur fuel maximum, but it is often lower for uses on land. In Europe, low sulphur fuel is often 1 per cent sulphur maximum, though in Japan and the USA it may be 0.3 per cent maximum. Sulphur content of residue is normally determined by the origin of the crude oil and it is costly to reduce it by refining processes.

Low sulphur residues are often waxy and have high pour points which, in these cases, may determine the storage and pumping temperature rather than viscosity. For heavy high sulphur fuels, pour point may also be specified but is usually less important because the flow properties are chiefly determined by viscosity.

2.4.7 Special products

In the scope of this manual it is only possible to touch on the main points of product properties and traders should be aware that not all quality matters are routine and special situations do arise. For example, metals and ash content of fuel oils are not normally a problem but with some fuels of Venezuelan origin they can be.

Also, there is a host of special products of which LPG and bitumen are probably the largest volume. LPG tests and specifications are relatively simple and largely aimed at ensuring that the pressure limits of the equipment used for them is not exceeded.

The largest volumes of bitumen sold are paving grades for road making and the specifications are usually fairly straightforward. However, traders may like to know that there are also some very specialised bitumen applications both for roads and other industrial uses and that there is a growing use of complex bitumen technology.

2.5 Crude oils

2.5.1 Hydrocarbon chemistry

Crude oils and therefore oil products are made up almost entirely of hydrocarbons which, as the name implies, are compounds of the elements carbon and hydrogen. These two elements combine in an enormous number of different ways and any one crude oil will contain billions of different hydrocarbon compounds. Most hydrocarbons are chemically quite stable and their common reaction is to burn in air or oxygen to give carbon dioxide, and water. When combustion is incomplete, as for example in internal combustion engines, some carbon monoxide is also formed. Hydrocarbons release a great deal of heat when they burn and therein lies their value.

Although crude oils consist almost entirely of hydrocarbons they usually contain small proportions of compounds containing sulphur, oxygen, nitrogen and metals. Some of these non-hydrocarbon compounds can be harmful, being corrosive or toxic, and have to be dealt with in refining processes.

2.5.2 Crude oil types

Crude oils were formed by action of geological processes on the remains of ancient marine life. Recoverable quantities are found trapped by particular rock formations in many different parts of the world. As an almost infinite number of different mixtures of different hydrocarbons are possible, no two crude oils are exactly alike. Crude oils from the same area are frequently similar but there are also exceptions.

Several hundred different crude oils are produced but many of them only in small quantities and there are about seventy crude oils which are widely known and regularly traded. The quality of each crude oil is tested and the results usually provided to customers and refiners. These quality assessments are called crude assays.

The most important characteristics of crude oils are described below and there is a summary for some of the better known traded crudes in Appendix 2.2.

Product yield

Different crude oils contain different proportions of the millions of different hydrocarbon compounds that can be found. One of the most important characteristics of a crude oil is the size distribution of the different hydrocarbon molecules. The smaller, lighter, more volatile hydrocarbons can be separated by simple distillation, which is the basic process in oil refining. Those crudes with a relatively large proportion of smaller, lighter hydrocarbons are referred to as 'light' crude oils and those with less as 'heavy' crude oils. The light crude oils tend to be more valuable than the heavy because they produce larger proportions of gasolines, kerosines and gasoils, collectively known as distillates, than heavy crude oils by simple refining processes (see also Section 2.6.7).

No single test can give a really reliable assessment of the product yield possible when a crude oil is refined but specific gravity gives some guidance; the lower the SG the more distillates will usually be produced. Unfortunately custom has it that the measure used is API gravity in degrees rather than SG. The relationship between the two is:

$$\text{API gravity}\ ^\circ \text{ at } 60^\circ\text{F} = (141.5 / \text{SG @ } 60/60^\circ\text{F}) - 131.5$$

API gravity is therefore inversely proportional to specific gravity and light crudes have API gravity of about 37° or above and heavy crudes 30° API or below. The following table shows API gravity and total atmospheric distillate yields for some crude oils:

Crude type	API (degrees)	Atmospheric distillate (per cent volume)
Ekofisk	44.4	72
Brass River	40.9	74
Brent	37.1	61
Arabian Light	34.0	55
Taching	32.2	34
Arabian Heavy	28.3	48
Champion	24.6	68
Bachequero	13.2	27

The above crudes have been deliberately chosen to show how unreliable API gravity can be as a guide to yields. The yields of crude oils of similar type (see above) show a closer correlation to API degrees. In the above list only the two Arabian crudes are really of the same type. The crude assay will normally give a simple product yield breakdown and this is a much more reliable guide to the actual yields obtainable (see Appendix 2.3).

The yield of a crude oil is based on simple separation by distillation into fractions (see Section 2.6.3) and the result is expressed either in per cent volume or per cent weight of the crude oil recovered. European refiners mostly use weight while those in the Americas or the Far East use volume.

For example, Brent Blend crude oil would give the following approximate yields from primary distillation:

Boiling range (degrees C)	**Product type**	**Product yield (% weight)**	**(% volume)**
C4 (or less)	LPG and gas	1.8	2.8
C5 – 85	Gasolines/naphthas	6.1	7.5
85 – 165	Gasolines/naphthas	14.2	15.7
165 – 235	Kerosine	12.2	12.8
235 – 300	Gasoil	12.8	12.8
300 – 350	Gasoil	9.8	9.6
> 350	Residues	43.1	39.2

The product yields are given in both per cent weight and per cent volume. In the middle (gasoil) fractions, it can be seen that there is little difference between the weight and volume yields. But the heavy residue fraction obviously has a higher percentage weight yield than percentage volume yield, and vice versa for the light fractions.

It should be noted that the "cut point" temperatures are not standard and are chosen by whoever is making the assay. C5 (pentanes) are usually taken to represent the lowest point at which hydrocarbons distilled from crude oil can be recovered at atmospheric pressure, but this may also be represented as a temperature, the IBP or initial boiling point. American crude oil assays will often quote temperatures in degrees Farenheit.

Hydrocarbon type

In Section 2.4.3, four types of hydrocarbon were mentioned. Olefins do not occur in natural crude oils, being produced in refining processes, but paraffins, naphthenes and aromatics have somewhat different properties and the proportions of each in a particular crude oil can be important. There is no clear cut measure such as a PONA analysis which can be used for crude oils and the proportion of each type can vary greatly between the light fractions and the heavy. The following is a brief summary of the main points of interest:

- **Gasoline/naphtha fractions**
  Paraffins have low octane numbers and make poor refinery feedstock but crack more easily and make excellent petrochemical feedstock. Naphthenes and aromatics have the reverse properties.

- **Kerosines**
  Paraffins have good smoke points but tend to have high freezing points. Napthenes are intermediate and aromatics have the reverse properties.

- **Gasoils**
  Paraffins have excellent cetane numbers but the larger and heavier paraffin molecules have high freezing points and tend to form waxy crystals which give higher CFPP results. Again naphthenes are intermediate and aromatics have the reverse properties.

- **Fuel oils**
  The heavy paraffins can have very high freezing points and highly paraffinic or waxy residues can have pour points as high as 35 or 40°C. They also have few asphaltene type molecules and are less viscous than naphthenic/aromatic residues. They cannot be used for bitumen manufacture. 'Non-paraffinic' or asphaltic residues have higher viscosities, lower pour points and make good bitumen. In these heavy fractions the distinction between hydrocarbon types becomes blurred because the molecules are so large and complex that they can have features of each type within the same molecule.

Sulphur content

The sulphur content of crude oils varies between about 0.1 per cent and 3.0 per cent weight. It is not only the total sulphur content that is important but also the form in which it occurs. Sulphur compounds usually occur in all fractions of crude oil but, generally, the heavier the fraction the higher the sulphur content. Some crude oils contain considerable quantities of hydrogen sulphide (H_2S) which is a gas under ambient conditions and extremely toxic. Special measures have therefore to be taken in their production and refining. Sulphur compounds can be removed from distillate fractions relatively easily (refer to Section 2.6.4) but it is much more difficult and expensive to remove them from residues.

Therefore, the production of a low sulphur fuel oil normally requires the refiner to start with a low sulphur crude. Most low sulphur crudes are paraffinic or waxy with high pour point residues. Most low pour point residues come from high sulphur crude.

Oxygen and metals

A few crude oils contain oxygen compounds in the form of naphthenic acids which can be highly corrosive. This is usually measured by a total acid number. Similarly, a few crude oils have high metals contents, particularly vanadium in the range of 250–400 parts per million (ppm) whereas 50 ppm or less would be normal. These metal compounds stay in the residues, never in atmospheric distillates but they can cause problems for refining and the fuel oil produced from them. Some Venezuelan crudes suffer from both these disadvantages.

2.5.3 Crude oil quality

A named crude oil may well be a blend of crude oils from a number of fields which are close together and for which it is economic to share common facilities such as pipelines, tankage, shipping terminals, etc. Many North Sea crudes are such blends, for example Brent and Flotta. The characteristics of the oil from the different constituent fields will be different and, as production rates are not constant, variations in the quality of the named but blended crude will vary. These can be short term variations caused by the need for field or pipeline maintenance work or long term gradual variations due to the build up and decline of production of component fields. Producers naturally try to limit these variations in quality but they can be quite significant to refiners. A major change may be accompanied by a revised crude assay but frequently there is no such revision. Refiners who are familiar with a particular crude will be aware of quality changes they have experienced and can advise on their severity.

There are a number of producing wells in every field and the oil from different wells may not be exactly the same quality. Also the quality of oil may gradually change as production proceeds in a field. Therefore, quality may also vary from a single field though these changes are not usually great.

A crude assay is an estimate of the quality of a crude oil but not a specification such as is used for products. Traders may need to be watchful on crude quality as significant changes can take place without breaching the generally rather imprecise descriptions in crude contracts.

2.5.4 Condensates and NGLs

The fluids produced from a well may be totally liquid under ambient conditions or totally gas but, usually, they are a mixture of the two. Gas and oil are separated in the field to produce a liquid which can be stored and shipped in at atmospheric temperatures and pressures. It is a matter of degree as to whether the gas associated with oil production is called 'associated gas' or oil produced with gas is called 'condensate'. Condensates are usually very light crude oils and frequently contain little or no gasoil and fuel oil fractions.

Natural gas liquids (NGLs) have a different origin. Oil field separation of oil and gas is imperfect so the gas produced, mainly methane and some ethane, contains appreciable amounts of propane, butane and heavier hydrocarbons. Even natural gas which produces no condensates at well head conditions may contain appreciable quantities of propane and heavier hydrocarbons. Therefore, these gases may be processed in a plant using refrigeration and absorption techniques to obtain a better separation of the hydrocarbons. The propane and heavier hydrocarbons are then themselves separated into propane and butane (LPG), which have to be stored and shipped at elevated pressure or reduced temperature, and a heavier fraction which is liquid under ambient conditions and which can be shipped conventionally. It is this liquid fraction which is called natural gas liquid (NGL). NGLs are very light liquids normally containing only gasoline/naphtha fractions with some kerosine. NGL production has increased rapidly in recent years and may be sold as such or remixed with crude oil, giving rise to another possible crude oil quality variation.

2.6 Oil refining

2.6.1 Oil refineries

Crude oils cannot be used directly except as a boiler fuel for reasons which it is hoped are now clear. (Crude oils are used as fuel in Japan but such use would be uneconomic under normal tax and environmental conditions.) Crude oil, therefore, has to be refined to make the products required by users. There are over a hundred oil refineries in Europe and many hundreds world-wide. All are, of course, unique in their location but very few are identical in processing or other facilities either, each having been designed for a particular set of circumstances. Refining processes will be described in Section 2.6.2 but some general points about oil refineries are worth noting.

Oil refineries are very expensive and rather permanent facilities as they cannot be moved. A modern refinery of normal size, starting from scratch or 'greenfield' would cost at least US $2 billion. 'Would' is the appropriate word here because it is extremely difficult to get permission to build a new refinery on a greenfield site in Europe, USA and Japan for environmental reasons, although new refineries are being built in Asia. Because refineries are expensive and permanent* they tend to change slowly, usually lagging considerably behind state of the art technology in one aspect or another.

Refineries are often thought of in terms of their processing plant only. However, only about half of the investment is in processing plant; the rest is in tankage, blending facilities, ship berths and loading equipment, road and rail car loading, utilities (steam, electricity, etc.), workshops, stores, fire fighting equipment, offices, etc. The first four of these items are of interest to traders who should, in particular, know something about the blending characteristics of oil products.

Refining is a large scale business. Most refineries are in the range of 50,000 to 150,000 b/d or 2.5 to 7.5 million tonnes per year crude oil intake capacity. However, some have a capacity of 300,000 b/d or more. 20,000 b/d is approximately equivalent to 1 million tonnes/year.

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* In the 1980s a number of refineries were closed completely because there was world-wide over capacity; it is not expected that many more will close as capacity is now in better balance with demand.

The capacity of a refinery is often quoted in round figures, as has been done above. The figure usually given is 'name plate' capacity. This usually refers to the design or achieved capacity per calendar day (e.g. bpcd) or per year of the atmospheric distillation units on a design crude. The effective capacity of a refinery varies with the crude being processed, usually the lighter the crude the lower the capacity. Capacities may also be given per stream day (e.g. bpsd), which means per day of normal operation. Stream day capacities are higher than calendar day or annual capacities because allowance has to be made for planned maintenance shut downs, often called 'turnarounds' and for breakdowns. Most refineries plan on averaging 330 to 350 stream days per year, except for visbreakers, thermal crackers and cokers which have to have more frequent decoking shutdowns. Average stream days per year were quoted because major shutdowns or turnarounds are usually carried out at two or three year intervals.

2.6.2 Refining processes

To convert crude oil into products the refinery has to sort the crude hydrocarbons into volatility or size ranges, which is done by distillation. It also has to remove undesirable non-hydrocarbon compounds, which requires treating processes. Although refineries can and do operate with simple distillation and treating alone, this may not be enough as it is usually necessary to change the size or shape of the hydrocarbons present in crude oil. There are therefore three basic types of refinery processes:

- **Physical separation**, which sorts hydrocarbons by size or shape,

- **Treating**, which removes undesirable contaminants,

- **Conversion**, which changes the shape or size of hydrocarbons.

Conversion is necessary for two reasons. First, the octane number of the naturally occurring gasoline fractions is not high enough for modern motor cars and most refineries need to make motor gasoline. A conversion process is required to make different, higher octane hydrocarbons from the ones which occur naturally.

Second, there is usually a greater demand for the distillate products than can be produced from natural crude oils. Some of the non-distillate residue, or fuel oil components have to be cracked into smaller more volatile hydrocarbons to satisfy the demand for distillate fuels.

Since all refinery processes are dealing with liquids and gases they look much alike, except perhaps for catalytic crackers. They consist of pumps, tubular heat exchangers, furnaces, columns, reactors, air coolers and vessels all connected by pipes.

2.6.3 Distillation and separation

Fractional distillation is the foundation of all refining. Not only is it used for the first (or primary) separation of crude oil into fractions but it is also used in many other conversion and treating processes to separate the products of reactors or to separate hydrocarbons from a solvent.

It is a continuous process with, for example, crude oil being pumped in and the fractions being continuously withdrawn (see Fig. 2.4). The principle is simple. The crude oil (or other mixture) is heated, typically to about 350°C, and pumped into a tower or column. By constantly removing heat at the top and constantly adding heat at the bottom, a temperature gradient is established in the column; which is cooler at the top and hotter at the bottom. Each hydrocarbon has its own boiling point and accumulates in a particular part of the column. If it is in too hot a part of the column it will vaporise and rise up, if in too cold a part of it will liquefy and drop down. Offtake pipes at various points of the column can therefore draw off fractions of specific boiling ranges.

No separation is perfect but it can be improved, in the design of the unit, by increasing the length of the column, and in the operation by increasing the heat withdrawal and addition. The capacity of the unit is set by the heating and pumping capacity and by the diameter of the column. If the unit is overloaded, separation efficiency falls very rapidly. On the other hand, most units can operate reasonably efficiently down to 50 per cent of their capacity.

The usual fractions withdrawn from a crude distillation unit are:

Fraction	Typical boiling range (degrees C)
A small quantity of gas	
LPGs	Less than 40
Light naphtha or tops	40 to 80
Heavy naphtha	80 to 165
Kerosine	165 to 235
Light gasoil	235 to 300
Heavy gasoil	300 to 360
Residue	Above 360

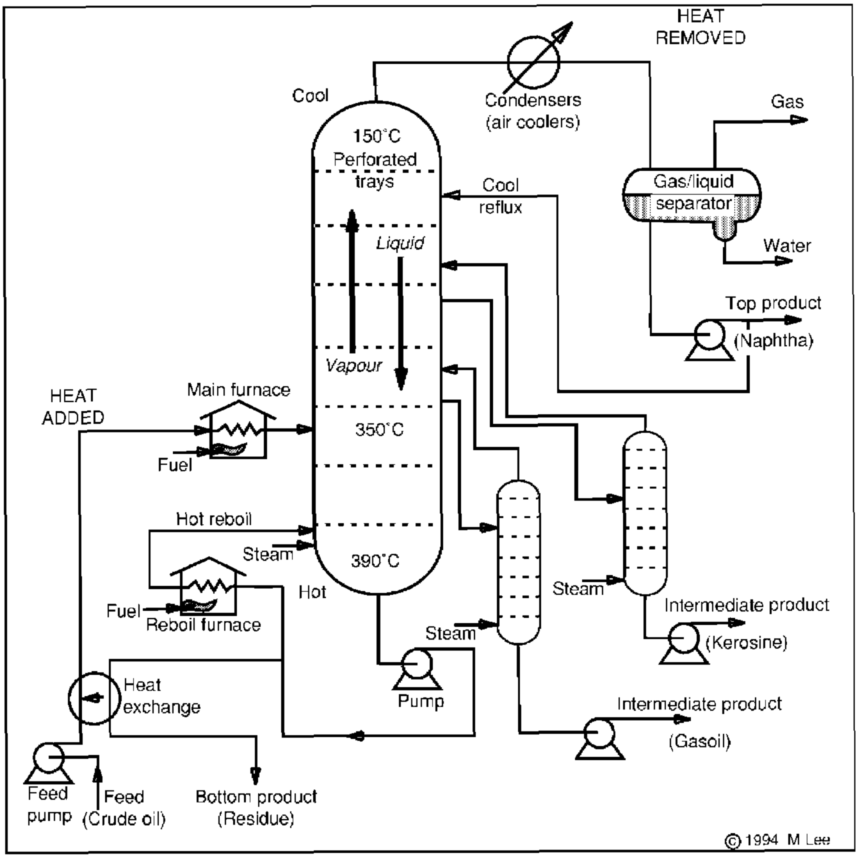


Figure 2.4 Fractional distillation

More than one column is used to obtain these fractions and some treating processes may be an integral part of the unit. The boiling range and yield of the fractions can be altered by altering the temperature gradient of the column.

Primary distillation of crude is carried out at a pressure only slightly above atmospheric. It is often called 'atmospheric distillation'. A temperature of about 370°C is the maximum that can be used because at higher temperatures the heavier hydrocarbons in crude oil start to break up or crack leaving deposits of coke which would clog the unit. The heavier the crude (the lower the API gravity) the more is left undistilled and emerges from the unit as 'atmospheric' or 'long' residue.

Vacuum distillation

More distillate can be obtained from the atmospheric residue by distilling at reduced pressure or vacuum. Typical flash zone pressures are 30 to 40 mm of mercury (Hg), atmospheric pressure being 760 mm Hg, and temperature about 390 to 400°C. Often more than half the atmospheric residue can be distilled off as 'vacuum gasoil' or 'waxy distillate' leaving the rest as 'vacuum' or 'short residue'. The separation is poor but, importantly, the asphaltenes and metals are left in the short residue. The short residue usually has a very high viscosity and would be quite solid like asphalt at ambient temperatures. To make it into a saleable fuel oil it has to be thinned or 'cut-back' with distillate fractions.

Other separation processes

There are several other commonly used physical separation processes, for instance solvent extraction processes such as furfural and sulfolane extraction of aromatics and molecular sieves used for the separation of light hydrocarbon isomers. However, none of these processes is used to anything like the extent of distillation.

2.6.4 Treating processes

Treating processes are aimed at removing, or neutralising the small quantities of harmful non-hydrocarbons which are found in all fractions from the distillation of crude oil. Sulphur compounds are the commonest and often the processes which deal with them also deal with other contaminants such as naphthenic acids (oxygen compounds). Low sulphur crudes often have negligible quantities of sulphur compounds in their distillate fractions and no treating is required. However very few refineries can rely safely on one hundred per cent low sulphur or sweet crudes for their feedstock and therefore nearly all of them include treating processes, for example Merox treating or hydrotreating.

Merox treating

The Merox process does not remove sulphur but converts reactive, corrosive and smelly mercaptans into inactive and largely harmless di-sulphides. It does this by oxidation with air in an aqueous caustic solution with a catalyst. It is a cheap process but the product must be dried properly after treatment, often by using salt and then a clay tower. There are some solid disposal problems. The process is mostly used for kerosine. There is a similar process, the Solutizer process, that does not use a catalyst, which is used for sweetening catalytically cracked gasoline but it is seldom used for straight run gasolines these days.

Hydrotreating

The most important process is hydrotreating or hydro-desulphurisation. There are many varieties of this process but the essentials are the same (see Fig. 2.5). The oil product is mixed with hydrogen gas and passed over a catalyst, usually cobalt/molybdenum, in fixed bed reactors, at high temperature and pressure. The sulphur compounds are converted into hydrogen sulphide which can easily be separated from the hydrocarbon fraction as it is a gas under normal conditions. The severity of the treatment required, that is the temperature, pressure and residence time on the catalyst, depends on the boiling range of the fraction and the degree of desulphurisation required. These processes ordinarily achieve about 90 per cent sulphur removal but can be made to effect almost complete removal.

The process can be applied to any oil fraction though only distillates are normally treated. Residue desulphurisation is possible but seldom applied. Hydrotreating is more expensive than Merox and needs a supply of hydrogen. The hydrogen sulphide gas produced also has to be dealt with, usually by concentration in an amine treater and then partial oxidation to elemental sulphur which can be transported and sold.

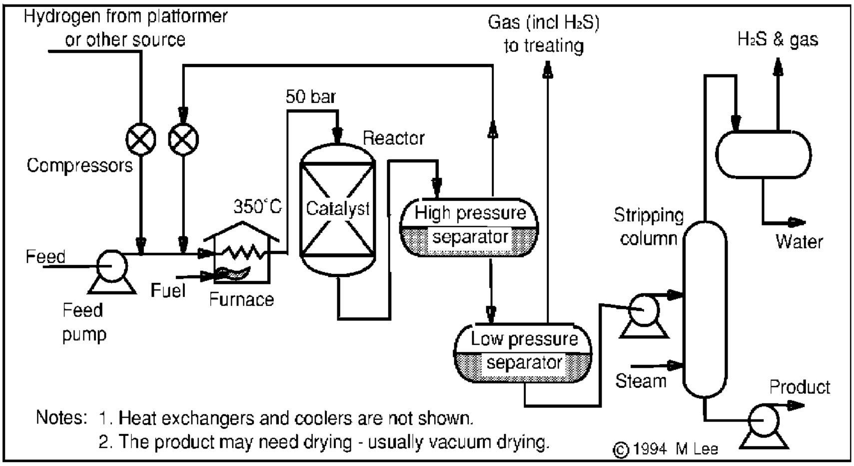


Figure 2.5 Hydrotreating (hydrodesulphurisation)

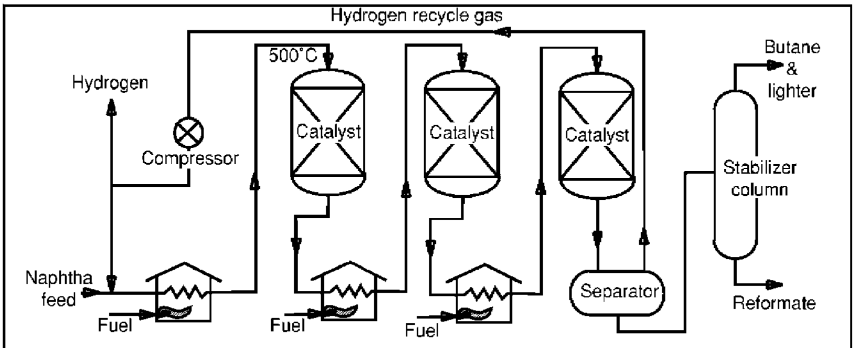
2.6.5 Conversion processes

Catalytic reforming

Straight run gasoline fractions have low octane numbers. Tops are often about 65 to 70 F1 and heavy naphtha 45 to 55 although some crudes with naphthenic and aromatic gasoline fractions are appreciably better. However, to make a gasoline of 95 F1 something better is obviously essential. The octane number of heavy naphtha can be increased to the range 95 to 100 F1 by catalytic reforming or platforming. In this process the naphtha is mixed with hydrogen and passed over a catalyst containing platinum and usually rhenium as well, at high temperature (see Fig. 2.6). The older units use catalyst in fixed beds and high pressure but modern units use a mobile catalyst and much lower pressure. The reactions which take place are complex but the result is much higher octane, some cracking to LPG and, importantly, a net production of hydrogen.

Some coke is formed in the reaction which deactivates the catalyst. In the old units high hydrogen pressure was used to inhibit the formation of coke and the unit was periodically taken out of operation to regenerate the catalyst by burning off the coke. In modern units, called CCR units, the catalyst is continuously regenerated so that pressure can be lowered, resulting in better reformate and hydrogen yields and also less down time.

The catalyst is very easily poisoned by sulphur. The sulphur content of the reformer or platformer feed must therefore be low, usually less than 1 ppm nowadays. To achieve this, hydrotreating is essential. Consequently there is a neat synergy between



This is a very simplified flow scheme of a SEMI REGENERATIVE REFORMER
Almost all reformers built now are CONTINUOUSLY REGENERATIVE (CCR).
CCR units have 3 or 4 reactors stacked one on top of the other and catalyst which flows through them, not fixed beds as shown above.

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Figure 2.6 Catalytic reforming (platforming)

platforming and hydrotreating. Hydrotreating is essential before platforming and platforming produces the hydrogen needed for hydrotreating. As platforming normally produces more hydrogen than is needed for treating its own feed, the other gasoline fractions are usually hydrotreated and some gasoil fractions as well.

The processing line-up of the simple fuels refinery consists of crude distillation, hydrotreating and platforming. It is often called a hydroskimming refinery and there are still many examples of such refineries. A simplified flow scheme is shown in Appendix 2.4.

Thermal cracking

Although catalytic reforming is a conversion process in that it produces real chemical changes in the hydrocarbons, the term 'conversion' is commonly applied only to residue conversion processes. Thermal cracking is a residue conversion process, aimed at increasing the yield of distillates from a crude oil. It takes the residue of either atmospheric or vacuum distillation and converts some of it to lighter distillate fractions.

It is a very simple process and works by heating the residues to temperatures in excess of 400°C so that some of the large molecules break up or crack into smaller ones (see Fig. 2.7). As was mentioned before, this process results in some coke deposition and thermal crackers are designed with this in mind. The coke has to be burned away periodically, usually three or four times a year.

The process is cheap but it gives only a rather small degree of conversion, up to 25 per cent, and the quality of the distillates

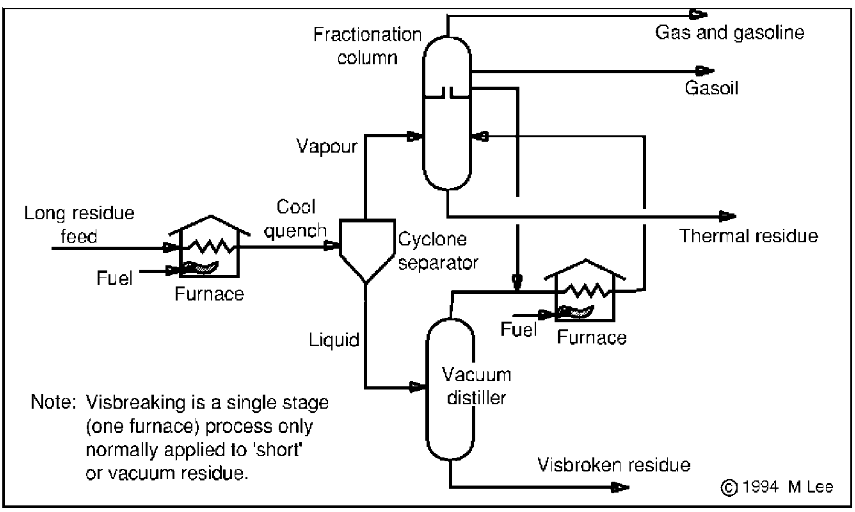


Figure 2.7 Thermal cracking (two-stage cracking)

produced is poor. There are many forms of thermal cracking but the simplest and probably the most used is a single stage unit operating on short or vacuum residue. Much of the distillate made is left in the residue or reblended with it and the result is really to reduce the viscosity of the residue, so these units are frequently called visbreakers. They can be valuable because they free good quality straight run distillates which would otherwise have to be used to thin or 'cut back' heavy residues to meet fuel oil viscosity specifications.

The limit to the severity of thermal cracking is usually the stability of the residue produced. Over-cracked residues can deposit solid matter especially if blended or mixed with a paraffinic fuel or diluent. A well run refinery will not over-crack but it is as well to be aware that it can happen.

A number of refineries have a hydroskimming processing line-up with the addition of a thermal cracker working on the long residue from the crude distiller. Such refineries are referred to as semi-complex refineries.

Catalytic cracking

Catalytic cracking is the most commonly used residue conversion process in Europe (see Fig. 2.8). The feedstock is mixed with hot finely divided catalyst, a zeolite or alumina, and the result is much more sensitive than in thermal cracking. The catalyst is so finely divided that, when mixed with air or vapour it behaves like a fluid, hence the name fluidized catalytic cracking unit or FCCU. Again coke is formed and deposited on the catalyst but coke rich catalyst is continuously withdrawn from the reactor and mixed with air in the regenerator where the coke is burned off providing the heat required for the process. The hot catalyst then returns to be mixed with the incoming feedstock and transferred to the reactor.

The catalyst is easily poisoned by metals in the feedstock and also asphaltenes produce a very high proportion of coke. Therefore, the feedstock is usually not whole atmospheric residue but the vacuum gasoil or waxy distillate produced by vacuum distillation. Some modern units are designed to take residues, especially the low sulphur low asphaltene, North Sea type residues.

FCCUs are essentially gasoline producers, converting up to 75 per cent or so of feedstock into motor gasoline fractions. By the nature of the process these gasoline fractions are olefinic and have good octane number, about 90 or 91 F1 without the addition of lead. However, because the feedstock often has up to 2 per cent sulphur content, much hydrogen sulphide and other sulphur compounds appear in the products and have to be removed. Hydrotreating

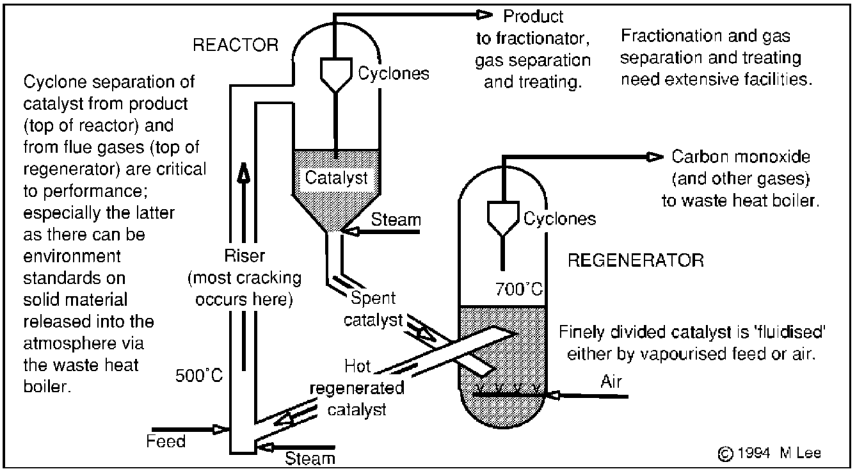


Figure 2.8 Catalytic cracking

removes the olefinic character and lowers the octane number sharply, so other treating methods have to be found.

FCCUs also make considerable quantities of gas, some of which can be converted to excellent quality gasoline by the alkylation process. Gasoil fractions are produced but these have high density and low cetane number.

The units are complex and expensive to build and are therefore usually designed for capacities of 5,000 to 10,000 tons per day. They are physically large and visually obtrusive and special measures have to be taken to separate the fine catalyst from flue gases discharged into the atmosphere. Also cat-cracked gasoline does not really have high enough octane number, especially F2, to meet the modern unleaded and low lead grades. Nevertheless they are still the work horse of the effort to convert residues into distillate products which has been such a feature of recent refining development due to the increase in the price of oil and the consequent substitution of fuel oil by other forms of energy. A simplified flow scheme of a 'complex' refinery including catalytic cracking is shown in Appendix 2.5.

Hydrocracking

The last conversion process to be mentioned here is hydrocracking. This process is different in kind from thermal cracking and catalytic cracking because it adds hydrogen in the cracking process rather than removing carbon as coke. The feed is passed through fixed catalyst beds in a hydrogen atmosphere at high pressure and temperature. Little coke is formed and the process is much more akin to hydrotreating, in fact it can be difficult to draw a line between severe hydrotreating which includes some cracking and mild hydrocracking. Because catalysts are used, as for FCCUs, the feedstock is usually vacuum distillate rather than the whole residue.

There are many types of hydrocracker but a common one is a two reactor series flow unit (see Fig. 2.9). The first reactor desulphurizes and denitrifies the feed and the second, using a different catalyst, produces the cracking. These units operate at very high pressure and achieve nearly 100 per cent conversion to distillates with FBP below 370°C. They are flexible and can vary their output between naphtha, kerosine and gasoil very widely. The quality of the products made is excellent, having virtually no sulphur and good burning properties. The heavy naphtha produced does not have good octane number and must be catalytically reformed. It is, however, an excellent reformer feed. Hydrocrackers can also use the poor quality gas oil fractions produced by thermal and catalytic crackers as feed.

The units are usually designed for capacities of 2,000 to 6,000 tons per day and are environmentally quite friendly. Their trouble is that they are expensive especially if hydrogen has to be generated from expensive oil (rather than cheap natural gas) to feed them; as they use 2 to 4 per cent weight hydrogen on feed this is often the case. However, because of the high quality products made, they are becoming more widely used in Europe (they are already widely used in the USA) and the combination of a CCR platformer, which produces 3 to 4 per cent hydrogen on feed, with a

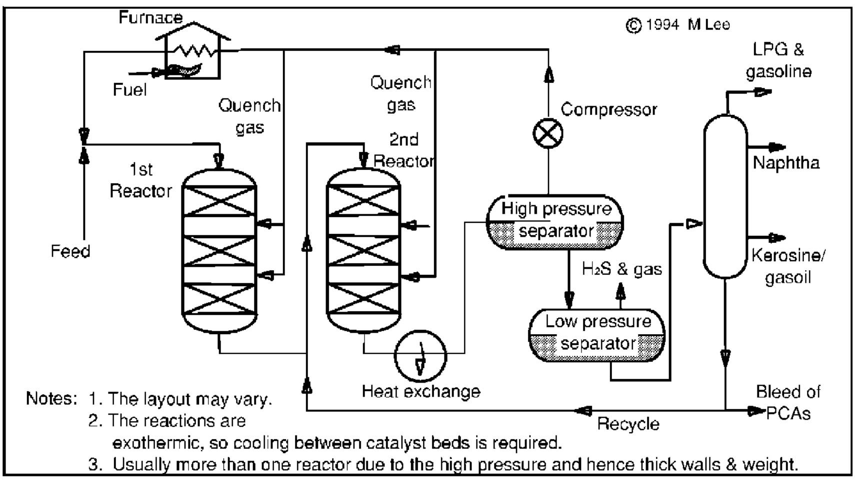


Figure 2.9 Hydrocracking

hydrocracker can reduce the cost by eliminating the need for a separate hydrogen manufacturing unit.

2.6.6 Blending

Few finished products are run straight from process units to tankage, except kerosine for Jet A1. Most other products are blended from a number of components produced by the refinery processes. The main purpose of blending is to make finished products in the most economic way. Single refinery streams can seldom be made to meet all the economically important specifications of a product simultaneously. A blend of two or more can be made to meet specifications closely without costly overshoots or 'quality give-away'. Blending can also add flexibility by allowing a large number of different finished grades to be made from relatively few components, thus saving time and tankage.

Two examples will illustrate the point. First, motor gasolines will often be blended from five components:

LPG	Good octane but very high RVP
Tops	Low octane and high volatility, but cheap
Isomerate	Moderate octane, high volatility
Reformate	High octane but low volatility
Cat cracked gasoline	Moderate octane and volatility

The refinery will probably make three or four grades of finished motor gasoline from these; unleaded Eurograde, leaded premium, unleaded regular and perhaps unleaded super. Blending is used here primarily to meet the economically important specifications as closely as possible.

Secondly, fuel oils may be blended from:

High sulphur residue	High viscosity, high sulphur
Low sulphur residue	Moderate viscosity, low sulphur
Cutter stock	Low viscosity, moderate or low sulphur

Six or seven different grades of fuel can be made at different viscosities and sulphur contents. Here a number of different grades of fuel can be made to order at the right viscosity and sulphur from few components. Often several different cutter stocks are used but these are also components of gasoils and diesels and stored for these products anyway.

Blending is frequently done 'in-line' straight into ships by automatic ratio and quality control. For road and rail loading small intermediate tanks are used.

Good blending requires accurate information on the quality of the components and a detailed knowledge of blending correlations. However, a trader may find it worth knowing which properties blend in a roughly proportional way, i.e., the mixture has roughly the average of the component properties, and which do not. This knowledge may help him in assessing the likely value or cost of departure from specifications. The following properties blend approximately proportionately:

- Density (except LPG), note that SG blends inversely.
- Sulphur content.
- Octane number.
- Aromatics content, PONA, etc..

The following properties do not blend proportionately:

- Colour. Too dark a colour can be difficult to lighten by blending, re-distillation may be required.
- Flash point. A small deviation in flash point is usually correctable by blending; a large deviation may require re-processing.
- Pour point, cloud point and CFPP. The blending behaviour of these is difficult to predict. Correction may be possible by the use of additives if these have not already been used.
- Viscosity. Blending is quite accurately predictable by the use of blending factors.
- Volatility. Correlations for ASTM boiling points, RVP, etc., do exist but they are not very easy to use or reliably accurate. Making a test blend is better when possible.
- Smoke point. Not often blended.

Oxygenates

The term "oxygenates" is used to describe some compounds of carbon, hydrogen and oxygen that are increasingly used for blending motor gasoline. These compounds are usually ethers, such as:

- Methyl tertiary butyl ether (MTBE)

- Ethyl tertiary butyl ether (ETBE)

- Tertiary amyl methyl ether (TAME)

or alcohols, such as:

- Ethyl alcohol, or ethanol

- Methyl alcohol, or methanol

- Iso-propyl alcohol

All these compounds have very high octane numbers. The ethers (or ketones) have low water solubility, low vapour pressures and are made by special petrochemical processes, either in a refinery or a chemical plant. The lower alcohols are water soluble and have rather high vapour pressure (iso-propyl alcohol and higher alcohols much less so) than the ketones used. Methanol is made chemically, but ethanol is usually made by fermentation of carbohydrates from biomass.

Outside the United States, the main purpose of using the ketone oxygenates is to improve the octane number of gasolines and they become popular because environmental controls required the lead content of gasolines to be reduced or removed (see Section 2.4.3). However, the effect of oxygenates on octane number is through blending rather than through chemical inhibition and so much larger quantities are required, typically 5 to 15 per cent by volume compared with 0.15 to 0.5 gms/litre for lead compounds. In the United States, oxygenates are also used for environmental reasons, mainly to improve air quality by reducing carbon monoxide emissions (see Section 2.7).

Alcohols are also used to improve octane number, but the water solubility of methyl and ethyl alcohols and, to a lesser extent, their volatility causes problems. It is common for oil products, including gasolines, to come into contact with water in storage and distribution systems. Hydrocarbon products (and ketones) are virtually immiscible with water so keeping them separate is usually easy. But, if a gasoline containing appreciable proportions of methanol or ethanol is in contact with water, phase separation can occur and special measures are needed to transport and store these gasolines to make sure that they do not come into contact with water.

Sometimes ethanol is used as a motor vehicle fuel on its own, for example in Brazil. Its attraction is that it can be made from renewable biomass — providing an outlet for farmers — and the engine modifications required to use it are not extensive. However, it is not economic to produce compared to vehicle fuels derived from petroleum and substantial subsidies are required to make it competitive. Methanol may also be used directly as a vehicle fuel and its attraction is that it can be made from natural gas. It may also be worth noting that many vegetable oils make good diesel fuels, although they are difficult to keep stable in storage. Like ethanol they are not economic to produce at present.

2.6.7 Flexibility

In present day conditions with a wide range of crude oils, products and intermediate streams available on free markets and where prices fluctuate rapidly, refiners can often gain a competitive edge from greater flexibility. This flexibility manifests itself in the ability to change crude types at short notice, to take intermediate feedstocks when they are available, for example vacuum gasoil, to meet changing proportions of products (often called 'cut of the barrel') and to make new or modified products when the price is right and ship them quickly by the means the customer wants.

In the refinery, flexibility comes from a combination of three elements:

- Flexibility of the processing units,
- Flexibility of the off-plot facilities, such as tankage, blending facilities, road and rail loading, barge and shipping facilities,
- The flexibility of mind and organisation to use the facilities to their best advantage.

Processing flexibility

<u>Crude distilling</u>
Foremost among the valuable process flexibilities is the ability to process crude oils of different yields and types. For example, although there is a good supply of low sulphur North Sea crudes in north-west Europe, a refiner would usually be very unwise to omit the treating facilities necessary to process higher sulphur Middle East crudes because there will be times when his margin is better on Middle East crude.

The above is a very simple example and in practice the best margins are usually obtained by refining several different crude oils so as to use the better properties of each to offset their individual defects. For instance, most refineries could not make one per cent sulphur fuel oil from Middle East crude but they would not need 100 per cent expensive North Sea crude to do so and a combination of the two types of crude would be the most economic way of making such a fuel oil.

The distinction drawn between processing and off-plot flexibility is not entirely realistic. Refiners cannot take advantage of a combination of crude oils nor make rapid changes in crude diet without adequate receiving and storage facilities. To get the best quality advantage from different crude oils it is often necessary to keep them segregated from each other, which can only be done if enough tankage is available.

The optimum programming of a refinery is a complex matter but an idea, in very simple form, of the flexibility obtainable from different crude oils is given in the following table of product yields from a hydroskimming refinery:

Products (% weight yields)	**North Sea**	**Arab Light**	**Arab Heavy**
LPG	1.5	1.5	1.5
Motor gasoline	20.1	19.4	14.9
Jet A1	6.0	6.0	6.0
Diesel fuel	31.7	26.2	11.9
Fuel oil 1% S	37.2	-	-
Fuel oil 3.5% S	-	43.3	62.3
Fuel and loss	3.5	3.6	3.4

<u>Secondary processing</u>

An example has been given as to how treating can provide flexibility by allowing a refinery to process both high and low sulphur crude oils, but conversion units such as cat. cracking and particularly hydrocracking also add flexibility to the processing output. The change of yields by changing crude oil has been illustrated above, but yields on the same crude oil can be changed by changing refinery operating conditions, particularly cut points between the fractions.

Products (% weight yields)	**Hydroskimming**		**Complex**	
	Max gasoline	Max diesel	Max gasoline	Max diesel
LPG	1.5	1.5	1.5	1.5
Motor gasoline	21.0	17.8	38.0	30.2
Kerosine	6.0	6.0	6.0	6.0
Diesel	24.2	28.2	29.1	38.5
Fuel oil	43.6	43.0	19.1	17.7
Fuel and loss	3.7	3.5	6.3	6.1

The flexibility to produce different proportions of finished products by changing operating conditions is greater in a complex refinery than in a simple one. This is demonstrated in the table above which compares the (illustrative) per cent weight yield flexibilities for a simple refinery and a complex refinery, both running Arab Light crude oil.

Hydroskimming (simple), semi-complex and complex refineries have been described very briefly because these terms are often used in the industry. However, many refineries are not pure examples of any particular type. For example, many complex refineries, which have cat. cracking and visbreaking, have crude distilling capacity larger than needed to load these conversion units. Therefore, up to the point where their conversion units are loaded they have a complex yield but, if they refine more crude, the incremental yield will be a hydroskimming yield.

Furthermore, the crude intake will be set by the varying demands for products and by economics so that at times a complex refinery may wish to run less crude than is required to load its conversion units. All this means that the ability to import and export intermediate/feedstock streams can be an important flexibility to a refinery. The intermediates most commonly traded are naphtha for platforming or petrochemical feed, long (or atmospheric) residue for vacuum distillation and cracking and vacuum gasoil (or waxy distillate) for cracking.

<u>Off-plot flexibility</u>

The factors that make up off-plot flexibility are fairly obvious; e.g. good tankage and in-line blending, capacity in berth and loading facilities for ships and barges, road and rail loading, etc. There are two points to be made about such facilities. First, good facilities are expensive so that, if a refinery has them, it must use them to good effect. Second, their value as a competitive weapon tends to be relative to that of others in the area. An inland refinery, say in Eastern Europe, may have little flexibility because it has to receive crude down one pipeline and distributes its products mainly through other limited pipelines but, if the alternative product supply is a long and expensive truck delivery from a distant refinery, this lack of flexibility may not be so important.

<u>Organisational flexibility</u>

The third component of flexibility was listed as flexibility of mind and organisation. This is a subject which can hardly be tackled in a chapter on the physical characteristics of oil but it does concern traders intimately.

Two functions have to be fulfilled for any refinery to work; that of running it, i.e. operating the units, maintaining them, supplying the utilities etc.; and that of using the refinery, i.e. planning the crude intake, product programme, etc. The latter is often called the supply function. However the organisation is set up these functions are separate, even if performed by the same individual; the operating function must run the refinery as safely and efficiently as possible and the supply function must use it to the best economic advantage. The functions are often in apparent conflict, e.g. a very profitable trading opportunity with, say, low sulphur diesel may have to be weighed against the safety of continuing to run a desulphurization unit, which is in need of maintenance.

All that can be said here is that a common overall purpose, good understanding and close co-operation between these two functions can make a dramatic contribution to refinery profitability. The trader, whether in the same company or not, is part of the supply function because without active participation in trading it is very hard for 'supply' to have a realistic assessment of physical trading opportunities and the prices likely to be paid or received.

2.6.8 Economics

The task of the refinery is to make the products required from the crudes and feedstocks available at the lowest cost. Refining costs may vary widely between different refineries, but, to put them into perspective, a complex or conversion refinery would typically have costs as follows:

	$/tonne
Cash operating costs	12.0
Fuel cost	4.5
Depreciation	2.0
Total	18.5

There are usually about 7.4 barrels of crude per tonne so the above is equivalent to US $2.50 per barrel.

The above costs compare with crude oil costs of about $100 per tonne (fob)*, Rotterdam gasoline prices of, say, $150 per tonne and a retail gasoline price including taxes (in UK) of about $1,000 per tonne. Refinery costs are therefore a small proportion of final price.

* Fob stands for free on board, i.e. without freight cost. Cif stands for cost, insurance and freight, i.e. including freight and insurance.

However, as margins in the downstream are very slim, variations of refinery costs are significant for profitability.

Depreciation of $2.00 per tonne does little more than cover the cost of investment in minor items and replacements. Capital employed in such a refinery might easily be reckoned to be $500 million or more (the replacement cost would be very much higher) and a return on this capital of 15 per cent before tax would add a charge of $10 per tonne.

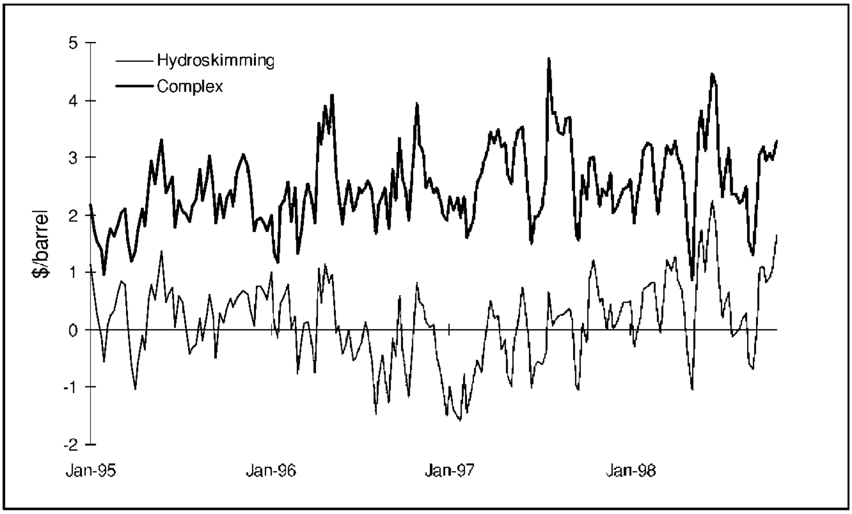
As a refinery's margin is an important measure of its performance it is worth giving two very simple examples, which can be worked out using the yields given above.

	Price ($/tonne)	**Hydroskimming Max gasoline Value** ($/tonne crude)	**Complex Max gasoline Value** ($/tonne crude)
Crude oil (cif)*	88		
Crude cost per tonne	88	88.0	88.0
LPG	124	1.9	1.9
Gasoline	136	28.6	51.7
Jet A1	130	7.8	7.8
Diesel	121	29.3	35.2
Fuel oil	60	26.2	11.5
Fuel and loss		0.0	0.0
Total product value		93.8	108.1
Gross refinery margin		5.8	20.1
Cash operating costs		6.0	12.0
Operating margin		–0.2	+8.1

The example above, which is based on prices from March 1998, illustrates the better margin obtained from a complex refinery. As can be seen from the graph of historical margins for North Sea Brent Blend in NW Europe shown in Fig 2.10, complex margins are generally rather higher than simple margins and the difference between simple and complex margins can be very large at times.

It is also worth noting that it is conventional to take the direct use of fuel as a yield loss rather than a separate cost and, therefore, the gross refinery margin (GRM) is the margin after subtracting the bulk of the fuel costs.

This convention can be a source of confusion because the refinery may use a significant quantity of natural gas as fuel or feedstock. If this is the case, the cost of the natural gas should be added to the crude cost to obtain the GRM. Also, electric power



Source: Petroleum Argus

Figure 2.10 Refinery margins, Brent Blend NW Europe

bought in is usually included in cash operating costs, if a refinery generates its own power, the cost will be largely in 'own use fuel' and the cost analyses of the two cases are not strictly comparable. One further note on GRM, it is calculated at the refinery fence and commonly on crude processed and products made during a period or for a certain quantity of crude (as was done above) using current prices. The actual margin in a period is the difference between the cost of crude bought and the proceeds of products sold and adjustments of stock and value will usually be needed to reconcile the two.

It should also be pointed out that 85 to 90 per cent of the cash operating costs are fixed costs, which combined with the high fixed capital costs, means that once a refinery or process unit is built it will be run, since any margin over the small variable cost (including fuel) will make some contribution to the fixed costs.

2.7 Environmental factors

The call for tougher environmental protection measures affects everyone. This trend gathered momentum in the 1980s and there can be no doubt at all that it is continuing strongly in the 1990s.

Environmental concerns affect refineries in two ways; indirectly through the products they are required to make and directly through controls on their own behaviour.

Many measures have already been implemented in both these classes; for instance legislation to reduce or remove the lead content of gasolines and limitations on the sulphur dioxide emissions of refineries. There are published plans for these controls to become more severe in future.

Each country determines what environmental protection measures will be imposed through its product specifications and on its refineries, although in the case of refineries and other industrial sites, local district authorities often impose their own conditions.

The EU Council attempts to exercise a co-ordinating role through Council Directives. Although these Directives are not necessarily fully implemented they do give an indication of the environmental control measures which can be expected. The European Commission (EC) also encourages and sponsors research programmes into technical and cost benefit aspects of environmental problems with a view to promoting new environmental control measures. One example is the joint oil and car industry programme, the European Programme on Emissions, Fuels and Engine Technologies (EPEFE), which is studying both engine design and fuel specifications and their interaction to find the best practical measures for vehicle emission pollution control, taking into account a wide range of possible options.

The following are likely to be subject to tighter controls:

Oil products

- **Gasolines**
  Complete removal of lead
  Lower benzene (presently 5 per cent max, down to 3 per cent or 1 per cent max) and, possibly, the control of aromatics
  Lower volatility
  Lower sulphur content

- **Diesel fuels**
  Lower sulphur; to 0.05 per cent weight in 1996, lower still in some areas

Lower final boiling point (smoke control)
Lower specific gravity
Higher cetane number

- **Fuel oils**
  Lower sulphur content, towards 1 per cent max.

Oil refineries

- Lower sulphur dioxide and nitrogen oxide emissions
- Lower particulate emissions
- Lower noise levels

As environmental measures are unevenly applied product specifications may be more severe in one country than another and refinery costs can also be higher. In Europe environmental legislation is probably toughest in Switzerland, Germany and Sweden.

CONCAWE is an oil industry body set up to advise both industry and governments on environmental measures. Its head-quarters are in The Hague and it can be a very useful source of information and advice.

To illustrate the complexity of environmental issues, it is worth dealing with two topical examples in more detail: reformulated gasolines in the United States and diesel fuel particulate emissions in Europe.

2.7.1 Reformulated gasolines

In the United States, the 1990 amendment to the Clean Air Act (CAA) covered a very wide range of measures to reduce environmental damage from oil refineries, utilities, other industries and motor vehicles. Its measures are interpreted, developed and enforced by the US Environmental Protection Agency (EPA). In the area of motor vehicle fuels, the 1990 amendment has two principal objectives:

- to reduce carbon monoxide (CO) levels in some 39 urban areas designated as "carbon monoxide non-attainment areas", where CO levels were higher than those considered acceptable, especially in the winter;

- to reduce the levels of ozone in nine areas particularly prone to ozone-induced smogs and designated as "extreme ozone non-attainment areas". (Ozone is not emitted directly from vehicle exhausts, but can be formed from some substances that are.)

To meet the first objective of reducing CO levels, gasolines sold in the relevant areas have to contain 2.7 per cent minimum weight of oxygen for a minimum period of four months in the winter. The oxygen is added to gasoline by blending in "oxygenates", for example MTBE (see Section 2.6.6). It has been shown that oxygenated gasolines produce exhaust gases with less CO than non-oxygenated gasolines. The oxygenated gasoline programme has been in operation since November 1992. Some of the original 39 CO non-attainment areas have now reduced CO to levels that take them out of this category, but oxygenated gasolines are — at present — still required.

To meet the second objective of reducing ozone levels, a much more complicated set of requirements was (and still is being) developed for gasolines. These are the "reformulated gasolines" or RFGs. Reformulated gasolines are required all the year round in 9 areas designated as "extreme ozone non-attainment areas". Areas with less severe ozone problems (designated as "severe" to "marginal") may opt to take part in the RFG programme and some have, although not as many as was originally expected. The concept of RFG began in California and this state tends to have the most severe restrictions. The first phase of the RFG programme covers 1995 to 1997 and the second stage from 1997 onwards.

The specifications for RFG are complex and some of the requirements, particularly in the second phase, are not absolutes but refer to EPA computer programs and to "Base Line" gasoline properties established for 1990. However, a minimum of 2 per cent weight oxygen is one requirement. The term RFG should only be applied to those more complex specifications needed to meet the second objective of reducing ozone formation, but it is sometimes used for oxygenated gasolines as well.

Reformulated gasolines, as developed in the United States, are unlikely to be used in Europe for two reasons. First, their introduction and application was possible because the EPA has nationwide authority — there is no equivalent agency in Europe. Secondly, there is considerable doubt as to whether RFGs are a cost-effective measure for exhaust pollution abatement. Most people believe that the measures required for a long term solution to vehicle exhaust emission pollution problems must include changes in vehicle design. Such design changes take years to become effective because of the slow turnover of the vehicle fleet and so short term action was necessary in the US for political reasons.

Also the car industry lobby in the US is more powerful than that of the oil industry.

The start of the RFG programme in the US has greatly reduced the export of gasoline from Europe to the US. Not only are the RFG specifications difficult to meet, but the documentation and detailed knowledge of the different specifications required are significant deterrents.

2.7.2 Diesel engine particulate emissions

In 1994/95 much attention was focused in Europe on diesel engine particulate (mainly solid carbon) emissions and their potential for causing — or exacerbating — respiratory problems. But so far there is no consensus on this difficult and complex subject.

First, there has been much discussion about which sizes of particle are the most damaging to health and it may be that the larger particles, which cause visible smoke from badly maintained diesel engines, are not the most dangerous.

Secondly, the mechanisms of particulate formation in diesel engines are not well understood. It is known that both engine design and fuel quality have an effect. In the case of fuel quality, high density, high final boiling point (FBP), high sulphur content and low cetane number tend to increase particulate emissions, but the relationships between these individual properties and particulate formation and the size distribution of particles are not accurately known.

The concern over particulates may well accelerate the tendency for EU countries to insist on lower density, FBP, sulphur and higher cetane numbers for diesel fuels. The maximum sulphur content for EU diesel fuel will be reduced to 0.05 per cent in 1996, but in some areas tax breaks are already given for diesels with a maximum sulphur content of 50 or even 10 parts per million (ppm) — the so-called "city diesels" — although the technical justification for such low sulphur contents seems rather weak.

The debate over particulates has tended to obscure the more positive aspects of diesel engine emissions compared with gasoline engines, for example, lower volatile organic compounds (VOC) and carbon monoxide (CO) emissions, and lower fuel consumption. If consumers are ultimately persuaded that diesel engines are less environmentally acceptable than gasoline engines — whatever the technical evidence — the shift away from gasolines to diesel fuels, already evident in most EU countries in recent years, may slow or even be reversed.

2.8 Measurement, sampling and testing

The measurement, sampling and testing of crude oil and products is a large subject and, as many aspects are integral to the contract between buyer and seller, traders will need a good knowledge of it. This section contains only a brief introduction.

2.8.1 Measurement

There are three methods of measuring quantities of oil in general use. Measurement of volume in tanks, either on shore or in ships, measurement of volume by flow meter and measurement of weight. This latter is used only for fairly small lots such as road and rail cars. Otherwise, weight has to be calculated from the volume, using the temperature and specific gravity.

Tank measurement

An essential for tank measurement is an accurate calibration of the volume in the tank in question against the height of liquid measured with a dip tape or automatic level gauge. These calibrations are usually made by independent surveyors and should be updated occasionally or when inaccuracy appears to be occurring since tanks can settle unevenly and suffer small shape changes.

A good assessment of the temperature of oil in the tank is needed since the volume will have to be converted to a standard temperature, usually 60°F. The specific gravity will also be needed, not only to convert volume to weight, but to use the temperature conversion tables issued by the IP or similar bodies, which it is standard practice to use. Therefore, the contents of the tank should be homogeneous and samples taken at several levels to demonstrate this.

Meter measurement

Properly installed and maintained turbine meters can give an accurate measurement of volume flow through a pipe. Their calibration has to be checked at regular intervals by means of a proving loop of known volume. Sampling and temperature measurement are usually rather simpler and more accurate and can be done automatically. This type of measurement is always used when blends are made direct into ships.

The error of volume measurement in loading a ship by either tank height or turbine meter is usually about ± 0.3 per cent. On the overall operation of loading followed by discharge at the destination the error is about ± 0.4 per cent. This excludes water measurement.

Weight measurement

Accurate weigh bridges can now be built more cheaply and are often used for road and rail car oil measurement, especially bitumen and other products which are sold by weight and are more difficult to measure by meter.

2.8.2 Sampling and testing

Tanks are traditionally sampled by lowering a sample bottle into the contents, pulling the plug at the desired level and withdrawing the bottle. This method only gives good results if the tank and its contents are homogeneous and the sampler is conscientious. Poor results are often found when testing for RVP because it is dependent on small quantities of volatile components which can be lost in the sampling and subsequent testing. Line samplers, which withdraw a continuous or intermittent sample from a loading or discharge line are usually more satisfactory.

The most difficult sampling and measuring problem is to get an accurate assessment of the water content of an oil, especially crude oil. The water is a separate phase and is not necessarily evenly distributed through the diameter of a pipe and can also travel in slugs. Line sampling is therefore not always accurate. The water usually settles well in shore tanks and the height of water can be detected by dipping with a measuring tape but the height differential of the water phase before and after receiving a cargo and settling may be small in a large tank and consequently difficult to measure accurately. For crude oil the settling may take time and not be even across the bottom of the tank.

For an average loading and unloading of crude oil the water measurement is assessed to add a further ± 0.1 per cent error but with some crudes can be much more.

Refinery laboratories usually provide a certificate of quality with the products supplied. This shows the results obtained on samples of the product certified against the full range of specification tests. Samples are also taken of shore and ship tanks when loading or discharge are taking place. Checks are made on these samples to ensure contamination is not occurring. Some samples are retained in case of later dispute. In many instances an inspector independent of both the buyer and seller is appointed to verify the quality and the quantity of any sale. Several well known companies offer this service.

For crude oils only API gravity and water content are commonly specified and tested.

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Appendix 2.1

Product properties

Refinery product	Characteristic properties
LPG	Vapour pressure Residue (pentanes and higher)
Gasoline	Octane number Vapour pressure Distillation Benzene content Lead content Oxygenate content
Naphtha	PONA Distillation No lead
Jet kerosine	Flash point Freezing point Aromatics Thermal stability
Diesel	Flash point Cold filter plugging point (CFPP) Cetane number Sulphur content
Gasoil/heating oil	Flash point Sulphur content Pour point
Fuel oil	Flash point Viscosity Density Sulphur content Conradsen carbon
Bitumen	Penetration R&B softening Ductility

Note: Appearance, specific gravity and water content are usually important to all products. Appearance is not important for fuel oils.

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Appendix 2.2

Crude oil distillation yields

Crude oil	Gravity	Sulphur	Gases	Gasoline/ Naphtha	Kerosine	Gasoil/ Diesel	Atmos. Residue
	°API	% wt	% wt	% wt	% wt	% wt	% wt
North Sea							
Brent Blend	37	0.3	1.8	20.3	12.3	24.6	41.0
Ekofisk	44	0.1	2.0	32.4	13.6	22.0	30.0
Flotta	36	1.2	2.1	20.1	11.7	21.9	44.4
Forties	37	0.3	2.8	19.5	11.7	24.0	42.0
Oseberg	34	0.3	1.5	17.8	12.6	26.1	42.0
Statfjord	38	0.2	1.6	23.2	12.5	25.7	37.0
Mediterranean							
Es Sider	37	0.4	1.2	19.8	9.3	27.7	42.0
Urals	33	1.4	1.7	17.6	12.3	21.4	47.0
Suez Blend	32	1.5	2.0	17.6	12.3	21.4	47.0
West Africa							
Bonny Light	37	0.1	2.0	21.2	13.1	29.7	34.0
Bonny Medium	25	0.2	0.5	7.0	10.7	34.8	47.0
Brass River	41	0.1	1.8	26.4	15.5	29.3	27.0
Forcados	29	0.2	0.6	12.9	12.3	37.2	37.0
Cabinda Blend	32	0.2	0.5	12.7	7.6	22.2	57.0
Arab Gulf							
Arab Light	34	1.8	1.1	18.0	12.3	23.6	45.0
Arab Heavy	28	2.9	1.8	14.1	9.6	21.5	53.0
Iran Light	34	1.4	1.6	18.5	12.6	23.3	44.0
Iran Heavy	31	1.7	1.4	17.5	10.8	20.3	50.0
Murban	40	0.8	0.5	24.7	15.8	25.0	34.0
Oman	34	1.0	1.0	15.4	12.0	23.1	48.5
Dubai	31	2.0	1.3	15.4	11.8	22.5	49.0
Far East							
Minas	35	0.1	0.5	10.8	8.4	22.3	58.0
Duri	21	0.2	0.1	4.4	6.2	13.3	76.0
Tapis	44	0.0	0.9	24.3	21.0	36.8	17.0
Daquing	32	0.1	0.5	8.3	6.3	16.9	68.0
Americas							
WTI	39	0.4	1.1	23.8	14.8	22.8	37.6
Bachequero	13	2.9	0.1	2.3	4.1	19.0	74.5

Notes: see over page

Notes

Distillation yields of crude oils are not precise data, so the above table should be used only for the purposes of comparison. The principal causes of variation are:

1. Date of sampling and treatment of the sample. The percentage of "gases" recorded is particularly subject to variation.

2. The cut points between fractions that are used. The percentage of atmospheric residue is particularly sensitive to the choice of cut point. The following approximate cuts points were used:

Gasoline/Naphtha	IBP to 165°C
Kerosine	165°C to 235°C
Gasoil/Diesel	235°C to 360°C
Atmospheric Residue	more than 360°C

Appendix 2.3

Crude oil assay

FLOTTA CRUDE

Production and Handling This crude is produced from the Piper, Claymore and Tartan fields in the British sector of the North Sea. Following the initial treatment of the oil on the respective offshore platforms, the crude oil is pumped ashore in a common sub-sea pipeline to the Flotta terminal in the Orkney Islands. At Flotta the oil is de-salted and stabilised prior to storage in floating roof tanks. The stabilised crude can be loaded to tankers either through lines to the jetty used for LPG shipments, as well or via the SPM (Single Point Mooring) buoys.

Type Medium sulphur. Moderate wax. Intermediate/Paraffinic.

GENERAL CHARACTERISTICS

CRUDE INSPECTION DATA

GRAVITY	API	35.6
SULPHUR	% WT	1.19
VISCOSITY AT 20C	CST	6.3
37.8C		4.1
ASH	% WT	0.004
SALT	MG/L	12
	LB/1000 BBL	4
WATER + SEDIMENT	% VOL	0.15
H_2S	% WT	NIL
POUR POINT	°C	+3
ACIDITY	mg koh/g	<0.05
ASPHALTENES	% WT	0.35

YIELDS

LIGHT DISTILLATE TO 165°C	% VOL	26.6
MIDDLE DISTILLATE 165-350°C	% VOL	31.9
RESIDUE ABOVE 350°C	% VOL	41.5

LOADING PORT DATA

(Current at the time of printing)
PORT — FLOTTA

	SPM	JETTY
LOA —	—	—
DRAUGHT — MAX	75 feet	63 feet
BREADTH —	—	—
DWT — MIN	35,000	4,000
— MAX	200,000	150,000
NOM LOAD RATE — MAX	80,000 BPH	80,000 BPH
OTHER —	Special regulations also apply	

REFINING CHARACTERISTICS

GENERAL This crude presents no problems in refining and gives a full range of specification products. The sulphur content at over 1.0% is higher than the general level of crudes from UKCS fields and requires hydrodesulphurisation of middle distillates to meet currently accepted standards.
Flotta crude resembles in many respects Iranian Light and features include:
Average yield of medium quality middle distillates.
Good reforming characteristics of naphtha fraction.
High yield of VGO cracking feedstock.
Residual yield of intermediate sulphur content.

LIGHT NAPHTHA Mercaptan content is nil requiring no sweetening.

NAPHTHAS Not readily suitable for Ethylene cracking due to low paraffin content. Hydrorefined product gives good performance in catalytic reformers.

ATK/KEROSINES	Mild sweetening or hydrotreating recommended for regular grades with aromatics content and smoke point both near borderline for specifications.
DIESEL/GASOILS	Products of medium cetane index meeting both winter and summer quality are yielded after desulphurisation to reduce sulphur from 0.6-0.8% weight.
RESIDUAL FUELS	With 2.2% sulphur in the 350C+ residue, blending into fuel oil pools is suggested especially with the reported pour points. Low metals concentrations are indicated. The 550C+ residue is extremely short with acceptable metals and sulphur but very high pour point.
CRACKING STOCKS	Full evaluation for cracking potential has not been carried out. However, a wide cut of catalytic cracker feedstock is indicated with moderate metals content and asphaltenes.
LUBE OILS	No evaluation work carried out and not considered warranting any development at this stage.
BITUMENS	Not considered suitable for Bitumen production due to high pour point of vacuum residue although asphaltene content is relatively high.
PETROCHEMICALS	The heavy naphtha has good potential for catalytic reformer feedstock for the production of BTX aromatics. Not readily suitable for cracking to produce ethylene and other higher order alkenes due to low paraffin content.

DISTILLATE DATA

		DISTILLATES					
TBP CUT POINT °C		C5-85	85-165	165-235	235-300	300-350	350-550
YIELD ON CRUDE	%WT	6.53	13.6	11.7	10.4	9.3	36.2
	%VOL	8.17	15.3	12.4	10.4	9.1	33.2
DENSITY AT 15C	KG/LITRE	.6694	.7547	.800	.8452	.8652	.9207
SULPHUR	%WT	<.01	0.10	0.14	0.58	1010	1.86
MERCAPTAN SULPHUR	%WT	NIL	NIL	0.0006	—	—	—
VISCOSITY AT 37.8 C	CST	—	—	—	2.59	8.38	—
50 C		—	—	—	—	—	32.4
CLOUD POINT	C	—	—	—	–22	4	—
POUR POINT	C	—	—	—	–21	3	—
CFP POINT	C	—	—	—	–25	–5	—
COPPER STRIP TEST		—	—	—	2C	2C	—
UOP K FACTOR		—	—	—	—	—	11.7
AROMATICS	%WT	—	—	22	—	—	—
SMOKE POINT	MM	—	—	21	—	—	—
FREEZING POINT	C	—	—	–50	—	—	—
ANILINE POINT	C	—	—	55.1	60	69.6	—
CETANE INDEX		—	—	—	47	53	—
CARBON RESIDUE		—	—	—	—	—	—
CONRADSON	%WT	—	—	—	0.008	0.042	—
RON (CLEAR)		73	—	—	—	—	—
RON (0.5g Pb/1Ltr)		88	—	—	—	—	—
MON (CLEAR)		69.7	—	—	—	—	—
MON (0.5g Pb/1Ltr)		82.5	—	—	—	—	—
PARAFFINS	%WT	69.3	51.9	—	—	—	—
NAPHTHENES	%WT	18.7	32.1	—	—	—	—
AROMATICS	%WT	12.0	16.0	—	—	—	0.31
VANADIUM	PPM WT	—	—	—	—	—	0.14
NICKEL	PPM WT	—	—	—	—	—	—

RESIDUE DATA

TBP CUT POINT °C		TOTAL CRUDE	RESIDUES 350	550
YIELD ON CRUDE	%WT	—	46.4	10.2
	%VOL	—	41.5	8.3
DENSITY AT 15C	KG/LITRE	.8462	.9450	1.040
SULPHUR	%WT	1.19	2.2	3.03
VISCOSITY AT 20C	CST	6.34	—	—
37.8C		4.06	—	—
82.2C		—	32.04	2370
98.9C		—	18.7	844
POUR POINT	C	3	33	51
ACIDITY	mg KOH/G	<0.05	<0.10	<0.10
ASH	%WT	0.004	—	—
CARBON RESIDUE CONRADSON	%WT	—	5.5	16.3
ASPHALTENES	%WT	0.35	0.98	5.37
VANADIUM	PPM WT	8.1	16	60
NICKEL	PPM WT	2.7	5.7	23
IRON	PPM WT	1.1	2.6	3.7

LIGHT HYDROCARBONS ANALYSIS

METHANE	% WT	NIL
ETHANE	% WT	0.01
PROPANE	% WT	0.50
ISO-BUTANE	% WT	0.24
N-BUTANE	% WT	1.32
TOTAL C1-C4	% WT	2.07
ISO-PENTANE	% WT	0.86
N-PENTANE	% WT	1.62

TBP DATA

TBP DATA TO 550C

ASTM 2892 to 370C ASTM D1160 370 to 550C

CUT POINT	C	16	27	58	66.5	70	85	95.5
TOTAL DISTILLATE	%WT	1.8	3.2	5.9	6.5	7.0	8.6	10.3
	%VOL	2.7	4.7	6.7	8.7	9.4	11.3	13.3
CUT POINT	C	104	118	128	139	149	165	175
TOTAL DISTILLATE	%WT	12.1	14.0	15.8	17.7	19.5	22.2	24.0
	%VOL	15.4	17.6	19.6	21.6	23.6	26.6	28.6
CUT POINT	C	187	198	210	222	235	249	262
TOTAL DISTILLATE	%WT	25.9	27.8	29.7	31.6	33.9	35.9	37.9
	%VOL	30.6	32.6	34.6	36.6	39.0	41.0	43.0
CUT POINT	C	274	286	300	309	320	330	342
TOTAL DISTILLATE	%WT	39.9	41.9	44.3	46.3	48.3	50.1	52.1
	%VOL	45.0	47.0	49.4	51.4	53.4	55.1	57.1
CUT POINT	C	350	360	370	394	417	440	462
TOTAL DISTILLATE	%WT	53.6	55.6	57.4	—	—	—	—
	%VOL	58.5	60.4	62.2	66.0	69.8	73.5	77.3
CUT POINT	C	486	510	532	550			
TOTAL DISTILLATE	%WT	—	—	—	89.8			
	%VOL	81.1	84.9	88.7	91.7			

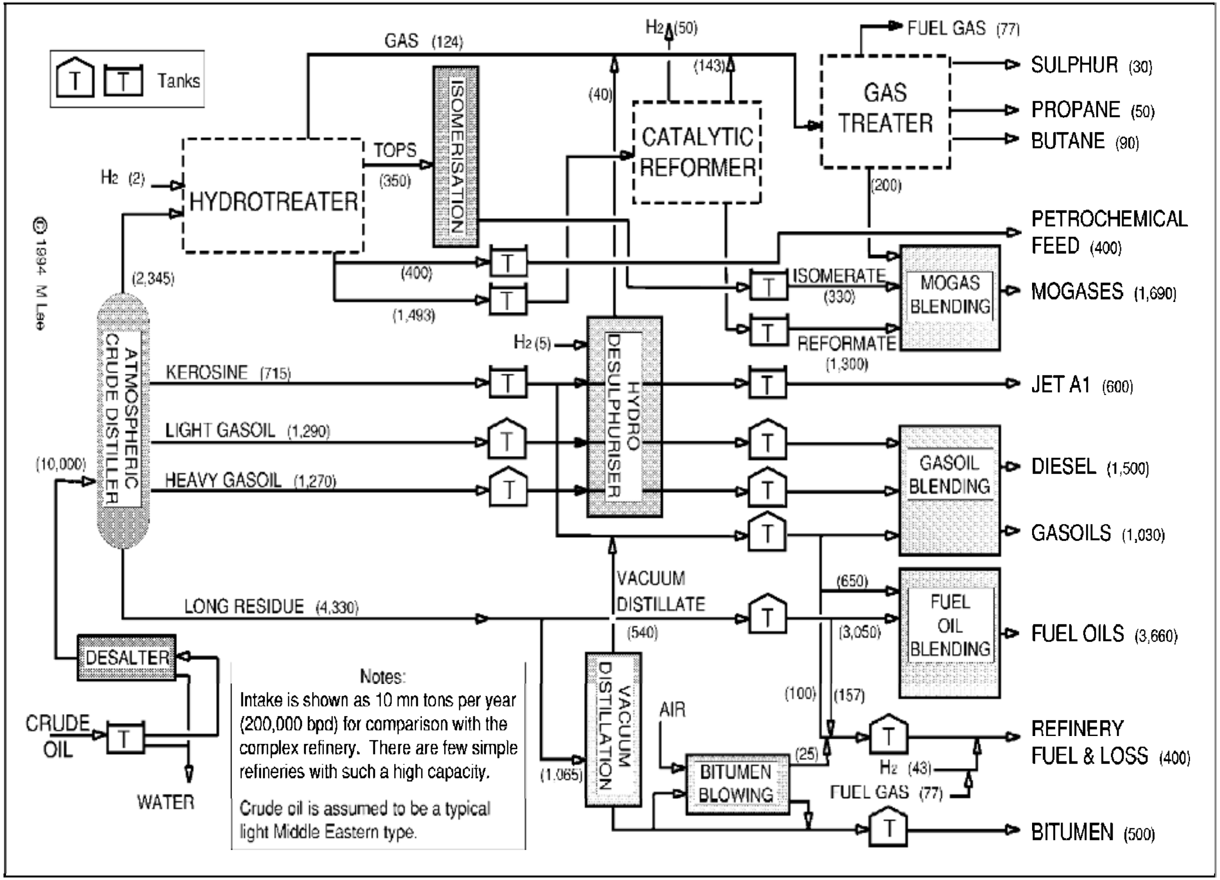
COMMENTS/ADDITIONAL INFORMATION

Notes

There is no standard form for a crude oil assay. They may vary from a quarter of a page to a booklet. Shorter summary assays as published, for example, by the *Oil & Gas Journal*, are probably the most frequently used.

Appendix 2.4

Simple refinery flow diagram



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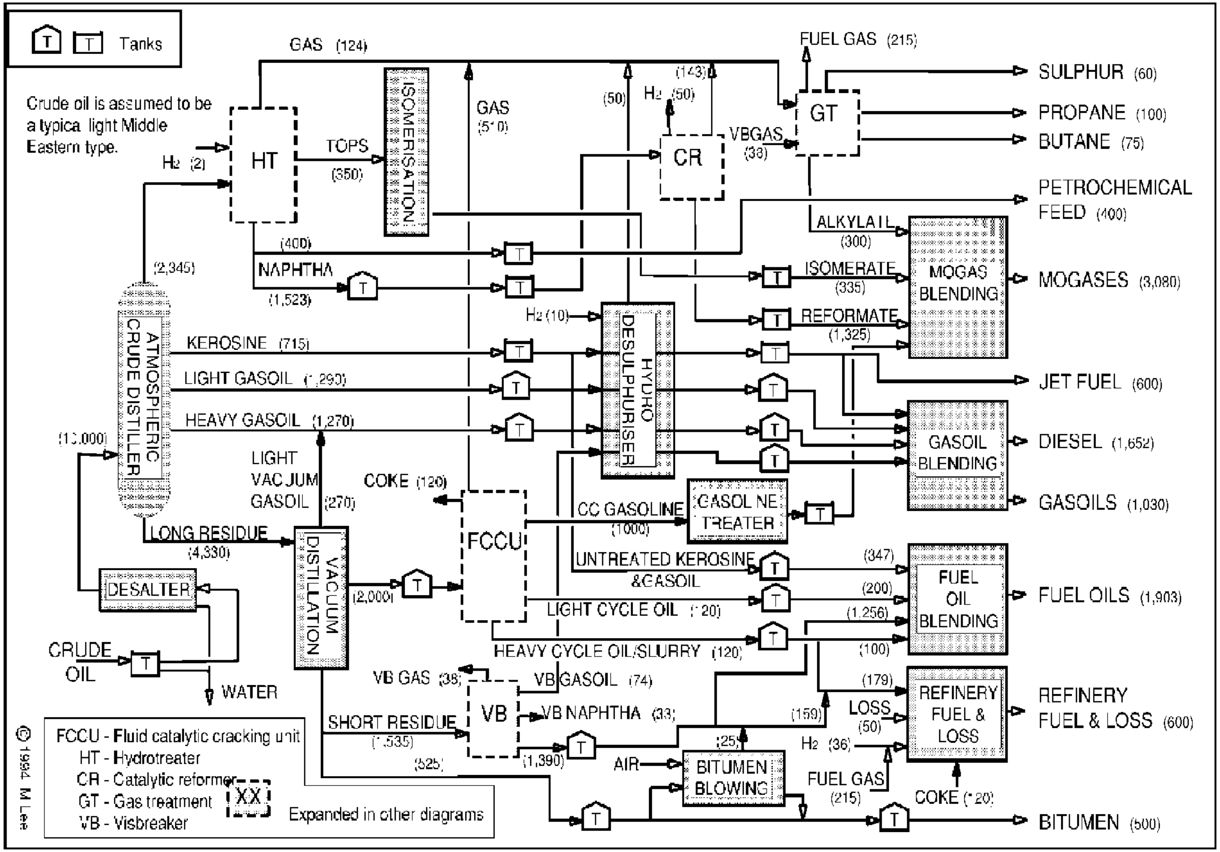
Appendix 2.5

Complex refinery flow diagram



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Appendix 2.6

Further reading

The Petroleum Handbook
Shell, 6th Edition, 1983, Elsevier

A straightforward, technically oriented, description of all phases of the oil industry. Clear, comprehensive and with good diagrams and illustrations.

Our Industry Petroleum
British Petroleum, 5th Edition, 1977, BP

Similar to Shell's *Petroleum Handbook*, but older and more company oriented.

Petroleum Refining for the Non-technical Person
Leffler, William L., 2nd Edition, 1985, PennWell Books

A description of hydrocarbon chemistry and oil refining processes. Clear, technical with little of economics.

Petroleum Refinery Process Economics
Maples, Robert E., 1993, PennWell Books

Good descriptions and flow diagrams of refinery processes, together with much product yield and cost data.

Modern Petroleum
Berger, Bill D. and Kenneth Anderson, 3rd Edition, 1992, PennWell Books

Technical description of the whole industry aimed at the non-technical person. Useful chapters on storage, measurement and refining.

Modern Petroleum Technology
Hodson, G.D. (ed), 1984, 2 volumes, Institute of Petroleum

Full technical description of refining processes and product properties (and other industry topics).

The Chemistry and Technology of Petroleum
Speight, James G. (Exxon), 1980, 2 volumes, Marcel Dekker

Comprehensive description of oil and gas processing.

The Illustrated Dictionary, Petroleum Reference
Langekamp, Robert D., 2nd edition 1982, PennWell Books

A good example of the many books of oil industry terms and jargon. This one includes abbreviations and conversion factors.

Paul Frankel: Common Carrier of Common Sense
Skeet, Ian (ed), 1989, Oxford University Press

A good selection of Paul Frankel's writings on the more fundamental, long-term aspects of oil supply and demand.

Oil and Gas Dictionary
Stevens, Paul, 1988, Richard Clay

Another good dictionary of terms.

Standard Methods for Analysis and Testing of Petroleum and Related Products
Institute of Petroleum, 1994, 2 volumes, John Wiley & Sons

Lays down, in full detail, IP test methods.

ASTM Standards, Section 5
American Society for Testing Methods, updated annually

Covers ASTM test methods. Complete description as above.

Oil & Gas Journal Data Book
Oil & Gas Journal, published annually, PennWell Books

Lists of oil companies, oil fields and refineries with brief details.

IP Petroleum Measurement Manual
Institute of Petroleum, about 20 separate volumes

Authoritative methods for measurement.

Manual of Petroleum Measurement Standards
API, American Petroleum Institute

Especially chapters 1-17. Similar to the IP Manual.

3 Oil pricing arrangements

Catherine Hamer

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3.1 Types of pricing mechanism

An essential requirement for successful oil trading is that buyer and seller can reach an agreement on price — or at least an agreed mechanism for determining price. However, this is not as simple as agreeing to sell at a fixed price x. Many variables, not least of all the currency and the unit of measurement (volume or weight), must be agreed before a contract can be signed.

The basis on which oil is priced has changed markedly over the past 20 years with the development of new techniques for oil trading. In the past, the majority of internationally traded oil was sold on a term basis at a fixed price. Term contracts were typically agreed for a period of a year or more and prices and volumes were reviewed periodically. This worked fine while prices remained reasonably static. But as political developments and supply disruptions made prices more volatile, sellers and buyers both recognised that a fixed price could be way out of line with the market price at the time the oil was moved. As a result, the market developed more flexible, or 'floating' pricing mechanisms.

Floating prices were usually linked to a published quotation, or the average of a set of published quotations, around the time the vessel loaded or discharged. Term supplies could still be agreed for an extended period of time, but the price of each cargo lifted under the term commitment would vary depending on the market prices at the time of loading or discharge.

Thus a seller would no longer find that his fixed price, perhaps agreed 10 months ago, was considerably lower than he could get for the oil at the time of delivery. Under a fixed price regime, he might have been tempted to renege on his original, but now loss making, deal. Conversely, a buyer would not find that he could buy oil on the spot market considerably cheaper at the time of delivery than the fixed price he had agreed several months previously.

As the market moved away from term supplies, more oil became available on a spot basis. Although negotiations centred on a single cargo rather than several loading over a period of time, the loading date might still be some time in the future. Meanwhile, market prices could still move dramatically. As a result, buyers and sellers turned increasingly to floating price formulae.

In the last fifteen years, the introduction of forward (paper) markets, futures, options and swaps has meant that floating prices have become the primary mechanism by which oil is priced. However, the floating price mechanisms have become increasingly sophisticated and complex, especially in the forward or paper markets, and pricing mechanisms have become increasingly separated from the actual physical cargo of oil. Indeed, one popular way of pricing oil is to use EFPs, the 'exchange of futures for physicals', or its swaps market equivalent, an EFS (see Chapter 8). Using these pricing mechanisms, the price to the buyer and seller can be different since each party can place or lift its associated futures position at a different time.

As 'paper' trading has developed and the liquidity of the markets grown, oil has increasingly been treated as a standardised commodity, which means that discussions between parties need only focus on price — or the pricing mechanism — and timing. At the same time, the development of pricing services has greatly increased the transparency of the markets. In some respects, this has made it easier to gauge the market price for a standard oil 'commodity'. However, much of the oil traded is not of standardised lots, but varies in quality, quantity, location, timing, etc. Such cargoes must be accurately valued relative to the standardised grades quoted by the pricing services, before floating formulae based on published price quotes can be used effectively.

Despite this trend towards floating prices, there is still a market for fixed prices amongst those end users, be they refiners or consumers, who need to know what their feedstock costs will be over a period. For example, a refiner may have sold petroleum products forward at a given price and wants to lock in a refining margin by buying his crude at a fixed price. Or a heating oil distributor might want to know at what level to set his heating oil prices to his customers over the next year. Because he obviously does not want to run the risk of buying at a higher price than he can sell at, he may ask his supplier to sell the heating oil to him at a fixed price, either on a term basis or as a spot cargo. In this way he can fix his costs, and guarantee his customers that their bills will not increase over, say, the next 12 months.

The requirement to fix future fuel costs has led to the emergence of a 'swaps' market. This adds further pricing flexibility because it offers a buyer of physical oil the possibility of continuing to take the oil from his supplier at a floating price, and yet insure himself against later adverse price movements. He may, for instance, have a long-standing relationship with a reliable supplier like a major oil company. Asking this kind of supplier for a fixed pricing mechanism might jeopardise the relationship by confusing the supplier, accustomed to the more established floating price basis. (There are notable exceptions amongst some of the major oil companies.) The oil buyer may choose to offload his price risk onto a third party who will provide, or swap, a fixed price against the floating price agreement. Typically, the third party does not make any delivery of oil, but provides an insurance against risk, by fixing the price. The third party will, in turn, often hedge his risk in the futures or options markets. It should be noted that the buyer is not only protected against adverse price movements but is also unable to take advantage of profitable price movements. If the buyer wants to fix a maximum purchase price, but still be able to take advantage of lower prices, an alternative strategy would be to purchase a call option (see Chapter 9).

Thus the pricing of oil would appear to have gone full circle. The difference now is that fixed pricing, although undergoing a small specialised resurgence in interest, is only one of many pricing mechanisms available to a sophisticated oil trader. Whilst some oil is sold at a fixed price per unit volume or weight, increasingly the price is calculated from a formula based on published or futures prices. Although a pricing arrangement may not always be based on published prices, the organisations involved in producing daily, or even hourly, price reports continue to wield what some people see as too much power, or at least a level of power out of proportion to their expertise and knowledge.

The growth of activity on the regulated and highly visible futures exchanges has gone some way towards diluting the power wielded by the pricing services. However, exchange-traded futures and options contracts are only available for a very limited range of crudes and refined products and these can never replace the much wider set of information provided by the pricing services.

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3.2 Fixed prices

3.2.1 Outright prices

A contract for the sale of a cargo of oil must specify, as well as the basic price, the guaranteed quality and agreed price adjustment for quality deviations, availability date range, where it is available, whether it includes freight and insurance and, where relevant, the question of duty (see Chapter 16). While there are other factors which can affect the actual cost of the oil, such as credit terms, the above factors will adequately describe what generally makes up the price of a cargo of oil. Many of these factors apply whether the price agreed is fixed or based on a formula, and this must be borne in mind when considering the following pricing mechanisms.

Quality

A seller may agree to sell an amount of oil of a particular guaranteed quality at a fixed price to a buyer, say gasoil at $170 per metric tonne. However, this may not be the final price paid for the oil. Many prices include an escalator/de-escalator clause, providing for price changes in case the quality of oil loaded deviates from that contracted for.

For example, gasoil in Europe is generally sold at x dollars per metric tonne, based on a specific gravity of 0.845. If the final gravity is 0.850 then the price will be reduced in proportion to the increase in gravity, i.e. the heavier the material the less valuable the product. The actual gravity will still need to be within the specification range acceptable for a product of marketable quality, otherwise the cargo will be considered outside the agreed specification, and the contract might be considered invalid.

The escalator/de-escalator may not only be based on gravity but could be based on actual sulphur level, cold properties (pour point, cloud point), octane, viscosity*, etc. In fact, anything can be used as an escalator/de-escalator, even the date of loading or discharge. A buyer and seller may agree that for each day's delay after an agreed date range, the price may be reduced by a given amount.

The important qualities for crude oil are generally gravity, measured in API degrees, metals content and sulphur. Any or all of

* For example, Russian straight-run fuel oil (E4), see Section 5.2.

these factors may be used to alter the final price paid for the crude oil should the quality vary from the contractual grade. An example of this might be Russian crude oil, Urals, which due to political and technical problems can vary on sulphur and metals. A prudent buyer might insist on an escalator/de-escalator clause in his contract. Even so, the oil should not vary so much as to make it unsuitable for the purpose for which it is intended. Clear limitations for critical specifications should still be set to ensure it is of marketable quality.

Currency

Crude is generally traded internationally in US dollars per barrel — 42 US gallons — although there is no reason why another currency should not be used if both parties agree. Indeed, in barter arrangements the oil may be paid for in tractors, livestock or any other commodity. In Europe, oil products that are being traded internationally are generally sold in US dollars per metric tonne. In the US, cents per gallon are used for clean products (gasoline, jet, naphtha, gasoil) and dollars per barrel are used for dirty products (fuel oils). In the Far East, US dollars per barrel are used, except for fuel oils and naphtha which are quoted in US dollars per metric tonne.

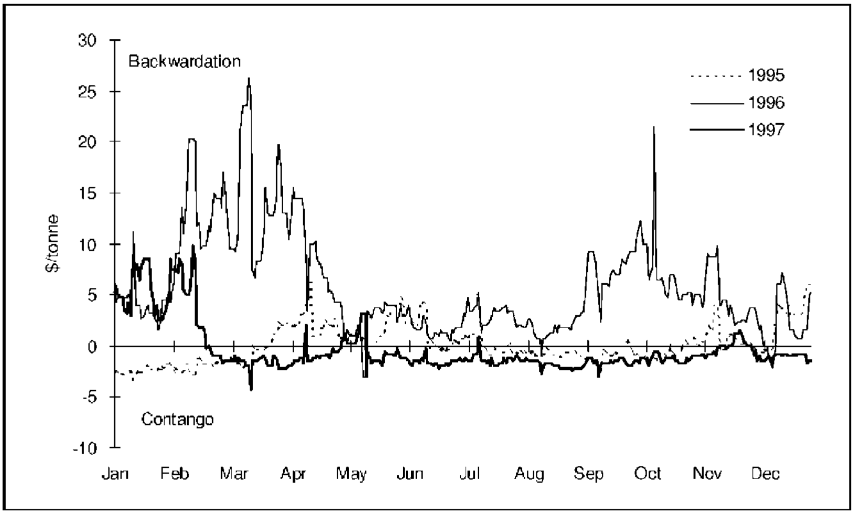
Inland domestic markets generally price the oil in local currency and units. For example, the UK prices gasoil in pence per litre whereas France uses French francs per litre.

However, none of the prices is valid unless accompanied by the specifications applicable to the quality of oil being priced. Therefore, to say that the price of crude oil is $18/barrel is meaningless unless one says that the crude oil referred to is, for instance, Brent, West Texas Intermediate (WTI) or Dubai.

Timing

The timing of the oil's availability is often critical. Crude may be required at a refinery by a particular date otherwise stocks — which are always kept close to an operational minimum in order to reduce costs — may drop too low, causing throughputs to be cutback or the refinery to be shut down. Conversely, products may have to be lifted from the refinery by a specified date otherwise storage tanks will be full, forcing the refinery to cut runs.

At certain times of the year, timing can also have a significant impact on pricing because the market is either in backwardation or contango. Backwardation is when the price of a commodity available on a prompt basis is higher than that for deferred



Source: IPE

Figure 3.1 IPE gasoil, nearby minus first delivery month

delivery. This situation often occurs with gasoline on the US futures market, the Nymex (New York Mercantile Exchange), during the summer months. Since the driving season in the northern hemisphere is considered to end in September, demand for gasoline, and thus the price, tails off towards the end of the year.

Example: Oil futures markets in backwardation, 14 May 1997

Delivery month	Nymex WTI crude $/barrel	Nymex gasoline cents/US gallon
June '97	21.39	64.38
July '97	21.29	63.36
August '97	21.16	62.36
September '97	21.04	61.26

Contango is when the commodity is cheapest in the prompt position and gets progressively more expensive in the future. This typically occurs for gasoil with the approach of summer, since demand for gasoil is heaviest in the heating season (see Fig. 3.1). Thus when gasoline is in backwardation, gasoil may be in contango, and vice versa. Therefore, when setting the price of oil, specifications should include not only its quality but also its delivery date range — e.g. whether it is prompt or deferred.

Market pressures have prompted some producers to offer late or early pricing in order to attract buyers. Nigeria, for example, offers flexible date ranges during which buyers can price their purchases (see Chapter 4). Instead of pricing a cargo five days after the date of the bill of lading (b/l), the buyer can either price it over a five day period starting 14 days after b/l or the five days preceding b/l. Other producers allow buyers to use the average of the month preceding or following b/l. These flexible date ranges allow purchasers to take advantage of a contango or backwardation in the crude oil market and to manage their price exposure more efficiently.

Example: Oil futures markets in contango, 10 July 1997

Delivery month	**IPE gasoil $/metric tonne**	**Nymex heating oil cents/US gallon**
August '97	161.75	52.11
September '97	164.00	52.79
October '97	166.25	53.59
November '97	168.25	54.49

Location

Another factor affecting price is the location of the oil. With crude this is generally fob (free on board) at the export terminal connected to the oil field. However, some crude oils are moved to the end of a pipeline to make them more easily accessible and if so, this must be specified when the price is agreed because it will affect the buyer's freight costs and therefore the value of this crude to him. For example, Iranian crude oil is either available fob Kharg Island in the Mideast Gulf, or fob Sidi Kerir at the Mediterranean end of the Sumed pipeline in Egypt (see Chapter 4).

On the other hand, similar quality products could be available all over the world produced by a number of different refineries. Whilst many are sold fob at the refinery, many more may be sold cif (including carriage, insurance and freight) at any one of hundreds of ports, pipelines or terminals. Thus the price of a cargo of Russian gasoil fob the Baltic, will be different from the price of the same cargo of gasoil cif Rotterdam.

Taxes and duties

Some markets require duty to be paid on oil when imported into the country. In the US, refined product prices are generally quoted 'inside duty', i.e. duty is included in the price quoted. The amount can be quite large, amounting to as much as 5 per cent of the total price. Hence, prices pertaining to these markets must specify whether or not the price includes duty.

Credit terms

Other, less transparent, factors may govern whether one deal on offer is more attractive than another. In a highly competitive buyers' market, such as at the beginning of 1998, these non-price factors become particularly important. For example, varying the credit terms to give the buyer extended credit provides a useful incentive to prospective purchasers as well as disguising the true cost of the oil when it is reported to senior management or government agencies.

3.2.2 Official selling prices

Until the mid-1980s most internationally traded crude oil, except that of US origin, sold on term contracts and was priced at an official selling price. This price was set, originally annually, by the Government, Government agency or National Oil Company of each producing country. The official selling prices (OSPs) generally reflected the market value of these crudes at the time the OSPs were set, but were only changed infrequently.

After the Iranian revolution, when spot prices rose to $40/barrel and above, producers were reluctant to fulfil their supply obligations at the lower OSP, and many reneged on their contracts to take advantage of higher spot prices. Once the oil market weakened in the early 1980s and prices started falling, the spot prices were frequently below term prices. As prices declined, it became the buyers' turn to try wriggling out of long term fixed price contracts.

Recognising that a yearly review was inadequate, and responding to buyers' requests, some countries, such as Mexico, Egypt and the former USSR, started setting their OSPs monthly thus moving towards spot pricing. In addition, North Sea producers who had to pay Petroleum Revenue Tax on the actual revenue received, started selling at OSP when the spot price was above, and at spot prices when these were below OSP. In this way, an increasing amount of oil reached the spot market to be sold at market prices, fluctuating around OSP.

Now few producers sell their crude at a fixed OSP. Whilst many will still quote an official price for their crude, the price a refiner actually pays for this crude is generally set at a premium or a discount to the OSP, the difference being achieved through negotiations and dependent on destination, either on a term basis, or for each cargo lifted.

Official selling prices exist now in a variety of forms and although mainly used by the Opec producers, are also used by some non-Opec producers such as Egypt, Oman, and Malaysia (see Appendix 4.1). Most OSPs are now based on a fixed differential to a floating price. Saudi Arabia, for example, announces the next month's price formula at the beginning of the preceding month. The formula varies depending on the destination, and may also vary with market conditions and wider political developments. Prices may, for instance, be lowered in an attempt to buy a larger share of a given geographical market or in order to send a political signal to other Opec members who may have started cheating on agreed production quotas.

Saudi crude which is to be moved into the Far East may be priced against 'the mean of the means' of quotes over a period of time for Oman crude and Dubai crude. On the other hand, Oman and Qatar set their prices retroactively, normally against Dubai quotations and possibly dated Brent. At the beginning of one month, they will announce at what level they will price all crude lifted under contract for the preceding month. Some crudes are restricted on destination in that the pricing formula only applies if the crude is moved into a specific region. In addition, many producers do not allow their crudes to be on-sold to traders, but insist that they be refined by the buyer.

OSPs may be used for certain oil products, but their importance fluctuates a great deal with the market. If the market is short of that particular quality of oil then the seller may hold out for higher prices.

3.2.3 Posted prices

Posted prices are peculiar to the US market (see Chapter 4). By law, every refinery is required to post at the refinery gate the price at which they will buy crude oil. These prices fluctuate from day to day, depending on the market, and between refiners who will place a different value on each crude depending on their circumstances.

These posted prices can be used by two parties to agree a price for a deal of crude oil. For example, a seller may have a cargo of crude which he wants to sell at an average of all the posted prices plus a quality differential. The buyer prefers to exclude the posted price of two refiners who he thinks are not representative of the market, and so the price is agreed based on a more limited number of posted prices.

3.2.4 Wholesale or rack prices

The price at which a road tanker, for example, can purchase fuel when loading from a refinery or depot, is known as the wholesale price in Europe. In the US, the road tanker will drive to a 'rack' and thus the wholesale price is referred to as the rack price.

Wholesale or rack prices are quoted, in local currency, by many pricing organisations, although coverage is particularly good in the US. The price is specific not only to the quality of oil concerned, but also to the location, and therefore one country may have many different wholesale prices for a particular quality of oil.

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3.3 Floating prices

As oil prices became more volatile, buying or selling oil at fixed prices became more problematic as there was increasing uncertainty about the value of the oil at the time it was to be loaded or discharged. A producer, selling a cargo of crude at $25/barrel on one day, might find that by the time the cargo of oil was actually lifted, the value of that oil could have gone up by $2/barrel. This dissuaded them from selling oil at a fixed price too soon before loading. However, the buyer and seller did not want to leave their positions open until the last minute for fear of being seen in a distressed position, and therefore forced to accept prices away from the normal market.

They therefore looked for a way of concluding a deal well before the cargo moved, but using a pricing basis which would reflect the market at the time the cargo actually moved. As the oil market moved away from fixed prices, and looked towards market related prices so a pricing formula based on published prices developed. This meant that the price actually paid could more closely reflect the market value of the oil at the time of moving the oil, rather than the value on the day it was sold.

More recently, the growth of the forward, futures, swaps and options markets has encouraged buyers and sellers to be more innovative with their pricing mechanisms. For example, refiners often prefer to price their crude purchases over the same time period as they are selling their products, thus obtaining a natural hedge to lock in a refining margin. The crude itself may be priced at a differential to dated Brent, so the seller can hedge the additional price exposure by using a combination of futures (IPE Brent) and swaps (Brent CFDs).

Pricing formulae are now so numerous as both buyers and sellers try to protect themselves against undue price fluctuations after concluding deals, that it would be impossible to even mention all the variations. However, some examples are included later in this chapter.

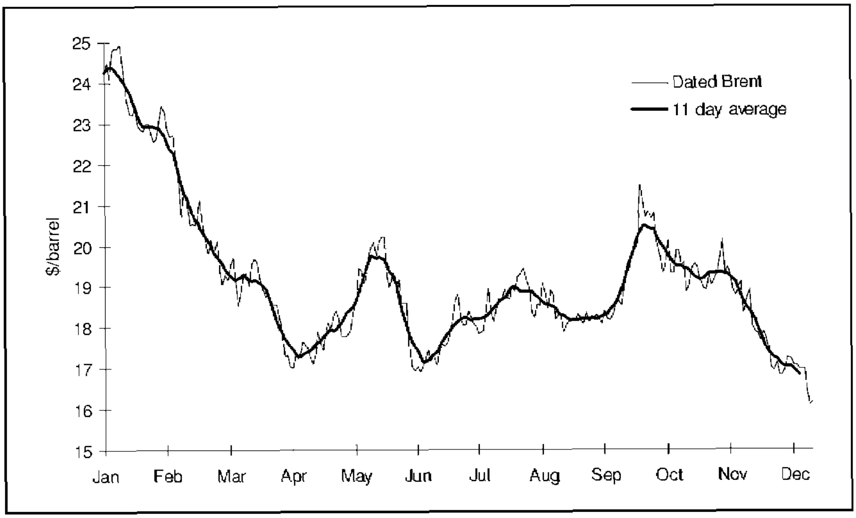
3.3.1 Fixed differential to published prices

The first publication to quote international oil prices regularly was *Platt's* which started in the 1930s, and thus it was *Platt's* published prices which were first used for pricing. However, the emergence of the spot market for oil in the 1980s prompted several new organisations to start up oil price reports.

Even so, *Platt's* continues to dominate the international oil market when it comes to pricing formulae based on published prices. There are some notable exceptions, e.g. *London Oil Reports* has been used for some feedstock prices, and *Petroleum Argus* has been used by the former Soviet Union to price their fuel oil. In addition, some crudes are sold by producing nations based on a 50:50 split of *Platt's* and *Argus* or *LOR* quotations, and *Reuters* and *Bridge Telerate* prices have also been used. In general, though, the market seems reluctant to break *Platt's* stranglehold on the oil market with respect to pricing, a role which *Platt's* claims to accept reluctantly.

Thus *Platt's* retains the ability to set oil market prices rather than just report them. *Platt's* dominance of market prices has been weakened by the success of futures markets for oil in New York and London. But other markets which do not yet have formal futures markets, such as jet and fuel oil, can be influenced by the *Platt's* prices quoted each evening which are also used as a basis for the thriving swaps markets in these products (see Chapter 10). Many deals are done at a differential to *Platt's* or other published prices. A transaction may, for instance, be concluded based on the mean of the means of *Platt's* and *Argus* high and low quotations for high sulphur fuel oil cif NWE as quoted on the bill of lading date, plus a premium of $1 per metric tonne.

The above example only uses the published prices on one day, that of the bill of lading date. By using the prices published on only

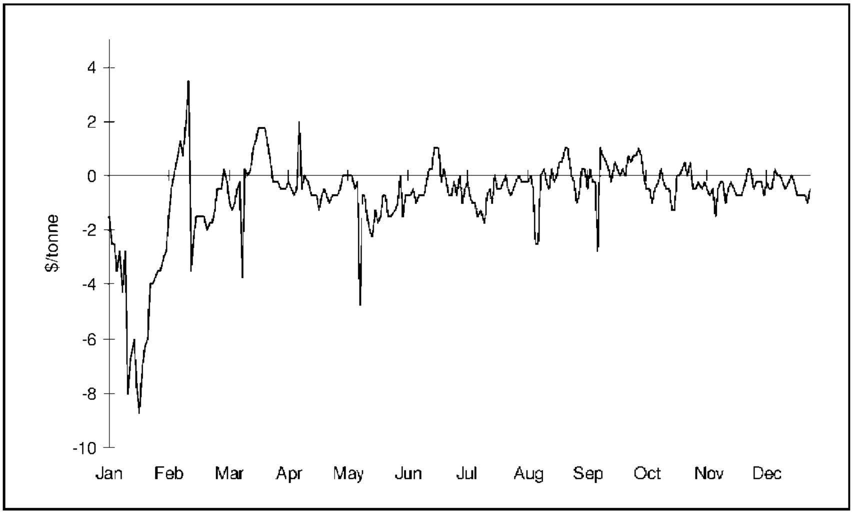


Source: Petroleum Argus

Figure 3.2 Dated Brent, spot and moving average prices, 1997 one day, the participants in the deal leave themselves open to one-off price rises or falls, or even scope for somebody to manipulate the published price, and therefore the price payable. In an attempt to minimise this, publication related prices may be based on a spread of published prices, such as the mean of the published prices on the bill of lading date plus and minus two working days, a mean of five published prices from each publication. Crude oil is often priced on an average of 11 prices, that is the price on bill of lading date plus/minus 5 working days (see Fig. 3.2).

Some traders use publication-related prices based on a mean of different quotes, such as the mean of the mean of cif gasoil cargoes NWE and fob gasoil barges ARA.

Over half of the internationally traded crude oils are quoted at a differential to Brent, since this crude is the most widely traded crude in the international oil market and therefore felt to be sufficiently transparent to be a valid benchmark (see Chapter 4). Another underlying factor, especially important in the early days of price volatility, is that Brent, coming from a politically stable democracy, has been a reliable source of crude oil supply. Brent is thought to be of a consistent quality, and not to vary over time. Therefore, any change in the differential to Brent for a given crude will reflect the relative market interest in that crude compared to Brent.



Source: Petroleum Argus, IPE

Figure 3.3 Gasoil, nearby IPE minus ARA barges, 1997

3.3.2 Fixed differential to futures prices

Rather than using published prices on which to base a formula, some deals may be based on a fixed differential to futures prices. In this case, both the differential and the method by which the absolute futures price is to be determined must be agreed at the time of concluding the deal. For example, it may be the settlement price of a given futures contract at the close of business on the date of the bill of lading (b/l). Or, the parties may agree 'last traded price' on the futures screen. This type of pricing mechanism has been known as 'trigger pricing', and gives either the buyer or the seller the option to choose when to set market price. The popularity of trigger pricing has waned recently, as people have recognised the opportunity for either party to manipulate the marker price ahead of the trigger being pulled, but it is still used.

It is vital that all these details be agreed at the time the deal is struck, and that no loopholes be left open that may cause problems, and possible law suits, at a later stage.

An extension to this type of pricing is the exchange for physical deals where a cargo of physical oil is sold to a buyer, who in return gives the seller a position on the futures market. The price of the physical oil will be determined by a previously agreed differential to the futures price (see Section 3.3.5 below).

3.3.3 Floating differential to published or futures prices

Rather than agreeing a fixed differential to a published or futures price, a formula may be agreed to calculate the differential. For example, one may price a cargo of crude at *Platt's* published differential of the relevant grade to Brent on the bill of lading. This may also be applied to the IPE futures price for Brent.

3.3.4 Pricing against a basket

In order to avoid an over reliance on the price of a particular marker crude or product which could be vulnerable to manipulation, a basket of quotes may be used. For example, dated Brent cargoes with a fixed loading date could be squeezed if one trader buys all the available physical Brent cargoes and then starts artificially to raise the price. So a crude which might otherwise be priced against Brent alone might be priced against an average of dated Brent, Forties and Ekofisk. This type of formula is, however, mainly used in transactions between producers rather than on the spot market. Even so, some US importers of West African crudes occasionally use a diversity of pricing baskets to ensure geographical supply dislocations in one area will not impact unduly on prices in another.

Another extension of this type of pricing is to agree the percentage of each published price which is to apply. For example, vacuum gasoil, a feedstock, may be priced as a percentage of the gasoline quotation, plus a percentage of the gasoil quotation on bill of lading, the total percentages not necessarily adding up to 100. Feedstocks and chemical components are often priced in this way, since many of these more specialised, less traded and therefore less transparent products are not quoted in absolute terms by price reporting organisations.

3.3.5 Exchange of futures for physical (EFP)

EFPs provide an alternative (and more formal) method of pricing a cargo of oil at a differential to the futures market. Instead of using an agreed published futures price, the buyer and seller either create or utilise existing futures positions that match their exposure on the physical oil market. On an agreed date the buyer (of the physical cargo) transfers ownership to the seller (of the physical cargo) of a number of futures contracts, equivalent or as close as possible to the volume of the cargo of oil. The value of the futures contracts at the agreed time when the transfer is made is used, together with the agreed differential to the futures contracts, to calculate the price of the physical oil, which is then paid for in the normal way, depending on the credit terms in the contract. Taking this deal in isolation, the seller then becomes long futures contracts and the buyer short futures contracts at the agreed level.

There are a number of advantages to pricing oil in this way. It allows two parties in the oil market, one who is long oil and one who is short, and who may both have the same views as to where the market is going, to reach agreement on a deal. They can do this by playing the futures market before and after the transaction of the deal, taking or closing their futures positions when they want to, and therefore effectively pricing the cargo when they want in smaller lots. Most traders rarely want to take large open positions, but sometimes liquidity in the futures market is insufficient for them to hedge a full cargo in one go without distorting screen prices. In such cases, EFP pricing may discreetly square each party's position without affecting floor prices.

There are many more sophisticated pricing techniques involving options, swaps and futures (see Chapters 8, 9 and 10).

3.3.6 Asian Petroleum Price Index (APPI)

In the Far East, crude oil is commonly priced in relation to the Asian Petroleum Price Index (APPI). APPI prices are established by a panel of market participants representing crude producers, refiners and traders who are active in the Far East oil market. APPI prices are also used to calculate the official Indonesian crude prices (ICPs) issued by Pertamina that are used both to price term sales and to assess the upstream tax owed by Indonesia's crude oil producers (see Chapter 4).

The APPI panel members now supply prices twice a week for a range of local crude oils to an independent agent (Peat Marwick). The submissions are then averaged after removing the highest and lowest prices and published every Tuesday and Thursday. The crudes quoted come from Indonesia, Malaysia, Papua New Guinea, China and Australia together with key imported grades such as Dubai, Oman, Murban, Arab Light and Arab Heavy.

The fact that APPI prices are only published twice a week limits their usefulness compared with the more frequent daily price reports produced by organisations such as *Platt's* and *Petroleum Argus*, especially during volatile market conditions. Another more serious limitation is the composition of the panel which contributes the market prices. In general, APPI prices have turned out to be lower than the spot market prices published by the price reporting agencies and spot transactions are often concluded at APPI prices plus a premium. Refiners obviously have an interest in lower prices. But it is often forgotten that crude producers also have an interest in keeping APPI prices low since upstream taxes are often based on APPI prices.

It has been suggested that panel prices constructed in the same way as the APPI could also be used in Europe, but participants have not been enthusiastic and the European market continues to rely heavily on *Platt's* prices, which — despite some criticisms — remain the basis for many crude oil deals employing price formulae. However, there is a move to make increased use of IPE Brent futures prices which some companies now regard as more representative of actual market prices.

3.4 Applying pricing mechanisms

3.4.1 Russian products

Russian gasoil

Russian gasoil is generally sold on a *Platt's* related pricing formula using a basket of quotes, namely 50 per cent cif cargoes for gasoil and 50 per cent fob barges for gasoil, structured in the following way.

The price of the cargo cif NWE is calculated from the mean of means of the cif cargoes and fob barges for NWE and Rotterdam for the 0.2 quotation for gasoil (0.2 per cent sulphur) as published by *Platt's* on the bill of lading date, plus an agreed premium (or discount).

If we take a specific example of a deal concluded on 16 July for 25,000 metric tonnes of Russian gasoil loading 22-24 July at a price of mean of the means plus $1.25. The buyer of the oil, a trader, sells on to an end consumer. This could be done at a fixed price or back to back (that is the same formula as it is being bought plus a premium). Alternatively, an EFP to gasoil futures on the IPE at a premium to the August futures might have been agreed. However, for the sake of simplicity, this option will not be considered in this chapter, but will be fully covered later in the manual.

Let us look at the trader's options and work through what each option might yield in terms of profit.

Say he has the option of selling the cargo before loading at a fixed price on 20 July of $169 per metric tonne. On that day he could also sell the cargo on a back to back basis of the mean of means on b/l plus $1.75.

The trader does not know what the cargo will cost him until it loads. On the 20th he has been given an anticipated loading date of the 22nd, but he strongly feels that the market will go down between now and then. He decides to sell at the fixed price of $169 per metric tonne. *Platt's* on that day is as follows:

cif cargoes NWE	165 - 167
mean of	166
fob barges Rotterdam	166 - 168
mean of	167
mean of means	166.5

The cargo loads and has a b/l date of the 22nd. *Platt's* of that day quotes for the 0.2 per cent gasoil is as follows:

cif cargoes NWE	163-165
mean of	164
fob barges Rotterdam	163-164.5
mean of	163.75
mean of means	163.875

Therefore the cost of the oil to the trader is $163.875 plus a premium of $1.25 = $165.125.

The trader sold this cargo at $169 so he makes $3.875 per metric tonne. Had he sold the cargo on a back to back basis at the mean of means plus $1.75 he would only have made 50 cents per metric tonne. However, by selling this back to back he would have locked in his profit, regardless of what the market, and therefore the *Platt's* prices, did.

Alternatively, the trader might have chosen to sell the cargo on an EFP basis against the August futures, say August plus 25 cents. The contract might have entitled the buyer to trigger the EFP any time before loading, and the buyer might choose to trigger it, say, at a level of $170.

Thus the trader would receive $170 plus 25 cents = $170.25 at a cost to him of $165.125, a profit on this leg of the transaction of $5.125.

However, the trader would be long approximately 250 lots of August IPE gasoil at $170. He could sell these immediately and lock in his total profit, or he could hold on to them in the hope that the market would rise further and he could make more money. By doing so he would also run the risk that the market might move down which could mean that he would end up giving back some of the profit made on the physical transaction. He might also prefer to sell his position in small lots, or he might have taken an opposing position when the deal was originally agreed, and therefore used these lots to set against his existing short position. All in all, he has a fully tradable position with which he could try to make more money.

Russian fuel oil

Russian fuel oil is generally sold at a price related to published prices. The formula often used is the mean of the means of the 3.5 per cent sulphur fuel oil quotation as published by *Platt's* on the bill of lading date, the day before the b/l date and the day after, for cif cargoes NWE and FOB barges Rotterdam plus the mean of the high and low quote for the E4 (Russian fuel oil) premium as quoted by *Platt's* plus a negotiated premium, for example $1.

During a short period in 1990/1991 the Russian formula for E4 used the mean of the premium as quoted by *Platt's* and by *Argus*. Although this generally no longer applies now, it has been used below as an example of how a variety of publications can be used in a pricing formulae.

	Platt's cif NWE cargoes	*Platt's* fob Rott barges	*Platt's* cif NWE E4	*Argus* cif NWE E4
b/l minus 1 day	62 - 64	66 - 67	18 - 19	17.5 - 18.5
b/l	63 - 65	67 - 68	18 - 19	18 - 19
b/l plus 1 day	64 - 66	68 - 70	19 - 20	18.5 - 19.5
mean	64	67.67	18.83	18.5
mean of means		65.84		18.665

Therefore the cargo of E4 Russian fuel oil will cost $65.84 plus $18.665 = $84.505 per metric tonne. (All figures have been rounded to the nearest 2 decimal points. In real life this would usually be calculated exactly or specified in the contract.)

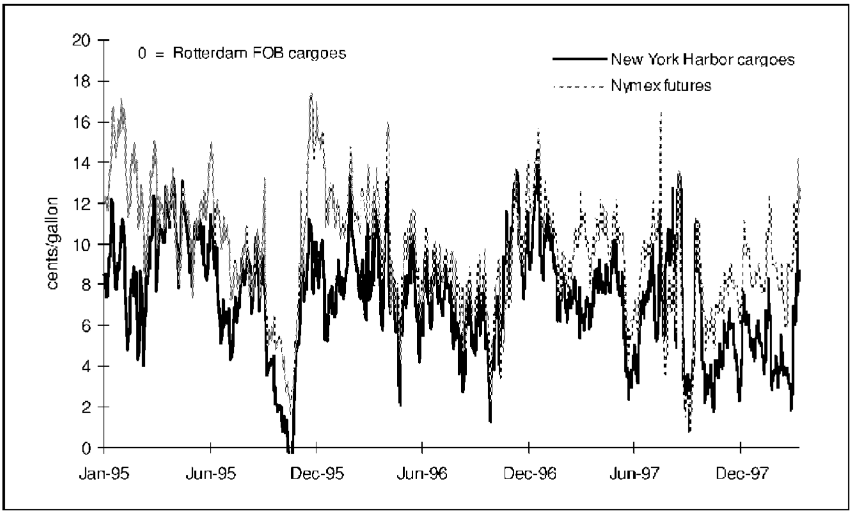
3.4.2 Unleaded gasoline

Unleaded regular or premium gasoline usually moves across the Atlantic from Europe to the US East Coast, or occasionally vice versa, depending on which direction the arbitrage works (see Fig. 3.4). The market for gasoline in the US is priced in cents per gallon, whereas gasoline in Europe is priced in dollars per metric tonne.

When US grade gasoline is being discussed fob Europe, it is usually based on a differential to the New York futures price for regular unleaded gasoline. Since December 1994, the futures contract has been based on regular *reformulated* gasoline (RFG), but European exports are still mainly conventional grades. There is no futures market for premium gasoline in the US. The differential to the futures gasoline should include the cost of moving the oil into the US East coast, and a deduction must be made for the US customs duty (the New York futures price includes duty).

Although discussion on unleaded gasoline prices will be based on a differential to the futures market, the cargo will often be sold at a fixed price which will correspond to the futures price less the discount agreed at the time the deal is concluded.

For example, a seller may have 25,000 metric tonnes of regular unleaded gasoline fob Antwerp available in ten days' time. He has been asking for the futures price for the prompt plus 1 month, (i.e. if the current prompt month is July, then the futures price in



Source: Petroleum Argus, Nymex

Figure 3.4 Unleaded gasoline, New York minus Rotterdam

question will be that for the month of August) less 4.5 cents. The buyer is only prepared to pay August less 5 cents. The two parties agree on August less 4.7 cents. The absolute price is calculated at the time the deal is finally agreed, when both parties agree that the August print at the time is 54.75, therefore the fixed price is 54.75 less 4.7 cents = 50.05 cents per gallon. Thus although all the discussions throughout the negotiations have been at a differential to the constantly changing futures screen, the price paid for the cargo is a fixed price.

3.4.3 Syrian crude oil

Souedie is a heavy crude (low API), produced by the Syrians, which is predominantly used for bitumen production. It is not an easy crude to trade, but is generally sold at a differential to Brent, even though its quality with respect to sulphur and gravity is vastly inferior. It is important to specify which Brent quotation will be used: forward Brent as quoted in the 15-day cargo market, or dated Brent, which represents the price one would have to pay to buy a cargo of Brent with fixed loading dates.

An example formula might be the mean of the dated Brent quotation as published by *Platt's* on the bill of lading date, the day before the bill of lading date and the day after, less $4/barrel. The bill of lading date falls on 5 July which is mid week. The *Platt's* prices for Brent on the relevant dates are as follows:

Date	dated Brent	15-day Brent July	15-day Brent August
4th July	17.80-18.00	18.00-18.20	17.75-17.95
5th July	17.90-18.05	18.10-18.30	17.85-18.00
6th July	17.90-18.05	18.10-18.25	17.85-18.00
mean of means	17.95	18.158	17.9

Thus the price of the cargo of crude at dated Brent minus $4/barrel would be $17.95 less $4 = $13.95/barrel. Had the formula been based on 15-day Brent for July, then the price would be $18.158 less $4 = $14.158/barrel. (N.B. Arrangements should be specified in the contract if any of the dates should fall on a day when *Platt's* is not published.)

Alternatively, the contract could be priced at a differential to the Brent futures market as traded on the London based International Petroleum Exchange (IPE). The buyer could then have the option to trigger the futures price to be used in calculating the final price, any given time when the futures market is open. Some contracts may allow for the price to be an average over a short period of time, say 10 minutes, to allow the other party to take some futures positions in order to hedge their risk.

3.4.4 Price swap

An inland heating oil distributor may be buying his supplies of gasoil from a major, who has a conveniently located refinery, at a formula price of the average of *Platt's* over the month for cargoes of gasoil 0.2 per cent sulphur cif NWE plus $4. So far he has been passing on any price fluctuations to his customers on a monthly basis, but the distributor's customers, not very happy with the fluctuating prices which create chaos for their budgeting, are very keen to purchase from him at a fixed price for a one year term. The distributor is not familiar with the workings of the futures and options markets, and simply does not have the time or the inclination to play these markets on a day to day basis. This level of commitment would be necessary if he made attempts to transfer the risk of buying floating and selling fixed onto the futures and options markets.

The current market price for heating oil is $172 per metric tonne. A trader agrees with the distributor to fix the price of the gasoil from the major at $172 per metric tonne, and buy back the floating price over a period of 12 months. (All figures are arbitrary.)

After the first month, the *Platt's* average for the month is $170 and so the major invoices the distributor for the oil lifted that month under contract at $174 per metric tonne. The trader therefore reimburses the distributor the difference between the invoice price and the agreed fixed price, $174 and $172 respectively, that is $2 per metric tonne. Thus the oil effectively only costs the distributor $172 per metric tonne.

The following month the market falls, and the average *Platt's* price falls to $165. The major invoices at $169, which is $3 below the agreed fixed price and therefore the distributor must pay back to the trader $3 per metric tonne. Therefore the oil is still costing him $172 per metric tonne.

Due to severe weather conditions in Europe and the USA, and some unexpected refinery closures, the price of gasoil rockets and the *Platt's* average for the next month comes to $187. The major invoices the distributor for the gasoil at $191 but the trader reimburses the distributor $19 per metric tonne to bring the cost of the oil to the distributor down to $172 per metric tonne.

Further examples of price swaps are discussed below in Chapters 10 and 11.

3.5 Sources of price information

Price information on crude oil and products can be obtained from a variety of sources, either by talking directly to participants in the market, or by using pricing information services.

Oil and energy pricing information services are not new. One might think that the supply and use of services such as *Reuters*, *Bridge Telerate*, *Platt's* and others are manifestations of modern technology. However, whilst this technology has dramatically altered the means by which the information is supplied, the basic concept of gathering pricing information is very old indeed. In ancient Rome, a public service existed to determine the price of such commodities as corn and timber.

Today's market is considerably more global than it was in the days of ancient Rome. Thirty years ago the idea that a reformer unit having problems in the US Gulf could affect product prices in Singapore seemed absurd. Each market, Europe, the USA and the Far East, existed in its own cocoon, self contained from the outside world. Producers, refiners and consumers traded with each other in their own markets without recourse to others outside their area of trading.

The increasing sophistication of trading companies, the adoption of financial trading tools and techniques, and the greater awareness of the oil market to arbitrage opportunities has changed all this. Now the success or otherwise of the Russian grain harvest can have an effect on product prices in NWE and the Mediterranean within a few hours. Therefore, anyone concerned with the value of oil must keep themselves fully up to date on a whole variety of information as regularly as possible. But even more important, they must learn to interpret the information available and reach an informed opinion.

A major contributing factor to this global outlook has been the explosion of information technology. Whilst information has always been sought, in times of extreme political instability as was seen at the end of 1990, and the first half of 1991, fast, reliable information becomes even more vital.

Much of what happened to oil prices over this period had little to do with supply and demand factors. It depended far more on what politicians were saying — or not saying — for example, what people were thinking might happen in the Middle East and the White House. With the screens as widely available as they are now, these events could be closely followed as they occurred.

There are times, however, when the screens can disseminate news too quickly without due consideration of the facts. In 1983 for example, an Opec meeting was taking place in London. It still holds the record for being the longest such meeting. For ten days or so, the comings and goings of each oil minister was watched and examined in great detail, in an attempt to interpret how the meeting was going. Their faces were scrutinised each time they left the meeting room for clues as to how the meeting was progressing and the likelihood of an agreement to halt the slide in oil prices. During the previous week, the price of a barrel of Brent crude oil had tumbled $10.

At one stage the screen services reported that a particular minister had left the meeting in a great hurry and rushed down the corridor with no word for the hovering journalists. The market immediately interpreted this as a serious rift between members with the talks on the verge of collapse. As a result the price of oil dropped sharply.

Later in the day it transpired that the poor man had merely eaten an unsatisfactory oyster the previous evening, and had left in a hurry for biological reasons! The news was too late to prevent the price slide, which obviously had been based on the flimsiest of reasons.

Pricing services have been unpopular in many circles since their inception, and are likely to remain so amongst those traders who prefer the market to be less transparent. However, pricing services are here to stay, in one form or other. Indeed, new services appear regularly, perhaps focusing on one specialised area of the market. One reason for their unpopularity is their vulnerability to abuse, but the ability to minimise this is very much in the hands of the users of these services. While contract pricing continues to be dominated by just one service, the scope for traders to manipulate the prices in their favour is great. A spread of quoted prices and some more imaginative pricing mechanisms would make this 'abuse' more difficult.

3.5.1 Mechanisms of price gathering

There are two basic ways in which one can obtain pricing information, neither of which are mutually exclusive. Prices can be obtained by speaking to the market, talking to fellow traders who might be buying and selling oil, and gauging at what price they would buy or sell. Oil brokers are also sources of pricing information, since it is their job to be as up to date as possible with who is in the market to do business at any one time, and at what price. This applies to physical oil transactions, forward business, swaps and over the counter transactions. Futures brokers should also be able to supply information about futures and options markets in terms of the level of interest amongst potential players, whether there are many players or whether it is quiet, and provide technical price analysis. Prices on the futures markets are quoted second by second via live feed from the exchanges to the screen services which then sell this information to their subscribers.

There are a number of problems attached to relying solely on these sources and methods. Firstly, ringing round to glean market information is very time consuming and relies on speaking to a large number of people in order to get a representative picture of the oil trading market. To be sure that deal information you may obtain is correct, both sides of a deal should be verified, and a cross section of the participants in the market place, majors, traders, refiners, brokers etc., should be spoken to. As an individual working for a trading company, and therefore a potential competitor of the people you need to speak to, the information they give you may not be entirely unbiased.

In addition, you could come up against the law if your conversations could be construed as discussing pricing policies that could contravene either the Treaty of Rome in Europe or the Robinson-Patman Act in the USA (see Chapter 17). Both these laws deal with anti-trust matters. This is a major problem for producers, although the law does not yet appear to apply to consumer cartels.

Brokers might not continue to be fully co-operative if a trader persists in taking information from them, but not giving them any business. A trader might therefore feel obliged to transact a deal through a broker, and pay his commission, if he is to continue taking information from the broker.

Information on the screen about the futures markets trading levels, is an accurate price indication for that commodity under the terms it is traded on the futures exchange, but will only provide a benchmark for other types of oil or even the same quality traded on the physical market. For example, the IPE gasoil contract allows for delivery in ARA. However, barges of gasoil, also often delivered in ARA, may trade at a differential to the screen at certain times. Prices on the futures markets may give little or no indication of the supply/demand balance effect on a particular quality of physical oil even if it is similar quality to that traded on the exchange.

With these problems to contend with, it is not surprising that most trading organisations subscribe to one or more pricing service. These publications provide a useful reference point, but it must always be remembered that their prices are generally out of date by the time they are received since they may not be published until 19:00 hours or later local time on the day to which the prices refer.

Published prices therefore have a limited value for fixing prices throughout the day. A price report may, nevertheless, be useful for broad assumptions. For example, the service may report dated Brent at a 10 cent/barrel discount to front month IPE futures, and Ekofisk yesterday traded at a 40 cent premium to dated Brent. If the screen shows front month futures Brent up 20 cents and brokers or other market sources inform you dated Brent has maintained its differential to the screen, you may assume that Ekofisk also has gained 20 cents.

These published prices, generally a range which represents, for example, a buy/sell range, will have been obtained in the same way that theoretically any trader could. The reporters for the pricing organisation will have spoken to a range of contacts in the appropriate market, and, using their expertise and knowledge, will arrive at an educated assessment of where they consider the market to be.

Thus the published price is not sacrosanct. It does not always mean that a buyer could necessarily purchase a specific quantity and quality of oil at that price. Nor does it necessarily mean that oil of that quality was traded at that price on that day. This is a very important distinction between prices quoted by *Platt's*, *Argus* or *London Oil Reports*, and those which flash up on real time screens such as *Reuters* and *Bridge Telerate* for futures prices. A last traded price quoted for Brent on the International Petroleum Exchange futures market in London will mean exactly that - a deal has been done at that price. The deal may however only be for one lot, of 1,000 barrels, which compared to a cargo of 500,000 barrels is small. The transaction may also have been concluded by a trader for manipulative reasons, exactly because it is a relatively cheap way of influencing prices in your favour if you are about to buy or sell 500 times as many barrels of oil.

In order to use price reports correctly, any user should understand how those prices are arrived at. All price reporting companies employ reporters and editors who spend their working days mainly talking to the market over the phone. Their aim is to establish what is happening in the market, and perhaps why, what deals have been concluded and what the sentiment of the market is. With this information in hand, they can make an assessment of market prices for crude and products at a particular time in the day.

To be of maximum use, information must be as accurate and as unbiased as possible. Immediately one must consider why traders would give what could be considered as confidential and commercially valuable information. Any company which closely guards its pricing policies, supply/demand positions, likely future requirements and current spot and term deals, must have a very good reason for divulging this information to a third party. They will know that a price reporter has to speak to many participants in the oil market. How can they be sure that the information given to the reporter does not find its way back to a competitor.

In order to persuade traders to divulge this information, certain guidelines have to be followed. Perhaps the most important is that information given in confidence remains confidential. Details of confidential deals may be passed on to a price reporter once a good relationship has been built up. Whilst the details of these deals cannot be published, the reporter can use the information when setting prices, but will only continue to receive the confidential information if it is not passed on to the market.

Secondly, there should be an exchange of information between the reporter and contacts. Due to space constraints, not all the information that a price reporter collects can be published. By speaking to the reporters directly, traders may get that little extra piece of information in the course of conversation which may help him to assess his position in the market. The trader can also use the reporter to check out rumours and ask specific questions which he himself may have difficulty in posing, for fear of revealing his position in the market.

3.5.2 Use of price reports

If one is to use price reports, and it is inevitable that any trader will have to do so at some time, it is vital that the user appreciates the methodology used by the pricing service to understand what the data represents. The methodology used by each pricing service is slightly different. Without this knowledge, confusion can arise which can lead to expensive mistakes.

Platt's, *Argus* and *Reuters* all quote 3 per cent sulphur fuel oil in NWE, but what does this figure represent? Is it bunker spec. or the specification used by the power generation sector? Does NWE mean UK or Rotterdam? If the reporter hears a deal done cif UK do they net it back to Rotterdam in order to equate it with their published prices? If a deal were done at 6.00pm London time, would the published price of that day reflect this deal? If the cargo traded was actually 2.7 per cent sulphur, how would that price be reflected in the published price of the day?

All price reporting services should have answers readily available to all these questions, and any user should ask for the company's pricing methodology manual. This gives details of how pricing services arrive at their prices, qualities of oil, locations, cut-off time, etc.

Consider the price of Brent. *Platt's*, *LOR* and *Argus* all quote Brent prices, but other differences apart, at what time do these services make their final assessment? Is it at close of business in London, New York, Houston or Tokyo? Prices can move significantly between, for example, 4:00p.m. New York and 6:00p.m. in Houston. Differences between the various assessments may simply reflect different markets rather than conflicting evaluations.

Perhaps more potentially confusing are the different roll over dates for crude oil, that is the change from one trading period to another. i.e. March barrels to April.

For their Dubai crude oil quotation, some publications will roll over on the last day of the calendar month. However, WTI futures rolls over on the third business day prior to the 25th of the month. Therefore, if you were making a comparison between Dubai crude and WTI you would be in danger of comparing different delivery months at the end of each month, which is very likely to distort the spread.

Another way in which data can be misleading is the high/low price quoted. Some pricing publications explain this as a buy/sell range. Others use the range to indicate the price of different qualities, e.g. naphtha quotes may reflect the buy/sell range of open specification naphtha, that is the quality traded in forward/paper deals. However, other pricing publications may define their naphtha high/low range as the price of the open specification naphtha for one quote, and prompt physical naphtha for the other.

These anomalies can be resolved by fully understanding what each price means. Analysis based on the incorrect interpretation of data could lead to the wrong conclusions, which in turn could mean commercial decisions may be taken on incorrect data.

3.5.3 Pitfalls

In an ideal situation all price quotations would be an accurate reflection of market values of a particular crude or product of a particular specification, at a specific location, of a specific size at a specific time. Discounts and premia to these prices should thus only reflect changes to these specifications. Unfortunately, life is not that simple.

Whilst some crudes and products are regularly traded, many are not. In these cases, price reporters have to price this oil at a differential to more regularly traded oil, and move the prices up or down in line. When a deal is reported for the rarely traded oil, the reporter hopes that his quoted price is not too out of line. For a number of reasons, this may not be the case. Then a reporter is faced with the decision of moving the quoted price by an abnormally large amount on one day, or moving it more gradually over a period of days to bring it back into line.

This is just one of many judgements which have to be made every trading day by price reporters. It is vital, therefore, that reporters have the necessary experience and qualifications to make these judgements. If this is not the case it can leave the reporter open to manipulation by traders who might choose to influence the published price in their favour.

A deal concluded on gasoline, the quality of which may not meet that of the quoted quality, may be given to the price reporter without specifying that the oil was off spec. The price achieved for the cargo is likely to be below market price and therefore the price reporter might mark the quoted price down accordingly, whereas, allowing for the difference in quality, the price perhaps should have stayed the same. An experienced price reporter would be wary of this type of game, and would check all the details of any deal reported, preferably with both parties involved. Experience would make them particularly wary of selective reporting of deals from traders not usually known for their co-operation.

3.5.4 Publications

The number of price reporting and price analysis services has grown rapidly since the 1980s, each fulfilling a different need. They can however, be grouped into various types of services as follows.

Newsletters were the first source of price information generally available. Although most are produced only on a weekly basis, their value lies in their depth of information, price analysis and considered comment upon developments with longer term implications for the oil markets.

As spot trading markets grew and traders demanded more than weekly price reports, daily telex and fax services emerged. These services can be delivered in hard copy, or by using on-line electronic services. As the technology developed so electronic data services became popular amongst those users needing data on an immediate basis, such as those using the futures and options markets. Additional software enables the customer to manipulate the data, and to produce graphic representations at the press of a few buttons. Many of these services are now also available through the internet.

The final group of price services are those where the customer can not only manipulate the data, but actually inputs some of the data. As an extension of this a number of attempts have been made to develop trading via computer networks, but these have not yet been successful, and now co-operative price reporting is concentrated on information distribution. The most successful of these is *APPI* (Asian Petroleum Price Index) which reports oil prices traded on the Asian markets. However, this service revealed its limitations during the 1990 Gulf crisis, when its weekly price reports were rapidly rendered out of date as the market remained volatile. *APPI* crude price assessments are now made twice-weekly.

The list below gives some examples of each of these groups of services. It is not exhaustive, and is being frequently added to.

It is therefore important to differentiate between services which offer analytical information, and those involved in price reporting. Many of the former subscribe to the latter in order to obtain the data which they then analyse.

For example, one may look at the *Reuters* screen for futures quotations, but at *Platt's* or *Argus* for cash quotations. Newsletters may supply background information and analysis of the impact of political events on the oil market. A time-sharing system, which can feed into your own in-house computer network, would mean that you could manipulate data, perhaps following your own pricing formula, or your profit & loss account against the current market values.

Newsletters

— delivered by fax, mail or via the internet
Arab Oil and Gas: reports on oil and gas trends in Arab and African nations: produced fortnightly
Energy Compass: various produced weekly and daily
FT Energy Economist: monthly
Middle East Economic Survey (MEES): weekly
Oil Buyers Guide: weekly and daily
Platt's Oilgram News: daily
Platt's Week: weekly
Argus Global Markets (AGM): weekly
Petroleum Intelligence Weekly (PIW): weekly

Daily oil price reports

— delivered by fax, telex or electronic means
AFM Oil Market Report (Germany)
Bloomberg
Bridge Telerate
London Oil Reports (LOR)

Platt's Oilgram Price Report
Oil Price Information Services (OPIS)
Petroleum Argus
Reuters
RIM Intelligence (Asia-Pacific)
The Bunker News Daily - Bunker prices

Online oil price and information services

<u>Dial up systems</u>

— via a modem either directly or through the internet
International Petroleum Exchange – closing prices only
New York Mercantile Exchange – delayed prices and closing prices
Reuters Data Services (Formerly IP Sharp)
Saladin Information Service (SIS) - uses third party price data
PDS On-Line Services – US & Canadian crude oil postings

<u>Real time systems</u>

— the connection is permanent via telephone lines or satellite.
Bloomberg Energy
Bridge Telerate (formerly Knight Ridder & Dow Jones)
Platt's Global Alert
Reuters Energy 2000
Saladin Information Service (SIS) - uses third party price data

Cooperative pricing services

APPI - Asian Petroleum Price Index
FEOP Index– Far East Oil Price Index

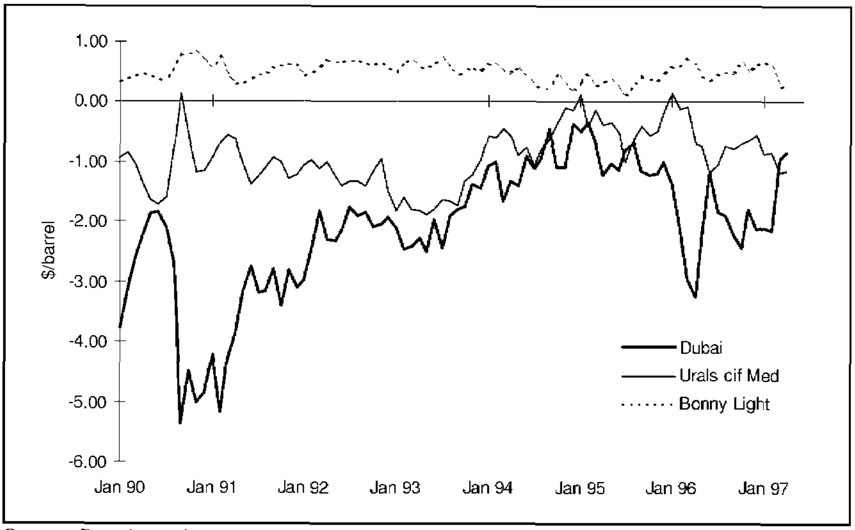
4 Crude oil markets

Petroleum Argus

4.1 Introduction

The physical crude market is the foundation of the oil market. There are more than a hundred grades of crude oil that could be traded being produced in over fifty countries around the world. In 1995, 28 million b/d of crude oil crossed international borders and nearly as much again was traded internally within the countries in which it was produced. As every grade and location represents a different price and the relative values of crudes are continually changing over time in response to shifts in supply and demand on both a local and an international scale, the crude oil market not only provides essential price information, but also endless trading opportunities for companies involved in the oil business.

The variation in the relative prices of crude oils is both remarkable and unpredictable. Over the past few years the price differential between light and heavy crudes has swung between the two extremes (see Fig. 4.1). Following Iraq's invasion of Kuwait in the summer of 1990, the price differential widened abruptly as Saudi Arabia and other producers increased the supply of heavy crudes to make up for the loss of supply from Iraq and Kuwait. But the differential has gradually narrowed since then as rising production from the North Sea and elsewhere gave lighter crudes an increasing share of production. By 1994, the price differentials



Source: Petroleum Argus

Figure 4.1 Spot price differentials against dated Brent between dated Brent and other crudes had reached their lowest level for many years, confounding earlier forecasts of a gradual widening of crude price differentials during the 1990s. But the price differential between light and heavy crudes widened abruptly again in early 1996 as a number of new North Sea fields were delayed and oil demand surged because of the cold winter weather, creating a temporary shortage in the Atlantic basin. Sour crude differentials continued to widen in 1997 following the resumption of limited Iraqi oil exports under the terms of the UN oil-for-aid deal, but price differentials between eastern and western markets narrowed as strong demand from Asia-Pacific refiners pulled increasing volumes of west African crude out of the Atlantic basin.

4.2 North Sea

The importance of the North Sea to the world oil market far outweighs its contribution to world oil supply. For over a decade, the North Sea crude oil market has been the preferred benchmark for the majority of internationally traded crudes. Although Nymex WTI is the most visible of the price markers used by the oil industry, more than 60 per cent of the physical crude market (about 20 million b/d) is actually priced against Brent, which is a North Sea crude. Because it is used in pricing formulas for crudes in the Atlantic Basin, the Mid-east Gulf, and now the Far East, Brent's influence extends far beyond the narrow confines of the North Sea. As a result, the North Sea market is closely watched by everyone involved in trading oil.

The North Sea provides more than 9 per cent of the world's crude oil production, with the bulk of the output coming from two countries, the UK and Norway, and minor amounts being contributed by Denmark and the Netherlands (see Table 4.1). Production has risen sharply in recent years as a succession of new fields were brought on stream. In 1997, North Sea crude production is expected to average 6.5 million b/d, a further increase over 1995 when production averaged 5.8 million b/d. By the end of 1997, North Sea production could reach 7 million b/d and further growth is expected up to the end of the decade. Output from the UK offshore sector is now growing more slowly, but Norway continues to make rapid gains and remains the largest crude oil producer in the North Sea in 1997. The UK also produces 100,000 b/d of crude onshore, mainly from the Wytch Farm field operated by BP.

Table 4.1 North Sea crude production and exports, 1996

Country	**Production b/d**	**Exports b/d**	**Capacity† b/d**
UK*	2,418,000	1,700,000	2,800,000
Norway	3,107,000	2,700,000	3,300,000
Denmark	210,000	115,000	230,000
Netherlands	39,000	17,000	40,000

Source: Petroleum Argus **excluding onshore* † *end year*

Oil is produced in the North Sea from about 150 fields and the output from the individual fields varies greatly in quality, with gravity ranging from 23° API to 50° API and sulphur content from virtually nil to 1.9 per cent. However, this variation is greatly reduced by blending. North Sea crudes are generally not available as output from individual fields. The economics of producing in the North Sea often require companies to share a common infrastructure so that crude from a number of fields becomes blended in pipelines, while other fields are developed as satellites of their larger neighbours with the oil produced being blended in storage tanks prior to offshore loading — although this is now changing as more floating production, storage and off-loading vessel (FPSO) systems are brought into operation.

Until recently, almost all the North Sea crude production streams were combined to form one of ten major export blends of more than 100,000 b/d — Forties, Statfjord, Brent, Oseberg, Gullfaks, Ekofisk, Flotta, DUC, Fulmar and Beryl — but the picture has changed since 1995 as new offshore loading fields came on stream in the UK and Norway, greatly increasing the variety of crudes available (see Table 4.2).

Table 4.2 North Sea crudes and loading terminals, 1996

Crude stream	Terminal	Location
Brent Blend	Sullom Voe	Shetland Islands, UK
Ekofisk	Tees River	England, UK
Flotta Blend	Scapa Flow	Orkney Islands, UK
Forties Blend	Hound Point	Scotland, UK
Oseberg	Sture	Norway
Denmark (DUC)	Kaegård	Denmark
Alba	Alba Field	Offshore
Beryl	Beryl Field	Offshore
Blenheim	Blenheim Field	Offshore
Draugen	Draugen Field	Offshore
Douglas/Lennox	Douglas Field	Offshore
Fife	Fife Field	Offshore
Fulmar	Fulmar Field	Offshore
Frøy	Frøy Field	Offshore
Gryphon	Gryphon Field	Offshore
Gullfaks	Gullfaks Field	Offshore or Mongstad
Gullfaks C	Gullfaks Field	Offshore or Mongstad
Harding*	Scapa Flow	Orkney Islands, UK
Heidrun	Heidrun Field	Offshore or Mongstad
Maureen	Maureen Field	Offshore
Sleipner	Sleipner Field	Offshore
Statfjord	Statfjord Field	Offshore
Troll	Troll Field	Offshore or Mongstad
Yme	Yme Field	Offshore or Mongstad

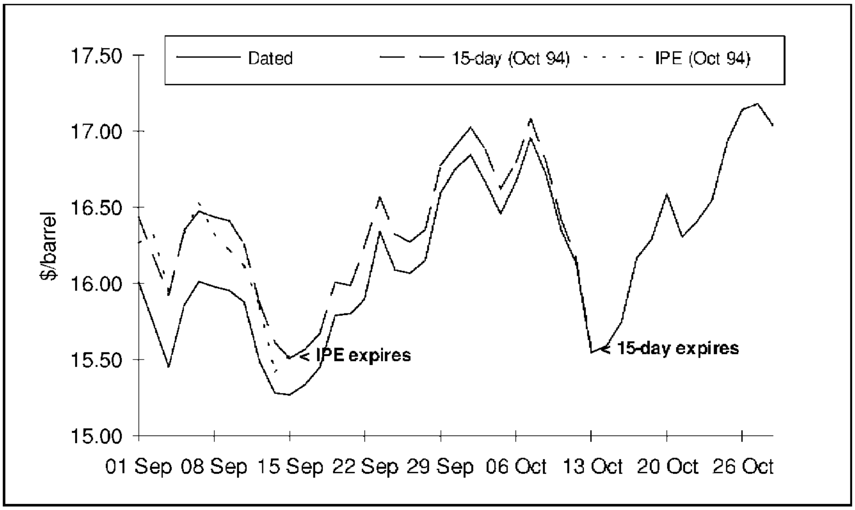
* *transported to Flotta terminal by shuttle tanker.*

Although the ten blends still accounted for over 80 per cent of the total output from the North Sea in 1996, there are now more than twenty-five different types of crude that can be traded. And the number will increase further in 1997 as new fields in the North Sea and other areas such as Liverpool Bay and west of Shetland start producing. New offshore loading fields in the North Sea include Captain, MacCulloch, Durward and Dauntless, Curlew, and Mallard in the UK sector, and Balder, Njord and Norne in the Norwegian sector. The Liverpool Bay fields, Douglas & Lennox are loaded offshore as a combined stream, while west of Shetland Foinaven (like Harding) will be transported to the Flotta terminal by shuttle tanker.

4.2.1 North Sea crude market

The North Sea market has many different dimensions since it involves a complex mixture of physical, forward, futures and swaps contracts (see Chapter 1). The most important market is for Brent crude, which is traded in several different forms:

- as a physical commodity, dated Brent,
- as a forward paper contract, 15-day Brent,
- as a futures contract, IPE Brent, and
- as a swaps contract, Brent CFDs.



Source: Petroleum Argus, IPE

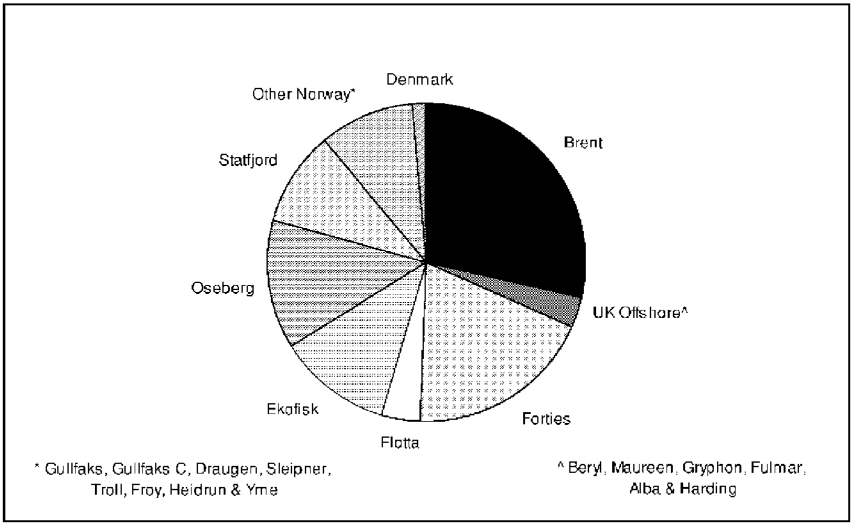
Figure 4.2 Dated, 15-day and IPE Brent prices, October 1994

The physical market trades cargoes of Brent Blend that have loading dates attached to them, hence the term "dated". The loading programme for Brent Blend, which assigns dates to individual cargoes, is released by the terminal operator in the middle of the month preceding delivery. This means that the earliest point at which a cargo can become "dated" is fifteen days before the start of the delivery month. As a result, the paper market for Brent Blend requires sellers to give a minimum of fifteen days' notice of their intention to nominate a specific physical cargo against a forward sale, which is why it is known as the "15-day" market (see Chapter 7).

Brent Blend is also actively traded as a futures contract on the London International Petroleum Exchange (IPE) for periods starting from one month ahead of delivery, but the contract is settled against a price index based on market reports of deals done in the 15-day market (see Chapter 8). And there is also a rapidly expanding short-term swaps or "contract for differences" (CFD) market, which is based on the price differential between the weekly average of *Platt's* assessments for dated Brent up to six weeks ahead (see Chapter 7). Dated Brent assessments are usually taken to apply to a period of two to three weeks ahead, and companies often need to be able to establish prices for periods that lie in the time frame between the "spot" and forward or futures markets.

But it is the composition and structure of the underlying physical market that accounts for much of its importance. First of all, the North Sea is a highly liquid market. This is because the upstream tax regulations in the UK give integrated companies producing oil an incentive to trade at arms' length in order to establish an independent and market-related price for tax purposes (see Chapter 15). For this reason, major integrated oil companies such as BP and Shell have always sold a large part of their production to third-parties in order to ensure that they are taxed at prevailing market prices rather than a reference price determined by the Oil Taxation Office (OTO). As a result, there is always a large amount of physical oil available to the market guaranteeing its liquidity.

Secondly, the North Sea is the only effective market for prompt crude available to companies trading oil. Nymex WTI ceases trading more than a month ahead of delivery because of the operational constraints imposed by the pipeline scheduling system in the US (see Section 4.5). And long-haul crudes from the Mid-east Gulf are loaded too far ahead to provide an alternative — even if spot trading were to be encouraged by the producers (see Section 4.6). But North Sea crudes are produced much closer to the market and can still be traded by European refiners up to a few days before they are delivered (see Fig. 4.2). As a result, the North Sea market



Source: Petroleum Argus

Figure 4.3 Composition of dated North Sea market, 1996

fills an essential gap in the term structure of the world oil market by providing a price reference for crude oil over a period of one to two months ahead. It is for this reason that dated Brent is used so widely in pricing formulas, rather than Nymex WTI or even IPE Brent which both expire too far ahead for the physical oil market (see Chapter 8).

Thirdly, the North Sea market operates as a physical arbitrage mechanism linking the various parts of the world oil market. Because North Sea crudes are generally light and sweet, they are attractive to any refiner if the price is right. The most important arbitrage opportunity operates across the Atlantic and the US imports, on average, between a third and a half of the North Sea's output. But North Sea crudes also move regularly to the Mediterranean, and, occasionally, to the Far East, thus ensuring that crude oil prices do not get too far out of line for too long in any region.

The importance of the physical oil market in the North Sea has encouraged the development of active and liquid paper markets, in particular the 15-day forward Brent market (see Chapter 7) and the IPE Brent futures contract (see Chapter 8), both of which play a major role in the oil market as a whole. The choice of Brent, rather than one of the other major North Sea production streams, reflects the much wider distribution of ownership between companies which prevents any one producer from squeezing the market.

Production of Brent Blend, however, has fallen over the past few years raising concerns about its future reliability as a price marker.

Nevertheless, dated Brent was the most actively traded grade in the physical North Sea market last year, representing nearly 30 per cent of the dated deals reported by *Petroleum Argus* in 1996 (see Fig. 4.3). This was a great improvement on the previous two years when dated Brent's share of the total slipped to under a quarter, leaving Forties as the most actively traded grade.

The decline of physical Brent volumes has prompted the development of an alternative market based on Forties. With production rising sharply as new fields such as Scott and Nelson are brought into the blend and a more diverse ownership structure involving 40 companies, the Forties blend now has the potential to replace Brent in the longer run. A trial forward paper contract known as "18-day" Forties is currently being traded one month ahead, usually at a differential to the 15-day Brent market. But displacing Brent as a price marker is not a simple task since, like WTI, it supports an elaborate structure of derivative trading instruments which would also need to be replaced.

4.2.2 United Kingdom

Crude oil production in the UK offshore sector is still on an upward trend, although delays to new offshore fields and unexpected problems with existing fields meant that output actually fell in 1996 instead of rising sharply as originally predicted. UK crude production (including onshore fields) averaged just over 2.5 million b/d in 1996, about 10,000 b/d less than in 1995.

Thirteen new fields came on stream in 1996 — Columba B (7,000 b/d), Pelican (36,000 b/d) and Magnus South (10,000 b/d), part of the Brent system; Andrew/Cyrus (55,000 b/d), Arkwright (7,000 b/d) and Thelma (25,000 b/d), part of the Forties system; Nevis (20,000 b/d) and Fergus (10,000 b/d), both of which load offshore as part of the Beryl and Fife streams respectively; the offshore Teal area fields (50,000 b/d); the offshore Harding field (60,000 b/d) which was delayed from 1996. The Banff field (35,000 b/d) was on an extended well-test during 1996, but will not start properly until 1998. Although the Douglas (40,000 b/d) and Lennox (30,000 b/d) fields in Liverpool Bay started up in 1996 they suffered from serious technical problems which constrained Douglas' output and delayed Lennox until 1997.

Table 4.3 United Kingdom export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Forties Blend	37.0	0.28	878,000
Brent Blend	38.0	0.18	750,000
Flotta Blend	37.4	0.97	224,000
Fulmar	40.0	0.30	123,000
Beryl	37.0	0.40	93,000
Alba	19.0	1.26	65,000
Gryphon	21.0	0.40	38,000
Fife	36.0	0.00	38,000
Harding	20.0	0.60	33,000
Douglas/Lennox	44.0/45.0	0.5/0.25	33,000
Blenheim	40.0	0.00	17,000
Maureen	38.5	0.00	9,500

Production is expected to average just over 2.8 million b/d in 1997, an increase of 240,000 b/d on 1996, as a further 13 fields are planned to come on stream, including the first production from Foinaven (120,000 b/d) west of Shetland. Other fields are Captain (63,000 b/d), the delayed J-Block — Judy & Joanne — (60,000 b/d), MacCulloch (60,000 b/d), Durward (38,000 b/d), Gannet E & F(20,000 b/d), Dauntless (10,000 b/d), Curlew (45,000 b/d), Mallard (16,000 b/d), Brae West (30,000 b/d), Erskine (30,000 b/d), Armada (25,000 b/d) and Kingfisher (37,000 b/d).

Forties Blend is now the largest of the UKCS crude streams since the addition of the 180,000 b/d Scott field in late 1993 and Nelson in 1994 (see Table 4.3). Further increases in UK production are expected in 1998 as more new fields are commissioned and existing fields are re-developed. Nearly $2 billion is being spent on the Brent field in order to recover an extra 34 million barrels of oil and 1,500 billion cubic feet of gas, extending the life of the field for at least another ten years, but the volume of Brent Blend crude is expected to continue declining slowly over the rest of the decade.

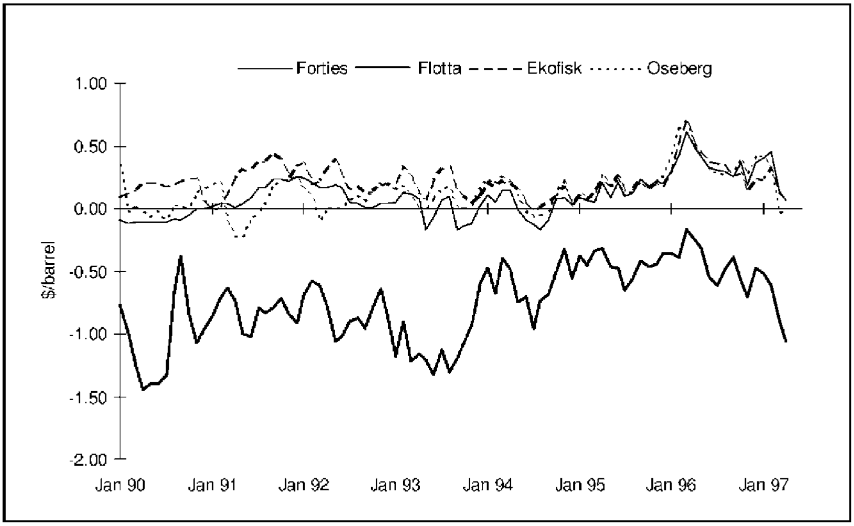
Brent Blend, which now combines the former Brent and Ninian blends into a single export stream is still the most important crude in the North Sea market. Although it is no longer the largest UK export crude by volume, it remains the reference grade against which all other North Sea and Atlantic Basin crudes are priced. The market for Brent is therefore watched with close attention by the international oil trading community.

Between 40 and 50 cargoes of Brent Blend are available each month and the eventual ownership and destination of each cargo is carefully monitored in case anyone attempts to squeeze the market, as has occasionally happened. With so many other grades of crude oil being priced against Brent, the temptation to manipulate the market is immense. However, successful squeezes are rare since the main equity producers are usually prepared to release additional cargoes from their refining systems if the market gets tight since they have a vested interest in the continued successful operation of the Brent market.

The physical Brent market normally trades 500,000 barrel cargoes available for lifting 10 to 25 days ahead and most market assessments for dated Brent are based on a continuously moving market "window" covering this period. Dated Brent is either traded outright at fixed prices or, more commonly, at a differential to either the 15-day forward Brent market or the IPE Brent futures screen. But companies that want a more precise time frame can use the CFD market to establish a price for a particular delivery week within the range covered by the dated market. The dated Brent market is therefore exposed to a complex set of arbitrage opportunities that not only help to keep prices in line with other related markets, but can also move prices in unexpected ways.

The other UKCS export crudes, mainly Forties, Flotta, Fulmar and Beryl, are usually priced at a differential to dated Brent (see Fig. 4.4). Although they are mainly relatively light crudes, Flotta has a much higher sulphur content than most North Sea crudes and normally trades at a discount to dated Brent. Production of heavy crudes is rising, however, now that Alba, Gryphon and Harding (20º API) have reached peak output. And more heavy crudes, Foinaven (25º API) and Captain (20º API), are coming on stream in 1997.

More than 60 oil and energy companies are now involved in the UK sector of the North Sea, although many of these have assigned their share of production to a partner in the field in production. Nearly 40 per cent of the oil produced from the UK sector of the North Sea is actually in the hands of just three companies: BP, Exxon and Royal Dutch/Shell. BP was the largest producer in 1995 with just under 400,000 b/d, followed by Exxon and Shell with nearly 300,000 b/d each, the two companies having a long-standing agreement to develop UKCS oilfields jointly. The next largest producers are Amerada Hess and Enterprise with just over 140,000 b/d each. Other companies producing more than 50,000 b/d include EEP — Elf Enterprise Petroleum — (89,000 b/d), Texaco (83,000 b/d), Conoco (80,000 b/d), Chevron (75,000 b/d), Deminex (73,000 b/d), Mobil (71,000 b/d), Elf (60,000 b/d) and Marathon (51,000 b/d).



Source: Petroleum Argus

Figure 4.4 North Sea crudes minus dated Brent

4.2.3 Norway

Oil production in the Norwegian sector of the North Sea continues to expand steadily, averaging 3.1 million b/d in 1996, an increase of 340,000 b/d over 1995. Output is expected to rise again in 1997 to an average of 3.4 million b/d.

Most of the growth last year came from four large new fields which came on stream in 1996 and reached their peak in 1996 — Statfjord North (70,000 b/d), Frøy (40,000 b/d), Troll (190,000 b/d) and Heidrun (200,000 b/d). A fifth field, Yme (50,000 b/d), was delayed until February 1996. Frøy is part of the Oseberg system and piped to Sture, but Troll and Heidrun are loaded offshore and available as separate grades (see Table 4.4).

Five new fields are planned for 1997 adding a further 470,000 b/d of peak capacity. Vigdis (100,000 b/d), which is part of the Gullfaks system, came onstream five months ahead of schedule in January 1997. Three of the remainder — Norne (205,000 b/d), Balder (73,000 b/d), Njord (70,000 b/d) — will load offshore, while Tordis East (25,000 b/d) will form part of the Gullfaks system. Since Norway can only consume a small fraction of the oil it produces, the country is a major exporter and it has now overtaken Iran as the second largest crude exporter in the world after Saudi Arabia.

In the Norwegian sector of the North Sea, the government plays a much larger role in the development and operation of oil fields than in the UK. Norway's state oil company, Statoil, is the biggest player as it has both its own equity share of production, 464,000 b/d (including NGLs), and also manages the Norwegian government's direct financial involvement (GDFI), which amounted to a further 962,000 b/d (including NGLs) in 1995. Statoil ranks as the third largest net seller of crude in the world and is the biggest exporter of North Sea oil. The company sold 730 million barrels of crude in 1996 — equivalent to 2 million b/d. Statoil's principal market remains north-west Europe, but large volumes are also sold to North America. The company intends to focus more strongly on south-east Asia and the Mediterranean in the future. The remainder of Norway's output is owned by approximately 20 European and American oil companies, including all the majors. The biggest private producers are Amoco, BP, Norsk Hydro, Phillips, Saga and Shell.

Table 4.4 Norwegian export crudes, 1996

Crude stream	**Gravity °API**	**Sulphur %wt**	**Production b/d**
Statfjord	38.0	0.27	759,000
Oseberg	34.0	0.30	691,000
Gullfaks	28.6	0.40	513,000
Ekofisk	43.0	0.21	509,000
Troll	29.0	0.30	227,000
Heidrun	29.0	0.49	209,000
Draugen	39.8	0.15	145,000
Sleipner	59.0	0.02	73,000
Yme	38.6	0.17	22,000

More than half Norway's crude production is loaded offshore at the Statfjord, Gullfaks, Draugen, Troll, Heidrun and Yme fields, while the remainder is piped ashore to terminals in the UK and Norway. Ekofisk is piped to the Tees River on the UK mainland, while Oseberg is piped to Sture in Norway. A small amount of Norwegian crude from the joint UK-Norway Murchison field is also available as part of the Brent system. Segregated production from the Gullfaks, Heidrun, Troll and Yme fields is also trans-shipped to Statoil's Mongstad terminal from where it can be exported to refineries outside NW Europe.

Norway's crudes used to be all light and low in sulphur making them highly attractive to refiners in Europe and North America, but new production from the Heidrun and Troll fields in the Haltenbanken area is much heavier with an API gravity of only 29° (see Table 4.4). Heidrun is also very acidic and can only be processed in a distillation column made of high quality steel, which limits its market to refineries that are able to take such crudes, like those on the US Gulf coast. Oseberg has a good gasoline yield and usually trades at a significant premium to Brent (see Fig. 4.4).

Like all other North Sea crudes, Norway's crudes are usually priced at a differential to dated Brent. Norwegian oil producers do not have the same tax incentive to sell on the open market as UKCS producers since all upstream taxes are paid on the basis of a government-determined retrospective "norm" price. However, there is no shortage of Norwegian crude on the market since most of the producers have other reasons for trading their output.

4.2.4 Denmark

Compared with Norway and the UK, Denmark is a relatively small oil producer, averaging around 210,000 b/d in 1996. But like Norway and the UK it exports a large proportion of its production, importing other grades to meet domestic refinery demand. Production has risen steadily in recent years as new fields were brought onstream and further gains are planned for 1997.

Denmark's crude is produced from a small group of offshore fields and piped ashore to form a single export blend, often known as DUC after the company which produces it, Dansk Undergrunds Consortium. DUC blend is medium gravity (34º API), low sulphur (0.2 per cent) crude. The majority of the production comes from the Dan (63,000 b/d), Skjold (43,000 b/d), Gorm (39,000 b/d) and Tyra (28,000 b/d) fields.

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4.3 Mediterranean

The major crude oil producers and exporters in the Mediterranean region are the countries of North Africa, principally Algeria, Libya and Egypt, Syria and Tunisia (see Table 4.5). The Mediterranean market is also supplied on a regular basis by crude oil from the former Soviet Union, Iran and now Iraq. Cargoes of Iranian crude are sold fob Sidi Kerir, the Mediterranean terminal of the Sumed pipeline west of Alexandria in Egypt. Limited Iraqi exports resumed in December 1996 under the terms of the UN oil-for-aid deal and about 60 per cent of the crude is sold fob Ceyhan, the export terminal for the Iraq-Turkey pipeline. Urals crude has become the most important price marker for the Mediterranean market, replacing spot sales of Iranian crudes which are now in short supply at Sidi Kerir as Iran increasingly favours term customers or direct sales to end-users.

Table 4.5 Mediterranean crude production and exports, 1996

Country	Production b/d	Exports b/d	Capacity† b/d
Algeria*	820,000	370,000	850,000
Libya	1,400,000	1,100,000	1,500,000
Egypt*	850,000	400,000	850,000
Syria	570,000	350,000	560,000
Tunisia	90,000	55,000	95,000
Russia‡	na	900,000	na
Iran‡	na	600,000	na
Iraq‡	na	360,000	na
Kazakstan‡	na	60,000	na

**excluding condensates ‡ Mediterranean exports only † end year*

4.3.1 Russia

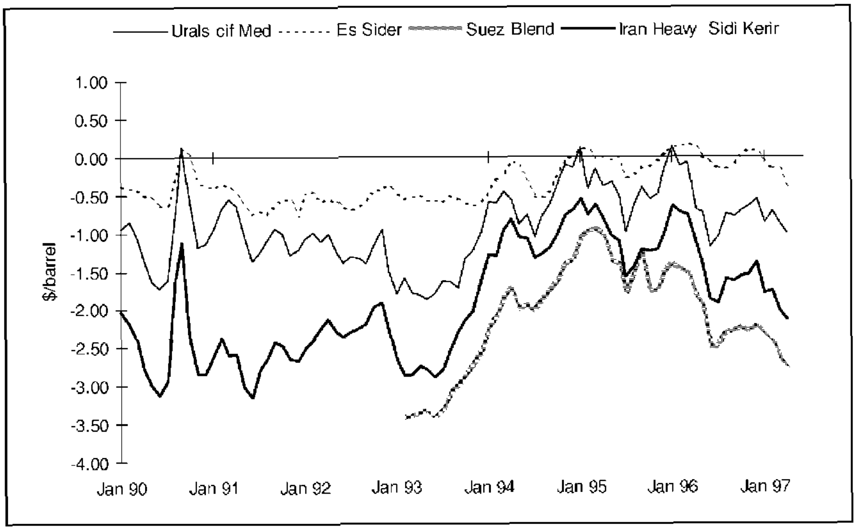
Although Russia is not a Mediterranean oil producer as such, up to 1 million b/d of crude is exported into the Mediterranean from the former Soviet Union. The vast majority of the exports are Urals, a medium gravity (33° API, 1.4 per cent sulphur) sour crude that is now the most important price marker in the Mediterranean spot market (see Fig. 4.5). Small volumes of higher quality Siberian Light and Kazakstan's very light Tengiz crude are also exported from the Black Sea ports.

Russian crude oil exports used to be highly seasonal, often falling to quite low levels in the first quarter as crude was diverted to domestic markets during the winter, but the pattern broke down in 1996/97 as the government maximised export volumes for state needs. The continuing need for hard currency and reliable payment has ensured that Russian oil exports are maintained on an annual basis, despite sharp falls in production since 1989. Following the independence of the Baltic States, the Mediterranean has become the most important sea-borne market for Russian crude. Between 700 and 900,000 b/d of Russian crude is also exported by the Druzhba (Friendship) pipeline to east and central Europe. Both pipeline and seaborne exports are priced at a discount to dated Brent that varies seasonally, being wider in the summer and narrower in the winter. Price differentials have firmed since the introduction in mid-1995 of a system of official export "co-ordinators" who control the flow of oil through the ports and pipelines.

Most of the Urals crude (600-700,000 b/d) is shipped to the Mediterranean market via the Black Sea port of Novorossiysk, but around 150-250,000 b/d is also exported from the Ukrainian port of Odessa. While there is an fob market in Urals at Novorossiysk, frequent loading delays at the port have deterred buyers from using their own vessels to collect the crude. As a result, most of the trade in Urals is on a delivered (cif) basis with the crude being transported either in Russian vessels or in vessels chartered by Russian exporters. Prices for Urals crude into the Mediterranean are based on delivery to Augusta in Sicily, with purchasers paying a premium (or discount) based on the differential freight cost for delivery to other ports. In addition, about 100,000 b/d of Siberian Light crude oil is exported from Tuapse.

Kazakstan

Direct shipments from Kazakstan began in 1996 as the Chevron/Mobil joint venture Tengizchevroil (TCO) opened up a number of new export routes for its growing production. The baseload of Tengiz exports is shipped through Russia's pipeline system allowing TCO to sell around 70,000 b/d through ports and the Druzhba pipeline. But Kazakstan only has a limited capacity allocation on the Russian pipeline system and delays in the construction of the 1.3mn b/d Tengiz-Novorossiysk pipeline have forced TCO to find alternative export routes, including rail to the Black Sea port of Odessa (40,000 b/d), pipeline from Baku to Ali Bairamly and then rail to Batumi in Georgia (20,000 b/d), and rail to Porvoo in Finland, where Neste buys 25,000 b/d of Tengiz crude.



Source: Petroleum Argus

Figure 4.5 Mediterranean crudes minus dated Brent

Avoiding the Russian pipeline system keeps the oil separate, allowing TCO to realise the higher value of its very light (46° API) low sulphur (0.5 per cent) crude. Tengiz is of a similar quality to Saharan Blend and was selling at a premium of over 80 cents/bl to dated Brent in early 1997.

4.3.2 Algeria

Algeria produces about 850,000 b/d of generally light crude oil, from more than 50 oil fields, most of which is pooled to form Saharan Blend (see Table 4.6). More than 350,000 b/d of Algeria's crude oil output is exported. Production is rising despite Opec quotas now that Algeria has allowed foreign companies to invest in its upstream sector. Foreign oil companies — Agip (70,000 b/d), Arco (30,000 b/d), Cepsa (20,000 b/d), PetroCanada (20,000 b/d) — accounted for 140,000 b/d of crude production in early 1997, and Repsol, Andarko and Louisiana Land and Energy (LL&E) plan to bring a further 35,000 b/d onstream by the end of the year.

Most of the output of Saharan Blend is sold directly by Algeria's state-owned oil company, Sonatrach, at negotiated monthly prices under a framework of term contracts. Crude from the Zarzaitine field, which straddles the border with Tunisia, is marketed separately also through term deals or by tender. In addition to its crude oil streams, Algeria produces a significant volume of condensate (equivalent to about 550,000 b/d of oil) which is sold separately.

Sonatrach sets contract prices for Saharan Blend fob Algeria, at a differential to dated Brent, towards the end of each month for liftings during the coming month. The differential can vary between customers.

Table 4.6 Algerian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Algerian Condensate	65.0	0.00	550,000
Saharan Blend	44.0	0.10	723,000
Zarzaitine	42.0	0.10	37,000

4.3.3 Libya

Libya has the capacity to produce approximately 1.5 million b/d of crude, but its actual output is restricted to slightly less than this by its output quota as a member of Opec (see Table 4.7). Plans to expand capacity and encourage investment by foreign oil companies have been hampered first by the UN embargo on the sale of some oil industry equipment to Libya and now the US Iran/Libya law which was passed in October 1996. Nevertheless, some European companies have not been deterred and the new Murzuk field, which is a joint venture between Repsol, Total and ÖMV, came onstream in December 1996.

About a third of Libya's oil output (some 450,000 b/d) is operated by European companies, Agip, Veba, OMV and Wintershall, while the rest is owned by Libya's National Oil Corporation (NOC). Just over 1 million b/d is exported, with Oilinvest — an NOC affiliate — (220,000 b/d) and Agip (200,000 b/d) being the biggest lifters. ÖMV takes 80,000 b/d, Repsol and Turkish refiner Tupras 60,000 b/d each, and Veba 55,000 b/d. Oilinvest used to lift twice as much, but has cut purchases in favour of North Sea grades. Occasional spot sales are also made to Asian customers like China and South Korea.

Since 1993, Libya has begun to enforce more rigidly the 'restricted destination' clause in its oil sales contracts and has reduced its sales of Es Sider crude to traders in favour of equity producers and refiners. This has virtually killed the spot market in Libyan Es Sider crude which had formerly acted as a price marker for other Mediterranean crudes, most notably Syrian Light. Libyan Es Sider is priced off dated Brent and usually trades at a differential of between –$0.30 and +$0.30/barrel against the North Sea grade.

The new Murzuk field came onstream in December 1996 at 45,000 b/d and production is expected to rise to 200,000 b/d by 1998. It is a very light crude (44º API) and of better quality than Es Sider or Sarir. Until the export pipeline and terminal are completed in late 1997, Murzuk will be refined at Libya's Zawia refinery and the equity participants will lift an equivalent volume of other grades.

Table 4.7 Libyan export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Brega	40.0	0.20	
Bu Attifel	40.0	0.30	170,000
Es Sider	37.0	0.27	445,000
Sarir	36.0	0.20	
Zueitina	41.0	0.20	100,000
Murzuk	44.0	minimal	45,000*

**December 1996.*

4.3.4 Egypt

Egypt produces just under 850,000 b/d of crude oil and about 35,000 b/d of condensates, principally from fields in the Gulf of Suez with additional volumes from fields in the Qattara Depression and the Libyan Plateau in the north-west of the country (see Table 4.8). Crude production rose marginally in 1996 averaging 850,000 b/d (890,000 b/d including condensates) and is expected to remain around this level in 1997. Crude from the Gulf of Suez is either shipped eastward through the Red Sea or is transported to the Mediterranean terminal at Sidi Kerir via the Sumed pipeline. Egypt refines just over half its production and exports the remainder (400,000 b/d).

The principal producer of crude in Egypt is the Gulf of Suez Petroleum Company (Gupco), a joint venture between the Egyptian General Petroleum Corporation (EGPC) and Amoco, which combines the output from its Gulf of Suez fields to produce nearly 400,000 b/d of Suez Blend. The other major oil producers in Egypt are: Petrobel (EGPC and Agip affiliate IEOC), which produces 230,000 b/d from the Belayim and Ras Gharib fields; Suez Oil Company (Deminex, Shell, Repsol and EGPC), which produces 70,000 b/d from the Ras Budran, Ras Fanar and Zeit Bay fields in the Gulf of Suez; Agiba (Agip), which produces 50,000 b/d; Khalda (Repsol, Phoenix and Samsung), which produces 35,000 b/d in the

Western Desert; and the Zaafarana Oil Company (British Gas, EGPC, Union Pacific, and Yukong), which started producing 20,000 b/d of heavy, high sulphur crude from the Gulf of Suez in early 1995.

Amoco sells its share of Suez Blend output (130,000 b/d) on its own behalf, while EGPC exports a further 180,000 b/d. More than half of EGPC's exports are sold under government-to-government contracts (more than 100,000 b/d to Israel and South Africa) or into minor equity holders (30,000 b/d). A further 50,000 b/d is sold to international refiners, leaving just 25,000 b/d which is sold to a range of term customers. New production of heavy crudes such as Zaafarana is likely to be exported mainly to the US.

Table 4.8 Egyptian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Suez Blend	33.0	1.4	395,000
Belayim	26.0	2.2	205,000
Ras Gharib	25.0	3.0	20,000
Ras Fanar	32.5	1.6	}
Ras Budran	24.8	2.4	} 70,000
Zeit Bay	34.5	1.4	}
Zaafarana	21.0	3.3	20,000

At the end of each month, the Egyptian General Petroleum Corporation sets a formula price for Suez Blend for the coming month. The formula used to be a weighted average of a discount to *Platt's* dated Brent quotes (60 per cent), a discount to Iranian Heavy quotes (20 per cent) and Suez Blend quotes (20 per cent), but EGPC switched to a simple differential to dated Brent from January 1996 after losing term contracts with customers who complained that the price was too high. Other Egyptian grades used to be priced relative to Suez Blend, but are now also priced against dated Brent. The company was criticised in the past for not being sufficiently responsive to the market when setting its official selling price for Suez Blend.

4.3.5 Syria

Syria's crude oil output has dropped to around 560,000 b/d after peaking at 600,000 b/d two years ago. About 225,000 b/d is refined domestically at the Banias and Homs refineries leaving around 335,000 b/d for export (see Table 4.9). The oldest fields, in the north-east of the country, are produced by the Syrian Petroleum

Company (SPC) and yield heavy crudes with gravities below 25° API which are blended to form Souedie. The more recently-discovered fields further south, exploited by the Al-Furat Petroleum Company (a joint venture between SPC, Shell and Deminex) yield much lighter grades with gravities between 30° and 45° API. These are blended with 60,000 b/d of similar crude produced by Deir ez Zor Petroleum Company (a joint venture between SPC and Elf) to form Syrian Light. Al-Furat production is falling more rapidly than expected and tough upstream terms have discouraged most companies from exploring in Syria. The only new production is from Tullow Oil's 7,000 b/d Kishima field which is scheduled to come onstream in April 1997.

Between 10 and 13 cargoes of Syrian Light and four cargoes of Souedie (each of 600,000 barrels) are exported each month with sales handled by Syrian state marketing company Sytrol at prices related to dated Brent. Syrian Light used to be priced against Libyan Es Sider, but Sytrol switched to dated Brent at the end of 1993 as the spot market for Es Sider contracted (see Section 4.3.3). Much of the output of Syrian Light is lifted under term contract by European refiners and traders. In 1996, the main buyers were BP, Shell, Elf, Total, Mobil, Agip, Isab, Oil Energy, Cepsa and Repsol.

Table 4.9 Syrian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Syrian Light	36.0	0.80	410,000
Souedie (Suwaydiah)	25.0	3.00	150,000

Since the spot trade in Es Sider collapsed in 1993, Syrian Light has become the *de facto* light sweet price marker for the Mediterranean market. Although lifted under term contracts which require written permission to resell Syrian crude, it is estimated that approximately 60 per cent of Syrian crude exports was sold on to other companies by lifters or was put through processing arrangements outside the lifters' own refining systems. But in January 1994, Sytrol began to enforce the onward sales clause more rigorously and, while this may not have curtailed the spot trade in Syrian Light completely, it has made it less liquid and less visible. This has deprived the Mediterranean market of a light sweet price marker and reduced spot market transparency.

Heavy Souedie crude is also priced against dated Brent.

4.3.6 Iran

Sales of Iranian crude oil on an fob basis from the northern terminal of the Sumed pipeline at Sidi Kerir have traditionally played an important role in the Mediterranean market. Although the volumes were never very large, the trade had a significant impact since it provided a spot market reference price for Mid-east Gulf crudes that could be used when negotiating term contracts with producers (see Section 4.6.2).

However, Iran cut the volumes of oil available for sale to third-parties at Sidi Kerir in 1994, partly through increased sales of crude to end-users on term contracts, and partly by enforcing the restricted destination and re-sale clauses in its term contracts. This has led to a dramatic fall in sales to traders and also to spot trade in Iranian crude at Sidi Kerir. The volume of "public" spot trade was further reduced in 1995 when the US government extended its embargo on purchases of Iran crude to the foreign subsidiaries of US companies. NIOC now sells exclusively to end-users. As a result the Sidi Kerir spot market has become both less liquid and less transparent. According to the *Argus Crude Oil Deals Database*, the number of confirmed spot deals at Sidi Kerir involving Iranian crude fell to around 60 in 1994 and 1995 compared with around 200 a few years before. Spot trade for Iranian crude in the Mediterranean remains very quiet, especially now more cargoes are moving to eastern refiners who are prepared to pay a higher price. About 600,000 b/d of Iranian crude is trans-shipped through Sumed, but less than 100,000 b/d is sold on the spot market.

4.3.7 Tunisia

Tunisian crude production averaged only 90,000 b/d in 1995 as new fields failed to replace falling output, further reducing its export potential. Although Tunisia's domestic consumption is around 80,000 b/d, the only refinery, Bizerte, has a capacity of 34,000 b/d and is unable to meet demand so the balance is met by product imports.

Tunisia's main export grades are the light sweet Zarzaitine (43º API, 0.1 per cent sulphur) and the heavy sourer Ashtart (29º API, 1 per cent sulphur). 'Zarzaitine' blend is actually a mixture of crudes produced from fields in both Algeria and Tunisia and exported from the Tunisian terminal of La Skhirra. Tunisia's share of the joint Algerian-Tunisian Zarzaitine field is now 72,000 b/d and the blend also includes crude from Tunisia's el-Borma (31,000 b/d), Sidi el-Kileni (13,500 b/d) and Belli (7,600 b/d) fields. Ashtart is produced and loaded offshore and production averaged 18,000 b/d in 1995. Tunisia's crude exports are all sold by spot tender. Exxon is the biggest buyer of Zarzaitine and Repsol of Ashtart.

The Tunisian state oil company, Entreprise Tunisienne d'Activités Pétrolières (ETAP) has a large shareholding in Tunisia's oil production, but the international oil companies have played an important role in the development of Tunisia's oil. Foreign companies currently producing oil in Tunisia are Agip (el-Borma), Kufpec – a Kuwaiti-owned company (Sidi el-Kileni), Marathon (Belli and Ezzaouia), British Gas (Cercina and others), Elf (Ashtart), Neste and Samedan – a US company (Tazarka).

4.3.8 Iraq

Limited Iraqi oil exports resumed in December 1996 under the terms of the UN oil-for-aid deal (Resolution 986). Iraq is allowed to export up to $2bn worth of oil over a renewable six-month period and exports are strictly controlled by UN monitors. In the first half of 1997, Iraq exported around 360,000 b/d of Kirkuk blend (36º API, 2 per cent sulphur) through the Iraq-Turkey pipeline to the Mediterranean port of Ceyhan. 26 companies signed term contracts and the biggest customer was the Turkish refiner, Tupras, which took 75,000 b/d. Exports to Europe are priced at a differential to dated Brent and exports to the US at a differential to spot WTI (see Appendix 4.2). Export volumes vary according to the realised price and changes in the formula price must be agreed by the UN.

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4.4 West Africa

The major oil producers in west Africa are Nigeria, Angola and Gabon (see Table 4.10). Nigeria is the only remaining member of Opec after Gabon left the organisation in June 1996. Smaller amounts of crude oil are also produced by Congo (270,000 b/d), Cameroon (110,000 b/d), Equatorial Guinea (60,000 b/d), Zaire (20,000 b/d), the Ivory Coast (20,000 b/d), South Africa (20,000 b/d) and Benin (3,000 b/d). Production began from Equatorial Guinea's offshore Zafiro field offshore in August 1996 and from South Africa's offshore Oribi field in early 1997. Crudes from the Congo, Cameroon, Equatorial Guinea, Zaire and Ivory Coast are also exported for sale on the international market. West African crudes are generally sweet and give a good yield of middle distillates, making them highly attractive to Asia-Pacific refiners who now regularly compete for supplies with European and US refiners (see Fig. 4.6). Up to 1 million b/d of west African crude now moves east when prices in the Atlantic basin are low relative to the Asia-Pacific market.

Table 4.10 West African crude production and exports, 1996

Country	Production b/d	Exports b/d	Capacity† b/d
Nigeria*	2,060,000	1,790,000	2,200,000
Angola	705,000	675,000	720,000
Gabon	370,000	350,000	370,000
Congo	200,000	180,000	270,000
Cameroon	105,000	85,000	110,000
Equatorial Guinea	20,000	20,000	40,000

* *excluding condensate* † *end year*

4.4.1 Nigeria

Nigeria is Africa's largest producer of crude oil, with output now running at around 2.2 million, well above its Opec quota of 1.865 million b/d (see Table 4.11). Over the past year, joint ventures with foreign companies have boosted output by 200,000 b/d and further expansion is planned to meet a capacity target of 2.5 million b/d by 2000.

The country exports nearly 1.8 million b/d, chiefly to the USA and southern Europe, but increasing volumes are now moving to India and east Asia. Nigeria's oil production is centred around the

Table 4.11 Nigerian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d	Main foreign participants
Bonny Light	36.7	0.12	430,000	Shell/Agip/Elf
Bonny Medium	25.2	0.23	70,000	Shell/Agip/Elf
Brass River	40.9	0.09	130,000	Agip/Phillips
Escravos	36.2	0.14	400,000	Chevron
Forcados	29.7	0.29	430,000	Shell/Agip/Elf
Pennington	36.6	0.07	80,000	Texaco/Chevron
Odudu	28.5	0.18	105,000	Elf
Qua Iboe	35.8	0.12	360,000	Mobil
Oso Condensate	47.7	0.05	110,000	Mobil
Ima*	45.0	0.10	40,000	Abacan

**production from offshore Ngo field (Ima blend) began in January 1997*

Niger Delta in the southeast of the country and adjacent offshore areas. Oil is produced under equity joint ventures including a number of multi-national oil companies as operators such as Shell (965,000 b/d), Mobil (365,000 b/d), Chevron (415,000 b/d), Agip/Phillips (140,000 b/d), Elf (135,000 b/d), and Texaco (80,000 b/d). Mobil also produces 110,000 b/d of Oso condensate which is not covered by Nigeria's Opec quota.

Just under half of Nigeria's crude oil exports used to be sold under one-year term contracts to around 30 companies, with volumes ranging from 10,000 b/d to 40,000 b/d. But Nigeria's term contracts are in disarray at present after 23 term contracts were cancelled in March 1996 and a further 12 axed from September 1996. The Nigerian National Petroleum Corporation (NNPC) is trying to renew term arrangements but a high degree of uncertainty remains and most of NNPC's customers are effectively spot buyers.

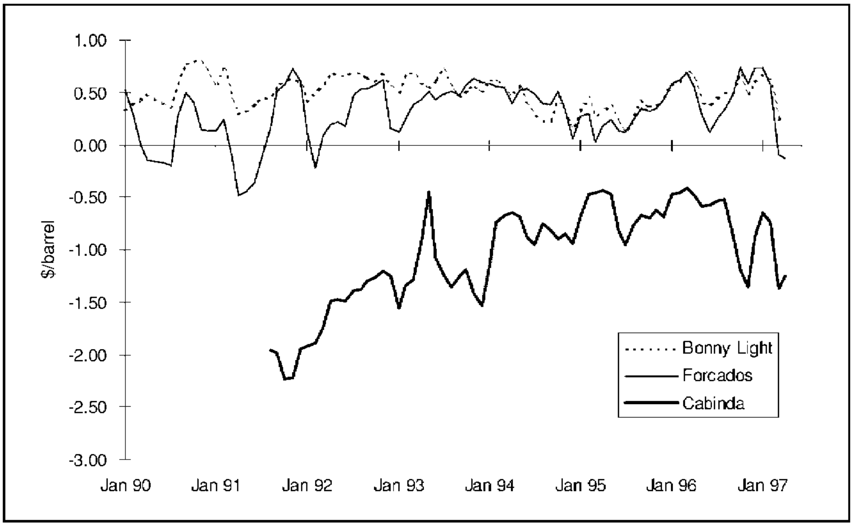
All applicants for crude term contracts with Nigeria must show an annual turnover of at least $100 million and a net worth of $40 million. They must also demonstrate a commitment to the development of the Nigerian economy. Failure to commit or make such investment within six months of signing a deal will cause the contract to be cancelled and the contract holder to forfeit a $1 million bond that they are required to post with a Nigerian bank.

Towards the end of each month, NNPC sets official selling price differentials to dated Brent for its export grades for the coming month (see Appendix 4.2). Until 1993, Nigeria's sweeter crudes, Pennington, Brass River, Bonny Light and Qua Iboe were all priced at the same level. In 1993, in an effort to maximise revenues from the sale of sweet crudes, Nigeria introduced differential pricing for its sweetest crudes. Since then, Pennington and Brass River have both been priced at a premium to Bonny Light and Qua Iboe.

Nigeria's standard pricing formula applies the announced differentials to dated Brent quotations over the five days following the date of the bill of lading. However, Nigeria also offers a delayed pricing option and an early pricing option. Under the deferred pricing option, prices are calculated on five days of dated Brent quotes starting 14 days after bill of lading. Prices under the delayed option are at premium to those under the standard pricing option and it is popular when the market is in backwardation. The delayed option was first introduced in 1991 and it re-appeared in 1994. For May 1996 the premium was 45 cents/barrel, reflecting the strong backwardation in the Brent market against which Nigerian grades are priced. The early pricing option is used when the market is in contango and allows lifters to price cargoes 5 days prior to the bill of lading.

4.4.2 Angola

Angola produces approximately 720,000 b/d of crude oil; most of this (410,000 b/d) is produced offshore by Chevron from the Cabinda enclave, which is separated from the rest of Angola by a strip of Zairean territory (see Table 4.12). Early production from the Nemba and Lomba fields also forms part of the Cabinda blend. Full production is scheduled for 1998.



Source: Petroleum Argus

Figure 4.6 West African crudes minus dated Brent

The remainder of Angola's oil production also comes mainly from offshore fields: Palanca, Soyo and Kiabo. Palanca blend (operated by Elf) output has reached 185,000 b/d since the Cobi and Pambi fields came on stream and is expected to rise to 195,000 in 1997. Output of the offshore Soyo blend (operated by Texaco) rose sharply to 100,000 b/d in 1996 following the installation of the Bague platform. The 5,000 b/d Kiabo field is operated by the Angolan state oil company, Sonangol.

The onshore Soyo fields were shut in when the area was occupied by Unita forces in January 1993, but Petrofina re-started production at 5,000 b/d in early 1996 and output has now reached 14,000 b/d. Petrofina plans to restore output to its original level of 25,000 b/d by the end of 1997.

Around 30,000 b/d of Angola's output is refined locally, leaving the remaining 680,000 b/d available for export. Production is expected to rise sharply to 780,000 b/d by 1998 as Chevron and Elf increase offshore output following a series of new finds.

Table 4.12 Angolan export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Cabinda†	32	0.2	415,000
Palanca	39	0.1	185,000
Soyo (onshore)*	34	0.2	5,000
Soyo (offshore)	34	0.2	85,000

**re-started early 1996*   *† includes early production from Nemba*

Chevron produces 40 per cent of Cabinda output (165,000 b/d), while its partners Elf and Agip each have around 10 per cent each. The remainder is sold by the state oil company, Sonangol, mostly under annual framework contracts, with each term cargo priced on an *ad hoc* basis.

4.4.3 Gabon

Gabon's crude production reached 370,000 b/d in 1996 following the commissioning of new fields, greatly exceeding its Opec quota of only 287,000 b/d. But Gabon finally left Opec in June 1996 after failing to pay its Opec membership dues for a number of years. Output is expected to decline to 350,000 b/d in 1998 and to 260,000 b/d by 2001 according to upstream consultants, Wood Mackenzie. More than half of the output of light sweet crude from the country's onshore fields is piped northwards to Elf's Cap Lopez terminal where it is sold as Rabi Light, while the remainder is sent south to

Shell's Gamba terminal where it is blended with crude of a similar quality from the Gamba field to form Rabi Blend (see Table 4.13).

Table 4.13 Gabonese export crudes, 1996

Crude stream	**Gravity °API**	**Sulphur %wt**	**Production b/d**
Rabi Light	33.0	0.1	130,000
Rabi Blend	33.8	0.1	100,000
Mandji (incl Obando)	30.0	1.1	115,000
Lucina	38.0	0.0	4,000
M'Bya	35.5	0.1	4,500
Ogwendjo	34.0	0.0	6,000

Gabon's second most important crude stream, the heavy, medium sour Mandji, is produced by Elf from a network of offshore fields and is also loaded via the Cap Lopez terminal where it is co-mingled with Obando (owned by French independent, Perenco, and Lasmo). Gabon's other crude streams, which account for the remaining 11,500 b/d of Gabon's capacity, are Lucina (now owned by Perenco), M'Bya (produced by Perenco), and Ogwendjo (85 per cent also owned by Perenco). All are produced from offshore fields, are similar in quality to Rabi and are loaded from floating storage.

4.4.4 Congo

Congo produces 270,000 b/d of crude oil ranging in gravity from 22.3° to 36.9°API from a number of offshore and onshore fields. Elf's new deep water field, Nkossa, came on stream in mid-1996 at around 70,000 b/d and is now producing 120,000 b/d. Another deep water field, Kitina, operated by Agip will come on stream by 1999, adding at least a further 30,000 b/d. The only foreign operating companies currently producing oil in Congo are Elf (255,000 b/d) and Agip (45,000 b/d), although Shell, Chevron and Occidental have both signed exploration and production deals in the country. Congo has a refinery capacity of 21,000 b/d, the rest of its crude output being exported. Congo's principal export grade is Djeno, a low sulphur, heavy crude with an API gravity of 26.8° and a 0.37 per cent sulphur content. Elf's Nkossa crude is much lighter with an API gravity of 38° and has a lower sulphur content.

4.4.5 Cameroon

Cameroon produces approximately 112,000 b/d of oil ranging from 17° to 42.5°API, mostly from offshore fields in the Rio del Rey

Basin. The country's principal operator is Elf, which produced around 90,000 b/d in 1996, while most of the remainder of the country's output is produced by Pecten International and French independent, Perenco. Production from the Kribi field started in early 1997 boosting production by 12,000 b/d, but declining output from other fields will cancel out the gains by 1998. Kribi is operated by Elf (51 per cent) and the other participants are Chevron (30 per cent), state Hydrocongo (18 per cent) and Energy Africa — an affiliate of South Africa's Engen — (4 per cent).

Cameroon has the capacity to refine 43,000 b/d of crude at its refinery at Limbe, most of which is from domestic output although some lighter Nigerian Brass River is also imported. The major export grade is Kole, which has a gravity of 34.9° API. It also produces Lokele (20° API) and Moudi crudes.

4.4.6 Equatorial Guinea

Equatorial Guinea's first oil field started production in August 1996. The offshore Zafiro field operated by Mobil was producing 40,000 b/d in early 1997 and is expected to reach 80,000 b/d by the end of the year. Zafiro is a low sulphur crude similar in quality to Angolan Cabinda and has an API gravity of 32°. Another new discovery, Jade, will start production towards the end of 1997 and will be tied into the Zafiro platform.

4.4.7 Zaire

Zaire produces 20,000 b/d of medium gravity (31.7° API) crude for export. Exxon is the main purchaser.

4.4.8 Ivory Coast

Ivory Coast produces 20,000 b/d of Lion crude. The field is owned and operated by United Meridian (UMC) and began production in 1995. All Lion crude is sold on a term basis and moves to South America and Europe. In 1996, Lion prices were negotiated at dated Brent minus $0.45/bl.

4.5 United States

4.5.1 US crude market

The United States is the largest crude oil market in the world. As well as being the second largest oil producer after Saudi Arabia it is also the biggest oil consumer, importing 7.5 million b/d of crude oil in 1996, just over half the crude required by US refineries (see Table 4.14). As a result, active spot markets have developed for both domestic and imported crude, which in turn have supported the growth of very large forward, futures and derivative markets. West Texas Intermediate (WTI) is the leading benchmark for the US domestic crude market since it forms the basis of the Nymex Light Sweet Crude futures contract (see Chapter 8).

However, it is important to realise that the US domestic crude market operates differently from markets that have developed in other parts of the world. Virtually every barrel of domestic crude, with the exception of Alaskan North Slope (ANS), is traded, priced and transported by pipeline rather than on waterborne tankers and barges. In addition, the government's ban on exports of crude produced in the US (apart from ANS), and the relative isolation of the populated east (Padd I) and west coast (Padd V) markets from the major producing and refining areas on the US Gulf coast (Padd III) have had a strong influence on the way in which markets and patterns of trade have evolved.

Table 4.14 US crude import dependence, 1996

District	Production b/d	Crude runs b/d	Imports b/d	Import dependence
Padd I	27,000	1,331,000	1,271,000	95.5%
Padd II	566,000	3,254,000	767,000	23.6%
Padd III	3,158,000	6,629,000	4,967,000	74.9%
Padd IV	368,000	469,000	124,000	26.4%
Padd V	2,352,000	2,498,000	353,000	14.1%
Total	6,471,000	14,181,000	7,482,000	52.8%

Source: US DOE/EIA, Petroleum Supply Monthly

US crude is produced in many states, the most important of which are Texas, Alaska, California, Louisiana, Oklahoma, Wyoming, New Mexico and Kansas. In addition, there is rising production in the Gulf of Mexico from new offshore fields such as Auger and Mars. Prices for most domestic crudes are linked either to cash prices for WTI or posted prices set by refiners for wellhead purchases. Because most domestic crude moves to both the market and the end user by pipeline, most barrels are traded on an fip (free in pipeline) basis either at the wellhead or at major gathering points such as Cushing, Oklahoma, Midland, Texas and St James, Louisiana (see Table 4.15). ANS is the main exception as it is moved by tanker from Alaska and can also now be exported. ANS is sold cif either on the US west coast or under term contract to Far East refiners such as Taiwan's CPC.

Another key difference between trade in most domestic crudes and trade in imported crudes (or ANS) is the method and timing of delivery. Since most domestic crudes are transported by pipeline, trading is conducted and deliveries are made on a 'rateable' basis. This means a company can buy or sell crude over the entire course of the month at a rate of "x" b/d giving refiners the flexibility to run the crude as it is received, thus reducing storage costs. In addition, rateable sales make domestic crudes popular for filling small gaps in refiners' slates. In contrast, imported crudes are generally traded either as a single parcel priced either on an fob basis at the loading port or on a cif or out-turn basis at the delivery port.

The most important "spot" crude market in the US is the cash WTI market, which also provides the underlying physical commodity for the Nymex WTI futures contract. Although it is a pipeline market, it does not trade on a rateable basis since there is sufficient storage capacity available at Cushing, Oklahoma to support a market which trades in highly flexible 'lots'. Cash WTI deals vary in size from tens of thousands to hundreds of thousands of barrels for a given delivery month and are also traded forward for periods of several months ahead, providing an alternative to the futures market, particularly outside normal exchange hours or during a crisis such as the start of the Gulf War when the Nymex was closed. Cash WTI deals are either done on a fixed basis or more usually at a differential to the Nymex crude futures contract. But liquidity has declined since Nymex introduced its 24-hour "Access" trading system and the cash WTI market is now most active during the *Platt's* pricing window which falls between the Nymex close and the start of Access trading (see Chapters 7 & 8).

Posted prices are also set by refiners and crude oil gatherers to reflect the price that these companies will pay at the wellhead for a specific grade of crude on a given day. Most of the domestic crude in the US is still sold by producers on a postings related basis according to the Houston-based consultants Purvin & Gertz. These include widely traded grades such as WTI, WTS and LLS, as well as small streams of crude located near a specific refiner's or gatherer's system. The methods by which posted prices are set have evolved over the years, but they were originally set to reflect market prices for a given crude less the gathering and transportation costs associated with bringing the crude from the wellhead to the market.

Other spot markets and trading instruments have developed alongside the huge volume of posted prices trade. The "postings-plus" or "P-plus" markets developed in the late 'eighties and is widely used as a pricing mechanism. In nearly all cases P-plus trade is based against the postings set by Koch Industries, which is the largest gathering company in the US. Some traders have attempted to use prices issued by other companies such as Texaco, but these have not met with much success. Instead most traders establish their postings premium by looking at the differential between Koch's posting and the nearby Nymex WTI futures price. The differential represents the premium that the buyer will pay over the relevant postings price in the next month when the crude is delivered rateably and invoiced.

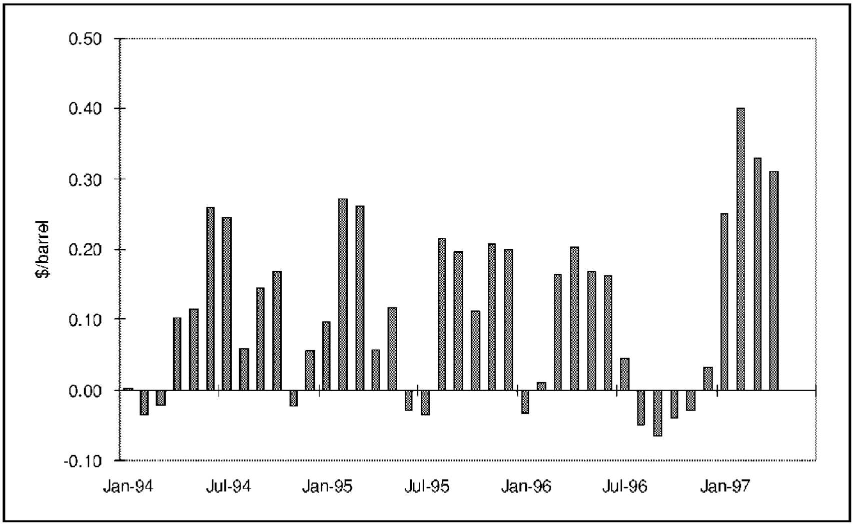
Other modes of trading that have become increasingly popular are three to six-month mini-term deals known as strips. For example, a buyer might agree to purchase 1,500 b/d of a particular grade for three months with all the crude priced at the same differential to three concurrent months of WTI prices. Since strips reduce the need for spot trading, their growing popularity contributed to the declining liquidity of the key US pipeline marker crudes in the early 'nineties.

Table 4.15 Key US domestic crudes, 1996

Crude stream	**Gravity °API**	**Sulphur %wt**	**Production b/d**
West Texas Intermediate (WTI)	40	0.40	450,000
Light Louisiana Sweet (LLS)	36	0.40	650,000
Heavy Louisana Sweet (HLS)	33	0.45	575,000
West Texas Sour (WTS)	32	1.60	780,000
Eugene Island	31	1.34	175,000
Mars	31	2.00	100,000*
Alaskan North Slope (ANS)	27	1.06	1,397,000

Source: Purvin & Gertz, Petroleum Supply Annual ** capacity*

WTI is also traded on a rateable basis for delivery at Midland, Texas. Midland is the junction where crude moving through pipelines from New Mexico and west Texas is either shipped north to Cushing or south to the Gulf coast. As a result, the differential between WTI at Midland and WTI at Cushing reflects the relative strength of demand from refiners in the mid-continent and those on the Gulf coast. In a balanced market, Cushing now trades at a



Source: Petroleum Argus

Figure 4.7 The Cushing Cushion, WTI Cushing–WTI Midland

premium of around 30 cents/barrel to Midland reflecting the additional transport costs. During the summer months, peak demand from midcontinent refiners can exceed the capacity of the Midland to Cushing pipeline and the price of WTI at Cushing can rise sharply in what is known as the 'Cushing Cushion' (see Fig. 4.7) — although increased pipeline capacity has alleviated this particular problem in recent years. But, despite the increased pipeline capacity, WTI still does not always move in step with other international marker crudes. Other US pipeline crudes, such as WTS and LLS, are all traded on a rateable basis.

4.5.2 East coast

The US east coast is highly dependent on crude imports as it is has little local production and is isolated from the domestic pipeline network. Most of the crude refined in the area is imported from the North Sea, West Africa, the Middle East and Latin America and purchased on an fob basis since the relatively small number of refiners means that there is no spot market for delivered crudes. Refineries are concentrated in the middle Atlantic states of Pennsylvania, New Jersey, Delaware and Virginia.

4.5.3 Gulf coast

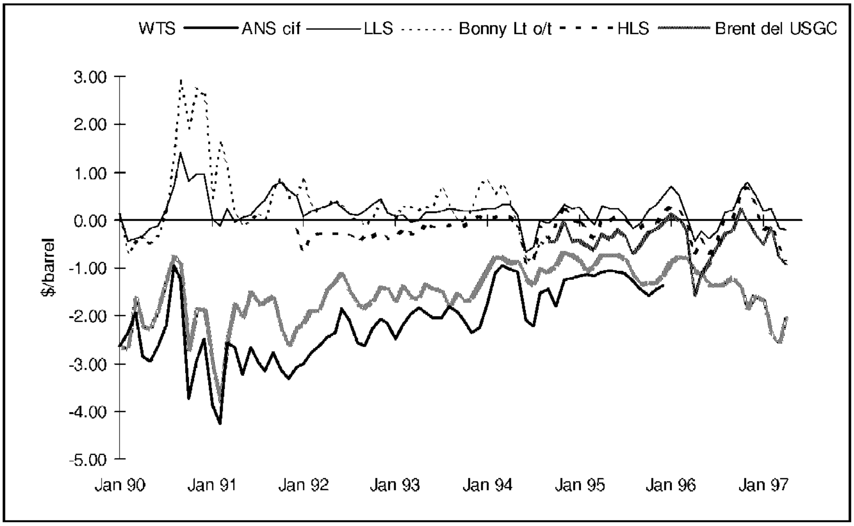
The Gulf coast is the biggest refining centre in the US. Stretching from Corpus Christi, Texas to Pascagoula, Mississippi, it consumes more than 7 million b/d of crude and draws its supplies both from imports and from domestic crude produced in Texas, Louisiana and the offshore fields. Offshore production from the Gulf of Mexico is increasing sharply as new deepwater fields are developed and could reach 1 million b/d by the end of the decade. Shell's 60,000 b/d Auger field came on stream in late 1994 and the 100,000 b/d Mars field, which is of similar quality to West Texas Sour and Arab Medium, started up in July 1996 and was producing around 80,000 b/d by mid-1997. Gulf coast refineries are typically large and highly upgraded. Because of their size, coastal location and deep conversion capacity, most Gulf coast refiners have the flexibility to process a wide variety of imported crudes in addition to the full range of domestic pipeline crudes. As a result, active spot markets for both domestic and foreign crudes have developed in the area.

The main domestic pipeline markets available to Gulf coast refiners are:

- Light Louisiana Sweet (LLS) based on St James, Louisiana,
- Heavy Louisiana Sweet (HLS) based on Empire, Louisiana,
- West Texas Intermediate (WTI) based on Midland, Texas,
- West Texas Sour (WTS) based on Midland, Texas.

LLS is very similar in quality to imported sweet crudes from the North Sea and West Africa and provides a good barometer of both refinery demand and foreign crude availabilities on the US Gulf coast (see Fig. 4.8). In addition, the new offshore Mars crude (XX° API, yy per cent sulphur) is rising in prominence and some see it providing a possible benchmark for sour crudes in the future.

Supplies of North Sea, West African and Latin American crudes are usually available on a spot basis as US refiners prefer to hold low crude stocks and there is a ready market for short-haul supplies. The most common grades of sweet crude include North Sea Brent and Oseberg, Nigerian Bonny Light, Bonny Medium, Forcados, Brass River and Qua Iboe, Angolan Palanca and Cabinda, and Colombian Cusiana. Spot sales of sour crude are usually confined to Colombian Caño Limon and Ecuadorean Oriente since tough resale restrictions are imposed by other major sour crude producers such as Saudi Arabia, Venezuela and Mexico. Prices for all imported crudes are linked — either directly or indirectly — to WTI quotations around the date of delivery. Some producers, like Mexico, actually use other pipeline grades, such as



Source: Petroleum Argus

Figure 4.8 US Gulf coast crudes minus WTI Cushing

WTS or LLS in their pricing formulas rather than WTI (see section 4.7.5), but these, in turn, are priced off WTI. Previously sour crudes were linked to ANS but the ANS market on the Gulf coast has completely dried up as most of this crude is delivered to the US west coast and can now be exported to the Far East.

The 1.4 million b/d Louisiana Offshore Oil Port (LOOP) is the only deepwater port in the US capable of discharging VLCC sized vessels. As a result, the bulk of imported crude must be lightered to refiners from larger vessels located in international waters. Most of the lightering is concentrated off the upper Texas coast near Galveston, but extensive lightering operations also occur in the Gulf of Mexico near refineries located in Corpus Christi. On average, Gulf coast lightering costs under 30 cents/barrel, but more stringent oil spill liability laws have reduced the pool of vessels available for lightering and costs are rising.

LOOP throughputs have fallen steadily this decade as long-haul producers make increasing use of Caribbean storage, allowing use of other ports with smaller vessels. The growing volumes of Latin American crudes are also transported on smaller vessels, some of which can discharge at Gulf coast ports. But throughputs are expected to rise in the future as output from a number of new offshore fields such as Mars will be linked by pipeline to LOOP.

4.5.4 Mid-continent

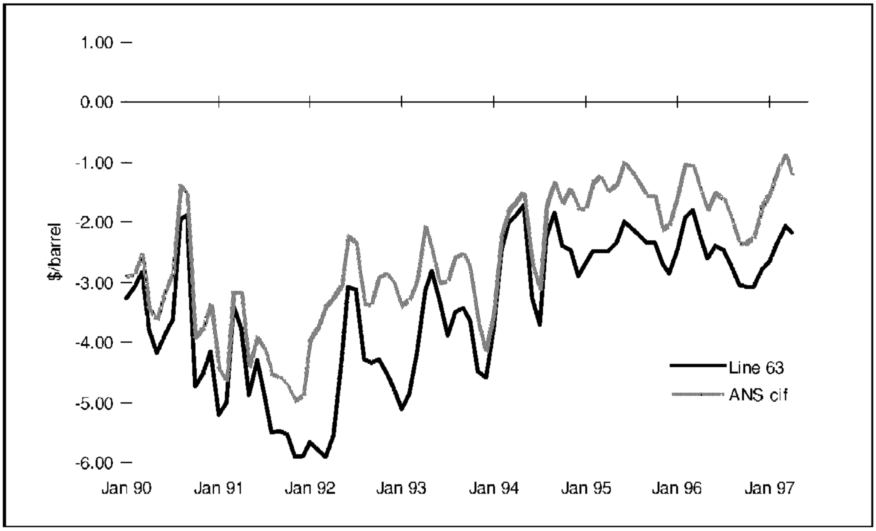
The landlocked US mid-continent region can have a disproportionate impact on the world oil market through its influence on domestic crude prices, in particular WTI at Cushing, Oklahoma. Refiners in this region are entirely dependent on pipeline supplies for both domestic and imported crudes and during the peak summer season the local demand for crude can exceed the capacity of the pipeline system to deliver it. In both 1989 and 1994 pipeline supply bottlenecks caused inland WTI prices at Cushing to increase sharply relative to domestic and imported crudes on the Gulf coast (see Fig. 4.8). US mid-continent refineries tend to be both smaller and less sophisticated than their Gulf coast counterparts. As a result, they have less flexibility over the grades they can process, typically preferring light sweet crudes. In addition, they often have only limited storage capacity since they are used to processing crude delivered on a rateable basis.

But new pipeline capacity from both Canada and the US Gulf coast has reduced summer supply constraints at Cushing. Canadian crude is increasingly important to the US mid-continent, which has provided a ready-made market for the unexpectedly sharp rise in Canadian crude production.

4.5.5 West coast

The US west coast crude market operates in almost complete isolation from other US refining centres. Its only link was the overflow of ANS supplies, which used to move to the Gulf coast, but shipments have virtually ceased. West coast refiners have extensive upgrading and de-sulphurisation capacity and run a slate that consists mainly of ANS, local Californian heavy crudes, and some Canadian crude. Other crude imports are limited and consist mainly of lighter, low sulphur crudes from the Far East. But imports have increased now that Alaskan crude can be exported and US west coast refiners are running more south American crude, for example, Ecuadorian Oriente, Argentinian Canadon Seco or Colombian Caño Limon.

ANS plays a dominant role in the west coast spot market, but most of the marginal supplies are typically in the hands of one company, BP, which owns the largest ANS share of production but now has no local refinery capacity. As a result, ANS prices can change abruptly relative to WTI particularly at the end of a delivery month (see Fig. 4.9). In the spot market, ANS is priced at a discount to WTI, either on an outturn cargo basis or on a pipeline basis.



Source: Petroleum Argus

Figure 4.9 US west coast crudes minus WTI Cushing

Local Californian crudes are typically traded on a postings related basis. The most common arrangement employs the average of the price postings made by Chevron, Mobil, Union, and Texaco (CMUT). The most actively traded grade used to be Line 63, a heavy sour crude blended from crudes taken from California's San Joaquin Valley, including light crude from the US Naval Reserve Elk Hills field, and the federally-owned offshore Outer Continental Shelf (OCS). But liquidity has declined since an earthquake destroyed another pipeline — the 50,000 b/d Line One — in early 1994, which meant that Line 63 throughputs have had to be pro-rated because of the capacity shortage, reducing the amount of crude available for spot trading in the Los Angeles area. Although its characteristics are similar to ANS, it still trades at a significant discount to ANS. Other commonly traded local crudes include 17° API Thums usually quoted cif Los Angeles, 13° API Kern River usually quoted on an fob basis, 13° API San Joaquin Valley (SJV) Heavy, and the heavy OCS blend.

4.6 Middle East

The seven countries surrounding the Gulf produce nearly a third of the world's crude and control most of the spare production capacity available to the world oil market (see Table 4.16). Six of the seven Gulf producers — Saudi Arabia, Iran, Iraq, Kuwait, Qatar and the United Arab Emirates — are members of Opec, but Oman is not and generally produces at or close to full capacity. Saudi Arabia is the most important in terms of reserves, capacity and output, but the combined output of the other Gulf producers is even greater and their output decisions can also have a significant impact on oil prices. The Yemen, located outside the Gulf on the southern edge of the Arabian peninsula, is also a significant regional crude exporter. Gulf exports rose sharply in 1997 with the start of limited oil sales by Iraq.

Table 4.16 Middle East crude production and exports, 1996

Country	Production b/d	Exports b/d	Capacity† b/d
Saudi Arabia‡	8,040,000	6,300,000	10,000,000
Iran	3,675,000	2,500,000	3,900,000
Iraq*	630,000	na	na
Kuwait‡	2,055,000	1,100,000	2,500,000
Oman	875,000	820,000	900,000
Qatar	480,000	420,000	530,000
United Arab Emirates	2,205,000	2,100,000	2,550,000
Yemen	360,000	295,000	385,000

‡ *includes 50 per cent share of Neutral Zone* † *end year*

* *Iraq began limited oil exports in December 1996*

Most Gulf crude is sold on a term basis, partly because of the time required to ship oil to refineries in the United States, Europe, and the Far East, and partly because major Opec producers such as Saudi Arabia and Kuwait are reluctant to see their crude being traded on the spot market and term contracts usually prohibit the secondary trading of Gulf crudes. Only about 3 per cent of Gulf crude is sold spot, either by equity producers in Oman, Abu Dhabi and Qatar or by those term contract holders able to do so, and this provides the basis of a fairly active regional spot and forward paper market. In 1996, strong demand from Asian refiners and rising oil prices boosted the volume of spot trade in Gulf crudes by more than 40 per cent. However, despite the Gulf producers' dislike of spot trading, most crude sold on term contracts is priced using a formula linked to spot price assessments for marker crudes such as WTI, Brent, Oman and Dubai (see Appendix 4.2). Saudi Arabia, Iran, and Kuwait all use formula pricing mechanisms, as did Iraq before exports ceased in August 1990. But Abu Dhabi, Oman and Qatar set official prices retroactively. Iraq now uses a formula set by the UN but linked to Saudi crude prices.

4.6.1 Saudi Arabia

Saudi Arabia produces an average of 8 million b/d of crude oil in line with its Opec quota, but monthly output volumes vary seasonally because associated gas is used for electricity generation. About 2 million b/d of Saudi Arabia's 10 million b/d capacity are unused. All crude in Saudi Arabia is produced by state oil company Saudi Aramco (see Table 4.17). Lighter grades tend to come from onshore fields particularly the giant Ghawar, and heavier ones from offshore fields such as Zuluf and Safaniya. Saudi Aramco started production of the new Arab Super Light, of far higher quality than other grades, in the second half of 1994, at 200,000 b/d but output has fallen to around 180,000 b/d because of low reservoir pressure in the Hawtah field and plans for further expansion have been shelved. Saudi Arabia also has a half share of output from the Neutral Zone on the border with Kuwait, which now totals around 525,000 b/d. Production is by Texaco (225,000 b/d) onshore and Japan's Arabian Oil Company (300,000 b/d) offshore.

Table 4.17 Saudi Arabian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Arab Super Light*	50	0.60	180,000
Berri (or Extra Light)	39	1.20	1,000,000
Arab Light	34	1.80	5,000,000
Arab Medium	31	2.40	1,100,000
Arab Heavy	27	2.90	500,000

** production started in mid-1994*

Since the start of 1994, Saudi Aramco has implemented a policy of maximising sales of lighter grades (Arab Light and Extra Light) at the expense of heavier ones (Arab Heavy and Medium). This was done by cutting availabilities of incremental volumes for heavy crude and narrowing the differential between light and heavy prices. The new 500,000 b/d Shaybah field is expected onstream in mid-1998 and its light (41.5° API) low sulphur crude will be blended with Arab Extra Light (Berri).

Roughly 1 million b/d is consumed locally and the rest exported (some in the form of products). Saudi Arabia exports around 6 million b/d of crude. Sales to North America have declined in recent years to about 20 per cent of the total. Eastern buyers now take around 50 per cent of Saudi exports and Europe around 25 per cent. Saudi Arabia provides the majority of crude used by its three international refining joint ventures, Star Enterprise in the US, Ssangyong in South Korea and Petron in the Philippines.

Saudi crude prices are determined by three main regional formulas, covering lifters in the east, US and Europe (see Appendix 4.2). Eastern prices are based on a premium or discount to average Oman and Dubai spot quotations during the month of loading, fob Ras Tanura. US prices switched from using ANS in January 1994 and are now based on WTI, fob Ras Tanura. Formulas involve a discount to spot assessments of WTI calculated over a five day period, 50 days after loading. There is also a less widely used formula for delivered sales into the US. The European formula involves a discount to dated Brent spot assessments in a five day period, 40 days after loading, fob Ras Tanura. There is also a separate formula for Mediterranean lifters fob Sidi Kerir, but changes to this are usually in line with the main European formula.

The formulas are issued in the first week of the month before loading. Nominations are then finalised mid-month. In addition to term volumes, lifters can request incremental barrels. Spot sales are banned, with destination restrictions enforced.

4.6.2 Iran

All Iranian crude is produced and sold by the state National Iranian Oil Company (NIOC). Around 550,000 b/d comes from offshore fields, rebuilt after heavy damage in the 1980-88 war with Iraq, and the rest onshore. Output in 1996 averaged 3.7 million b/d, just under Iran's total capacity of 3.9 million b/d. Plans to expand Iran's capacity to 4.5 million b/d have been hampered by US sanctions which have made it difficult to obtain oil field equipment and spares. Iran is also finding more gas and condensate than oil and recently cut its oil reserve estimates. But further repairs and expansions to offshore fields are expected to raise capacity over the next few years.

Iran has two main export grades, Iranian Heavy and Light, which account for over 90 per cent of the total (see Table 4.18). With domestic consumption of around 1.1 million b/d, Iranian exports average around 2.5 million b/d. Iranian Heavy exports vary from 1.4 million b/d to 1.6 million b/d, and Light from 900,000 b/d to

1.1 million b/d. Other grades include around 120,000 b/d of Lavan Blend and smaller volumes of Foroozan Blend and Sirri.

Table 4.18 Iranian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Iran Light	34	1.40	1,400,000
Iran Heavy	31	1.70	2,000,000
Lavan Blend	34	1.80	120,000

NIOC has different policies for eastern and western sales. All eastern sales are on a term basis. Prices are linked to averages of spot Oman and Dubai quotes during the month of loading. Iranian Light is priced at a differential to spot Oman and Iranian Heavy to Dubai (see Appendix 4.2). Formulas are set quarterly but can be renegotiated if the level of comparable crudes — particularly Saudi Arabia's Arab Medium and Light — changes significantly. The formula protects against sharp swings in the value of Iranian crude against Oman and Dubai through an Automatic Adjustment Factor (AAF). This involves a fixed differential of 77 cents/barrel between Oman and Dubai. The actual differential between Oman and Dubai is then subtracted from this, and the result divided by two, giving an AAF. The AAF is then subtracted from the Iranian Heavy price and added to the Iranian Light price.

Westbound sales are looser. Term contracts — running between three months and a year — have a framework volume, and actual amounts can vary considerably from month to month. In addition, around one fifth of western sales are spot. Prices are negotiated with each lifter, based on a differential to dated Brent assessments on five days around bill of lading. Eastern sales and most western ones are fob Kharg Island. However, NIOC also sells on a delivered basis, using tankers brought round the Cape or storage in Rotterdam and Le Havre. In 1994, NIOC started using the Sumed pipeline across Egypt, selling from the northern terminal of Sidi Kerir to Mediterranean end users.

Spot trade in Iranian crude has traditionally been active in the Mediterranean and northwest Europe, based on a differential to dated Brent fob Sidi Kerir or on a delivered basis (see Section 4.3.6). However, volumes available for traders have fallen since 1994, undermining market activity. NIOC exerts close control over spot activity, insisting on observation of destination specifications, asking traders to sell spot cargoes to end-users not other traders, and introducing new terms such as restrictions on sales into public tenders. As a result, spot trade tends to be secretive and illiquid.

Up to 600,000 b/d of Iranian crude flows through Sumed, but only about 100,000 b/d is sold spot.

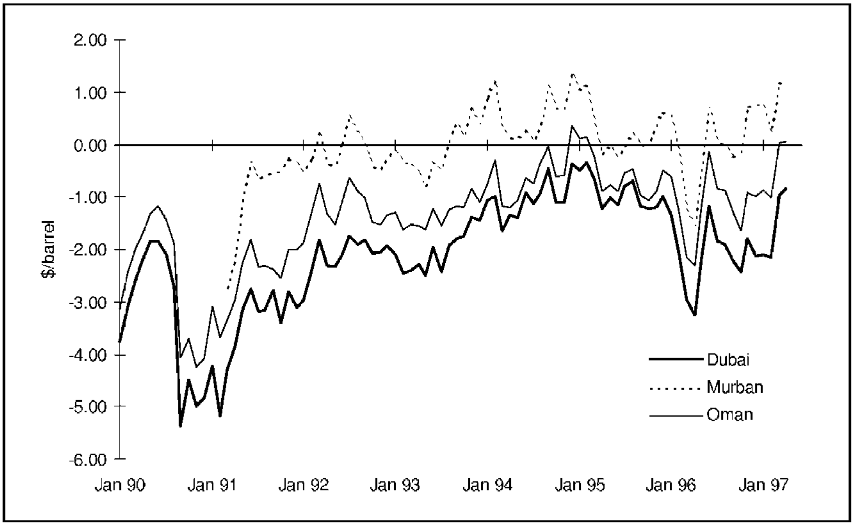
Around 900,000 b/d of Iranian exports goes to the east, with Japan taking 400,000 b/d to 500,000 b/d and South Korea around 230,000 b/d. The remaining 1.6 million b/d goes to the west. US companies are now prohibited from purchasing Iranian crude for use anywhere in the world following the extension of sanctions to the foreign subsidiaries of US companies in June 1995. But discreet marketing by NIOC has succeeded in placing most of the former 400,000 b/d sales to US companies with European refiners. NIOC also sells over 250,000 b/d to South Africa and 60,000 b/d to Brazil.

Iran also has a 40,000 b/d exchange deal with Kazakstan in which Kazakstan lifts Iran Light in return for a blend of Kazak crudes delivered to refineries in the north of Iran.

4.6.3 Iraq

Iraq is currently exporting 600-700,000 b/d of crude under the terms of the UN oil-for-aid deal. Iraq was unable to export crude for sale on the international market for more than six years. Following the invasion of Kuwait by Iraq in August 1990, the United Nations imposed trade sanctions banning oil exports. The trade ban was followed by further UN Resolutions during the Iraqi occupation and after the Gulf War which set out the terms under which Iraq will be allowed to export oil again. But the Iraqi regime under Saddam Hussein has so far failed to comply with the UN terms. Some now believe that the US is unlikely to agree to lift sanctions against Iraqi oil exports as long as Saddam Hussein remains in power, even if he unexpectedly changes his position and complies with all the UN Resolutions.

But Iraq finally accepted the terms of UN Resolution 986 — which allow for the limited export of Iraqi oil to pay for humanitarian aid within Iraq — in 1986 and began exports in December. The agreement enables Iraq to sell up to $1 billion worth of oil every 90 days for an initial period of 180 days, which is equivalent to 600-700,000 b/d of crude depending on market prices. Each transaction has to be approved by the UN sanctions committee and 26 companies have now signed term contracts. About 360,000 b/d of Kirkuk is being sold fob the Mediterranean port of Ceyhan and the about 300,000 b/d of Basrah Light fob Mina al-Bakr in the Gulf. Kirkuk sales to Europe are priced at a differential to dated Brent and Kirkuk and Basrah Light sales to the US are priced at a differential to spot WTI. Basrah Light sales to the Asia-Pacific are priced at a differential to the average of



Source: Petroleum Argus

Figure 4.10 Mideast Gulf crudes minus dated Brent

Oman and Dubai and closely track Saudi prices. The price differentials used in the formulas are also controlled by the UN.

Table 4.19 Iraqi crudes, 1995

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Basrah Light	34	2.10	340,000
Kirkuk	36	2.00	250,000
Fao Blend	28	3.50	na

Before the invasion of Kuwait, Iraq was producing 3 million b/d of crude oil, 1.5 million b/d of which was being exported, mainly through government-to-government deals in exchange for armaments. The majority of Iraqi crude exports were from Ceyhan (1 million b/d) with the remainder going by sea from the Gulf port of Mina al Bakr or via the IPSA pipeline through Saudi Arabia to the Red Sea. Iraq produces two grades of light crude oil, Basrah Light and Kirkuk, and a heavy sour crude, Fao Blend, that originally started production at the end of 1989 (see Table 4.19).

4.6.4 Kuwait

Kuwait has a single blended export crude, Kuwait Export. Plans to separate a lighter stream (37°API to 40°API) were prepared in the

1980s but were set back by the Gulf crisis. Average production in 1996 was just over 2 million b/d in line with Kuwait's Opec quota, leaving some 500,000 b/d of spare capacity shut in. Reconstruction of Kuwait's damaged facilities is now virtually complete and there are plans to expand upstream capacity to 3 million b/d by 2005. Kuwait's output includes its half share of the 525,000 b/d Neutral Zone.

All Kuwait's crude is sold on term contracts. About 900,000 b/d is refined locally leaving 1.1 million b/d for export. In 1996, 600,000 b/d went to Asia-Pacific refiners, 210,000 b/d to the US, 195,000 b/d to Europe and 90,000 b/d to South Africa. Pricing is linked to Saudi Arabia's formula for Arab Medium, which is of similar quality. It has traditionally been set at a discount of 10 cents/barrel to 15 cents/barrel, but good demand in the west has allowed Kuwait to raise this to parity (see Appendix 4.2). Eastern sales remain at a discount. Kuwait stopped basing US sales on the Arab Medium formula in the second half of 1993 using a basket of ANS, WTI and WTS instead, but restored its policy in January 1994 after Saudi Arabia switched from ANS to WTI.

State Kuwait Petroleum Corporation (KPC) produces all crude in Kuwait, although the government is considering opening border areas to foreign exploration. Production from the Neutral Zone is shared with Saudi Arabia (see above).

Immediately after the Gulf War, Kuwait concentrated on sales to the east but later built up solid markets in the US and Europe. Restoration of Kuwait's large refining sector means that around 900,000 b/d is processed and used locally or exported as products.

KPC subsidiary Kuwait Petroleum International already has a well established refining and retail network in Europe, but is now redirecting its efforts towards the rapidly growing Asia-Pacific region. KPI closed its 100,000 b/d Naples refinery in late 1993 and recently shut down its 56,500 b/d Danish refinery. It still operates a 75,500 b/d refinery in Rotterdam and has purchased a 50 per cent shareholding in Agip's 300,000 b/d Milazzo refinery. KPI sells 250,000 b/d of products in the European market and plans to have 300-350,000 b/d of refinery capacity.

4.6.5 Oman

Oman produces 900,000 b/d of crude and plans to increase capacity to 1 million b/d by 2000. There is a single Oman export blend, a light crude (36°API) with a low (0.8 per cent) sulphur content. Production is dominated by Petroleum Development Oman (PDO) whose shareholders are the government (60 per cent), Shell (34 per cent), Total (4 per cent) and Partex (2 per cent). PDO accounted for about 825,000 b/d of 1996 production of 875,000 b/d. A handful of independents also produce in Oman, the biggest being Occidental at 50,000 b/d. Small volumes of crude or condensate are produced by Elf, Japex and Canada's IPC.

Oman prices are set retroactively at the end of each month by the Ministry of Petroleum and Minerals (MPM), based on the government's assessment of market conditions and comments from from lifters (see Appendix 4.1). The Oman price is set at a premium to spot assessments of first month Dubai during the month in question, although this is not formally acknowledged by the ministry. Contracts are negotiated every six months, from January or July. Equity sellers negotiate their own contracts, which are set at fixed premiums to the MPM price.

Oman exports around 820,000 b/d, with sales dominated by eastern end users. Oman crude is also attractive to US west coast refiners because of its good yield of light products and demand may increase further now that the ANS export ban has been lifted. There is an active spot market in Oman (see Fig. 4.10), partly because of the extent of foreign participation, although this involves cargoes (500,000 barrels each) from both the government and equity holders, particularly Shell. The government issued a statement in mid-1994 warning lifters against the resale of cargoes. However, this was not enforced and spot trade continued. Deals are done at a premium or discount to the MPM price, which is not known at the time of the transaction.

4.6.6 Qatar

Qatar produces 550,000 b/d of crude oil, well above its Opec quota of 378,000 b/d. State Qatar General Petroleum Corporation (QGPC) produces around 470,000 b/d — 270,000 b/d from the onshore Dukhan field and the rest from the offshore Bul Hanine, Maydan Mahzam, Idd al-Shargi, al-Shaheen, al-Rayyan and al-Khaleej fields. But the offshore sector is open to foreign participation and foreign companies have been allowed to maximise output without constraint, pushing Qatar's total production up in recent years. Qatar also produces growing volumes of condensate; production doubled to 60,000 b/d in October 1996 as the Qatargas LNG project came onstream.

Occidental is the main foreign producer, boosting output from the Idd al-Shargi field to 65,000 b/d from under 20,000 b/d in 1994. Other foreign producers are: Maersk, which produced 30,000 b/d from its al-Shaheen field in 1995; Arco, which started production from its 30,000 b/d al-Rayyan field in November 1996; and Elf and Agip which brought the 30,000 b/d al-Khaleej field on stream in

March 1997. Qatar has now boosted its capacity target to 700,000 b/d by the year 2000.

Qatar has two main export grades, Qatar Land (Dukhan) and Qatar Marine (see Table 4.20). Retroactive prices are set each month by QGPC, determined as a variable premium to the Omani MPM price (see Appendix 4.1). Qatar Land is more expensive than Marine, but the width of the differential varies on market conditions. Both grades are traded on the spot market, but less actively than Omani and UAE crude. Foreign producers also sell cargoes of al-Shaheen (30° API, 1.9 per cent sulphur), al-Rayyan (25° API, 3 per cent sulphur), and al-Khaleej (28° API, 2 per cent sulphur). The heavy al-Rayyan uses Saudi Arab Heavy as a benchmark, while al-Khlaleej has been sold by Maersk at a differential to Dubai.

Table 4.20 Qatari export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Qatar Land (Dukhan)	42	1.30	270,000
Qatar Marine	35	1.60	200,000

Around 60,000 b/d of output is refined locally at Umm Said, leaving the rest for export. Most sales are to the east, although some go west, for example to Brazil.

4.6.7 United Arab Emirates

The UAE's main producer is Abu Dhabi, which accounted for around 1.9 million b/d of the total UAE production of 2.2 million b/d in 1996 (see Table 4.21). Foreign companies hold equity stakes in all production. Output from Dubai is falling and dropped to only 250,000 b/d by the end of 1996. Dubai crude, however, remains an important regional marker grade and is used, together with Oman, in many of the Arab Gulf pricing formulas. Another emirate, Sharjah also produces 5,000 b/d from the Mubarak field operated by Crescent Petroluem.

Abu Dhabi

The main Abu Dhabi export grade is Murban, produced onshore from five main fields by Abu Dhabi Company for Onshore Oil Operations (Adco). Its shareholders are Adnoc (60 per cent), BP (9.5 per cent), Shell (9.5 per cent), Total (9.5 per cent), Exxon (4.75 per cent), Mobil (4.75 per cent) and Partex (2 per cent). Adco now has capacity of nearly 1.2 million b/d, but is unable to use more than 900,000 b/d because the UAE adheres to its Opec quota. Abu Dhabi also produces 130,000 b/d of Thamama condensate.

Abu Dhabi Marine Operating Company (Adma-Opco) produces from the offshore Lower Zakum and Umm Shaif fields. Its shareholders are Adnoc (60 per cent), BP (14.66 per cent), Total (13.33 per cent) and Japan's Jodco (12 per cent). Adma-Opco has capacity of around 500,000 b/d, with plans to raise it to 600,000 b/d by the end of the decade. In 1996 production rose to 440,000 b/d as output from the Upper Zakum field reached a plateau.

Table 4.21 United Arab Emirates export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Abu Dhabi			
Murban	40	0.8	900,000
Lower Zakum	40	1.1	200,000
Upper Zakum	34	1.8	500,000
Abu al-Bakhoosh (ABK)	32	1.9	45,000
Umm Shaif	37	1.5	220,000
Dubai			
Dubai	31	2.0	285,000

Zakum Development Company (Zadco), produces from the offshore Upper Zakum field, and comprises just Adnoc (88 per cent) and Jodco (12 per cent). Its capacity has risen quickly, from 330,000 b/d in 1993 to 500,000 b/d by 1995, but plans to expand to 600,000 b/d have been shelved because of high costs. Because of the heavy investment, Adnoc has allowed Zadco to produce at capacity since 1995, reining in the other main producers to keep the UAE total close to its Opec quota.

Other operators produce around 80,000 b/d offshore. The main one is Abu al-Bukhoosh on the maritime border with Iran, operated by Total. It produces around 45,000 b/d of ABK crude.

Like Oman, Adnoc sets retroactive prices at the end of each month for its crudes: Murban, Lower Zakum, Umm Shaif and Upper Zakum (see Appendix 4.1). Foreign equity partners negotiate their own term contracts, but use pricing based on a premium to the official Adnoc price. Adnoc does not conduct spot trade in its share of production, enforcing destination restrictions on its cargoes. However, a sizeable spot market is supported by the foreign partners' share, with Murban the most active, followed by Lower Zakum and Umm Shaif (see Fig. 4.10). Cargoes (500,000 barrels) are traded at a premium or discount to the Adnoc price. Upper Zakum is traded only occasionally on the spot market, because of the dominant Adnoc shareholding. Spot cargoes of ABK are traded from time to time, but with prices based on the official MPM not Adnoc price, as it is closer to Oman in quality.

Adnoc's share of 1996 Abu Dhabi output was just over 1.2 million b/d, with foreign partners at about 640,000 b/d. Around 80 per cent of Adnoc's term sales are to the east, its light grades particularly popular in Japan. Smaller volumes move west to Africa and Europe.

Dubai

Dubai crude comes from four offshore fields, Fateh, SW Fateh, Falah and Rashid. Its reserves are officially 4 billion barrels but there are doubts as to whether this is all recoverable. Exports are from the offshore Fateh terminal, with a standard cargo size of 500,000 barrels.

Dubai production is operated by Conoco, with a 30 per cent stake in the consortium. The other shareholders are Total (30 per cent), Repsol (25 per cent), Germany's DEA-RWE (10 per cent) and Wintershall (5 per cent). Output peaked at 420,000 b/d in 1991 but the ageing reservoirs are now in decline. New wells gave temporary support in the spring of 1994, but the level fell back towards 300,000 b/d late in the year and had dropped to only 260,000 b/d by early 1997. Production is expected to fall to below 170,000 b/d by 1999. The prospects for future Dubai production are bleak now that Conoco has been forced to drop plans for a gas injection project using gas from Iran's offshore Sirri field because of US sanctions.

At current production levels, between 15 and 16 cargoes load each month, but traders say that the market will be too illiquid when output drops to the equivalent of 10 cargoes in 1999. Some Dubai cargoes are sold on a term basis by equity holders, but there is also an active spot market. This led to its emergence as a marker crude for other Gulf exporters in the 1980s. Saudi Arabia, Kuwait and Iran use Dubai and Oman in their eastern sales formulas, while Oman uses Dubai in establishing its monthly official price.

Dubai has the most active forward market in the Gulf with trade in both intermonth and Brent/Dubai spreads, which developed in the late 1980s (see Chapter 7). However, this is small compared with Brent and diminished during the Gulf crisis and with the decline in production. Companies buy and sell paper contracts up to one year ahead of the loading month. As the loading month approaches, speculative traders will usually have balanced their sales and purchases of paper contracts. Only those actually wanting a physical cargo will remain with open positions. Once the loading programme is released, cargo dates are passed down the 'daisy chain' of paper transactions by companies with balanced positions who have not booked out. At the end of the chain is the company with an open position, which takes delivery of the actual cargo.

The market is governed by General Terms and Conditions (GT+Cs) drawn up by operator Conoco. Previous loose regulations for the passage of dates resulted in problems and disputes, but these have been tightened up in new GT+Cs introduced for loadings from May 1994. Each trader now only has one hour to pass on dates, with the process limited to two business days. In contrast to Brent, there is very little trade once dates are allocated to a cargo.

The new GT+Cs helped provide some support to market liquidity and trading volumes have recovered despite the declining output. The market remains dominated by a handful of companies, including equity sellers Conoco, Total and Repsol, oil majors BP and Caltex, and traders Phibro, J. Aron, Morgan Stanley and J.P. Morgan. The biggest buyer is still the Indian Oil Corporation through its monthly import tenders — although purchases were nearly halved in 1995 as IOC sought alternative supplies — and its decisions can have a fundamental impact on the market's performance. There is also a growing market in Dubai swaps which do not require physical delivery.

4.6.8 Yemen

Oil production in the Yemen has risen sharply as new fields were brought on stream following the end of the civil war, and has now reached 385,000 b/d. Yemen exports two grades of crude oil, Marib Light and Masila (see Table 4.22). The Marib/Jawf field is operated by Hunt Petroleum and the Masila field is operated by Canadian Occidental. Saudi Nimir Petroleum has re-started output from Shabwa Block 4 but now produces less than 2,000 b/d. Hunt's Hleiwa field in Jannah Block 5 came onstream in October 1996 and is currently producing 25,000 b/d; output is expected to rise to 75,000 b/d by 1998. Jannah output is blended into the Marib Light export blend. The Yemen government has a stake in the production from all fields and remains a substantial seller of Yemeni crudes. About 65,000 b/d of Marib Light is usually processed at the Aden and Marib refineries to meet local demand.

Table 4.22 Yemeni export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Marib Light*	48.0	0.1	175,000
Masila	30.5	0.6	180,000

Official prices for Yemeni crudes are set in advance on a quarterly basis. Masila has proved popular as a low sulphur alternative to Oman since production began in the middle of 1993, particularly in areas such as South Korea with limited desulphurisation capacity. It also benefits from pricing against dated Brent, which is seen as cheap relative to other Middle East sour crudes. Interest in Marib Light has waned since 1994 as the crude stream now contains 30,000 b/d of condensate, which has raised its gravity from 41° to 48° API. Marib Light sales are linked to dated Brent. Masila sales by the government are also tied to Brent. Canadian Occidental offers an alternative linkage to a basket of Oman's official (MPM) price, dated Brent and front month Dubai, although recent sales have been linked to the Yemen government's OSP.

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4.7 Asia Pacific

Countries in the Asia Pacific region and Australia produce about 6 million b/d or a tenth of world oil production. The main crude producers are China, Indonesia, Malaysia, Australia, Thailand, Brunei, Vietnam and New Zealand (see Table 4.23). Recent additions include Papua New Guinea and the Philippines, both of which began producing in mid-1992. But only four of the eight major producers in the region — Indonesia, Malaysia, Australia and Papua New Guinea — are significant exporters, and it is therefore crudes from these countries which are most frequently traded.

Table 4.23 Far East crude production and exports, 1996

Country	Production b/d	Exports b/d	Capacity† b/d
Australia*	536,000	220,000	620,000
Brunei	150,000	140,000	160,000
China	3,120,000	320,000	3,200,000
Indonesia	1,380,000	800,000	1,400,000
Malaysia*	716,000	370,000	730,000
Papua New Guinea	110,000	110,000	110,000
Vietnam	150,000	100,000	150,000

* *including condensates* † *end year*

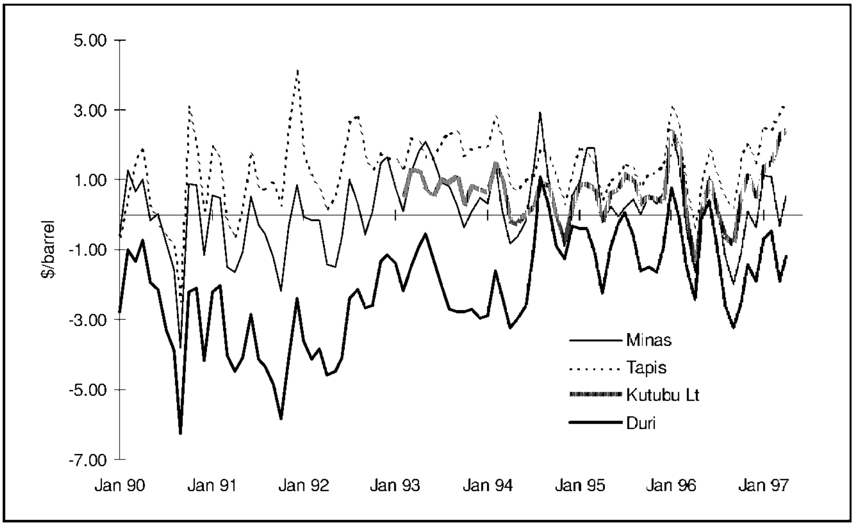
Asia Pacific crudes encompass a wide range of properties. Their gravities range from 20°API to 45°API and above. But with the exception of some Chinese crudes, they all have a particularly low sulphur content. Few grades, even the heavy Indonesian crudes like Duri, contain more than 0.2 per cent sulphur by weight.

The majority of Asia Pacific crudes are traded on the basis of the Asian Petroleum Price Index (APPI), which is now published twice a week in a bid to improve the accuracy of the price assessments. Unlike the independent price assessments published by Petroleum Argus or *Platt's*, the APPI is based on estimates of market prices for twenty regional grades of crude oil (see Table 4.24) supplied to the accounting firm Peat Marwick in Hong Kong by a panel of local producers, end-users and traders some of whom may hold positions in the crudes they are assessing. Participating companies submit their assessments to Peat Marwick for publication on Tuesday and Thursday. Any contributions that are too high or too low compared with the rest are discarded and the remainder are processed to give a 10 cents/barrel spread for each crude. Assessments are supposed to reflect the spot market price for the specific crude loading in the time period for which the assessment is being made. The APPI for Tapis is the most widely used price marker in the region, providing a benchmark for 900,000 b/d of light sweet crudes.

Table 4.24 Crudes assessed by APPI

Indonesia:	Arun Condensate, Attaka, Belida, Ardjuna, Minas, Widuri, Cinta, Duri
Malaysia:	Tapis
Australia:	Gippsland, NW Shelf Condensate, Cossack
Papua New Guinea:	Kutubu Light
China:	Daqing
Mid-east Gulf:	Oman, Arab Light, Murban, Dubai, Arab Heavy

But the role of APPI Tapis as a marker has been repeatedly criticised. Although Tapis is the largest light crude stream in Asia with output of 360,000 b/d, only small volumes are now sold spot making the market relatively illiquid. Increased refinery capacity in Malaysia has restricted the amount of Tapis being exported and only around four 500,000 barel cargoes are sold on the spot market each month. Over the past few years, the volume of spot trade in Tapis has nearly halved, leading to accusations that the price is



Source: Petroleum Argus

Figure 4.11 Asia Pacific crudes minus dated Brent being inflated by a small group of buyers who are prepared to pay a premium for familiarity.

Crude prices in the Asia Pacific region often appear to move erratically compared with other international markets such as Brent, Dubai and WTI (see Fig. 4.11). There are three reasons for this. First, Asia Pacific crude prices are determined by a small spot market which is primarily influenced by regional supply and demand factors, in particular Japanese power utilities and seasonal distillate demand. Secondly, there is an inter-relationship between the prices for Indonesian and Malaysian crudes since both Minas and Tapis are used in the Indonesian Crude Price (ICP) formula, even though the markets for the two crudes are very different. And thirdly, there is a time lag built into the ICP formula which perpetuates the effect of a strong or weak market on regional prices. As a result, some regional light sweet crude producers are keen to use Brent as a price marker. With increasing volumes of Brent-related west African crude now moving east and the IPE Brent futures contract being traded on the Singapore International Monetary Exchange (Simex), Brent's influence is gaining ground in the Asia Pacific market.

4.7.1 Indonesia

Indonesia produces about 30 different crude streams all of which have a low sulphur content. Although over half the crude streams are light, with gravities higher than 34°API, these are only produced in small quantities. Medium to heavy waxy crudes, principally Minas, account for about half of Indonesia's production (see Table 4.25). Production is falling as Indonesia continues to find more gas than oil and foreign companies find that upstream terms are better in other countries. The last major find was the Belida field in 1992 which now produces 120,000 b/d of light sweet crude oil.

The ownership of Indonesian crude is divided between the government and equity producers who have production sharing contracts. The main equity producers are Caltex (Minas and Duri), Maxus (Cinta and Widuri), and Mobil and Unocal (Attaka). The state oil company, Pertamina, handles about 85 per cent of the crude oil produced, selling through its regional affiliates, Korea Indonesia Petroleum Company (KIPCO), Perta Oil, Indoil and Pacific Petroleum.

Table 4.25 Indonesian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Kalimantan			
Handil	33	0.10	60,000
Attaka	42	0.09	47,000
Badak	41	0.08	42,000
Sumatra			
Minas	34	0.09	470,000
Arun Condensate	54	0.00	40,000
Duri	21	0.19	225,000
Java Sea			
Widuri	33	0.08	90,000
Ardjuna	37	0.09	120,000
Belida	44	0.10	120,000
Cinta	33	0.12	50,000

Indonesia exports about 800,000 b/d of its 1.6 million b/d production of crude and condensate. Over half of this goes to Japan, while Australasia, Korea, Taiwan and China take 5-10 per cent each. Because the sulphur content of Indonesian crudes is so low they can be burnt directly in Japanese power stations. But rapid growth in oil consumption is expected to reduce the volume of oil available for export to around 400,000 by the year 2000 at which point Indonesia could become a net oil importer.

Official selling prices for Indonesian crudes (ICPs) are issued monthly in arrears by Pertamina. The prices were originally calculated using only APPI spot market assessments according to a published formula which, though complicated, is predictable. But this was not sufficiently responsive to spot price movements and Pertamina now use an average of the APPI ICP formula and spot price assessments published by *Platt's* and RIM.

The Indonesian crude price formula is calculated in two parts:

> First, the prices of five basket crudes (Oman, Dubai, Minas, Tapis and Gippsland) published by APPI during the delivery month are averaged to form the monthly basket price. Although APPI assessments now appear bi-weekly, Indonesia will continue to use a weekly average in its ICP formula. As there are five crudes involved, the monthly basket price is an average of either 20 or 25 numbers depending on the month.
>
> Secondly, a premium or discount to the basket price is calculated for each grade of Indonesian crude. In order to

minimise the impact of short-term market fluctuations this is based on 52 weeks of data up to and including the last assessment published in the month prior to the delivery month. A fixed price differential is used for production streams of less than 20,000 b/d that have no APPI assessment.

The ICP formula described above has been used since April 1993. Before then the monthly basket price was calculated over a period between the 16th of the month prior to delivery and the 15th of the delivery month. However, it was changed following pressure from end-users to bring the timing in line with other producers in the region who all calculate their term prices on a calendar month basis.

Since October 1994, all crudes have been priced using a modified formula that includes spot price assessments. This was initially introduced in April 1993 just for heavy crudes, notably Duri and Widuri, to ensure that the much lighter basket price did not distort term prices. But continued criticism of the unresponsive nature of a pricing formula based purely on rolling 52-week averages has finally persuaded Pertamina to move to a more flexible pricing system. Pertamina has increased the proportion of spot price assessments used in calculating its ICP price. Plans to use quarterly averages appear to have been shelved..

Instead of basing the entire calculation on a differential to the basket price, the new ICP is calculated as a simple average of the standard formula and an average of the spot market quotations for each crude during the delivery month. Because of concern over the valuation of Indonesian crudes, the basis of the spot market assessments was widened to include *Platt's* and RIM quotations. These additional daily price assessments are included only for the period covered by the equivalent weekly APPI price assessments. Pertamina recently decided to exclude APPI spot market quotations from the spot market average from April 1996 onwards.

4.7.2 Malaysia

Malaysia produces about 655,000 b/d of mainly light low sulphur crudes, the most important being Tapis, which is widely used as a regional price marker (see Table 4.26). But export volumes have fallen to around 370,000 b/d as new refinery capacity in Malaysia absorbs more domestic production, undermining the liquidity of the Tapis spot market.

The ownership of Malaysian crude is divided between the state oil company, Petronas, and 41 oil companies of which Esso and

Shell are the most important. About one third is used in local refineries, Petronas sells about a third of the total production on term contracts to Japanese and Korean refiners, India, Thailand, Taiwan and Sri Lanka as well as major oil companies and traders, and the rest is sold spot either by Petronas or companies with production sharing agreements.

Table 4.26 Malaysian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Tapis	44	0.20	360,000
Labuan	33	0.10	120,000
Miri	36	0.10	65,000
Dulang	40	0.12	55,000
Bintulu	26	0.13	50,000

Petronas sets an official selling price (OSP) for Malaysian crudes retroactively around the end of each delivery month. Malaysia sets its OSP using the monthly average of *Platt's* and APPI Tapis quotes plus a premium decided by Petronas. Any spot deals or tenders concluded at fixed prices are also taken into account. Separate prices are set for each of the five export grades, but the differentials between crudes hardly change. Spot trading of Tapis is often done at a premium to the APPI Tapis price (usually the average three assessments around the date of the bill of lading).

4.7.3 Australia

Australia is a net importer of crude oil but also exported more than 200,000 b/d of its 540,000 b/d production of crude and condensates in 1996. Production should be rising rapidly at present, but repeated problems with new offshore fields restricted output well below Australia's capacity of over 600,000 b/d. Production is expected to rise in 1997 and 1998 as new fields come onstream, boosting capacity to over 700,000 b/d. Almost all Australian crudes are light and have a very low sulphur content (see Table 4.27). They are popular in southeast Asia, but their generally higher naphtha cut makes them second choice to Malaysian crudes which have a higher distillate yield.

Table 4.27 Australian export crudes, 1996

Crude stream	Gravity °API	Sulphur %wt	Production b/d
Timor Sea			
Jabiru	42	0.04	18,000
Challis/Cassini	40	0.07	13,000
Skua	42	0.01	14,000
North West Shelf			
Cossack*	48	0.04	120,000
Thevenard Island	36	0.05	50,000
NWS Condensate	54	0.01	80,000
Griffin	55	0.03	80,000
Barrow Island	37	0.05	15,000
Bass Strait			
Gippsland	45	0.10	210,000

** capacity, average production is lower.*

Gippsland crude, produced in the Bass Strait off the coast of Victoria in Southern Australia has traditionally made up the bulk of Australian production, but exports have gradually dried up as production has been falling. However, growing imports of crude from Papua New Guinea by east coast refiners have recently freed up more Gippsland crude for export and the commissioning of the Bream and Tuna fields in 1997 should add 45,000 b/d to production.

The bulk of Australian crude exports come from the newer producing regions of the Timor Sea and North-West Shelf areas off the north and north-west coasts of western Australia, which now account for more than half Australia's output. The new offshore Cossack crude stream, operated by Woodside Petroleum, first started up in November 1995, but the production vessel was damaged by storms and production resumed in February 1996. Cossack was expected to reach 120,000 b/d in 1996, but the field has been beset with problems and output was much lower. Another offshore field, Wandoo (40,000 b/d), came onstream in March 1997. These producing regions are far from most of Australia's refining centres and generally find a better price on the international market. About a third of Australian crude exports go to Japan, other major buyers include Singapore, Indonesia and the US.

Unlike the other major producing countries in the region there is no close government participation in the Australian oil industry. Crude production is handled by private companies who pay taxes to the government. The major producing companies in Australia include Broken Hill Proprietary (BHP), Esso, Ampol Exploration, Santos and Woodside Petroleum.

Australian producers generally sell both spot and term crude on the basis of APPI Tapis price assessments. Usually prices are negotiated at a premium or discount to the average of the three APPI assessments published around the date of the bill of lading.

4.7.4 China

China exports just over 300,000 b/d of the 3.2 million b/d of crude that it produces. Most exports are through term deals, barter arrangements or government to government arrangements. Japan is the main importer of Chinese crude, taking about 200,000 b/d. Exports are made partly to earn hard currency and partly for geographical and logistical reasons. But rising demand means that China is no longer a net exporter of crude oil. It is also a growing importer of refined product because of a shortage of refinery capacity in the south of the country.

China's main export grade is Daqing (33º API, 0.08 per cent sulphur), which is similar in quality to Indonesia's Minas and is used for burning in Japanese utilities as well as for refining. Exports of Daqing are priced in relation to the ICPs and APPIs of Minas and Cinta crudes. The price is an average of the average of the two ICPs for the delivery months and the average of the APPI price assessments for the two crudes published during the delivery month. Spot trade in Chinese crudes is infrequent, although occasional cargoes are sold into Japan or the US, usually by Japanese trading firms. Spot cargoes are usually sold on an OSP related basis but sometimes on a WTI basis.

4.7.5 Papua New Guinea

Papua New Guinea began producing crude in mid-1992 and output rose quickly to average 140,000 b/d in 1994, but production fell to only 110,000 b/d in 1995 and 1996. Further increases are expected in 1997 as the Gobe field is brought on stream. All the crude produced is exported and the single export grade, Kutubu Light (44º API, 0.04 per cent sulphur) has become an important regional marker.

Companies involved in producing Kutubu include BP, Chevron, Ampol Exploration, Broken Hill Proprietary and Mitsubishi Oil. Petroleum Resources Kutubu (PRK) is responsible for the Papua New Guinea government's 22.5 per cent shareholding in the field. Kutubu is sold at prices related to Tapis APPI.

4.7.6 Vietnam

Vietnam produces just over 150,000 b/d of crude oil from the offshore Bach Ho (White Tiger) and Dai Hung (Big Bear) fields. Production is forecast to rise over the next few years as new fields are being developed and the US embargo has been lifted, although some foreign companies have now left the country after disputes over upstream investment terms.

Oil was discovered in 1974 but production did not start until 1986 when the Bach Ho field was brought on stream by Vietsovpetro, a joint venture between Vietnam and the former USSR. Dai Hung, originally operated by a consortium led by Broken Hill Propriety (BHP), started up in October 1994. Most of the crude is exported to Japan either for refining or to be burnt in power utilities. But Dai Hung production has fallen from 35,000 b/d to 15,000 b/d and the field's reserve estimates have been downgraded, and BHP has now withdrawn from the project. Bach Ho crude (32º API, 0.10 per cent sulphur) is similar in quality to Minas and the term price is set every six months as a premium to the Minas ICP. Bach Ho is occasionally traded spot, also on a Minas APPI basis. Dai Hung (39º API, 0.08 per cent sulphur) is a lighter gravity crude.

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4.8 Latin America

Oil production in Latin America has grown steadily over the last ten years, increasing by more than 30 per cent since 1986 and exceeding 8.5 million b/d in 1996. The major oil producers in Latin America are Venezuela, Mexico, Brazil, Argentina, Colombia, Ecuador, Trinidad & Tobago and Peru (see Table 4.28). Venezuela is now the only Opec producer in Latin America since Ecuador left the organisation in 1993. The major oil exporters in the region are Venezuela, Mexico, Colombia, Argentina, Ecuador and Trinidad & Tobago. Although production is rising rapidly in Brazil, it remains a net crude importer and only exports a small volume of its own output. Peru exports small amounts of its heavy Loreto crude in order to balance its crude slate and refines the rest, exporting the surplus as products.

Table 4.28 Latin America crude production and exports, 1996

Country	Production b/d	Exports b/d	Capacity† b/d
Argentina	780,000	300,000	820,000
Brazil	780,000	10,000	860,000
Colombia	630,000	390,000	650,000
Ecuador	385,000	250,000	390,000
Mexico	2,860,000	1,500,000	2,890,000
Peru	120,000	20,000	130,000
Trinidad & Tobago	130,000	60,000	130,000
Venezuela	2,998,000	2,000,000	3,150,000

† end year

4.8.1 Argentina

Argentina's oil production is centred on four main producing regions — the Noroeste, in the far north of the country close to the borders with Bolivia and Paraguay; the Cuyo-Mendoza and Neuquen Basins in the west of the country close to the border with Chile; the Golfo San Jorge, in the south of the country and the Austral Basin in the extreme south and on the island of Tierra del Fuego. Most of the recent increases in production have come from the southern provinces of Neuquen, Austral and Chubut.

Argentina has the most liberalised oil sector in Latin America. After the election of President Carlos Menem in 1989, the country went through a period of rapid reform, culminating in the privatisation of the state oil company YPF. The sale of YPF has also encouraged the growth of other privately-owned oil companies which now account for more than half Argentina's oil output (see Table 4.29).

Argentina's oil production has grown dramatically since privatisation, rising from 480,000 b/d at the start of the decade to more than 800,000 b/d by the end of 1996 — output grew by 10 per cent in 1996. In addition, Argentina produces around 63,000 b/d of condensate. A low taxation regime, introduced by the Menem government after its election in 1989, has also encouraged the exploitation of relatively marginal fields. Over the same period, the lack of growth in Argentina's own economy has freed virtually all the new output for export, allowing the country's volume of crude oil exports to rise to around 300,000 b/d. Output is expected to continue to grow until the end of the decade, reaching 850,000 b/d by 2000, but rising domestic demand should absorb most of the increased output and will begin to eat into export volumes thereafter.

Table 4.29 Argentinian crude production by company, 1996

Company	**Production b/d**
YPF	360,000
Perez Companc	92,000
San Jorge	65,000
Amoco	60,000
Astra	40,000
Total	35,000
Bridas	25,000
Tecpetrol	23,000
Pluspetrol	19,000
Others	90,000

Most of Argentina's crude oil exports remain within the Americas. The country's most important customers are Brazil, which took 120,000 b/d in 1996, Chile (105,000 b/d) and the United States (60,000 b/d). Other customers include Uruguay, South Africa and Taiwan.

Argentina's crude oil exports move both by tanker and through the 100,000 b/d TransAndean pipeline to the Chilean port of Concepción. This latter route gives Argentinian exporters access to Asian and US west coast markets for limited quantities of oil. Argentina's crude oil trade with the US involves mainly term sales by YPF to Gulf coast refiners – with Exxon accounting for about one third of the volume – while smaller Argentinian companies tend to concentrate on regional markets.

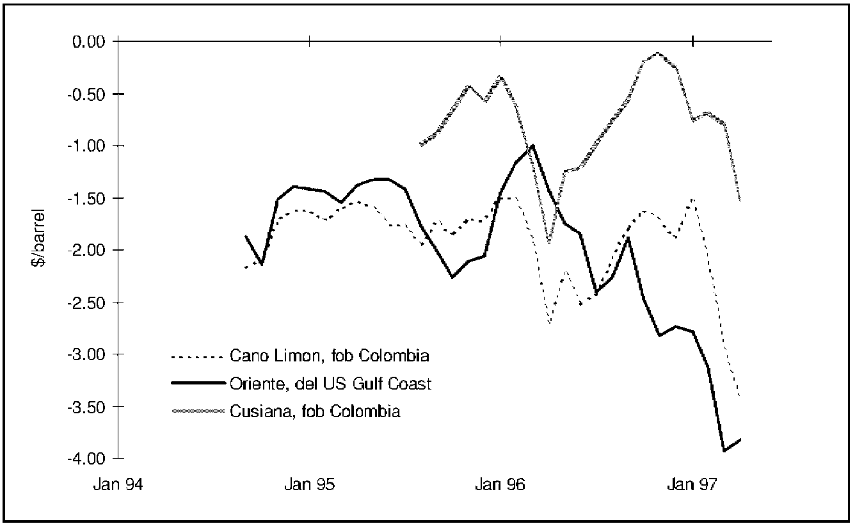
Table 4.30 Argentinian export crudes, 1996

Crude stream	Exports b/d	Gravity (° API)	Sulphur % wt	Loading port
Canadon Seco	45,000	25.7	0.23	Celeta Olivia
Escalante	30,000	24.1	0.19	Bahia Blanca
Medanito	160,000	35.1	0.43	Bahia Blanca
Rincon	50,000	36.1	0.28	Concepción (Chile)

Argentina's crude prices are based on a formula tied to West Texas Intermediate at Cushing or to dated Brent.

4.8.2 Brazil

Brazil's oil production has almost quadrupled in the last 15 years, rising from 220,000 b/d in 1981 to 860,000 b/d by the end of 1996. Brazil is a world leader in offshore production technology and the majority of its oil production comes from offshore fields, which now account for 70 per cent of the country's oil output. The most important of the offshore oil provinces is the prolific Campos Basin, located some 375 km east of Rio de Janeiro. Production from three new fields in the Campos Basin — Marlim, Albacora and Barracuda — is expected to add some 800,000 b/d to Brazil's oil output by the year 2000, raising the country's oil production to around 1.5 million b/d.



Source: Petroleum Argus

Figure 4.12 Latin America crudes minus WTI Cushing

Although Brazil has the capacity to refine slightly more than 1.5 million b/d of crude, it does not have sufficient upgrading capacity to handle the large volumes of heavy crude that will come from the new Campos Basin fields without reducing the production of much-needed light products. As a result, the small volume of heavy sweet crude currently exported by Brazil is likely to grow in coming years following the liberalisation of the upstream oil industry currently underway in the country. By the year 2000, Brazil could be exporting as much as 500,000 b/d of heavy (20° API) Campos basin crude. A trial cargo of Marlim crude — the first cargo of Brazilian crude to be exported for 10 years — was lifted in June 1996 by Austria's ÖMV.

The recent liberalisation of joint ventures could further improve the long-term outlook for crude production. In the meantime, Brazil will remain a large importer of crude from west Africa and Latin America, especially Venezuela and Argentina.

4.8.3 Colombia

Colombia has rapidly become a major producer of oil in Latin America. Its output has grown from less than 200,000 b/d in 1986 to nearly 650,000 b/d by the end of 1996 and is expected to continue to increase as new fields are brought onstream in 1997. Colombia's oil production should reach 1 million b/d by the turn of the century. The discovery of the Cusiana and Cupiagua fields added between 2 and 2.5 billion barrels of reserves and, by the year 2000 once both fields are producing at peak rates, should contribute around 800,000 b/d to Colombia's expected output of 1 million b/d.

Most of Colombia's crude oil is produced from the Llanos Basin (Cusiana & Cupiagua fields among others) and from the Caño Limon and neighbouring fields close to the border with Venezuela. Crude is also produced from fields along the Magdalena Valley. Output from all these provinces is piped northwards to the export port of Covenas on Colombia's Caribbean coast. A small amount of oil (around 60,000 b/d) is also produced from fields in the Putumayo area, close to the border with Ecuador. This oil is transported via the Trans-Andean pipeline to the Pacific Ocean port of Tumaco. Colombia's oil production and export levels have been restricted somewhat by the frequent bombing of both its oil export pipelines and such attacks frequently disrupt loading schedules at Covenas.

Table 4.31 Colombian export crudes, 1996

Crude stream	Exports b/d	Gravity (° API)	Sulphur % wt	Loading port
Caño Limon	160,000	29.5	0.47	Covenas
Cusiana	128,000	36.3	0.25	Covenas
South Blend	60,000			Tumaco
Vasconia	45,000	25.3	0.81	Covenas

Production from the Caño Limon field, which has been the mainstay of Colombia's oil output is declining and is expected to fall from a peak of 220,000 b/d in 1990 to around 110,000 b/d by the turn of the century. The decline in production from Caño Limon will be more than offset by the increase in production from the Llanos Basin fields, with the added benefit that the new crude stream is both lighter and sweeter than the one that it will replace. A new 500,000 b/d export pipeline linking the Llanos Basin fields to the port of Covenas is currently under construction and is due for completion in late 1997 or early 1998, greatly increasing Colombia's oil export capacity.

Historically, Caño Limon has been Colombia's main export grade. The oil is sold by the state company Ecopetrol, which markets 50 per cent of the exports, and by Shell and Occidental. Ecopetrol sells most of its share of Caño Limon on three to six month term contracts, priced off West Texas Intermediate, but also sells some as spot cargoes. Shell and Occidental generally sell their share of Caño Limon exports on a spot basis to refiners on the US Gulf coast. Shell also sells the heavier Vasconia crude in the same market. The erratic nature of Colombian exports has prevented many customers in the US from entering into term contracts for supplies.

Cusiana crude has been sold for export on a spot basis since June 1995. As with its other grades, Ecopetrol is keen to tie up short term contracts for its share of exports, but has also been sellin spot cargoes. Foreign partners BP and Total either sell on a spot basis or put the crude through their own US refining systems, while Triton has sold its share of Cusiana crude production forward to finance operations. Cusiana is usually priced against WTI at Cushing or sometimes a combination of WTI, LLS and Brent. Cusiana exports are set to double in mid-1997 as new pipeline capacity comes onstream and then rise further through the rest of 1997 and early 1998. Cusiana is now an alternative delivery option under the Nymex Light Sweet Crude (WTI) futures contract (see Chapter 8).

Colombia exported 225,000 b/d of crude to the US in 1996, compared with 207,000 b/d in 1995 and 146,000 b/d in 1994. This volume is likely to increase as output from Cusiana and Cupiagua increases in the coming years, more than offsetting declines in other areas.

4.8.4 Ecuador

Ecuador's crude oil output has grown by almost 20 per cent in the four years since it left Opec, rising from 330,000 b/d in 1992 to 390,000 b/d by the end of 1996. The country plans to expand production by a further 50 per cent to 600,000 b/d by the turn of the century, but additional pipeline capacity from the major oil-producing province of Oriente in the northeast of the country is required before this can be realised. Recent political upheavals in Ecuador and disputes over pricing have set back plans to expand production and exports.

The US Gulf coast is the largest export market for Ecuador's crude oil, with additional volumes going to the US west coast, Brazil and South Korea. Ecuador exported 93,000 b/d of crude to the US in 1996, much the same volume as in the previous two years. Ecuador's major export grade, Oriente, used to be similar in quality to Alaskan North Slope, but is becoming progressively heavier and more sulphurous as the output from new fields is added to the crude stream. In the past year or so, its gravity has dropped from 28.8 to 25.4°API and its sulphur content has risen from 1 to 1.3 per cent by weight. As a result, the crude is becoming much less attractive to refiners (see Fig. 4.12).

Table 4.32 Ecuadorean export crudes, 1996

Crude stream	Exports b/d	Gravity (° API)	Sulphur % wt	Loading port
Oriente	250,000	25.4	1.3	Esmereldas

Oriente is marketed exclusively by Petroecuador. It is sold fob. and is priced off Alaskan North Slope or West Texas Intermediate (since 1Q97, previously the pricing formula used West Texas Sour), with differentials determined by destination. The crude is loaded at Esmereldas in the north of the country and cargoes are limited by the capacity of the Panama Canal to 50,000 tonne ships. Oriente crude is, as far as possible, sold under annual term contracts, usually in multiples of 12,000 b/d, although Petroecuador has at times been forced to resort to spot sales on a temporary basis. The main purchasers of Ecuador's crude are Tripetrol and Glencore who contribute to the active spot trade in Oriente once the cargoes have been lifted.

4.8.5 Mexico

Mexico's oil production grew by 8 per cent in 1996, averaging 2.86 million b/d for the year. Output is expected to grow further in 1997 to an average level of 3.2 million b/d. Two fields, Cantarell and Abkatum, both located offshore in the Bay of Campeche, account for around 40 per cent of Mexico's entire crude oil production while the remainder comes from some 70 fields located both offshore and onshore along the country's Gulf of Mexico coast. Stagnant domestic oil demand has allowed Mexico to boost the volume of its oil exports as production has increased in the last two years, but it may be difficult for the country to maintain the growth in exports as the economy picks up.

Mexico has three crude oil export grades (see Table 4.33) — the heavy, sour Maya (21.5°API, 3.4 per cent sulphur), the medium to light, high-sulphur Isthmus (33.3°API, 1.2 per cent sulphur) and the light, low-sulphur Olmeca (39.1°API, 0.7 percent sulphur).

Maya, which accounts for around 60 per cent of total overseas sales, is blended from the output of a number of offshore fields, including Cantarell, in the Bay of Campeche and is exported from the Cayo Arcas open-sea terminal in the Caribbean and from Salina Cruz on Mexico's Pacific coast.

Isthmus is blended from the output of a number of fields and is similar in quality to Arabian Light and West Texas Sour. Most Isthmus crude is refined in Mexico, leaving 200-300,000 b/d for export. Isthmus crude is exported from the Dos Bocas terminal on the southern shore of the Bay of Campeche and, like Maya, from the Salina Cruz terminal on the Pacific coast.

Olmeca, which is favoured as a feedstock for lubricants and petrochemicals, is also a blend of crudes from a number of fields. It is exported from the Dos Bocas terminal on Mexico's Caribbean coast.

Table 4.33 Mexican export crudes, 1996

Crude stream	Exports b/d	Gravity (° API)	Sulphur % wt	Loading port
Isthmus	200,000	33.3	1.22	Dos Bocas/Salina Cruz
Maya	850,000	21.5	3.43	Cayo Arcas/Salina Cruz
Olmeca	450,000	39.1	0.72	Dos Bocas

The majority of the crude oil exported from Mexico is sold in the United States; but smaller volumes find their way to Spain — where Petroleos Mexicanos (Pemex) holds a refining stake — and Japan, which are the next biggest buyers of Mexican crude. Mexico's oil exports to the US have grown steadily during the 1990s and it is now the third largest source of imports after Venezuela and Saudi Arabia. The US imported 1.2 million b/d of crude from Mexico in 1996, almost 20 per cent more than it imported in 1995 and nearly 30 per cent more than it imported in 1994.

Most Mexican crude is sold on an fob basis by Pemex to refiners under term contracts. Third-party trading in Mexican crude is prohibited. Mexico's location as a short-haul supplier to the US and its flexibility over monthly liftings has tended to outweigh the complex price formulas (see Table 4.34) and the frequent loading disruptions caused by bad weather conditions. Recently Mexico has been seeking to sell crude to refiners on the US west coast in order to alleviate the growing glut of sour crudes in the Caribbean basin.

Table 4.34 Pricing formulas for Mexican export crudes, 1997

Crude stream	Destination	Weighting
Isthmus	US	(0.4*WTS) + (0.4*LLS) + (0.2*dtd Brent)
Isthmus	Europe	(0.887*dtd Brent) + (0.113*3.5%FO)- (0.16*(1%FO – 3.5%FO))
Isthmus	Far East	(0.5*Oman) + (0.5*Dubai)
Maya	US	(0.4*WTS) + (0.4*3%FO) + (0.2*dtd Brent)
Maya	Europe	(0.527*dtd Brent) + (0.467*3.5%FO) – (0.25*(1%FO – 3.5%FO))
Maya	Far East	(0.5*Oman) + (0.5*Dubai)
Olmeca	US	(0.333*WTS) + (0.333*LLS) + (0.333*dtd Brent)

4.8.6 Peru

Peru currently produces around 130,000 b/d of crude oil, but hopes to boost its output to 150,000 b/d by 1998. Although the country's oil reserves are only a fraction of those of Venezuela or Mexico, the sweetening of investment terms has ensured that Peru has attracted the interest of several of the major oil companies.

At present, Occidental produces around half of Peru's output from its Block 1-AB on the disputed border with Ecuador. This oil is sold to Petroperu under the terms of Occidental's risk service contract. Most of the remainder is produced by Petroperu from its Block 8 (33,000 b/d) in the Maranon basin in the northern jungle and Block X (15,000 b/d) in the northern coastal plain of Talara, and by Petromar which recovers some 20,000 b/d from the country's offshore fields.

Peru's oil law was altered in 1993 to allow private companies to dispose of their oil as they see fit, rather than forcing them to sell it to Petroperu. Since then, more than a dozen new contracts have been signed with private companies, both domestic and foreign, and it is hoped that the increased exploration work that has resulted from this revision will boost production from existing areas and lead to the opening up of new areas. Areas of particular interest are the Madre de Dios basin in the southern jungle and the Ucayali basin in the central region of the Peruvian jungle. Neither area is served by pipelines, but exploration in Ucayali has led to the discovery of four oil and three gas/condensate fields which could be commercially exploited.

Peru has a refining capacity of 147,000 b/d, while domestic consumption is currently around 120,000 b/d. The country is a net importer of crude and a net exporter of oil products. Peru currently exports about two cargoes a month of its heavy (19º API) Loreto crude to the US in order to balance its refining slate.

4.8.7 Trinidad and Tobago

Seven companies in Trinidad and Tobago currently produce around 130,000 b/d of crude (see Table 4.35). Output has begun to increase again in recent years after declining from a peak level of close to 200,000 b/d in 1980 to 110,000 b/d in 1993.

Trinidad and Tobago exported 58,000 b/d of crude to the US in 1996, slightly less than the 62,000 b/d it exported there in each of the two previous years.

Table 4.35 Trinidad and Tobago's crude production, 1996

Company	**Production b/d**
Amoco Trinidad	60,000
Enron	6,500
Moraven	500
PCOL	660
Petrotrin	28,750
TNA	31,700
Trintomar	1,200

4.8.8 Venezuela

Venezuela's oil production has grown spectacularly in recent years, rising from 1.75 million b/d in 1985 to an average level of almost 3 million b/d in 1996 — although the Venezuelan government disputes this figure, claiming that the country's output is still in line with its Opec quota allocation of 2.359 million b/d.

Nonetheless, the state oil company, Petroleos de Venezuela (PdVSA), plans to boost output capacity to 6.3 million b/d by the year 2006. While PdVSA has itself undertaken substantial investment to boost production, Venezuela has recently opened its upstream oil sector to foreign companies in three ways.

Firstly, a number of marginal fields with minimal existing production have been offered to private companies to reactivate and develop. Two marginal field bidding rounds had been completed by the end of 1996 and a third group of fields is being offered in 1997. Output from the fields offered in the first two rounds has risen from 76,000 b/d in 1995 to 190,000 b/d in 1996.

Secondly, eight areas were awarded to private companies in January 1996 under exploration and production risk contracts. On discovery of oil, joint ventures will be formed between the private companies and PdVSA to exploit the fields.

*Table 4.36 Venezuelan extra-heavy crude upgrading contracts**

Venezuelan partner	Foreign partner(s)	Volume of crude b/d	Volume of synthetic crude b/d
Maraven	Total/Statoil/Norsk Hydro	170,000	156,000
Maraven	Conoco	120,000	102,000
Corpoven	Arco/Texaco/Phillips	207,000	164,000
Corpoven	Exxon	n.a.	n.a.
Lagoven	Mobil	100,000	87,000

** already signed or under negotiation*

Thirdly, association contracts have been signed or are being negotiated between PdVSA subsidiaries and private companies to produce and transform extra-heavy crude from the Orinoco belt into 20°API synthetic crude (see Table 4.36).

Venezuelan crudes are generally heavy, with Tia Juana Light at 32°API, the lightest crude stream available for export (see Table 4.37). The potential market for most Venezuelan crudes is limited because few refiners are able to process heavy crudes with a high metals content. Venezuela has sought to overcome this difficulty by investing in sophisticated refinery capacity both at home and abroad. As a result, much of the oil that the country produces remains within its own refining system.

Venezuela has 2.4 mn b/d of refining capacity in Venezuela, the Caribbean, the US and Europe, leaving it with around 700,000 b/d of crude to sell to third parties. The bulk of this excess is sold into the US market, although some also finds its way into the sophisticated refineries in Europe. In 1996, Venezuela became the largest single supplier of imported oil to the US: its exports to the US of 1.305 million b/d exceeded those of Saudi Arabia for the first time.

Table 4.37 Venezuelan export crudes, 1996

Crude stream	**Exports b/d**	**Gravity (° API)**	**Sulphur % wt**	**Loading port**
Bachaquero		13.0	2.68	Punta Cardon
BCF-17		16.2	2.47	La Salina
Boscan		10.1	5.40	Bajo Grande
Furrial		30.0	1.10	Puerto La Cruz
Tia Juana Heavy		12.3	2.82	Punta Cardon
Tia Juana Light		32.0	1.20	La Salina

Although Venezuela still posts prices for its crudes, most sales are on a term-contract basis. These contracts — handled by the PdV subsidiaries Corpoven, Lagoven and Maraven — are generally extremely flexible, allowing variations in both price and volume to suit individual purchasers.

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Appendix 4.1

Official crude prices, 1993

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MIDDLE EAST												
ABU DHABI•												
Murban	16.90	17.90	17.95	17.85	17.55	17.25	16.00	16.50	15.90	16.65	15.40	14.00
L Zakum	16.80	17.80	17.85	17.75	17.45	17.15	15.90	16.40	15.80	16.55	15.30	13.90
U Zakum	15.40	16.40	16.40	16.30	15.95	15.55	14.15	14.70	14.10	14.80	13.55	12.10
Umm Shaif	16.55	17.55	17.55	17.45	17.15	16.85	15.60	16.10	15.50	16.25	15.00	13.55
OMAN*												
Oman	15.84	16.80	16.95	17.05	16.70	16.46	15.21	15.46	14.60	15.26	14.12	12.68
QATAR*												
Dukhan/Land	16.34	17.30	17.45	17.55	17.20	16.96	15.71	15.96	15.25	15.98	14.95	13.43
Marine	16.19	17.15	17.30	17.40	17.05	16.81	15.56	15.81	14.95	15.70	14.70	13.18
EGYPT*												
Suez Blend	14.44	15.16	15.39	15.34	15.19	14.20	13.47	13.56	13.06	13.71	12.39	11.03
Ras al-Behar	15.09	15.81	16.04	15.94	15.84	14.85	14.12	14.21	13.71	14.36	13.04	11.68
Zeit Bay	15.04	15.76	15.99	15.89	15.79	14.80	14.07	14.16	13.66	14.31	12.99	11.63
Belayim	13.04	13.66	13.89	13.89	13.74	12.80	12.07	12.16	11.66	12.36	11.04	9.68
Ras Budran	11.69	12.41	12.79	12.84	12.74	11.86	11.22	11.36	10.86	11.56	10.29	9.03
Ras Gharib	11.14	11.76	11.99	12.04	11.94	11.06	10.42	10.56	10.06	10.76	9.49	8.33
FAR EAST												
INDONESIA*	^	^	^									
Minas	17.89	17.51	18.42	18.84	18.67	18.41	17.44	17.56	17.01	17.13	16.07	14.50
Duri	15.32	14.96	15.92	16.61	16.70	16.07	14.68	14.35	13.70	13.93	12.87	11.17
Lalang	18.07	17.68	18.59	18.99	18.80	18.52	17.53	17.65	17.07	17.19	16.12	14.56
MALAYSIA*												
Tapis	19.50	19.30	20.35	21.00	20.55	19.70	18.95	18.95	18.95	18.30	17.70	16.05
Labuan	19.40	19.20	20.25	20.90	20.45	19.60	19.05	19.05	19.05	18.40	17.80	16.15
Miri	19.20	19.00	20.05	20.70	20.25	19.40	18.85	18.85	18.85	18.20	17.60	15.95
Bintulu	18.70	18.50	19.55	20.20	19.75	18.90	18.45	18.45	18.45	17.80	17.20	15.55
BRUNEI*												
Seria Lt	19.40	19.10	20.25	20.90	20.35	19.60	18.85	18.85	18.80	18.20	17.60	15.95
OPEC BASKET#												
Average	16.71	17.66	18.15	18.12	17.89	17.08	15.95	15.90	15.24	15.75	14.47	12.88

#Saharan Blend, Minas, Bonny Light, Arab Light, Dubai, Tia Juana and Isthmus crudes.

**retroactive +forward ^midmonth*

Source: Petroleum Argus

Official crude prices, 1994

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MIDDLE EAST												
ABU DHABI *												
Murban	15.10	14.60	13.75	15.45	16.10	17.00	17.60	17.00	16.70	16.90	17.55	16.85
L Zakum	15.00	14.50	13.65	15.35	16.00	16.90	17.50	16.90	16.60	16.80	17.45	16.75
U Zakum	13.30	12.80	12.05	13.90	14.65	15.65	16.40	15.75	15.30	15.40	16.05	15.50
Umm Shaif	14.65	14.15	13.30	15.00	15.60	16.50	17.10	16.50	16.20	16.40	17.05	16.35
OMAN*												
Oman	13.78	13.24	12.35	14.20	15.05	16.08	16.90	16.21	15.71	15.84	16.64	16.04
QATAR*												
Dukhan/Land	14.58	14.14	13.33	15.02	15.80	16.68	17.38	16.79	16.40	16.58	17.22	16.62
Marine	14.35	13.94	13.13	14.84	15.62	16.51	17.18	16.59	16.20	16.40	17.03	16.44
EGYPT*												
Suez Blend	12.00	11.65	12.00	13.56	14.54	15.09	15.92	14.92	14.23	14.87	15.85	14.58
Ras al-Behar	12.65	12.30	12.65	14.16	15.14	15.69	16.52	15.47	14.73	15.42	16.40	15.13
Zeit Bay	12.60	12.25	12.60	14.11	15.09	15.64	16.47	15.42	14.73	15.37	16.35	15.08
Belayim	10.70	10.35	10.75	12.56	13.59	14.14	14.97	14.02	13.33	13.92	14.85	13.68
Ras Budran	10.05	9.70	10.10	11.91	13.04	13.59	14.57	13.62	13.03	13.62	14.55	13.33
Ras Gharib	9.40	9.05	9.40	11.21	12.34	12.89	13.82	12.87	12.28	12.87	13.85	12.78
FAR EAST												
INDONESIA*												
Minas	15.04	15.20	14.46	15.04	15.76	16.58	17.56	17.63	16.38	16.35	16.42	16.27
Duri	11.69	12.17	11.45	11.98	12.97	13.88	15.64	16.22	14.93	14.73	15.01	14.82
Lalang	15.09	15.24	14.50	15.10	15.83	16.65	17.63	17.69	16.42	16.30	16.45	16.25
MALAYSIA*												
Tapis	15.70	16.55	16.10	15.85	16.70	17.30	18.65	19.35	18.10	18.05	17.60	17.60
Labuan	15.80	16.65	16.20	15.95	16.80	17.40	18.75	19.45	18.20	18.15	17.70	17.70
Miri	15.60	16.45	16.00	15.75	16.60	17.20	18.60	19.25	18.00	17.95	17.50	17.50
Bintulu	15.20	16.05	15.60	15.35	16.20	16.80	18.15	19.05	17.80	17.75	17.30	17.30
BRUNEI*												
Seria Lt	15.60	16.45	16.00	15.75	16.65	17.20	18.50	19.35	18.05	18.00	17.55	17.55
OPEC BASKET#												
Average	13.71	13.76	13.34	14.52	15.74	16.50	17.41	16.86	15.71	16.13	16.72	15.84

#Saharan Blend, Minas, Bonny Light, Arab Light, Dubai, Tia Juana and Isthmus crudes.
**retroactive +forward ^midmonth*
Source: Petroleum Argus

Official crude prices, 1995

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MIDDLE EAST												
ABU DHABI *												
Murban	17.35	17.90	17.40	18.45	18.20	17.00	15.80	16.30	16.50	16.00	16.95	18.40
L Zakum	17.25	17.80	17.30	17.40	18.15	16.95	15.75	16.30	16.50	16.00	16.95	18.40
U Zakum	16.05	16.75	16.35	17.50	17.35	16.20	15.00	15.35	15.45	14.80	15.65	16.95
Umm Shaif	16.90	17.50	17.00	18.05	17.80	16.60	15.40	15.90	16.10	15.60	16.55	18.00
OMAN*												
Oman	16.55	17.10	16.60	17.70	17.49	16.43	15.18	15.56	15.60	15.00	15.96	17.48
QATAR*												
Dukhan/Land	17.16	17.69	17.15	18.20	17.86	16.66	15.44	15.87	15.98	15.44	16.38	17.80
Marine	16.98	17.54	17.01	18.00	17.72	16.52	15.30	15.73	15.84	15.32	16.26	17.68
EGYPT*												
Suez Blend	15.54	16.23	16.18	17.83	17.40	16.13	14.26	14.16	14.99	14.51	15.25	16.50
Ras al-Behar	16.09	16.68	16.58	18.23	17.80	16.53	14.66	14.61	15.44	14.96	15.70	16.95
Zeit Bay	16.04	16.63	16.53	18.18	17.75	16.48	14.61	14.56	15.39	14.91	15.65	16.90
Belayim	14.74	15.53	15.48	17.13	16.75	15.43	13.56	13.26	14.29	13.81	15.55	15.80
Ras Budran	14.44	15.23	15.18	16.88	16.55	15.18	13.46	13.26	14.14	13.66	14.40	15.65
Ras Gharib	13.84	14.63	14.58	16.28	15.85	14.58	12.71	12.56	13.44	12.96	13.70	14.95
FAR EAST												
INDONESIA*												
Minas	17.17	18.16	18.20	18.41	18.50	17.42	16.21	16.48	16.58	16.38	16.96	18.34
Duri	15.57	16.27	15.94	16.46	16.96	16.38	15.28	15.15	15.12	14.71	15.25	16.72
Widuri	16.36	17.32	17.42	17.71	17.94	16.92	15.63	15.92	16.00	15.76	16.36	17.70
MALAYSIA*												
Tapis	18.46	19.13	19.09	19.57	19.80	18.91	17.52	17.51	17.60	17.36	18.13	19.72
Labuan	18.56	19.23	19.19	19.67	19.90	19.01	17.62	17.61	17.70	17.46	18.23	19.82
Miri	18.36	19.03	18.99	19.47	19.70	18.81	17.42	17.41	17.50	17.26	18.03	19.62
Bintulu	18.16	18.83	18.79	19.27	19.50	18.61	17.22	17.21	17.30	17.06	17.83	19.42
BRUNEI*												
Seria Lt	18.05	19.00	19.35	18.85	19.90	19.40	17.90	17.55	17.60	17.35	17.75	19.10
OPEC BASKET#												
Average	16.67	17.29	17.15	18.28	18.13	16.98	15.63	15.95	16.35	15.85	16.49	17.74

#Saharan Blend, Minas, Bonny Light, Arab Light, Dubai, Tia Juana and Isthmus crudes.
**retroactive +forward ^midmonth*
Source: Petroleum Argus

Official crude prices, 1996

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MIDDLE EAST												
ABU DHABI *												
Murban	18.20	17.45	18.45	19.25	18.60	19.00	19.55	20.45	22.30	23.80	23.10	24.20
L Zakum	18.20	17.45	18.45	19.30	18.65	19.10	19.65	20.50	22.35	23.85	23.15	24.25
U Zakum	16.65	15.90	16.95	17.70	16.95	17.30	17.85	18.75	20.55	21.95	21.20	22.10
Umm Shaif	17.80	17.05	18.05	18.85	18.25	18.70	19.25	20.15	22.00	23.55	22.85	23.95
OMAN*												
Oman	17.26	16.50	17.77	18.63	17.89	18.24	18.77	19.60	21.20	22.50	21.80	22.80
QATAR*												
Dukhan/Land	17.63	16.90	17.93	18.80	18.15	18.45	19.05	19.93	21.75	23.11	22.49	23.50
Marine	17.53	16.80	17.83	18.68	18.04	18.37	18.76	19.84	21.66	23.03	22.42	23.43
EGYPT*: differential to dated Brent												
Suez Blend	-1.45	-1.20	-1.55	-1.45	-1.65	-1.80	-2.50	-2.40	-2.25	-2.15	-2.10	-2.35
Ras al-Behar	-1.05	-0.85	-0.95	-0.95	-0.95	-1.20	-1.65	-1.55	-1.45	-1.35	-1.35	-1.60
Zeit Bay	-1.10	-0.90	-1.00	-1.00	-1.00	-1.25	-1.70	-1.60	-1.50	-1.40	-1.40	-1.65
Belayim	-2.20	-1.85	-2.05	-2.18	-2.38	-2.53	-3.20	-3.05	-3.00	-3.00	-3.15	-3.20
Ras Budran	-2.35	-2.00	-2.20	-2.33	-2.53	-2.75	-3.40	-3.25	-3.20	-3.20	-3.35	-3.50
Ras Gharib	-3.10	-2.90	-3.10	-3.23	-3.43	-3.65	-4.30	-4.05	-4.00	-4.00	-4.00	-4.00
FAR EAST												
INDONESIA*												
Minas	19.35	18.87	19.19	19.33	18.94	19.28	19.71	19.49	21.02	23.12	22.60	23.11
Duri	17.72	17.17	17.60	18.17	18.16	18.12	18.18	17.97	19.46	21.54	21.07	21.56
Widuri	18.67	18.19	18.53	18.73	18.27	18.57	19.05	18.93	20.35	22.33	21.80	22.30
MALAYSIA*												
Tapis	20.89	21.05	21.61	21.25	20.58	20.66	20.86	21.19	23.01	25.70	25.04	25.44
Labuan	20.99	21.15	21.71	21.35	20.68	20.76	20.96	21.29	23.11	25.80	25.16	25.54
Miri	20.97	21.13	21.51	21.15	20.48	20.56	20.76	21.09	22.91	25.60	24.94	25.34
Bintulu	20.59	20.75	21.31	20.95	20.28	20.36	20.56	20.89	22.71	25.40	24.74	25.14
BRUNEI*												
Seria Lt	20.85	21.20	21.65	21.75	20.60	20.55	21.10	21.05	22.20	24.80	26.20	25.25
OPEC BASKET#												
Average	18.05	17.90	19.35	20.24	28.92	18.37	19.29	19.94	21.68	23.28	22.20	23.51

#Saharan Blend, Minas, Bonny Light, Arab Light, Dubai, Tia Juana and Isthmus crudes.

**retroactive*

Source: Petroleum Argus

Official crude prices, 1997

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MIDDLE EAST												
ABU DHABI *												
Murban	23.75	20.85	20.05	18.30								
L Zakum	23.80	20.90	20.10	18.35								
U Zakum	21.65	18.90	18.25	16.70								
Umm Shaif	23.50	20.60	19.80	18.05								
OMAN*												
Oman	22.50	19.72	19.10	17.53								
QATAR*												
Dukhan/Land	23.16	20.33	19.50	17.94								
Marine	23.09	20.25	19.36	17.72								
EGYPT*: differential to dated Brent												
Suez Blend	-2.10	-2.35	-2.50	-2.75								
Ras al-Behar	-1.60	-1.75	-1.90	-2.10								
Zeit Bay	-1.65	-1.80	-1.95	-2.15								
Belayim	-3.35	-3.60	-3.60	-3.70								
Ras Budran	-3.65	-3.80	-3.80	-3.85								
Ras Gharib	-4.20	-4.35	-4.35	-4.40								
FAR EAST												
INDONESIA*												
Minas	24.13	21.36	19.24	18.28								
Duri	22.47	19.80	17.63	16.62								
Widuri	23.28	20.54	18.39	17.41								
MALAYSIA*												
Tapis	26.23	23.79	22.39	21.23								
Labuan	26.38	23.94	22.54	21.38								
Miri	26.33	23.89	22.49	21.33								
Bintulu	25.83	23.39	21.99	20.83								
BRUNEI*												
Seria Lt	26.75	25.35	22.95	22.10								
OPEC BASKET#												
Average	23.19	20.49	18.69	17.46								

#Saharan Blend, Minas, Bonny Light, Arab Light, Dubai, Tia Juana and Isthmus crudes.
**retroactive*
Source: Petroleum Argus

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Appendix 4.2

Formula crude prices, 1993

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SAUDI ARABIA fob Ras Tanura												
fob US: spot ANS												
Arab Lt	-1.00	-1.00	-1.00	-1.00	-1.20	-1.40	-1.40	-1.50	-1.30	-1.30	-1.20	-1.20
Arab Med	-2.25	-2.40	-2.40	-2.40	-2.60	-2.70	-2.70	-2.90	-2.60	-2.60	-2.60	-2.60
Arab Hy	-3.15	-3.50	-3.30	-3.30	-3.50	-3.60	-3.60	-3.90	-3.50	-3.50	-3.50	-3.50
Berri	-0.15	0.10	0.10	0.10	-0.20	-0.50	-0.50	-0.50	-0.30	-0.30	-0.20	-0.20
cif USGC: spot ANS												
Arab Lt	0.10	0.10	0.10	0.10	-0.10	-0.30	-0.30	-0.40	-0.20	-0.20	-0.10	-0.10
Arab Med	-1.15	-1.30	-1.30	-1.30	-1.50	-1.60	-1.60	-1.80	-1.50	-1.50	-1.50	-1.50
Arab Hy	-2.05	-2.40	-2.20	-2.20	-2.40	-2.50	-2.50	-2.80	-2.40	-2.40	-2.40	-2.40
fob Europe: dtd Brent												
Arab Lt	-1.85	-2.15	-2.30	-2.30	-2.50	-2.65	-2.65	-2.65	-2.45	-2.35	-2.20	-2.00
Arab Med	-3.10	-3.60	-3.70	-3.70	-3.70	-4.00	-4.00	-4.00	-3.80	-3.65	-3.50	-3.30
Arab Hy	-4.05	-4.75	-4.75	-4.75	-4.75	-5.05	-5.05	-5.05	-4.85	-4.70	-4.60	-4.35
Berri	-1.10	-1.10	-1.30	-1.40	-1.65	-1.85	-1.85	-1.85	-1.65	-1.55	-1.35	-1.15
fob Far East: avg Oman/Dubai												
Arab Lt	0.40	0.40	0.30	0.30	0.30	0.30	0.30	0.20	0.20	0.20	0.30	0.30
Arab Med	-1.15	-1.30	-1.30	-1.30	-1.30	-1.30	-1.30	-1.40	-1.30	-1.20	-1.10	-1.15
Arab Hy	-2.30	-2.65	-2.65	-2.50	-2.50	-2.50	-2.50	-2.60	-2.40	-2.25	-2.15	-2.25
Berri	1.35	1.50	1.30	1.25	1.15	1.15	1.15	1.10	1.20	1.30	1.45	1.50
IRAN: Oman or Dubai*												
Iran Lt	even	even	-0.20	-0.20	-0.20	-0.20	-0.30	-0.40	-0.40	-0.40	-0.30	-0.30
Iran Hy	-0.93	-1.08	-0.98	-0.98	-0.98	-0.98	-0.98	-1.08	-0.98	-0.88	-0.78	-0.78
** for Iran Lt use Oman, for Iran Hy use Dubai, fob Kharg Island destination Far East*												
KUWAIT: avg Oman/Dubai												
Kuwait	-1.25	-1.40	-1.40	-1.40	-1.40	-1.40	-1.40	-1.50	-1.40	-1.30	-1.20	-1.25
fob Mina al-Ahmadi destination Far East												
QATAR: avg spot Oman												
Dukhan	0.50	0.50	0.50	0.50	0.50	0.50	0.53	0.50	0.65	0.72	0.83	0.75
Marine	0.35	0.35	0.35	0.35	0.35	0.35	0.38	0.35	0.35	0.44	0.58	0.50
NIGERIA: to dtd Brent†												
Bonny Light	0.40	0.4	0.57	0.57	0.50	0.40	0.52	0.62	0.40	0.33	0.42	0.52
Brass River	0.40	0.40	0.57	0.67	0.60	0.57	0.62	0.72	0.50	0.43	0.59	0.70
Qua Iboe	0.40	0.40	0.57	0.57	0.50	0.40	0.52	0.62	0.40	0.33	0.42	0.52
Pennington	0.40	0.40	0.57	0.77	0.70	0.67	0.75	0.85	0.70	0.63	0.79	0.92
Forcados	-0.20	even	0.15	0.25	0.30	0.40	0.30	0.40	0.45	0.38	0.48	0.60
Escravos	0.35	0.35	0.52	0.52	0.45	0.35	0.47	0.57	0.35	0.28	0.37	0.47
Bonny Medium	-0.35	-0.15	even	0.10	0.20	0.25	0.10	0.20	0.20	0.13	0.22	0.35
†priced five days after bill of lading												
MEXICO to FE: avg Oman/Dubai												
Isthmus	0.90	0.85	0.75	0.70	0.70	0.70	0.70	0.60	0.60	0.60	0.70	0.70
Maya	-4.20	-4.65	-4.60	-4.45	-4.45	-4.45	-4.35	-4.50	-4.20	-4.00	-4.00	-4.15

Source: Petroleum Argus

Formula crude prices, 1994

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SAUDI ARABIA fob Ras Tanura												
fob US: spot WTI												
Arab Lt	-3.60	-3.25	-3.00	-3.00	-3.00	-2.80	-2.80	-3.25	-2.80	-3.05	-2.75	-2.85
Arab Med	-5.05	-4.40	-4.10	-4.10	-4.05	-3.75	-3.70	-4.10	-3.55	-4.00	-3.55	-3.55
Arab Hy	-6.00	-5.20	-4.90	-4.90	-4.80	-4.40	-4.30	-4.65	-4.00	-4.60	-4.00	-4.00
Berri	-2.60	-2.40	-2.15	-2.05	-2.50	-1.95	-1.95	-2.40	-2.00	-2.15	-2.00	-2.15
cif USGC: spot WTI												
Arab Lt	-2.50	-2.15	-1.90	-1.90	-1.90	-1.70	-1.70	-2.10	-1.65	-1.85	-1.50	-1.65
Arab Med	-3.95	-3.30	-3.00	-3.00	-2.95	-2.65	-2.60	-2.95	-2.40	-2.80	-2.35	-2.35
Arab Hy	-4.90	-4.10	-3.80	-3.80	-3.70	-3.30	-3.20	-3.50	-2.85	-3.40	-2.80	-2.80
fob Europe: dtd Brent												
Arab Lt	-1.90	-1.80	-1.60	-1.60	-1.50	-1.50	-1.50	-1.60	-1.60	-1.60	-1.45	-1.45
Arab Med	-3.20	-3.05	-2.65	-2.45	-2.30	-2.25	-2.15	-2.30	-2.15	-2.40	-2.20	-2.00
Arab Hy	-4.25	-4.00	-3.45	-3.05	-2.85	-2.75	-2.60	-2.80	-2.55	-3.00	-2.80	-2.55
Berri	-1.05	-0.95	-0.85	-0.95	-0.85	-0.95	-1.00	-1.10	-1.10	-0.90	-0.75	-0.95
fob Far East: avg Oman/Dubai												
Arab Lt	0.35	0.35	0.45	0.40	0.40	0.65	0.50	0.55	0.40	0.50	0.50	0.50
Arab Med	-1.30	-1.05	-0.70	-0.80	-0.80	-0.40	-0.30	-0.25	-0.10	-0.55	-0.55	-0.45
Arab Hy	-2.50	-2.10	-1.50	-1.60	-1.60	-1.10	-0.90	-0.85	-0.50	-1.20	-1.20	-1.10
Berri	1.55	1.45	1.45	1.30	1.20	1.35	1.10	1.10	0.80	1.20	1.20	1.20
IRAN: Oman or Dubai*												
Iran Lt	-0.30	-0.30	-0.20	-0.27	-0.27	-0.02	-0.17	-0.17	-0.27	-0.17	-0.17	-0.17
Iran Hy	-0.93	-0.68	-0.33	-0.40	-0.40	even	0.12	0.12	0.32	-0.18	-0.18	-0.18
** for Iran Lt use Oman, for Iran Hy use Dubai, fob Kharg Island destination Far East*												
KUWAIT: avg Oman/Dubai												
Kuwait	-1.40	-1.15	-0.80	-0.90	-0.90	-0.50	-0.40	-0.35	-0.20	-0.65	-0.65	-0.55
fob Mina al-Ahmadi destination Far East												
QATAR: avg spot Oman												
Dukhan	0.80	0.90	0.98	0.82	0.75	0.60	0.48	0.58	0.69	0.74	0.58	0.58
Marine	0.57	0.70	0.78	0.64	0.57	0.43	0.28	0.38	0.49	0.56	0.39	0.40
NIGERIA: to dtd Brent†												
Bonny Light	0.35	0.68	0.45	0.43	0.45	0.37	0.33	0.20	0.15	0.22	0.41	0.00
Brass River	0.55	0.84	0.60	0.58	0.58	0.50	0.40	0.28	0.15	0.24	0.48	0.05
Qua Iboe	0.35	0.68	0.45	0.43	0.45	0.37	0.33	0.20	0.15	0.22	0.41	0.00
Pennington	0.70	1.04	0.75	0.73	0.75	0.70	0.60	0.50	0.45	0.52	0.73	0.35
Forcados	0.40	0.60	0.42	0.40	0.32	0.40	0.40	0.40	0.30	0.33	0.47	0.00
Escravos	0.30	0.63	0.40	0.38	0.40	0.32	0.28	0.15	0.10	0.17	0.36	-0.05
Bonny Medium	0.15	0.42	0.30	0.22	0.14	0.22	0.25	0.15	0.07	0.15	0.29	-0.17
†priced five days after bill of lading												
MEXICO to FE: avg Oman/Dubai												
Isthmus	0.65	0.65	0.75	0.70	0.70	0.95	0.80	0.85	0.70	0.80	0.80	0.80
Maya	-4.25	-3.85	-3.25	-3.25	-3.05	-2.50	-2.10	-1.90	-1.20	-2.40	-2.30	-2.20

Source: Petroleum Argus

Formula crude prices, 1995

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SAUDI ARABIA fob Ras Tanura												
fob US: spot WTI												
Arab Lt	-2.35	-2.50	-2.50	-2.25	-2.65	-2.75	-2.70	-2.65	-2.70	-2.85	-2.55	-2.80
Arab Med	-2.90	-3.20	-3.10	-2.80	-3.25	-3.45	-3.25	-3.20	-3.40	-3.60	-3.20	-3.60
Arab Hy	-3.25	-3.25	-3.50	-3.05	-3.65	-3.85	-3.45	-3.45	-3.80	-4.05	-3.55	-4.05
Berri	-1.85	-1.85	-1.85	-1.80	-2.00	-2.00	-2.10	-2.05	-2.05	-2.15	-1.95	-2.15
cif USGC: spot WTI												
Arab Lt	-1.15	-1.35	-1.30	-1.05	-1.45	-1.55	-1.50	-1.45	-1.50	-1.65	-1.35	-1.60
Arab Med	-1.70	-2.05	-1.90	-1.60	-2.05	-2.25	-2.05	-2.00	-2.20	-2.40	-2.00	-2.40
Arab Hy	-2.05	-2.50	-2.30	-1.85	-2.45	-2.65	-2.25	-2.25	-2.60	-2.85	-2.35	-2.85
fob Europe: dtd Brent												
Arab Lt	-1.15	-1.15	-1.15	-1.15	-1.15	-1.35	-1.35	-1.60	-1.50	-1.30	-1.30	-1.45
Arab Med	-1.70	-1.60	-1.70	-1.55	-1.70	-1.90	-1.90	-2.35	-2.25	-2.05	-1.95	-2.10
Arab Hy	-2.05	-1.85	-2.05	-1.80	-2.05	-2.25	-2.25	-2.80	-2.70	-2.50	-2.35	-2.50
Berri	-0.75	-0.85	-0.75	-0.85	-0.85	-1.00	-1.00	-1.15	-1.05	-0.85	-0.85	-1.00
fob Far East: avg Oman/Dubai												
Arab Lt	0.50	0.50	0.50	0.50	0.40	0.50	0.50	0.50	0.50	0.50	0.50	0.60
Arab Med	-0.40	-0.45	-0.15	-0.05	-0.05	-0.05	-0.05	-0.15	-0.05	-0.20	-0.20	-0.10
Arab Hy	-1.00	-1.10	-0.60	-1.80	-0.45	-0.55	-0.55	-0.85	-0.65	-0.70	-0.70	-0.40
Berri	1.20	1.10	0.95	0.85	0.75	0.90	0.90	0.90	0.80	0.90	0.90	1.05
IRAN: Oman or Dubai*												
Iran Lt	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.17	-0.17	-0.07
Iran Hy	-0.03	-0.03	0.22	0.29	0.29	0.29	0.29	0.19	0.29	0.07	0.07	0.17
** for Iran Lt use Oman, for Iran Hy use Dubai, fob Kharg Island destination Far East*												
KUWAIT: avg Oman/Dubai												
Kuwait	-0.50	-0.55	-0.25	-0.15	-0.15	-0.15	-0.15	-0.25	-0.15	-0.25	-0.30	-0.20
fob Mina al-Ahmadi destination Far East												
QATAR: avg spot Oman												
Dukhan	0.61	0.59	0.55	0.45	0.37	0.23	0.26	0.31	0.38	0.44	0.42	0.32
Marine	0.43	0.44	0.41	0.30	0.23	0.09	0.12	0.17	0.24	0.32	0.30	0.20
NIGERIA: to dtd Brent†												
Bonny Light	0.09	0.32	0.40	0.15	0.28	0.33	0.14	0.05	0.10	0.28	0.32	0.22
Brass River	0.15	0.42	0.50	0.25	0.38	0.40	0.18	0.08	0.16	0.34	0.40	0.30
Qua Iboe	0.09	0.32	0.40	0.15	0.28	0.33	0.14	0.05	0.10	0.28	0.32	0.22
Pennington	0.45	0.72	0.75	0.55	0.78	0.68	0.30	0.25	0.30	0.50	0.55	0.47
Forcados	0.04	0.20	0.12	0.05	0.18	0.20	0.09	0.03	0.10	0.24	0.28	0.22
Escravos	0.04	0.27	0.35	0.10	0.26	0.30	0.09	0.00	0.06	0.24	0.28	0.20
Bonny Medium	-0.13	0.10	0.02	-0.12	0.06	0.06	0.00	0.10	-0.04	0.13	0.18	0.12
†priced five days after bill of lading												
MEXICO to US: to Mexican formula												
Isthmus	-0.95	-0.95	-0.85	-0.75	-0.75	-0.90	-0.90	-1.00	-1.00	-1.00	-0.90	-0.90
Maya	-1.45	-1.35	-1.25	-1.15	-1.25	-1.35	-1.35	-1.35	-1.35	-1.65	-1.50	-1.40

Source: Petroleum Argus

Formula crude prices, 1996

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SAUDI ARABIA fob Ras Tanura												
fob US: spot WTI												
Arab Lt	-2.60	-2.40	-2.40	-2.50	-2.50	-2.95	-2.85	-3.05	-3.25	-3.00	-2.85	-2.80
Arab Med	-3.30	-3.10	-3.15	-3.20	-3.35	-3.80	-3.60	-3.70	-4.05	-3.85	-3.75	-3.80
Arab Hy	-3.70	-3.55	-3.65	-3.80	-3.95	-4.40	-4.10	-4.10	-4.55	-4.40	-4.40	-4.40
Berri	-2.05	-1.85	-1.80	-1.85	-1.85	-2.25	-2.20	-2.40	-2.50	-2.20	-2.00	-2.10
cif USGC: spot WTI												
Arab Lt	-1.40	-1.20	-1.20	-1.30	-1.30	-1.75	-1.65	-1.85	-2.05	-1.80	-1.65	-1.75
Arab Med	-2.10	-1.90	-1.95	-2.00	-2.15	-2.60	-2.40	-2.50	-2.85	-2.65	-2.55	-2.60
Arab Hy	-2.50	-2.35	-2.45	-2.60	-2.75	-3.20	-2.90	-2.90	-3.35	-3.20	-3.20	-3.20
fob Europe: dtd Brent												
Arab Lt	-1.40	-1.10	-1.20	-1.20	-1.30	-1.40	-1.65	-1.80	-1.80	-1.70	-1.60	-1.85
Arab Med	-2.05	-1.70	-1.80	-1.90	-2.05	-2.15	-2.55	-2.70	-2.70	-2.65	-2.85	-3.05
Arab Hy	-2.40	-1.95	-2.05	-2.20	-2.35	-2.45	-2.95	-3.10	-3.10	-3.10	-3.45	-3.60
Berri	-0.95	-0.65	-0.75	-0.70	-0.70	-0.75	-0.85	-1.00	-1.00	-0.85	-0.85	-1.00
fob Far East: avg Oman/Dubai												
Arab Lt	0.60	0.60	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.60	0.75
Arab Med	-0.20	-0.20	-0.25	-0.35	-0.35	-0.35	-0.60	-0.50	-0.50	-0.50	-0.30	-0.30
Arab Hy	-0.55	-0.55	-0.60	-0.75	-0.75	-0.75	-1.25	-1.00	-1.20	-1.10	-1.05	-1.15
Berri	1.20	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.55	1.85
IRAN: Oman or Dubai*												
Iran Lt	-0.07	-0.07	-0.07	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12	-0.12
Iran Hy	0.07	0.07	0.07	-0.08	-0.08	-0.08	-0.33	-0.23	-0.23	-0.13	-0.13	-0.13
** for Iran Lt use Oman, for Iran Hy use Dubai, fob Kharg Island destination Far East*												
KUWAIT: avg Oman/Dubai												
Kuwait	-0.30	-0.30	-0.35	-0.45	-0.45	-0.45	-0.70	-0.70	-0.70	-0.50	-0.40	-0.40
fob Mina al-Ahmadi destination Far East												
QATAR: avg spot Oman												
Dukhan	0.37	0.40	0.16	0.17	0.26	0.21	0.28	0.33	0.55	0.61	0.69	0.68
Marine	0.27	0.30	0.06	0.05	0.15	0.13	0.19	0.24	0.46	0.53	0.62	0.61
NIGERIA: to dtd Brent†												
Bonny Light	0.32	0.48	0.48	0.60	0.61	0.28	0.25	0.34	0.43	0.36	0.63	0.45
Brass River	0.38	0.48	0.46	0.62	0.63	0.31	0.29	0.37	0.47	0.38	0.63	0.41
Qua Iboe	0.32	0.48	0.48	0.60	0.61	0.28	0.25	0.34	0.43	0.36	0.63	0.45
Pennington	0.55	0.65	0.70	0.80	0.83	0.48	0.46	0.55	0.66	0.64	0.95	0.80
Forcados	0.29	0.48	0.50	0.60	0.50	0.20	-0.05	0.17	0.23	0.36	0.70	0.50
Escravos	0.29	0.45	0.43	0.57	0.58	0.22	0.21	0.30	0.40	0.32	0.60	0.40
Bonny Medium	0.16	0.38	0.34	0.48	0.38	0.07	-0.17	0.05	0.10	0.28	0.63	0.40
†priced five days after bill of lading												
MEXICO to US: to Mexican formula												
Isthmus	-0.80	-0.70	-0.70	-0.80	-0.70	-0.70	-0.70	-0.70	-0.70	-0.90	-1.00	-0.90
Maya	-1.55	-1.55	-1.55	-1.75	-1.60	-1.50	-1.40	-1.20	-1.10	-1.20	-1.60	-1.75

Source: Petroleum Argus

Formula crude prices, 1997

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SAUDI ARABIA fob Ras Tanura												
fob US: spot WTI												
Arab Lt	-2.80	-3.05	-3.30	-3.45	-3.60							
Arab Med	-3.65	-3.95	-4.35	-4.50	-4.65							
Arab Hy	-4.25	-4.65	-5.20	-5.35	-5.50							
Berri	-1.90	-2.05	-2.15	-2.35	-2.60							
cif USGC: spot WTI												
Arab Lt	-1.60	-1.85	-2.10	-2.25	-2.40							
Arab Med	-2.45	-2.75	-3.15	-3.30	-3.45							
Arab Hy	-3.10	-3.45	-4.00	-4.15	-4.30							
fob Europe: dtd Brent												
Arab Lt	-1.85	-1.85	-1.85	-1.95	-2.25							
Arab Med	-3.05	-3.05	-3.15	-3.15								
Arab Hy	-3.60	-3.60	-3.80	-3.80	-4.30							
Berri	-1.00	-1.00	-0.90	-1.10	-1.35							
fob Far East: avg Oman/Dubai												
Arab Lt	0.75	0.75	0.60	0.60	0.60							
Arab Med	-0.30	-0.30	-0.40	-0.40	-0.50							
Arab Hy	-1.15	-1.15	-1.25	-1.25	-1.35							
Berri	2.00	2.85	1.95	1.70	1.50							
IRAN: Oman or Dubai*												
Iran Lt	0.08	0.08	-0.07	-0.07	-0.17							
Iran Hy	-0.03	-0.03	-0.13	-0.13	-0.23							
** for Iran Lt use Oman, for Iran Hy use Dubai, fob Kharg Island destination Far East*												
KUWAIT: avg Oman/Dubai												
Kuwait	-0.40	-0.40	-0.50	-0.50	-0.60							
fob Mina al-Ahmadi destination Far East												
QATAR: avg spot Oman												
Dukhan	0.66	0.61	0.40	0.41								
Marine	0.59	0.53	0.26	0.19								
NIGERIA: to dtd Brent†												
Bonny Light	0.50	0.53	0.58	0.04	0.15							
Brass River	0.38	0.45	0.59	0.09	0.25							
Qua Iboe	0.50	0.53	0.58	0.04	0.15							
Pennington	0.85	0.88	0.93	0.22	0.35							
Forcados	0.60	0.68	0.47	-0.40	-0.30							
Escravos	0.38	0.44	0.52	-0.04	0.07							
Bonny Medium	0.50	0.53	0.35	-0.50	-0.40							
†priced five days after bill of lading												
MEXICO to US: to Mexican formula												
Isthmus	-1.00	-1.00	-1.15	-1.35	-1.70							
Maya	-1.75	-1.75	-1.75	-1.75	-2.25							

Source: Petroleum Argus

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Appendix 4.3

Spot crude prices, 1993

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NORTH SEA												
Brent	17.41	18.46	18.76	18.63	18.52	17.65	16.78	16.69	16.00	16.60	15.18	13.65
Forties	17.46	18.60	18.88	18.70	18.36	17.58	16.84	16.78	15.84	16.46	15.06	13.68
Flotta	16.22	17.56	17.54	17.46	17.31	16.33	15.65	15.39	14.81	15.53	14.25	13.07
Ekofisk	17.59	18.80	19.03	18.75	18.60	17.87	17.09	17.04	16.14	16.70	15.21	13.75
Oseberg	17.55	18.64	18.88	18.61	18.51	17.73	16.92	16.87	16.01	16.61	15.20	13.81
MEDITERRANEAN												
Urals cif Med	15.60	16.87	16.97	16.81	16.64	15.86	15.14	15.04	14.28	15.26	13.95	12.68
Es Sider	16.94	17.91	18.23	18.13	17.96	17.08	16.19	16.18	15.45	16.00	14.55	13.05
Suez Blend		15.05	15.36	15.29	15.19	14.22	13.46	13.59	13.01	13.73	12.44	11.11
Iran Hvy SK	14.75	15.59	15.91	15.87	15.73	14.75	13.99	14.19	13.69	14.45	13.14	12.06
Syrian Lt												
WEST AFRICA												
Bonny Lt	17.88	19.14	19.45	19.22	19.06	18.27	17.51	17.24	16.45	17.09	15.76	14.14
Bonny Med	17.35	18.55	18.95	18.88	18.79	17.86	17.07	16.97	16.26	16.91	15.54	14.02
Forcados	17.52	18.71	19.14	19.05	19.03	18.08	17.26	17.20	16.47	17.17	15.81	14.23
Brass River		19.35	19.63	19.35	19.20	18.36	17.59	17.35	16.59	17.26	15.97	14.35
Cabinda	15.87	17.12	17.47	17.69	17.91	16.58	15.54	15.35	14.76	15.41	13.77	12.14
ARAB GULF												
Dubai	15.33	16.01	16.36	16.36	16.05	15.69	14.34	14.78	14.20	14.85	13.79	12.28
Oman	16.12	16.83	17.24	17.09	16.92	16.45	15.24	15.45	14.84	15.41	14.33	12.62
Murban	17.30	18.12	18.43	18.09	17.73	17.33	16.28	16.77	16.41	16.75	15.86	14.10
FAR EAST												
Tapis	19.01	19.71	20.97	20.76	20.14	19.25	18.87	19.00	18.41	18.29	17.06	15.66
Minas	18.22	18.56	19.96	20.47	20.61	19.26	17.71	17.46	16.30	16.26	15.29	14.17
Duri	16.04	16.30	17.27	17.75	17.93	16.40	14.75	13.93	13.23	13.83	12.47	10.69
Gippsland	18.29	18.85	20.02	19.96	19.33	18.28	18.06	17.80	17.18	16.93	15.88	14.25
Kutubu Lt		18.95	20.06	19.90	19.22	18.17	17.83	17.60	17.06	16.85	16.01	14.44
Widuri	17.67	17.91	19.22	19.94	20.17	18.77	17.01	16.41	15.03	14.84	13.77	12.58
UNITED STATES												
WTI Cushing	19.06	20.06	20.32	20.26	19.95	19.06	17.87	18.01	17.52	18.14	16.57	14.47
WTI Midland	18.97	20.03	20.27	20.18	19.87	19.00	17.91	18.11	17.46	18.08	16.47	14.43
WTS	17.31	18.70	18.71	18.62	18.61	17.65	16.41	16.16	16.00	16.45	14.91	13.11
LLS St James	19.13	20.17	20.30	20.24	20.10	19.21	18.05	18.25	17.74	18.34	16.76	14.70
ANS USGC	16.57	17.88	18.37	18.42	18.00	17.02	15.83	16.20	15.60	16.05	14.23	12.24
Bonny Lt US	19.05	20.34	20.61	20.46	20.22	19.34	18.58	18.33	17.47	18.12	16.83	15.20

Source: Petroleum Argus daily assessments. Averages calculated using a five day week.

Spot crude prices, 1994

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NORTH SEA												
Brent	14.23	13.78	13.83	15.03	16.14	16.74	17.59	16.81	15.87	16.49	17.16	15.92
Forties	14.33	13.83	13.98	15.18	16.14	16.65	17.47	16.64	15.78	16.56	17.25	15.95
Flotta	13.76	13.11	13.43	14.55	15.40	16.04	16.63	16.07	15.19	15.99	16.84	16.10
Ekofisk	14.43	13.95	14.06	15.25	16.31	16.78	17.57	16.82	15.92	16.58	17.34	15.98
Oseberg	14.48	13.98	14.09	15.25	16.24	16.72	17.53	16.76	15.84	16.62	17.38	15.93
MEDITERRANEAN												
Urals cif Med	13.63	13.18	13.38	14.46	15.27	15.97	16.53	16.01	15.24	16.13	17.06	15.80
Es Sider	13.77	13.48	13.59	14.95	16.06	16.40	17.08	16.23	15.41	16.25	17.11	15.94
Suez Blend	11.98	11.68	11.96	13.30	14.16	14.80	15.58	14.90	14.11	14.85	15.75	14.57
Iran Hvy SK	12.94	12.48	12.88	14.20	15.08	15.66	16.25	15.52	14.69	15.47	16.40	15.24
Syrian Lt									15.55	16.09	17.06	15.90
WEST AFRICA												
Bonny Lt	14.85	14.40	14.35	15.50	16.70	17.14	17.89	17.04	16.09	16.95	17.49	16.09
Bonny Med	14.63	14.17	14.21	15.32	16.48	17.09	17.85	16.94	16.07	16.83	17.35	15.84
Forcados	14.81	14.34	14.37	15.45	16.66	17.28	18.08	17.20	16.26	17.00	17.50	16.00
Brass River	15.03	14.54	14.44	15.64	16.84	17.20	17.93	17.01	16.13	17.01	17.55	16.14
Cabinda	13.08	13.04	13.16	14.39	15.45	15.87	16.64	16.06	15.06	15.60	16.31	14.98
ARAB GULF												
Dubai	13.17	12.78	12.17	13.72	14.76	15.83	16.47	15.85	15.42	15.41	16.08	15.58
Oman	13.48	13.48	12.67	13.89	15.09	16.09	16.85	16.45	15.84	15.88	16.57	16.31
Murban	15.10	15.01	14.11	15.25	16.26	17.01	17.63	17.13	16.99	17.19	17.84	17.29
FAR EAST												
Tapis	16.18	16.60	15.90	16.01	16.80	17.74	18.68	18.70	17.61	17.56	17.46	17.10
Minas	14.58	15.26	13.93	14.35	15.53	16.56	18.94	19.76	16.87	16.52	16.28	16.48
Duri	11.36	12.19	11.49	11.93	13.18	14.15	16.64	17.93	16.15	15.62	15.90	15.59
Gippsland	14.67	15.08	14.88	15.11	16.04	16.87	17.88	17.85	16.81	16.77	16.71	16.28
Kutubu Lt	14.91	15.26	14.78	15.03	15.89	16.75	17.81	17.80	16.73	16.41	16.38	16.15
Widuri	13.31	14.02	13.01	13.50	14.73	15.63	18.18	20.04	16.93	15.75	15.80	15.79
UNITED STATES												
WTI Cushing	15.04	14.75	14.67	16.35	17.90	19.06	19.66	18.38	17.44	17.71	18.08	17.18
WTI Midland	15.03	14.79	14.69	16.25	17.79	18.80	19.41	18.32	17.29	17.54	18.10	17.12
WTS	13.97	13.98	13.89	15.47	17.03	17.83	18.30	17.37	16.35	16.73	17.40	16.45
LLS St James	15.29	14.98	15.00	16.66	18.01	18.40	19.11	18.36	17.37	17.79	18.40	17.42
ANS USGC	13.30	13.66	13.72	15.33	16.81	16.97	17.46	16.84	15.98	15.90	16.82	15.95
Bonny Lt US	15.90	15.26	15.43	16.72	17.70	18.21	18.88	17.92	16.97	na	na	na

Source: Petroleum Argus daily assessments. Averages calculated using a five day week.

Spot crude prices, 1995

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NORTH SEA												
Brent	16.56	17.07	17.00	18.64	18.31	17.30	15.85	16.09	16.70	16.12	16.84	17.91
Forties	16.64	17.13	17.05	18.85	18.40	17.51	15.94	16.21	16.93	16.31	17.05	18.11
Flotta	16.18	16.62	16.66	18.32	17.85	16.83	15.20	15.53	16.28	15.66	16.40	17.55
Ekofisk	16.67	17.13	17.13	18.87	18.49	17.57	15.99	16.25	16.93	16.29	17.03	18.08
Oseberg	16.69	17.15	17.11	18.91	18.49	17.54	15.94	16.23	16.91	16.27	17.05	18.16
MEDITERRANEAN												
Urals cif Med	16.67	16.65	16.85	18.25	17.97	16.79	14.85	15.46	16.31	15.56	16.34	17.73
Es Sider	16.64	17.18	16.98	18.64	18.27	17.29	15.57	15.82	16.56	15.99	16.76	17.92
Suez Blend	15.48	16.10	16.07	17.64	16.97	15.92	14.05	14.57	15.47	14.38	15.08	16.37
Iran Hvy SK	16.00	16.31	16.37	18.25	17.97	16.79	14.28	14.65	15.49	14.86	15.62	16.90
Syrian Lt	16.56	16.78	16.70	18.29	18.00	16.98	15.16	15.50	16.35	15.81	16.52	17.80
WEST AFRICA												
Bonny Lt	16.88	17.52	17.27	18.95	18.70	17.53	15.95	16.35	17.13	16.50	17.21	18.35
Bonny Med	16.63	17.21	16.89	18.67	18.43	17.31	15.82	16.19	16.93	16.30	17.00	18.17
Forcados	16.83	17.36	17.04	18.82	18.56	17.44	15.96	16.33	17.05	16.44	17.19	18.34
Brass River	16.93	17.58	17.33	19.02	18.77	17.56	16.01	16.41	17.19	16.56	17.25	18.37
Cabinda	15.88	16.60	16.54	18.20	17.84	16.48	14.90	15.33	16.03	15.42	16.21	17.22
ARAB GULF												
Dubai	16.07	16.73	16.33	17.40	17.30	16.17	15.04	15.41	15.54	14.90	15.64	16.91
Oman	16.68	17.20	16.77	17.74	17.55	16.40	15.31	15.61	15.73	15.04	15.94	17.41
Murban	17.57	18.18	17.43	18.43	18.30	17.05	15.82	16.29	16.70	16.13	17.21	18.53
FAR EAST												
Tapis	18.54	18.83	18.40	19.02	19.32	18.37	17.32	17.47	17.49	17.26	18.03	19.29
Minas	17.51	18.96	18.90	18.43	18.86	17.25	16.06	16.53	16.72	16.63	17.17	18.55
Duri	16.15	16.67	15.92	16.38	17.40	17.04	15.91	15.52	15.11	14.63	15.19	16.96
Gippsland	17.62	17.99	17.77	18.40	18.78	17.99	17.03	17.09	17.14	16.91	17.48	18.63
Kutubu Lt	17.46	17.95	17.75	18.44	18.92	18.03	17.01	17.08	17.03	16.65	17.29	18.30
Widuri	16.45	18.01	18.20	17.87	18.29	17.12	15.58	16.04	16.17	15.97	16.55	17.83
UNITED STATES												
WTI Cushing	18.02	18.55	18.53	19.87	19.74	18.43	17.31	18.02	18.21	17.43	17.99	19.03
WTI Midland	17.93	18.28	18.27	19.82	19.62	18.46	17.34	17.81	18.01	17.32	17.78	18.83
WTS	17.18	17.47	17.57	19.14	19.02	17.71	16.49	16.88	16.87	16.12	16.68	17.83
LLS St James	18.30	18.64	18.45	20.17	19.97	18.67	17.40	17.85	18.14	17.66	18.32	19.53
ANS USGC	16.85	17.40	17.36	18.79	18.69	17.36	16.21	16.74	16.76	15.84	16.54	17.67
Brent USGC	17.61	18.05	17.93	19.59	19.34	18.24	17.00	17.29	17.70	17.18	17.80	18.96

Source: Petroleum Argus daily assessments. Averages calculated using quoted days only.

Spot crude prices, 1996

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NORTH SEA												
Brent	17.88	17.98	19.85	20.88	19.16	18.45	19.60	20.51	22.56	24.14	22.72	23.82
Forties	18.17	18.40	20.47	21.36	19.56	18.77	19.90	20.80	22.81	24.51	22.91	24.20
Flotta	17.52	17.60	19.68	20.63	18.85	17.90	18.98	20.02	22.17	23.56	22.02	23.35
Ekofisk	18.18	18.52	20.56	21.40	19.60	18.83	19.97	20.86	22.82	24.42	22.85	24.07
Oseberg	18.31	18.62	20.55	21.37	19.57	18.74	19.89	20.78	22.83	24.55	22.99	24.25
MEDITERRANEAN												
Urals cif Med	18.01	17.86	19.77	20.19	18.43	17.27	18.56	19.76	21.77	23.45	22.08	23.27
Es Sider	18.01	18.12	20.03	21.03	19.16	18.37	19.45	20.35	22.45	24.16	22.80	23.91
Suez Blend	16.48	16.52	18.34	19.06	17.22	15.95	17.12	18.20	20.29	21.91	20.45	21.60
Iran Hvy SK	17.24	17.26	19.10	19.75	17.76	16.58	17.68	18.90	20.92	22.58	21.17	22.44
Syrian Lt	18.02	18.01	19.92	20.64	18.78	17.83	18.90	20.02	22.23	23.96	22.68	23.75
WEST AFRICA												
Bonny Lt	18.45	18.58	20.56	21.52	19.58	18.82	20.05	21.00	23.04	24.82	23.18	24.43
Bonny Med	18.31	18.44	20.45	21.32	19.32	18.46	19.72	20.69	22.91	24.74	23.15	24.44
Forcados	18.46	18.61	20.54	21.42	19.45	18.56	19.85	20.84	23.04	24.87	23.31	24.56
Brass River	18.44	18.58	20.57	21.55	19.63	18.89	20.09	21.02	23.06	24.79	23.13	24.29
Cabinda	17.40	17.52	19.45	20.39	18.58	17.88	19.07	19.99	21.71	22.96	21.36	22.95
ARAB GULF												
Dubai	16.52	15.90	16.90	17.63	16.95	17.27	17.76	18.60	20.32	21.71	20.93	21.70
Oman	17.27	16.72	17.70	18.56	17.95	18.31	18.76	19.65	21.27	22.49	21.81	22.84
Murban	18.45	17.87	18.64	19.32	18.68	19.15	19.65	20.51	22.31	23.98	23.44	24.59
FAR EAST												
Tapis	21.03	20.53	20.51	20.45	20.07	20.33	20.68	20.94	22.71	25.82	24.77	25.28
Minas	20.27	19.51	19.39	19.25	19.08	19.51	19.87	19.32	20.57	23.06	22.82	23.45
Duri	18.67	17.88	18.33	18.46	19.03	18.84	18.58	17.93	19.33	21.62	21.29	21.93
Gippsland	19.94	20.00	19.97	20.02	20.08	20.05	20.44	20.89	22.58	25.44	24.60	25.24
Kutubu Lt	20.27	19.87	19.64	19.51	19.34	19.42	19.63	19.91	21.74	24.74	23.88	24.28
Widuri	19.49	19.00	18.90	18.67	18.27	18.67	19.21	18.59	19.88	22.19	21.94	22.48
AMERICAS												
WTI Cushing	18.87	19.03	21.31	23.51	21.18	20.42	21.29	21.92	24.00	24.90	23.75	25.36
WTI Midland	18.90	19.02	21.15	23.30	21.01	20.26	21.24	21.97	24.06	24.94	23.78	25.32
WTS	17.98	18.24	20.54	22.46	20.03	19.07	19.93	20.60	22.78	23.49	21.87	23.77
LLS St James	19.58	19.54	21.38	23.05	20.95	20.02	21.06	22.07	24.21	25.52	24.53	25.88
Brent USGC	18.99	19.06	21.10	21.91	20.03	19.54	20.72	21.63	23.76	25.15	23.71	25.01
Oriente	17.41	17.87	20.31	22.08	19.43	18.58	18.88	19.65	22.11	22.43	20.93	22.62
Caño Limon	17.36	17.52	19.40	20.78	18.99	17.90	18.86	19.84	22.21	23.29	22.04	23.46
Cusiana	18.53	18.40	20.11	21.56	19.93	19.20	23.31	21.15	23.44	24.71	23.63	25.11
ANS USWC	17.30	18.01	20.26	22.02	19.37	18.92	19.69	19.99	21.65	22.56	21.48	23.58

Source: Petroleum Argus daily assessments. Averages calculated using quoted days only.

Spot crude prices, 1997

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NORTH SEA												
Brent	23.55	20.92	19.15	17.61								
Forties	23.94	21.37	19.29	17.67								
Flotta	23.03	20.31	18.25	16.55								
Ekofisk	23.78	21.24	19.27	17.67								
Oseberg	23.96	21.23	19.12	17.59								
MEDITERRANEAN												
Urals cif Med	22.68	20.06	17.97	16.45								
Es Sider	23.49	20.78	18.99	17.21								
Suez Blend	21.22	18.50	16.49	14.84								
Iran Hvy SK	21.77	19.17	17.12	15.47								
Syrian Lt	23.20	20.57	18.38	16.69								
WEST AFRICA												
Bonny Lt	24.21	21.55	19.40	17.90								
Bonny Med	24.20	21.45	19.09	17.42								
Forcados	24.28	21.49	19.06	17.48								
Brass River	24.12	21.58	19.41	17.93								
Cabinda	22.90	20.18	17.79	16.36								
ARAB GULF												
Dubai	21.44	18.77	18.18	16.77								
Oman	22.69	19.90	19.20	17.68								
Murban	24.32	21.14	20.34	18.70								
FAR EAST												
Tapis	26.07	23.32	22.07	20.80								
Minas	24.65	21.98	18.82	18.17								
Duri	22.86	20.46	17.23	16.43								
Gippsland	26.03	23.32	22.07	20.80								
Kutubu Lt	24.90	22.41	21.40	20.01								
Widuri	23.62	21.09	18.14	17.33								
AMERICAS												
WTI Cushing	25.13	22.18	20.98	19.70								
WTI Midland	24.88	21.78	20.65	19.39								
WTS	23.48	19.80	18.37	17.69								
LLS St James	25.31	22.43	20.82	19.50								
Brent USGC	24.61	22.03	20.16	18.76								
Oriente	22.35	19.05	17.06	15.88								
Caño Limon	23.64	20.06	18.04	16.24								
Cusiana	24.38	21.50	20.20	18.15								
ANS USWC	23.58	21.02	20.11	18.47								

Source: Petroleum Argus daily assessments. Averages calculated using quoted days only.

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Appendix 4.4

Further reading

Petroleum Argus Oil Market Guides

A series of occasional booklets providing detailed coverage of the main international crude and products markets, explaining how they operate, the methods of pricing, and the trading instruments used in each region.

Middle East Crude Oil Pricing
1st edition, October 1991; 2nd edition, 1996 (forthcoming)

Guide to the US Crude Market
1st edition, May 1992; 2nd edition, 1996

Guide to the Far East Crude Market
2nd edition, June 1993

Guide to the North Sea Crude Market
1st edition, 1997 (forthcoming)

Newsletters

The former *Weekly Petroleum Argus (WPA)* has been expanded into two publications, each with a more clearly defined focus.

Argus Global Markets (AGM) now provides a topical and intelligent editorial on the market; news and analysis of latest developments; crude, product and futures market reviews; background history to set current prices in context; freight rates and oil market fundamentals.

The new *Weekly Petroleum Argus* covers upstream and downstream investment; corporate strategy and profiles; mergers and acquisitions; oil and gas finance and the geopolitics of energy.

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5 Product markets

Petroleum Argus

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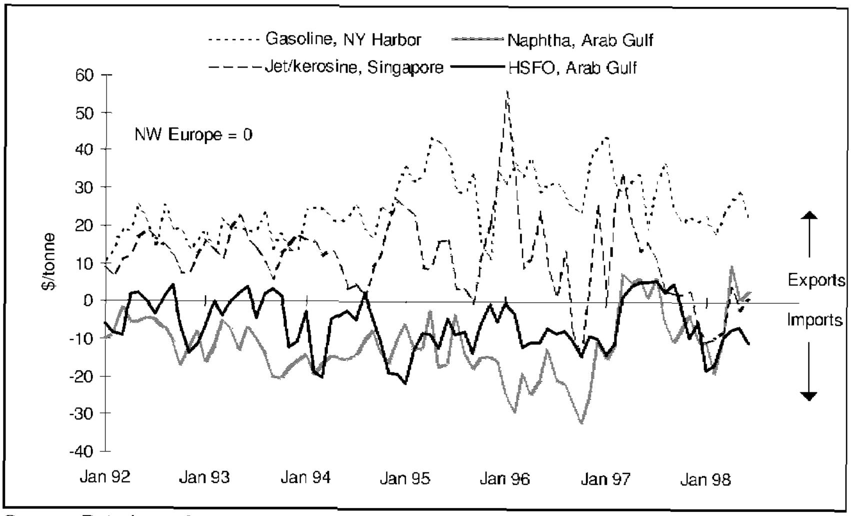
5.1 Introduction

Refined product markets differ from crude in several respects. First, the scale of operation is usually much smaller. A typical crude deal involves 500,000 or even 1,000,000 barrels of oil, while a typical product deal might only involve 5,000 or 10,000 barrels. As a result, the sums of money at stake are considerably lower. Secondly, quality is paramount. Refiners not only expect — but are used to coping with — variations in crude oil quality and these would not undermine the viability of a deal. Refined products must meet very stringent quality specifications if they are to be sold to final consumers and the delivery of an off-spec cargo would be regarded as a breach of contract. Rigorous quality tests therefore form an important part of any transaction involving refined products. Finally, there are many more opportunities for arbitrage in the products market. Price differentials between the various grades of refined product are constantly shifting — either at the same location, or thousands of miles away — and many traders make a steady living from breaking bulk, blending grades, or moving cargoes around the world.

No refiner or marketer is able to operate a completely balanced system and the primary function of the products market is to



Source: Petroleum Argus

Figure 5.1 North-west Europe: refined product arbitrage redistribute the individual surpluses and deficits that inevitably arise at each location. As a result, the broad structure of the refined products market depends on the interaction between the composition of the demand barrel, the mix of refinery capacity, and the type of crude oil being run in each of the major geographical regions. Although these patterns change over time, there are regular flows of product from one region to another and the market sets relative price levels accordingly (see Fig. 5.1). Europe, for example, exports gasoline to the US and gasoil to the Far East, but imports naphtha and fuel oil for use as refinery feedstocks. The US exports distillates to South America and the Far East. And the mid-east Gulf is a net exporter of naphtha and fuel oil to both the Far East and Europe.

In recent years, there have been a number of significant shifts in the pattern of world product trade that have affected the relationship between prices in the different refining centres. The Iraqi invasion of Kuwait in 1990 destroyed several highly sophisticated refineries in the mid-east Gulf, temporarily removing an important source of light and middle distillate exports to both Europe and the Far East. This shortfall was replaced by US refiners who had been investing heavily in new upgrading plant and were able to increase their yields of distillate products much faster than they had anticipated. As a result, the US became a net exporter of middle distillates, after years of being a net importer. But US refiners are now running close to full capacity, creating opportunities for refiners in Europe and Latin America to export growing volumes of gasoline and gasoline blending components to the huge US market.

Recently, the sudden collapse of Asian demand has reversed the flow of product trade between east and west. After being a net importer of refined products across the barrel for many years as demand growth outpaced the expansion of refinery capacity, the Asia Pacific region now finds that it has a product surplus which is being exported to Europe, Latin America and the US west coast when the arbitrage is open.

5.2 Europe

The European products market is one of the largest and most sophisticated in the world. European countries consumed some 15.8 million b/d of oil products in 1997, of which 13.2 million b/d was consumed in the fifteen countries of the European Union (EU).

Europe is also an important swing refining centre. There is nearly 17 million b/d of crude distillation capacity in Europe, including almost 3 million b/d in eastern Europe. With a large number of relatively sophisticated refineries it is able to import low quality feedstocks such as straight run fuel oil and naphtha, principally from Russia and the Middle East, and turn them into high quality products such as gasoline and jet fuel for export.

The greatest concentration of refining capacity in Europe is to be found in the Amsterdam-Rotterdam-Antwerp (ARA) region of the Netherlands and Belgium where there is nearly 2 million b/d of capacity. The four main consuming markets of Europe are Germany, France, Italy and the UK which, together, accounted for 65 per cent of EU(15) oil demand and 54 per cent of total demand in Europe in 1997. As a result, there is an active international trade in oil products within Europe.

In northern Europe, physical trade is based on Rotterdam which is strategically placed at the mouth of the Rhine river and a major refining centre in its own right. While in southern Europe, physical trade is based on Genoa. Prices are typically quoted on both an fob and cif basis for a wide range of imported and exported cargoes, and Rotterdam also has an active fob barge market trading much smaller quantities between refiners and for inland delivery.

Table 5.1 OECD Europe product supply and demand, 1997

Product	**Consumption† million b/d**	**Refinery output* million b/d**	**Net imports million b/d**
Gasoline	2.98	3.49	–0.38
Naphtha	1.13	1.07	0.19
Kerosine	0.93	0.98	0.00
Gasoil/Diesel	5.13	5.02	0.13
Fuel oil	1.94	2.06	0.01
Total	**13.40**	**13.65**	**0.14**

*Source: IEA, OECD Quarterly Oil & Gas Statistics † incl bunkers *excl fuel*

5.2.1 Gasoline

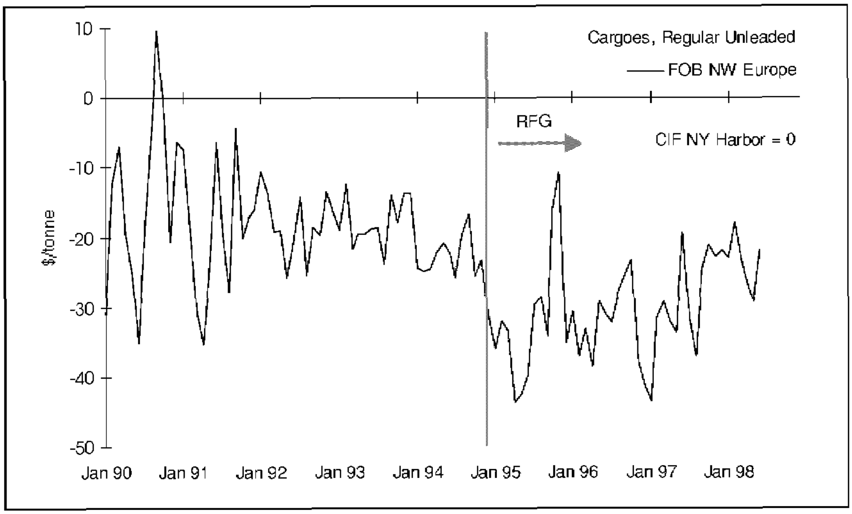
Over the last few years, unleaded gasoline has taken a growing share of the European market and premium unleaded gasoline (Eurograde) is now the most actively traded grade (see Table 5.2). But the market remains unstandardised with significant differences between the specifications of gasoline consumed in European countries and in the major export markets. The key specifications are octane — expressed as Research Octane Number (RON) and Motor Octane Number (MON) — vapour pressure and, increasingly, benzene (see Section 2.4.3). In Italy, the benzene content for gasoline will be restricted to a maximum of one per cent from July 1998. The rest of the European Union is expected to follow suit.

Premium leaded and regular unleaded gasoline are also important as they still have a large market share in some European countries (see Table 5.2). Germany is a major consumer of regular unleaded and Italy and Spain are major consumers of premium leaded gasoline. In addition, the Motor Octane Number (MON) of gasoline varies from country to country. Also European refiners need to meet export quality standards and much tighter US gasoline specifications mean that refiners must decide in advance which market they intend to supply. The most important difference is the requirement to use oxygenates such as MTBE to comply with US gasoline emission controls (see Section 5.3.1).

Table 5.2 Breakdown of gasoline sales in Europe, 1997

% share	Premium leaded 98 RON	Superplus unleaded 98 RON	Eurograde unleaded 95 RON	Regular unleaded 91 RON
Austria	–	15	51	34
Belgium	21	38	41	–
Denmark	**17*	17	52	14
Finland	**13*	15	72	–
France	39	42	19	–
Germany	–	6	57	37
Greece	59	2	39	–
Ireland	28	4	68	–
Italy	49	–	51	–
Luxembourg	12	36	48	4
Netherlands	**9*	13	78	–
Portugal	53	19	28	–
Spain	59	11	30	–
Sweden	**20*	–	80	–
Switzerland	9	6	85	–
United Kingdom	28	2	70	–
Europe	***2 24**	**11**	**53**	**11**

*Source: OPAL, Oil Price Assessments Ltd * lead replacement gasoline (LRG)*



Source: Petroleum Argus

Figure 5.2 Gasoline: north-west Europe minus NY Harbor prices

The European gasoline market is affected by seasonal factors. Consumption peaks in the summer, but the market is most active in the spring when the change from winter to summer specifications prompts refiners to turn over their inventories. Spring can also be the peak period for trans-Atlantic trade. The US is a net importer of gasoline and refiners, particularly in northwest Europe, are major suppliers if the arbitrage is profitable. Trans-Atlantic freight costs for a 30,000 tonne cargo of gasoline are of the order of 5 cents/US gallon ($18/tonne). But the differential would need to be wider if the European refiner was aiming specifically for the reformulated gasoline (RFG) market (see Fig. 5.2). Most European gasoline exports to the US are either used as blending components or sold into non-RFG markets. The Conoco refinery in the UK is one of the very few plants that can actually manufacture RFG for the US market.

Cargo sizes for European grades are much smaller than trans-Atlantic cargoes. In NW Europe, typical traded cargo sizes are 10,000 tonnes, in the Mediterranean cargo sizes are around 20,000 tonnes and trans-Atlantic cargoes are usually 30,000 tonnes but can be bigger. A shortage of catalytic cracking capacity in southern Europe — caused by the move to lower lead content and therefore a higher octane number — has created the opportunity for large volumes of gasoline to be exported from north-west Europe into southern Europe, reversing the traditional flow of gasoline trade in the region.

Regular unleaded gasoline produced by southern European refiners is also well suited to the US market. However, the US market operates under different constraints to the European market and even standard measurements such as octane can be different. Octane in the US, for example, is measured by an average of RON and MON numbers — premium gasoline is now universally 93((RON+MON)/2) and regular gasoline is 87((RON+MON)/2). Export grades are usually referred to by their US Colonial Pipeline codes, e.g. A1, M3, V5. Gasoline grades are given different letters to differentiate between conventional and reformulated gasoline, octane number and oxygen content. Numbers are then added to distinguish between the RVP and oxygen content required at different times of year (see Section 5.3.1).

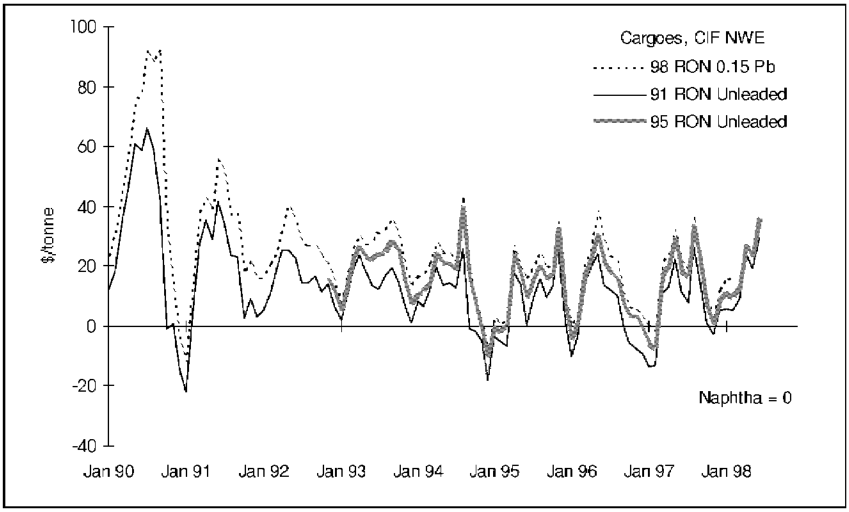
In addition to the European gasoline cargo markets, there is an active market on barges of 1,000 tonnes and 2,000 tonnes along the river Rhine. Product is moved from ARA refineries and storage facilities to distributors in Germany, the Benelux countries and Switzerland. The barge market in Rotterdam can slow to a trickle if gasoline prices in Germany are lower than those in Rotterdam or if Rhine water levels are either too low or too high to allow barge traffic. There is also an active gasoline barge swaps market (see Chapter 10).

5.2.2 Naphtha

Europe has a well developed petrochemical industry and a large number of sophisticated refineries specialising in the production of gasoline. As a result there is a ready market for both naphtha with a high paraffinic content, which is preferred as a feedstock for ethylene crackers, and naphtha with a high naphthenic and aromatic content (N+A), which is preferred as a feedstock for reformers to make gasoline (see Fig. 5.3).

The European naphtha market is based on imported cargoes, mainly from simple hydroskimming refineries in North Africa and the Middle East. The market is dominated by Algeria, but supplies also come from Egypt, Libya, Greece and Syria. In the Middle East, Saudi Arabia and Bahrain are the main exporters. Occasionally, Venezuelan material is exported if the arbitrage is profitable. Russian supplies once dominated the market in Europe, but traded volumes have fallen sharply as the volume and consistency of Russian product has deteriorated.

Cargo trading in the Mediterranean is largely conducted on an fob basis, with prices quoted at the major loading ports in Algeria, Libya and Egypt. This material is then sold as a cif (delivered) cargo into the petrochemical and refining centres of the south of



Source: Petroleum Argus

Figure 5.3 Gasoline minus naphtha prices

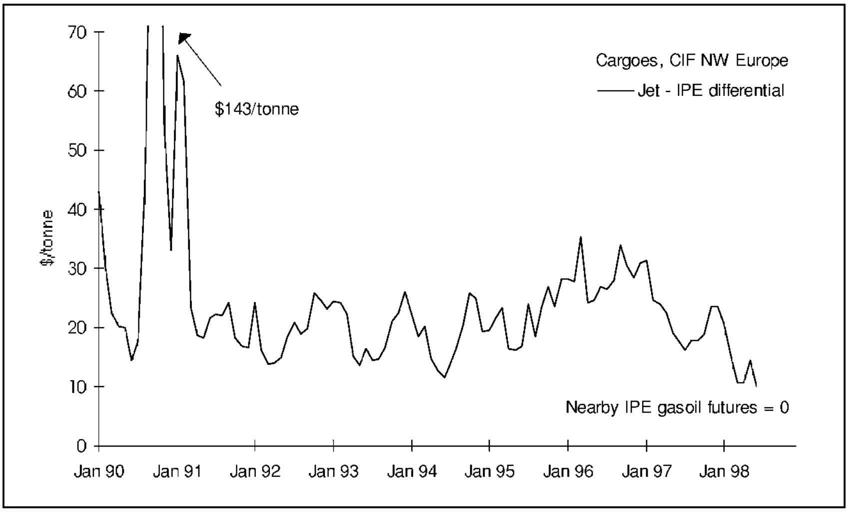
France and north-west Europe. Trade also occurs into the Italian ports of Genoa, Priolo and Venice, either for petrochemical processing or pipeline shipment to the petrochemical and refinery companies of Germany.

Cargo trading in north-west Europe is largely conducted on a cif basis and an active market has developed for price swaps between the traders, refiners and petrochemical companies that buy and sell naphtha (see Chapter 10). The swaps market has replaced the former "forward" market which was judged too inflexible as a hedging tool (see Chapter 7). Barge trading in the ARA range is less active than the cargo market since buyers typically want much larger quantities.

European naphtha imports are dominated by high paraffinic grades from Algeria, Morocco, Saudi Arabia and Bahrain and from refineries in Greece. Supplies of high N+A naphtha are imported from refineries in Libya and Syria. Algeria also exports a modest amount of full range material from the refinery at Arzew, and full range naphtha is also imported into Europe from Egypt and Tunisia.

5.2.3 Jet kerosine

Europe is a net exporter of jet kerosine and so the market is largely based on fob cargoes. The main exporters in north-west Europe are refiners in the ARA region, but the bulk of the spot supply comes



Source: Petroleum Argus, IPE

Figure 5.4 Jet kerosine minus nearby IPE gasoil futures prices

from Mediterranean refiners, especially those based in the Italian islands. The market tends to be very secretive since the number of buyers is relatively restricted and the quantities involved can be very large. As a result, prices can be volatile and companies often use price swaps based on *Platt's* quotations to hedge their purchases and sales (see Chapter 10). Jet kerosine price swaps are traded at a differential to the nearby IPE gasoil futures contract (see Fig. 5.4).

There are basically two types of jet kerosine, DERD 2494 or JP1 and dual purpose kerosine (DPK). European Union (EU) countries insist that jet fuel for aviation use must conform to the DERD 2494 specification and have a refinery guarantee certificate. DERD 2494 specifications include sulphur content (max 0.3 per cent), flashpoint (min 38°C), freezing point (max –47°C), density (at 15°C, min 0.775, max 0.840) and cetane index (38). In winter, jet fuel can be used for blending purposes to improve the cold properties of gasoil.

DPK can be used as blending stock or for domestic heating if it has the appropriate smoke point and colour. Algerian jet can be used both as aviation fuel and as heating fuel as it conforms to the specifications for both. Russian jet fuel does not have the necessary certificate to qualify as DERD 2494 and is used as a blendstock in the Rotterdam region. As with other products from Russian refineries, the quality is variable and this lowers its value relative to jet from other sources.

The majority of jet kerosine in Europe is traded under long term contracts between refiners and European consumers. There is, however, an export spot market for jet kerosine based around refineries in the Mediterranean. Buying interest comes principally from northwest Europe. Arbitrage opportunities also open to the Far East and, occasionally, the US Gulf. Price volatility in the Mediterranean spot jet kerosine market tends to be high.

5.2.4 Gasoil

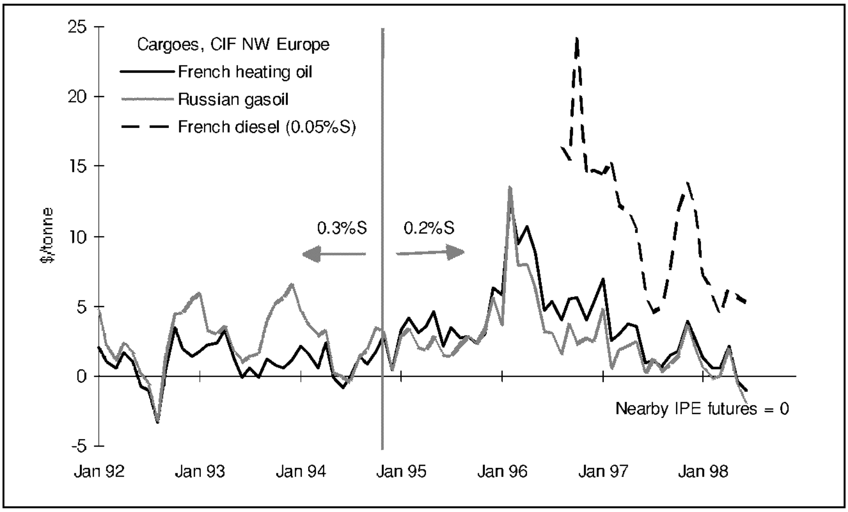
Gasoil is used extensively throughout Europe as a fuel for domestic central heating systems, particularly in Germany. But growing demand for diesel as an automotive fuel means that this is now the largest market overall (see Table 5.3).

Product quality standards for heating gasoil and automotive diesel have become much more stringent in recent years and the market is increasingly fragmented as blending opportunities are constrained. Environmental controls on air pollution reduced the maximum sulphur content of European gasoil to 0.2 per cent from the end of 1994 and specifications for diesel were tightened further in October 1996, limiting sulphur content to 0.05 per cent. In winter, cold properties such as cloud point, pour point and cold filter plugging point become important especially for diesel, and gasoil with good cold properties usually commands a premium.

Table 5.3 Breakdown of gasoil sales in Europe, 1996

	Automotive diesel '000 b/d	**Other gasoil '000 b/d**	**Automotive diesel share**
Austria	52	50	51%
Belgium	86	132	39%
Denmark	42	44	49%
Finland	31	48	39%
France	471	390	55%
Germany	478	834	36%
Greece	50	67	43%
Ireland	18	27	40%
Italy	315	171	65%
Luxembourg	12	8	62%
Netherlands	95	37	72%
Norway	26	47	35%
Portugal	51	17	75%
Spain	185	205	47%
Sweden	40	76	34%
United Kingdom	293	169	63%
European 15 + Norway	**2,224**	**2,322**	**49%**

Source: Eurostat



Source: Petroleum Argus, IPE

Figure 5.5 Gasoil minus nearby IPE gasoil futures prices

All European refiners produce gasoil as part of their mainstream operations, but imports remain an important source of supply, especially for gasoil with good cold properties that can be blended to make winter grade diesel. The main sources of gasoil imports are Russia and Algeria. In the past, Russian gasoil provided the foundation for Europe's first and most active forward paper contract (see Chapter 7), but liquidity collapsed in 1993/94 after exports became erratic and the IPE gasoil futures contract has replaced it as a price marker (see Fig. 5.5).

Russian gasoil is no longer as valuable to the western European market as its sulphur content — 0.2 per cent — makes it a less attractive blendstock for diesel. Its value is expected to decrease further as the market for ultra-low sulphur or "city" diesel expands and when the sulphur content of heating gasoil is also reduced to 0.05 per cent as planned by EU environmental legislation. At present there is no deadline for the changeover.

Gasoil cargoes are traded on both a cif and fob basis. Average cargoes are the traditional 'handy' size for clean products of between 20,000 and 25,000 tonnes. Prices are typically negotiated at a differential to the IPE gas oil futures contract, which is most closely related to the ARA barge market. Barges trade out of the ARA range in 1000 to 5000 tonne lots, and move mainly into the Benelux countries and Germany.

Gasoil prices are affected by a number of factors including variations in product quality standards set by the major European consuming countries, differences between the cold properties of winter and summer gasoil, and fluctuations in Russian and other import availabilities. As a result, there is continuous and active arbitrage between the cif cargo, fob cargo and barge markets.

The European gasoil cargo market divides into north-west Europe and the Mediterranean. In north-west Europe, Germany is the major importer — either through Hamburg or Rotterdam — and now absorbs most of the available Russian supplies. France occasionally imports Russian gasoil for quality reasons, particularly in winter, but meets most of its demand from local refineries. Scandinavian and UK refiners are net suppliers to the rest of Europe. The growth of the European diesel market has left the region with a 10 million tonne gasoil deficit which is supplied by imports from Russia and Algeria. There is now one EU-wide diesel grade — EN590 — but cold properties vary from country to country. For example, German EN590 has more stringent cold properties than French EN590 to cope with the colder weather.

During the summer, trade on the north-west European cargo market is more or less restricted to diesel grades with the majority of spot trade for French quality based on 20,000 tonne cargoes delivered into the port of Le Havre. But during the winter, a wider variety of gasoils are traded classified according to their cold properties. German diesel has three grades — summer, winter and intermediate — each with different cold properties. French "fuel oil domestique" (FOD) can now only be used as a heating oil because of its higher sulphur content.

Russian gasoil exports to Europe became erratic after the break-up of the Soviet Union and the deterioration of relations between Russia and Latvia, through which the bulk of Russia's gasoil exports to north-west Europe must pass. Russian gasoil specifications, such as sulphur content, cold point and pour point, are variable and quality suffers at times from bacterial contamination, although this is only a problem during the summer months as winter temperatures are too low to support the bacteria.

Deutsche Industrie Normal (DIN) grade gasoil, for heating, is only used in Germany. The specification varies from 4°C cloud point and –7°C cold filter plugging point during the summer to 0°C cloud point and –12°C cold filter plugging point in winter, but this will change to a single all-year-round specification (1 to 3°C cloud point and –10 to –12°C cold filter plugging point) from October 1998. Unofficially, German refiners have been producing the new specification since the start of 1998. DIN gasoil is produced by German, Scandinavian and UK refiners and trades on the barge markets and in cargo lots. Trade is much heavier in winter when

German refiners are unable to satisfy local demand. German winter diesel is used from the start of November to the end of February and summer diesel is used between the start of April and the end of September. Intermediate diesel is used in March and October.

In the Mediterranean, the main sources of supply are Russia, Algeria and the Italian offshore refineries. The Mediterranean equivalent of FOD, Italian 0.2 per cent sulphur gasoil, is sold out of the Italian islands refineries on an fob basis, priced against European price quotations. Italian refiners also produce gasoil with a sulphur content ranging from 0.3 to 1 per cent for export to the Far East, eastern Mediterranean and west Africa if the arbitrage opens. This is usually sold in bulk lots of 40,000 to 70,000 tonnes and is traded at a discount to the 0.2 per cent sulphur grade.

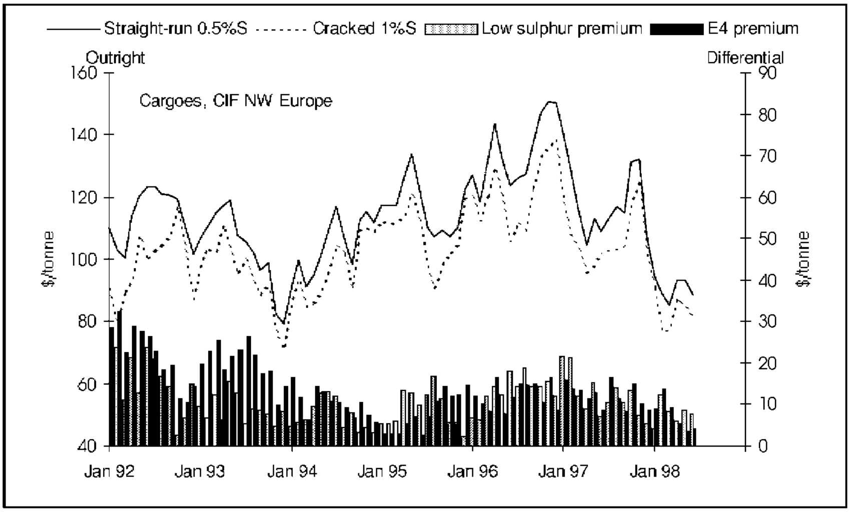
Algerian gasoil is of a low density with low cloud, pour and cold filter plugging points. As such, it provides a valuable blending stock. Algerian gasoil is often sold on a formula basis fob Skikda or, in smaller volumes, fob Arzew. It is also sold into north-west Europe on a cif basis at a premium over the IPE gasoil contract. Typical cargo sizes are 30,000 tonnes.

5.2.5 Residual fuel oil

Fuel oil is burnt in power stations and used as a fuel to power ships (bunkers). It is manufactured in two distinct forms: straight run and cracked. Straight run fuel oil is the product of primary (atmospheric) distillation and is typically sold (at a premium) as a feedstock to refiners who have unused vacuum distillation and cracking capacity and can therefore upgrade it into more valuable products such as gasoline and gas oil. Cracked fuel oil is produced from what is left after upgrading and is usually less valuable than straight run fuel oil (see Fig. 5.6).

The straight run and cracked markets are separate and only converge when high refinery runs ensure that the straight run market is over-supplied, forcing poorer quality grades into the burning market. All refiners are potential sellers of straight run fuel oil, depending on their crude slate, distillation capacity and the size and sophistication of their upgrading units. The buyers for straight run fuel are refiners wanting to increase their gasoline and gas oil output, whereas the buyers for cracked fuel are power utilities, large industrial concerns and companies with bunkering outlets. If the price is sufficiently low, blenders will also buy straight-run fuel oil to add to the cracked fuel oil pool in order to reduce its viscosity, thus making it more valuable.

The price of cracked fuel oil depends on its composition. The most important properties are sulphur and metals content, viscosity



Source: Petroleum Argus

Figure 5.6 Straight run and cracked fuel oil prices

and specific gravity. Sulphur is restricted for environmental reasons and most utilities cannot burn high sulphur material unless they have installed flue-gas desulphurisation facilities. Metals such as vanadium can cause engine damage and their content is restricted in the bunker market. And sulphur, density water content and ash all affect the heat output of fuel oil and therefore its value in the burning market. Specific gravity is a key consideration in the bunker market since lower gravity material is easier to separate from water. The specific gravity of fuel oil can vary from 0.991 to over 1.000, but material with a specific gravity of 1.000 (the same as water) is never used as bunker fuel.

Low quality European material is often delivered into west Africa, particularly Senegal and Cote d'Ivoire. In addition to utility demand, bunker supplies for west African ports are also supplied by traders from the Mediterranean. Bunker sales go farther afield than west Africa. When the arbitrage to the Far East is open, material from the Mediterranean often moves to the bunkering centres of Fujairah and Singapore.

High sulphur fuel oil cargoes

Most of the spot buying interest for high sulphur cracked fuel oil in north-west Europe used to come from power utilities in the UK, Eire and Portugal, but this market has largely disappeared over the last few years as gas has taken a larger share of the electricity generation market. The Portuguese power utility CPPE (formerly EDP) still tenders for high sulphur fuel oil. But the UK utilities now only buy one cargo in six months.

In the UK, the quality specifications varied from buyer to buyer. The largest utility, National Power was the most flexible because it has the facilities to blend fuel oil to any required density at its Littlebrook power station on the River Thames. National Power can take fuel oil up to 1.005 sg and can also take material with vanadium levels as high as 300 ppm and with a high viscosity level of 120 cst at 80°C. The now defunct forward paper market for high sulphur fuel oil (Littlebrook Lottery) was based on physical delivery into the Littlebrook terminal.

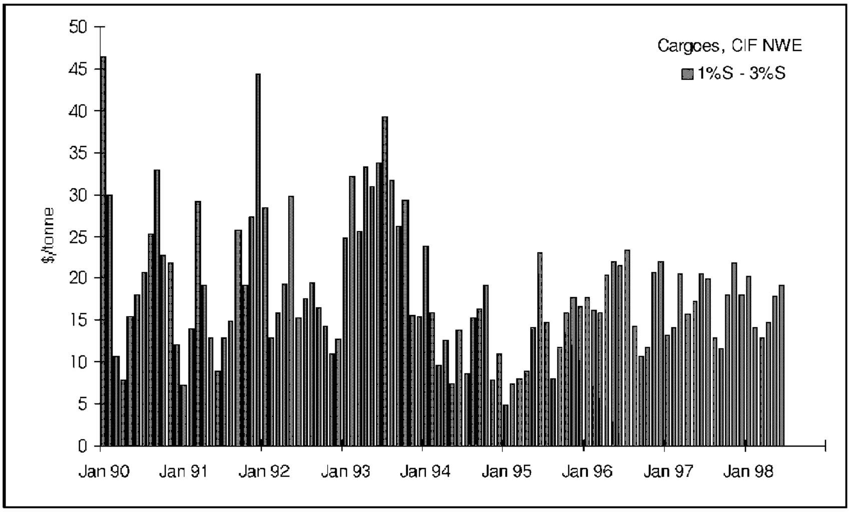
Other UK utilities are not as flexible and require more precise sulphur and density specifications. Both Powergen and Scottish Hydro buy 3 per cent sulphur 0.998 sg material. The petrochemicals giant ICI is the other main end-user of cracked fuel oil in the UK. ICI has restrictions on metals content and buys 3.5 per cent sulphur, 1.005 sg, 150 ppm vanadium material for use in its own power station. Portugal's national utility company, Electricidade de Portugal (EdP) was the most regular single buyer of cracked high sulphur fuel oil in Europe, purchasing 3.5 per cent sulphur, 0.998 sg material. In addition, Electricité de France (EdF) sometimes needs to enter the spot market when low rainfall or plant shutdowns restrict nuclear output. Utilities in Spain typically buy all their fuel oil from domestic refiners.

The high sulphur fuel oil market in the Mediterranean covers a wider range of specifications than in NW Europe. Several countries, including Romania, Bulgaria, Greece, Cyprus, Malta and the Lebanon, have regular utility tenders. But Italy, which is the largest utility market, usually burns low sulphur fuel oil although Enel now buys some medium and high sulphur fuel oil since it can meet its sulphur emissions target through improved technology and increased use of gas. Enel will also take straight-run cargoes from the Black Sea and north Africa and, occasionally, Indonesian low sulpur waxy residue (LSWR).

The bunker market in the Mediterranean is highly active, but unlike Rotterdam in NW Europe, there is no natural Mediterranean centre for bunkering operations.

Low sulphur fuel oil cargoes

The Italian state utility, Enel, is the world's largest single buyer of fuel oil. In a typical year some 6 million tonnes will be bought on a tender basis from traders, 5 million tonnes from refiners and a further 5 million tonnes from oil producers. The tender basis



Source: Petroleum Argus

Figure 5.7 Low sulphur minus high sulphur fuel oil prices

recently changed from a formula based on a mixture of fob north-west Europe and fob Mediterranean quotes to one based on cif Mediterranean quotes (see Fig. 5.7). Low sulphur fuel oil is also exported to utilities on the US Gulf and US east coast, but the US market tends to follow Europe since Enel is such a large consumer.

Most of Europe's low sulphur fuel oil (LSFO) supply comes from north-west European and Scandinavian refiners, with most trade done on an fob basis. Although European cargoes are generally 25,000 tonnes, Scandinavian refiners tend to sell cargoes of up to 40,000 tonnes.

Barges

In north-west Europe there is also an active barge market operating in the Rotterdam-Antwerp area. The high sulphur barge market supplies bunkers, inland demand and is used to top-up export cargoes. The most commonly traded grade is 3.5 per cent sulphur, 380 cst viscosity and 0.991 density. Barge price quotations are usually used in the active high sulphur swaps market. Low sulphur barges supply the inland market in Germany and the Benelux countries. Additional quality specifications for low sulphur fuel oil include flash point and metals content.

Flash point is the temperature (measured in °C) at which oil ignites and restrictions apply to the transport of oil through German towns. For safety reasons, lower flash material cannot go up the Rhine beyond the Ruhr. The most common flashpoints are 65°C and 100°C — the latter commanding a price premium. Although most refiners do produce 100°C flash point material, few will guarantee it and flash point can be a problem for trading companies.

LSFO metal restrictions are based on nickel content. The current restriction in Germany is 24 ppm, which compares with 30 ppm required by the Italian utility Enel.

Straight run fuel oil

Straight run fuel oil (SRFO) is generally used as a refinery feedstock, but both high and low sulphur SRFO occasionally find their way onto the burning market.

SRFO is divided broadly into high and low sulphur product, although the variety of specifications within these categories is as broad as the crude slate from which they are derived. SRFO will usually carry a premium over cracked fuel because it can be processed to produce more valuable products in addition to its cracked fuel yield.

Russian E4 (named after the Engler measure of its viscosity) is one of the most commonly traded grades of SRFO in north-west Europe and acts as a price marker. In the Mediterranean, Russian M100 and M40 (M standing for 'mazut' which is the Russian for fuel oil) is more commonly seen, although there are now considerable quantities of M40 and M100 available in northwest Europe from Tallinn and St Petersburg. The volume of Russian trade is highly seasonal, and it has been usual in recent years for exports to be banned altogether by the Russian government during the winter months.

The break-up of the former Soviet Union has affected the quality of fuel oil exports. This is most easily seen in the viscosity of the material. Previously all E4 product was blended into standard product at the Lithuanian port of Klaipeda, but specifications started to fluctuate because the refineries which produce E4 no longer export through a centralised system. At present, the viscosity of E4 ranges between 2.4 and 3.2 Engler, but 4 Engler is still taken as the price basis, with a standard premium or discount of $0.40 per tonne for every 0.1 Engler below or above 4 degrees.

Other regular suppliers of high sulphur SRFO (also known as high sulphur straight run fuel or HSSR) into the Mediterranean market are Turkey, Portugal and Egypt. Iranian HSSR is normally sold into Canada or the Caribbean, but if supplies of better quality Russian HSSR are tight, traders might offer the material into the Mediterranean or NW European markets. Poor quality, high sulphur Syrian material regularly goes into the burning markets of the Mediterranean, or into the US for the spring bitumen season. Saudi Arabia produces various grades of HSSR, of which over 2 million tonnes are exported each year.

The main sellers of low sulphur SRFO (also known as low sulphur straight run fuel or LSSR) are refineries without upgrading units. The buyers are refiners who wish to run more feedstock through spare cracking capacity. Although North Sea straight run is the most actively traded in north-west Europe, Portuguese and North African material is also available. Leixos material from Portugal's Oporto refinery has a high metals content but gives a good vacuum gasoil (VGO) yield and usually goes into the US market. North African grades generally have a low sulphur content — LSSR from Algeria is practically VGO — and LSSR from Algeria, Egypt and Tunisia also finds its way onto the market. The high pour point and nickel content of Libyan LSSR reduces its value, as do destination restrictions resulting from Libya's exclusion from the US market. However, its low sulphur content makes it popular with refiners and traders in Europe.

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5.3 United States

The United States is the single largest user of oil products in the world, consuming 18.6 million b/d of refined products in 1997. Its demand barrel is also exceptionally light compared with most other countries. Distillate products — gasoline, heating oil, diesel and jet fuel — account for 70 per cent of US product demand and gasoline alone constitutes 43 per cent of the total (see Table 5.4). But, despite having the world's largest and most sophisticated refining system, the US remains dependent on imports of refined products from Venezuela, Canada, Algeria, Europe, the Caribbean and Asia. Imports averaged 1.9 million b/d in 1997 — 10 per cent of total US products demand — and the key consuming markets in the north-east rely on imports to meet about 17 per cent of gasoline demand and 16 per cent of heating oil demand. Despite its dependence on imports, the US also exported 900,000 b/d of refined products in 1997, mainly to Latin America where refiners can sell product that does not meet the much tighter domestic quality specifications.

Table 5.4 United States product supply and demand, 1997

Product	Consumption million b/d	Refinery output million b/d	Net imports million b/d
Gasoline	8.01	7.74	+0.17
Distillate fuel oil	3.43	3.39	+0.08
Jet fuel	1.60	1.55	+0.06
Residual fuel oil	0.80	0.71	+0.08
Other products*	4.78	3.36	+0.66†
Total	**18.62**	**16.75**	**+1.04**

Source: EIA   * *includes LPG* † *includes blending components*

Waterborne imports — especially for gasoline and gasoline blending components — play an important role in the overall US supply and demand balance. Although US refineries are among the most complex in the world and produce a very high yield of gasoline, capacity is now fully utilised for most of the year, leaving the country increasingly dependent on imports to meet rising gasoline demand. But the volume of spot product trade has declined in recent years as the structure of the market changed. There are now fewer companies operating downstream because of mergers. More oil moves in integrated channels as a result of joint ventures with foreign producers. And environmental regulations have created a fragmented market with many more grades of product.

The US refined products market is divided into two distinct markets separated by the physical barrier of the Rocky Mountains with very little movement of products between the two. Increasingly strict environmental regulations have also served to fragment the US market, with products meeting different specifications required in various parts of the country.

Physical trade in oil products east of the Rockies is centred on Boston, Massachusetts and New York Harbor for the north-east of the country, on the Colonial pipeline which links Gulf coast refiners to consumers along the Atlantic coast as far north as New York, and on the Explorer and Williams pipelines that link the Gulf coast to Tulsa, Chicago and Minneapolis. There is also a relatively small Gulf coast cargo market which serves shipments to the state of Florida and for export.

Within the west coast market, most trade occurs on the Southern California and Santa Fe Pacific pipelines. The two pipelines supply California, Nevada and the western part of Arizona from Los Angeles and San Francisco. The west coast is isolated from the rest of the US market by the high cost of transport and relative prices can differ by as much as 20 cents/gallon.

Complex environmental rules — which have required massive investments in refinery upgrading and have led to rising product storage costs — together with slim trading margins have conspired to reduce the number of companies willing to participate in both the Atlantic coast and the west coast refined products markets. Indeed, the west coast market is now almost entirely dominated by five companies, Arco, Chevron, Exxon, Equilon — a new joint downstream venture between Texaco and Shell — and Tosco.

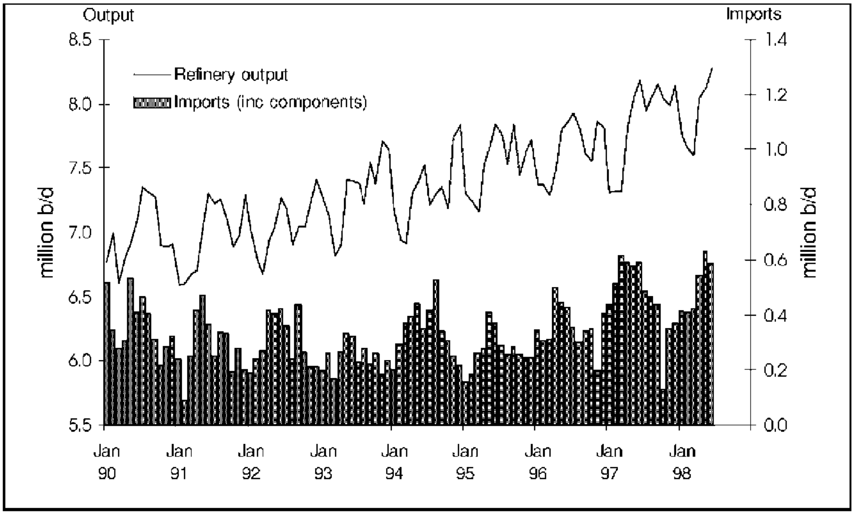
5.3.1 Gasoline

US gasoline demand is the highest in the world, averaging just over 8 million b/d in 1997, and consumption has recently been growing at around 1.5 per cent a year spurred on by strong economic growth and a shift to less efficient vehicles. But, although domestic gasoline production capacity has expanded greatly over the last ten years as refiners have brought more upgrading capacity on stream, the US remains dependent on imports to meet demand — especially in the high consuming centres of the north-east. Imports briefly fell after the introduction of reformulated gasoline in 1995 but have since recovered, supported by the revival of the New York Harbor gasoline blending market, and are now higher than ever (see Fig. 5.8). Foreign producers initially found it difficult to meet the new environmental standards, but restrictions on imports were successfully challenged as discriminatory in the World Trade Organisation (WTO) under the 1994 General Agreement on Trade and Tariffs (GATT) by Venezuela and Brazil, which now form important sources of supply. European refiners also export "off-spec" gasoline to the US which is used for blending. Imports of gasoline blending components averaged 200,000 b/d in 1997 compared with 309,000 b/d for finished gasoline.

Gasoline quality specifications

The 1990 amendments to the US Clean Air Act (CAA) are the strictest environmental regulations in the world. They set limits on sulphur, carbon monoxide and ozone-forming emissions. The CAA rules have included a number of measures aimed at reducing harmful emissions from the combustion of gasoline and, as a result, have significantly altered the physical characteristics of gasoline sold in the US. The first measure was the lead-phasedown programme, initiated in the early 1980s, which has resulted in only unleaded gasoline now being permitted for sale in the US.

The second phase of the CAA regulations placed limits on the volatility of gasoline throughout the year and was introduced to combat increased vapour emissions resulting from the extensive use of butane as a blending component. The third phase of the regulations, effective from the autumn of 1992, was aimed at reducing carbon monoxide emissions and required the use of



Source: Argus Fundamentals, EIA

Figure 5.8 Gasoline: US refinery output and imports gasoline with a 15 per cent oxygen content by volume for either 4 or 6 months between 1 October and 1 April in 41 major US cities.

The introduction of reformulated gasoline (RFG) in 1995 was intended to reduce the build-up of ozone in the atmosphere. RFG must be supplied to nine major US urban areas with the most severe summertime ozone levels since 1 January 1995. A number of other urban areas also opted to join the scheme — but some then decided to leave it, creating confusion for suppliers and temporarily limiting the trading horizons of the Nymex unleaded gasoline futures contract. By 1997 RFG accounted for 32 per cent of the total US gasoline market, and 39 per cent of the highly urbanised PAD District I market.

RFG is being introduced in a number of stages. Phase I, which runs from 1995 to 1999, involves two steps. The first step, which began in January 1995, required US refiners to produce RFG with a lower content of ozone-forming and other specified toxic air pollutants than the actual supplies that they produced in 1990. Each refiner established its own "baseline" gasoline quality and used a "simple model" to certify its RFG output based on the reduction in oxygen, benzene and aromatics content and RVP. But the second step, which began in January 1998, requires US refiners to achieve additional reductions in olefins, sulphur and the percentage of fuel evaporated at 200 and 300ºF. This is known as the "complex model" and imposes a new statutory (average) baseline for sulphur and olefins which all refiners must meet. Further reductions in the level of toxic air pollutants (TAP), volatile organic compounds (VOC) and nitrogen oxide (NOx) emissions will be required under Phase II of the RFG program which starts on 1 January 2000.

Foreign refiners were initially required to meet the statutory (average) baseline — which made it much more difficult for them to export RFG to the US. But this ruling was found to be discriminatory under GATT by the WTO in 1996 and foreign refiners are now allowed to establish their own individual 1990 baselines in the same way as domestic refiners. If foreign refiners do not establish their own baseline, exports to the US are regulated through the company importing the RFG and are subject to the importer's own baseline. Coventional gasoline imports are also monitored as part of the wider "anti-dumping" rule — which is intended to ensure that average per gallon emissions of specified pollutants are not worse than 1990 levels — and more stringent standards could be set in the future if the average quality of conventional gasoline imports deteriorates.

The US north-east gasoline market

The majority of gasoline imports into the US arrive in the key consuming centres of the north-east, which rely on imports to meet up to one fifth of their gasoline demand. The two main gasoline import cargo markets are based on New York Harbor and Boston, Massachusetts, but imports are also taken into other ports in the region, such as New Haven and Portsmouth. Imports are typically drawn in from Canadian, European, Caribbean and Venezuelan refiners. Many European refiners now produce gasoline which meets US RFG specifications, but an active blending market has emerged in New York involving companies such as Itochu, George E. Warren and BP. Gasoline blendstocks come from Brazil, Algeria, Romania, Argentina and other countries. The finished gasoline is then sold into the New York Harbor barge market or into the mid-continent via the Buckeye pipeline.

Boston used to be an active cargo market, since it depends solely on waterborne imports to meet demand, but few cargoes are now traded on a cif basis. Most finished gasoline is bought by US distributors on an fob basis in Europe and cif sales are limited mainly to 50–150,000 barrel part-cargoes. But blendstocks are sold on a cif basis into New York. New England has no refining capacity and the 2 million b/d Colonial pipeline terminates at New York Harbor. Boston requires smaller vessels due to port restrictions: maximum cargo sizes are 225,000 barrels. While New York Harbor can accept cargoes of up to 500,000 barrels, only the majors and the largest international traders can take physical delivery of cargoes of this size.

Since Boston marketers are net short of gasoline, many sign long-term supply contracts with exporting nations. In the past these firms also traded on the spot market to balance their positions, supporting the development of an active forward market — 'Boston Bingo' — which allows for the sale or purchase of cargoes up to two months forward. Boston Bingo contracts are for 225,000 barrel cargoes. But the Boston Bingo market has almost disappeared now that most importers buy product on an fob basis in Europe, and forward trade is limited to only a few players.

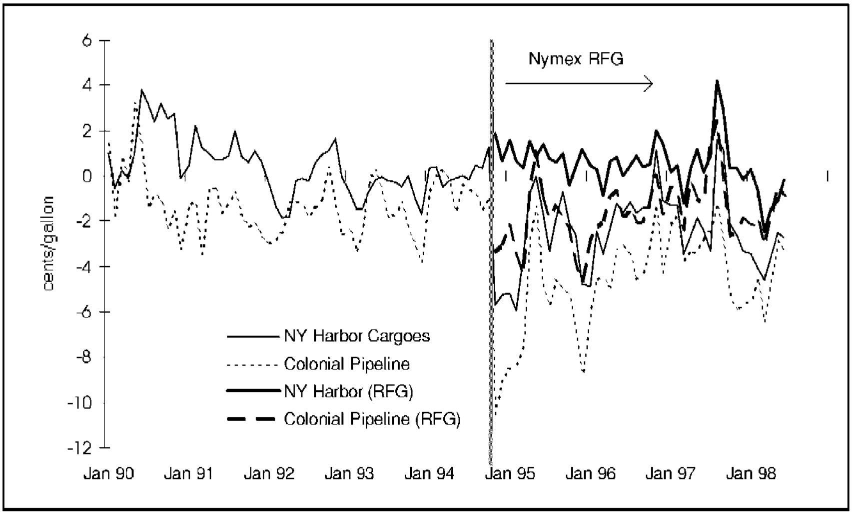
Most trade in the New York Harbor market is for regular unleaded gasoline — reflecting its dominance of the retail market where it commands a 65 per cent share. Regular unleaded gasoline serves as the pricing benchmark for premium (which accounts for 20 per cent of the retail market) and for midgrade (which accounts for the remaining 10 per cent). New York is at the centre of the north-east consuming region and is supplied either by sea, via the

Colonial pipeline or from local refiners. It is also the first input point for the Buckeye Pipeline serving the US Midwest.

Most of the trade is for 25,000 barrel barge lots. Barges are typically sold on a free on board (fob) basis from anywhere in New York Harbor. But trading volumes have fallen sharply in recent years and the barge market has become increasingly prompt. Trade has also developed for 'off-line' supplies, which are 25,000 barrel lots delivered to terminals at the end of the Colonial pipeline in Linden, New Jersey. This trade is closely linked to the arbitrage between Gulf coast and New York Harbor markets. Trades are also done "delivered Buckeye" available at Buckeye breakout storage.

Although barge volumes are suitable for meeting incremental supply, most demand is met with waterborne cargo imports. About two gasoline cargoes a day (around 425,000 b/d) are delivered to the New York Harbor market during the peak driving season between June and August, compared with only 5–7 barge lots (125–280,000 b/d).

The prices for clean product cargoes in Boston and New York are rarely the same. The alternative to imports is New York barges plus freight of 1–1.25 cents/gallon. Cargoes in New York usually carry a premium to barges as traders are often willing to pay more to obtain the volume they require in a single transaction instead of 8–10 barge transactions.



Source: Petroleum Argus, Nymex

Figure 5.9 Unleaded gasoline: spot minus Nymex futures prices

The Gulf coast gasoline market

The majority of Gulf coast gasoline trade occurs on the 1.9 million b/d Colonial pipeline, which takes in products from refineries in Texas, Louisiana and Mississippi and serves the Atlantic coast markets with the exception of Florida. The Colonial pipeline specifications typically set the standard for the Nymex clean products futures contracts, the Boston Bingo market and other physical trade along the US Gulf and Atlantic coasts.

The Colonial pipeline has active product codes for 38 different grades of gasoline (including RFG) and multiple vapour pressures for each grade, seven grades of kerosene, 16 grades of heating oil and diesel and one grade of transmix (the interface between gasoline and distillate batches). About half the codes are for "fungible" products that meet published Colonial specifications and the rest are for segregated branded products or blendstocks. In the case of fungible products, shippers may not receive the actual product delivered to the pipeline but receive the equivalent quality material. Gasoline grades are given different letters (see below) to distinguish between conventional, reformulated, octane number and oxygen content. Attached to these letters are numbers, which indicate the RVP and oxygen content at various times of the year. For example, regular grade gasoline used in the New York area in winter is coded A5.

Letter codes:	**A**	**C**	**D**	**M**	**P**	**R**	**S**	**U**	**V**
Octane	87	92	93	87	92	93	87	92	93
RFG	✓	✓	✓						
Conventional				✓	✓	✓	✓	✓	✓
Non-oxygenated				✓	✓	✓			
Oxygenate allowed							✓	✓	✓
Numeric codes: reformulated gasoline									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
RVP (psi)	7.4	8.3	11.5	13.5	15.0	8.3	11.5	13.5	15.0
Oxygen 1.5–2.7% wt	✓	✓	✓	✓	✓				
Oxygen 2.7–2.9% wt						✓	✓	✓	✓
Numeric codes: conventional gasoline									
	0	**1**	**2**	**3**	**4**	**5**			
RVP (psi)	7.0	7.8	9.0	11.5	13.5	15.0			

The Colonial pipeline market centres around the first input point to the pipeline at Pasadena in Texas. The basis for most trades is free in pipe (fip) Pasadena, Texas. Regular and premium unleaded gasoline (both conventional and reformulated) account for about 55 per cent of the total refined products shipped on the pipeline. The size of lots traded are typically 25,000 barrels (the minimum size of a fungible product batch) and the volume of gasoline shipments on the pipeline is around 1 million b/d.

Like the Atlantic coast cargo and barge markets, all product trading on the Colonial pipeline is done relative to the New York based Nymex gasoline contracts, but using the following month Nymex contract because it requires, on average, 19 days to move products from one end of the line to the other. While regular unleaded gasoline deals are done at futures-related prices, premium unleaded gasoline is typically discussed relative to regular unleaded conventional gasoline prices. The most actively traded Colonial gasoline grade is conventional southern grade (M), with southern RVP. Premium conventional (V) and regular RFG (A) are also traded, at a differential to M grade.

The Colonial forward market has traded as much as eight months ahead, but is normally confined to one month forward with the prompt half cycle (5 days) receiving most attention. Trade has frequently been disrupted in recent years by pro-rationing and independently scheduled pumping cycles.

Florida is completely dependent on waterborne supplies and Gulf coast cargo and barge shipments have grown steadily over the last decade. However, little spot trade occurs as most companies transfer supplies from their Gulf coast refineries to retail networks in Florida. Traders meet seasonal demand surges through cargoes from Europe and South America and Florida is attractive to foreign refiners as the state does not require the use of reformulated gasoline. Ports such as Wilmington, North Carolina and Savannah, Georgia have also become regular importers of gasoline. Florida trade is often tied up on contract with Venezuelan or Gulf coast refiners.

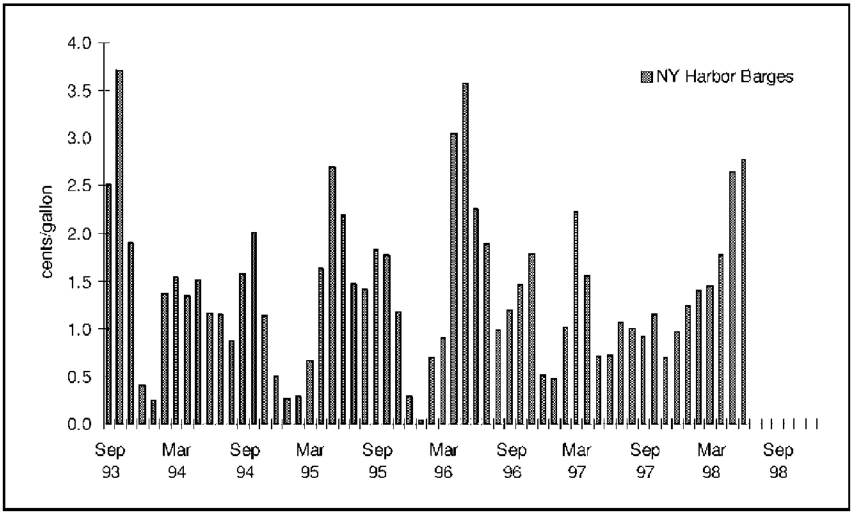
5.3.2 Distillate fuel oil

Demand for middle distillates in the US is less than half the demand for gasoline, averaging just over 3.4 million b/d in 1997, but it is growing nearly twice as fast, especially in the transport sector where diesel demand is being driven by strong economic growth. About one third of the distillate market is heating oil (used to heat homes and businesses, primarily in the north-east) and two-thirds low sulphur diesel fuel (used mainly in the truck transport sector and predominantly in the industrial heartland of the mid-continent and on the Atlantic coast). Heating oil demand is highly seasonal, while diesel demand is relatively steady, with a slight dip in the winter months (January and February).

The structure of the US distillate market changed with the introduction of a new low sulphur specification for diesel fuel as a result of the 1990 amendments to the Clean Air Act. Previously there was no practical distinction between heating oil and diesel as far as many refiners were concerned since they produced mid-sulphur distillates with a high cetane level that could be used in both markets. But the maximum sulphur content of diesel fuel was reduced from 0.2 to 0.05 per cent from 1 October 1993 and the two markets are now segregated. The premium for low sulphur diesel over heating oil is highly seasonal and varies between 2–3 cents/gallon in early summer and less than one cent/gallon in winter (see Fig. 5.10). Heating oil is dyed red to distinguish it from road diesel. Diesel is also dyed in the north-east states of the US to stop highway tax evasion by distributors.

The US north-east distillate market

The main consuming centres of the US north-east remain dependent on imports to meet seasonal demand surges for heating oil. Imports meet an average of 15 per cent of distillate demand in PADD I, but this proportion can rise during the peak winter consuming months. Pre-positioning of inventory is a major issue in the heating oil markets. In the winter of 1996-97, when heating oil markets were in backwardation and stocks were low, the Colonial pipeline was unable to move enough oil at short notice from the US Gulf coast to meet demand and companies had to charter ships instead. But in the winter of 1997-98, the contango encouraged



Source: Petroleum Argus

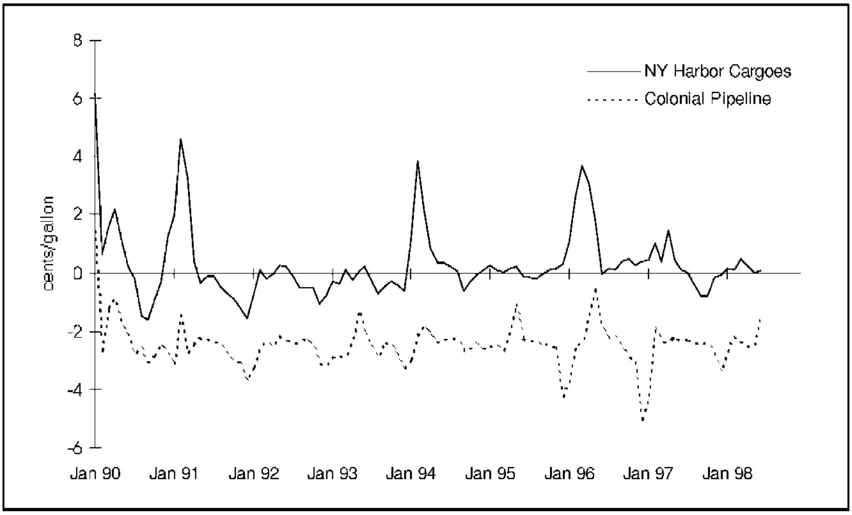
Figure 5.10 Distillate fuel oil: low sulphur diesel premium stockbuilding in the north-east and supplies were adequate.

The majority of heating oil cargo imports arrive in Boston, Massachusetts. Cold winters and isolation from the rest of the US supply and distribution system make Boston one of the most important heating oil cargo markets, but spot trade has fallen sharply in recent years as term contracts with refiners in Canada and Venezuela have become more prevalent. It is less important as a market for diesel fuel since it is not a centre for truck transport. Low sulphur diesel barge trade is much more active in New York Harbor due to local transport needs and access to the Buckeye Pipeline, which is used to supply product to Pennsylvania and Ohio. Cargo trade in both low sulphur diesel and heating oil in New York Harbor is rare, being restricted to periods of extremely cold weather. Blending of distillates occurs only during the winter to improve cold weather performance.

Heating oil and low sulphur diesel are traded predominantly in 25,000 barrel barge lots in New York Harbor. Like the gasoline barge market, most trade is restricted to prompt deals, or delivery within three days, although deals are occasionally transacted from 10 to 30 days forward.

The Gulf coast distillate cargo market

Rising distillate demand in Latin America has made the Gulf coast an increasingly active cargo export market; it now accounts for



Source: Petroleum Argus, Nymex

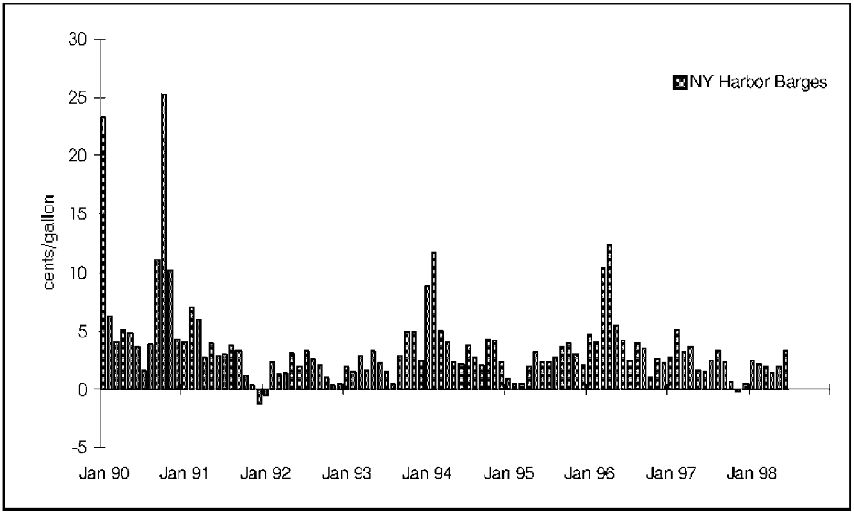
Figure 5.11 Distillate fuel oil: spot minus Nymex futures prices about two thirds of US distillate exports. Exports are particularly attractive to US refiners who require secure outlets for distillates which do not meet tighter US sulphur limits. Most distillate exports go to countries such as Brazil, Ecuador, Peru and Argentina. Brazil has become a major importer, but switches its purchases between the Gulf coast, Mediterranean and Far East depending on price.

Gulf coast distillate cargoes are normally priced on a publication-related basis, but are also done against Nymex heating oil futures prices.

Cargo market trade is steady, but the greatest volume of distillate trade on the Gulf coast is on the Colonial pipeline which transports about 500,000 b/d of heating oil and low sulphur diesel. Most of this now trades on the Colonial spot market as the volume of forward or 'paper' trade has declined in recent years.

5.3.3 Jet fuel

Total US jet fuel demand was 1.6 million b/d in 1997, most of which is met from domestic refinery output. Imports, which averaged just under 100,000 b/d, are mostly delivered to Florida, New York and Boston from refineries in Venezuela and the Virgin Islands. Jet fuel is rarely traded on the spot market. Almost all jet fuel is sold by refiners to airlines on a contract basis. Airlines enter the market only during transport-led demand surges and rarely sell excess supplies. But jet fuel, which has superior cold weather properties, is



Source: Petroleum Argus, Nymex

Figure 5.12 Jet fuel: spot minus Nymex No. 2 futures prices also an excellent blending stock for heating oil and low sulphur diesel supplies. As a result, harsh winter weather can lead to a surge in jet fuel trading in the US north-east. Jet fuel is also bought by power utilities for the gas-turbine units that meet peak demand, especially when electricity prices surge as hot or cold weather arrives. What little trade does occur in the markets of the US north-east is either in 25,000 barrels barge lots, or in volumes of 10,000 barrels or less. Barges are normally priced relative to the near month heating oil futures contract.

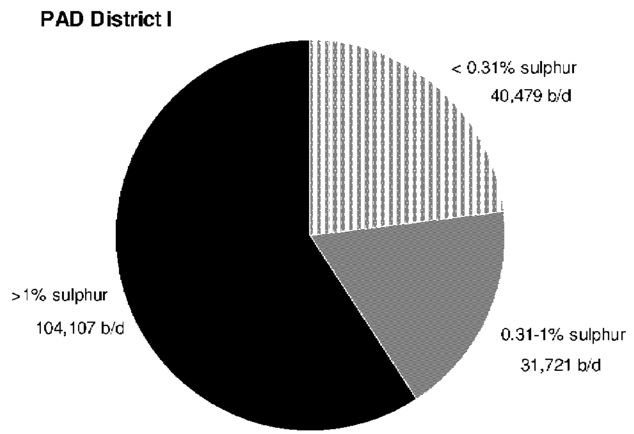
Most jet fuel trade on the Gulf coast takes place on the Colonial pipeline. Jet fuel pipeline movements averaged around 300,000 b/d in 1997. Most jet fuel is kept in the internal systems of refiners to meet commitments to airlines. Jet fuel prices on the Colonial pipeline are driven by demand from the airline hubs in the states of the US southeast. There is a small Gulf coast jet fuel export market, but its importance has declined as exports of the product have fallen.

Two grades of jet fuel are traded within the US: 55 grade and 54 grade. 55 grade has a higher flash point and a lower sulphur content and is often used to reduce sulphur in blending. There are important differences between the specifications of jet fuel used for internal US flights and those required for international flights. Jet fuel exported to the Far East, Europe or South America must meet the international DERD 2494 standard which specifies higher flash and lower freezing points than US 54 grade jet fuel (see section 5.2.3).

5.3.4 Residual fuel oil

Residual fuel oil demand in the US stabilised at around 800,000 b/d in 1996–97 after a long period of decline during which more natural gas was used in power generation. Fuel oil remains a flexible means of generating electricity without the need for long-term supply contracts and this has put a floor under demand. Fuel oil use increased in early 1998 as prices fell to very low levels making it more competitive against natural gas (see Fig. 5.14).

The main US fuel oil consumers in 1997 were utilities (38 per cent), ship bunkering (41 per cent) and industrial/commercial users (21 per cent). Most of the utilities which burn fuel oil to generate electricity are located along the Atlantic coast and are easily served by waterborne cargoes or domestic barges. But fuel oil use in power generation has fallen sharply over the past ten years because of competition from natural gas, which has a lower sulphur content and is often cheaper, especially in states — such as New York and New Jersey — that have imposed additional taxes on fuel oil.



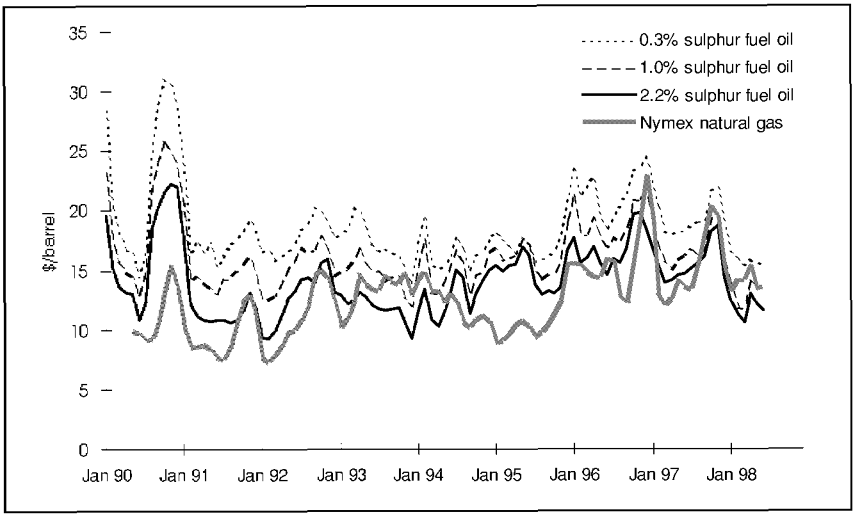
Source: EIA

Figure 5.13 Residual fuel oil: PAD District I imports, 1997

Environmental rules have also played an important role in limiting residual fuel oil use in power generation. Atlantic coast utilities burn a variety of grades of fuel oil — ranging from 0.3 per cent to 2.2 per cent sulphur. In the past, state environmental regulations typically forced utilities to burn lower sulphur fuel oils, but utilities now have more flexibility as pollution controls are based on emissions rather than fuel type. If a utility burns more gas it gets "emission credits" which can be offset against a higher sulphur fuel oil. Thus a utility like Florida Power and Light can choose to burn either 1 or 2 per cent sulphur fuel depending on the price of gas.

Utilities do not have direct purchase contracts with producing countries for fuel oil supplies. As a result, a trading community exists that buys fuel oil from producing countries in Latin America and west Africa, or from traders and refiners in Europe, Canada, the Caribbean or elsewhere and markets it to US utilities. Traders purchase most of their fuel oil under term contracts and supply it to refiners under annual or bi-annual contracts. Traders may be forced onto the spot market in order to satisfy their contractual obligations in periods of heightened demand. Burning crudes from the North Sea (Alba, Gryphon) and the Far East (Duri) are also used in the Atlantic coast market during periods of high demand.

Much of the utilities' term purchases, as well as the exporting countries' term sales, are priced relative to assessments made either by *Argus* or *Platt's* at the time of loading or delivery — plus or minus a differential based on quality, freight or market



Source: Petroleum Argus, Nymex

Figure 5.14 Residual fuel: NY Harbor cargo & natural gas prices

conditions. In order to avoid the risk of manipulation, many utilities and national oil companies have recently moved to basket pricing and include both *Argus* and *Platt's* in their sales and purchase contract formulas. Spot trade also takes place on either *Argus* or *Platt's* quotations, or a combination of both, especially when prices are changing rapidly and fixed levels are difficult to determine. Since residual fuel oil prices are also used in formulas to determine contract prices for heavy crudes from Venezuela, Mexico and Canada, the market is subject to a wide range of influences and can be highly volatile.

As utilities require fuel oil with specific maximum sulphur levels — typically 0.3 per cent, 1 per cent, 2 per cent or 2.2 per cent — any oil with a sulphur content that falls between these levels lends itself to blending since there is no tolerance for higher sulphur. Utilities can reject a cargo that does not meet its specifications for sulphur content — or other product qualities such as viscosity, gravity, pour point, asphaltene and vanadium content — so accurate blending is essential. Increased liabilities for ship owners in the event of an oil spill have limited the availability of dirty tankers and barges. As a result, freight rates and the vetting of ships has become a major issue in the fuel oil market.

Refiners and marketers are the most active participants in blending; end users rarely blend fuel oil themselves. The Gulf coast is the largest fuel oil storage region in the western hemisphere, but more fuel oil blending now takes place in the Caribbean than the

Gulf coast or New York Harbor. US fuel oil markets are closely linked to Europe and the Mediterranean and the buying patterns of Enel, Italy's state power utility, can have a significant impact on US price levels.

The US Gulf coast bunker market — from Houston to Florida — used to be the most active in the world, but has now been overtaken by Singapore (see section 5.4.6). Bunkers are sold in lots ranging from 500 tonnes to 1,500 tonnes, although 1,000 tonnes is more typical. Supplies are sourced from US Gulf coast refineries and from Mexico and Venezuela. Bunker prices on the Gulf coast are based on local fundamental supply and demand balances, but prices in other major global bunkering ports can affect Gulf coast prices.

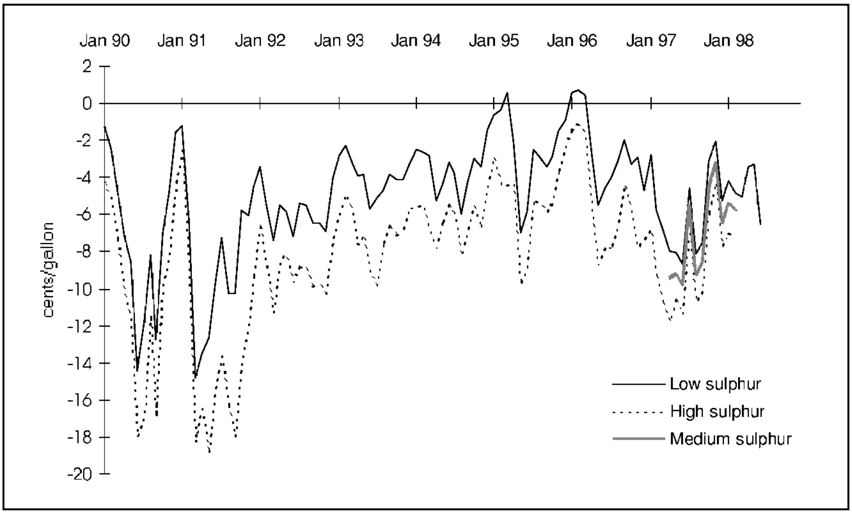
5.3.5 Vacuum gasoil

Vacuum gasoil (VGO) is used mainly as a feedstock for catalytic crackers, although some refiners can also run high quality grades of straight run fuel oil with a high VGO yield. US refiners have the capacity to crack 5.4 million b/d of the product. The primary spot market for VGO is based on the Gulf coast refineries. There is also some spot activity into east coast refineries in Pennsylvania and New Jersey, but this market now trades relative to the US Gulf coast.

Supply comes from both domestic and foreign refineries, the latter mainly in Europe and the Caribbean (Aruba and Venezuela). The market tends to fluctuate depending on changes in refinery balances in Europe, the US, Venezuela and Aruba (Coastal). Supplies of foreign material flow regularly from Venezuela, Spain and Aruba. Venezuelan contract holders in 1998 were Exxon, Tosco, Conoco and Citgo. Traders participate in the market, but a number left the business in 1997. Blenders often supply prompt VGO to Gulf coast refiners on the Mississippi river and in Houston.

The start-up of a vacuum distillation unit at TransAmerican Refining's Norco plant in Louisiana in 1994 created a division between the domestic and imported VGO markets. Cargo imports will now typically trade into the Gulf coast between Houston and Corpus Christi, Texas, but the Gulf coast east of Houston seeks domestic supply at a lower price.

VGO cargoes are traded on a delivered Gulf coast basis. Prices are expressed as a differential to a formula based on a mixture of *Platt's* spot waterborne price assessments in the ratio 70:30 unleaded gasoline to heating oil. The import duty on VGO is equivalent to 0.30–0.35 cents/gallon. Domestic material (including supplies from Canada) always trades at prices including duty, while



Source: Petroleum Argus

Figure 5.15 Vacuum gasoil: US Gulf coast cargo differentials

imported material trades at prices excluding duty since duties only become the responsibility of the final purchaser once material arrives in the US.

VGO prices are very sensitive to product specifications — the higher the sulphur, the larger the discount (see Fig. 5.15). Most requirements on the Gulf coast are contracted for 0.5 per cent maximum sulphur VGO. High sulphur VGO is typically up to 2 per cent, but some interest has been seen for material with a sulphur content higher than 2 per cent as Gulf coast refiners invest in more desulphurisation capacity. Medium sulphur VGO typically has a sulphur content in the range 0.8 to 1.2 per cent. Other key product specifications that affect prices are aniline point, Conradsen carbon residue, nickel and vanadium content.

5.3.6 Other products

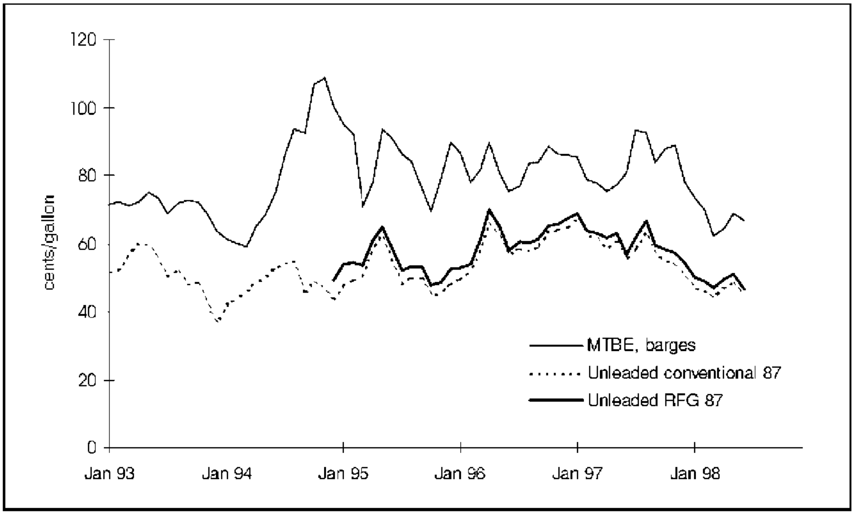
Naphtha

The most actively traded naphtha in the US is catalytic reformer grade which is used to produce regular and premium gasoline. Reforming naphtha — also known as heavy naphtha — typically contains a mixture of 40 to 50 per cent naphthenes and aromatics (N+A) with a minimum initial boiling point (IBP) of 150ºF and usually trades at a premium to full range or petrochemical naphtha. But the introduction of RFG reduced the aromatics content of gasoline and this — together with a decline in demand for premium grades — eroded the demand for reforming naphtha. Total naphtha imports averaged 51,000 b/d in 1997 with Venezuela, Mexico, Puerto Rico and Algeria being the most important sources of supply.

Anywhere from 50,000 b/d to 80,000 b/d is traded daily on the US Gulf coast. But cargo holders often find that material must be parcelled off into the domestic barge market — which is the main determinant of market levels in the US — and naphtha typically trades in increments of 50,000 barrels. Trade occurs on both a delivered US Gulf coast and a delivered US Atlantic coast basis, and is priced at a differential to *Platt's* regular unleaded gasoline waterborne assessment fob US Gulf coast.

Methyl tertiary butyl ether (MTBE)

Methyl tertiary butyl ether (MTBE) became an increasingly important component in gasoline production from 1994 onwards with the introduction of reformulated gasoline (RFG). Regulations now require a minimum MTBE content of 15 per cent by volume in finished RFG to meet specifications on aromatic content. MTBE is both an octane enhancer and an oxygenate that helps to prevent carbon monoxide from being formed on combustion. Refiner demand for MTBE is approximately 250,000 b/d, of which about 200,000 b/d is met from local supplies. The rest is imported, principally from Canada, northwest Europe and Saudi Arabia.



Source: Petroleum Argus

Figure 5.16 US Gulf coast MTBE & unleaded gasoline prices

MTBE is traded on a spot basis on both the Gulf coast and New York Harbor markets. Gulf coast MTBE is traded on a fixed-price basis in cents per US gallon. It is most often done in barge lots of 25,000 barrels or smaller and is generally priced on an fob basis.

5.3.7 West coast markets

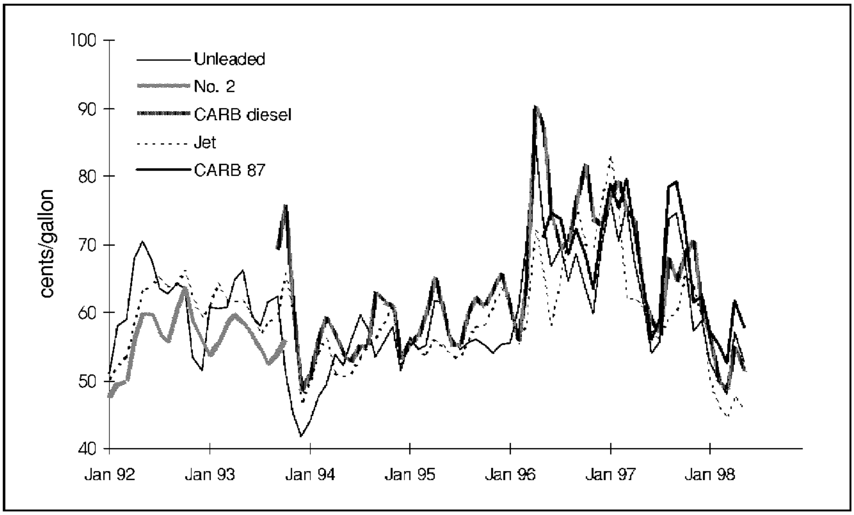
The US west coast market is unique in its virtual isolation from the international products markets. It has become dominated by five companies — Arco, Chevron, Exxon, Equilon and Tosco — since independent refiners have largely been forced out of the region through their inability to pay for the massive refinery upgrades required to meet the environmental mandates imposed by the Clean Air Act and the California Air Resources Board (CARB).

CARB is a state agency that proposes and implements environmental legislation in California, which now has the strictest gasoline regulations in the US. Los Angeles and San Diego were obliged to join the RFG programme from 1 January 1995 and local specifications on vapour pressure, sulphur, aromatics, benzene and olefins content were tightened in 1996 creating a CARB gasoline specification for the whole of California. In addition, CARB diesel specifications are tougher than those in the rest of the US as they also require a lower aromatic content to reduce the risk of ozone pollution.

Total west coast refining capacity is nearly 3 million b/d (1.9 million b/d in California) and the refineries are among the most sophisticated in the world, often with upgrading facilities to accommodate the predominantly heavy sour crude slate available in the region. West coast refined product prices are discussed in absolute terms — rather than at a differential to futures contract prices as is common in the Gulf coast and north-east markets — since the Nymex futures prices are not a good price reference for the isolated west coast market. As a result, swaps rather than futures are used to hedge forward price risks. High freight costs and careful stock management by west coast refiners typically limit the arbitrage opportunities from the US Gulf coast, but imports from Asia-Pacific have increased in 1998 following the collapse in regional demand.

Gasoline and blending components

Increased gasoline production capacity at west coast refineries, stringent specifications for petroleum products and stagnant gasoline demand have all resulted in the west coast becoming almost self-sufficient in gasoline supply for its 1.4 million b/d



Source: Petroleum Argus

Figure 5.17 US west coast: Los Angeles pipeline prices

market. As a result, imported gasoline cargoes have become increasingly rare and only a few refiners (Valero and Hess) produce CARB grade gasoline; shipments out of the west coast do occur though with refiners exporting conventional (non-CARB) gasoline. In particular, gasoline is sold into the Gulf coast market when west coast stocks grow above normal levels in order to bolster local prices. West coast refiners also export reformate to the Far East since the aromatics content of gasoline has been strictly limited under environmental legislation, although the growth in Asia-Pacific refinery capacity has reduced the opportunity to do this.

Within the west coast market, most gasoline trade occurs on the Southern California and Santa Fe Pacific Pipeline (SFPP).The 340,000 b/d Southern California pipeline (formerly the Santa Fe West Pipeline) originates in Los Angeles and supplies San Diego, Phoenix, Tucson and Las Vegas through the Calnev system. The 129,000 b/d Santa Fe North Pipeline originates in San Francisco and supplies Fresno, Stockton, Sacramento and Reno, Nevada. The Southern California pipeline is to expand its capacity to 520,000 b/d in 1999 in order to overcome bottlenecks in its gasoline and distillate shipments.

Trade in the Los Angeles area is on a free-in-pipe (fip) Watson (Los Angeles area) basis, typically in lots of 25,000 barrels. Trade in the San Francisco area is fip Concord for lots of between 5,000 barrels and 20,000 barrels. There are four loading cycles a month and trade typically focuses on the next prompt cycle. Spot market trading activity has fallen sharply in recent years as refiners have become more integrated, relying on the market only for marginal supplies.

Distillate fuel oil

Total distillate demand on the US west coast averaged 422,000 b/d in 1997, almost all of it in farming, truck and rail transport. A small amount of diesel fuel is used in the Pacific north-west for space heating.

Tight sulphur limits have all but stopped cargo imports into the west coast and local distillate supplies not meeting the 0.05 per cent sulphur limit are normally exported to the Far East and South America. Exports averaged 47,000 b/d in 1997. Export cargoes are typically sold on a free on board (fob) basis with reference to a published price report, with a normal pricing window of three to five days.

Jet fuel

The west coast consumed some 437,000 b/d of jet fuel in 1997, most of which comes from local refineries. As elsewhere, most jet fuel is sold to airlines on a contract basis, the Los Angeles and San Francisco markets only being used to manage short-term supply imbalances.

Most of the region's imports (which average about 5,000 b/d) are also purchased on a contract basis. The major suppliers are Korea, the Virgin Islands and Venezuela, with some additional volume coming from Japan and the Netherlands Antilles. Nearly all jet cargo imports are priced relative to published price assessments.

Residual fuel oil

The extensive upgrading of west coast refineries has severely reduced the volume of residual fuel oil produced in the region, but exports still averaged 46,000 b/d in 1997. Low sulphur waxy residue (LSWR) is sometimes imported by power utilities from Malaysia and Indonesia if the price is right. Imports of residual fuel oil averaged 5,000 b/d in 1997.

The west coast bunker market was greatly reduced by a bunker tax imposed in 1991 and not withdrawn before demand had been slashed. Vessels in the Pacific rely more frequently on the abundant — and often cheaper — supplies in Singapore, although bunker fuel is also sourced either from Tesoro's Alaskan refinery, or imports from Venezuela, Peru and Ecuador.

5.4 Asia Pacific

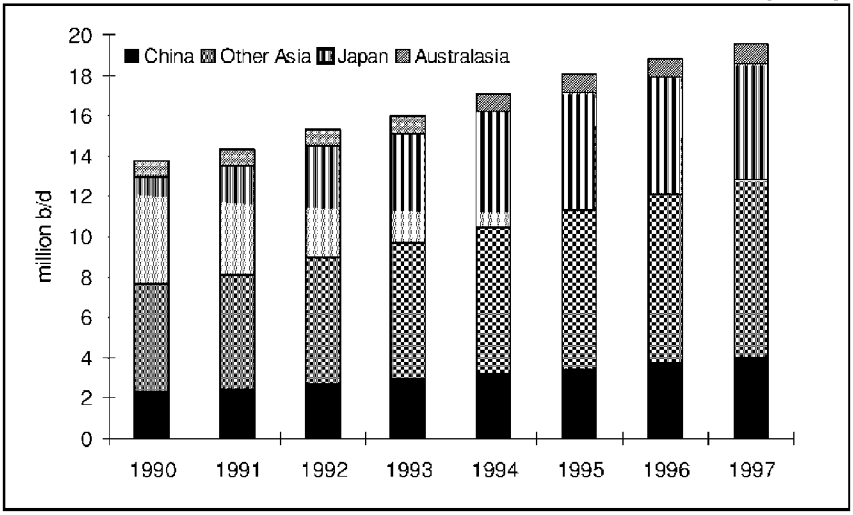
The Asia Pacific region was the world's fastest growing market for oil products until the economic crisis brought demand growth to an unexpected standstill in 1998. A combination of rapid industrialisation, rising standards of living, growing populations and economic liberalisation had provided a strong stimulus for oil demand growth in the area. Asia Pacific oil demand grew at an average rate of 5 per cent from 1993 to 1997, compared with an increase of only 1.6 per cent for the world as a whole.

Table 5.5 Asia Pacific product supply and demand, 1997

Area	**Consumption million b/d**	**Refinery runs million b/d**	**Net imports million b/d**
Australasia	0.95	0.87	–0.07
China	4.01	3.09	+0.41
Japan	5.79	4.33	+0.93
Other Asia	8.78	8.12	+1.11
Asia Pacific	**19.53**	**16.41**	**+2.38**

Source: BP Statistical Review of World Energy

In 1997, over 85 per cent of the Asia Pacific's 19.5 million b/d total oil consumption was supplied by refineries in the area, but the sudden downturn in demand in 1998 has created a temporary



Source: BP Statistical Review of World Energy

Figure 5.18 Asia Pacific oil demand growth, 1990-97 product surplus, reversing the normal pattern of trade flows between east and west. The Asia Pacific region has traditionally been a net importer of refined products across the barrel, most of which come from the Middle East, the US west coast and — when market conditions are right — from as far afield as the Mediterranean and northwest Europe. But the demand collapse forced Asian refiners to find new export markets in 1998.

Asia Pacific refining capacity expanded rapidly in the 1990s but failed to keep pace with even stronger demand growth. Nearly 5 million b/d of new crude distillation plant has been commissioned since 1990 compared with an increase of nearly 6 million b/d in Asia Pacific oil demand. Refineries are also relatively unsophisticated compared with Europe and the United States. Less than a third of the region's 18 million b/d of crude distillation capacity has associated catalytic or hydro-cracking plant to increase the output of lighter products. As a result, the region produces a much higher yield of residual fuel oil than is common in western markets, but its output is not sufficient to meet local demand, which accounts for 20 per cent of total Asia Pacific oil consumption by volume (see Table 5.6). However, most new refineries are being built with upgrading capacity and this is gradually changing the balance of product trade in the region, which has now become a net exporter of gasoline.

Table 5.6 Asia Pacific oil product consumption, '000 b/d

	1994	1995	1996	1997	97 share
Gasolines†	3,794	4,078	4,296	4,559	23.6%
Middle distillates	6,263	6,736	7,174	7,406	37.9%
Residual fuel oil	4,009	3,976	3,956	3,919	20.1%
Other products	3,004	3,240	3,418	3,600	18.4%
Total	**17,070**	**18,030**	**18,845**	**19,525**	**100.0%**

Source: BP Statistical Review of World Energy † *includes naphtha*

Singapore remains the centre of spot market trade in the region. Although it is not a swing refining centre like NW Europe or the Mediterranean — since its refineries usually run flat out — it is strategically located at the cross-roads of the region's product trading flows, its four refineries are owned by the oil majors, it has independent storage facilities, and it is an important financial and commodity trading centre in a region where government controls are still the norm rather than the exception. As a result, Singapore prices are used as an almost universal reference for the majority of product trade throughout the Asia Pacific region, even if the actual price levels are really being determined by arbitrage with other key markets in the Middle East or Europe. But Singapore's role as a price marker is now under threat as new refinery capacity in South Korea and Thailand has turned these former importers into exporters, creating the potential for alternative price markers.

5.4.1 Gasoline

Asia Pacific gasoline consumption is estimated at around 3.2 million b/d for the region as a whole in 1997. It represents 16 per cent of total oil demand and has grown at over 5 per cent a year on average for the past five years.

But the rapid expansion of new, more sophisticated, refinery capacity means that the Asia Pacific region became a net exporter of around 75,000 b/d of gasoline in 1997 and this volume is likely to be much higher in 1998. Japan and China are by far the biggest consumers of gasoline with Australia, India, Indonesia, New Zealand, South Korea and Taiwan also consuming large volumes (see Table 5.7). Over the past few years, trade in premium unleaded gasoline has replaced trade in leaded grades and 95 RON unleaded gasoline cargoes fob Singapore now provide the price reference for product trade in the region, although Korean refiners are trying to create their own local benchmark. Only Japan, South Korea and Taiwan have so far phased out all leaded gasoline sales, but India is planning to switch completely by 1999, closely followed by China, Malaysia, the Philippines, Singapore and Thailand by the year 2000. Indonesia's planned 1999 switch has been delayed by the economic crisis in that country.

Table 5.7 Asia Pacific country gasoline specifications, 1998

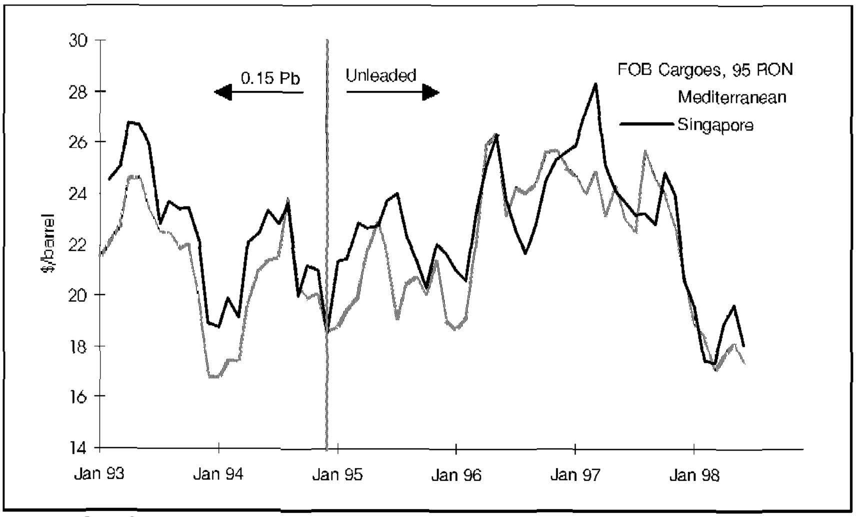
	Leaded	**Unleaded**
Australia	96 RON 0.3 Pb	96 & 91 RON
China	97 RON 0.15 Pb	93 & 91 RON
Hong Kong		98 RON
India	93 & 87 RON 0.15 Pb	
Indonesia	98 RON 0.15 Pb	68 RON
Japan		100, 98 & 91 RON
Malaysia		97 & 95 RON
New Zealand	96 RON 0.15 — 0.30 Pb	91 RON
Pakistan	97 & 87 RON 0.84 Pb, 80 RON 0.42 Pb	
Philippines	95 & 83 RON 0.15 Pb	95 RON
Singapore	97 RON 0.15 Pb	98 & 97 RON
South Korea		100 — 95 RON
Taiwan		97 & 95 RON
Thailand	97, 95 & 87 RON 0.15 Pb	98, 95 & 92 RON
Vietnam	83 RON 0.4 Pb	

As few of the Asia Pacific countries experience a winter season as such, most gasoline producers are not required to differentiate between winter and summer grades except in some northern Asian countries — such as Korea, Taiwan and Japan — where minor seasonal adjustments are made to gasoline specifications. Singapore gasoline cargoes typically have a Reid Vapour Pressure (RVP) of 9 to 10 pounds per square inch (psi), which covers the seasonal range. Benzene is currently limited to a maximum of 5 per cent, but Japan is moving to a maximum of 1 per cent from 1 January 1999.

Of the region's major consumers, Taiwan is the most important spot market buyer. Taiwan, Japan, South Korea and Australia are regular buyers of both reformate — a gasoline blendstock — and finished gasoline on the Singapore spot market during the peak summer driving season. India and Indonesia are both able to meet their domestic needs, while New Zealand imports from Australia and is seldom seen on the Singapore spot market.

Singapore remains the main centre of gasoline spot trade in Asia. But the country's status as swing supplier for the region has been eroded over the past year as expansions of refining capacity in other Asian countries have cut the local dependency on imports. Export cargoes from Korea, China, Thailand and Malaysia are competing with Singapore's refineries for outlets into other net importing countries in the region as well as the growing export market into the Middle East.

Taiwan remains the largest spot buyer in the Asia Pacific



Source: Petroleum Argus

Figure 5.19 Gasoline: Singapore & Mediterranean prices region, buying monthly through open tenders which specify reformate rather than finished gasoline. Vietnam is a regular buyer of around 20,000 b/d of low octane gasoline as it has to import all its needs, mainly from China and Russia. Purchases are made mainly through quarterly term tenders. South Korea and Japan still tend to buy reformate — the main gasoline component — on the spot market during the peak driving summer months or when refineries are shut for maintenance work, but both are becoming agressive sellers of finished gasoline. Japanese imports of reformate are largely met by Abu Dhabi and Kuwait, but South Korean buyers are often seen buying reformate on the spot market in Singapore. Australia is a large buyer of finished motor gasoline on the Singapore spot market. Thailand is now a net exporter following expansions at its refineries. And the Philippines is a net importer of gasoline, but is seldom seen on the spot market.

Singapore's four refineries still function as the region's swing producers. Independent storage facilities have boosted Singapore's capacity to make any grade of gasoline required in the region as they allow traders — as well as refiners — to blend gasoline. Indonesia became a gasoline exporter during the second half of 1994, exporting between 600,000 and 1 million barrels each month. Malaysia, which used to buy about 8,000 b/d on the spot market, had become a net exporter by the end of 1994 when it started selling 95 RON and 97 RON unleaded gasoline from its new 100,000 b/d Malacca refinery. It also exports reformate regularly from Malacca to Japan. The Middle East countries are not significant suppliers of motor gasoline or reformate to Asia Pacific countries and other needs are usually met by arbitrage from Europe and the Mediterranean.

But the region still lacks a clear gasoline price marker. Most cargoes in the Singapore gasoline market are now traded at a premium or discount to the *Platt's* published quotes of either the 95 RON or 97 RON unleaded grade. Previously, the regional marker grade was the Malaysian 97 RON leaded (0.15g/l) grade, but spot trade in this grade has dried up since Malaysia stopped buying on the spot market after the start-up of its 100,000 b/d Malacca refinery and 95 RON unleaded gasoline has still not achieved sufficient liquidity to act as an undisputed benchmark. Some gasoline and most reformate cargoes are traded against the published naphtha quotes. Indications of fixed price levels used to derived from the Singapore gasoline swaps market, but this has now dried up completely. Taiwanese state Chinese Petroleum Corporation (CPC), the region's largest spot buyer, awards its monthly tenders at a fixed price c+f basis. This tender is usually seen as an important indicator of general price trends in the

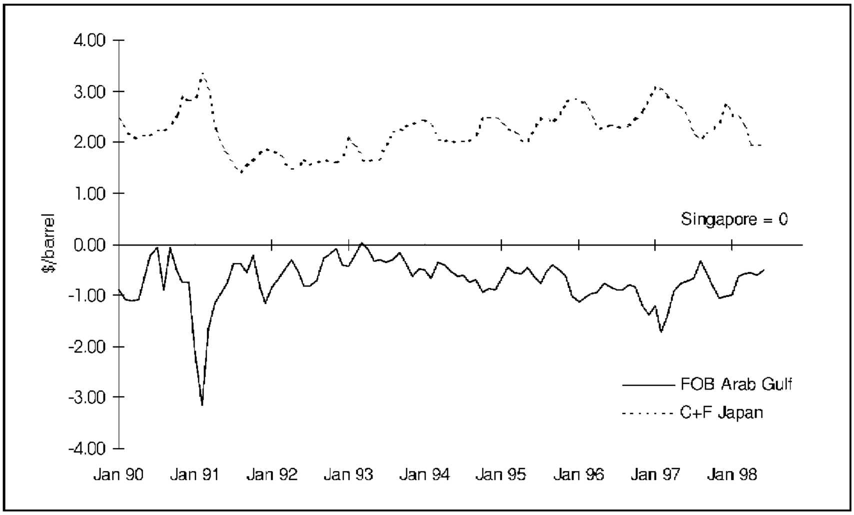
Singapore market. Cargo volumes traded spot in the Singapore market vary between 25,000 barrels and 200,000 barrels.

5.4.2 Naphtha

Naphtha is used as a feedstock to produce both motor gasoline and ethylene for the petrochemical industry, but the most visible naphtha trade is for light petrochemical grades. North Asia has a well developed petrochemical industry which provides a ready market for paraffinic or full range naphtha. Japan has the largest and most well-established petrochemical market, with 7.6 million tonnes/year of ethylene capacity using around 500,000 b/d of naphtha feedstock, while South Korea's petrochemical complex has grown to become a major competitor for Japan importing 210,000 b/d of naphtha in 1997 to feed its 4.9 million tonnes/year of ethylene capacity. Asia is structurally short of naphtha as a petrochemical feedstock, importing 500,000 b/d in 1997, mainly from the Middle East. Although naphtha demand has slumped in 1998 because of the economic crisis, Asia's imports need are still expected to add up to at least 400,000 b/d.

Asian petrochemical end-users use naphtha for around 90 per cent of their feedstock requirements, compared with a world average of around 50 per cent. For this reason, security of supply is of particular importance to consumers, especially the Japanese petrochemical companies who prefer to purchase most of their supplies through term contracts with the Japanese trading houses, the shosha. The shosha in turn secure most of their supplies from Middle East producers, either directly or via the majors and western traders. Despite the economic crisis, Kuwait was still able to obtain a $6/tonne premium over Middle East quotes for term naphtha contracts in 1998. South Korean petrochemical companies were the biggest spot market buyers in Asia in 1997, but were absent from the market in early 1998 as domestic demand collapsed amid cash flow and credit problems. China is largely self-sufficient, although it occasionally appears on the spot market to buy limited volumes. Thailand began importing naphtha in 1994 to supply the new Thai Olefins petrochemical plant, while Indonesia remains a net exporter.

The main sellers are Middle East producers — Saudi Arabia, Kuwait, UAE, Bahrain, Qatar, Yemen and Iran — which supplied 17.5 million tonnes (430,000 b/d) in 1997. In the future, growing volumes of Middle East naphtha will come from new condensate splitters in Qatar and the UAE. Most of the remaining naphtha imports came from other Asian countries, but other sources — including Mediterranean exporters Algeria, Egypt, Greece and



Source: Petroleum Argus

Figure 5.20 Naphtha: Arab Gulf & Japan minus Singapore prices

Turkey, as well as Mexico and the US west coast — are becoming increasingly important sources of supply for the Asian market.

The open specification delivered market c+f Japan is the most actively traded spot market. Spot and term prices across the Asia Pacific region are linked directly or indirectly to this market through freight netbacks to Singapore and the Middle East. The original open specification contract was drafted by Mitsubishi Corporation in 1986, and has been the industry standard ever since. It specifies the delivery of cargoes of between 22,500 and 27,500 tonnes of physical naphtha delivered into Japan, allowing a "wet circle" of trade in naphtha to develop. As well as giving the option of physical delivery, the open specification contract is also used as a forward paper market — a "dry circle" — for hedging physical positions. In this case, the standard cargo volume hedged is usually a standard 25,000 tonnes (see Chapter 7).

Open specification material typically has a minimum of 65 per cent paraffins with a density of 0.650–0.740 specific gravity (SG) at 60°F and a maximum olefins content of 1 per cent. Petrochemical end users prefer light naphtha with a specific gravity of 0.650–0.690 for their high ethylene yields, although full range naphtha with a high paraffinic yield is also considered desirable. These specifications are mainly met by cargoes from Middle Eastern refineries. Naphtha cargoes from China, India, Australia, New Zealand or Indonesia are acceptable if they meet the above specifications as well as additional restrictions concerning chlorine, mercury and arsenic.

Singapore spot price assessments are derived using an MR freight netback from Japan and applying a conversion factor of nine barrels per tonne. But some trade is also conducted on a fixed price basis and there is a moderately active Singapore naphtha swaps market which provides an alternative hedging mechanism to the Japan forward market (see Chapter 10).

5.4.3 Jet/kerosine

Jet/kerosine was the fastest growing oil product in the Asia Pacific region until the economic crisis undermined demand. Rapid economic development has encouraged exponential growth of air travel for both business and leisure activities, but this was badly hit in 1998. In addition, kerosine is widely used as a domestic heating fuel in north Asia and demand for this product reaches a seasonal high in winter. Smaller markets also exist for kerosine as a burning fuel for lighting, cooking and heating in some of the developing countries, mainly in the rural areas of the Indian subcontinent, Vietnam and Indonesia. In 1997, Asia Pacific jet fuel demand was 900,000 b/d and heating kerosine demand was 1.2 million b/d, making a total of more than 10 per cent of total product consumption, a much higher proportion than in either Europe or the US.

The Asia Pacific region is usually a net importer of jet/kerosine — mainly from the Middle East — but the combination of a mild winter and the unexpected economic crisis turned it temporarily into a net exporter during the first half of 1998 as high stocks depressed local prices. Jet/kerosine imports averaged 250,000 b/d in 1997 and the supply balance was expected to shift slowly to a slight overall surplus by the year 2000 with the addition of new refining capacity. Demand for imports into two of the main consumers in the region, Japan and India is still expected to rise. But increased availabilities from new refineries in Malaysia, Taiwan and China, as well as the region's main export centre Singapore are boosting regional supply. And South Korea's import requirements have fallen sharply after the recent expansion in refinery capacity.

Four distinct grades of jet/kerosine are traded in the Asia Pacific:

1) Jet A1 — used as a commercial aircraft fuel and conforming to the DERD 2494 specification.

2) Superior kerosine oil or illuminating kerosine (SKO) — mainly used in the rural areas of the Indian subcontinent for cooking and lighting.

3) Dual purpose kerosine (DPK) — mainly used in north Asia for heating. Dual purpose kerosine, as its name suggests, can also be used as an aviation fuel.

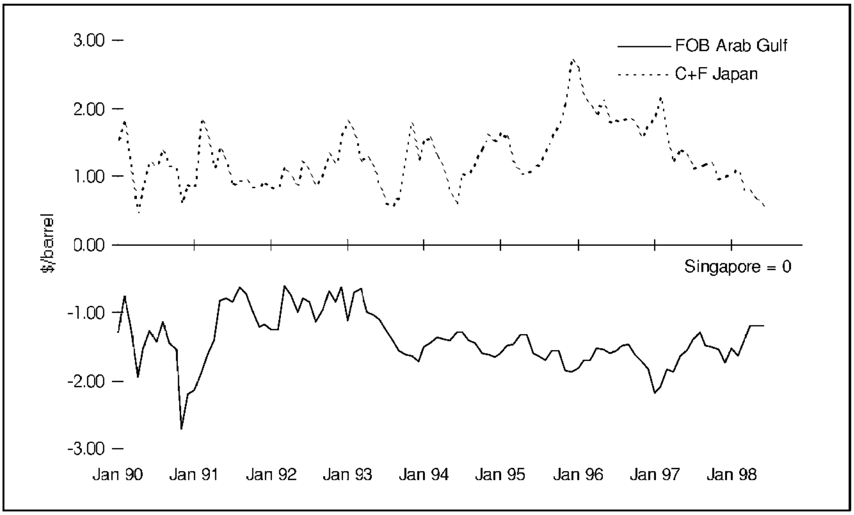
4) Pure kerosine — used mainly for heating.

India still buys significant volumes of kerosine through monthly spot purchasing tenders issued by the state-owned Indian Oil Company (IOC) that provide a good guide to price levels in the Middle East. Spot cargoes are traded relative to the mean of *Platt's* fob Arab Gulf price assessment (MOPAG). Cargoes are never traded on a fixed-price basis as the Gulf quotation is a netback from the Singapore market minus a freight differential. IOC also frequently tenders to buy jet A1, the amount depending on the level of domestic supplies.

Middle Eastern cargoes usually cover the requirements to the Indian west coast, while cargoes sourced from Singapore are usually used to supply the eastern ports. Although Indian imports of kerosine were deregulated to meet booming demand, imports by private and foreign companies are still subject to some government controls. India's other kerosine requirements are covered through term contracts with the main Middle East suppliers which now play an increasing role in India's product supply arrangements.

Singapore's refineries produce around 170,000 b/d of jet, more than two thirds of which is available for export. The physical fob market sees trade in cargo lots of up to 250,000 barrels, occasionally on a fixed price basis, but mainly at a floating price related to *Platt's* fob Singapore quotes. Trade usually takes place for lifting within a 10–40 day time-frame, physical barrels rarely being traded very far forward. There is also an active jet swaps market which trades at a differential to *Platt's* Singapore gasoil quotations (see Chapter 10).

One of the largest spot buyers of fob Singapore jet A1 was Indonesia which imported 60,000 b/d in 1997, but demand has collapsed in 1998. Malaysia also produces a small amount of illuminating kerosine — a cargo a month — around 7,500 b/d — at its Kerteh refinery which is usually exported at a premium over Singapore prices. The 100,000 b/d Petronas refinery at Malacca produces a similar amount of dual purpose kerosine which covers the country's domestic requirements.



Source: Petroleum Argus

Figure 5.21 Jet / kerosine: Arab Gulf & Japan minus Singapore prices

Japan and South Korea normally import kerosine for heating purposes during the winter, although Japanese refiners also buy bonded (non-taxable) jet for aviation use and normal jet which can be desulphurised into pure heating kerosine. The Middle East used to supply much of Japan's and South Korea's kerosine needs, but rising throughputs in Japan and South Korea have eroded the demand for imports. The Middle East kerosine grade exported from Gulf refineries in Saudi Arabia, Kuwait and the United Arab Emirates is usually good quality DPK, but cargoes will often be sold into the Indian subcontinent to cover SKO burning requirements.

Most Middle East exports are through term contracts to customers and, as a result, spot trade is thin. Kuwait has become the main spot seller since the restoration and expansion of its refining capacity after the Gulf crisis to a level of nearly 1 million b/d. It now dominates selling into most of India's monthly spot tenders for middle distillates and has cornered many of the import markets in the region with term contracts into India, Pakistan, Indonesia, South Korea, Japan and the US Defense Fuel Supply Center.

5.4.4 Gasoil

Gasoil, which is used as automotive diesel, high speed diesel and marine diesel, has provided the main engine for growth in oil demand across the Asia Pacific region. The booming economies in many countries in the region, such as China, India, Indonesia, South Korea, Vietnam and Thailand have recently seen double digit increases in gasoil consumption, and overall demand has been growing at more than 5 per cent in recent years. In 1997, Asia Pacific demand for all forms of gasoil averaged 5.7 million b/d, 29 per cent of the region's total oil consumption.

Automotive diesel is the main transport fuel for most of the developing countries in the Asia Pacific region, with marine diesel used for small water-borne vessels. Gasoil is also extensively used in Vietnam and Indonesia for power generation — the Philippines has now switched away from gasoil in favour of fuel oil for the bulk of its oil-fired power generation. Gasoil use in the agricultural sector is high in China and India, especially during the Chinese summer harvest season, and the post-monsoon season in India.

Table 5.8 Asia Pacific gasoil sulphur specification limits, 1998

0.05%	**0.25%**	**0.5%**	**1%**
Japan	India	Singapore	Vietnam
South Korea		Malaysia	India
Taiwan		Indonesia	Nepal
Hong Kong*		Philippines	Pakistan
		China	Sri Lanka
		Thailand	Bangladesh
		India	
		Australia	
		Hong Kong	

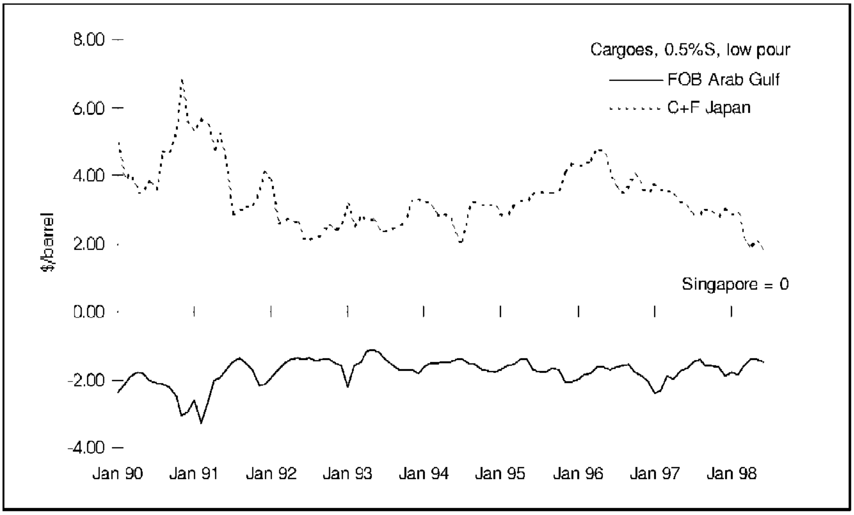
** automotive diesel*

Gasoil trade in the Asia Pacific and Middle East encompasses a wide range of different specification requirements (see Table 5.8). National governments have imposed sulphur limits in an attempt to reduce sulphur emissions and pollution. The sulphur content is the most important factor in determining the price differential between grades across the region. Once again, Japan has led the way within the region towards burning cleaner fuels. Sulphur content in Japanese diesel was cut to 0.05 per cent by 1996 and this was extended to heating gasoil in October 1997. Other countries are moving in this direction, albeit at a slower pace. South Korea and Taiwan also plan to cut sulphur content to 0.05 per cent in 1998. And Thailand is aiming to follow suit in 1999. Hong Kong cut the sulphur content for automotive diesel to 0.05 per cent in April 1997, but the industrial sector is still allowed to use 0.5 per cent sulphur gasoil.

Since most of the Asia Pacific region lies within the equatorial climate zone, large areas of the regional market are not required to meet the low pour points necessary in the northern hemisphere. The most widely used gasoil grade therefore has a relatively high pour point range of 6–9°C. But low pour gasoils are still required in north Asia, where automotive fuels must be able to remain functional at much lower temperatures. Northern China and Hong Kong require a maximum pour point of 0°C in the winter season, while Japan and South Korea require maximum pour points of –20°C and –5°C respectively. The minimum cetane index for Japanese automotive diesel is 50.

As patterns of trade vary according to seasonal variations and product specification requirements, gasoil markets in the Asia Pacific region can attract exports from all around the world, and cargoes from the swing refining centres of Singapore and the Middle East are frequently supplemented by product from NW Europe, the Mediterranean and the US. Like other main products, demand growth for gasoil slowed abruptly in 1998 leaving refiners holding high stocks which depressed prices, choking off the normal flow of imports into the region. But the high sulphur content of Asian gasoil has limited the destination for exports to markets in Latin America.

Singapore plays a key role as the region's major supplier of gasoil. Gasoil accounts for around 35 per cent of Singapore refiners' output, with exports from Singapore at just below 300,000 b/d. The largest volume of gasoil from Singapore is exported to Hong Kong, which supplies the rapidly developing neighbouring provinces of



Source: Petroleum Argus

Figure 5.22 Gasoil: Arab Gulf & Japan minus Singapore prices southern China. The bulk of the rest of Singapore's gasoil exports go into neighbouring Thailand and Malaysia, or directly into China. Soaring gasoil consumption has made China a major buyer and an important influence in the Asian market, but government restrictions on imports imposed from May 1994 have made Chinese buying erratic and smuggling is widespread. Domestic price controls were eased in June 1998 after bureaucratic delays meant that it was cheaper to import gasoil than to refine it locally. Chinese gasoil demand accounts for a tenth of total Asian gasoil demand and imports averaged 150,000 b/d in 1997.

Indonesia and Malaysia — two of the largest crude oil producers in the region — do not have enough refinery capacity to cover domestic demand and both are regular buyers of 0.5 per cent sulphur low pour gasoil. Indonesia usually buys on a delivered basis which generally attracts arbitrage cargoes from outside the region, rather than Singapore barrels.

North Asian countries — Japan and South Korea — are unable to cover their low sulphur low pour gasoil requirements from Singapore. Product specifications are much tighter than in south-east Asia and spot imports have become rare since higher domestic refinery runs have made Japan and South Korea increasingly self-sufficient in gasoil. Any shortfalls in north Asian supply are usually met by term liftings of "pure", or straight run, gasoil from Algeria or Italy in the Mediterranean, which typically has a very low (0.05–0.2 per cent) sulphur content and pour point (–15 to –20°C).

Australia and New Zealand also use and produce low pour gasoil for their cold seasons but growing domestic demand has ended the export of small volumes of superior quality gasoil to Japan and South Korea in recent years. Instead, Australia looks set to become a regular importer of gasoil, with majors such as BP, Shell, Mobil and the Chevron/Texaco joint venture Caltex importing from international affiliates and sometimes from the international spot market.

The monthly spot buying tender issued by the Indian Oil Corporation is the most transparent element in the 1 per cent sulphur gasoil market, although term purchases are becoming increasingly important (see Section 5.4.4). India also buys 0.25 and 0.5 per cent sulphur gasoil to supply markets in urban areas. Tender volumes are usually highest late in the year, when agricultural demand rises after the end of the monsoon season. Imports into the east coast are a standard 45,000 tonnes, while imports into the west coast are 30,000 tonnes, due to draught restrictions at India's ports. Imports into the east coast are most commonly priced against Singapore spot price assessments, while imports into the west coast are usually priced against Middle East price assessments.

Middle East refiners are now producing more of the lower sulphur grades of gasoil to meet the specifications of countries east of the Indian subcontinent, but the average sulphur content of exporters such as Kuwait remains around 0.2 per cent, well above the 0.05 per cent level now set in Japan, South Korea and Taiwan. Rising domestic demand in some Middle Eastern states, such as Saudi Arabia and Iran, has also cut the amount of gasoil available for export from the region in the last few years, although recent cuts in domestic price subsidies in both countries have slowed the growth in demand.

Most of the gasoil exported from the Middle East is sold on term contracts. Spot trade is usually based on either *Platt's* Singapore or Middle East price assessments, plus a premium for east of Suez destinations or — as with Abu Dhabi — half on posted prices and half on spot market assessments. Saudi Aramco and Abu Dhabi's state oil company, Adnoc, both use a 50:50 mixture of *Platt's* and *Argus* price assessments. *Argus* produces a daily assessment of premia talked over the mean of *Platt's* Arab Gulf (MOPAG) price assessments, and these have been used in addition to the *Platt's* price assessment by companies such as Shell and Caltex in term and spot sales. There is also an active gasoil swaps market based on *Platt's* Singapore price quotations (see Chapter 10)

5.4.5 Low sulphur waxy residue

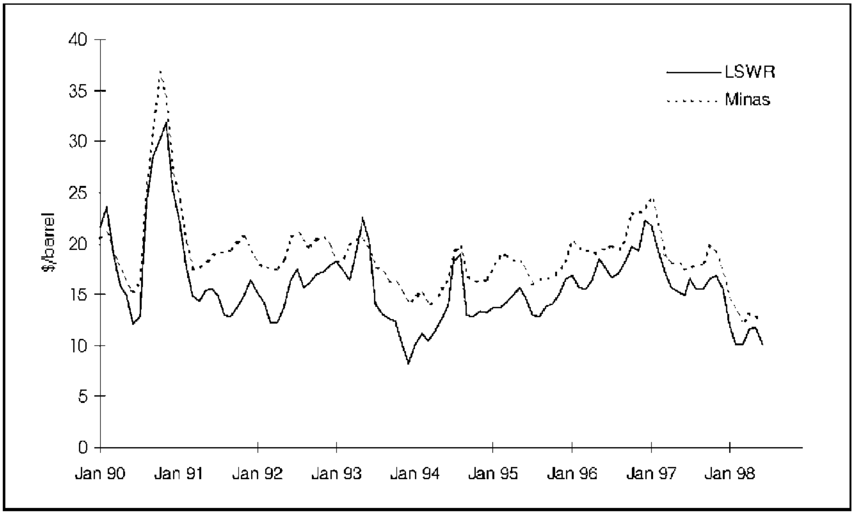
The low sulphur waxy residue (LSWR) market is one of the most opaque product markets in the Asia Pacific region, both because of illiquidity and because of its complicated pricing structure making it difficult to establish a reliable buy-sell range. The LSWR market is no bigger than 200,000 b/d, yet at least three different pricing mechanisms are used.

LSWR is traded in two forms — straight run and cracked/mixed — both for direct burning in electricity power generation and as a feedstock. Indonesia's state oil company, Pertamina, which exports around 3.5 million barrels per month of cracked/mixed 0.2 per cent sulphur material, is the largest regional producer of LSWR. Asia consumes around 1.1 million b/d of LSWR in total, but demand has slumped in 1998 as utilities were left with high stocks because of the mild winter and regional economic crisis.

The most actively traded LSWR market is for Indonesian cracked/mixed material, which is mainly sold to Japanese utilities for direct burning in power stations. Japan has the region's strictest limitations on the sulphur content of oil for use in power generation — allowing just 0.2 per cent sulphur by weight — and burns a mixture of low sulphur crude oil, such as Indonesia's Minas or Duri, domestically produced LSWR and imported LSWR. Imports of LSWR average just over 100,000 b/d, but can vary widely depending on weather conditions in Japan, particularly during the summer season. Peak demand is typically in the summer when domestic air conditioning boosts electricity demand.

Pertamina now sells LSWR direct to customers after disbanding its marketing affiliates from July 1998. The floating formula price is now based on a straight average of *Argus*, *Platt's*, *RIM* and *FEOP* assessments. Virtually all spot LSWR trade is therefore done relative to the Pertamina formula. It should be noted that LSWR price assessments are fob Indonesia.

When Japanese demand is limited — usually during the autumn or early spring — surplus barrels are sometimes sold into the US market either for utility burning or as a refinery feedstock. In 1998, weak demand and low prices have created opportunities for exports to Latin America and Europe, where LSWR is being purchased by Enel, the Italian power utility, instead of low sulphur fuel oil. LSWR is usually blended en route to the US or in storage prior to delivery in order to meet the standard utility burning specifications. Because Indonesian LSWR is typically "cracked/mixed" material — that is, a mixture of cracked and straight run LSWR — the straight run component can be used by



Source: Petroleum Argus

Figure 5.23 Low sulphur waxy residue & Minas crude prices some US Gulf coast refiners as a feedstock for vacuum gasoil units.

When spot trade is more active into the US than into Japan, the value of Indonesian LSWR can be assessed using netbacks from the US market. If the LSWR is to be used as a refinery feedstock, prices are usually set a discount to West Texas Intermediate (WTI) crude for the month of delivery. But when it is sold into the burning market, the netback is based on spot assessments for 0.3 per cent sulphur high pour residual fuel oil for the month of delivery, allowing for the lower thermal content of LSWR.

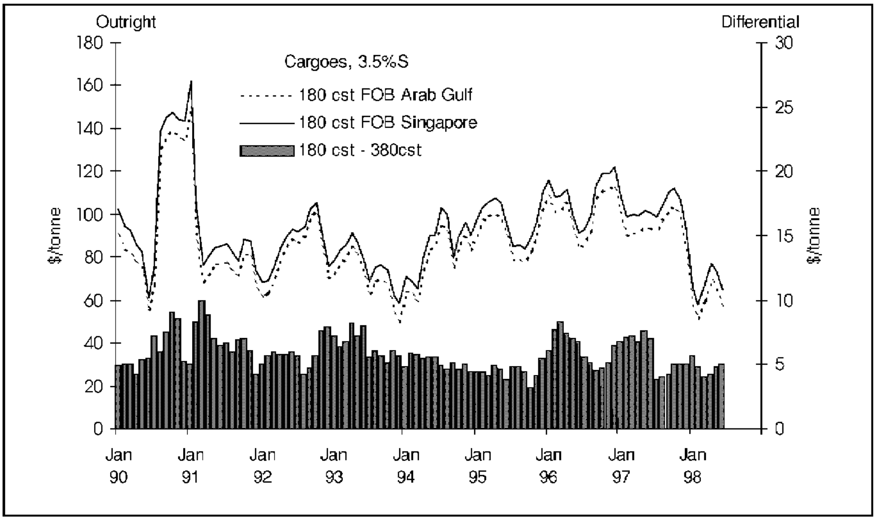
Indonesian LSWR has a thermal content of 144,000 Btu/barrel, below the standard US requirement of 148,000 Btu/barrel, which typically translates into a discount of around 40 cents/barrel. The US utility, ConEd, also sets a maximum pour point specification of 110°F, which may be exceeded by some cargoes of Indonesian LSWR, which can have a pour point of between 105 and 120°F. US import duties also vary depending on API gravity. Duties are 23 cents/barrel for imports with a gravity of 24.7°API or lower and 28 cents/barrel for imports with a higher API gravity.

The market for straight run LSWR in Singapore is even less liquid than that for cracked/mixed material. Esso Singapore is the only refiner which regularly sells spot cargoes of 0.3 per cent sulphur LSWR — around 500,000 barrels per month in cargoes of around 200,000 barrels each. Most straight run LSWR in Singapore is typically sold at a premium of around $1.50/barrel over the *Platt's* straight run price quotation, fob Singapore.

5.4.6 Residual fuel oil

In the Asia Pacific region, virtually all the high sulphur fuel oil traded — both cracked and straight run — ends up in the burning market, either for power stations or marine bunkers. Only straight run low sulphur waxy residue — sold primarily from Singapore and Malaysia — is actively marketed as a refinery feedstock. Demand for fuel oil by power utilities is falling as natural gas production in the region grows. The three countries which account for a large part of the region's demand for high sulphur fuel oil — Indonesia, Malaysia, Singapore and Thailand — are all planning to increase gas burning for power generation. Asia Pacific demand for fuel oil averaged 3.9 million b/d in 1997, down nearly 1 per cent on the previous year despite strong growth in bunker demand.

Tighter environmental legislation is gradually changing the structure of the residual fuel oil burning markets in Asia. Some countries have already taken the lead by cutting the sulphur content of utility fuel and low sulphur grades account for around 45 per cent of regional fuel oil consumption. Japan is at the forefront



Source: Petroleum Argus

Figure 5.24 Residual fuel oil: Singapore & Arab Gulf prices

and now only burns oil with a sulphur content of 0.2 per cent or less in its power stations. Taiwan cut sulphur limits to 0.5 per cent in 1996 and South Korea is introducing a limit of 0.3 per cent for fuel oil burnt in urban areas from July 1998. Singapore and Thailand have shifted from burning high sulphur fuel oil (3.5 per cent) to burning predominantly intermediate grades (2 per cent) over the last few years. The Thai utility, Egat, is already using 0.5 per cent sulphur grades in urban areas. China has been importing medium sulphur fuel oil for burning in major cities since 1996 and is moving to 1.5 per cent sulphur fuel oil for the Shanghai area. Malaysia and the Philippines are expected to move to 1 per cent sulphur by 2000. But Indonesia continues to burn high sulphur material as it plans to switch to gas.

Bunkers provide the backbone of the fuel oil market in Singapore, but cargoes are also sold into the utility burning markets of China, Thailand, Malaysia, the Philippines and Indonesia. Spot fuel oil is sold at both fixed and floating prices in Singapore. The main spot sellers are Singapore refiners, Korean refiners, and western and Singapore-based traders. The main buyers are traders and companies that supply regional end-users, power utilities and the Singapore bunker market.

Fuel oil spot trade in the Asia Pacific region is often done on a fixed price basis either fob or c+f Singapore and the two main traded grades are 3.5 per cent sulphur 180 cst and 3.5 per cent sulphur 380 cst. Prices for 180 cst material used to bear a close relation to Singapore's Simex fuel oil contract, but the contract is no longer traded despite being relaunched with new specifications in April 1997 and the market now uses swaps for hedging instead (see Chapter 8). When physical activity is limited or the outlook for prices uncertain, buyers and sellers often prefer to trade at a floating price differential over Singapore market assessments. In these circumstances, fuel oil is typically traded at a premium of $1–2 over *Platt's* fob Singapore quotation.

With a principal diet of heavy sour crudes from the Middle East, all of Singapore's refiners are sellers of high sulphur fuel oil. Korean refiners, who have only limited upgrading capacity, are regular sellers of high sulphur fuel oil to the north Asian market, particularly China. The Singapore and Korean refiners all supply their own bunker sales as well as the cargo market. Taiwan sells around 60,000 tonnes/month (13,000 b/d) of high sulphur fuel oil in regular monthly tenders, while buying low sulphur fuel oil for its own domestic consumption. Japan's high sulphur fuel oil output is largely confined to its own bunker market. Exports of medium and low sulphur fuel oil are made to China from third party processing at the refineries on the southern Japanese island of Okinawa.

The other main source of residual fuel oil for the region is the Middle East. Much of the residual fuel oil output of this region is straight run material. With an active bunkering market centred on Fujairah at the mouth of the Arabian/Persian Gulf, much of the region's residual fuel oil output is sold directly to local bunker suppliers.

Exports leaving the Gulf can head east or west, depending on market conditions, but westbound sales are increasingly becoming the exception to the rule. Exports to the East will usually end up being sold directly into the utility end-users in the region, or else used for blending in Singapore to supply the bunker market.

Singapore has become the world's largest bunkering centre in the last three years, with bunker sales of more than 300,000 b/d in 1997 — about half of Asia Pacific bunker demand. Bunker sales now outstrip high sulphur fuel oil output from Singapore's own refineries, and Singapore fuel oil demand has for many years attracted imports from Venezuela, the US west coast, the Middle East and the Mediterranean.

But other bunkering centres are emerging to take some of Singapore's market share. South Korea, which now has large surpluses of domestically produced high sulphur fuel oil, is an active bunker supplier to the north Asian market selling around 140,000 b/d in 1997. And the port of Fujairah at the mouth of the Middle East Gulf has also grown to prominence as the bunkering terminal for most of the oil tanker traffic emerging from the Gulf, although sales were disrupted by the collapse of the Greek trader Metro in early 1998.

The shift towards lower sulphur fuel oil specifications in several major Asian consuming countries has created a market for medium and low sulphur grade fuel oil over the last few years, greatly increasing the demand for low sulphur crudes — mainly from west Africa — by refiners. But the region is expected to remain short of the required medium and low sulphur fuel oil grades. Asia Pacific demand for low sulphur fuel oil averaged 1.6 million b/d in 1997, but only 85 per cent was produced in the region leaving around 240,000 b/d to be imported.

Japan and Korea now produce some low sulphur grades, and new refineries being built in Thailand are able to produce low sulphur fuel oil to meet that country's requirements, but the bulk of supplies have had to be imported, either from the US west coast or north-west Europe. However, these volumes are set to fall as west coast refiners build more conversion capacity to meet local demand for lighter products. Low sulphur exports from the US are used by traders for blending higher sulphur material for selling into the Asia Pacific market. If US supplies are cut, blenders will have to look further afield to regions such as West Africa and South America as they seek to supply Asia's growing low sulphur demand.

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Appendix 5.1

Spot product prices, 1993

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	21.95	22.69	23.47	24.66	24.91	23.67	22.76	22.14	21.55	21.99	19.69	16.57
Naphtha	19.83	19.54	19.30	19.88	20.53	19.48	18.43	17.83	16.81	17.58	16.60	14.61
Jet kerosine	24.23	24.59	25.00	24.46	23.91	23.13	22.10	22.20	22.77	24.29	23.69	21.59
Gasoil	22.57	23.04	23.74	24.25	23.61	22.21	21.48	21.47	21.97	22.91	22.09	19.46
SR fuel 0.7%S*	15.59	16.20	16.82	17.21	17.45	15.78	15.46	14.98	14.19	14.49	12.08	11.62
Heavy fuel 1.0%S	15.20	16.31	16.07	17.42	16.26	14.90	15.68	14.65	13.83	14.33	12.19	11.15
Heavy fuel 3.0%S	11.39	11.35	12.14	12.31	11.50	9.69	9.59	9.75	9.80	9.81	9.83	8.81
MEDITERRANEAN CIF CARGOES												
Gasoline 97 .15Pb	22.73	23.20	23.90	25.77	25.80	24.68	23.86	23.69	23.04	23.34	21.19	18.19
Naphtha	19.56	19.19	18.94	19.64	20.29	19.16	18.18	17.43	16.60	17.28	16.25	14.31
Jet kerosine*	23.41	23.59	23.74	23.37	22.75	21.99	20.73	20.65	21.35	23.06	22.56	20.18
Gasoil	22.74	22.98	23.36	24.07	23.57	21.81	21.18	21.54	21.79	23.02	22.41	19.87
Heavy fuel 1.0%S	15.48	16.77	16.76	17.63	16.76	15.23	15.85	14.84	13.84	14.33	12.22	11.31
Heavy fuel 3.5%S	11.90	11.64	12.12	12.34	11.73	9.71	9.10	9.79	9.79	9.72	9.26	8.20
NY HARBOR DEL CARGOES												
Gasoline 93 unl	23.61	23.17	25.02	26.39	26.79	25.29	24.19	25.32	22.96	23.38	20.41	17.72
Jet kerosine	23.52	24.14	24.90	24.13	24.51	23.36	21.84	22.18	23.13	24.86	23.44	19.80
No 2 heating oil	22.49	23.52	24.34	23.38	23.08	22.31	21.07	21.59	21.97	22.76	21.35	18.43
No 6 fuel 0.3%S	17.96	18.39	20.24	20.13	18.60	17.05	16.48	16.88	16.52	16.39	14.89	13.75
No 6 fuel 1.0%S	14.85	15.02	15.73	16.79	15.64	14.98	14.94	14.11	14.38	14.63	12.61	11.88
No 6 fuel 3.0%S	12.43	11.25	11.47	12.55	12.29	11.26	10.71	10.82	10.67	10.72	9.64	8.84
US GULF COAST FOB CARGOES												
Gasoline 92 unl	22.73	22.50	25.01	26.87	26.77	24.45	22.91	23.73	21.75	22.11	18.99	16.58
No 2 heating oil	21.47	22.52	23.01	22.50	22.43	21.39	20.18	20.74	21.15	21.91	20.41	17.50
No 6 fuel 1.0%S	13.35	13.55	14.40	15.81	15.15	13.97	14.01	13.13	13.04	13.16	11.54	10.82
Heavy fuel 3.0%S	11.22	10.95	11.32	12.22	11.39	9.85	9.23	10.14	10.27	10.15	8.13	7.82
SINGAPORE FOB CARGOES												
Gasoline 97 .15Pb	n.a.	24.56	25.10	26.78	26.70	25.91	22.81	23.66	23.36	23.44	22.06	18.94
Naphtha	18.44	18.48	18.70	19.20	19.39	19.03	17.64	16.61	14.80	15.70	15.29	13.34
Jet kerosine	25.33	25.35	25.40	25.85	25.84	24.29	22.98	22.61	22.56	24.95	24.71	22.51
Gasoil LP	24.83	24.96	24.80	25.71	25.92	24.00	22.79	22.72	22.93	24.25	23.48	21.44
LSWR	18.23	17.31	16.50	19.14	22.52	20.36	14.09	13.07	12.63	12.46	10.10	8.24
Heavy fuel 380cst	11.22	12.19	12.51	13.14	12.66	11.03	9.95	10.95	11.18	10.91	8.86	8.36

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*

Spot product prices, 1994

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	16.82	17.69	17.63	20.03	21.17	21.79	22.13	24.30	20.99	21.08	20.69	18.95
Naphtha	14.46	15.13	14.78	15.83	17.30	17.87	18.48	18.13	17.69	18.71	19.40	18.72
Jet kerosine	21.16	20.36	20.13	20.75	20.80	20.82	21.16	21.51	21.69	22.57	22.37	20.51
Gasoil	19.69	19.26	18.64	20.27	20.27	20.33	20.53	20.69	20.29	20.62	20.68	19.13
SR fuel 0.7%S*	13.41	14.59	13.37	13.96	15.07	16.01	17.14	15.61	14.40	16.51	16.90	16.39
Heavy fuel 1.0%S	13.63	14.71	13.30	13.42	14.16	15.08	16.43	16.00	14.19	17.17	17.40	17.04
Heavy fuel 3.0%S	9.97	12.32	11.89	11.54	13.12	13.03	15.19	13.73	11.71	14.27	16.29	15.44
MEDITERRANEAN CIF CARGOES												
Gasoline 97 .15Pb	18.00	18.77	18.91	21.20	22.49	22.93	23.04	25.47	21.63	21.06	21.35	19.88
Naphtha	14.09	14.68	14.48	15.52	17.05	17.55	18.18	17.97	17.37	18.33	19.08	18.38
Jet kerosine*	20.15	18.78	18.70	19.13	19.14	19.17	19.62	19.99	20.07	21.06	21.14	19.27
Gasoil	19.78	19.18	18.34	19.75	19.93	19.98	20.08	20.27	19.73	20.23	20.84	19.38
Heavy fuel 1.0%S	13.61	14.66	13.30	13.42	14.16	15.23	16.63	16.05	14.34	17.52	17.73	17.16
Heavy fuel 3.5%S	9.70	11.62	11.23	10.97	12.76	12.40	14.98	13.90	11.56	14.50	16.21	14.86
NY HARBOR DEL CARGOES												
Gasoline 93 unl	20.49	22.04	21.13	23.26	24.53	25.49	27.36	27.43	22.24	24.82	24.10	21.22
Jet Kerosine	23.73	24.13	20.03	20.74	21.16	21.60	22.53	22.03	21.30	22.22	22.63	21.51
No 2 heating oil	21.18	22.85	19.65	19.85	20.24	20.80	21.10	20.87	20.16	20.39	20.90	20.47
No 6 fuel 0.3%S	17.65	19.66	15.72	15.01	15.29	16.34	17.89	16.71	14.85	16.26	16.66	17.63
No 6 fuel 1.0%S	15.32	17.56	13.21	13.09	14.07	15.51	16.78	15.59	12.84	14.60	14.83	16.50
No 6 fuel 3.0%S	10.69	11.28	10.06	9.84	10.74	12.69	14.65	14.00	11.14	12.80	13.90	14.59
US GULF COAST FOB CARGOES												
Gasoline 92 unl	19.04	19.78	20.97	22.36	22.98	24.33	25.82	25.24	20.50	22.10	20.76	19.01
No 2 heating oil	19.47	19.49	17.93	18.78	19.32	19.85	20.18	20.01	19.48	19.55	20.05	19.44
No 6 fuel 1.0%S	12.12	13.13	12.03	12.76	13.58	14.63	15.38	14.43	12.73	14.01	14.30	14.43
Heavy fuel 3.0%S	9.55	9.86	9.25	10.81	11.39	12.89	14.38	12.88	10.64	13.14	13.73	13.33
SINGAPORE FOB CARGOES												
Gasoline 97 .15Pb	18.77	19.89	19.10	22.09	22.42	23.34	22.78	23.64	20.02	21.18	20.99	18.48
Naphtha	13.40	13.62	13.29	14.63	16.16	16.80	17.55	17.69	17.55	18.16	18.46	18.52
Jet kerosine	22.16	21.36	20.63	21.47	21.01	20.24	20.72	20.60	21.82	23.20	24.07	22.78
Gasoil LP	21.06	20.56	19.62	20.96	21.10	20.15	20.57	20.44	20.67	21.43	21.93	21.63
LSWR	10.13	11.16	10.48	11.35	12.71	14.03	18.20	18.89	12.96	12.79	13.39	13.20
Heavy fuel 380cst	10.45	10.03	9.41	11.60	13.35	13.34	15.55	15.11	11.74	13.40	14.45	13.58

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*

Spot product prices, 1995

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	19.30	19.91	20.67	23.13	24.33	22.68	20.13	21.21	21.26	20.38	22.12	20.05
Naphtha	17.96	18.66	19.18	18.76	20.61	19.99	16.92	17.41	18.03	16.93	16.87	17.74
Jet kerosine	20.69	21.06	21.61	22.20	21.94	21.36	21.87	21.75	22.89	22.22	22.80	25.10
Gasoil	19.68	19.91	20.13	21.74	21.61	20.58	20.35	20.86	21.41	20.17	21.31	23.57
SR fuel 0.7%S*	17.22	17.24	17.25	18.53	19.61	17.81	16.14	15.70	16.03	15.70	16.15	17.90
Heavy fuel 1.0%S	17.59	17.60	17.50	17.77	18.99	17.54	15.33	14.16	15.37	15.91	16.39	18.79
Heavy fuel 3.0%S	16.97	16.56	16.39	16.50	16.92	14.03	13.12	13.02	13.63	13.54	13.72	16.31
MEDITERRANEAN CIF CARGOES												
Gasoline 97 .15Pb	20.47	21.22	21.45	23.33	24.60	23.64	20.85	22.30	22.68	21.77	23.23	21.12
Naphtha	17.67	18.38	18.83	18.33	20.33	19.68	16.81	17.21	17.80	16.67	16.42	17.38
Jet kerosine*	19.57	19.62	20.27	20.91	20.48	19.91	20.23	19.67	21.05	20.66	21.50	22.98
Gasoil	20.20	20.14	19.49	21.19	21.28	20.43	19.83	20.62	21.59	20.35	21.44	24.16
Heavy fuel 1.0%S	17.68	17.39	17.56	18.24	19.22	17.47	15.18	14.04	15.58	16.19	16.45	18.68
Heavy fuel 3.5%S	16.75	16.46	16.01	15.98	16.69	14.17	12.88	12.77	14.06	14.48	14.31	15.99
NY HARBOR DEL CARGOES												
Gasoline 93 unl	23.62	24.01	23.10	28.39	30.37	27.10	23.25	24.72	25.65	21.77	22.72	25.94
Jet kerosine	20.76	20.40	19.76	21.87	22.55	21.26	20.75	21.98	22.90	22.41	23.19	25.22
No 2 heating oil	20.33	20.15	19.43	20.95	21.23	20.13	19.66	20.74	21.22	20.65	21.89	24.37
No 6 fuel 0.3%S	18.33	17.45	16.95	16.28	17.68	17.22	15.74	15.93	16.03	16.48	17.73	20.98
No 6 fuel 1.0%S	16.80	15.80	16.10	16.28	17.59	17.05	15.08	14.16	14.58	14.66	15.61	19.01
No 6 fuel 3.0%S	15.16	14.90	15.27	15.43	16.72	15.91	12.90	12.48	13.18	13.03	13.04	15.68
US GULF COAST FOB CARGOES												
Gasoline 92 unl	21.39	21.72	22.21	26.62	28.27	24.96	22.04	22.54	22.22	20.08	20.73	21.75
No 2 heating oil	19.25	19.20	18.48	20.28	21.05	19.54	18.88	19.98	20.38	19.71	20.88	22.59
No 6 fuel 1.0%S	14.35	14.69	14.69	14.98	16.69	16.16	13.40	13.02	13.88	13.94	13.95	16.34
Heavy fuel 3.0%S	13.30	14.41	14.50	15.01	16.30	15.08	12.34	11.98	12.23	12.57	12.63	14.85
SINGAPORE FOB CARGOES												
Gasoline 95 unl	21.33	21.44	22.87	22.64	22.76	23.76	24.02	24.35	23.53	21.77	22.97	22.03
Naphtha	17.99	17.76	18.37	19.08	19.14	18.79	17.33	16.43	16.42	15.82	15.89	17.07
Jet kerosine	22.61	22.72	21.54	22.15	22.96	22.29	21.04	20.83	21.63	22.66	24.72	28.26
Gasoil LP	21.38	21.36	21.14	22.16	23.02	22.41	21.09	20.36	20.49	20.48	21.98	24.34
LSWR	13.66	13.66	14.30	14.87	15.64	14.57	12.97	12.84	13.81	14.09	14.99	16.56
Heavy fuel 380cst	14.67	15.60	16.15	16.21	15.99	14.22	12.75	12.78	12.59	13.61	14.59	16.56

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*

Spot product prices, 1996

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	20.00	20.59	22.97	26.69	26.33	23.40	24.72	25.06	25.82	27.57	27.25	26.64
Naphtha	19.07	18.91	19.46	22.21	21.03	19.30	20.91	21.48	23.17	25.19	24.90	24.81
Jet kerosine	24.42	25.31	27.33	25.82	24.15	23.98	25.76	27.09	32.04	33.44	31.27	31.57
Gasoil (fod)	22.79	24.69	25.38	25.47	23.39	22.35	24.37	25.40	30.03	32.01	29.75	29.92
SR fuel 0.7%S*	18.64	17.41	19.42	21.07	19.33	19.13	18.5	18.71	20.03	21.55	22.14	22.05
Heavy fuel 1.0%S	18.88	17.63	18.91	20.32	18.73	16.58	17.55	17.08	19.22	20.8	21.25	21.72
Heavy fuel 3.0%S	16.23	15.23	16.57	17.24	15.41	13.30	13.99	14.96	17.69	19.12	18.15	18.41
MEDITERRANEAN CIF CARGOES												
Gasoline 97 .15Pb	20.89	21.46	24.37	28.03	28.20	25.02	26.24	26.12	26.41	27.56	27.68	27.06
Naphtha	18.68	18.58	19.07	21.77	20.83	19.14	20.60	21.30	22.88	24.81	24.47	24.47
Jet kerosine*	23.16	23.36	26.09	24.78	22.65	22.40	23.99	25.33	30.23	31.33	29.32	29.90
Gasoil	23.96	23.74	25.10	26.03	23.64	22.41	23.88	25.22	30.11	31.53	29.92	29.63
Heavy fuel 1.0%S	19.16	18.07	19.21	20.71	19.03	17.40	18.17	16.96	19.36	21.14	21.72	22.15
Heavy fuel 3.5%S	16.09	15.40	16.45	16.32	15.56	11.63	13.96	14.90	17.49	19.78	18.36	18.70
NY HARBOR DEL CARGOES												
Gasoline 93 unl	23.39	24.21	25.87	31.26	29.18	26.50	28.40	27.38	28.00	29.79	30.59	30.49
Jet kerosine	24.98	25.15	26.57	27.79	24.41	23.40	24.64	27.19	30.80	31.80	31.08	31.83
No 2 heating oil	23.54	24.97	26.11	26.27	23.52	21.71	23.55	25.43	28.60	30.55	29.58	30.48
No 6 fuel 0.3%S	23.68	21.08	22.13	22.71	19.39	18.39	19.51	20.32	21.49	23.36	23.63	24.46
No 6 fuel 1.0%S	21.35	17.98	17.93	19.41	17.78	16.84	17.70	17.26	18.48	20.97	20.85	21.81
No 6 fuel 3.0%S	15.67	14.56	14.91	15.83	15.11	14.35	14.91	14.96	16.42	19.26	18.99	17.33
US GULF COAST FOB CARGOES												
Gasoline 93 unl†	21.75	22.02	22.49	25.81	29.25	27.23	24.19	25.22	24.89	28.03	28.34	28.51
No 2 heating oil	21.57	22.41	23.25	24.26	22.55	21.19	22.77	24.67	27.57	29.32	28.40	28.40
No 6 fuel 1.0%S	16.41	16.14	17.67	18.81	17.75	15.97	16.56	16.75	17.06	19.71	18.64	19.13
Heavy fuel 3.0%S	14.25	14.56	15.39	15.97	15.08	14.34	13.75	14.53	16.49	19.39	17.50	16.18
SINGAPORE FOB CARGOES												
Gasoline 95 unl	21.94	21.47	24.25	26.37	27.35	24.85	23.56	22.77	23.69	25.42	26.18	26.39
Naphtha	17.50	16.70	18.36	20.40	19.51	18.75	19.54	20.01	21.04	22.46	23.34	25.02
Jet kerosine	30.36	28.16	27.21	26.12	26.13	24.06	24.79	27.57	29.79	30.19	31.04	33.70
Gasoil LP	25.28	26.45	25.85	25.56	26.49	24.29	24.38	25.39	27.74	29.99	30.77	32.63
LSWR	16.78	15.69	15.49	16.45	18.46	17.67	16.66	17.13	18.25	19.70	19.27	22.32
Heavy fuel 380cst	17.37	15.88	15.82	16.55	14.72	13.32	13.80	14.85	17.27	18.10	18.03	18.26

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*
† 92 unleaded until 13 September 1996.

Spot product prices, 1997

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	26.38	25.27	25.21	23.97	25.21	23.84	23.60	26.91	25.56	24.58	23.26	21.61
Naphtha	25.10	24.26	21.54	20.05	20.13	19.98	20.02	21.21	21.23	22.09	21.54	19.11
Jet kerosine	31.38	26.11	24.40	23.71	24.33	22.92	22.97	23.78	23.47	25.43	25.55	23.33
Gasoil	29.87	24.61	22.95	22.53	23.60	21.99	22.23	22.82	22.59	24.56	24.37	21.82
SR fuel 0.7%S*	20.62	18.92	16.96	15.38	16.57	16.00	16.61	17.18	16.83	19.26	19.36	15.72
Heavy fuel 1.0%S	18.70	16.90	16.23	15.07	15.33	16.03	16.14	16.21	16.36	18.50	19.57	15.99
Heavy fuel 3.0%S	16.77	14.82	13.11	12.72	12.74	12.92	13.12	14.30	14.66	15.81	16.27	13.28
MEDITERRANEAN CIF CARGOES												
Gasoline 95 Unl	26.48	25.59	26.50	24.67	25.93	24.55	24.04	27.35	26.17	25.54	24.23	22.31
Naphtha	24.69	23.78	21.15	19.62	19.65	19.82	19.93	20.90	20.81	21.64	21.26	18.78
Jet kerosine*	29.40	24.63	22.50	22.20	22.56	21.14	21.27	22.20	21.76	23.95	25.09	22.28
Gasoil	29.14	23.87	22.73	22.98	23.46	21.37	22.11	22.83	22.47	24.82	25.23	21.76
Heavy fuel 1.0%S	19.20	17.46	16.86	15.71	15.99	16.69	16.58	16.77	16.90	18.71	20.01	16.35
Heavy fuel 3.5%S	17.73	15.28	13.36	13.83	13.64	13.57	13.92	14.68	14.94	16.33	16.92	13.41
NY HARBOR DEL CARGOES												
Gasoline 93 unl	29.58	27.73	27.71	27.30	28.34	26.22	28.15	31.33	27.87	26.09	24.06	22.68
Jet kerosine	30.88	27.26	24.63	24.15	24.38	23.12	23.78	24.62	24.00	25.30	24.84	22.62
No 2 heating oil	29.42	25.51	23.17	23.60	23.62	22.12	22.43	22.85	22.41	24.22	23.92	21.69
No 6 fuel 0.3%S	18.51	16.95	15.57	14.96	15.87	16.14	16.71	16.22	16.72	19.43	19.48	15.89
No 6 fuel 1.0%S	18.51	16.95	15.57	14.96	15.87	16.14	16.71	16.22	16.72	19.43	19.48	15.89
No 6 fuel 3.0%S	15.94	15.15	13.59	14.01	14.50	14.37	14.78	15.39	15.87	17.41	17.77	13.76
US GULF COAST FOB CARGOES												
Gasoline 93 unl	29.50	27.22	27.45	26.22	27.28	25.45	26.72	29.10	26.15	24.65	23.19	22.36
No 2 heating oil	27.58	24.20	22.17	22.07	22.76	21.35	21.70	22.35	22.00	23.81	23.06	20.53
No 6 fuel 1.0%S	17.23	15.78	14.55	15.08	15.32	16.16	15.87	16.36	16.49	18.30	18.64	14.62
Heavy fuel 3.0%S	15.17	13.05	13.30	13.36	14.35	13.98	14.33	15.66	15.21	16.66	16.29	11.83
SINGAPORE FOB CARGOES												
Gasoline 95 unl	26.68	28.12	29.02	25.70	24.72	24.18	23.86	24.55	24.50	25.81	24.74	21.01
Naphtha	24.65	24.72	23.78	21.53	21.59	20.81	21.42	20.99	20.58	22.10	22.22	19.01
Jet kerosine	30.30	28.18	27.38	25.04	24.72	23.67	23.07	22.84	22.49	24.41	24.62	21.26
Gasoil LP	28.40	25.42	27.02	26.80	25.20	22.92	21.37	22.44	23.18	23.81	23.89	20.85
LSWR	21.78	19.44	17.18	15.70	15.29	14.96	16.60	15.52	15.58	16.51	16.81	15.48
Heavy fuel 380cst	16.04	14.54	14.70	14.66	14.93	14.80	15.05	15.76	16.77	16.96	16.07	13.85

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*

Spot product prices, 1998

$/barrel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NW EUROPE CIF CARGOES												
Gasoline 95 unl	20.04	19.39	18.25	18.90	19.21	18.68						
Naphtha	17.38	16.93	15.54	14.49	15.26	13.32						
Jet kerosine	20.74	19.41	17.76	18.29	18.24	16.31						
Gasoil	19.32	18.50	17.40	18.19	17.29	15.76						
SR fuel 0.7%S*	13.90	13.07	12.50	13.66	13.82	13.17						
Heavy fuel 1.0%S	14.24	12.03	12.10	13.69	13.29	12.76						
Heavy fuel 3.0%S	11.14	9.89	10.17	11.47	10.60	9.84						
MEDITERRANEAN CIF CARGOES												
Gasoline 95 unl	20.41	19.87	18.57	19.22	19.54	18.86						
Naphtha	17.03	17.04	15.44	14.30	15.01	12.97						
Jet kerosine*	19.50	18.02	16.50	17.40	17.87	15.40						
Gasoil	18.88	18.45	17.69	18.24	17.42	15.32						
Heavy fuel 1.0%S	14.57	12.60	12.48	13.98	13.60	13.15						
Heavy fuel 3.5%S	11.41	9.73	10.39	11.82	11.19	10.52						
NY HARBOR DEL CARGOES												
Gasoline 93 unl	21.42	20.19	20.04	21.81	22.70	21.85						
Jet kerosine	21.19	20.07	18.90	19.08	18.74	17.93						
No 2 heating oil	19.81	18.85	17.92	18.29	17.59	16.20						
No 6 fuel 0.3%S	16.47	15.97	15.27	15.89	15.59	15.11						
No 6 fuel 1.0%S	13.72	11.89	11.76	14.08	13.58	13.29						
No 6 fuel 3.0%S	11.41	10.22	9.87	12.19	11.56	10.94						
US GULF COAST FOB CARGOES												
Gasoline 93 unl	20.89	20.33	19.71	22.07	22.37	21.12						
No 2 heating oil	18.85	18.10	16.97	17.41	16.73	15.74						
No 6 fuel 1.0%S	12.74	12.28	11.06	13.75	13.18	13.18						
Heavy fuel 3.0%S	9.77	10.19	7.99	11.50	10.83	10.43						
SINGAPORE FOB CARGOES												
Gasoline 95 unl	20.07	18.20	18.56	20.00	20.51	18.84						
Naphtha	17.19	15.44	15.05	16.17	15.94	14.14						
Jet kerosine	18.30	17.04	15.63	17.69	16.83	15.36						
Gasoil LP	17.88	17.46	16.16	17.66	16.19	15.27						
LSWR	12.04	10.10	10.15	11.60	11.75	10.12						
Heavy fuel 380cst	9.54	8.38	9.94	11.51	10.82	9.44						

*Source: Petroleum Argus daily assessments. Averages calculated using a five day week. *FOB.*

Appendix 5.2

Further reading

Petroleum Argus Oil Market Guides

A series of occasional booklets providing detailed coverage of the main international crude and products markets, explaining how they operate, the methods of pricing, and the trading instruments used in each region.

Argus Guide to European Products Markets
1st edition, August 1993

Argus Guide to the International Liquefied Petroleum Gas Market
1st edition, September 1993

Argus Guide to the US Products Markets
1st edition, February 1995

Argus Guide to the Asia Pacific Products Markets
1st edition, October 1995

Newsletters

The former *Weekly Petroleum Argus (WPA)* has been expanded into two publications, each with a more clearly defined focus.

Argus Global Markets (AGM) provides a topical and intelligent editorial on the market; news and analysis of latest developments; crude, product and futures market reviews; background history to set current prices in context; freight rates and oil market fundamentals.

The new *Weekly Petroleum Argus* covers upstream and downstream investment; corporate strategy and profiles;

mergers and acquisitions; oil and gas finance and the geopolitics of energy.

Other *Argus* newsletters include:

Argus Fundamentals — a monthly round-up and analysis of oil supply, demand and stocks worldwide, including tanker movements.

Argus FSU Energy — a weekly newsletter covering oil, gas and electricity in the former Soviet Union and eastern Europe.

Argus LatAm Energy — a twice monthly newsletter covering oil, gas and electricity in Latin America.

Argus LPG World — a twice monthly newsletter and senior management brief on the international LPG markets.

Argus Gas Connections — a twice monthly newsletter covering the European gas and power generation markets.

6 Futures and forward contracts

Sally Clubley & David Long

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6.1 Introduction

Futures contracts remain the most important risk management instruments used in the oil market today – despite the growth of the swaps market (*see Chapter 8*). Not only do they add an extra dimension to oil trading by allowing participants to buy or sell for future delivery, but they provide an essential transparent forward pricing framework that supports other derivative trading instruments such as options and swaps (*see Chapter 10*). The volume of oil traded on these markets is now more than 4 times total world demand. They are an integral part of the oil industry and the first point of reference for traders.

Forward contracts have now almost disappeared from many parts of the oil market, having been replaced by swaps and other instruments. But the forward Brent contract remains significant, despite the continuing success of the Brent futures market. Elsewhere there are still a few forward contracts trading (*see Chapter 7*). Even in Brent the volumes traded have declined sharply, but the fact that much of the internationally traded crude is priced, directly or indirectly, against dated Brent – the physical basis of the forward Brent market – means that some activity and much significance remain in the market.

One of the main advantages of forward markets over futures markets in the past was that the industry could introduce a new forward contract to meet hedging needs much more quickly than the futures markets, which were hampered by regulatory requirements. But it is now much easier to launch new futures contracts. In addition, this advantage is shared with the swaps market, which is also much more flexible about the types of crude and product traded. And the reluctance of the new electronic trading platforms to get involved in physical contracts is likely to support the trend away from forward contracts (*see Chapter 11*).

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6.2 What are futures and forward contracts?

Futures and forward contracts are both simple trading instruments involving the purchase or sale of a specified quantity and quality for delivery at a specific time in the future and under standardised terms and conditions at a fixed price agreed now. This enables companies to fix their purchase or sale price ahead of time, either to reduce uncertainty (hedging) or as a means of speculating about the future price of oil.

Unlike a spot contract, where the cargo and payment are exchanged almost immediately, a forward or futures contract is not settled until the delivery date which may be months or even years ahead. Trading forward contracts often involves little or no initial outlay while futures contracts require only a small percentage payment. Both instruments can therefore provide a relatively cheap method of hedging or speculating. This forms a large part of their attraction.

During the lifetime of a forward contract, however, buyer and seller are exposed to the risk of default since the prevailing market price at the time of delivery may be very different from the original contract price. If prices rise the buyer (who holds what is known as a long position) makes a profit and the seller (who has a short position) makes a loss. If prices fall, the buyer loses and the seller profits. Futures contracts reduce the risk of default with margins, which means that all profits and losses are settled daily.

Although both forwards and futures apparently fulfil the same function, there are major differences between them in terms of the method of doing business, standardisation of the contracts, organisation of the market, costs and security and the regulatory environment and these all affect the way in which they are used and risks involved in trading them.

6.2.1 Method of doing business

Futures markets are based on the principle of novation: buyer and seller agree a deal on the floor of the exchange, but when this is registered the clearing organisation steps into the middle of the deal. Both buyer and seller then have a contract with the clearing house and not with each other. Because of the substitution of the clearing organisation, any deal concluded is effectively made with the market and any reversing deal can therefore be settled out immediately, regardless of the actual counterparty. The clearing house, which differs in form from exchange to exchange, acts as guarantor for the deal. All futures contracts have to be effected through a floor member of the relevant exchange, usually a futures broker and held by a clearing member. This member is the principal to the deal; the client (unless a clearing member itself) then has a corresponding deal with that member.

Forward contracts are agreed between 2 principals. A cash broker may be used, but its role is as intermediary only. There is no formal organisation guaranteeing performance. Anyone with a forward contract is therefore relying on its counterparty to perform under the terms of the deal. A company which has bought a forward contract can effectively close it out by selling it, but as there is no clearing house this is normally to a different counterparty. A series of purchases and sales therefore results in the creation of a chain of buyers and sellers who, theoretically, are obliged to pass a physical cargo from one to another. In practice loops in these chains are identified and an agreed cash settlement, known as a bookout, is agreed between the participants, but there can still be difficulties as the physical nominations have to be passed from company to company.

6.2.2 Degree of standardisation

Theoretically, forward contracts do not need to be standardised: each agreement can be adjusted to the requirements of the 2 parties to the deal. In practice, however, they need to be standardised in order to fulfil a useful hedging or speculative function. All the active forward contracts now traded, in both crude and products, are standard contracts, leaving only the price and the contract month to be negotiated between the 2 parties. Forward contracts are developed by the oil industry and contract terms are the industry norm for that crude or product. Forward contracts are for a normal traded quantity, for example a 500,000 barrel cargo of crude oil or a barge-load of gasoline.

Futures contracts are standard by definition. All terms are laid down by the exchanges, after consultation with the industry. In order to encourage speculative interest, exchange futures contracts are normally for small quantities, such as 1,000 barrels or 100 tonnes. As with a standard forward contract, only the delivery month and price can be negotiated.

6.2.3 Organisation of the market

Forward contracts are traded between market participants and there is no obligation to report the price of any deal done, although information is regularly exchanged between companies involved in the markets and reported by the various price reporting systems. Prices are therefore generally known but not entirely transparent. The identity of the participants is similarly semi-transparent.

All futures contracts are conducted by a trading method known as open outcry, or its screen trading equivalent. Floor member buyers and sellers call out prices until agreement is reached. In most cases these floor members will be acting on behalf of industry or other clients, whose identity will not be revealed to the market at large – though the clearing house will be informed in some futures markets. The prices are immediately published on the screen information systems. They are therefore totally transparent, but the identity of the clients is hidden.

6.2.4 Costs and security

Forward contracts have a very low cost prior to settlement. There is no contractual obligation for payment until settlement, though most companies are required to put up a letter of credit on entering a deal. Payment would then be required either when the deal is booked-out or after physical delivery takes place, in accordance with the contract terms. If the transaction is initially done through a broker, there would also be a commission to pay.

Futures contracts have a higher financial cost. In order to provide the guarantee of performance on all contracts, the clearing houses of the exchanges require payment of an initial margin, sometimes known as a deposit. The amount is fixed by the clearing house and is increased at times of high price volatility, but it is normally around $1,500–2,500 per contract, or $1.50–2.50 per barrel. In addition, each contract is marked to market each night and the full difference payable daily. This means that each contract is effectively re-established each night at that day's settlement price.

For example, if one Brent contract of 1,000 barrels was bought at $22.00/barrel and the market settled at $22.50/barrel the buyer would receive 50 cents/barrel or $500 and the position would be revalued at $22.50/barrel. This process – known as "marking to market" – is repeated each day (*see below*). The payments are known as variation margins.

Example: Variation margin

		$/barrel
Day 1	Brent bought at	22.00
	Market settles at	22.50
	Buyer receives	**0.50**
	Position revalued	22.50
Day 2	Market settles at	22.30
	Buyer pays	**0.20**
	Position revalued	22.30
Day 3	Market settles at	22.60
	Buyer receives	**0.30**
	Position revalued	22.60

The clearing house monitors the positions of all its clearing members and, in most cases, the members' customers. If necessary, margin requirements can be increased for individual members or customers in order to maintain the guarantee.

In addition to initial and variation margins, a negotiable commission is payable to the futures broker used and the exchange and clearing house take small fees: these would normally total less than 1.5 cents/barrel.

6.2.5 Regulatory environment

Futures markets are regulated by law in the various countries in which they operate. Each country has a specific body charged with monitoring the operation of the market and its members ensuring that the rules of the exchanges and the investor protection laws are upheld. The 2 best known are the Commodity Futures Trading Commission* (CFTC) in the US and the Financial Services Authority† (FSA) – formerly the Securities and Investments Board (SIB) – in the UK (*see Chapter 17*). All new futures contracts have to be approved by the appropriate body and all brokers are monitored, including spot checks. The regulations are aimed at ensuring a fair market with all buyers and sellers, of whatever size, receiving equal treatment. The exchanges have comprehensive monitoring methods, including

* www.cftc.gov
† www.fsa.gov.uk

video and sound tapes, to ensure that the trading floor is operated within the rules.

Forward contracts have no formal regulations attached and (unlike futures contracts) are specifically exempted from direct regulatory control in both the US and UK. However, there is an unwritten code of practice operated by the industry, some of which is supported by case law after a series of court cases dealing with certain aspects of the contracts. All forward contracts are subject to normal contract law under the jurisdiction specified in the contract.

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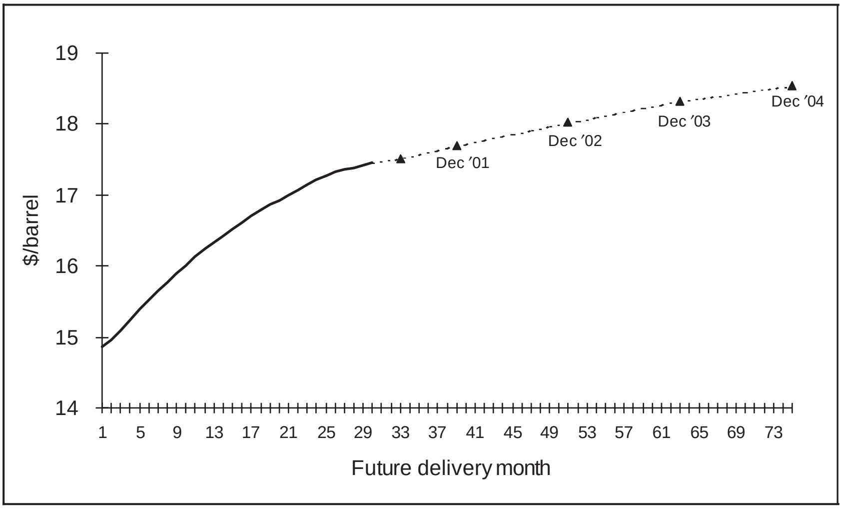
6.3 The pricing of futures and forward contracts

Futures and forward contracts enable companies to establish a price for future delivery. Such prices are not only useful to the parties concerned but also to the market as a whole as they help create a price profile stretching into the future. Forward prices are not predictions of the price at the specified time in the future – they are the price at which it is currently possible to transact business for that time in the future and are influenced by a range of factors including the type of company engaged in trading forward. The forward curve can, however, provide a useful indication of the current industry consensus price and enable companies to reallocate their surpluses and shortfalls accordingly. Before futures and forward contracts were introduced to the oil industry, all transactions had to be carried out on the spot market which often made it difficult to interpret price movements.

Although the majority of futures and forward transactions are for only a few months ahead, trading can extend much further out. In the refined products markets, there is usually enough liquidity to support trading over a period of at least a year ahead. And in the crude oil market, trading horizons regularly extend 3–5 years ahead. The most active futures contract, Nymex WTI,



Source: Nymex

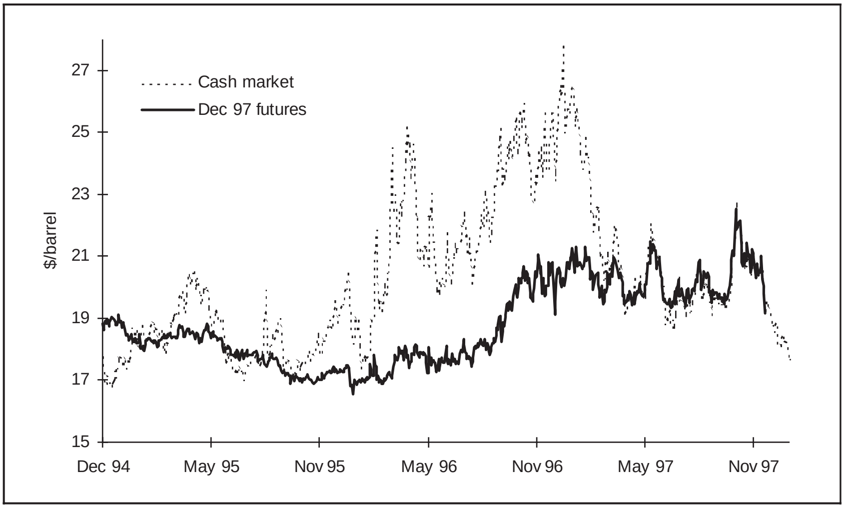
Figure 6.1 WTI futures price curve, 17 September 1998 can now be traded up to 7 years ahead and the forward price curve is used to determine the price of longer-term pricing instruments such as swaps (see Fig. 6.1).

6.3.1 Relationship to physical market

Prices for futures and forward contracts can be very different from those of the underlying physical commodity. But as a forward or futures contract approaches expiry, the 2 must converge as, at the point of expiry, they become interchangeable: a buyer of a forward or futures contract will receive physical oil at the same time and under virtually the same conditions as a buyer on the physical market (see Fig. 6.2).

There are occasional exceptions to this rule due to defects in the market delivery mechanism or a contract design which favours buyers over sellers or vice versa. But any contracts liable to regular squeezes, where either buyers or sellers can exert undue pressure on the other, will not survive. The volumes traded on the futures market make any attempt to squeeze by buying or selling as much oil as is deliverable and attempting to extract a premium from the other side very difficult.

There are occasional squeezes, however, on both forwards and futures. It is often easier on a forward crude market, such as Brent where a limited number of physical cargoes are



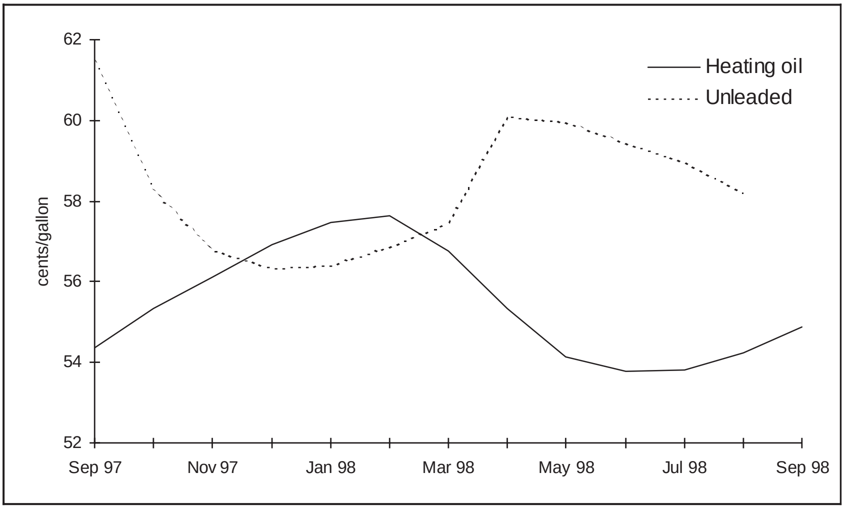
Source: Petroleum Argus, Nymex

Figure 6.2 Convergence of WTI futures and cash markets available each month, than on contracts where supply is virtually unlimited.

There are specific terms used to describe the differential in price between the nearby contract and the later months. If the nearby contract is at a premium to the later month the market is said to be in backwardation; if the nearby month is at a discount the market is in contango. Changes in these differentials can be due to various factors and can therefore be difficult to interpret. But they are important as they influence the pricing of many of the derivative instruments such as swaps and options.

6.3.2 Term structure of prices

Price spreads in the futures and forward product markets exhibit strong seasonal patterns reflecting changes in demand and in stock levels held by the industry (see Fig. 6.3). In agricultural commodities these differences normally reflect changes in supply when the product is harvested: in oil the changes are demand led. For example, gasoline demand reaches its peak in the summer months: this means the price structure will normally show a higher price in the summer contract months than the winter ones. That is, the market will be in contango from mid-winter to mid-summer and in backwardation thereafter. This does not mean that the absolute spot price in the summer will be higher



Source: Nymex

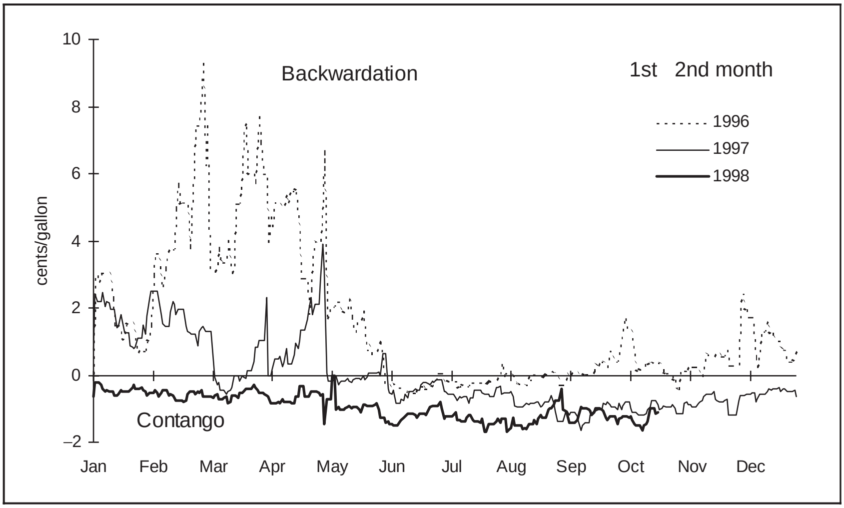
Figure 6.3 Forward product price curves (11 August 1998) than the absolute spot price in the winter, merely that the price curve will peak in the summer. The pattern for gasoil or heating oil is the reverse.

There is a limit on the size of the contango possible in a market. If it is possible to buy the oil one month, pay for it, move it into storage, insure it and deliver it back to the market one month or more later at a profit, traders will do it. This trading, known as cash and carry, will prevent the spread widening. The limit is not absolute because freight rates, storage charges and interest rates can all change, but it does represent the widest possible spread, at least until storage is full.

Example: Cash and carry arbitrage

	Buy March heating oil	74.00 cents/gall
	Sell April heating oil	77.00 cents/gall
March	Take delivery of heating oil futures at:	74.00 cents/gall
	Pay storage costs for 6 weeks:	2.30 cents/gall
	Interest costs, product losses etc.	0.25 cents/gall
		76.55 cents/gall
April	Deliver heating oil at:	77.00 cents/gall
	Net profit/loss:	+0.45 cents/gall

In this case the trader would have made a profit of 0.45 cents/gall, less dealing costs. Storage costs, insurance and other time-



Source: Nymex

Figure 6.4 Nymex heating oil, contango and backwardation sensitive costs will depend on the exact time of delivery in each month: in most futures markets the buyer chooses when to take delivery subject to agreement from the seller's facility, so delivery would be taken as late as possible in the first month. In some instances it may not be possible to take delivery by in-tank transfer: in these cases it would be necessary to include transportation to different storage tanks in the calculation.

Backwardation does not have the same limits (see Fig. 6.4). Although it is theoretically possible to deliver oil onto the market and buy it back one month or more later, the arbitrage procedure is less attractive this way round as oil has to be transported to the delivery location and may be of a different quality from the contract. In practice, backwardation is unlimited as companies will pay virtually any price when their need for supply becomes desperate.

6.3.3 Arbitrage relationships

The spread between futures and forward markets and the underlying physical markets is ultimately constrained by the opportunities for arbitrage between the two. Arbitrage is the simultaneous buying of a product in one market and sale of the same product in a different market. If a profit can be realised in this way, traders will be moving the product or crude from one market and delivering it into the other. The limits on the spread are therefore determined, like the cost of cash and carry, by the costs involved. In practice, product is rarely moved between one futures market and another, but the fact that the spread is limited by the opportunities for arbitrage will attract speculative trading into the spread.

Arbitrage in the commodity markets is not the same as in the financial markets – it is not a risk-free way of locking in the price difference between 2 markets because the commodity has to be moved physically from one market to the other with all the operational and price risks involved in doing that.

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6.4 How are futures and forward contracts used?

6.4.1 Trading instruments

Futures and forward contracts can be used in many different ways depending on the motives and circumstances of the parties involved. The continued co-existence of the 2 forms of trading in the crude oil market not only provides a wide range of opportunities for the enterprising trader but offers companies involved in producing, refining and marketing oil a broad choice of possible instruments. These range from forward physical contracts, which are essentially extensions to the spot market, through forward paper contracts, which offer many of the benefits of futures trading and some of their own, to futures contracts themselves, with different attractions. In addition, futures contracts provide the means of combining 2 forms of trading through the use of the EFP (exchange for physical) delivery mechanism, which enables supply to be separated from price.

Forward physical contracts

The purpose of a forward physical contract is to establish a price for future delivery. In some ways it can be regarded as an extension of the spot market since, like a spot contract, it can be difficult to negotiate as it is tailored to the requirements of buyer and seller. It can also be difficult to distinguish between the 2 as many seemingly spot contracts in fact agree a delivery a month or more ahead, particularly in the crude oil market.

Forward paper contracts

These are the contracts normally meant when forward contracts are mentioned. They are the standardised forms of agreement for future delivery that are easily traded. Contract terms such as quality and the terms and locations for delivery are designed to be acceptable to the widest possible range of participants to improve liquidity.

Traders can therefore use the forward markets in the same way as futures contracts for hedging purposes since sales and purchases can often be closed out by taking the opposite position with a different counterparty. This settlement is dependent on the identification of a loop in a chain of sales and purchases. It is important to remember, however, that if such “bookouts” are not agreed the outstanding puchase and sale obligations remain in place until the physical nomination has been passed down the chain. This process can lead to difficulties. For example, the forward 15-day Brent contract specifies that nominations be received by 5 pm London time. If a company receives a nomination just before that time and is unable to pass it on with the required 15 days notice of the first day of the loading date range, the nomination process stops and the company is left holding a physical cargo. The company would then have to nominate or even buy a different forward contract to meet its outstanding sale obligation and (possibly) dispose of the physical cargo – all of which may have very different values to the original forward contract (*see Chapters 7 and 16*).

Futures contracts

The purpose of a futures contract is to provide a suitable hedging mechanism for the associated industry, to provide security, to minimise the risk of manipulation and to create price transparency. They are traded by open outcry on a market floor (or its screen equivalent) and are monitored and guaranteed by a clearing house. The prices and quantities of all transactions are published.

The vast majority (more than 99 per cent) of futures contracts do not result in the physical delivery of oil. It is, however, important that the physical delivery terms are as close as possible to those in the underlying physical market in order for price convergence to occur at the point of expiry, when futures and physical trading should be substitutable.

Some futures contracts, such as Brent on the IPE, are not designed for physical delivery. Although physical delivery is possible, if both buyer and seller wish it, Brent contracts open at expiry are normally settled against an index price derived from the physical market. The contract was designed this way because of the difficulties in matching the physical delivery procedures with a realistic futures market.

Exchange for physicals (EFPs)

The EFP delivery mechanism is a means of using the futures market to price a physical transaction without getting involved in the exchange delivery process. Companies wishing to take physical delivery but requiring a different grade of oil, location or other change to the exchange rules, or who wish to choose their counterparty, can agree a physical deal in the same way as normal, but instead of agreeing an outright price negotiate a differential to a specified futures contract.

The physical deal is agreed and takes place in the normal way. Meanwhile, both parties have to establish a futures position: the buyer must, at some point, buy the agreed futures contracts and the seller sell the same quantity of the same contract. The two futures contracts are settled out at an agreed price by notifying the exchange that an EFP is being registered. The price does not matter as the same price is used as the basis for the invoice on the physical deal (*see Chapter 8*).

The registration of the EFP can create a futures position if the buyer has not yet bought or the seller sold. In this case, the futures contracts are treated just like any other and are subject to initial and variation margins.

EFPs are widely used in the oil markets. They have enabled term contracts, where a buyer agrees to buy a series of cargoes from a supplier over a period of time, to reappear after a period of disuse because they allow each party to maintain control over pricing while guaranteeing physical supply or outlets.

6.4.2 Trading motives

There are 3 main uses for futures and forward markets: hedging, speculation and arbitrage. The aim of hedging is to protect a physical position from a major adverse price movement. Speculators aim to make money by correctly predicting the price movement in a market. Arbitrageurs take advantage of temporary price distortions in the market. In practice, however, it is often difficult to distinguish between the different motives. The choice of a hedging instrument, for example, will include a calculation of any arbitrage value. In some countries, however, it can affect the tax and accounting position of the trade.

Hedging

Companies involved in the physical oil market can protect themselves against adverse price movements by taking an opposite position on the futures or forward market to that held on the physical market. In this way any loss in the physical market should be offset by a corresponding gain on the futures or forward market. A hedge will rarely, if ever, be perfect, but if chosen correctly will provide some insurance.

Hedging can be used for various purposes. It can, for example, protect a buyer of oil against a fall in price while oil is in transit. An oil trader who has bought a cargo of physical oil would sell an equivalent volume of oil futures or forward contracts. This is known as a short hedge because the trader takes a short futures position. As soon as the physical cargo is sold, the hedge is lifted, i.e. the futures contracts are bought back.

Effective hedging depends on the assumption that prices in the physical and forward or futures markets move together. Ideally the differential between the two, the basis, would remain constant but in practice this rarely happens either because the product or crude being hedged is not identical in every respect to the futures or forward contract being used, or because the degree of backwardation or contango in the forward or futures market changes.

Example: Short hedge

Company A buys a 500,000 barrel cargo of crude oil from a supplier for $22/barrel. The current futures price is $22.20/barrel. It decides to sell futures as a hedge. A few days later it sells the physical cargo for $21.50/barrel and buys back its futures contracts, which are now trading at $21.60/barrel.

	Physical Market	$/bl	Futures Market	$/bl
Day 1	Cargo bought at:	$22.00		
			Futures sold at	$22.20
Day 6	Cargo sold at:	$21.50		
			Futures bought at	$21.60
	Loss	–$0.50	Profit	+$0.60

In this case the hedger has taken a larger profit on the futures than the loss made on the physical market. This results from a change in the basis, which is the differential between the futures market and the product actually being traded.

Example: Long hedge

In the same way, a company which is short of oil in the physical market will use a long hedge, i.e. will buy futures, to protect itself against a rise in price. For example, a gasoil distributor might agree to sell oil to a customer at a fixed price for some months ahead. In order to protect itself against a rise in price it will buy futures. When the company buys the oil to fulfil the order, the hedge will be lifted.

	Physical Market	$/tonne	Futures Market	$/tonne
Month 1	Oil sold at:	$223		
			Futures bought at	$222
Month 2	Oil bought at:	$230		
			Futures sold at	$228
	Loss	–$7	Profit	+$6

In this case the futures profit did not quite match the loss on the physical market: again this was due to a change in the basis.

Speculation

Speculation is the opposite of hedging. Speculators take a position on the market purely in order to make a profit. Futures and forwards markets are ideally suited to this activity as there are none of the operational problems which can arise if speculation is carried out with physical cargoes of oil.

Speculators are regarded as undesirable by some in the market, but they are a necessary part of any futures market as they take on the risk which hedgers are trying to lay off. Many speculators, particularly the local floor traders, hold onto their positions for a very short time and are in and out of the market several times each day, increasing liquidity and making it easier for hedgers to trade when they want to.

Hedge funds and other large investment funds are also major users of the the futures markets. They normally trade on a technical basis, using price charts and theories of price movement to determine when and how much to buy and sell. They can cause temporary price anomalies but these are usually very short-lived as industry participants are quick to take advantage of any movement that appears illogical in the light of physical market conditions.

Example: Speculating on a price rise

A strike at an off-shore oil platform interrupts production in the North Sea. As a result, prices are expected to rise and a speculator buys IPE Brent futures in the hope of making a profit. Several days later, the strike is settled and production is restored so the speculator closes out his position before prices can fall back again. Since there is no physical transaction involved the 2 trades must be classed as purely speculative.

	Physical Market	$/bl	Futures Market	$/bl
Day 1	No transaction		Futures bought at	$23.20
Day 5	No transaction		Futures sold at	$25.10
			Profit	+$1.90

Arbitrage and spreads

Arbitrage, the simultaneous buying of a product or crude in one market and sale in another, is one of the means by which prices in different markets are kept in line. When price relationships move out of line, however briefly, arbitrageurs will come into the market, buying the under-priced one and selling the over-priced, thus helping to bring price back into line. In many cases the contract specifications are not exactly the same: it is not possible for example to take delivery from the Nymex heating oil contract and deliver it onto the IPE. But the limits to the differential between the 2 are still governed by the costs of transport, insurance etc. across the Atlantic.

Example: Heating oil arbitrage

August gasoil on the IPE and heating oil on the Nymex are trading at the same price. Many traders expect Nymex heating oil to move to a premium over the IPE because of good demand in the US and plentiful stocks in Europe. They therefore buy Nymex heating oil contracts and sell IPE gasoil, subsequently reversing the process when the spread has widened.

IPE gasoil contracts are 100 tonnes and Nymex heating oil contracts are 1,000 gallons. It is therefore necessary to trade *3* Nymex heating oil contracts for every *4* IPE gasoil contracts. Furthermore, IPE gasoil prices are quoted in $/tonne while Nymex heating oil prices are quoted in cents/gallon. In order to convert cents/gallon into $/tonne the Nymex heating oil price is multiplied by 3.13 because there are 313 gallons of heating oil in a tonne assuming an average specific gravity for gasoil of 0.845 kg/litre. Both contracts have a maximum specific gravity but a range is deliverable so traders tend to use different factors. The important thing is to use the same factor to put on and take off the spread.

	Nymex heating oil	Price cts/gall	Price \$/tonne	IPE gasoil	Price \$/tonne	Price differential
21 June	Buy 3 at:	75.27	235.60	Sell 4 at:	236.00	–0.40
22 July	Sell 3 at:	75.08	235.00	Buy 4 at:	230.00	+5.00
	Loss	–0.19	–0.60	Profit	+6.00	+ 4.60

The total profit in this case is \$4.60/tonne and is determined by the change in the differential so the direction of the market move is irrelevant.

Other spreads traded include inter-month spreads, where the price in one month is out of line with that in another. These spreads are limited by the cash and carry cost, as described earlier, and, in some cases, by the costs of "lending" oil to the market.

Spreads between different futures or forward markets are also traded actively. For example the differential between oil products and crude oil can be traded. The best example of this is the crack spread on the Nymex where the spread between heating oil, gasoline and crude is traded as if it were a paper refinery. Traders will either buy gasoline and heating oil and sell crude or vice versa. In the physical market when this spread narrows refiners will reduce capacity throughput and traders are seeking to mimic this on the futures market. It is not a perfect match because there are only 2 product futures contracts available while a refinery produces many more, but it is sufficiently close to provide trading opportunities.

Example: Crack spread arbitrage

A trader notes that the Nymex crack spread in August is trading at \$5.00/barrel, narrower than normal. Crack spreads involve an equivalent number of crude and product contracts, usually 2 gasoline and 1 heating oil against 3 crude oil: a 3:2:1 crack spread of \$5.00 means that the products are trading at a \$5.00 premium to crude oil. When the spread widens to \$6.50 the trader decides to take his profit. There are 42 US gallons in a barrel of oil.

2 gasoline contracts bought at	76.00 cts/gall	(\$31.92/bl)
1 heating oil contract bought at	72.64 cts/gall	(\$30.51/bl)
3 crude oil contracts sold at		\$26.45/bl

Differential = $(2 \times 31.92 + 30.51)/3 - 26.45 = \$5.00/\text{bl}$

When the spread increases the reverse transaction is done.

2 gasoline contracts sold at	84.00 cts/gall	($35.28/bl)
1 heating oil contract sold at	78.43 cts/gall	($32.94/bl)
3 crude oil contracts bought at		$28.00/bl

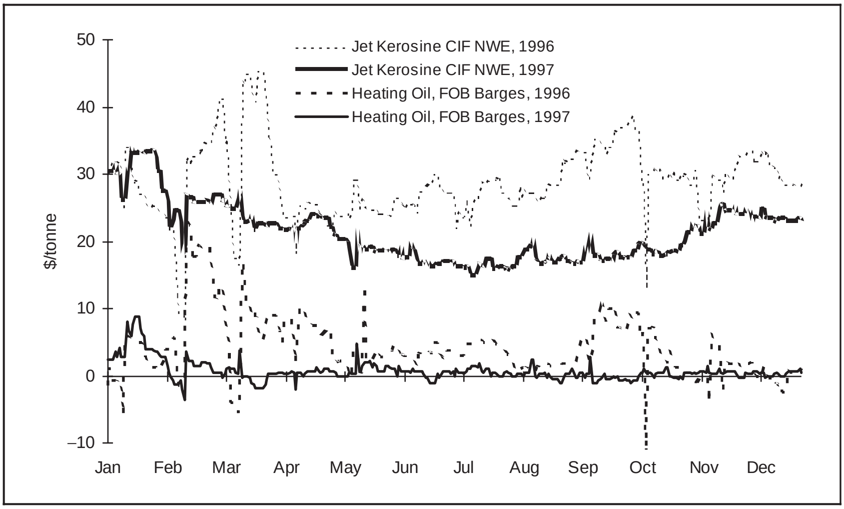
Differential = $(2 \times 35.28 + 32.94)/3 - 28.00$ = $6.50/bl

As with any spread, the overall direction of the market does not matter in determining profitability, it is only the differential between the contracts traded which matters.

6.4.3 Hedging and basis risk

Basis risk is an essential consideration in any hedging programme. The basis is the difference in price between the product or crude to be hedged and the hedging instrument being used. The closer the relationship between the two the more effective the hedging will be. As there are very few futures contracts traded almost everyone using them is exposed to some basis risk.

Before starting any hedging programme it is necessary to establish the historical basis relationship by comparing prices over as long a period as possible. In many cases, there is a clearly defined seasonal change in the relationship and provided this is taken into account hedging can be effective (see Fig. 6.5). Or the relationship can be affected by other factors some of which may



Source: Petroleum Argus, IPE

Figure 6.5 Basis risk against the IPE gasoil contract be foreseeable. But there will be some products and crudes for which no satisfactory relationship can be identified. In these cases it would be worth looking at other futures, swaps or forward contracts to see if a more effective instrument can be found.

It was largely the erratic nature of the basis between jet fuel and fuel oil and the futures and forward instruments available which led to the rapid growth of swaps markets in these 2 products in the early part of the 1990s. Consumers of the 2 products had not been able to establish a predictable basis relationship and therefore preferred to hedge with a direct swap contract.

In many cases, however, a satisfactory basis can be established and this should be taken into account each time a hedging decision is made. For example, if a gasoil trader has established that the local market in which he is active normally trades at a premium of between $5 and $9 to the futures market, he can use this information to improve his hedging efficiency by hedging when the basis move is likely to be attractive.

Thus, if the local market is trading at a $5 premium to the IPE, a trader considering buying gasoil futures to hedge a short physical position could improve his hedging efficiency because the basis is more likely to widen than narrow. Since the trader is concerned about the risk of falling prices, he wants the basis to be at its narrowest. If the historical basis relationship holds, futures prices could potentially fall by $4 more than the local physical market. On the other hand, if the premium is already $9 it is not a good time to hedge since the basis is more likely to narrow and prices on the futures market could rise by $4 relative to the local physical market.

Impact on hedge efficiency	Basis widens	Basis narrows
Long hedge (short physical)	Worse	Better
Short hedge (long physical)	Better	Worse

If the trader is selling futures to hedge a long physical position rather than buying and therefore considering a long hedge, the reverse applies: a $5 premium would be a poor hedging opportunity, but a $9 premium would be unattractive.

In a major price move, basis relationships can become insignificant since any protection is better than none at all. But in a quieter market changes in the basis can outweigh any benefits to be obtained from hedging.

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6.5 Conclusions

Futures and forward contracts have different strengths and weaknesses when used for either hedging or speculation. These can be summarised as follows:

	Forwards	Futures
Contract	Developed by industry	Fixed by exchange
Size	Bulk with operational tolerances	Small and fixed
Structure	Chains	Novation
Settlement	Offsets/bookouts	By Clearing House
Costs	Letters of credit, brokerage	Margins, fees, brokerage
Regulation	Informal	Formal
Security	Counterparty risk (same as physical market)	Clearing House guarantees
Users	Trade, financial institutions	Trade, financial institutions, locals
Profit/loss	On closure/delivery	Daily marking to market

The choice of futures or forwards and of which particular contract will depend on the circumstances. The most important consideration is that of basis risk: how closely does the product or crude to be hedged match the hedging instrument. The better the match, the better the hedge.

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7 Forward paper markets

David Long

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7.1 Introduction

Forward "paper" contracts have played an important role in the development of the oil market. By providing a standardised form of agreement that could be easily traded in much the same way as a futures contract, forward paper markets such as 15-day Brent made a significant contribution to the rapid growth in trading activity during the 1980s and the consequent improvements in liquidity and price transparency. Without the flexibility offered by informal forward paper contracts, the speed of development of the oil market might have been much slower since new futures contracts take time to develop and have not always been successful. But forward markets also have their limitations since they ultimately involve physical delivery — which can make it difficult or costly to close out positions — and the industry now prefers to use swaps wherever possible.

To begin with, forward and futures contracts were seen as competing instruments and many expected that futures markets would eventually replace the forward paper markets, as has often happened in other commodity markets. However, experience has shown that forward paper contracts can still play a key role in the oil market, often in parallel with successful futures contracts such as Brent and WTI. In the case of oil, forward markets appear to play a complementary role to the futures markets since they provide some benefits that are not available from futures contracts.

First, they can be traded around the clock and therefore provide a trading instrument that can be used outside normal futures exchange hours — this proved invaluable at the start of the Gulf War. Secondly, they enable companies to trade much larger quantities of oil in a single transaction. Thirdly, they enable participants to choose their trading partners. And, fourthly, they involve physical delivery which some companies prefer either for practical or fiscal reasons.

Compared with the markets for new trading instruments such as swaps or over-the-counter (OTC) options which are growing rapidly, forward paper markets have reached a more mature phase of development and a number of contracts have recently ceased trading. Nevertheless, they remain an important and potentially innovative sector of the oil market capable of generating new contracts if required, especially if swaps are subjected to a more restrictive regulatory regime than applies at present (see Chapter 17). Although the turnover of the forward paper markets is now much smaller than that of the futures markets, forward paper

Table 7.1 Forward paper markets, 1997

Europe	United States	Arab Gulf and Far East
15-day Brent	WTI and other pipeline crudes	Dubai crude
	Colonial Pipeline Boston Bingo	O/S naphtha

contracts still play a key role in areas where they retain a comparative advantage.

At present, there are only five successful oil futures contracts in operation on the three energy exchanges (see Chapter 8), but there are still more forward paper contracts in active use around the world — although forward trading volumes are now much lower and time horizons are much nearer than they used to be. In practice, the strongest competition has come not from the futures market, but from swaps which are able to mimic many of the essential characteristics of a forward paper contract without posing the problems sometimes associated with physical delivery. As a result, most of the recent innovations such as Brent "contracts for differences" (CFDs) and the so-called "Paper" Tapis market have been based on swaps rather than a conventional forward paper contract. Also a number of previously active forward paper markets*, such as Russian gasoil, Littlebrook fuel oil, and European open-spec naphtha have now been replaced by swaps (see also Chapter 10). However, forward paper trading remains an important part of the oil market in the North Sea, the United States and the Far East and still plays a significant role in establishing prices for forward delivery.

* Further information about these now defunct forward paper contracts can be found in the Appendices to this chapter.

7.2 Structure and organisation

Although forward paper markets fulfil many of the same functions as futures markets they differ in terms of their method of operation, structure and organisation. Forward paper contracts are not traded on a formal futures exchange (which is subject to external regulation) but are traded informally between principals who must regulate themselves. In the US, forward paper contracts are specifically excluded from regulation under the Commodity Exchange Act (CEA) by the Commodity Futures Trading Commission (CFTC). But in the UK, participants are expected to regulate themselves according to the provisions of the Financial Services Act (FSA) 1986 and markets are subject to the overall supervision of of the Financial Services Authority (FSA) — formerly the Securities and Investments Board (SIB).

In addition, there is no clearing house to manage and guarantee the matching and delivery of contracts so the participants must also do this for themselves. Nor is there any obligation to publish the details of any deal that is done so there is less price transparency than on a futures market. As a result, forward paper markets tend to attract a narrower set of participants than futures markets since using them involves risks and requires dedicated manpower to maintain contact with the market. Generally speaking these are the larger oil companies and traders who are active in the physical oil market and the Wall Street investment banks who also play the role of market maker.

7.2.1 Method of operation

Business on the forward paper markets is usually conducted over the telephone. Participants either trade directly between each other or through specialist brokers who provide a useful service by quoting bid-ask levels for forward contracts and enabling participants to test the market without revealing their identity. However, forward deals cannot be concluded anonymously (as they can on the futures market) since the identity of the counterpart will affect the terms of the deal if credit or delivery risks arise. In such cases, credit guarantees such as a letter of credit will be required (see Chapter 13). Once the terms of the deal have been agreed between the counterparts, confirmation will be sent by telex or fax.

Forward paper contracts are based on physical delivery of the underlying commodity during an agreed time period in the future, either a full calendar month or a specified part of it. Although they specify standard quantities and qualities, and are subject to a mutually agreed set of terms and conditions in order to provide a flexible trading instrument, they can only be discharged by nominating a suitable physical cargo against the paper contract.

Nominations are usually at the seller's discretion*, subject to a minimum notice period, and the buyer therefore has no control over the precise date on which the contract will be liquidated. As a result, forward paper positions remain open until the seller nominates a particular cargo of physical oil to meet his contractual obligations. At this point the buyer must either decide to accept physical delivery, or pass on the nomination to a third party against another forward sale, thus closing out his position. This rather haphazard process creates what is known as a "daisy chain" of paper contracts that link the original supplier of the physical cargo to the ultimate purchaser. In active forward markets daisy chains can include hundreds of links, many of which involve the same companies.

In order to reduce the complexity and uncertainty of the market clearing process, participants can agree in advance to identify and "book out" circles of contracts that start and end with the same party (see Chapter 12). In this case the parties involved agree to pay each other the difference between the purchase and sale price, thus reducing the cash flow associated with the transactions. However, booking out does not remove the obligation to make physical nominations and the process only works as long as no one defaults on the agreement when the contracts are actually discharged.

7.2.2 Market organisation

Since forward markets are organised by the participants and not by an exchange or clearing house, forward contracts involve a number of delivery risks for the parties concerned that do not arise in the case of futures contracts. First, it is not always possible to close out a position even if a company has both bought and sold a paper contract. If, for example, the notice period for nominations has expired the buyer cannot pass on his cargo to another company which leaves him with not only an unwanted physical cargo, but also the obligation to supply another physical cargo with suitable delivery dates.

*In the case of the Dubai paper market, buyers are entitled to nominate their preferred loading date range subject to acceptance by the terminal operators (*see 7.5.1*).

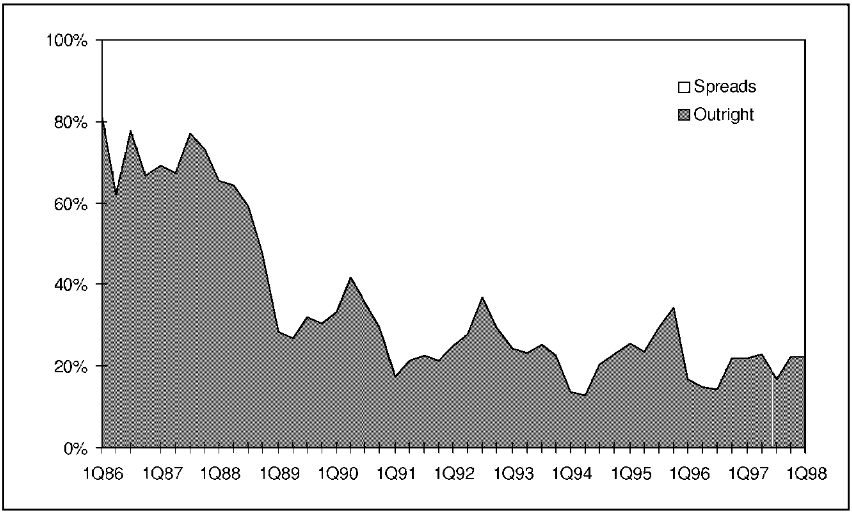
In the 15-day Brent market, for example, sellers are obliged to give 15 working days' notice of the first day of the loading date range for the physical cargo and the working day is deemed to end at 5pm London time. Nominations received just before or at 5pm on the 16th day before loading cannot therefore be passed on and unscrupulous traders have been known to disconnect telephones and telex machines to avoid being "five o'clocked".

Secondly, forward contracts typically involve a loading tolerance of plus or minus 5 or even 10 per cent that can be exercised at the seller's discretion. Although this is meant to provide for operational flexibility, it is often used by paper sellers to maximise their profits or minimise their losses. Companies can therefore never be certain of the exact size of their position since the seller may nominate minimum or maximum volumes against the paper contract. In the case of the European "open-spec" naphtha market the range used to be from 17 to 25,000 tonnes, a range of 8,000 tonnes or nearly 40 per cent of the average cargo volume.

Thirdly, in forward markets which trade cargoes for CIF delivery, it is possible to pass nominations from one delivery month to the next thus delaying the discharge of vessels and incurring demurrage charges that get passed down the chain of paper contracts. As a result, buyers can find that they are facing hidden costs and may need to resort to legal action to recover them from the companies that are actually responsible. In the case of the "open-spec" naphtha market, contracts now specify that demurrage charges will be shared between all the companies involved in a chain, not just the one which ends up taking delivery.

7.2.3 Market structure

The more active forward paper markets offer opportunities for spread trading as well as outright deals. In order to encourage liquidity both between contract months and between similar contracts, such as 15-day Brent and paper Dubai, companies can agree to link pairs of forward contracts in order to create a "spread" trade. Thus a company that wants to roll over its short position from October to November can agree to buy October and sell November with the same counterpart. Similarly, a company that wants to convert a short Dubai position to a short Brent position can agree to buy Dubai and sell Brent in the same way. Spread trades can be used both to hedge and speculate and now constitute the majority of the total trading volume in the larger forward paper markets.



Source: Petroleum Argus

Figure 7.1 Share of outright deals in 15-day Brent market

The growth of spread trading at the expense of outright deals has led to accusations that prices in the forward paper markets are the result of a circular process that bears little relation to the supply-demand fundamentals. In the words of one market commentator, "the tail wags the dog". Such accusations, however, do not take into account the practicalities of trading on the forward paper markets and therefore misunderstand the purpose of spread trading. Between 1987 and 1994 the proportion of outright deals reported by *Petroleum Argus* in the 15-day Brent market declined from 75 per cent to 20 per cent. The downward trend halted in 1994 and the proportion of outright deals briefly recovered to over 30 per cent at the end of 1995, but has since stabilised at around 20 per cent. As a result, the number of outright deals reported now averages 2–3 per day compared with over 20 in the late 1980s (see Fig. 7.1). Outright deals are typically concentrated in the second nearby delivery month, which is also the most liquid.

Given the risks associated with trading forward paper contracts it is not surprising that companies should prefer to engage in spread trading wherever possible since this, at least, ensures that the paper position can be liquidated without difficulty. Outright deals are therefore largely confined to the month with the greatest liquidity in order to minimise the delivery risks. The same argument can also be applied to the paper Dubai market which, since the Gulf crisis in 1990, has traded almost exclusively as a spread market against 15-day Brent.

7.2.4 Sources of price information

Price assessments for most forward paper markets are widely available from specialist price reporting organisations such as *Petroleum Argus, Platt's* and *Reuters*. In addition, there are specialist brokers and market makers in each market who are usually willing to quote a bid/ask range for the most active forward paper contracts.

Since there is no formal obligation for participants to report the prices of deals done, the accuracy of any published price assessment ultimately depends on the skill and thoroughness of individual price reporters and their parent organisations. However, since it is also in the participants' interests to have reasonably accurate assessments published, most participants are prepared to co-operate with the price reporting organisations in order to ensure that sensible numbers are printed.

Of course, each participant will attempt to keep part of their activities "private and confidential" so it is never possible to guarantee that a given assessment is perfectly accurate. But the fact that so many other trading activities now make use of published price assessments in order to calculate weekly or monthly averages for pricing formulas means that the industry keeps a close eye on the accuracy of assessments and is quick to complain if the numbers seem out of line (see Chapter 3). In the case of 15-day Brent, published price assessments are also used to establish the IPE's Brent price index, which is used to settle Brent futures contracts (see Chapter 8).

Screen quotes are available for the most active markets from on-line specialists such as *Reuters*, *Bridge Telerate*, and *Bloomberg*. These typically include the main forward crude markets: Brent, Dubai and WTI and are updated frequently during the day as prices change. But the primary source of pricing information for the forward crude markets remains the daily price assessments published by price reporting organisations such as *Petroleum Argus, Platt's*, *London Oil Report (LOR)* and *RIM*. Both *Platt's* and *Argus* are widely used in pricing formulas and as the basis for swap contracts and the UK OTO has agreed that their North Sea price assessments can be used for tax purposes. In addition, *Petroleum Argus* publishes regular daily price assessments for the remaining forward product markets in the US and the Far East.

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7.3 Europe

Forward paper markets have traditionally been very important in north-west Europe and were originally preferred to futures markets by many participants. The largest forward paper market, the 15-day Brent market, is based on a blend of North Sea crudes and London is the most important trading centre. In addition, there used to be active forward paper markets for refined products such as naphtha, gasoil and fuel oil — but all the liquidity has now moved into swaps (see Chapter 10). Although the London International Petroleum Exchange (IPE) has tried to establish futures contracts for most of these grades, only the IPE Brent and gasoil contracts have actually succeeded and over-the-counter (OTC) forward and swaps markets remain an effective alternative to formal futures markets. There were never any forward paper contracts based on Mediterranean delivery, but there are now a number of active swaps markets for both crude and products.

Table 7.2 Liquidity in European forward paper markets, 1997

Market	Contract size	Daily deals	Estimated turnover	Physical base
15-day Brent	500,000 bls	25-30	13mn b/d	0.7mn b/d
Futures markets				
IPE Brent	1,000 bls	40,719	40.7mn b/d	
IPE gasoil	100 t	15,935	15.9mn b/d	

7.3.1 15-day Brent

Contract

The 15-day Brent market trades paper cargoes of Brent Blend crude oil for delivery fob Sullom Voe during any future calendar month. The current Brent cargo size is 500,000 bls, which is subject to an operational tolerance of ± 5 per cent. Smaller quantities can be traded on the Brent "partials" market, a paper market operated by the larger market makers dealing in part-cargo quantities that can be converted into full cargoes if required. The forward contract is based on Shell's General Terms and Conditions (see Chapter 16). There are no alternative delivery options. Prices are negotiated in US dollars per barrel.

Brent Blend is a light low sulphur crude oil very similar in quality to West Texas Intermediate. Since July 1990 it has been formed from a combination of the output from both the Brent and Ninian systems, which together produced an average of 670,000 b/d in 1997. It is the largest of the North Sea export streams, which, together with its diverse ownership structure makes it a suitable basis for a forward paper market. More than 30 companies have an equity share in the production of Brent Blend, of which the three largest are Exxon, Shell and BP who together own just over two-thirds of the total output. On average, there are between 40 and 50 cargoes of Brent available each month which could be nominated against paper contracts.

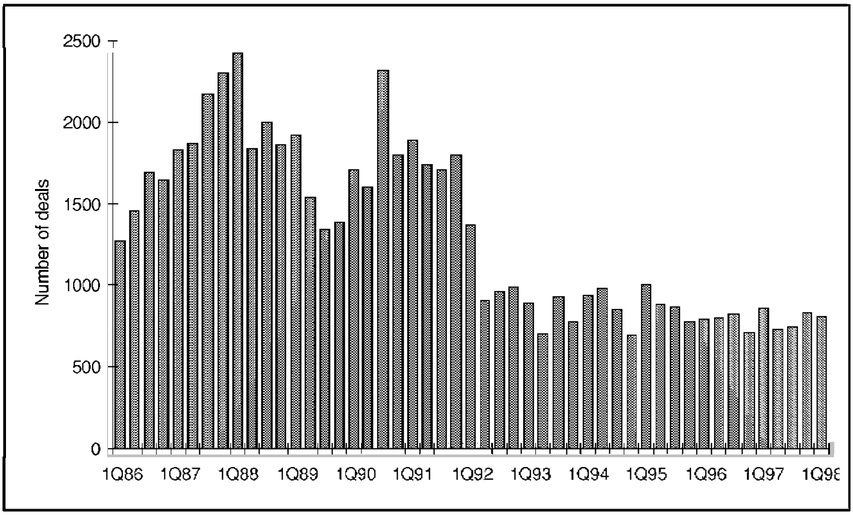
Terminology

The market is known as the "15-day" Brent market because the contract specifies that each seller must give his buyer at least 15 days' notice of the first day of the three day loading date range for the physical cargo that is to be nominated against the paper contract. Cargoes loading with less than 15 days' notice cannot be nominated against a paper contract and are traded as spot or "dated" cargoes.

The loading programme for Brent Blend is published on the 15th of the month preceding delivery, which means that cargoes can be nominated against paper contracts during the last half of the month preceding the delivery month and the first half of the delivery month. Since the loading date range specified in the nomination against a forward paper contract for a particular delivery month must not spill over into the following month, 15-day Brent trading for the next forward month effectively ceases between the 10th and the 12th of the month preceding delivery and the market "rolls over" to the next nearby month at this date.

Liquidity

The 15-day Brent market is the most liquid of the forward paper markets. In 1997 Petroleum Argus reported nearly 3200 deals, an average of just under 13 per day, but industry sources estimate the true size of the market to be at least two times this volume, suggesting a total turnover of around 13 million b/d, or about an eighth of the volume of the Nymex Light Sweet Crude contract. Liquidity is typically concentrated in the second nearby delivery month, which is roughly equivalent to the first nearby Nymex light sweet crude futures contract month. Paper contracts are traded up to one year ahead and there is sufficient liquidity for regular



Source: Petroleum Argus

Figure 7.2 Reported trading volumes in 15-day Brent market

assessments to be published for delivery periods four to five months ahead.

Brent trading volumes peaked in early 1988, when Argus reported an average of over 30 deals per day, before falling in the late 1980s to an average of just under 20 per day as uncertainty over the legal status of the market increased as a result of the Transnor case (see Fig. 7.2). Volumes subsequently recovered close to their earlier levels, partly as a result of the US CFTC ruling in September 1990, which confirmed that the 15-day Brent market was an international forward market and not subject to US government regulation, and partly as a result of the price volatility that followed the Iraqi invasion of Kuwait. Reported trading volumes then remained fairly constant at an average of nearly 25 per day until the middle of 1992 when they fell to about 15 per day. Over the past few years reported trading volumes have averaged around 13 deals a day. The sharp reduction in 15-day Brent volumes from 1992 onwards is partly because of the growing popularity of the IPE Brent futures contracts and partly because of the introduction of the Brent Contract for Differences (CFD), which have enabled companies to hedge cargoes priced against dated Brent without using the forward 15-day Brent market (see below).

The 15-day Brent market is not just a European market. Brent is used as a price marker for the majority of internationally traded crudes and Brent forward paper contracts are traded around the globe 24 hours a day. When the London market closes trading moves to Houston and when that closes to Tokyo and Singapore. Paper Brent is widely traded not only because it provides a valuable trading instrument outside Nymex and IPE trading hours, but also because it provides a better hedge for companies operating outside the US. In the Far East "partial" Brent contracts are also popular as these offer companies the opportunity of trading smaller volumes of oil. Once the IPE opens partial Brent contracts are usually converted into futures positions via the EFP delivery mechanism.

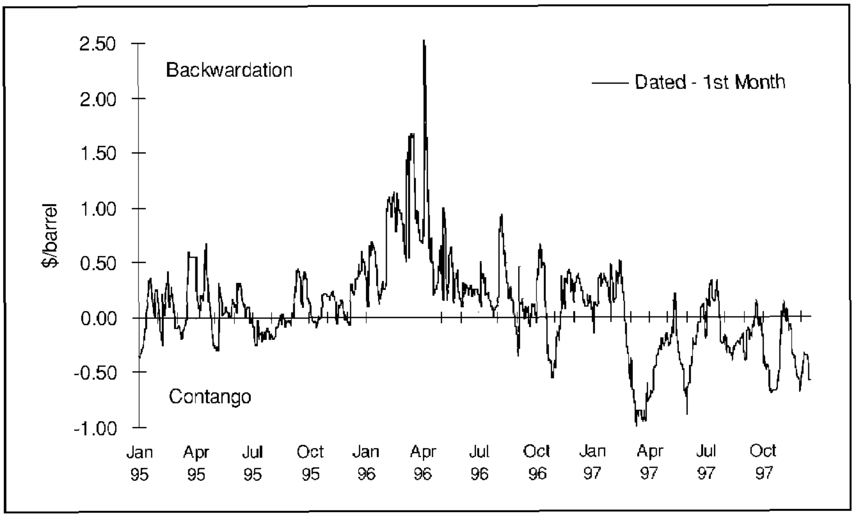
Tax spinning

It is important to realise that one of the reasons for the continued success of the 15-day Brent market is the tax regime operating on the UK Continental Shelf (UKCS). Petroleum Revenue Tax (PRT) is levied on companies producing oil on the basis of the "market price". In the case of bona-fide third party transactions, the tax reference price is the price of the deal. But in the case of internal transfers between (say) the production and refining subsidiaries of the same integrated company, the tax reference price for a given month is estimated as an average by the UK Office of Oil Taxation (OTO) using information supplied by companies over a 45 day trading period (see Chapter 15).

In a falling market, differences between the two methods of valuing a cargo for tax purposes give integrated companies an incentive to sell to third parties since the average price assessed by the OTO lags behind the market. This is known as "tax spinning", and UK government concerns about the potential scale of "lost" tax revenues have resulted in progressively tighter rules being introduced to limit the scope for spinning. Since January 1 1993, companies only have 24 hours in which to decide whether to nominate a cargo against a 15-day Brent trade for tax purposes. Of course the reverse applies if prices are rising, and it is likely that more dated cargoes will be available to wet chains in a falling market than in a rising market, which can affect the delivery risks for other companies.

Contracts for differences (CFDs)

Brent is also important because of the prominent role it plays in the pricing of internationally traded crude oil. The vast majority of Atlantic Basin crudes are currently priced using formulas that are explicitly linked to Brent, and many Arab Gulf crudes are implicitly linked to Brent as a result of close arbitrage between the 15-day Brent market and the paper Dubai market (see 7.5.1). Although



Source: Petroleum Argus

Figure 7.3 Basis risk between dated and 15-day Brent

most pricing formulas are usually based on dated Brent rather than 15-day Brent, the need to hedge the value of cargoes while they are on the water means that many companies use the forward Brent market to hedge a wide variety of crudes in both the Atlantic Basin and the Arab Gulf markets.

However, the scale of the residual basis risk between the nearby 15-day Brent contract and dated Brent has led to the development of an active intermediate market in "contracts for differences" or CFDs to provide companies with a more accurate hedging instrument (see Fig. 7.3). CFDs are a purely financial instrument – a price swap rather than a true forward contract – but they are widely used as an extension of the 15-day Brent market. In the case of Brent, CFDs are now sufficiently liquid to generate regular published price assessments for over the four to six week period between the time horizon for prompt, wet dated Brent (loading 2-10 days ahead) and the time horizon for the first nearby 15-day forward paper Brent.

CFDs are normally traded in relation to weekly delivery periods (Monday-Friday) and are settled on the basis of the average of published price assessments for the week in question. In the case of Brent, up to six forward weekly periods may be traded at any moment and prices are quoted at a differential to the nearby 15-day Brent forward market contract. For example, during late April 1994 May Brent was already partly "wet" so CFDs were being quoted at a differential to June 15-day Brent, e.g. May 2-6 = June

+0.13/0.15, May 9-13 = June +0.09/0.13, and May 16-20 = June +0.05/0.08.

CFDs allow companies buying and selling crude at prices related to dated Brent to control their exposure to the rapidly fluctuating differential between the dated and 15-day paper markets. For example, a refiner who buys another North Sea crude such as Forties loading in two weeks' time at a price of dated Brent + 0.15 can fix the cost of the cargo using a combination of CFDs and 15-day Brent.

Assuming the deal was done in late April and the cargo is scheduled for loading at Hound Point in the date range 17-19 May, the refiner could fix the purchase price by buying a June 15-day Brent paper contract at the current market level of $15.75/bl and locking in the differential between dated and June Brent by buying a CFD for the week of May 16-20 at June + 0.06. As a result, the refiner is securely hedged not only against fluctuations in the absolute price of crude but also fluctuations in the differential between dated and 15-day Brent which could otherwise undermine the benefits of hedging.

Example: Hedging using CFDs

On 29 April, the refiner:

buys Forties at	dated Brent + 0.15
buys June Brent at	$15.75
buys May 16-20 CFD at	June + 0.06

yielding an implied net price of: $15.96

The actual purchase price is established during the week when the cargo is lifted at which point the refiner closes out his 15-day Brent position, settles his CFD contract with the swaps provider and calculates the outcome of the Forties pricing formula.

Assuming the Forties formula is based on the average of dated Brent quotations over a period of 5 days around the bill of lading (18 May), and the refiner sells his June 15-day Brent contract at $15.90/bl, the net price paid for the cargo of Forties is calculated as follows:

average price for dated Brent (16-20 May):	$16.00
plus formula differential agreed for Forties	+ $0.15
minus profit on purchase and sale of June Brent	– $0.15
minus net payment from swaps provider for CFD	– $0.04
equals net price paid by refiner	$15.96

The advantages of using CFDs to improve the effectiveness of hedging are obvious from the example above. If the refiner had not used a CFD to fix the differential between the paper and dated markets he would have paid an extra 4 cents a barrel since the actual average differential between dated and June Brent in the week of 16-20 May turned out to be June + 0.10, 4 cents higher than the June + 0.06 quoted by the CFD market at the end of April. Of course, the differential might have narrowed instead of widening, in which case the refiner would have paid a higher price by hedging with CFDs. However, the purpose of hedging is to create certainty instead of uncertainty and what matters to the refiner is to be able to fix his purchase price whatever happens to the spread between dated and 15-day Brent. And this would not be possible without CFDs given the inherent volatility of the dated to paper spread.

The introduction of CFDs has changed the structure of the Brent market as they have created an important parallel trading activity at the most volatile end of the forward market attracting the interest of the larger oil traders and Wall Street banks as well as the major oil companies. CFDs were first introduced by Shell and BP in the late 1980s and the CFD contract is still based on Shell terms. According to *Petroleum Argus*, industry sources estimate that more than 30 Brent CFDs are traded per day, the equivalent of at least 15 million b/d of crude. This compares with 25 to 30 transactions on the 15-day Brent market (13 million b/d) and over 40 thousand lots on the IPE Brent futures market (41 million b/d). The success of Brent CFDs has also encouraged the IPE to propose the introduction of a dated Brent futures contract which would mimic the essential characteristics of the CFD market in an attempt to capture some of the liquidity and trading interest currently enjoyed by CFDs, but this has not met with much support from the industry (see Chapter 8).

Participants

The main participants in the 15-day Brent market are oil companies producing North Sea crude, European and US refiners who lift North Sea crude, and the Wall Street investment banks and large international trading companies who act as market makers and provide essential liquidity.

Over the last few years, the balance of trading activity between the main groups of participants has ebbed and flowed. Between 1990 and 1993, the Wall Street banks and the international trading companies reduced their level of activity in the 15-

day Brent market, focusing instead on the rapidly expanding new markets in swaps and options (including CFDs). According to data collected by *Petroleum Argus*, these two groups of participants represented only 37 per cent of the deals reported in 1993 compared with 49 per cent in 1991. As a result, the importance of integrated and major oil companies grew again, rising to 50 per cent in 1993 compared with only 40 per cent in 1991. However, the Wall Street banks and international trading companies expanded their presence again in the 15-day market during 1994 and 1995, partly because of the entry of new and important player, the US investment bank, J.P. Morgan, and partly because the trading companies need to hold large positions in the 15-day Brent market to balance their activities in Brent CFDs and swaps (see Table 7.3).

Table 7.3 Participants in the 15-day Brent market

Participant	1991	1992	1993	1994	1995	1996	1997
Major	17%	23%	27%	26%	25%	25%	30%
Integrated	23%	19%	23%	21%	15%	17%	14%
Trader	27%	24%	17%	20%	22%	23%	18%
Wall Street	22%	23%	20%	17%	25%	25%	22%
Other	11%	11%	13%	16%	13%	10%	16%

Source: Petroleum Argus

The 15-day Brent market remains highly concentrated. In 1997, more than three-quarters of the deals reported by *Petroleum Argus* involved one of only ten companies. According to Argus, the most active companies were: BP, J.P. Morgan, J.Aron, Phibro, Shell, Statoil, Koch, Arcadia, Morgan Stanley and Vitol.

7.3.2 Naphtha

The forward paper market for naphtha in north-west Europe continued to trade until 1996, when liquidity finally dried up as the market moved over entirely to swaps. Like naphtha swaps, the forward contract was based on imported cargoes from the Middle East, north Africa, Eastern Europe and the former Soviet Union (see Appendix 7.4). However, with such a wide range of sources it was difficult to devise a standard paper contract that is not only broad enough to satisfy the needs of the major participants but also narrow enough to avoid exploitation by unscrupulous traders. Despite calls for a better hedging instrument, the IPE failed in its attempt to launch a naphtha futures contract. Instead the industry turned to swaps — which now provide the main hedging instrument (see Chapter 10).

7.3.3 Gasoil

Gasoil is the largest product market in north-west Europe as it is used for both heating and automotive (diesel) purposes. The IPE has a very successful gasoil futures contract based on the Rotterdam barge market, but there were also two forward paper contracts that operated in parallel based on the cif NW European cargo markets for Russian gasoil and French heating oil or fuel oil domestique (FOD), each of which has slightly different quality specifications (see Appendix 7.1 and 7.5).

The forward Russian gasoil market (sometimes known as "Russian Roulette") was the first forward product paper market to be introduced into north-west Europe and was the main hedging instrument used by product traders until the IPE launched its second (and more successful) gasoil contract in 1984. After then, the volume of trading on the Russian gasoil market declined and the IPE became the most active contract from about 1988 onwards. Trading dried up altogether in 1995 because the quality, quantity and timing of Russian gasoil exports became too uncertain and companies now use swaps instead (see Chapter 10). In the past, differences in quality between the three hedging instruments and the closer links between the forward markets and the physical gasoil market ensured that the paper markets could provide a useful function, but companies now find that swaps and EFPs are a more effective means of handling basis risk.

Table 7.4 European gasoil quality specifications, 1998

Characteristic	German barges	IPE contract	Russian	French heating
Specific gravity	0.845	0.820-0.860	0.836	up to 0.880
Sulphur (%wt)	0.2 max	0.2 max	0.2 max	0.2 max
Cetane index	45 min	45 min		40 min
Pour point (°C)	–9	n.a.	–15	–9
Cloud point (°C)	+3(+1)*	+5(+1)*	–12	+2
CFPP (°C)	–7(–11)*	–4(–11)*	–12	–4

* *summer(winter)*

The more transparent IPE gasoil market became the price reference first for the forward markets and now the swaps market. Prices are quoted and deals done at a differential to the IPE. In addition, traders can use the EFP mechanism to take advantage of the credit protection offered by the exchange and its clearing house. Although the forward FOD market lasted longer than the forward

Russian market, trading dried up towards the end of 1996 and all the liquidity has now moved into swaps.

7.3.4 Fuel oil

The heavy fuel oil market in Europe is highly fragmented since the quality specifications differ considerably from market to market. In Scandinavia and Germany only low sulphur fuel oil can be burnt in power stations. However, attempts to create a forward paper market for low sulphur fuel oil delivered into Sweden during the mid-1980s did not succeed and there is now a low sulphur fuel oil swaps market instead. In addition, there is an active high sulphur fuel oil swaps market based on the Rotterdam barge market.

There used to be an active forward paper contract for CIF cargoes of high sulphur fuel oil delivered into the Littlebrook power station in the UK, but this has ceased trading (see Appendix 7.2). The UK utilities market represented the lower end of the quality scale which is also closest to the bunker market. Companies trading Littlebrook grade fuel oil therefore used it to hedge bunker grade fuel oil in other markets, for example tenders into the Middle East, but this is now done with swaps (see Chapter 10).

7.3.5 Propane

The development of a flourishing spot market in north-west Europe for liquefied petroleum gases (LPGs), butane and propane, based mainly on North Sea production initially encouraged the development of forward markets for hedging cargo-sized quantities. The most active of these was the forward "flexi"-propane contract but this is no longer active (see Appendix 7.3). The growing volatility of the price spread between butane and propane has also prompted (unsuccessful) attempts to start an equivalent forward butane market. As with other forward paper markets, companies now find that price swaps can provide most of their hedging needs (see Chapter 10).

7.4 United States

Although the United States is generally regarded as the home of oil futures following the success of the Nymex crude oil, gasoline and heating oil contracts, it is important to realise that there are still a number of active forward markets for both crude oil and refined products that operate in parallel with the futures markets. The existence of a large network of open-access pipelines which is used to move oil from the producer to the refiner, and the refiner to the consumer, has created the basis for a number of forward markets, such as the "cash" WTI and the Colonial Pipeline product markets. In addition, the product import requirements of the markets in Boston and New York Harbors have led to the development of forward markets based on waterborne delivery. But trading volumes declined following the introduction of the Nymex "Access" system which enables market participants to trade futures contracts almost continuously around the clock (see Chapter 8). And activity in both the spot and forward markets has been further depressed by new environmental rules which have left the US oil products markets increasingly fragmented.

7.4.1 Crude oil

The linch-pin of the US crude oil market is West Texas Intermediate (WTI) which is traded in a variety of forms, including forward "cash WTI" contracts for delivery in 1,000 barrel lots at Cushing, Oklahoma. It also forms the basis for the Nymex light sweet crude contract since it is one of the delivery options and represents the most active spot market for crude oil in the United States (see Chapter 4).

WTI is a blend of crude oils collected by pipeline from oil fields in New Mexico and West Texas. Current production amounts to around 0.5 million b/d. Unlike the international cargo markets which allow companies to trade oil for delivery at very short notice, US pipeline operators expect traders to nominate their delivery programmes before the end of the month preceding delivery. As a result, the "spot" or "nearby" delivery month in the US crude market is usually equivalent to the first forward month in the Brent market. All US crude contracts therefore start trading further ahead than the prompt market in Europe and the closing date for pipeline nominations determines both the delivery date for the Nymex light sweet crude contract and the roll-over date for the US crude oil market. Pipeline nominations must be made by the

25th of the month preceding delivery (or the first business day before the 25th if this is not a business day) to allow time for scheduling, and the Nymex light sweet crude contract ceases trading three business days earlier in order to allow companies to make or take delivery of physical crude oil in the following month. Cash markets therefore continue to trade each delivery month for up to three days after the expiry of the Nymex light sweet crude contract.

Cash WTI is both a spot and a forward market. Contracts for the nearby (first forward) month are effectively spot contracts since it is not possible to trade closer to the delivery date. But contracts for delivery months further ahead are forward paper contracts that can be used to achieve a variety of trading objectives, although liquidity is now confined to only the first three forward delivery months and longer term deals are usually executed directly on the Nymex futures market or as a swap (see Chapter 10). Like 15-day Brent, cash WTI can be traded when the futures exchanges are closed and provides a useful vehicle for responding to events, such as the Gulf War, that may disturb the markets when the Nymex is closed. Also, like 15-day Brent, it allows companies to trade much larger volumes in a single transaction than can be achieved on the futures market and the average cash WTI deal is the equivalent of 50-75 futures contracts.

Because of the size and importance of the Nymex Light Sweet Crude contract, cash WTI deals are usually negotiated and agreed at a differential to the futures price (see Chapter 4). During exchange trading hours companies deal on the basis of the current bid and ask levels quoted by the futures market, but outside normal trading hours the market either uses the latest settlement price or trades at a differential to prices quoted by the Nymex Access 24 hour trading system. Although cash WTI is an unregulated forward market, companies can also use the Nymex EFP procedures to obtain the protection offered by the futures exchange.

In addition to the forward market for cash WTI at Cushing, forward contracts are also traded for rateable quantities (i.e. b/d rather than barrels) of WTI at Midland, Texas which is the point at which WTI can be either pumped north to Cushing and the mid-continent refiners, or south to the Gulf coast. However, the trading horizon for WTI Midland contracts is even shorter than for cash WTI at Cushing and liquidity is now concentrated in the first forward month. The WTI Midland market typically trades in contract multiples of 2,500 b/d per month. A number of other spot pipeline crude markets also have a limited forward dimension. The most liquid of these are West Texas Sour (WTS) and Light

Louisiana Sweet (LLS), which also trade in multiples of 2,500 b/d per month.

In addition to the forward pipeline markets for Lower 48 crudes, there also used to be a forward cargo market for Alaskan North Slope (ANS) crude delivered to the US Gulf coast. But, although this was an active and liquid market in the mid-1980s when large volumes of ANS moved to the Gulf coast, the forward market has completely dried up as most of the ANS is either refined by west coast refiners or can now be exported to other Far East refiners. The Gulf coast ANS market no longer provides a reliable price marker and producers such as Saudi Arabia, Mexico and Ecuador have been obliged to remove ANS quotations from their term pricing formulas for crudes delivered into the US market.

7.4.2 Refined products

The US also retains a few forward product markets that operate in parallel with the much more liquid futures markets on the Nymex. As with crude, the forward product markets allow companies to hedge or speculate against the price differential (or basis) between the highly standardised quality and delivery terms of the futures contract and the slightly different terms associated with physical delivery in the most active spot markets. But, although the delivery terms are different, the pricing mechanism remains the same and all forward clean product contracts are negotiated and priced at a differential to the relevant futures contract and often subsequently converted into futures positions using the Nymex EFP delivery procedures.

The two most active forward products markets in the US are the Colonial Pipeline market and the "Boston Bingo" cargo market. Smaller scale forward paper markets for utility grade 1 per cent sulphur fuel oil imported into the US Atlantic coast and 3 per cent sulphur fuel oil on the US Gulf Coast have now been replaced with swaps (see Chapter 10).

Colonial Pipeline

The Colonial Pipeline delivers white products from the US Gulf coast to the North-eastern states and the forward market allows companies to trade the basis between the Gulf coast market and the New York Harbor market which underpins the Nymex products contracts. The Colonial Pipeline market is based on the forward delivery periods (or cycles) and the standard delivery grades specified by the pipeline company. Each delivery cycle covers a period of 10 days, making three cycles per month, although it is also possible to trade shorter half-cycle periods.

The minimum batch size is 25,000 barrels. The forward market trades conventional southern (M) grade gasoline and No. 2 heating oil (76 grade). Activity is centred on the last cycle of the month — which is effectively an "any month" contract because delivery is at the seller's option. But trade beyond the current month has become rare and much of the hedging has been transferred to customised swaps.

The Colonial gasoline market is still the most active gasoline market in the US, trading an estimated 150,000 b/d in 25,000 barrel lots. Attempts by the Nymex to capture some of the basis trading activity currently enjoyed by the forward product market by launching a competing Gulf coast gasoline contract failed because the industry still needs a trading instrument that is closely linked to the cash market with three delivery cycles per month rather than the monthly settlement offered by the Nymex contract. However, changes to US gasoline quality specifications on a state by state basis as a result of the US Clean Air Act — especially since the introduction of reformulated gasoline in January 1995 (see Chapter 2) — have fragmented the gasoline market and reduced the effectiveness of both the forward and futures markets as hedging instruments. It has also narrowed the focus of most traders onto the very prompt cash markets.

The Colonial jet and heating oil markets are more seasonal than the gasoline market and mainly flourish during the winter months from October to April. During peak periods the market trades an estimated 150,000 b/d of heating oil and the 75,000 b/d of jet kerosine in 25,000 barrel lots. The market is now dominated by local refiners since the Wall Street banks — who used to play the role of market maker — abandoned it in recent years.

Boston Bingo

The US Atlantic coast from New York to Boston is the main destination of imported cargoes of refined products from Europe and South America. The Boston Harbor market enables companies to trade the basis between imported cargoes of gasoline and heating oil and the relevant Nymex futures contracts. It acts primarily as a hedge on the difference in volume between the Nymex barge contract and the much larger imported cargoes. The "Boston Bingo" markets tend to be highly seasonal, a forward market for imported gasoline cargoes operates in the spring, while a forward market for heating oil operates in the autumn. Both markets trade paper cargoes for delivery into Boston (or other north-east ports) during half-month delivery periods. Quality specifications are based on Colonial Pipeline grades for gasoline and heating oil.

The Boston Bingo markets are used primarily by importers seeking to hedge large physical quantities of gasoline or heating oil. On average the markets trade about ten 225,000 barrel cargoes per month for each product type, although the seasonal peak can be higher. Most of the trading activity is for small part cargoes up to 15 days out. Volumes used to be much higher in the 1980s when large traders such as Clarendon, Vitol and Stinnes played an active role in the import market and used the Boston Bingo forward contract to hedge the value of their cargoes and to speculate on the level of backwardation or contango. However, exporters such as Venezuela are now selling directly to companies with retail outlets which do not routinely use the forward cargo market for hedging. In addition, the fragmentation of the gasoline market because of environmental regulations has reduced the volume traded and narrowed the focus to the next two half-month periods. Many US distributors now buy gasoline in Europe on an fob basis and do not trade the cargoes. As a result, the speculative activity which boosted forward trading volumes in the early 1990's has disappeared, leaving the Nymex futures contract as the primary vehicle for hedging gasoline imports.

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7.5 Arab Gulf and Far East

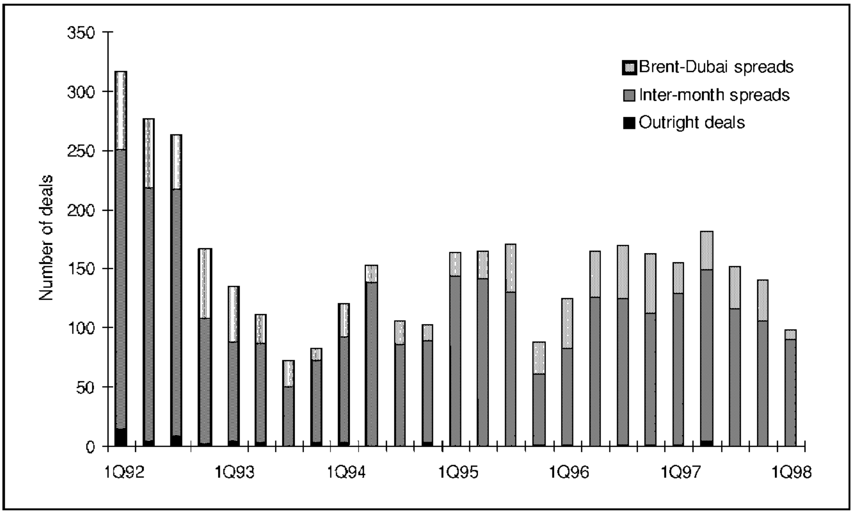
Oil derivatives, including forward and futures markets, are still relatively underdeveloped in the Arab Gulf and Far East. The reasons for this are not entirely clear, but it is due partly to the reluctance of many potential participants to get involved in what they perceive as a purely speculative trading activity, partly to the continued importance of term contracts, and partly to the generally lower level of price volatility in these markets. As a result, it has proved difficult to establish liquid markets for oil derivatives contracts and those that have taken root have much lower levels of liquidity than their counterparts in Europe or the US.

In the case of crude oil, the most active forward market remains the Dubai paper market, although this is now much less active than it used to be because of falling production levels for Dubai crude, and it now trades mainly as an extension of the 15-day Brent market and is gradually being replaced with swaps. In the case of products, the forward naphtha market was temporarily undermined by the reduction in exports from the Arab Gulf following the Iraqi invasion of Kuwait and the abolition of controls on the level of refinery throughputs in Japan. But changes to contract specifications to allow alternative sources of imports and the reconstruction of Kuwait's refineries have restored liquidity to the open-specification naphtha market which is based on imports into Japan. Although some liquidity has moved from the forward paper market to swaps, some traders in the Far East still prefer to use a market that has a clear physical basis. However, swaps are gaining in popularity in the region, especially for other products, and have contributed to the difficulties facing the Simex fuel oil futures contract (see Chapter 8).

7.5.1 Dubai crude

The Dubai market is the only true forward crude market operating in the Far East. Other forward paper markets such as the "paper" Tapis market are based on swaps rather than physical delivery (see Chapter 10). Together with Oman, Dubai is widely used as the pricing basis for most term contracts involving Arab Gulf crudes moving east. But liquidity on the forward Dubai market is falling as companies switch to swaps, which provide a more flexible hedging mechanism (see Fig. 7.4).

In the past, forward Dubai trading volumes rivalled those of Brent, but, since the Gulf crisis, liquidity has greatly diminished



Source: Petroleum Argus

Figure 7.4 Reported trading volumes in Dubai forward market

and the majority of paper Dubai deals are now either spread trades against the 15-day Brent market or inter-month spreads in the Dubai market itself. Outright trading in forward Dubai has virtually dried up because of problems with cargo nomination procedures and the impact of monthly tenders by the Indian Oil Company which often takes most of the available cargoes. However, liquidity recovered to some extent following the introduction of tighter nomination procedures in Conoco's new General Terms & Conditions from May 1994. Since 1995, trading levels in the Dubai market have averaged 2–3 deals per day compared with only 1–2 in 1993. But the volume of swap trading rose sharply in 1997 as Chinese traders entered the market to hedge their growing imports. Swaps are more flexible than the forward Dubai contract as they can be tailored to individual needs and do not involve difficult cargo nominations.

Contract

The forward market for Dubai trades 500,000 barrel cargoes of Dubai Fateh crude delivered fob the Fateh terminal in the Arab Gulf. The contract is based on Conoco's standard terms and conditions which were revised in 1994 after extensive consultation with market participants to overcome problems with the nomination procedure (*see below*). Prices are negotiated in US dollars per barrel, usually as a spread against 15-day Brent or between forward delivery months in the Dubai market. There is also an active paper market in "partial" Dubai contracts for companies that want to trade smaller quantities, and a growing Dubai swaps market mainly used by companies involved in processing deals (see Chapter 10).

Dubai is a medium gravity sour crude very similar to Saudi Arabian Light. Although production is relatively low for an Arab Gulf crude (only 0.3 million b/d), the fact that there are a large number of equity producers involved makes it a suitable choice for the physical basis of a forward paper market. The field operator is Conoco (30 per cent), but Total and Repsol also have major share holdings of 30 per cent and 25 per cent respectively. Other equity producers include Texaco/Rheinoel (10 per cent), and Wintershall (5 per cent). Former shareholder Sun sold its 5 per cent share to Total in 1993. However, falling production threatens to undermine the market over the next few years (see Chapter 4).

Organisation

The organisation and operation of the Dubai market is very similar to the 15-day Brent market, although the volumes are much smaller. Companies trading in the Dubai market buy and sell paper contracts for delivery up to six months ahead and the market turns over many times the underlying physical volume of Dubai before cargoes become available for loading. Like Brent, most of the paper deals are "booked out" before the delivery month approaches, leaving only those companies that want to take physical delivery holding open positions.

However, the nomination procedure for Dubai is different from Brent since it is the buyer rather than the seller who nominates the lifting dates (subject to the agreement of the loading terminal). In the Dubai market, companies wishing to take delivery of a physical cargo nominate their preferred lifting dates to the terminal operators either directly or down a daisy chain before the lifting schedule is announced. According to the contract, nominations cannot be "unreasonably rejected", but delays in passing on dates and the declining number of physical Dubai cargoes meant that companies were not only unable to obtain their preferred dates but also did not receive their revised dates until very late in the day. In June 1993 a chain collapsed when a company refused to lift a cargo saying that it had not received the loading dates until after the nomination deadline, the 18th of the preceding month. As a result, the terminal operator, Conoco, has revised its General Terms and Conditions to prevent traders abusing the system.

From May 1994, buyers must submit requests for loading dates *seven* London business days before the 18th of the month preceding loading (the deadline for equity holders is *five* days). The loading programme will then be released to equity holders *three* days before the 18th and all dates must be passed to buyers before 6pm London time on the 18th. In order to prevent delays, companies involved in chains must pass dates on *within one hour* of receiving them and the contract allows buyers to take legal action for damages against a seller for late transmission of dates.

In 1995, confusion over three paper chains from the September programme resulted in a "dry chain" in which no physical oil was delivered. Although this did cause problems for those concerned, Conoco has not yet proposed any further changes to its GT&Cs since traders failed to come up with any detailed suggestions to prevent this from happening again in the future.

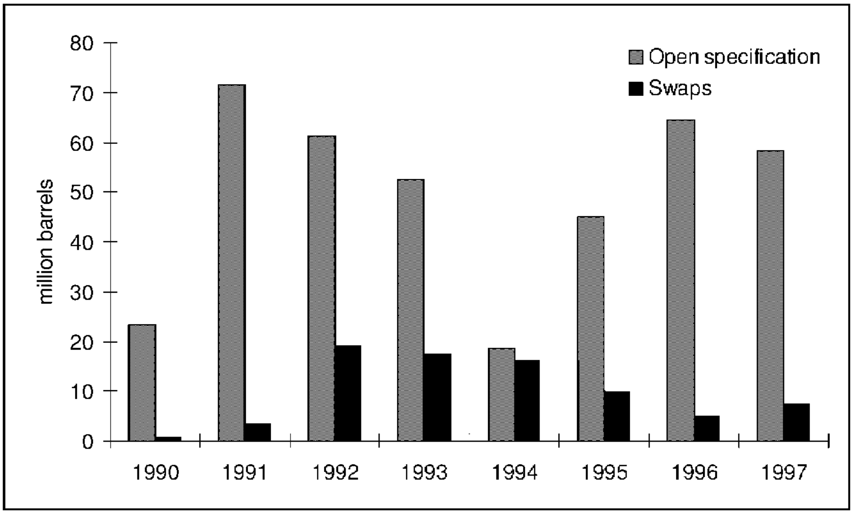
Participants

The number and type of participants in the Dubai market has changed radically over the years. The market was originally dominated by the Japanese trading houses (*sogo shosha*) who were looking for a more appropriate hedging mechanism for Arab Gulf crudes than 15-day Brent. Other participants included the major oil companies and Dubai equity producers. However, many of the *shosha* left the market at the end of 1987 following heavy losses and their place was taken by the Wall Street companies who now play the role of market maker in so many markets.

In the 1990s, the main participants are now the large trading companies since many producers and end-users have ceased to play an active role in the paper Dubai market. According to *Petroleum Argus*, the most active companies in 1997 were Phibro, BP, Shell, Statoil, Total, Arcadia, Indian Oil Corporation (IOC), Vitol, Mitsui, and Koch. Many of these also use the market to supply oil to IOC which issues regular tenders, although IOC has recently avoided buying Dubai in some months.

7.5.2 Naphtha

The Japanese open-spec naphtha market has recovered much of its liquidity and is now restored to its former position as the primary forward product market in the Far East (see Fig. 7.5). The loss of key sources of supply in the Arab Gulf following the Iraqi invasion of Kuwait left companies wary of trading in a market that depended on physical delivery of naphtha from only a small number of allowable sources. As a result the volume of swaps



Source: Petroleum Argus

Figure 7.5 Trading volumes in the Asia Pacific naphtha market

trading increased rapidly in the early 1990s, largely at the expense of the open-spec naphtha market. But the reconstruction of Kuwait's refineries, the expansion of the petro-chemical industry in the Far East, and the decision to relax strict controls on ports of origin from October 1996 revitalised the market. Open-spec naphtha trading volumes recovered sharply from 1995 onwards, averaging 6–8 deals per week in 1996 and 1997 compared with only 1–2 deals per week in 1994. However, activity slumped in early 1998 as the Asian financial crisis deepened.

Contract

The Far East open-spec naphtha market trades paper cargoes of naphtha for forward delivery C&F Japan during an agreed half-month delivery period. The standard cargo size is 25,000 tonnes, subject to an operational tolerance of ± 10 per cent. Prices are negotiated in US dollars per tonne. The market now accepts cargoes from any port of origin, subject to certain minimum quality specifications.

Constraints on both the origin of the naphtha and its destination have been a subject of controversy amongst market participants over the past few years, adding to the problems facing the contract. Following pressure from South Korean traders, the 1996 annual naphtha forum finally agreed to allow cargoes from anywhere in the world to be offered for delivery into Japan against the forward open-spec naphtha contract from October 1996. But moves to expand the delivery terms to include Korea and Taiwan are still being resisted. The contract was also changed in 1991 to bring it more in line with the European open-spec naphtha market.

7.6 Future developments

Forward paper contracts continue to be an important sector of the oil market. Neither futures or swaps have been able to replace them entirely, although both are often more convenient to use. The close link between the underlying physical market and forward paper contracts makes them ideally suited to companies that are in the business of supplying physical oil and the need for an effective short-term hedging instrument has inevitably attracted the interest of the bigger traders and banks who are willing to take on the price risk associated with the near-term oil market.

15-day Brent remains a special case since it has become the linch-pin of the international crude market. Although the Nymex light sweet crude contract is the most actively traded, it will never replace Brent because WTI is ultimately a domestic pipeline crude that cannot be exported. Brent and WTI prices often diverge and companies trading on the international crude market need an alternative instrument. Nor can the IPE Brent futures contract provide an adequate substitute since it is based on a price index rather than physical delivery and expires too far ahead. With so much price volatility in the short-term, companies need a market that responds to the underlying fundamentals, and the current combination of 15-day Brent and CFDs fulfils this function highly effectively for most participants.

Finally, the continued threat of tougher regulation for derivatives such as swaps and OTC options is likely to ensure that the oil market retains its current diverse set of trading instruments. Because forward markets ultimately involve physical delivery, they have usually been excluded from regulation designed to combat speculation and protect individual investors. If plans to control derivatives trading are implemented, forward markets could become more popular again.

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Appendix 7.1 Russian gasoil

The forward Russian gasoil market is currently inactive, but the contract specifications are retained here for reference together with a brief history of the market.

Contract

The Russian gasoil market trades paper cargoes of gasoil for delivery cif ARA during the first half (1-15) of the month. The contract specifications were drawn up by brokers. The cargo size can vary from 18-22,000 tonnes and the specification is based on an agreed range of quality characteristics for gasoil exports from the former Soviet Union (see Table 7.4). Prices are negotiated in US dollars per tonne, usually at a differential to the IPE gasoil futures market.

History

Although Russian gasoil is valued for its excellent quality characteristics, in particular its good cold properties, the quality has become much more variable as a result of the organisational chaos affecting most of the oil industry in the former Soviet Union and disputes over the ownership and operation of refinery, pipeline and terminal facilities in Latvia. As a result, not all cargoes exported can be sure of meeting the quality specifications required by the forward paper market; traders have also had difficulty obtaining cargoes large enough to deliver into the forward contract. In particular there have been frequent problems with bacterial contamination, especially in the summer when higher temperatures encourage the growth of bacteria in old and poorly managed storage facilities.

Russian gasoil is expected to be a good quality gasoil with a low specific gravity, sulphur content and cloud point and a high cetane index. Its properties ensure that it is suitable for both automotive and heating uses. It is also valued as a blending component for winter grades. In the past, Russian gasoil was subject to EEC import duties (3.5 per cent of the cif landed value) and traders tried to take advantages of various loopholes in the legislation to avoid paying import duty. Such loopholes included attempts to classify gasoil as a feedstock (which are duty free) by treating it with caustic soda (known as "stabilisation") or flashing it through a vacuum distillation unit.

In the 1980s, a spectacular failure in the stabilisation process left heating oil purchasers with gasoil that would not burn and resulted in tighter rules for importers and the banning of caustic soda treatment in the Netherlands. Since 1990, however, gasoil imports from the former Soviet Union have been exempt from import duties. Ironically, the widespread bacterial contamination of Russian gasoil in the summer of 1992 could have been more easily contained if the caustic soda treatment had been continued.

In the Russian gasoil market companies selling forward contracts are obliged to give buyers two clear working days' notice of the arrival of a cargo that is to be nominated against the paper contract. Since the contract is a cif delivery contract it is possible for cargoes to be rolled over from one delivery period to the next thus incurring demurrage charges on the vessel carrying the cargo. When the market is in contango this can be an attractive option for traders and rapidly escalating and punitive demurrage charges were introduced for Russian vessels carrying gasoil exports to Europe. As a result, disputes over the responsibility for demurrage charges are a recurrent feature of the Russian gasoil market.

The main players in the Russian gasoil market were the companies who have contracts to import Russian gasoil. Most of the trading was conducted by a small group of companies who included Vulcan, AOT and Galaxy. However, problems with the quality, quantity and timing of Russian gasoil exports since 1994 have effectively killed the market since traders cannot be sure of obtaining material that meets the specifications of the forward paper contract. If Russian gasoil exports become more reliable again, the market could revive — although this may be difficult to achieve given the current widespread use of swaps and futures for hedging.

Appendix 7.2 Littlebrook fuel oil

The forward Littlebrook fuel oil market no longer exists, but the contract specifications are retained here for reference together with a brief history of the market.

Contract

The forward market for heavy fuel oil used to trade cargoes of high sulphur fuel oil for cif delivery in the first half of each calendar month (1-15) to the Littlebrook power station on the Thames estuary in the UK. For this reason it was also known as the "Littlebrook" market or the "Littlebrook Lottery". The contract size was 20,000 tonnes and was based on the quality specifications required by National Power, one of the two UK main utility companies. The contract itself was based on BP terms and conditions. Prices were negotiated in US dollars per tonne at outright levels.

Littlebrook quality specifications are highly flexible and allow traders to deliver 3 per cent high sulphur fuel oil of up to 1.005 specific gravity, a high vanadium content (330ppm) and a high viscosity level (120cst at 80°C). However, the forward paper contract was based on a specific gravity of 0.998 since most other major European utilities have much tighter quality specifications for high sulphur fuel oil, with lower limits for specific gravity, viscosity and vanadium content and the bunker market requires fuel oil with a specific gravity less than water, i.e. under 1.000.

History

Liquidity in the Littlebrook market suffered a major setback in 1989 when the UK authorities started to levy VAT on non-domestic fuel and power. As a result, fuel oil imported into the UK became liable to VAT at the point of discharge, the VAT being the liability of the importer and not the original supplier. Since 95 per cent of the cargoes nominated into Littlebrook chains are of non-UK origin, the changes created a significant price risk for companies not registered for VAT in the UK and trading volumes slumped. The market has now ceased trading altogether. During the early 1990s, trading volumes averaged 4–5 deals per day for delivery periods of up to three months ahead compared with 10–15 in the late 1980s.

The original Littlebrook contract was not designed to cope with the question of VAT and the documentation was often inadequate even for those companies registered for VAT. However, changes to the contract proposed by Shell made it clear that cargoes may be liable for VAT and ensured that cargoes will be supplied with a valid tax invoice. As a result, many companies initially returned to the Littlebrook market but trading eventually dried up as companies transferred their interest to swaps.

The bulk of the activity in the Littlebrook market was conducted by traders such as Phibro, Vitol and Cargill and refiners such as Shell, Texaco and Chevron. The ultimate buyers were, of course, the power utilities who are regular purchasers on the spot market, but most of the paper activity was between traders and refiners for delivery periods about two months ahead.

Appendix 7.3 Flexi-propane

The forward flexi-propane market no longer exists, but the contract specifications are retained here for reference together with a brief history of the market.

Contract

The forward "flexi"-propane market used to trade paper cargoes of propane for delivery ex-ship at Flushing (or a number of other specified delivery locations) during an agreed forward delivery month. Cargo sizes were up to 10,000 tonnes. Trading activity usually averaged less than one cargo a day for delivery periods of up to three months ahead. Prices were negotiated in US dollars per tonne at fixed levels.

Propane is produced both by refiners and as a by-product from oil and gas fields. Most of the propane delivered into the NW Europe flexi-propane contract is produced from North Sea fields. It is used as a final product for heating or as feedstock for petrochemical plants. It requires specialised transportation, delivery and storage facilities. Limited storage capacity and the seasonal nature of heating demand mean that the market is more active in the winter and prices often rise sharply at this time.

History

The forward propane market operated for about five years between 1989 and 1994 and was used by about 20 companies, mainly major oil companies such as BP and Shell which are involved in producing propane in the North Sea, large petrochemical companies such as ICI and Dow who regularly buy propane, and traders such as Vitol and Transammonia. At its peak in 1990 the flexi-propane market traded up to 100 cargoes per month, but volumes fell sharply as companies started using swaps instead. Towards the end of 1994 trading volumes fell to around 10 cargoes per month, posing problems for companies trying to close out forward positions. The major producers, BP and Shell, initially supported the contract which they regarded as a useful hedging instrument for the North Sea market, but they now prefer to use swaps.

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Appendix 7.4 European O/S naphtha

The European forward open-specification (O/S) naphtha market no longer exists, but the contract specifications are retained here for reference together with a brief history of the market.

Contract

The open-spec (O/S) naphtha market used to trade paper cargoes of naphtha for C&F delivery in the ARA range between the 5th and the 25th of the month. The cargo size could be anywhere between 20,000 to 25,000 tonnes and the specification allowed for a broad range of naphthenic and paraffinic naphthas suitable for use both in the refining and petrochemical industries. The forward contract was based on the Dow open-spec naphtha contract. Prices are negotiated in US dollars per tonne at fixed levels.

Naphtha is a light fraction produced by atmospheric distillation with boiling points between 30 and 180 degrees centigrade. It is used by refiners as a feedstock for catalytic reformers to make gasoline and by petrochemical companies as a cracker feedstock to make ethylene. The contract specification was very broad and allowed for product of any origin to be delivered as long as it meets the quality parameters. Attempts to narrow the quality range were resisted as this would limit the number of cargoes that could be nominated and increase the risk of squeezes.

The most important quality specifications are the proportion of paraffinic hydrocarbons (minimum content: 65 per cent) and the presence of MTBE. Paraffinic hydrocarbons determine its suitability as a reformer feedstock and trace quantities of MTBE can render it unsuitable as a petrochemical feedstock. Because naphtha is a feedstock destined for further processing, cargoes are not liable for import duty and are exempt from VAT. As a result, the open-spec naphtha market avoided the problems caused in other forward markets by the introduction of new (and imprecise) VAT rules from 1 January 1993 (see Appendix 7.2).

History

The open-spec naphtha contract originally had an unusually large volume tolerance of 17,000 to 25,000 tonnes which created problems when cargoes were nominated. The wide tolerance was necessary to allow for delivery of cargo quantities from a wide variety of origins, but traders also used it to maximise their gains or minimise their losses. In the past, extensive use of the delivery tolerance meant that companies were frequently left with part cargoes of naphtha that had not been nominated into a paper chain leading to disputes over ownership. Furthermore, it was not possible to nominate more than 17,000 tonnes on the last trading day which could leave companies holding an unwanted 8,000 tonnes of naphtha, nearly 40 per cent of the initial cargo volume.

As a result of frequent "abuses", changes to the contract were introduced in November 1990 to reduce the benefits from the "tolerance game" and to allow companies to nominate the full 25,000 tonnes on the last day of trading. In the new contract, cargo nominations of up to 21,000 tonnes are priced at the fixed price agreed by the buyer and seller, but nominations for the remaining 4,000 tonnes are priced according to market quotes. The formula used takes the average of *Platt's* low quotations for the last five working days of the delivery period.

The open-spec naphtha contract has also been prone to squeezes since only a small number of physical cargoes are typically used to wet paper chains. At its peak, the open-spec naphtha market traded about 350 contracts per month and chains involving over 60 deals were common, but the forward market has lost most of its former liquidity to swaps and now trades about one cargo a week.

In 1989 a prompt squeeze by one of the large trading companies stifled liquidity in the market and it took the Gulf crisis and changes to the contract to boost liquidity again. Attempts by the IPE to capitalise on the problems in the open-spec market by launching a naphtha futures contract in 1991, have so far failed and the forward naphtha market continued to thrive until recently. During 1992, however, concerns over the hedging efficiency of the open-spec market, in particular the basis risk created by the delivery tolerance, have prompted a decline in forward trading as many of the participants switched to swaps instead. Forward market trading volumes fell dramatically from around 200 per month in 1991 to around 5 per month in 1995 while the volume of swaps trading has grown and trading finally dries up in 1996.

The main players in the open-spec naphtha market were refiners, petrochemical companies and traders who import cargoes from North Africa and the Middle East. All these companies now also trade swaps.

Appendix 7.5 Fuel oil domestique

The European forward fuel oil domestique (FOD) market no longer exists, but the contract specifications are retained here for reference together with a brief history of the market.

Contract

The fuel oil domestique (FOD) market used to trade forward (or flexi) cargoes for delivery cif Le Havre during half-month delivery periods up to six months forward. Unlike Russian gasoil, the FOD market traded both halves of the month (1-15 and 16-30/31). Cargo sizes were typically in the range 20-25,000 tonnes and prices were negotiated in US dollars per tonne at a differential to the nearby IPE gasoil futures contract. In the first half of the month the nearby IPE contract is for the same calendar month, but in the second half of the month the nearby IPE contract will be for next calendar month. For example, second half April and first half May FOD contracts trade at a differential to May IPE gasoil.

The quality specifications of fuel oil domestique were the same for summer and winter. FOD is a low sulphur gasoil with good automotive characteristics, typically 48 cetane (see Table 7.4). In winter it is only suitable for heating as its cold properties do not meet the more stringent requirements of gasoil moteur (GOM), but in summer it could be used to supply both the heating and automotive markets — although this was no longer possible after low (0.05 per cent) sulphur diesel was introduced in October 1996.

History

Liquidity in both the forward gasoil markets was badly affected by the introduction of new rules for VAT and import duties from 1 January 1993 as a result of the Single European Act. Disagreements between European member states over the application of the new rules created confusion and uncertainty for traders who faced the possibility that VAT and excise duties could be imposed at every stage in a chain of forward contracts, greatly increasing the costs and risks of trading.

Previously, oil movements within the EC were treated as imports and VAT was chargeable at the point of consumption, not on any preceding paper deal. But the new rules introduced liability for VAT and excise duty on every delivery under a forward paper contract unless the cargo was destined for export and the seller became liable for unpaid taxes and duties. And, while some countries such as the UK were willing to allow traders to use a loophole in the legislation by specifying an "unknown" destination, others were not and the situation became very uncertain.

Although contracts were modified to include a clause passing liability for tax onto the end-user, many companies also insisted on letters of credit for up to four times the original value of the cargo in order to cover potential liabilities. As a result, smaller companies became unwilling to trade as they could not afford the additional costs of the revised letters of credit. So far plans to simplify the taxation of chain transactions have not been implemented despite strong pressure from the European Association of Oil Traders (UPEI) and the volume of forward trade remains depressed. These additional costs, together with the supply difficulties experienced by Russian gasoil traders have effectively killed the forward market for Russian gasoil. Forward trading continued for FOD during 1995 at a greatly reduced level, but this dried up in early 1996 as cold weather and refinery problems in the UK left the market short of physical supplies. All the activity has now switched to swaps.

8 Oil futures exchanges

Sally Clubley

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8.1 Introduction

Commodity futures markets have existed for thousands of years. In their current form, commodity markets can be traced back to the corn markets of the Middle Ages when producers (farmers), merchants and end-users would all meet in a specific place and agree prices using a system similar to the open outcry method used in today's futures markets. Today, the term commodity has come to cover a much wider variety of products, ranging from the traditional agricultural crops through meat and metals to oil and financial instruments.

Nobody now doubts that oil is a commodity, although the idea was strongly resisted by many when the futures markets were first mooted. Since the mid-1980s, when futures and price risk management first established themselves as an integral part of the industry, the oil sector has been transformed. Similar transformations are now taking place in liberalising the gas and electricity sectors. The traditional isolated producer-refiner-retailer supply chain of the integrated oil companies is now a thing of the past. Although integrated companies still exist, they generally operate as a series of separate enterprises under one corporate umbrella. The trading sections of the major oil companies are now similar in many ways to large independent traders and investment banks, some of which trade oil purely as a derivative product.

Although some modifications were necessary to translate the instruments offered in other markets to make them attractive to the oil industry, the introduction of futures trading – and, subsequently, swaps, options and other derivative instruments – has completely changed the way in which oil is priced and looks set to change it still further. Perhaps the most significant difference between oil and other commodities remains the reluctance of many state oil producers to become involved. This has begun to change but the oil futures and derivatives markets still tend to be dominated by trading companies, refiners and oil consumers. Many of the price risk management instruments now offered depend very heavily on the existence of liquid forward and futures markets and these have developed in tandem with the other changes in the industry.

8.1.1 Oil futures markets

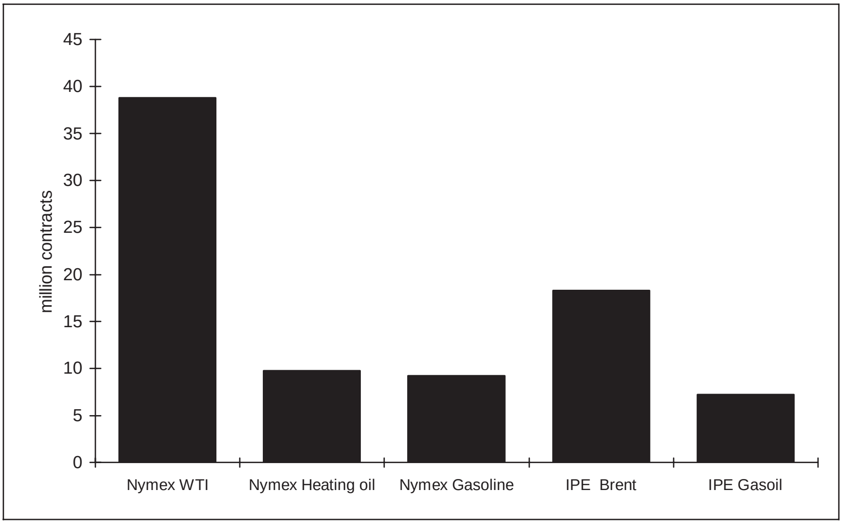
The first of the "modern" commodity markets began trading over 150 years ago. It was at this time that contracts began to be formalised and centred on exchanges which established trading rules and administered dealings. Today's markets are a direct development of these agricultural markets, which were initially located in London and Chicago. The development of futures markets has been centred on a few major exchanges ever since, although there are also various small, usually specialised, centres elsewhere. Chicago, which has two futures exchanges, is the largest commodity trading centre in the world but has so far been unsuccessful in its attempts to introduce oil or other energy contracts.

The commodity exchanges that currently trade oil futures contracts are:

- New York Mercantile Exchange (Nymex),
- International Petroleum Exchange of London (IPE), and
- Tokyo Commodity Exchange (Tocom)

Of these the Nymex, which introduced the first successful oil contract, is by far the largest (see Fig. 8.1). The Singapore International Monetary Exchange (Simex) – now part of the Singapore Exchange – tried to establish itself as an international energy exchange but has failed to launch a successful oil futures contract of its own.

In the early days of oil exploration in the US a forward/futures market was established, but this was short-lived and did not survive the oil industry's shift of focus from Pennsylvania to



Source: Nymex & IPE

Figure 8.1 Futures contract trading volumes, 2001

Texas. The development of the industry at this stage did not allow for a futures market to be established. It was not until the mid-1970s when the spot market had developed to a stage where a futures market became a viable proposition that successful contracts could be introduced.

In 1978, Nymex, which was looking for ways to reduce its dependency on its flagging potato contract, introduced a heating oil contract and a fuel oil contract, both for delivery in New York Harbor. Heating oil, as the IPE was to discover a few years later, is an ideal candidate for a futures contract as it meets the requirements of ready standardisation, fluctuating prices and, by this time, many participants.

The heating oil contract did not have an auspicious start. At the end of 1980 it was still trading daily volumes of under 100 contracts and was not taken seriously by the industry in the US, while outside the US its existence was barely even known. Nymex marketed the contract heavily and backed up the campaign with a major education programme. Gradually their efforts paid off and the industry began to accept that there might be some advantages to be gained by using the market. The sharp price rises that followed the outbreak of the Iran/Iraq war gave a further boost to industry interest and the contract began to grow steadily. The fuel oil contract, however, never attracted any interest and was abandoned, as have several been since on both Nymex and the IPE.

The commodity market community in London was not deterred by the slow initial growth of the heating oil contract from working to develop their own contract in gasoil, to be introduced in 1981. European traders were, despite having been involved to some extent in the development, extremely sceptical about the need for a futures market and the contract, like heating oil, had a slow start.

Gradually, however, the two contracts saw volumes begin to increase. The marketing and education programmes continued, by now with the participation of more futures brokers who began to see the signs of a successful market. As more and more traders understood the theories of the markets they began to use them. Although it was difficult to find the liquidity to do any worthwhile hedging in the early months, many traders did run pilot programmes and learnt how the markets worked.

The volume on both contracts increased steadily over the next year or two and both exchanges began to consider introducing new contracts. Nymex introduced its crude oil contract in 1983 and it was this, combined with the collapse in the oil price in early 1986, that encouraged rapid growth, leading to the

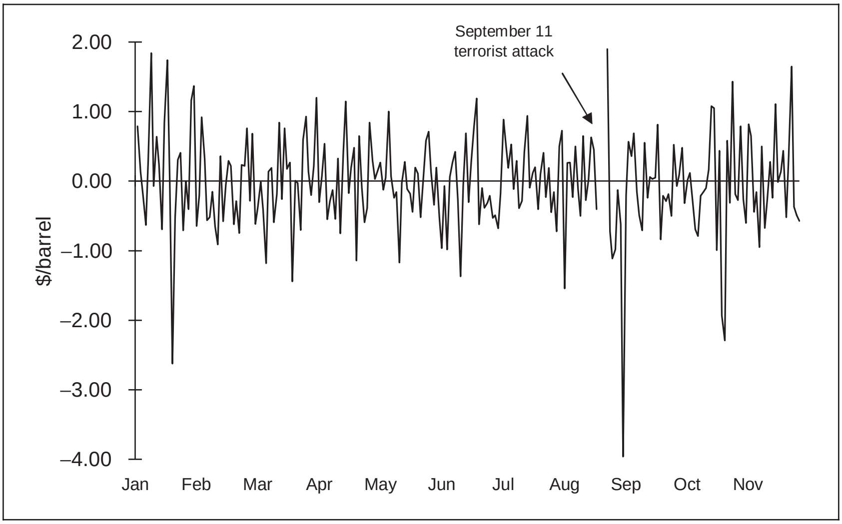


Figure 8.2 Daily price changes for Nymex WTI, 2001

complete absorption of futures into the daily lives of the oil industry. Over the next 15 years more than 20 different oil and gas contracts were introduced by the 2 exchanges. There are currently only 5 actively traded oil futures contracts (see Fig. 8.1). This may seem a poor success rate but it does in fact exceed the commodity market average.

8.1.2 Successful and unsuccessful contracts

In order to be successful, a futures contract must be based on a commodity that has:

- a volatile price,
- a quality specification that can be standardised,
- a wide range of participants in the market.

As oil is a commodity with a highly volatile price, most of the contracts that have failed have done so because of a failure in the quality specification, although some have suffered from a lack of participants.

Despite extensive consultation between the exchanges and the industry before introducing a new product, they have still not managed to get it right very often. This has sometimes been because the part of the industry consulted was too small and unrepresentative or because too much reliance was placed on the opinions of 1 or 2 large companies.

Price volatility

Volatile prices are essential because without them there is no need for people to use futures markets (see Fig. 8.2). The prime function of a futures market is to provide a hedging mechanism for the related industry. It is easy to plan and budget for a commodity which has a stable price or even one with regular seasonal fluctuations and there is therefore no reason to hedge.

Standard quality specification

It is not easy to come up with a standard quality specification which will attract the whole of one sector of the industry and, although any contract can be used as a reference for other similar products, it is vitally important in the early days of a contract that the specification is acceptable to the users.

The problems can be exacerbated in markets as fragmented as, for example, the European gasoline industry. Until recently, each country had its own gasoline specification. This is now changing with the increasingly widespread use of standard specification gasoline, but means that the IPE has had great difficulty in coming up with a universally acceptable gasoline specification. And the chances of a successful gasoline futures contract being introduced in London have diminished with the growth of the over the counter (OTC) swaps market (*see Chapter 10*). In the US, where much of the gasoline in the New York Harbor area is delivered by a pipeline which has its own specification, the design of a futures contract is a little easier (although subsequent changes to gasoline specifications in different states have caused some problems).

Similarly Brent crude oil is delivered in standard 500,000 barrel cargoes. The delivery procedure cannot therefore be used on a futures market trading in 1,000 barrel lots. The size of the futures contract cannot be raised to 500,000 barrels because it would preclude too many potential users from participating. A compromise therefore has to be reached. At first the IPE tried having an ARA (Amsterdam, Rotterdam, Antwerp) delivery, but Brent is not traded physically in this way so there was no reference price with which the users could compare the futures price and so the contract failed. The use of cash settlement rather than physical delivery solved the problem and enabled the Brent contract to become very successful.

Range of participants

A wide range of participants on both sides of the market is also essential in order to ensure that there is enough interest in the price movement, in both directions, and enough liquidity on the market. A product for which there are only 1 or 2 suppliers will not have an active free market.

Futures markets, like any other, can only trade when a buyer and seller agree a price: the more players there are on both sides, the more likely such an agreement is. A lack of participants was one of the main reasons for the failure of the IPE's naphtha contract in 1991/92.

Other requirements

One other requirement for a new contract is that it should offer something that is not already available elsewhere.

In the late 1980s there was an attempt to open an exchange in Rotterdam, trading gasoil and Brent in competition with virtually identical contracts on the IPE. The exchange was not a success, largely because there was no benefit to participants in moving from a liquid London market with a proven track record to an illiquid new market trading in the same time zone.

What is a successful contract?

Successful contracts can be defined as those which are liquid enough for users to trade the volume they wish to trade at the time of their choosing without moving the price significantly. Inevitably a large buy or sell order will move the price to some degree, particularly if it is accompanied by other similar orders, but market users have to be able to trade when they want.

The overall volumes traded on the market give a good guide to how liquid the contract is. However, the volume is not traded evenly through the day on any of the current energy contracts. For example, roughly two thirds of the Nymex WTI volume is done in the first and last hours of trading.

Another important measure of a successful contract is open interest, which is published by the exchanges on a daily basis. Open interest is the total number of outstanding bought and sold contracts at the close of each day's business. Contracts that are "day-traded" (bought and sold within a single trading day) do not contribute to open interest, although they are part of the total trading volume. When a contract expires, open interest represents the number of contracts which will go through to delivery. Open interest is also used as an indicator for technical analysis. A fall in open interest on a given day suggests that more contracts were closed out than opened, whereas a rise suggests the opposite.

In the case of the Nymex, the Commodity Futures Trading Commission* (CFTC) also publishes a weekly breakdown of the composition of open interest, which identifies the total long and short positions reported by those commercial and non-commercial traders whose individual open interest position is at least 300 contracts. Commercial traders are defined as companies whose business involves handling the physical commodity, i.e. hedgers, while non-commercial traders are companies whose business is purely financial, i.e. speculators. Although there are grey areas in this breakdown as some companies are difficult to categorise, it still gives a useful picture of the profile of market use. It provides evidence that the overwhelming majority of futures market trading is carried out by industry participants, though it does not indicate whether these companies are hedging or trading speculatively.

* www.cftc.gov

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8.2 The oil futures exchanges

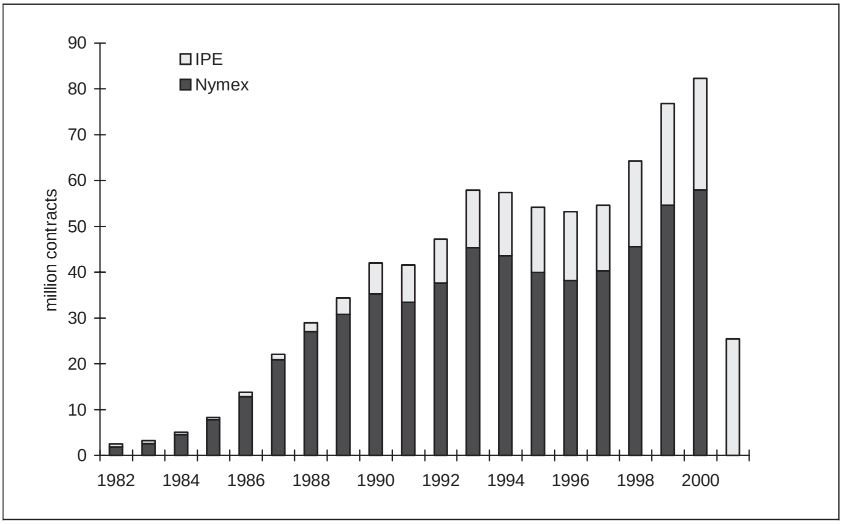
By the middle of 2001, the 2 major energy futures exchanges – Nymex and IPE – had 7 successful oil and gas contracts out of a total of over 20 that had been tried. Simex – which formerly listed oil futures contracts – merged in 1999 with the Stock Exchange of Singapore to form the Singapore Exchange. Tocom lists three oil futures contracts which are mainly traded by Japanese companies.

Nymex	IPE	Tocom
WTI	Gasoil	Dubai/Oman
Heating oil	Brent	Gasoline
Unleaded gasoline	Natural gas	Kerosene
Natural gas		

8.2.1 New York Mercantile Exchange (Nymex)

The most successful oil futures market is the Nymex,* which provided 3 of the 5 actively traded oil futures contracts in 2001 (see Fig. 8.3).

The success of the Nymex is largely due to the importance of its WTI crude contract which has become an international



Source: Nymex & IPE

Figure 8.3 Oil futures trading volumes, 1982–2001

* www.nymex.com

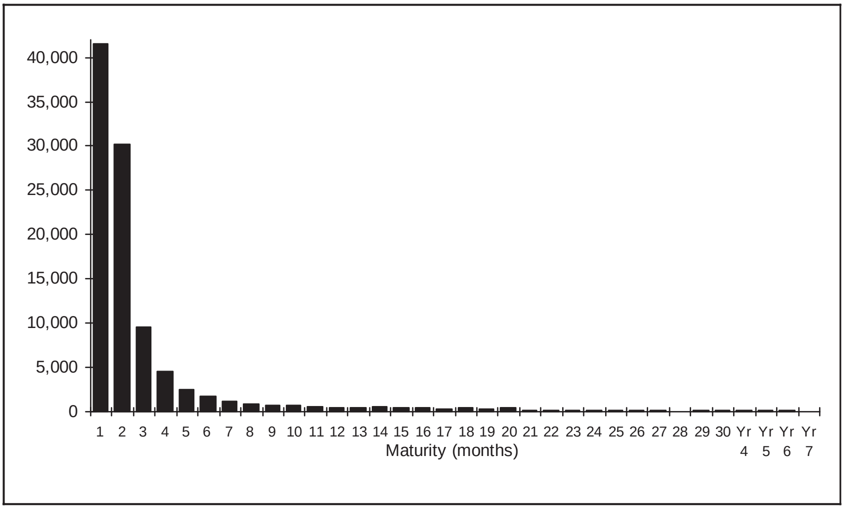
marker for the world oil industry, although the Nymex also has 2 other highly successful oil contracts in its heating oil and unleaded gasoline and a successful oil-related natural gas contract. In addition, the Nymex offers a wide range of price spread contracts, such as the "crack spread" that enables participants to hedge refinery margins with a single transaction.

Nymex Light Sweet Crude (WTI)

Contract unit:	1,000 barrels (42,000 US gallons)
Price quotation:	US dollars and cents per barrel
Trading months:	30 consecutive months plus 5 long-dated futures up to 7 years ahead
Last trading day:	3rd business day prior to 25th calendar day of month preceding the delivery month
Daily limit:	\$3 per barrel (\$6 if previous day settles at limit), except first 2 months for which prices can move \$15 per barrel. If prices move by \$7.50/barrel in either of the first 2 months, limits in all months become \$7.50/barrel in the direction of the move.
Standard delivery:	fob Cushing, Oklahoma

Nymex's light sweet crude oil contract is normally called WTI after the West Texas Intermediate crude delivered as standard against it. This traded an average daily volume of around 154,000 contracts during 2000, a small increase over the previous year. Introduced in 1985, the contract had an active start and has continued to grow virtually every year. A trebling of the oil price during 1999 and 2000 followed by sharp falls in 2001 have ensured continued growth in activity in recent years.

The contract requires delivery to be made by pipeline, fob seller's facility Cushing, Oklahoma, with special rules for small (5,000 barrels or less) deliveries. The delivery system matches the normal physical delivery for WTI very closely: all deliveries are rateable over the course of the month and must be initiated on or after the first calendar day and completed by the last calendar day of the delivery month. The futures contract ceases trading, or expires, 3 business days before the twenty-fifth calendar day of the month before delivery. (This is to allow for pipeline scheduling.) There is provision for other crude oils to be delivered, at seller's option, with certain differentials agreed by the exchange. At present, the list of alternative grades is confined to 3 North Sea crudes, Brent Blend, Oseberg and Forties, two



Source: Nymex

Figure 8.4 WTI daily average volumes by maturity, 1997

Nigerian crudes, Bonny Light and Qua Iboe, and a Colombian crude, Cusiana. Brent, Forties and Oseberg are currently priced at a discount of $0.30/barrel to WTI, Bonny Light and Cusiana at a premium of $0.15/barrel, and Qua Iboe at a premium of $0.05/barrel.

WTI trades further forward than any of the other current futures contracts (see Fig. 8.4). There are 30 consecutive months traded at any time, plus a further 5 long-dated contracts extending up to 7 years ahead for the 36th, 48th, 60th, 72nd and 84th months. The exchange has also introduced "strip" trading, which allows market users to trade an equal number of crude oil futures contracts for any number of consecutive months from 2 to 30 months in a single transaction. Prices are fixed at a differential to the previous night's settlement. As with all commodity futures, the activity on the WTI market is concentrated in the nearby months.

The WTI contract has become, to a large extent, the industry's world-wide standard price. This is, on the face of it, a little surprising as WTI is a low volume US domestic crude and cannot be exported. It is not, therefore, a truly international crude oil. But the US is the largest importer of crude oil in the world and as such its traders, who use WTI as standard, have a very large influence on international prices.

There have been times when the differential between the price of WTI and those of other crudes has become very distorted, notably during 2 successive summers in the late 1980s and then again in 1994. These distortions occurred because of the shortage of WTI on the US domestic market during the gasoline season. (WTI is a gasoline rich crude oil.) After the first 2 squeezes the Nymex amended its rules to allow for the delivery of specified foreign crudes (at discounts/premiums fixed by the Exchange from time to time).

Although they caused problems at the time, these episodes illustrate how much easier it is for an established contract to endure hiccups than it is for a new one. Had any newly-introduced contract had similar problems it would simply have disappeared, however promptly and effectively action were taken by the relevant exchange.

Nymex Number 2 Heating Oil

Contract unit:	42,000 US gallons (1,000 barrels)
Price quotation:	US dollars and cents per gallon
Trading months:	18 consecutive months starting with the next calendar month
Last trading day:	Last business day of the month preceding the delivery month
Daily limit:	4 cents/gallon (6¢ if previous day settles at limit, then 9¢ if it settles at 6¢), except the first 2 months for which prices can move by 40 cents/gallon. If prices move by \$0.20/gallon in either of the first 2 months, limits in all months become \$0.20/gallon in the direction of the move.
Standard delivery:	fob New York Harbor

Heating oil, which uses the industry pipeline specification for delivery in New York Harbor as its standard, is the oldest energy contract on the Nymex. It traded an average of around 39,000 contracts per day during 2000, up slightly on the previous year.

Delivery is fob seller's facility in New York Harbor, ex-shore with all duties, entitlements, taxes, fees and other charges paid. The seller's shore facility must be capable of delivering into barges, but the buyer may request delivery by truck (subject to a surcharge and if available at the seller's facility). Delivery may also be completed by pipeline, tanker, book transfer or inter- or intra-facility transfer. Deliveries may only be initiated the day after the fifth business day and must be completed before the last business day of the delivery month.

Nymex Unleaded Gasoline

Contract unit:	42,000 US gallons (1,000 barrels)
Price quotation:	US dollars and cents per gallon
Trading months:	12 consecutive months
Last trading day:	Last business day preceding the delivery month
Daily limit:	4 cents/gallon (6¢ if previous day settles at limit then 9¢ if it settles at 6¢), except the first 2 months for which prices can move by 40 cents/gallon. If prices move by $0.20/gallon in either of the first 2 months, limits in all months become $0.20/gallon in the direction of the move.
Standard delivery:	fob New York Harbor

The unleaded gasoline contract replaced the earlier leaded gasoline contract in the mid-1980s. The 2 ran in parallel for a time and then the older contract was dropped. Unleaded gasoline traded an average daily volume of around 37,000 in 2000, an increase of more than 10 per cent over 1999 as gasoline prices rose sharply on the back of rising crude prices. Like the heating oil contract it uses the industry pipeline specification as standard, but there are now problems with determining any standards in the US gasoline market as different states adopt different environmental controls. The delivery rules are the same as the Nymex heating oil contract.

During 1995, confusion over the introduction of reformulated gasoline (RFG) disrupted the Nymex gasoline contract. Since that time there have been several changes in delivery specification and the Nymex contract now generally conforms to industry standards for Phase II complex model reformulated gasoline.

Nymex Natural Gas

Contract unit:	10,000 MMBtu
Price quotation:	US dollars and cents per MMBtu
Trading months:	36 consecutive months commencing with the next calendar month plus a long-dated contract initially listed 36 months out
Last trading day:	3rd business day before the first calendar day of the delivery month
Daily limit:	\$0.30/MMBtu (\$0.60 if previous day settles at limit) except the first 2 months for which prices can move by \$1.50/MMBtu. If prices move by \$0.75/MMBtu in either of the first 2 months, limits in all months become \$1.50/MMBtu in the direction of the move.
Standard delivery:	fip Henry Hub, Louisiana

The fourth successful contract on Nymex is natural gas for delivery at Henry Hub, Louisiana. This contract traded around 71,000 lots per day during 2000 – a small drop on the previous year – and continues to trade actively. It is primarily a US domestic contract. The contract has become well-established within the US natural gas market, which has embraced commoditisation more willingly than the oil industry did 10 years earlier.

Nymex has also had other, regional, natural gas contracts with different delivery points, but none of these have made any impact on the industry. Instead of trading different contracts, the gas industry has preferred, like the oil industry, to have one active contract and trade everything else at differentials.

Nymex Propane

Contract unit:	42,000 US gallons (1,000 barrels)
Price quotation:	US dollars and cents per gallon
Trading months:	15 consecutive months
Last trading day:	Last business day of month preceding the delivery month
Daily limit:	4 cents/gallon (6¢ if previous day settles at limit) except first 2 months for which prices can move by 40 cents/gallon. If prices move by $0.20/gallon in either of the first 2 months, limits in all months become $0.20/ gallon in the direction of the move.
Standard delivery:	fob Texas Eastern Products Pipeline Company, Texas

There is another contract trading on Nymex, though with limited activity. It is the propane contract which has been in existence for many years and was bought from the New York Cotton Exchange a few years ago. It trades very low volumes. It is unlikely to become a major international contract, though it may eventually become a more useful domestic one.

Nymex Brent Crude

Contract unit:	1,000 barrels (42,000 US gallons)
Price quotation:	US dollars and cents per barrel
Trading months:	18 consecutive months
Last trading day:	Business day before the 15th to last calendar day of the month prior to the delivery month
Daily limit:	No daily limit.
Standard delivery:	Cash settlement

During 2001 the Nymex introduced a Brent crude contract, putting itself in direct competition with the IPE for the first time. The contract – which is also based on cash settlement – is virtually identical to the IPE's Brent contract, although the calculation of the settlement price is slightly different as it uses only *Platts* price assessments (*see Section 8.3 below*). The settlement price is specifically calculated for the purpose and is based on a mixture of outright deals traded on and hourly price assessments for the forward 15-day Brent market during the New York trading day on the final day of trading for the relevant delivery month.

Nymex believes that it can attract trading away from the IPE because of the opportunities for cross-margining Brent and WTI spreads traded on the same exchange. Brent-WTI spreads account for a large volume of futures trading and these require full initial margins if traded separately on the Nymex and IPE. But exchanges usually have much smaller initial spread margins and trading the 2 contracts on Nymex would reduce the size of the initial margins required for trading Brent-WTI spreads. In order to encourage trading in the new Brent contract, Nymex has waived all clearing and exchange fees for the first year and is offering rebates on WTI spread trades.

So far volumes have been modest with 49,565 contracts traded in 2001 – an average of around 660 per day – following the contract launch on 5 September, just before the 11 September terrorist attack on New York which may have dampened interest in the new contract.

Nymex tried again in 2000 to stimulate interest in a sour crude oil contract, this time based on the prices of Middle East Dubai and Oman crudes. It was the first cash settlement contract to be traded on the exchange. Instead of physical delivery, contracts outstanding at expiry were settled at the monthly average price of Dubai and Oman crudes as reported by 6 price reporting agencies. It could only be traded through the Nymex Access electronic trading platform. But trading volumes remained small and the contract was delisted in 2001.

Nymex also has other energy futures products, including a variety of electricity contracts and a coal contract. Trading in electricity futures began in June 1996, but none of them has had any lasting success. So far, it has not been possible to overcome the problem that the underlying electricity market is broken up into relatively small disconnected regional transmission systems, each of which is too small to sustain its own contract.

Nymex is also planning to introducing a range of new contracts as part of its eNymex system (*see below*). But these will be a mixture of swaps and physical contracts, not futures contracts.

Nymex spreads

The Nymex also offers a number of standardised “price spread” contracts that can be traded as a single transaction, thus reducing brokerage costs and margin calls. The most popular of these is the “crack spread” which enables participants to trade the price differential between the crude and products contracts and so hedge (or speculate over) refinery margins.

The crack spread is currently traded on the Nymex floor as a combination of heating oil and gasoline contracts traded against an equivalent number of crude oil contracts. It is designed to provide a vehicle for trading the refinery margin. Nymex trades its intermarket spreads in a separate pit from the straightforward contracts. Heating oil, gasoline and crude oil are all traded against each other on a one-for-one basis and there is also the crack spread. The most common combinations are 3 crude: 2 gasoline + 1 heating oil and 5 crude: 3 gasoline + 2 heating oil.

Other spreads commonly traded in the oil markets are Brent: WTI, gasoil: heating oil, and gasoil: Brent. In all spread trading, one contract is bought and the other sold, in equal quantities. (Sometimes traders wish to use unequal quantities in which case they cannot take advantage of beneficial initial margin rates.) Thus for example, a refiner wishing to protect refinery margin ahead may buy crude and sell a combination of heating oil and gasoline.

Example: hedging refinery margins

The gasoline and heating oil element of the refinery margin can be hedged on the futures market using the Nymex crack spread. For example, in the case of a 3 : 2 : 1 spread, 3 crude contracts are traded against 2 gasoline and 1 heating oil.

	Futures		Physical	
Feb	Sell June crack spread	$7.80/barrel		
Mar	Buy June crack spread	$6.96/barrel	Buy crude	$28.60/barrel
			Sell gasoline	$0.880/gallon
			Sell heating oil	$0.786/gallon
	Profit	$0.84/barrel	Margin	$7.04/barrel

By adding the futures profit to the margin achieved on the physical market, an overall margin of $7.88/barrel is made. This is close to the original futures crack spread level of $7.80/barrel. Hedges are rarely perfect.

The crack spread is traded as a differential, but after trading the component contracts are priced. For example, the original differential of $7.80/barrel could be broken down as WTI: $26.50/barrel, unleaded gasoline: 84 cents/gallon, and heating oil: 77 cents/gallon. It is, however, only the differential that is relevant.

8.2.2 International Petroleum Exchange (IPE)

The only exchange to trade nothing but energy contracts is the International Petroleum Exchange† of London which introduced its first contract in gasoil in 1981. This was not initially a success, but changes to the contract specification in 1985 made it more attractive to participants. The other successful oil futures contract on the IPE is the Brent crude contract, which also required several changes to its specifications before it took off. In addition, the IPE has tried a Dubai crude contract, a heavy fuel oil contract, a naphtha contract and a gasoline contract, but all have failed. Unlike the Nymex with its WTI contract, the IPE chose cash settlement rather than physical delivery for its Brent crude contract, although there is a physical delivery option. The IPE also has a successful natural gas futures contract which was launched in January 1997.

IPE Gasoil

Contract unit:	100 tonnes
Price quotation:	US dollars and cents per tonne
Trading months:	12 consecutive months then quarterly up to 24 months forward then half-yearly to 36 months
Last trading day:	2 business days before the 14th of the delivery month
Daily limit:	No daily limit imposed by IPE
Standard delivery:	fob ARA, Vlissingen or Ghent

The gasoil contract, which requires standard delivery of German DIN grade gasoil with 1 or 2 small changes in specification, traded an average daily volume of around 28,000 during 2000, an increase of 16 per cent compared with the previous year. The pricing standard is fob ARA (Amsterdam, Rotterdam, Antwerp) and the lot size is 100 metric tons. The delivery options include Vlissingen and Ghent. Gasoil is now traded up to 36 months forward. Deliveries must be made between the 16th and the last calendar day of the delivery month.

When the contract was first introduced the delivery system was a somewhat complicated warrant system. In retrospect it is a little surprising that the contract enjoyed any success as the

† www.ipe.uk.com, www.ipemarkets.com

delivery was so far away from the industry norm. It may demonstrate the luck of timing in the introduction of a new contract; others introduced since have failed on less significant problems. The standard fob delivery, introduced a few years later, was welcomed by the industry.

IPE Brent Crude

Contract unit:	1,000 barrels
Price quotation:	US dollars and cents per barrel
Trading months:	12 consecutive months then quarterly up to 24 months then half-yearly up to 36 months
Last trading day:	Last business day before the 15th of the month preceding the delivery month
Daily limit:	No daily limit imposed by IPE
Standard delivery:	Cash settlement or EFP (Exchange of future for physical)

The IPE's Brent contract – which now trades for up to 36 months ahead – has also become very successful, though in this case at the third attempt. Brent's cumbersome physical delivery procedures (*see Chapter 7*) are unsuitable for a futures contract and the IPE finally settled on a cash settlement contract instead of the more common physical delivery, although there is also provision for physical delivery of whole cargoes using the EFP mechanism.

Cash settlement simply means that contracts left open at expiry are settled by cash transfer instead of the physical transfer of crude oil. Anyone with an open hedge position should therefore be in a position to buy or sell physical Brent at the cash settlement price, which is derived from physical transactions during the day, so the hedge provides as good a protection against adverse price movement as a physical delivery contract. Traders with full-cargo sized positions can use the EFP mechanism to effect physical delivery.

Brent traded an average of around 67,000 contracts per day during 2000, a slight decline on the previous year. Like WTI, the contract is for 1,000 barrels.

IPE Natural Gas National Balancing Point (NBP)

Contract unit:	1,000 therms of natural gas per day for contract duration (minimum of 5 lots)
Price quotation:	UK sterling, pence per therm
Trading months:	*Monthly contract:* up to 15 months forward, then quarterly to 36 months *Balance of month contract:* strip of daily contracts for the balance of the current month *Daily contract:* daily contract for up to 7 days from the day ahead
Last trading day:	*Monthly contract:* 2 business days before the first calendar day of the delivery month *Balance of month contract:* 2 business days prior to the penultimate calendar day of the delivery month *Daily contract:* 1600 hours on business day prior to delivery *Daily limit:* No daily limit imposed by IPE
Standard delivery:	Transfer of rights at the NBP

The IPE launched a UK natural gas contract in 1997. The contract, which is based on the transfer of natural gas rights at the National Balancing Point (NBP) – a notional point where the balancing of gas within the UK National Transmission System (NTS) occurs, trades daily contracts of 1,000 therms per day for delivery either for groups of calendar month days (28, 29, 30 or 31 days) up to 36 months forward, or for the number of days remaining for the balance of the delivery month after the expiry date of the contract, or for individual days up to 7 days ahead. Trades must take place in multiples of 5 contracts per day. Delivery must be made daily no later than 18:30 on the day prior to the delivery day via Transco's AT link system. EFPs may take place at any time up to 30 minutes after the cessation of the contract. So far, the IPE's natural gas contract has been well received by the industry and the number of participants and the level of open interest are both rising. The natural gas contract traded an average volume of just over 2,000 lots per day during 2000, an increase of 71 per cent over the previous year.

The IPE natural gas contract was the first energy contract to be traded entirely electronically. Orders are entered through terminals operating what is, in effect, an electronic pit system. Terminals are held by both IPE members and a special category of trade membership that allows gas traders to belong to the market and trade directly. All contracts must be cleared through an IPE clearing member. The IPE recently extended its electronic trading system to include both Brent and gasoil for a limited period before the start of the normal pit trading day.

8.2.3 Tokyo Commodity Exchange (Tocom)

The Tokyo Commodity Exchange† (Tocom) trades crude oil, gasoline and kerosene. All three contracts have a lot size of 100 kilolitres, or around 630 barrels and prices are quoted in Japanese yen per kilolitre.

Both product contracts involve physical delivery and are based on standard Japanese domestic product specifications. The crude oil contract is cash settlement only and is based on the average price of Dubai and Oman as reported by 6 price reporting agencies. It was introduced in September 2001 and has had a very promising start, averaging around 11,000 contracts per day in the last 4 months of the year.

Futures trading is largely by domestic Japanese companies. Gasoline volumes are good, averaging around 65,000 contracts per day during 2001. The kerosene contract traded about half that volume.

† www.tocom.or.jp

8.3 Delivery procedures

The vast majority of futures contracts are never delivered (see Table 8.1). Instead, most participants prefer to close out (or roll over) their positions well before the last day of trading for each delivery month. This is because futures contracts are either traded in conjunction with a position in the physical market to protect against an adverse price movement, or used in a speculative fashion to benefit from a favourable one – neither of which requires delivery of the physical commodity underlying the contract.

Nevertheless, physical delivery remains an important part of the operation of the futures market since it ensures that the futures prices remain anchored to the underlying physical market and arbitrage dictates that participants will always take (or make) delivery when it pays them to do so. Although cash-settled contracts do not involve physical delivery, the same rules apply and participants will take advantage of arbitrage opportunities between the contract and the cash settlement price in the same way.

In addition to physical delivery of the standardised commodity specified in the futures contract (or its cash equivalent), participants may also employ 1 of 3 other possible delivery mechanisms. These include:

- exchange of futures for physical (EFP),
- exchange of futures for swaps* (EFS),
- alternative delivery procedure (ADP).

Table 8.1 Nymex crude oil deliveries, 2000

	Volume traded	Standard delivery	ADP	EFP
January	3,423,387	0	399	57,553
February	2,615,920	0	466	70,244
March	3,053,238	0	1,167	44,683
April	2,824,373	342	646	50,044
May	2,878,375	0	607	66,701
June	3,613,338	0	426	37,843
July	2,947,528	0	947	52,125
August	2,850,730	0	21	51,743
September	3,905,950	0	528	37,681
October	2,855,157	0	477	53,058
November	3,110,651	0	12	49,231
December	4,728,734	76	2,202	47,097

* IPE and Nymex Brent contract only.

These delivery procedures and their variations are designed to make the contracts as flexible as possible and therefore to encourage the industry's use of the exchanges. The EFP procedure is particularly useful, but ADPs also have an important part to play.

8.3.1 Standard delivery

In normal circumstances the exchanges match the outstanding buyers and sellers when a contract ceases trading. The brokers are informed of each other's identity and the delivery procedure proceeds according to the rules on the different exchanges. These rules vary from contract to contract but are, with the exception of cash-settled contracts such as Brent, similar and reflect the operation of the physical market. In all delivery rules the terms buyer and seller refer to the clearing member of the market, usually the broker.

Nymex refined products

Heating oil and gasoline on Nymex have the same delivery procedures. Both product contracts cease trading on the last business day of the month preceding delivery. On the first day of the delivery month the seller must notify the exchange of the location from which he will be delivering. Buyers and sellers are notified of each other's identity 2 days after trading ceases. The buyer then has 48 hours in which to choose a method of delivery and nominate a preferred 5 day delivery range. Two days before delivery takes place, the buyer has to lodge the full value of the delivery with his broker: the seller is paid in full the business day following delivery. There are additional margin requirements for both buyer and seller once trading has ceased.

All deliveries must take place after the fifth business day of the month and be completed before the last business day. If the seller is not able to meet the buyer's preference because of logistical problems at the terminal he may refuse it, but must accept the next nomination, which must be entirely outside the first. The seller cannot refuse for any other reason.

Deliveries are made into barge or truck, by pipeline, tanker, book transfer or inter- or intra-facility transfer at buyer's option, but there is a small surcharge for truck deliveries. Inspection costs are shared by buyer and seller, though the seller has to bear all the quality inspection costs if the product is outside the specification.

Nymex crude

The Nymex light sweet crude oil contract is different from the product contracts, reflecting differences in physical trading. The light sweet crude contract (commonly known as WTI, but the contract also allows for physical delivery of specific domestic and foreign grades) ceases trading 3 business days before the 25th calendar day of the month before delivery.

On the last trading day the seller notifies the exchange of the pipeline at Cushing, Oklahoma which he will use to make delivery. Two business days after the last trading day, buyer and seller will be notified of each other's identity. The following business day the buyer will notify the seller where he will take the crude. (The costs of pumping crude from one pipeline or facility to another are for the buyer's account.) The seller is then able to put in a scheduling notice to the facility not later than the last business day of the month.

The buyer must lodge the full value of the delivery with the exchange 3 days after the last trading day. Payment to the seller is made on the 20th calendar day of the month after the delivery month. This can be done by T-bills or letter of credit. There is also an additional margin requirement for both buyer and seller once trading has ceased.

Unlike the products, either buyer or seller may appoint an inspector. Anyone who chooses to do so must bear the full cost of the inspection.

The Nymex Brent crude contract is cash settlement only. The Brent contract ceases trading on the last business day before the 15th to last calendar day of the month prior to the delivery month – this is consistent with the operation of the forward 15-day Brent market on which the contract is based (*see Chapter 7*).

The settlement price for the Nymex Brent contract is calculated for the exchange by *Platts*. The index is an average of 3 components: the weighted average of all reported cash deals in the first month of the 15-day Brent contract; the weighted average of a first month value calculated by taking the second month deals adjusted by the average of the spread value between the first and second month and, thirdly, the average of hourly price indications of the 15-day Brent market. All the elements are based on Brent activity during the Exchange trading day.

Platts and Nymex publish this index throughout the expiration day and the final value, published after 4:00pm on expiration day, is used to settle all outstanding Brent contracts on expiry.

IPE refined products

Gasoil ceases trading at 12.00 noon 2 business days before the 14th calendar day of the delivery month. On this day all sellers must notify the clearing house of the location of the product by 14.00 hours. As soon as possible after this time the clearing house matches buyers and sellers and notifies them.

The buyer must nominate a preferred 5 day delivery range the following morning by 10.00. As with Nymex, the seller can only refuse by proving congestion at the loading terminal. If refusing, he must do so by 12.00. The buyer must then give 48 hours notice of the arrival of the barge. (Inter- and intra-facility and pipeline transfers are also possible, as is loading into another type of vessel if the seller's facility permits. Deliveries at Vlissingen are discounted by $0.50 per tonne.) All deliveries must take place between the 16th and the last day of the delivery month.

The buyer, who chooses the inspector, and seller, who has some rights to refuse, share the costs of inspection unless the product fails to meet the specification in which case the seller must pay.

The seller must lodge all the documents relating to the delivery with the clearing house within 4 days of the delivery being completed. The buyer has to make payment the following business day by 12.00 noon.

IPE crude

The IPE's Brent contract has no real delivery procedure as the contract is for cash settlement, although physical delivery is possible under the EFP rules. Trading ceases at the close of business of the last business day before the 15th day before the first day of the delivery month. Within 2 business days, all contracts are settled against the Brent index price for the last trading day. The Brent index is published daily and is a weighted average of all the Brent deals done for the prompt futures month the previous day. The IPE uses all available published sources to calculate the number and there are specified procedures for dealing with any day where no cargoes are traded.

The Brent index is the weighted average of all the confirmed 15-day Brent market deals for the appropriate delivery month as reported by various media sources, including all the major telex and screen-based price reporting services. The index is issued at noon each day based on the deals done during the previous day.

If there are not enough actual outright trades reported by the media, the Brent index is the average of the confirmed deals (as above) and 2 other figures:

1. The weighted average of the *second* month 15-day Brent deals reported by the media plus or minus the average differential between the first and second months as given in reports of spreads traded.
   For example, if June is the month for which the index is being assessed, the IPE would take the weighted average of reported July deals and add (if July was trading at a discount to June) or subtract (if July was trading at a premium) the weighted average of reported June/July spreads. Thus, if the weighted average July price was $26.40 and the average June/ July spread was June + $0.20, the price used in calculating the Brent index would be $26.20.
2. A straight average of all the media assessments made during the day.
   All the relevant media sources publish price assessments for the Brent market, either throughout the day in the case of the electronic media or at the end of the day in the case of the telex/fax services. All these assessments are averaged.

8.3.2 Exchange of futures for physical (EFP)

EFPs involve the exchange of a futures position for a physical one. Thus the buyer of oil can "give" a long futures position to the seller and receive oil in exchange. Buyer and seller can both establish futures positions in their own time, at prices unknown to each other. When the physical transaction is agreed or the delivery takes place an EFP is registered on the exchange giving each side a closing futures position. The price at which this is done is the same price as that on which the physical transaction is invoiced. In addition, there will normally be a price differential agreed for the physical side of the transaction reflecting quality and locational differences.

Under the exchange rules all EFPs have to be supported by a physical transaction and the exchange can ask to see evidence of the physical transfer. Under the IPE rules, and those for the Nymex Brent crude contract, the physical transfer can be a swap. Swaps are covered in detail elsewhere (*see Chapter 10*) but essentially involve a trader fixing an unknown floating price in the future for a fixed price now and reversing the transactions at a later date. It works in a similar way to a futures hedge, but using published prices rather than exchange ones: the swap is reversed at the time the physical transaction takes place so the trader has effectively fixed his price in advance.

EFPs are used extensively on all energy futures markets. As Table 8.1 shows, virtually all the deliveries made into the Nymex WTI contract are EFPs. In the past, term contracts, where the buyer agreed to take a certain volume of oil each month, for example, on both products and crude were common. When prices became very volatile at the beginning of the 1980s these agreements tended to die out as neither side was prepared to commit itself, even at market-related prices. The use of EFPs, however, enables such long term deals to be struck and, in theory at least, each side can then price when the time is right. In this way supply has been separated from price: a buyer can be sure he will have the oil required without having to commit on price.

EFPs are also useful when, for example, a seller wishes to dispose of a cargo physically but wishes to keep open the possibility of a higher price. Normally an EFP will be registered at a date close to the date of delivery or on the day the deal is agreed and the reference price will be the closest futures equivalent to the physical deal: for example a June Brent EFP would be based on a June Brent quote. There are occasions, however, when EFPs continue pricing many months after the cargo has physically changed hands. This can make accounting difficult, but means that a cargo can be sold today, for example, at next year's prices.

Care must be taken when trading EFPs that arrangements have been made for dealing with the volume tolerance on the physical deal – normally the EFP will be for the exact volume delivered if this quantity is known or for the theoretical amount traded if the EFP is registered earlier. Adjustments for tolerance then have to be made later. Similarly any differential, or the basis for calculating it, between the product or crude traded and the futures price must be agreed. EFPs must be registered within 1 hour of the expiry of the relevant futures contract in London, though on Nymex they can be registered until noon on the day following the end of trading.

Technically, EFPs are considered to be a method of delivery. They do require delivery of oil, but the delivery is not performed under the rules of the exchange and, although the performance of the futures contracts is guaranteed by the exchange, the delivery of the physical oil is not guaranteed. Counterparty risk is therefore the same as in any other trade agreed between 2 parties.

Example: exchange of futures for physical (EFP)

Company A agrees to sell Company B 500,000 barrels of Bonny Light crude to be priced using an EFP based on June Brent plus a premium of 50 cents/barrel. The EFP is to be registered either on the date of the bill of lading or on 10 May, whichever is the sooner, at the closing price of the previous trading day.

Company A has to build up a short position of 500 IPE Brent contracts and Company B has to build up an equivalent long position. Assuming that they have both done this by 10 May and that the EFP is registered on that date, the net buying and selling price for each company is determined as follows:

Seller: Company A		Buyer: Company B	
Sells futures at:	$27.45	Buys futures at:	$27.10
EFP registered at:	$27.25	EFP registered at:	$27.25
Profit on futures:	$ 0.20	Profit on futures:	$ 0.15
Invoices B at:	$27.75*	Invoice from A:	$27.75*
Futures profit:	$ 0.20	Futures profit:	$ 0.15
Net selling price:	$27.95	Net buying price:	$27.60

** EFP registration price plus 50 cents/barrel premium as agreed*

Both parties thus have a net price equal to their original futures price plus the 50 cents/barrel premium agreed. The EFP registration price is not relevant to the end result, but a figure must be assigned to it in order to close out the futures positions.

8.3.3 Exchange of futures for swaps (EFS)

An exchange of futures for swaps (EFS) is virtually identical to an EFP. Instead of exchanging the futures position for a physical position it is exchanged for a swap. In many cases a swap can provide a closer hedge than the futures market and this mechanism enables a hedger to convert a hedge from one type of price risk management instrument to another. Many product sales are made on an average *Platt's* price over a month and a swap can therefore give a more exact match than a futures hedge. The futures exchange can ask for evidence of a properly documented swap deal if an EFS is reported, just as it can for a physical deal if an EFP is reported.

Example: exchange of futures for swaps (EFS)

In this case, Company B has sold July gasoil futures in April at an average price of $200/tonne in order to hedge unsold product in stock in case prices should fall. In early May, B sells the physical product priced at the average of *Platt's* NW Europe cif gasoil quotations for the month of July plus a quality premium of $3/tonne. B therefore decides that a swap would provide a better hedging instrument because it can be matched more exactly to the underlying reference price agreed for the physical sale.

Under the terms of the swap, B agrees to sell at a fixed price of $195/tonne and the swap is then reversed at a floating price calculated from the average of the mean of *Platt's* cif NWE gasoil quotations for the whole of July. The contract is settled by difference, so B either pays the swap provider if the average is greater than $195/tonne or receives the difference if it is lower. In order to close out the existing futures position, the EFS is then registered on the floor of the exchange at $195/tonne, the fixed price agreed in the swap, which leaves B with a net profit on the EFS of $5/tonne.

April	Futures sold at:	$200	
May	EFS registered at:	$195	
	Net profit on futures:		$5
May	Fixed price on swap:	$195	
July	Swap reversed at:	$182	
	Net profit on swap:		$13
July	Sale of physical oil:		$185*

** including $3/tonne quality premium*

Net price received by Company B = ($182 + $3) + $5 + $13 = $203

In July, the average *Platt's* cif NWE gasoil price is $182/tonne and the swap is reversed at this level. B therefore receives a payment of $13/tonne from the swap provider to make up his fixed selling price of $195/tonne. In addition, B receives a payment of $185/tonne ($182/tonne plus the agreed $3/tonne quality premium) from the company that purchased the physical gasoil. As a result, the total price received by B for its gasoil is $203/tonne, which is the price paid by the buyer plus the futures profit plus the swap profit.

Had the market moved up instead of down, Company B would have made a loss on the futures market and the swap, but would have received a higher price from its physical customer.

With both EFPs and EFSs, the registration of the EFP or EFS can close out or create a futures position for either party. As soon as an EFP/EFS is registered any futures contracts that are created are treated in the normal way and become subject to margin calls. They must be closed out by the time the contract expires or they will be included in the normal delivery process.

8.3.4 Alternative delivery procedure (ADP)

In addition to the normal exchange delivery procedures and the EFP mechanism, all the futures contracts allow for an Alternative Delivery Procedure or ADP. This allows delivery to take place between a buyer and seller matched up by the exchange, but in a different manner from that prescribed in the rules. The differences could be in location, quality or any other term, but it must be agreed between buyer and seller.

One common example of an ADP is the delivery of non-EU qualified material under the IPE gasoil contract. If buyer and seller agree to the delivery of such product, the exchange is notified that an ADP will take place. In this case, the IPE no longer guarantees delivery and the contract becomes like any other deal concluded directly between 2 principals. The gasoil futures positions are closed out at the settlement price on the day before the contract expires. Any discount or premium relating to the new delivery terms is negotiated directly between the 2 parties involved.

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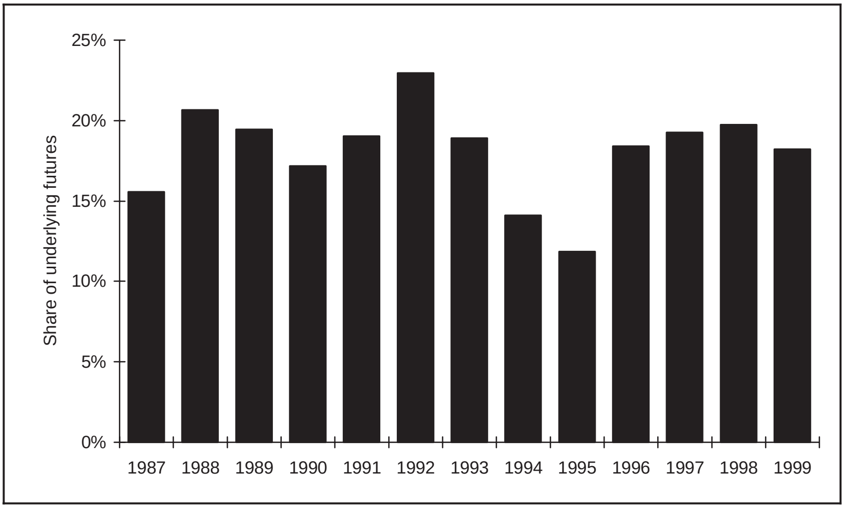
8.4 Options on oil futures

Both Nymex and the IPE have, in addition to their futures contracts, a number of options contracts (*see Chapter 9*). At present these are available for the 4 most successful US oil and gas futures contracts, WTI, heating oil, gasoline and natural gas, for Brent and gasoil on the IPE and for the new Nymex Brent and Brent/WTI spread contracts. The Nymex also offers a "crack spread" option based on a ratio of one heating oil contract to one light sweet crude contract. Options offer a number of greater trading opportunities to the industry and others and increase pricing flexibility. Exchange options, however, find it difficult to compete with average price OTC options, which often give more appropriate cover at a lower price.

Nymex	IPE	Tocom
WTI	Gasoil	none
Heating oil	Brent	
Unleaded gasoline		
Natural gas		
Brent		
Crack spread		
Brent/WTI spread		



Source: Nymex

Figure 8.5 Nymex energy options as share of futures, 1987–99

All the exchange option contracts currently available are options on futures: this means that on exercise the buyer will receive futures contracts. All option contracts, which are available in the same contract months as the underlying futures contracts, expire a few days before the futures to enable buyers who exercise to get out of their positions.

The success of an options contract is normally measured as a proportion of the underlying futures contract (see Fig. 8.5). Brent options averaged just over 3 per cent of the underlying futures contracts in 1999, slightly more than the previous year. In absolute terms, the volume of options trading rose by almost 50 per cent, to an average of just under 2,000 contracts per day. Nymex's WTI contract saw options trading at over 22 per cent of the underlying futures contracts in 1999, an average of 32,388 contracts per day.

Product options on both the IPE and Nymex have not so far been as active as the comparable crude oil contracts and there has been little discernible growth in recent years. Nymex heating oil and gasoline options traded an average of 2,760 and 2,381 contracts per day respectively in 1999, representing around 7 per cent of the underlying futures contracts. IPE gasoil options only traded an average of 414 contracts per day in 1999, less than 2 per cent of the underlying futures contracts.

Nymex introduced a crack spread option contract in November 1994. These options are for either heating oil/crude or gasoline/crude, but neither has seen very active trading. It is the first spread option traded on the oil futures exchanges and is a logical extension of the market, but has not yet attracted much interest.

8.5 Clearing mechanisms

8.5.1 Organisation

In most respects the 2 energy futures exchanges are very similar. There are minor differences in the way in which the exchanges operate and in the rules for delivery, but the overall principles are the same. One significant difference in the ways the floor operates is that in London a broker can be buyer and seller of the same lot(s) on the floor of the exchange but on Nymex that is not allowed except under certain conditions.

Traditionally, futures markets were membership organisations but this has now changed for the IPE and Nymex. Both exchanges have de-mutualised and the IPE has now been taken over by the Inter-continental Exchange* (ICE), an industry-backed electronic trading platform (*see Chapter 11*). Demutualisation has had little apparent effect on the day-to-day operations of the two exchanges – the former members remain actively involved in the markets as clearing and floor brokers and continue to operate in the same way. Both exchanges are managed by executives reporting to boards elected by the shareholders. But the IPE faces a major change following its takeover by ICE, which plans to close the trading floor and switch entirely to electronic trading.

8.5.2 Financial guarantees

The financial performance of all futures contracts is guaranteed by the clearing houses of the exchanges. This guarantee technically applies to the clearing member of the market: any company trading through a clearing member theoretically has normal counterparty risk so it is important to know the financial standing of the broker. In practice, the clearing houses have always honoured their members' client contracts.

The clearing house in London is the London Clearing House (LCH), a body jointly owned by a number of major UK exchanges with their members and shareholders. On Nymex the clearing is done through a mutual corporation of the exchange clearing members, who all have to put up funds to trade. Positions are limited by the funds deposited. The clearing houses on all the energy exchanges have weathered some problems over the years

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* www.intercontinentalexchange.com, www.intcx.com

in which energy contracts have traded, but have always managed to fulfil their guarantees – in some cases by entering the physical market to buy oil to meet delivery obligations.

8.5.3 Margin calls

In order to maintain this financial guarantee the clearing houses require an initial margin, or deposit, to be paid against each futures contract traded, whether bought or sold. This margin is payable when the contract is traded and is returned when the position is closed. It is intended to protect the clearing house against 2 days' price movements and can be varied with no notice when conditions change. Normally, the initial margin is around $2,000–3,500 per contract ($2.50–3.50 per barrel) on Nymex and $1,500–2,500 per contract ($1.50–2.00 per barrel on crude, $15–25 per tonne on products) on the IPE. In volatile market conditions, this margin is frequently increased. It is also raised as the contract nears the end of trading.

In addition, a variation margin is payable each day. This represents the difference in value between the contract when it was bought or sold and the current market value. It is calculated daily against the end of day settlement price and payable in full the following day. Thus if a trader buys a Brent contract at $25 per barrel and the market settles at $24.50, $0.50 per barrel or $500 is payable. If it settles at $25.50 the buyer will receive $500.

8.6 Future developments

The physical oil market operates 24 hours a day and although volumes of business done vary with the overlap between the working hours of Europe and the US being the most active, there is plenty of business done at other times. In an effort to meet the needs of the industry more fully all the exchanges have developed various ways of increasing market hours.

There are 3 main ways in which this can be done: the exchanges can be open for longer hours, the same contracts can be traded on different exchanges in different time zones or the current exchange practices can be supplemented with electronic trading.

Nymex chose the electronic route and has now been operating its Access system since June 1993. The system is available virtually all the time the markets are shut, between Sunday evening and Friday afternoon New York time. Nymex claims that it is not intended, however successful it becomes, to replace the market floor, though many in industry feel that there is a threat to the traditional marketplace. Theoretically a more perfect market would exist on the screen and participants may be willing to exchange the benefits of that for the traditional open outcry trading pits. In developing its Brent contract, Nymex consulted with a wide range of crude oil traders and found that the open outcry pit system remained a popular way of trading. It was for this reason, amongst others, that the exchange decided to trade Brent on the floor and not through Access.

The IPE has also introduced an electronic trading system (ETS) for its natural gas contract and recently extended this to its other oil futures contracts, Brent and gasoil, for a limited period before the start of the normal pit trading day. The IPE also had an agreement with the Singapore International Monetary Exchange (Simex) to trade its Brent contract during the Singapore trading day, but this failed to generate any real business.

Other commodities have tried other approaches. Some of the US financial markets open for 2 or 3 sessions during each 24 hour day, hoping to catch business from each of the major time zones. But the heavy costs of such operations are not often recovered by the volume of business done. Although the start-up costs of the electronic systems are high the ongoing costs should be lower.

Electronic trading platforms have developed in large numbers in the energy industry over the last few years (*see Chapter 11*). They take various forms, but most trade physical contracts and swaps. Oil futures contracts are still only traded out of the normal exchange hours on Nymex's Access and the IPE's ETS, although the IPE is planning to move oil futures trading to a new electronic platform following the takeover by the Inter-continental Exchange (ICE).

There is still widespread support within the oil industry for the pit trading system, but there are also many traders who feel that electronic trading is inevitable, if not entirely desirable. Certainly, within the emerging gas and electricity trading communities electronic trading is playing a very large part. The main disadvantage, in many eyes, is the lack of "market feel". Although many of the systems include a list of potential bids and offers below and above the current best bid/offer prices, this does not – they say – give the same indication as the trading floor.

It is also likely that the participation of locals would fall in an electronic market. Locals are those who trade the floor of the market for their own account (although some also take client orders). They trade speculatively in and out of the market several times a day, taking small profits. By doing this they add significantly to market liquidity. Locals are much more prevalent in New York than in London.

While screen trading is supplementary to floor trading this is probably not too much of a disadvantage: liquidity is not expected to be as high as on the market floor. Should electronic trading take over from the floor, however, it could become a problem. There is nothing to stop locals screen trading, but, relying as they do on small changes in sentiment in the market, there are unlikely to be as many. The working conditions would also be very different, and while many of those who have seen the Nymex trading floor cannot conceive of working there, many locals feel similarly about sitting in front of a screen. A new type of local would therefore need to develop.

One major advantage for the users of the market is that costs would be significantly reduced if screen trading were to take over completely from the floor. Brokers' overheads would be sharply reduced and many larger users would probably become members of the market entitling them to their own link to the market. Many of the biggest users are already members but electronic trading would make membership more attractive to others.

Electronic trading platforms also make it possible to automate credit control, scheduling and invoicing as well as trade matching and clearing. This not only cuts costs but also reduces the chances for errors in the transmission of information within and between organisations, and speeds up the process. But these advantages are not confined to futures trading – any electronic platform that can combine physical trading, futures contracts and OTC instruments could have a major impact on the market.

Until recently there was a degree of co-operation between the two energy exchanges, Nymex and the IPE. But this has now changed with Nymex introducing a Brent contract in direct competition with the IPE and developing their electronic trading system, enymex, to compete with the most popular electronic platform operated by ICE, the new owners of the IPE.

There is also likely to be an increased blurring of the lines between the different price risk management instruments. At present, futures and options on futures are cleared and margined while other OTC instruments are not. Clearing allows purchases and sales to be closed out automatically and substitutes the clearing house as a party to all contracts thus eliminating counterparty risk. Enymex plans to introduce clearing for all of the instruments it lists and it seems likely that ICE will provide a similar system. ICE trades a wide range of outright and differential swaps in the oil market, as well as various other energy products and metals but does not yet offer any clearing services. ICE is owned by several large energy trading companies and investment banks and is the first multi-counterpart electronic trading system to make inroads into the oil industry.

It is possible that one dominant oil trading system or exchange will emerge in the future as liquidity migrates to the cheapest and most effective trading environment, but it is still far too early to say which one it will be – Nymex, ICE/IPE or some new entrant. As far as the futures markets are concerned the key requirements are liquidity and financial credibility.

Despite the high failure rate of new contracts, there are likely to be several introduced in the next few years. Some of these will be futures contracts and some option contracts. At present, both Nymex and the IPE are looking towards the liberalising gas and electricity markets for new contracts, as well as the new areas of emissions and telecommunications bandwidth. With the advent of electronic trading it is much easier and cheaper to introduce new contracts.

Other new contracts may include more refined product contracts in an attempt to provide a better spread of contracts to meet all industry requirements. Various refined product contracts have been tried without success in the past, but they are obvious holes in the current market coverage and so will doubtless be tried again.

There is a danger that in introducing too many contracts the liquidity of all markets will be reduced. Each successful market brings in its own range of participants, but may also take business from existing markets which have been used as the best available hedging instrument. It is not necessary for every product to have its own contract, but it is desirable that everyone in the oil industry can find a product which has some statistically proven relationship with the product in which they are interested.

When the first of the “Wall Street refiners”, as the US investment banks were known, arrived on the market in the late 1980s the futures markets saw these companies as something of a threat because they appeared to be trying to take much of the business off the exchange floors to be done over the counter. In fact, they are only able to offer their highly specific instruments to their clients because liquid future markets exist in which they can lay off their risk.

9 Options

David Knox

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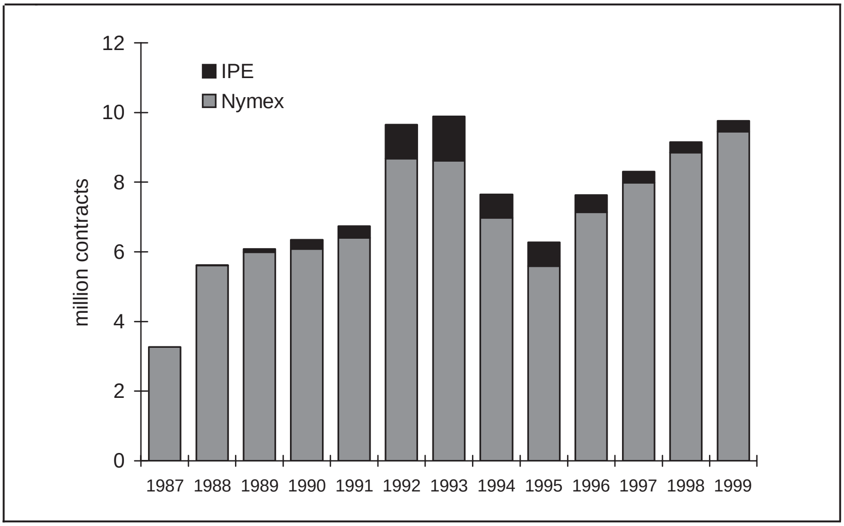
9.1 Introduction

Options allow the user to create a position that reflects virtually any market view or risk profile. They are more flexible than forwards or futures, which can only be used to take a long or short position. Combining options with other instruments allows participants to structure risk management and trading strategies that can match or control their exposure.

Options have existed for many years, often embedded in normal commercial contracts, but they were rarely regarded as an asset and – as a result – were largely undervalued. However, now that mathematical models provide an accepted method for valuing assets, a standardised methodology is widely used for calculating option values and risk. And the fact that these models have proved to be robust throughout the volatility cycle has given the industry the confidence to expand and develop the options market.

Options are currently traded both on the regulated futures exchanges and on the unregulated "over-the-counter" (OTC) market. The OTC market offers more flexibility and frequently provides the innovative pressure required to develop new contracts. Exchange trading of options formally began in 1973 when the Chicago Board of Trade (CBOT) created the Chicago Board



Source: Nymex, IPE

Figure 9.1 Growth of exchange-traded oil options, 1987–1999

Options Exchange (CBOE) to offer options on individual company stocks and many other exchanges have followed suit. Options have spread rapidly from company stocks to the financial and commodity markets, including oil.

The first exchange traded options in oil were traded on the International Petroleum Exchange (IPE) in 1983 on an informal basis, and by the end of 1986 there was enough interest from the industry for the New York Mercantile Exchange (Nymex) to launch an options contract based on West Texas Intermediate (WTI) crude. Since then, several more exchange-traded options contracts have been created by the Nymex and the IPE including New York Harbor heating oil and gasoline, the Nymex 3:2:1 "crack spread", US natural gas, Brent crude oil and north-west Europe gasoil. The OTC market has also expanded greatly in terms of participants and the types of contracts offered. OTC contracts are written on a greater variety of crude oils, products and natural gas pricing indices.

Over the past 10 years, the use of options in the energy industry has increased rapidly, largely because of their success as an effective risk management and trading tool. Further growth in the options market will come from a wider acceptance by those sectors of the economy that recognise the need to protect the value of their assets from the volatility of the market.

9.2 What is an option?

Options work like insurance. They provide the buyer (or *option holder*) with protection against the adverse effects of unpredictable future price movements in exchange for a fixed payment (or *premium*) that is paid in advance to the seller (or *option writer*). The option holder's risk is limited to the premium – which is retained by the option writer whatever happens to prices – while the option writer's risk is unlimited, because the option holder must be compensated for any adverse price movements.

Options are different from other trading instruments because they give the option holder the *right, but not the obligation,* to buy (or sell) an underlying asset at a specified price during an agreed period of time. As a result, an options contract will only be *exercised* if the market moves in favour of the holder.

9.2.1 Option contracts

There are 2 basic types of option contract:

- *call* options, which give the holder the right to buy, and,
- *put* options, which give the holder the right to sell.

The buyer of a call option pays a premium to the seller and, in return, has the right (but not the obligation) to buy a specific amount and type of oil at a fixed price, before or at a given date.

The buyer of a put option pays a premium to the seller and, in return, has the right (but not the obligation) to sell a specific amount and type of oil at a fixed price, before or at a given date.

The option seller is obliged under the contract to buy or sell should the buyer exercise its right. In return for assuming this obligation, the option seller receives the option premium – a non-refundable payment – from the option buyer. Option premiums are typically paid up front (usually within 2 business days following the date of the transaction) unless the option contract is traded on an exchange, in which case the margin rules operated by the exchange will apply.

The fixed price is usually known as the *strike* or *exercise price*. The date agreed in the contracts is usually known as the *expiration date*, the *exercise date* or the *maturity* of the option. If the market price of the underlying asset changes so that it becomes profitable for the buyer to exercise the option, it is described as being in-the-money and acquires an *intrinsic value* as a result. Options that remain unprofitable are described as being out-of-the-money. If the market price is the same as the

Table 9.1 Basic options terminology

Buyer	Also known as the option holder. The buyer of an option pays a premium (a sum of money) and has the right (but not the obligation) to exercise the option into the underlying contract.
Seller	Also known as the writer or grantor of the option. The seller receives the premium from the option buyer, and is obliged to assume the opposite position to the option buyer.
Call option	Gives the option holder the right to buy a specific amount of a specified type of commodity at a fixed price. The option writer must sell the commodity should the holder exercise his right to buy.
Put option	Gives the option holder the right to sell a specific amount of a specified type of commodity at a fixed price. The option writer must buy the commodity should the holder exercise his right to sell.
Underlying commodity	Can be any type of crude oil, refined product or natural gas that is specified in the options contract.
Quantity	An agreed amount of the underlying commodity that is to be delivered under the terms of the contract. Can be measured in barrels, tonnes, litres, gallons or mmbtus.
Premium	A fixed non-returnable payment made by the option holder to the option writer. The premium is the maximum amount the buyer can lose. The seller receives the premium and in return underwrites the contract. The premium is usually quoted in the same units as the underlying commodity, for example: $ per barrel, $ per tonne, cents per gallon, cents per litre, $ per mmbtu.
Strike price	A fixed price at which the holder of a call option has the right to buy the underlying commodity. Also the fixed price at which the holder of a put option has the right to sell the underlying commodity.
Exercise	The action taken by the option holder who wishes to acquire or sell the underlying commodity as specified on the option contract.
Expiration date	The last day on which an option can be exercised.
Intrinsic value	The amount of money that could be realised by exercising an option.
In-the-money	An option is deemed to be in-the-money if it has an intrinsic value. Its intrinsic value is the amount by which it is in-the-money.

Table 9.1 Continued

Out-of-the-money	A call option is deemed to be out-of-the-money if the market price is below the strike price.
At-the-money	An option is deemed to be at-the-money if the market price is the same as the option strike price. An at-the-money option has no intrinsic value.
Extrinsic value	The amount by which the premium of an option exceeds its intrinsic value. Also known as the time value of an option.

Table 9.2 Option prices, $/barrel

Underlying market price: $20.00, 30 days left to expiry

Strike price	Calls		Puts	
	Premium	Status	Premium	Status
18.00	2.05	in-the-money	0.05	out-of-the-money
19.00	1.20	in-the-money	0.20	out-of-the-money
20.00	0.56	at-the-money	0.56	at-the-money
21.00	0.21	out-of-the-money	1.21	in-the-money
22.00	0.08	out-of-the-money	2.08	in-the-money

exercise price, the option is described as being at-the-money (see Table 9.2).

A call option has an intrinsic value when the strike price is below the market price. For example, if the strike price is $18/barrel and the market price is $20/barrel, the intrinsic value of the call option is $2/barrel.

A put option has an intrinsic value when the strike price is above the market price. For example, if the strike price is $22/barrel and the market price is $20/barrel, the intrinsic value of the put option is $2/barrel.

An option may be out-of-the-money and still have a *premium value*. This is because of the option's *time value* or *extrinsic value*. As long as an option has time left to expiry, there is a probability that it might end up in-the-money before expiry, in which case it would acquire an *intrinsic value*.

For example, if a call option has 30 days left to expiration, the strike price is $20/barrel and the market price is $19/barrel, the option premium is $0.21/barrel even though it has no intrinsic value at present.

9.2.2 Types of option

Options can be based on and therefore exercised into a wide variety of trading instruments. They can also be traded either on a futures exchange or as private transactions on the OTC market.

Exchange traded options are based on futures contracts and are standardised contracts. The settlement terms are fixed, the expiry dates are fixed, and only a limited range of strike prices are quoted at any point in time. As a result, the premium is the only negotiable component.

OTC options are more flexible as they can be tailored to meet any set of specifications required. Everything in the contract is negotiable: the quantity, type, delivery or settlement procedure of the underlying asset, the expiry date, and the strike price for the contract.

Like futures contracts, exchange-traded options are guaranteed by the clearing organisation that underwrites the exchange. OTC options are guaranteed by the counterparties in the contract and are subject to the normal contractual performance risks associated with trading directly with companies. OTC contracts are usually based on an ISDA* (International Swaps and Derivatives Association) contract or sometimes on a company's own contract – although this is now being discouraged for the sake of standardisation.

Exchange-traded options

Exchange-traded options are bought and sold on the trading floors of the futures exchanges in designated areas (called pits) which are located near the underlying futures contract pit. Prices are quoted in the trading pits by open outcry. Registered brokers execute orders placed with them on behalf of their clients on the exchange. Price quotes can be obtained either electronically through price reporting vendors or by asking a broker to enquire on the exchange.

Trading in options may commence once an account is opened with a clearing exchange member. To place an order to buy or sell, the client informs the exchange broker of the trade details, the order is then passed to the trading floor where a floor broker

* www.isda.org.

will execute the order in the trading pit. Once a trade has taken place, the information is logged and reported. Prices and trades are logged real-time and are displayed electronically on the exchange floor and also fed into vendor price reporting systems available to the public.

The transaction is then cleared and allocated to your account. The option position you now hold in the account will be marked to market at the close of business each day. You may be required to place funds with your clearing broker to cover deposit and variation margins in order to offset the costs of adverse market movements to your position.

Brokers are required by exchanges to provide you with financial statements showing the value of your position to the market. The transparency of prices on the exchange allows position holders to monitor their own exposure.

Premiums on the Nymex are payable immediately. On the International Petroleum Exchange (IPE), however, premiums are not transferred because of the exchange's margining system. In all cases the clearing organisation is the counterparty to the transaction.

OTC options

OTC options are contracts made between two counterparties. Companies who transact in this manner are typically major oil companies, refiners, producers, distributors, end users (including transport and utility companies), banks, traders, insurance companies and investment funds.

Trading in the OTC market offers greater flexibility and benefits. In particular:

- positions can be tailored to match any risk profile,
- contracts can be exercised into a wide range of refined products, crude oils and natural gas,
- pricing periods, timing, location and price indices can all be negotiated thus eliminating any basis risk,
- large volumes can be more easily traded,
- trade and project finance can be combined with OTC options to provide alternatives to traditional financing methods,
- investor participation vehicles can be constructed to reflect risk appetites,
- transaction details are generally kept confidential between the counterparties,
- transaction costs are often lower,

- direct dealing relationships between companies can often enhance trading relationships.

A company wishing to trade an OTC option may call on a number of counterparties with whom credit lines and contracts are in place. A quote (in the form of a price) would then be requested. Once a trade has taken place, it is agreed verbally on the telephone, followed by a fax or telex for confirmation and then a signed original contract.

Premiums tend to be paid within 2 business days (although some companies may specify 5 business days). A company will typically have a pre-arranged amount of trade credit available with a number of other counterparties. Letters of credit, bank guarantees and deposits are sometimes required to secure trading lines.

Positions are marked to market daily, although some companies operate on an intra-day basis.

Exercising options

There two basic methods of exercising options:

- *American* options, which can be exercised at any time up to the expiry date, and
- *European* options, which can only be exercised on the expiry date.

Exchange traded options are all American, while OTC options can be of either type. Some option writers prefer to sell European options as this allows them to plan their exposure more accurately.

Options are usually exercised when the buyer notifies the option writer of their intention to do so. In the case of an exchange traded option the notification is sent to the clearing organisation via a clearing member of the exchange, the option is then converted into an appropriate futures position on the following business day. In the case of an OTC option the buyer typically notifies the option writer by telephone (followed up with telex or fax confirmation) and the underlying asset is delivered as specified in the contract. In both cases, options are usually automatically exercised on the last day of trading if they are deemed to be in-the-money.

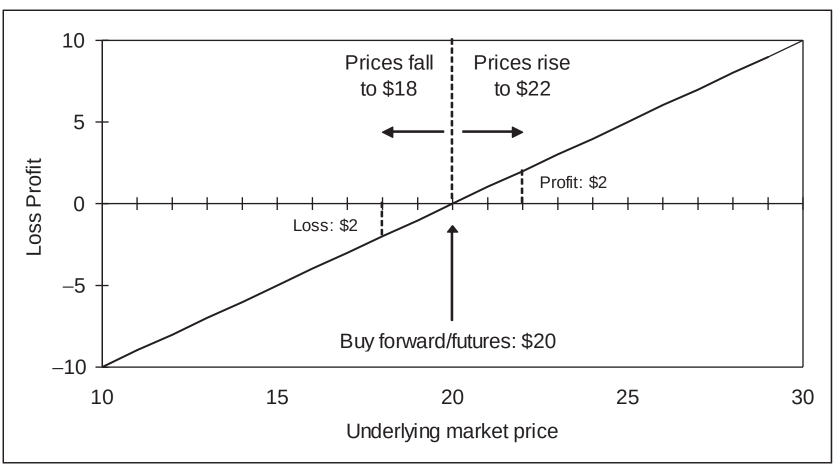
Another method of settling or exercising options that is regulary used in the OTC market is the *Asian* or *average settlement price* option. *Asian* or *average price* options are typically settled in cash. The settlement is calculated using the average of the price settlements of an index over the life of a contract. Asian options are typically used to match the pricing methods used in the physical markets. Sellers of options sometimes prefer these to American or European types as exposure to volatile market movements may be reduced due to the averaging of prices.

9.2.3 Option trading positions

There are four basic option trading positions, each of which has its own characteristic profile of risk and reward:

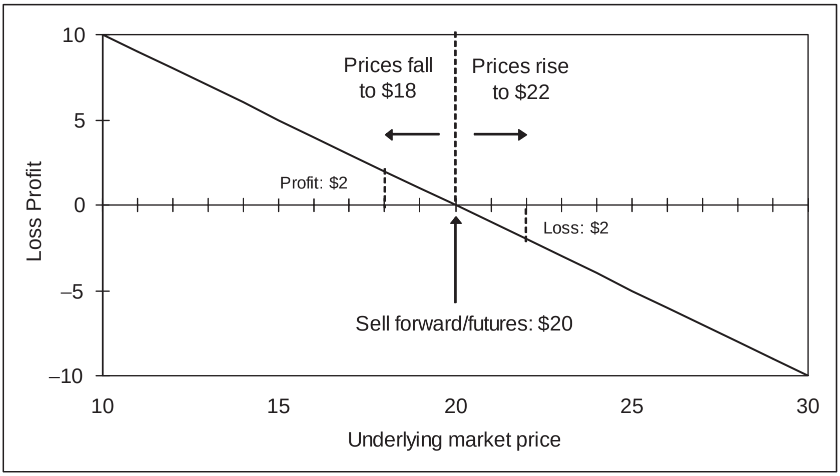
- *buy a call*, i.e. purchase an option to buy the underlying commodity or asset,
- *buy a put*, i.e. purchase an option to sell the underlying commodity or asset,
- *sell a call*, i.e. write a contract that gives the purchaser the option to buy the underlying commodity or asset,
- *sell a put*, i.e. write a contract that gives the purchaser the option to sell the underlying commodity or asset.

In forward and futures markets, both buyer and seller have the same symmetric price risks. In the case of the buyer, any potential profit from a rise in prices is mirrored by the potential loss from a decline in prices (see Fig. 9.2). And the exact opposite applies to the seller (see Fig. 9.3). As a result, there are



Source: Standard Bank London Ltd

Figure 9.2 Buying a forward or futures contract



Source: Standard Bank London Ltd

Figure 9.3 Selling a forward or futures contact

only 2 basic types of forward or futures trading position, long and short.

In the options market, however, the buyer and seller have very different exposures to price risk. The option holder's profit is unlimited, while the loss is limited to the premium paid. And the option writer's profit is limited to the premium received, while the loss is unlimited.

Buying a call option

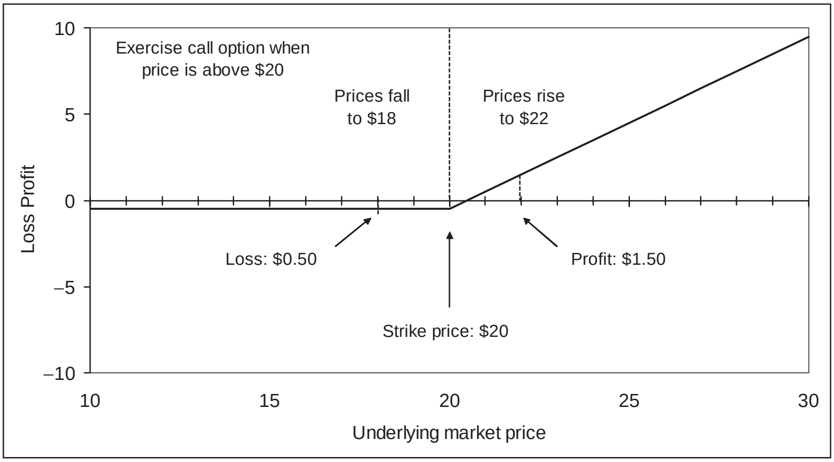
The holder of a call option (which confers the right to buy at an agreed price) makes an unlimited profit if prices rise and only loses a fixed amount if prices fall (see Fig. 9.4). The risks on the upside are therefore the same as for a long forward or futures contract (see Fig. 9.2).

Example

Buy a call option:

Strike price:	$20.00/barrel
Premium:	$0.50/barrel

If the price of oil rises to $22/barrel at expiration of the contract, the option will have an in-the-money value or intrinsic value of $2.00/barrel and will therefore be automatically exercised. The



Source: Standard Bank London Ltd

Figure 9.4 Buying a call option

profit on this transaction is $1.50/barrel, which is calculated by subtracting the call option premium from the intrinsic value:

$$\$2.00 - \$0.50 = \$1.50/\text{barrel}$$

If the price of oil falls to $18/barrel, the option will expire out of the money, have no intrinsic value and will not be exercised. The loss on this transaction is therefore limited to the premium paid, $0.50/barrel.

Buying a put option

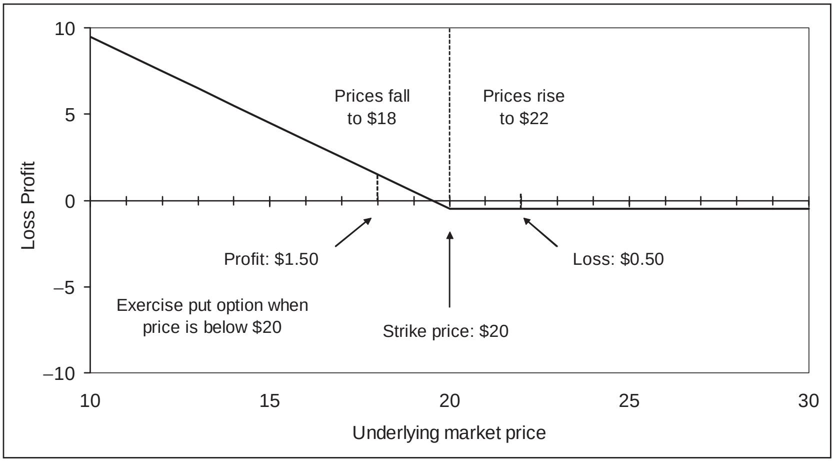
The holder of a put option (which confers the right to sell at an agreed price) makes an unlimited profit if prices fall, and only loses a fixed amount if prices rise (see Fig. 9.5). The risks on the upside are therefore the same as for a short forward or futures contract (see Fig. 9.3).

Example

Buy a put option:

Strike price:	$20.00/barrel
Premium:	$0.50/barrel

If the price of oil falls to $18/barrel at expiration of the contract, the option will have an in-the-money value or intrinsic value of $2.00/barrel and will be automatically exercised. The profit of the



Source: Standard Bank London Ltd

Figure 9.5 Payoff from buying a put option

transaction is $1.50/barrel and is calculated by subtracting the put option premium from the intrinsic value:

$2.00 – $0.50 = $1.50/barrel

If the price of oil rises to $22/barrel at expiration, the option will be out-of-the-money, have no intrinsic value and will not be exercised. The loss on this transaction is therefore limited to the premium paid, $0.50/barrel.

Selling a call option

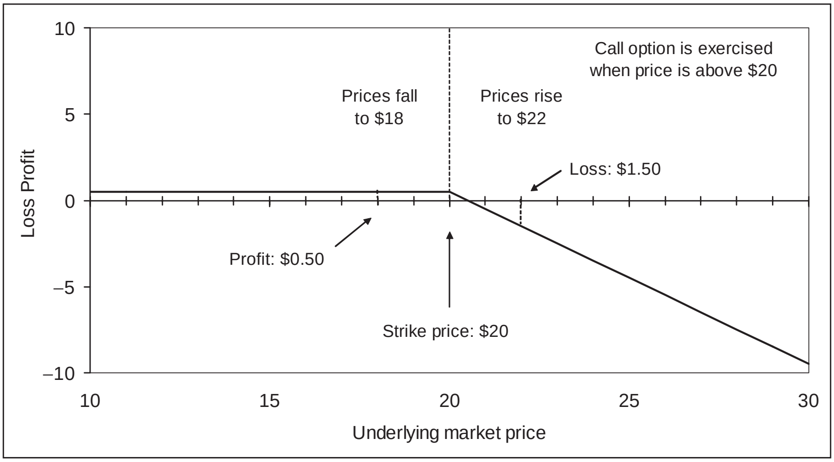
The writer of a call option (which gives the holder the right to buy at an agreed price) makes a fixed profit if prices fall, and is exposed to an unlimited loss if prices rise (see Fig. 9.6). The risks on the downside are therefore the same as for a short futures or forward contract (see Fig. 9.3).

Example

Sell a call option:

Strike price:	$20.00/barrel
Premium:	$0.50/barrel

If the price of oil is at or below $20/barrel at expiration of the contract, the option will expire out-of-the-money – so will not be



Source: Standard Bank London Ltd

Figure 9.6 Selling a call option

exercised – and the seller keeps the premium received. The profit on this trade is therefore limited to the premium: $0.50/barrel.

If the price of oil rises to $22/barrel at expiration the option will be exercised and the writer is obligated to sell oil at $20/barrel. The loss on this transaction is $1.50/barrel and is calculated by subtracting the market price from the strike price:

$$\$20 - \$22 = -\$2/\text{barrel}$$

and adding the premium received:

$$-\$2.00 + \$0.50 = -\$1.50/\text{barrel}$$

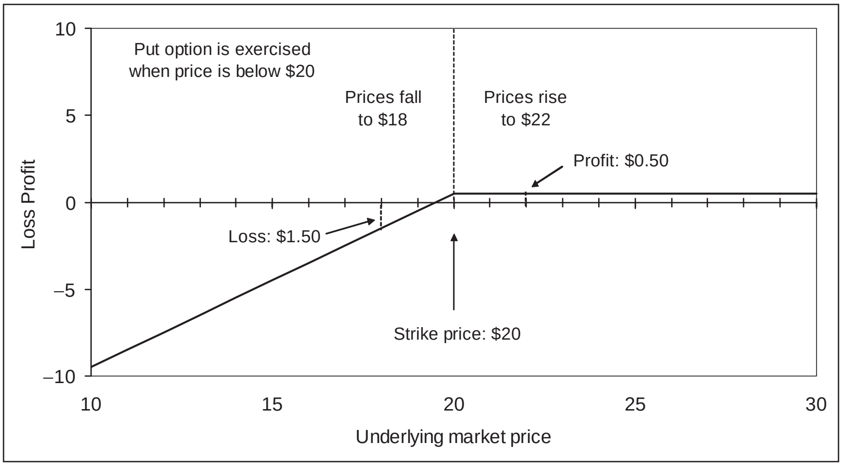
Selling a put option

The writer of a put option (which gives the holder the right to sell at an agreed price) makes a fixed profit if prices rise, and is exposed to an unlimited loss if prices fall (see Fig. 9.7). The risks on the downside are therefore the same as that of a long futures or forward contract (see Fig. 9.2).

Example

Sell a put option:

Strike price:	$20.00/barrel
Premium:	$0.50/barrel



Source: Standard Bank London Ltd

Figure 9.7 Selling a put option

If the price of oil is at or above $20/barrel at expiration of the contract, the option will expire out-of-the-money – so will not be exercised – and the seller keeps the premium received. The profit on this trade is limited to the premium: $0.50/barrel.

If the price of oil falls below $20/barrel at expiration, the contract will have an intrinsic value – calculated by subtracting the strike price from the market price – and will be exercised.

If the price of oil falls to $18/barrel at expiration, the seller is still obliged to buy at $20/barrel. The loss on this transaction is $1.50/barrel and is calculated by subtracting the premium received from the intrinsic value:

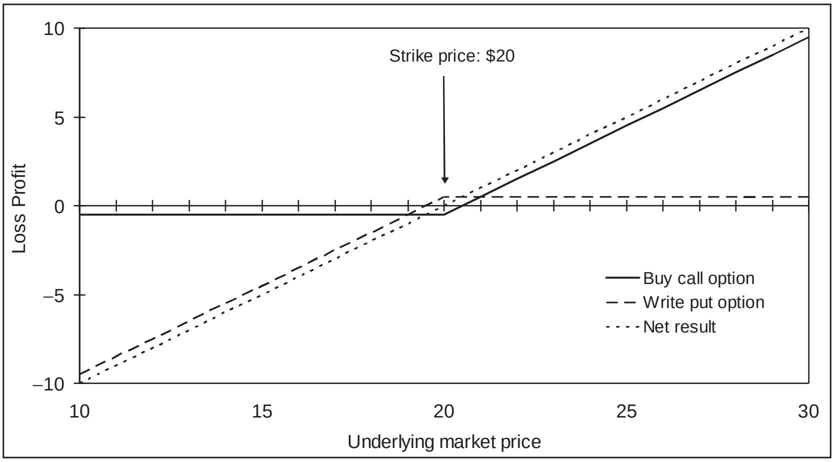
$$\$2.00 - \$0.50 = \$1.50/\text{barrel}$$

9.2.4 Synthetic contracts

Options contracts can also be used to replicate a short or long position in the forward or futures market. For example, it should now be clear from comparing their respective risk and reward profiles, that taking a long position in the forward or futures market is equivalent to simultaneously selling a put and buying a call at the same strike price and for the same maturity:

$$+\text{FORWARD} = +\text{CALL} - \text{PUT}$$

This is known as a synthetic long forward or futures position (see Fig. 9.8).



Source: Standard Bank London Ltd

Figure 9.8 Synthetic long forward or futures contract

Example

Buy a $20/barrel call option:	–$0.50/barrel
Sell a $20/barrel put option:	+$0.50/barrel
Net cost of transaction:	$0.00/barrel

If prices rise to $21/barrel, the call option will have an intrinsic value of $1/barrel and the put option will have no intrinsic value. The profit on the transaction is the intrinsic value minus the net cost:

$$\$1.00 - \$0.00 = \$1.00/\text{barrel}$$

If prices fall to $19/barrel, the call option will have no intrinsic value and the put option will have an intrinsic value of –$1.00/barrel. The profit of the transaction is therefore:

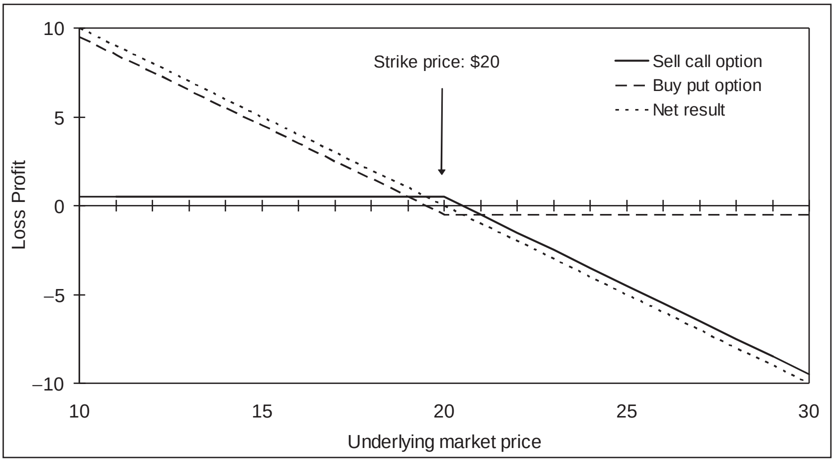
$$-\$1.00 - \$0.00 = -\$1.00/\text{barrel}$$

This position has the same profit/loss profile as a long futures or forward position at $20/barrel (see Fig. 9.2).

Similarly, taking a short position in the forward or futures market is equivalent to simultaneously buying a put and selling a call at the same strike price and for the same maturity:

$$-\text{FORWARD} = -\text{CALL} + \text{PUT}$$

This is a short synthetic forward or futures position (see Fig. 9.9).



Source: Standard Bank London Ltd

Figure 9.9 Synthetic short forward or futures contract

Example

Buy a $20/barrel put option:	–$0.50/barrel
Sell a $20/barrel call option:	+$0.50/barrel
Net cost of transaction:	$0.00/barrel

If prices fall to $19/barrel, the put option will have an intrinsic value of $1/barrel and the call option will have no intrinsic value. The profit on the transaction is the intrinsic value minus the net cost:

$1.00 – $0.00 = $1.00/barrel

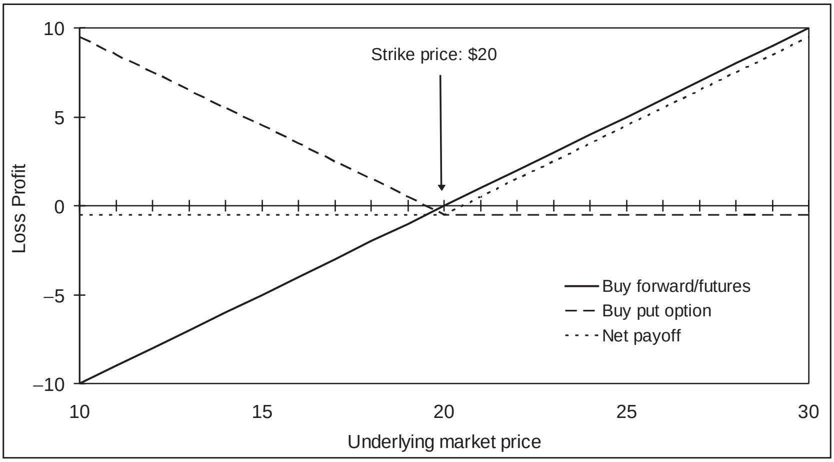
If prices rise to $21/barrel, the put option will have no intrinsic value and the call option will have an intrinsic value of –$1.00/barrel. The profit on the transaction is therefore:

–$1.00 – $0.00 = –$1.00/barrel

This position has the same profit/loss profile as a long futures or forward position at $20/barrel (see Fig. 9.3).

Furthermore, it is also possible to replicate the risk and reward characteristics of a call (or put) option with an appropriate combination of forward or futures contracts and a put (or call) option.

For example, buying a put option and taking a long position in the forward or futures market is equivalent to buying a call option (see Fig. 9.10):



Source: Standard Bank London Ltd

Figure 9.10 Synthetic long call option

$$+\text{CALL} = +\text{FORWARD} + \text{PUT}$$

Buying a call option and taking a short position in the forward or futures market is equivalent to buying a put option:

$$+\text{PUT} = +\text{CALL} - \text{FORWARD}$$

And, by re-arrangement, selling a put or selling a call is also equivalent to:

$$-\text{PUT} = +\text{FORWARD} - \text{CALL}$$

$$-\text{CALL} = -\text{PUT} - \text{FORWARD}$$

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9.3 Using options

Options can be used to achieve a great variety of possible outcomes depending on the exposure and risk preferences of the user. Given the inherent flexibility of the four basic option positions, even simple trading strategies can yield different results. Combinations of option contracts can be used to produce tailor-made risk management and trading profiles, often at a very low cost. This section describes 4 common option trading strategies that are widely used in the oil industry.

9.3.1 Producer hedge

An oil producer would like to hedge the value of its production. The current price of crude is $20/barrel. The producer expects prices to fluctuate in the range of $19–$21/barrel during the period of the hedge, but is concerned about the risk of prices falling below $19/barrel. If the producer is also prepared to accept a maximum price of $21/barrel for its production, a combination of put and call options can be used to hedge at no cost.

Example

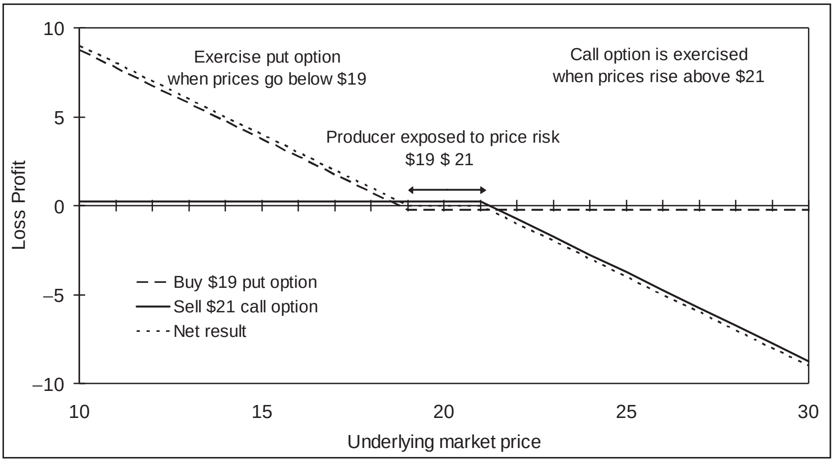
Buy a $19/barrel put option:	–$0.25/barrel
Sell a $21/barrel call option:	+$0.25/barrel
Net cost of transaction:	$0.00/barrel

The result of this strategy is to limit the downside and upside price risks to a range between $19/barrel and $21/barrel (see Fig. 9.11).

If prices fall below $19/barrel, the $19 put option will be exercised giving the producer the right to sell its output at $19/barrel, however low prices go.

If prices rise above $21/barrel, the $21 call option will be exercised and the producer will be obliged to sell crude at $21/barrel, however high prices go. If prices are between $19/barrel and $21/barrel, neither option will be exercised and the producer sells its crude at the prevailing market price.

This trading strategy is known as a zero cost collar. The strike price of the options can be set at any level, but the put and call options must be equally far out-of-the-money if the cost of the put and call premium is to be the same.



Source: Standard Bank London Ltd

Figure 9.11 Hedging crude oil sales, zero cost collar

9.3.2 Airline hedge

An airline has based its jet fuel purchasing budget on a maximum price of $190/tonne for the winter period. The current price for jet kerosene cif NW Europe is $170/tonne. The purchasing department have decided not to lock in a price at the current market level because they feel that prices may fall further to around $150/tonne. To protect themselves against a price move above $190/tonne, the purchasing department could buy $190 call options at a cost of $1/tonne.

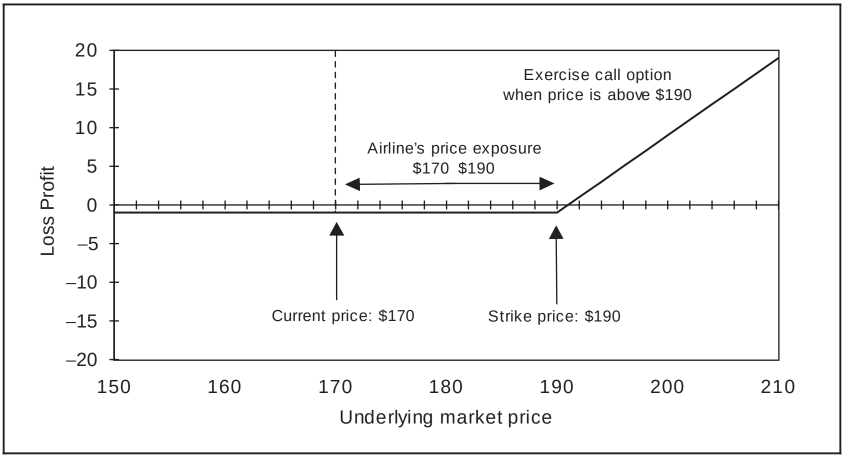
Example

Buy a $190/tonne call option:	–$1.00/tonne
Net cost of transaction:	$1.00/tonne

The result of this strategy is to limit the upside price risk so that the maximum price paid by the airline for its jet fuel would be $190/tonne (see Fig. 9.12).

If prices remain below $190/tonne, the $190 call option will not be exercised and the purchasing department can meet its budget target with direct purchases on the spot market.

If prices rise above $190/tonne, the $190 call option will be exercised and the airline can obtain its supplies from the option writer at $190/tonne, however high spot market prices go.



Source: Standard Bank London Ltd

Figure 9.12 Hedging fuel purchases, buy a call option

If the airline purchasing department thinks that the $1/tonne premium is too expensive, they could consider selling put options to finance the cost of buying the call option. Selling a $150 put option would generate a premium of $1/tonne that exactly offsets the cost of buying the $190 call option (a zero cost collar).

Example

Buy a $190/tonne call option:	–$1.00/tonne
Sell a $150/tonne put option:	+$1.00/tonne
Net cost of transaction:	$0.00/tonne

The result of this strategy is to limit the upside and downside price risks to a range between $190/tonne and $150/tonne.

If prices rise above $190/tonne, the $190 call option will be exercised giving the purchasing department the right to buy its supplies at a maximum price of $190/tonne, however high prices go.

If prices fall below $150/tonne, the $150 put option will be exercised and the purchasing department will be obliged to buy jet fuel at $150/tonne, however low prices go. If prices are between $150/tonne and $190/tonne, neither option will be exercised and the airline buys its jet fuel at the prevailing market price.

Both these strategies are widely used by airlines and the strike prices can be set at any level.

9.3.3 Reducing storage costs

A trader is holding product in storage at a monthly cost of \$2.50/tonne. The current market price of the refined product is \$155/tonne. If prices rise by \$5/tonne the trader will sell the product, otherwise the long position will be maintained. However, the cost of storage can be reduced by selling an out-of-the-money call option that still allows the trader to make a profit should prices rise by \$5/tonne.

Example

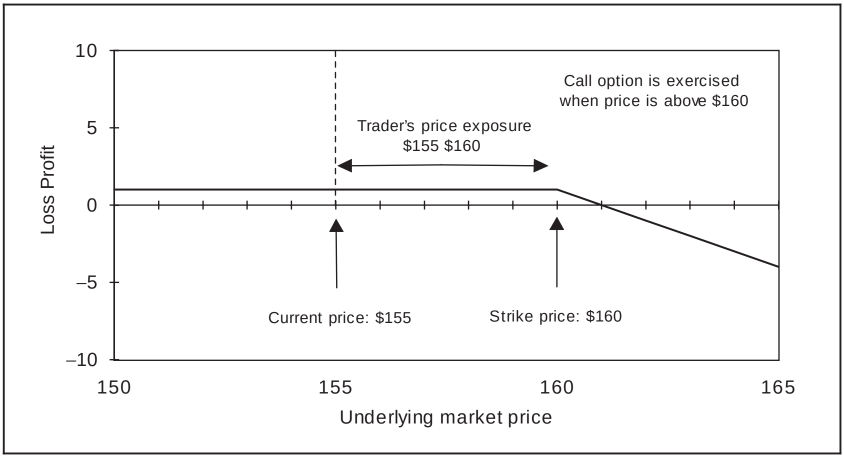
Sell a \$160/tonne call option:	+\$1.00/tonne
Net cost of transaction:	+\$1.00/tonne

This strategy caps the maximum sales price for the trader's product at \$160/tonne in exchange for a fixed premium of \$1/tonne that can be offset against the cost of storage (see Fig. 9.13).

If market prices remain below \$160/tonne until expiration, the \$160 call option will not be exercised and the trader will keep the product in storage as planned. However, the trader still retains the \$1/tonne call premium paid by the option holder and so the net storage cost is reduced:

$$\$2.50 – \$1.00 = \$1.50/\text{tonne}$$

If market prices rise above \$160/tonne, the \$160 call option will be exercised by the holder and the trader will only receive a



Source: Standard Bank London Ltd

Figure 9.13 Reducing storage costs, sell a call option maximum selling price of $160/tonne, however high prices go. However, the trader still retains the $1/tonne option premium and so achieves the $5/tonne profit objective at a lower storage cost.

9.3.4 Refinery margin hedge

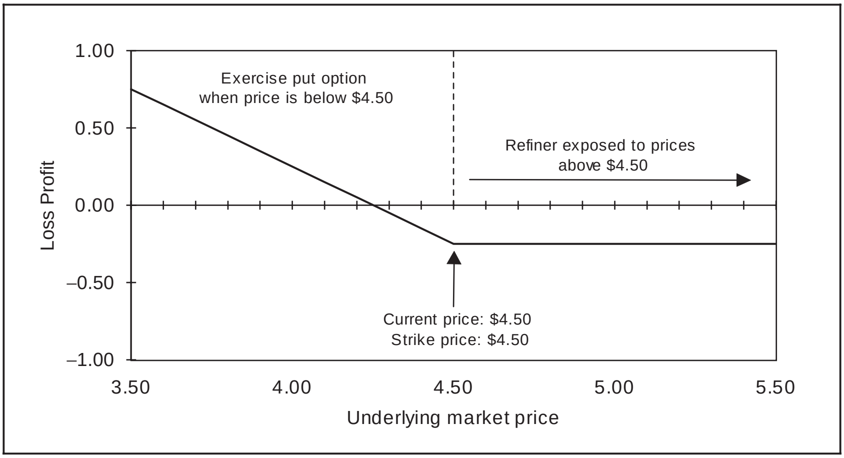
A refiner would like to hedge the gas oil crack spread without losing the opportunity to profit from higher margins should the spread widen in the future. The current crack spread between Brent and gas oil is $4.50/barrel. If the refiner buys an at-the-money crack spread put option at a cost of $0.25/barrel, it will be protected against a narrowing of the crack spread. But if the crack spread widens, the refiner will be able to benefit from the increase after allowing for the cost of the put option.

Example

Buy a $4.50/barrel put option:	–$0.25/barrel
Net cost of transaction:	–$0.25/barrel

This strategy eliminates the downside risk on the crack spread and leaves the refiner free to participate in any upside price movements (see Fig. 9.14).

If the crack spread falls below the current market level of $4.50/barrel, the refiner will exercise his option to sell at this price, thus avoiding any exposure to a narrower crack spread.



Source: Standard Bank London Ltd

Figure 9.14 Hedging refinery margins, buy a put option

If the crack spread widens, the put option will not be exercised and the refiner is free to sell at the higher market price. However, the potential profit is reduced by the cost of the premium paid for the put option. For example, if the crack spread widens to $5/barrel, the net gain to the refiner would be:

$$\$5.00 - \$4.50 - \$0.25 = +\$0.25/\text{barrel}$$

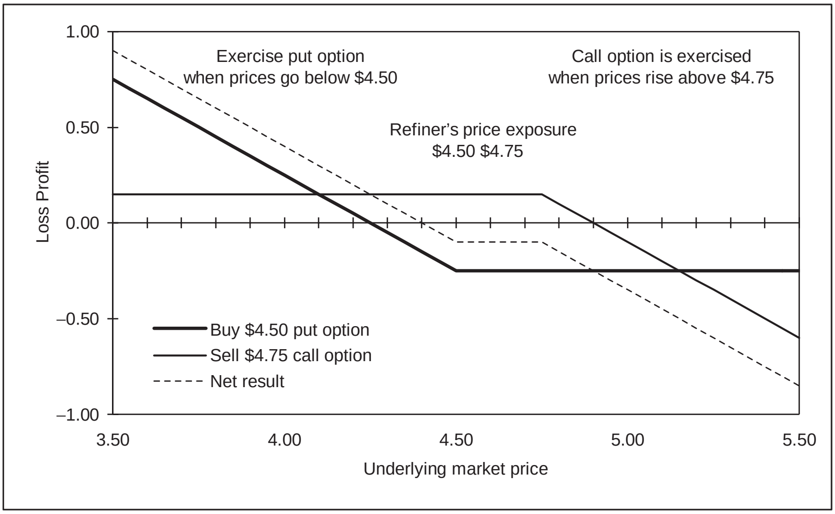
If the refiner feels that the put option premium is too high, it could reduce the cost of hedging by selling out-of-the-money call options.

Example

Buy a $4.50/barrel put option:	–$0.25/barrel
Sell a $4.75/barrel call option:	+$0.15/barrel
Net cost of transaction:	–$0.10/barrel

This strategy eliminates the downside price risk on the crack spread and caps the upside profit potential for the refiner in exchange for a lower cost of hedging (see Fig. 9.15).

If the crack spread falls below the current market level of $4.50/barrel, the refiner will exercise the option to sell at this price, thus avoiding any exposure to a narrower crack spread. The call option will not be exercised by the holder, but the refiner



Source: Standard Bank London Ltd

Figure 9.15 Hedging refinery margins, low cost collar option will retain the premium received and this reduces the cost of hedging:

$$-\$0.25 + \$0.15 = -\$0.10/\text{barrel}$$

This is known as a low cost collar option.

If the crack spread widens to more than $4.50/barrel, the put option will not be exercised leaving the refiner free to sell at the higher market price. Any additional profit from the widening crack spread above $4.75/barrel is offset by the call option, which will now be exercised by the holder. As a result, the refiner will be obliged to sell the crack spread at $4.75/barrel, whatever happens to prices. However, the refiner still makes a profit, because the net cost of hedging is less than the increase in the crack spread:

$$(\$4.75 - \$4.50) + (-\$0.25 + \$0.15) = +\$0.15/\text{barrel}$$

Once again, the put and call strike prices can be set at any level required by the refiner.

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9.4 Pricing options

The price of an option, like any other derivative trading instrument, is determined partly through arbitrage and partly by the market itself. In the case of options, the key arbitrage relationships are with the forward and futures markets for the underlying commodity or asset.

Since different combinations of option contracts can be used to replicate the trading characteristics of forwards and futures, the price of an option cannot get very far out of line with its forward or futures market equivalent. In the same way, arbitrage also ensures that the strict price relationship between the 2 sides of the options market – puts and calls – remains intact. This is known as *put–call parity*. As a result, the options market itself is primarily concerned with the question of future price volatility, which is what determines the price of an option once the underlying arbitrage relationships have been taken into account.

9.4.1 Put–call parity

Options contracts can be used to replicate a short or long position in the forward or futures market (*see Section 9.2.4*).

For example, taking a long position in the forward or futures market is equivalent to simultaneously buying a call and selling a put option at the same strike price and for the same maturity:

+FORWARD = + CALL – PUT

Example

Buy a $20/barrel call option:	–$0.25/barrel
Sell a $20/barrel put option:	+$0.25/barrel
Net cost of transaction:	$0.00/barrel

Assume both options will expire in 30 days' time.

If the underlying futures contract is trading at $20/barrel at expiry, the profit/loss on the trade will be zero as both option positions have no intrinsic value.

If the underlying futures contract is trading at $21/barrel at expiry, the short put option will expire worthless (i.e. with no intrinsic value), while the long call option will have an intrinsic value of $1/barrel.

If the underlying futures contract is trading at $19/barrel at expiry, the long call option will expire worthless (i.e. with no intrinsic value), while the short put option will have an intrinsic value of –$1/barrel.

Compare these outcomes to a long position in the underlying futures contract at $20/barrel (see Fig. 9.2). They are identical.

Similarly, taking a short position in the forward or futures market is equivalent to simultaneously buying a put and selling a call at the same strike price and for the same maturity.

–FORWARD = – CALL + PUT

Example

Buy a $20/barrel put option:	–$0.25/barrel
Sell a $20/barrel call option:	+$0.25/barrel
Net cost of transaction:	$0.00/barrel

Assume both options will expire in 30 days' time.

If the underlying futures contract is trading at $20/barrel at expiry, the profit/(loss) on the trade will be zero as both option positions have no intrinsic value.

If the underlying futures contract is trading at $21/barrel at expiry, the short call option will expire worthless (i.e. with no intrinsic value), while the long put option will have an intrinsic value of $1/barrel.

If the underlying futures contract is trading at $19/barrel at expiry, the long put option will expire worthless (i.e. with no intrinsic value), while the short call option will have an intrinsic value of –$1/barrel.

Compare these outcomes to a short position in the underlying futures contract at $20/barrel (see Fig. 9.3). They are also identical.

Conversion arbitrage

The fact that options can create identical results to a futures or forward position creates the possibility of arbitrage between them. Market forces should therefore keep prices in line with each other.

Example

Futures contract:	$20.00/barrel
$17/barrel call option:	$0.25/barrel
$17/barrel put option:	$0.25/barrel

If the $20 call and put option premiums were different to each other when the futures price was also at $20/barrel, arbitrage would be possible.

For example, if the cost of a $20 call option was $0.30/barrel and the cost of a put option was $0.25/barrel, it would be possible to create a synthetic short futures position equivalent to $20.05/barrel and simultaneously buy the actual futures contract at $20.00/barrel, thus locking in $0.05/barrel profit on the transaction:

Sell $20 call option	+$0.30/barrel
Buy $20 put option	–$0.25/barrel
= Synthetic short futures position	$20.05/barrel
Long futures	–$20.00/barrel
Short synthetic futures	+$20.05/barrel
Net profit on transaction:	$0.05/barrel

Such an arbitrage opportunity could not exist for long and parity between puts and calls would quickly be re-established.

9.4.2 Factors affecting option prices

There are 5 key factors that affect the price of an option based on an underlying commodity, such as oil, that pays no dividend:

- the current price of the underlying commodity,
- the strike price of the option,
- the time remaining to expiry,
- the future price volatility of the underlying commodity, and
- the current (risk free) interest rate for borrowing money.

In financial terms, the price of an option is simply the present value of the future income stream that can be expected from holding the option contract. Although the actual value of any future income stream from the option will not be known for certain until it expires, the market takes a view based on the expected price volatility of the underlying commodity and this can be deduced from the option premium by comparing it with the strike price and the current price of the underlying commodity.

The value of any option premium can therefore be split into two parts, the current (or *intrinsic*) value of the contract and the future (or *time*) value of the contract:

$$\text{Option premium} = \text{Intrinsic value} + \text{Time value}$$

The intrinsic value of an options contract is easily determined since it depends on whether or not the contract is in the money.

$$\text{Intrinsic value of call} = \text{Underlying value} - \text{Strike price}$$

$$\text{Intrinsic value of put} = \text{Strike price} - \text{Underlying value}$$

$$\text{Time value} = \text{Option premium} - \text{Intrinsic value}$$

Example

Underlying futures:	$20.00/barrel
$19/barrel call option:	$1.21/barrel

The $19 call option is in-the-money with an intrinsic value of $1.00/barrel:

$$\$20.00 - \$19.00 = \$1.00,$$

and a time value of $0.21/barrel:

$$\$1.21 - \$1.00 = \$0.21.$$

Example

Underlying futures:	$20.00/barrel
$19/barrel put option:	$0.21/barrel

The $19 put option is out-of-the-money and has no intrinsic value because there would be nothing to be gained from exercising a put option when the underlying price is above the strike price. However, the put option still has a time value of $0.21/barrel:

$$\$1.21 - \$0.00 = \$0.21.$$

The time value of an option increases with the length of the period to expiry. This is because there is a greater opportunity for prices to trade over a wider range as more time elapses. The same principle applies to a house insurance policy. A policy that has 1 year left to expiry will have a higher premium than one expiring in 6 months' time because there is a greater chance of a claim.

At-the-money options have the highest time value as there is an equal probability that they will be in- or out-of-the-money at expiration. If an option is out-of-the-money, it is more probable that it will expire out-of-the-money than an option that is nearer to or at-the-money since the underlying prices will have to change by much more to reach the strike price and, as a result, will have a lower time value. Similarly, an option that is deep in-the-money, is more likely to expire in-the-money than an option that is nearer to or at-the-money for the same reasons.

Example

Underlying futures:	\$20.00/barrel
\$19/barrel put option	\$0.20/barrel
\$20/barrel put option:	\$0.56/barrel
\$22/barrel put option:	\$2.08/barrel

The \$20 put option is at-the-money and so has no intrinsic value:

$$\$20.00 - \$20.00 = \$0.00,$$

as a result the entire value of the premium is due to its time value:

$$\$0.56 - \$0.00 = \$0.56.$$

The \$19 put option is out-of-the-money and also has no intrinsic value. However, its premium – and therefore its time value – is lower than for the \$20 at-the-money call option:

$$\$0.20 - \$0.00 = \$0.20.$$

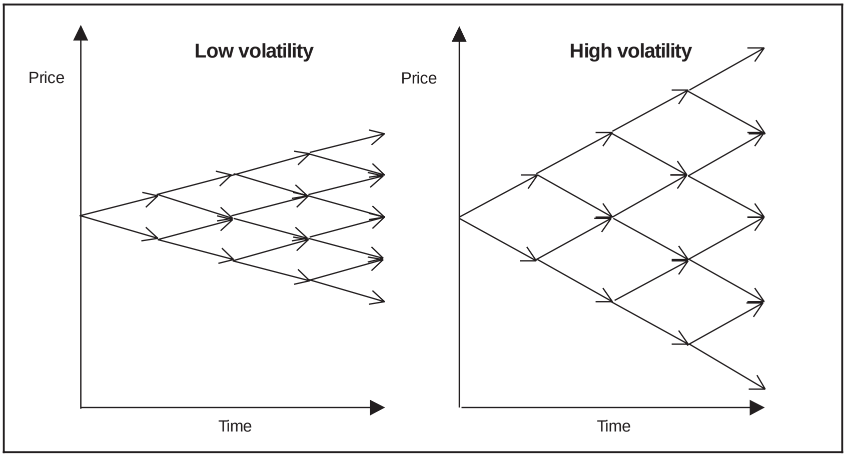
The \$22 put option is in-the-money and has an intrinsic value of \$2.00/barrel:

$$\$22.00 - \$20.00 = \$2.00.$$

However, its time value is lower because it is even further away from the money than the \$19 put option:

$$\$2.08 - \$2.00 = \$0.08.$$

Volatility is the most important factor in option pricing. It measures the likely magnitude of price changes over a given period, and is expressed as a percentage of the underlying market price. Volatility is calculated as the annualised standard deviation of the distribution of percentage changes in daily prices, which is assumed to be a normal distribution (*see Section 9.4.3*). This allows option users to assign known confidence limits to the future trading range of the market. For example, a market volatility of 20 per cent means there is a 68 per cent chance that the price of oil will lie within a range of ±20 per cent around the current price level a year from now. The greater the market volatility, the greater the range that prices are likely to trade in (see Fig. 9.16).



Source: Standard Bank London Ltd

Figure 9.16 Effect of volatility on price behaviour

Example

Current price of crude oil is \$18.00/barrel
Market volatility = ±20%.

$$\$18 \times +\ 20\% = +\ \$3.60/\text{barrel}$$

$$\$18 \times -\ 20\% = -\ \$3.60/\text{barrel}$$

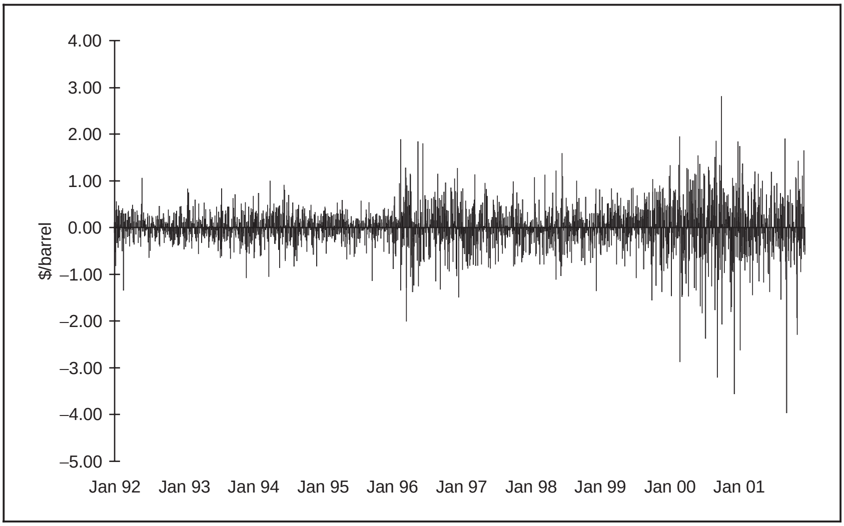
The time value of an option increases with the volatility of the market. If volatility is expected to be low, the future trading range will be narrower and the present value of the potential income stream from holding an option will be smaller since there is a lower probability of a large change in prices before expiry. However, if volatility is expected to be high, the future trading range will be wider and the present value of the potential income stream from holding an option will be larger since there is a higher probability of a large change in prices before expiry.

9.4.3 Measuring price volatility

There are 2 types of price volatility used in pricing options:

- historical volatility
- implied volatility

Historical volatility – as its name suggests – is the range that prices have traded in over a given period in the past. Implied



Source: Standard Bank London Ltd

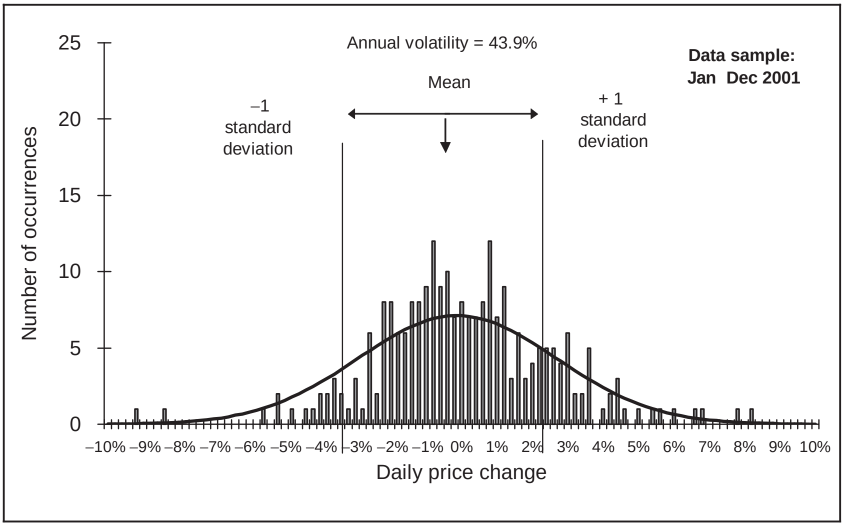
Figure 9.17 Daily price changes, nearby WTI futures contract

volatility is the range that prices are expected to trade over a given period in the future. Implied values are calculated by inputting option premiums into an option pricing model. When assessing the appropriate volatility to use when calculating option premiums, it is important to look at both.

Historical volatility allows us to see how prices have behaved under known market conditions. From this, we may be able to build a confidence level to help us in assessing the predictability of current market situations.

Implied volatility allows us to see the market's view of what the expected trading range of prices will be over a given period. Implied rates are continually changing to reflect the market's view. Implied volatility is a powerful tool for analysing price risk. It allows us to assess the impact that prices will have on our assets with a given probability.

In general, oil prices appear to behave approximately like a random walk (see Fig. 9.17) and the statistical characteristics of the distribution of price changes conform reasonably closely to those of a normal distribution (see Fig. 9.18). This means the probability that prices might change by a certain amount over a specified period of time can be described by a single statistical measure – the *standard deviation*. In the case of a normal distribution, 68.3 per cent of the price changes are expected to fall within a range of ± one standard deviation of the mean.



Source: Standard Bank London Ltd

Figure 9.18 Distribution of daily price changes, nearby WTI futures

Calculating historical volatility

Price volatility is always expressed in terms of the annualised standard deviation of percentage price changes. This provides a common measure of the likely scale of price movement over a known period that can be used in any financial calculation of option prices.

Example

The historical volatility of oil futures prices over a 30 day period can be calculated as follows (see Table 9.3):

1. divide the closing price of day 2 by day 1 (and so on) to obtain a series of daily price ratios,
2. convert the series of price ratios into natural logarithms,
3. calculate the mean of the series of daily logarithms,
4. subtract the mean from each daily logarithm and square the result,
5. sum the daily squared results,
6. divide the sum by 29, the number of daily changes: 30 – 1,

Table 9.3 Calculating historical volatility, 30 day period

Trading day	Closing price	Price ratio	Log of ratio	Log – mean	Square differences
1	19.81				
2	19.77	0.99798	–0.00202	0.00245	0.00001
3	19.41	0.98179	–0.01838	–0.01390	0.00019
4	19.26	0.99227	–0.00776	–0.00329	0.00001
5	18.69	0.97040	–0.03004	–0.02557	0.00065
6	18.69	1.00000	0.00000	0.00447	0.00002
7	18.78	1.00482	0.00480	0.00928	0.00009
8	18.89	1.00586	0.00584	0.01031	0.00011
9	18.90	1.00053	0.00053	0.00500	0.00003
10	19.14	1.01270	0.01262	0.01709	0.00029
11	19.25	1.00575	0.00573	0.01020	0.00010
12	19.06	0.99013	–0.00992	–0.00545	0.00003
13	19.13	1.00367	0.00367	0.00814	0.00007
14	18.91	0.98850	–0.01157	–0.00709	0.00005
15	18.80	0.99418	–0.00583	–0.00136	0.00000
16	18.86	1.00319	0.00319	0.00766	0.00006
17	18.91	1.00265	0.00265	0.00712	0.00005
18	19.05	1.00740	0.00738	0.01185	0.00014
19	18.94	0.99423	–0.00579	–0.00132	0.00000
20	18.84	0.99472	–0.00529	–0.00082	0.00000
21	18.22	0.96709	–0.03346	–0.02899	0.00084
22	18.01	0.98847	–0.01159	–0.00712	0.00005
23	17.46	0.96946	–0.03101	–0.02654	0.00070
24	17.50	1.00229	0.00229	0.00676	0.00005
25	17.49	0.99943	–0.00057	0.00390	0.00002
26	17.64	1.00858	0.00854	0.01301	0.00017
27	17.77	1.00737	0.00734	0.01182	0.00014
28	17.97	1.01125	0.01119	0.01567	0.00025
29	17.56	0.97718	–0.02308	–0.01861	0.00035
30	17.40	0.99089	–0.00915	–0.00468	0.00002

1. Calculate ratio of daily price changes

2. Convert to natural logs

4. Subtract mean from daily logs

5. Square the result

3. Calculate mean of log price changes → –0.00447

0.00448 ← 6. Sum the squares

0.00015 ← 7. Divide sum by 29

0.01242 ← 8. Take square root

Annualised volatility = 19.88% ← 9. Multiply by Sq root(256)

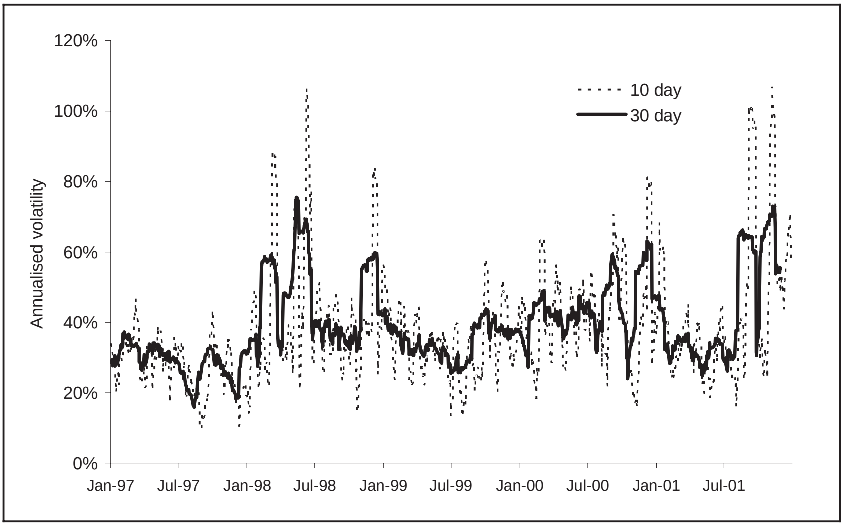
7. take the square root of the result to obtain the standard deviation,
8. multiply the standard deviation by the square root of 256 (the number of business days in the year) to obtain the annualised price volatility.

In order to keep track of the changing level of price volatility in the market, options traders use computer programs to calculate and plot a continuously moving measure of price volatility over a variety of different historical time periods. The most commonly used are 5, 10, 20 and 30 days. As can be seen from Fig. 9.19, historical price volatility in the oil market is far from constant and, in the case of Nymex WTI, 30 day historical volatility has varied from 10 per cent to over 35 per cent since January 1992.

Other, more elaborate, calculations of historical price volatility make use of open, high and low as well as closing prices to capture the intra-day price volatility experienced by the market.

Calculating implied volatility

Implied volatility is the market's estimate of future price volatility, which is embedded in the option premium. It can be calculated using one of a number of option pricing models. The most



Source: Standard Bank London Ltd

Figure 9.19 Historical price volatility, nearby WTI futures frequently used model was developed in 1973 by Fischer Black* and Myron Scholes and is known as the *Black–Scholes* model. The *Black–Scholes* model applies to European call options.

The *Black–Scholes* model requires five inputs – the current price, the strike price, time to expiration, the risk free interest rate, and the future price volatility of the market – in order to calculate the "fair" premium for a call option (see Fig. 9.20). 4 of the 5 inputs can be easily obtained from the market. The fifth input – future price volatility – must be estimated. However, the market's view of volatility – implied volatility – can be derived from the call option premium using the *Black–Scholes* model. Instead of using future volatility as an input to the model to compute the premium, the calculation is performed in reverse and the premium is used to obtain the implied market volatility.

The relationship between market volatility and option prices can be seen in Table 9.4. This shows how the premium for a $16 at-the-money European call option for Brent crude rises with increasing market volatility. The higher the volatility, the higher the option premium.

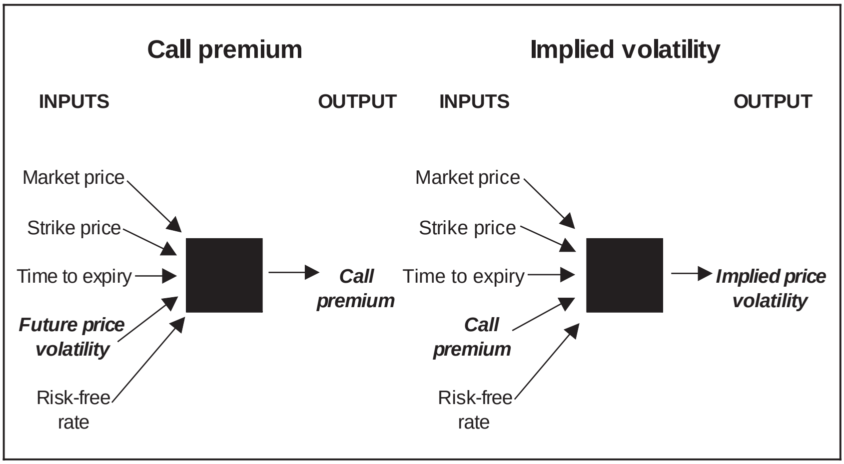
Higher volatility implies that prices will trade in a greater range over time, which is why the option premium is also higher. Figure 9.21 shows the expected trading range assuming volatilities of 20 and 30 per cent. Prices are expected to trade in the range between the lower and upper confidence limits – i.e. ± one standard deviation – 68 per cent of the time, and outside these limits the remaining 32 per cent of the time.

Table 9.4 Effect of volatility on option prices, $/barrel

$16 at the money option, 30 days left to expiry

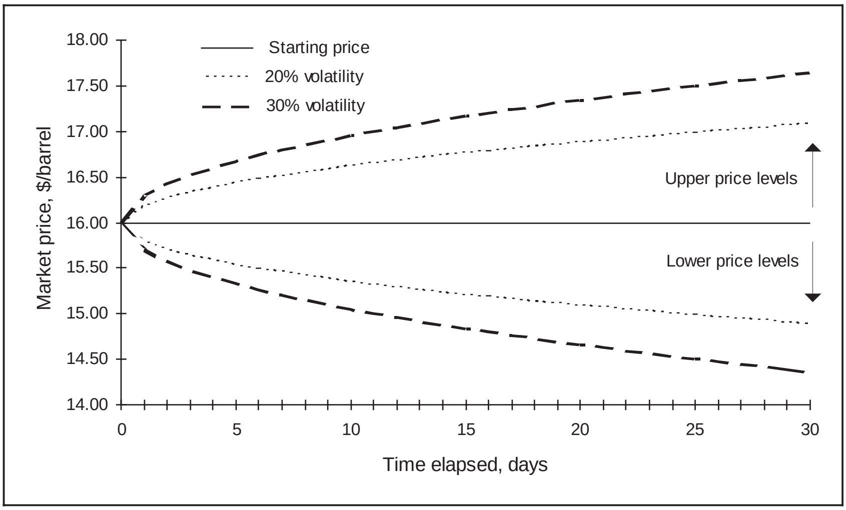
Market volatility	Calls	Puts
15%	0.25	0.25
20%	0.31	0.31
25%	0.46	0.46
30%	0.55	0.55
35%	0.67	0.67

*Black, F. & Scholes, M. (1973), The pricing of options and corporate liabilities, *Journal of Political Economy*, 81, pp 637–659.



Source: Standard Bank London Ltd

Figure 9.20 Using the Black–Scholes option pricing model



Source: Standard Bank London Ltd

Figure 9.21 Effect of volatility on market trading range

Calculating the expected trading range

Starting price:	$16.00/barrel
Expected volatility:	20%

Assume 256 trading days in year.

To calculate the expected trading range over a period of 1 day:

1. Take the square root of 256 days divided by 1 day,

$$\sqrt{(256/1)} = 16,$$

2. Divide the expected volatility by the result of step 1,

$$20\% \div 16 = 1.25\%,$$

3. Multiply the starting price by the result of step 2,

$$\$16 \times 1.25\% = 0.20/\text{barrel}$$

4. The expected trading range over a 1 day period is therefore:

$$\$16 \pm 0.20/\text{barrel}$$

To calculate the expected trading range over a period of 1 week:

1. Take the square root of 256 days divided by 5 days,

$$\sqrt{(256/5)} = 7.1554,$$

2. Divide the expected volatility by the result of step 1,

$$20\% \div 7.1554 = 2.795\%,$$

3. Multiply the starting price by the result of step 2,

$$\$16 \times 2.795\% = 0.4472/\text{barrel},$$

4. The expected trading range over a week is therefore:

$$\$16 \pm 0.45/\text{barrel}$$

To calculate the expected trading range over a period of 1 month:

1. Take the square root of 256 days divided by 20 days,

$$\sqrt{(256/20)} = 3.5777,$$

2. Divide the expected volatility by the result of step 1,

$$20\% \div 3.5777 = 5.590\%,$$

3. Multiply the starting price by the result of step 2,

$$\$16 \times 5.590\% = 0.8944/\text{barrel},$$

4. The expected trading range over a month is therefore:

$$\$16 \pm 0.89/\text{barrel}$$

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Appendix 9.1

Jet fuel option indication, price cap

Option Type:	Price Cap
Option Style:	Asian
Option Buyer:	Airline
Option Seller:	Standard Bank
Commodities:	Jet Fuel
Reference Price:	PlattsMarketScan assessment for Jet Kero CIF NWE Cargoes
Start Date:	1 July 2001
End Date:	31 Dec 2001
Price Assessment:	Monthly
Quantity:	"X" barrels per month
Cap Strike Price:	$"X"/barrel
Premium:	$"X"/barrel
Payments:	Cash settlement within 5 business days of each month end.

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Appendix 9.2

Jet fuel option indication, zero premium collar

Option Type:	Zero premium collar
Option Style:	Asian
Option Buyer:	Airline
Option Seller:	Standard Bank
Commodities:	Jet Fuel
Reference Price:	PlattsMarketScan assessment for Jet Kero CIF NWE Cargoes
Start Date:	1 July 2001
End Date:	31 Dec 2001
Price Assessment:	Monthly
Quantity:	"X" barrels per month
Cap Strike Price:	$"X"/barrel
Floor Strike Price:	$"X"/barrel
Premium:	Zero
Payments:	Cash settlement within 5 business days of each month end.

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10 Swaps

David Long

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10.1 Introduction

Swaps are a relatively new form of "over-the-counter" (OTC) derivative trading instrument that has proved to be ideally suited to the complexities of the oil market. They were first introduced into financial markets in the early 1980s where they were used to hedge interest rate risks. But it was soon realised that the same instrument could be used to transfer price risks for any asset, and swaps spread rapidly to the commodity markets, including oil. With them came new players such as the banks, who were seeking opportunities to diversify their investment activities and to apply their recently-acquired financial engineering skills.

The attraction of swaps is three-fold. First, they are purely financial transactions and can therefore be traded without incurring the quality risks and other delivery problems normally associated with physical oil contracts. Secondly, they offer the prospect of the "perfect hedge" since they can be tailored exactly to meet the requirements of each participant. And, thirdly, and most importantly, they can be traded far into the future since they are not constrained by the more limited time-horizons of existing futures or forward markets. Swaps therefore provide a uniquely flexible means of filling the gaps in the oil market left by other trading instruments. As a result, the oil swaps business has grown rapidly over the past few years.

Swaps are now firmly established as an integral part of the oil market. Short-term swaps have evolved from being largely private transactions between companies to become a more standardised and transparent form of trading instrument that is widely used as a substitute for forward paper contracts, many of which have now been displaced by swaps (see Chapter 7). Negotiating long-term swaps is still more time consuming than using other oil trading instruments, which can sometimes provide the same degree of risk protection at a lower cost. Companies are also exposed to credit risks that can be difficult to control. But, despite these problems, swaps have made an important contribution to the oil market and are here to stay.

Over the past ten years, the OTC market in oil has grown rapidly. As well as swaps, which are the simplest form of OTC financial derivative instrument, companies can also trade OTC options (e.g. caps, collars and floors), swaptions (an option which is exercised into a swap), and a wide range of more exotic derivative structures which can be tailored to suit the needs of each company.

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10.2 What is a swap?

A swap is a purely financial transaction that is designed to transfer price risk. It is a private agreement between two parties to exchange cash at pre-arranged dates in the future according to an agreed pricing formula. It guarantees the swap user (who is risk averse) a fixed price for a specified asset over an agreed time period in the future and assigns any profit (or loss) that might arise as a result of subsequent price changes to the swap provider (who is a risk taker). It can be applied to any asset for which a mutually acceptable pricing mechanism can be established and, since it does not involve delivery, leaves the swap user free to make separate arrangements for the physical disposal of the asset.

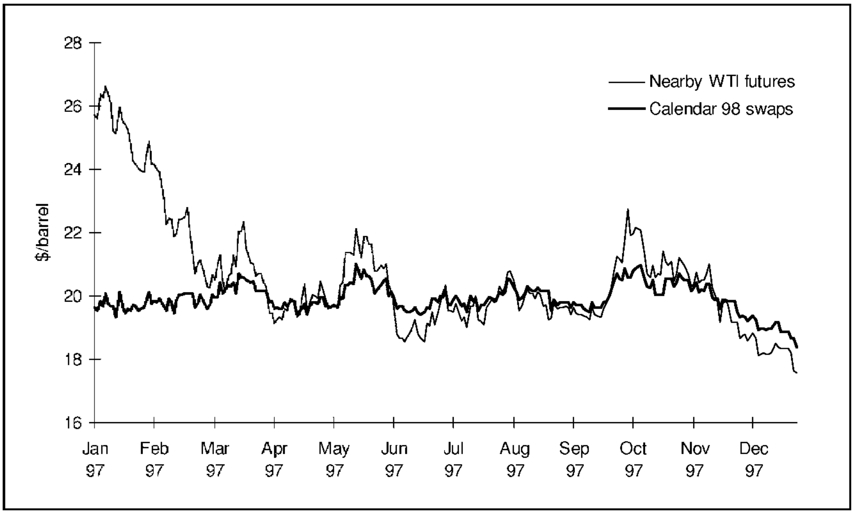
In some ways swaps are very similar to futures contracts. Both involve an agreement to buy or sell a specified quantity and quality of oil (or any other commodity) at a particular location and date in the future at a fixed price agreed at the time the contract is negotiated. And both can be used to hedge price risks created as a result of positions held in the physical oil market, or to speculate over the future course of prices. But, although the objectives may be similar, the operation of the two types of contract is very different and has led to an entirely different market structure and regulatory environment for swaps.

10.2.1 Swap contracts

Fixed for floating

A typical swap contract involves two linked transactions. First, there is an agreement for the swap provider to buy (or sell) a particular quantity of the underlying asset from the swap user at a fixed price over a specified future time period. And, secondly, there is an agreement for the swap user to sell (or buy) back the quantity of the same asset over the same time period from the swap provider at a floating price, which can be determined by any mutually acceptable set of rules.

The two notional transactions are necessary to eliminate any requirement to deliver the asset. But as the same parties are involved on both sides of the two transactions, the contract is actually settled by paying the difference between the fixed price and the floating price to whichever party has gained overall. For



Source: Nymex, Intercapital

Figure 10.1 Nearby WTI futures and calendar 98 swaps prices

this reason, swaps are also known as "fixed for floating agreements" or "contracts for differences*".

For example, an oil producer who is concerned about the risk of lower oil prices over the next six months could use a price swap to fix the price of all or part of his output for that period. Like hedging with a futures contract, this involves two parallel sets of transactions, one paper and one physical, in which the profits (or losses) from the paper transaction are used to offset any losses (or gains) on the physical transaction.

In this case the paper transaction is the swap agreement, which specifies that the producer will:

(a) sell a certain number of barrels of his particular grade of crude oil each month to the swap provider at an agreed fixed price, and,

(b) buy back the same quantity and quality of oil at the same time at a market related price determined according to an agreed formula.

If the formula price exceeds the fixed price, the producer pays the difference to the swaps provider, while, if the formula price is less than the fixed price, the swaps provider pays the difference to

* Brent CFDs are in fact a "contract for differences" - i.e. a price swap - based on the price differential between dated Brent and a specified forward delivery month for Brent crude.

the producer. Any profits (or losses) which the swap user makes on the swap contract are then used to offset any losses (or gains) that arise because of changes in the market price when the producer actually sells his oil on the physical oil market. In this way the producer ends up with the equivalent of a fixed price for his oil over the entire period.

Example: WTI producer, one year hedge

A small WTI producer wants to take advantage of high oil prices during the fourth quarter of 1997 to lock in a good price for part of his next year's production in case prices collapse. He decides in mid-October 1997 that prices have peaked and agrees a price swap to sell 1,000 b/d at the current swap market price of $20.50/barrel for the whole of 1998 (see Fig. 10.1).

The structure of the swap deal is as follows:

(1) The producer agrees to sell 1,000 b/d of WTI to the swap dealer at a fixed price of $20.50/barrel throughout 1998,

(2) The producer agrees to buy back the same quantity from the swap dealer at a floating price based on the quarterly average settlement price for the nearby Nymex WTI futures contract,

(3) Payments are to be made quarterly within five business days of the end of the quarter based on the difference between the agreed fixed price of $20.50/barrel and the value of the price index. If the index price is higher than the fixed price, the producer pays the swap dealer. If the index price is lower than the fixed price the swap dealer pays the producer.

In 1998, the producer sells his actual output in the physical market at market prices, which, combined with the net value of the payments from the swap deal, provides him with the fixed price guaranteed by the swap deal.

The net payments to (+) or by (–) the producer in the swap deal are as follows (98Q4 is a forecast):

Period	**WTI price**	**Fixed price**	**Price difference**	**Quantity (bls)**	**Payments ($)**
98Q1	15.95	20.50	+4.55	90,000	+409,500
98Q2	14.69	20.50	+5.81	91,000	+528,710
98Q3	14.15	20.50	+6.35	92,000	+584,200
98Q4	*14.00*	20.50	+6.50	92,000	+598,000
1998	14.69	20.50	+5.81	365,000	+2,120,410

And, the receipts from the sale of WTI in the physical oil market are:

Period	WTI price	Quantity (bls)	Receipts ($)
98Q1	15.95	90,000	1,435,500
98Q2	14.69	91,000	1,336,790
98Q3	14.15	92,000	1,301,800
98Q4	*14.00*	92,000	1,288,000
1998	14.69	365,000	5,362,090

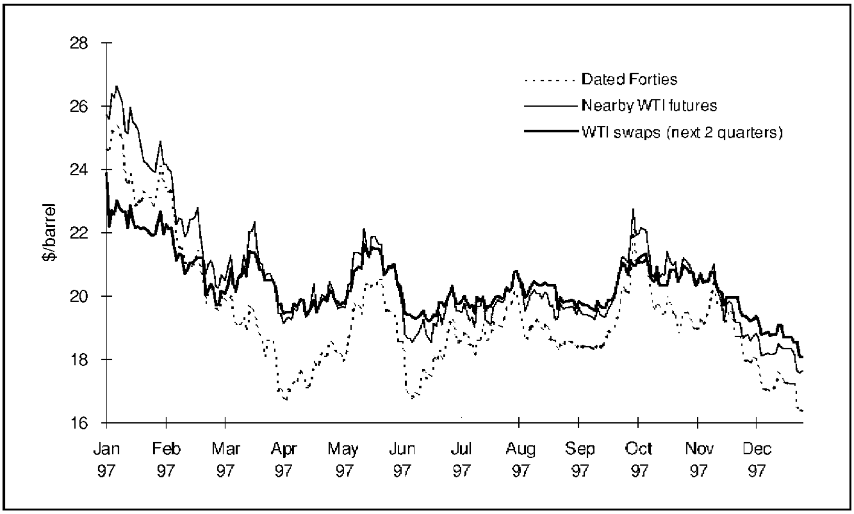
The combined proceeds from the swap deal and the physical sales are therefore:

Period	Sales proceeds ($)	Swap proceeds ($)	Total proceeds ($)	Quantity sold (bls)	Price achieved ($/bl)
98Q1	1,435,500	+409,500	1,845,000	90,000	20.50
98Q2	1,336,790	+528,710	1,865,500	91,000	20.50
98Q3	1,301,800	+584,200	1,886,000	92,000	20.50
98Q4	1,288,000	+598,000	1,886,000	92,000	20.50
1998	5,362,090	+2,120,410	7,482,500	365,000	20.50

Thus, the producer achieves the target price of $20.50/barrel for his output in 1998, compared with an annual average price of $14.69/barrel, which he would have received if he had not entered into the swap. In this case the swap price turned out to be higher than the actual market price since oil prices collapsed in 1998. But prices could have risen sharply as they did in 1996. Either way, the producer can be sure of receiving an average price of $20.50/barrel for his crude — whatever happens to market prices in 1998.

Tailor-made hedges

Although the principle is the same as hedging with a futures contract, swaps are much more flexible since there are no constraints on the quantity, quality, timing, and delivery terms of the underlying commodity. Companies using swaps to hedge can specify any amount, grade, time period, or delivery arrangement for the oil and can use any form of price marker that they think is suitable for the task. As a result, it is possible for companies not only to reduce the basis risk that limits the effectiveness of futures contracts for hedging, but also to extend the trading horizon of the market far beyond the time limits imposed by existing futures markets. Swaps therefore provide an instrument that can be used



Source: Petroleum Argus, Nymex & Intercapital

Figure 10.2 Dated Forties, WTI futures and swaps prices

to fill many of the gaps that are left in the oil market by other instruments such as forward and futures contracts.

For example, companies producing grades of crude oil that are not traded on the futures market can use swaps to fix the price of their output with much greater accuracy than can be achieved with a futures contract as long as they can find an alternative price marker that can be relied upon to track the price of their particular grade of crude oil. In most cases companies use prices published by one or more of the larger price reporting services such as *Argus* or *Platt's* as the basis for the floating price in the swap agreement as these are generally accepted as being both independent and representative of market trends. But any pricing mechanism can be used that is both visible and acceptable to the parties involved.

Example: North Sea producer, six month hedge

A North Sea Forties producer is concerned about rapidly falling oil prices in the first quarter of 1997 and wants to take advantage of a favourable price differential for his grade of crude to lock in a price for the next six months' production (see Fig. 10.2).

He decides in early March 1997 that the Forties/WTI differential is now very favourable and that oil prices are unlikely to recover in the short term and agrees a price swap to sell 1,000 b/d of Forties crude at a discount of $1.20/barrel to the current WTI swap market price of $20.20/barrel for the period April to September 1997.

The structure of the swap deal is as follows:

(1) The producer agrees to sell 1,000 b/d of Forties to the swap dealer at a fixed price of $19.00/barrel from April to September 1997,

(2) The producer agrees to buy back the same quantity from the swap dealer at a floating price based on the monthly average dated Forties price assessment reported by *Argus* for each calendar month,

(3) Payments are to be made monthly within five business days of the end of each month based on the difference between the agreed fixed price of $19.00/barrel and the value of the price index. If the index price is higher than the fixed price, the producer pays the swap dealer. If the index price is lower than the fixed price the swap dealer pays the producer.

As before, the producer sells his actual output during the summer of 1997 on the physical market at market prices, which, combined with the net value of the payments from the swap deal, provides him with the fixed price guaranteed by the swap deal.

The net payments to (+) or by (–) the producer from the swap deal are as follows:

Period	Forties price	Fixed price	Price difference	Quantity (bls)	Payments ($)
Apr 97	17.55	19.00	1.45	30,000	43,500
May 97	19.44	19.00	–0.44	31,000	–13,547
Jun 97	17.71	19.00	1.29	30,000	38,640
Jul 97	18.90	19.00	0.10	31,000	3,193
Aug 97	19.01	19.00	–0.01	31,000	–248
Sep 97	18.79	19.00	0.22	30,000	6,450
2Q/3Q97	18.57	19.00	0.43	183,000	77,988

The combined proceeds from the swap deal and the physical sales are therefore:

Period	Sales proceeds ($)	Swap proceeds ($)	Total proceeds ($)	Quantity sold (bls)	Price achieved ($/bl)
Apr 97	526,500	43,500	570,000	30,000	19.00
May 97	602,547	–13,547	589,000	31,000	19.00
Jun 97	531,360	38,640	570,000	30,000	19.00
Jul 97	585,807	3,193	589,000	31,000	19.00
Aug 97	589,248	–248	589,000	31,000	19.00
Sep 97	563,550	6,450	570,000	30,000	19.00
2Q/3Q97	3,399,012	77,988	3,477,000	183,000	19.00

Thus, the producer achieves the target price of $19.00/barrel for part of his Forties output in the summer of 1997, compared with an average price of $18.57/barrel which he would have received if he had not entered into the swap deal.

Longer-term hedges

A crude producer can also use swaps to fix the price of his output over a much longer time period, five or ten years ahead, thus hedging his price risk well beyond the time horizon of even the WTI futures market. Such long term price swaps are particularly attractive to producers seeking finance to develop a new oil field since they can eliminate the risk that prices may fall below the level of their costs and so obtain better financial terms for their investment funds. In such cases the natural counterpart for the swap deal may actually be the bank which is lending the money since the bank may also be active in the swaps market and therefore interested in linking the two transactions in its investment portfolio.

Example: WTI producer, five year hedge

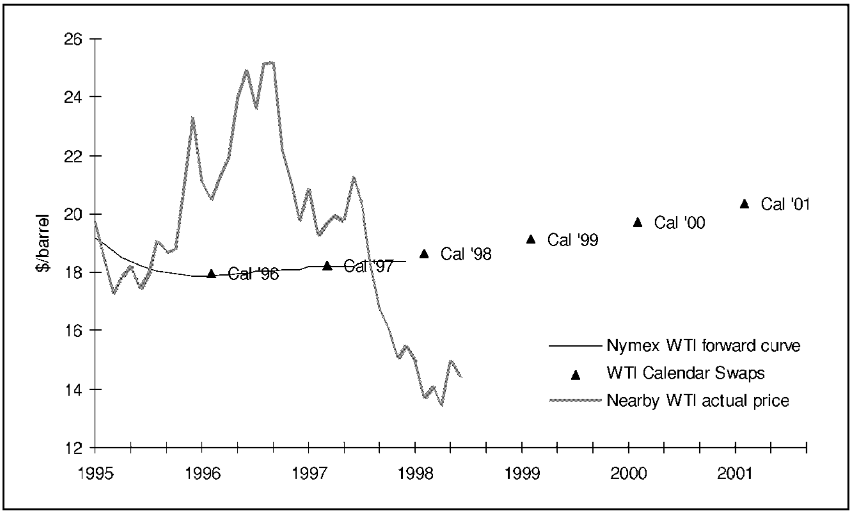
A WTI producer decided to take advantage of the high oil prices at the end of the first quarter of 1995 to lock in a price for a further part of his production for five years.

He therefore agreed a price swap to sell 1,000 b/d at the then current swap market prices for each of the five calendar years from 1996 to 2000 (see Fig. 10.3):

Time period	Swaps price
Cal '96	17.95
Cal '97	18.25
Cal '98	18.65
Cal '99	19.15
Cal '00	19.73

The structure of the swap deal is as follows:

(1) The producer agrees to sell 1,000 b/d of WTI to the swap dealer at an agreed fixed price for each of the five calendar years starting in 1996 and ending in 2000,



Source: Nymex, Intercapital

Figure 10.3 Long-term WTI swaps prices, 31 March 1995

(2) The producer agrees to buy back the same quantity from the swap dealer at a floating price based on the quarterly average settlement price for the nearby Nymex WTI futures contract,

(3) Payments are to be made quarterly within five business days of the end of each quarter based on the difference between the agreed fixed price for each calendar year and the value of the price index. If the index price is higher than the fixed price, the producer pays the swap dealer. If the index price is lower, the swap dealer pays the producer.

At the same time the producer sells his actual output in the physical oil market at current market prices, which, combined with the net value of the payments from the swap deal, provides him with the fixed price guaranteed by the swap deal.

In practice, oil prices rose sharply in 1996 after companies ran down stocks and the resumption of Iraqi oil exports was delayed, and then remained higher than the agreed swap price for most of 1997 (see Fig. 10.3). But oil prices collapsed in 1998 as Asia slipped unexpectedly into recession, triggering a massive stockbuild, and seem unlikely to recover strongly before the end of the swap contract.

Using actual prices to the end of October 1998 — and the forward curve from mid-November 1998 to value the remainder of the contract — the net annual payments to (+) or by (–) the producer from the swap deal would be:

Period	WTI price	Fixed price	Price difference	Quantity (bls)	Payments ($)
1996	22.03	17.95	–4.08	366,000	–1,493,280
1997	20.61	18.25	–2.36	365,000	–861,400
1998	14.69	18.65	+3.96	365,000	1,445,400
1999	*15.00*	19.15	+4.15	365,000	1,514,750
2000	*16.50*	19.73	+3.23	366,000	1,182,180
1996-2000	17.77	18.75	+0.98	1,827,000	1,787,650

The combined annual proceeds from the swap deal and the physical sales are therefore:

Period	Sales proceeds ($)	Swap proceeds ($)	Total proceeds ($)	Quantity sold (bls)	Price achieved ($/bl)
1996	8,062,980	–1,493,280	6,569,700	366,000	17.95
1997	7,522,650	–861,400	6,661,250	365,000	18.25
1998	5,361,850	1,445,400	6,807,250	365,000	18.65
1999	5,475,000	1,514,750	6,989,750	365,000	19.15
2000	6,039,000	1,182,180	7,221,180	366,000	19.73
1996-2000	32,461,480	1,787,650	34,249,130	1,827,000	18.75

Thus, the producer achieves an average price of $18.75/barrel for his output over the five year period from 1996 to 2000, compared with the projected average price of $17.77/barrel which he might have received if he had not entered into the swap deal. The swap deal illustrates very effectively the huge uncertainties associated with oil prices over a five-year period and the large variations in cashflow which can occur between the two parties.

When the deal was done, the swap prices looked favourable, but the producer had to make large payments to the swap provider in the first two years because oil prices rose unexpectedly. The cashflows were reversed in 1998 when prices fell sharply and the swap provider had to pay the producer, and the deal now looks profitable for the producer again. Of course if prices recover more strongly than expected in 1999 and 2000, the producer might not necessarily be better off. However, whatever happens to oil prices over the five year period, he can be sure of getting $18.75/barrel for his output as a result of the swap deal.

Trading flexibility

As can be seen from the three examples given above, there is no limit (other than the imagination of the parties involved) to the number of different applications that can be devised for swaps.

Because they are so flexible, they have proved to be a particularly useful form of trading instrument for the oil market, which suffers more from the problem of basis risk than other commodity markets. As a result, they have not only increased the diversity of contracts available in the short-term oil market, but also extended the trading horizon of the oil market far into the future.

10.2.2 Regulation

At present swaps operate in a much looser regulatory environment than futures contracts since they are regarded as commercial transactions that are not available to the general public (see Chapter 17). In the United States they were awarded a special exempt status by the Commodity Futures Trading Commission (CFTC) in 1989 under the terms of the Commodity Exchange Act (CEA). While in the United Kingdom they qualify for self-regulation under the terms of the Financial Services Act (FSA) 1986.

As a result, the swaps market has been able to grow rapidly since it is not subject to the kind of regulatory delays that characterise futures contracts and there are few constraints on the pace of innovation as long as companies do not introduce modifications that would compromise the basic characteristics of a swap agreement (see below). The initiative for ensuring that this does not happen has been taken by the International Swaps and Derivatives Association (ISDA), which has drafted a model "Master Agreement" that satisfies the current legislative controls and can be used as the basis for all swap transactions.

The ISDA Master Agreement is widely used in the industry since it also enables companies to pool their mutual exposures through a "netting" clause. Without netting each transaction would stand alone and a company might find that it had to pay money owed to a bankrupt counterparty under one contract while being unable to reclaim money owed by the same company under another contract. With netting, the two contracts can be considered together and the company would only have to pay the net amount owed to the bankrupt counterparty. ISDA has also been instrumental in persuading an increasing number of countries to incorporate the principle of netting in national legislation by promoting its "Model Netting Act".

There is, however, a basic tension between the US and UK regulatory regimes which still overshadows the development of the swaps market and explains why the market has expanded faster outside the US. According to the CFTC, swaps must satisfy six criteria if they are to be exempt from the provisions of the CEA:

- they must be settled in cash,
- they must be individually tailored and not subject to a standardised form of agreement,
- there must be no system of offset as might be provided by a futures exchange,
- there must be no central clearing or margining system,
- the transaction must be undertaken as part of the parties' line of business,
- swaps must not be marketed to the general public.

In the eyes of the US regulatory regime, swaps therefore differ substantially from futures contracts which, according to the CFTC have four key features:

- they are standardised contracts for future delivery of the commodity,
- they are directly or indirectly offered to the general public,
- they are generally secured by earnest money or margins,
- they are used primarily for the purpose of assuming or shifting the risk of the change of value of commodities.

In addition, the CFTC observes that most futures contracts are offset before the delivery date.

However, the CFTC is coming under increasing pressure to tighten the regulations governing swaps and other OTC instruments. Concern over accounting standards and the financial exposure of companies engaged in trading derivatives has prompted calls for stricter capital standards and greater disclosure in annual reports. And the US General Accounting Office (GAO) report released in May 1994 recommended ending the current exemption of OTC derivatives and swaps from federal regulations.

The GAO report concluded that the rapid growth in derivatives trade among smaller firms was a possible threat to the integrity of the US financial system since they may not have enough capital to sustain sizeable losses. The report also found that current accounting standards are incomplete and inconsistent and have not kept pace with business practices and recommended co-ordination between US and foreign regulators to create international derivatives trading standards.

Until recently, the US regulatory authorities rejected the calls for new legislation, arguing that steps have already been taken to ensure that only well-capitalised firms engage in derivatives trading. But the CFTC is now proposing to carry out a review of the OTC market in order to see whether or not further controls are required. The proposed CTFC review has provoked a storm of protest from market participants and financial organisations — including ISDA — and exposed differences of opinion between the CFTC and the US Securities and Exchange Commission (SEC) over how OTC markets should be regulated. Legislation to prevent the CFTC from regulating OTC derivatives is being prepared by the US Senate, and Congress is due to consider the issues in 1999. But the debate is far from over and new controls may yet have to be introduced in order to satisfy the critics.

10.2.3 Market structure

The private and bilateral nature of swap agreements means that the structure and organisation of the swaps market is more like a forward paper market than the futures market.

Although they are extremely flexible trading instruments, and therefore potentially very attractive to hedgers in the oil market, they are not inherently transparent since it can be difficult to compare the terms of different deals and parties may not be keen to divulge the details. In addition, the lack of any central clearing house or margining system, and the long-term nature of some swap agreements, creates credit risks which can affect the relative price of even very similar agreements.

However, like forward paper contracts, which swaps have largely replaced, the need for liquidity has encouraged swap providers and users to focus on a small number of standardised swap contracts that are actively traded, enabling market makers to operate effectively and raising the level of price transparency in the swaps market. In addition, some swaps brokers have been instrumental in promoting the wider dissemination of price information in order to encourage new players into the market.

The key players in the swaps market are the swap providers who are prepared to shoulder the price risk (see Fig. 10.4). These include a wide variety of companies: banks, commodity traders, oil companies and dedicated swap providers. In order to trade successfully such companies require good credit lines and an effective means of managing the risk.

Ideally, swaps providers would like to run a balanced book, acting purely as an intermediary who matches buyers to sellers in order to offset the risk. But this is not always possible in practice and so swaps providers must be prepared to "warehouse" the risk and use other trading instruments such as futures and options to limit their exposure. Alternatively, swaps providers may be oil companies who are using swaps to balance their existing exposure as net sellers or net buyers in the physical market.

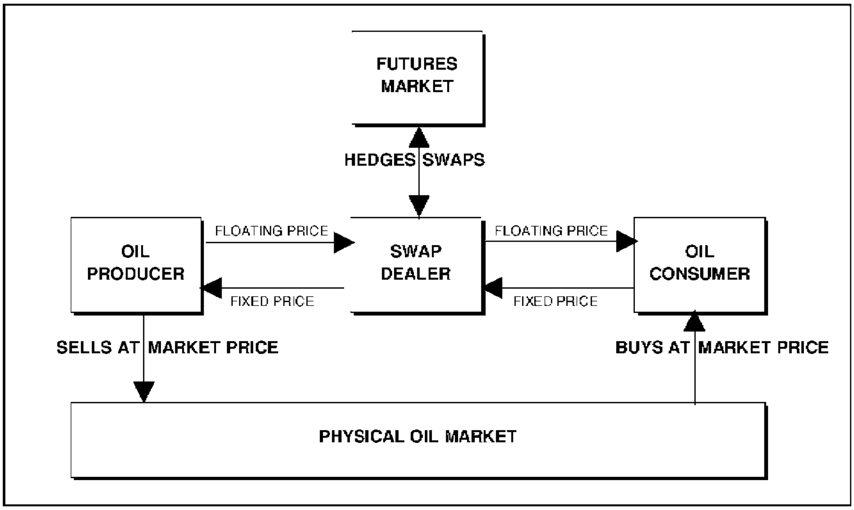


Figure 10.4 Structure of the swaps market

In practice, many swap deals are ultimately hedged on the forward and futures markets, as is demonstrated by the expansion in the liquidity of the back months in the major futures markets, leaving the swap providers to manage the residual basis and credit risks associated with each individual deal.

The balance of players in the swaps market depends on the time-scale of the swap contract. Over the past year or so, oil companies have come to play an increasingly important role in the short-term swaps market, reducing the need for market-makers to facilitate transactions by warehousing the risk.

Short-term swaps are now widely traded directly between oil companies with offsetting positions in the physical market and swap markets for some refined products have become so standardised that they are now widely used as an alternative to forward or futures contracts.

Long-term swaps, however, remain less standardised and market-makers continue to play an important role in negotiating contracts and transferring the risk (see Chapter 11). Since some long-term swap contracts are tied to investment projects it is not surprising that banks are active in this market.

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10.3 Pricing swaps

Arbitrage relationships between the swap and forward or futures markets create the basic framework for determining the price of a swap. In addition, there are other, less tangible, components to the swap price that are determined partly by the market and partly by the nature of the parties involved.

Generally speaking, the price of a swap depends on three main factors:

- the cost of hedging the swap position,
- the credit rating of the swap user, and
- the margin required by the swap provider.

However, by far the most important of these is the cost of hedging the position created by the swap agreement. This, in turn, depends partly on the term structure of the forward or futures market being used to hedge the price risk, partly on the different payment structures, and partly on the basis risk associated with the hedging instrument.

Although other factors, such as the credit rating of the swap user and the margin required by the swap provider do play a role, their significance has diminished as the market becomes more liquid and the level of competition between the swaps providers has intensified.

10.3.1 Replicating swaps with futures

The basic principles of swap pricing are quite straightforward. In theoretical terms, a swap agreement is equivalent to holding a portfolio of forward or futures contracts and arbitrage will therefore ensure that the price ultimately reflects this.

For example, a simple swap agreement between an oil producer and a swap provider to sell a specified quantity of crude oil at a fixed price over a period of one year can be reproduced as a discounted portfolio of short futures contracts equivalent to the same volume of oil for each of the delivery months nominated in the contract. The floating part of the agreement is then reproduced by buying back a daily (pro-rata) stream of futures contracts throughout each delivery month.

Example: Replicating swaps using futures

Arbitrage between the swaps market and the forward and futures markets ensures that swaps are priced as if they were equivalent to holding a portfolio of forward or futures contracts. In cases where the swap is based on an actively traded futures contract, the price relationship is clear and the same result can be obtained using the futures market as long as the swap user is prepared to manage the resulting portfolio of contracts.

For example, the WTI producer in the example above could replicate the one year price swap by selling a portfolio of Nymex WTI contracts for nearby delivery months throughout 1998 in mid-October 1997 and then buying them back as the year unwinds. The fixed price is established by creating a weighted discounted portfolio of nearby contracts that are equivalent to the volume the producer is trying to hedge, in this case 1,000 b/d for calendar 1998. The mix of contracts required to replicate the swap is determined by the number of trading days in each month, the roll-over dates for the nearby futures contract, and the payment schedule agreed under the swaps contract.

For example, there are 20 trading days in January 1998 (January 1 and 19 are Nymex holidays), and the last trading day for the nearby February contract is January 20. After this date the nearby contract becomes March. As a result, the February contract trades for 12 days during January and the March contract trades for 8 days.

Calendar month	Calendar days	Trading days	Division of contracts due to rollover dates		Number of contracts	Contract month
Jan-98	31	20	12	8	19	Feb-98
Feb-98	28	19	14	5	33	Mar-98
Mar-98	31	22	15	7	28	Apr-98
Apr-98	30	21	14	7	30	May-98
May-98	31	20	13	7	30	Jun-98
Jun-98	30	22	16	6	33	Jul-98
Jul-98	31	22	14	8	28	Aug-98
Aug-98	31	21	14	7	32	Sep-98
Sep-98	30	21	15	6	32	Oct-98
Oct-98	31	22	14	8	28	Nov-98
Nov-98	30	19	15	4	35	Dec-98
Dec-98	31	22	15	7	27	Jan-99
					10	Feb-99
TOTALS	365	251	171	80	365	

Thus, the producer will need to sell 12/20 × 31 = 18.6 February contracts and 8/20 × 31 = 12.4 March contracts to fix the price of 1,000 b/d of his calendar day output in January 1998. As it is not possible to sell fractions of a 1,000 barrel contract he will need to round up (or down) to obtain an exact multiple of contracts. In order to identify the total number of contracts for the whole of 1998, the same calculation must be carried out for each month and the results must then be discounted to reflect the different payment schedule for the swap contract.

Futures contracts are marked to market every day but the swap contract is to be settled within five business days of the end of each quarter. As a result, fewer futures contracts are initially required to replicate the swaps contract since the present value of the swap contract in each quarter must be discounted back from the future payment dates. This is also known as "delta" hedging.

For example, the discount factor for the portfolio of futures contracts required to replicate the first quarter swap depends on the current interest rate (r) and the time (t) left before payment is required:

$$\text{Discount factor} = e^{-rt}$$

If the first quarter 1998 swap is being replicated in mid-October 1997, the time left before payment is 140 days, i.e. the 45 days remaining until the end of the 1997, the 90 days in the first quarter of 1998 and the 5 days grace after the end of the first quarter before payment is required. Assuming the relevant interest rate is 5%, the discount factor is calculated as follows:

$$\text{Discount factor} = e^{-0.05*(140/365)} = 0.981$$

Thus the nominal number of futures contracts required to hedge the first quarter swap must be reduced by a factor of 0.981. Similar calculations are required for the second, third and fourth quarters.

Contract month	Nominal contracts	Discount factor	Discounted contracts
Feb-98	19	0.981	19
Mar-98	33	0.981	32
Apr-98	28	0.981	27
May-98	10	0.981	10
1Q98	90		88

The current market value of the resulting portfolio of "discounted" contracts can then be established by obtaining bids (and asks) from the futures market and calculating a weighted average price for the quarter:

Contract month	Discounted contracts	Market price ($/barrel)
Feb-98	19	20.99
Mar-98	32	20.90
Apr-98	27	20.81
May-98	10	20.72
1Q98	88	

Average price = ((19*20.99)+(32*20.90)+(27*20.81)+(10*20.72))/88

i.e. 1Q98 weighted average price= $20.87/barrel

Combining this result with similar calculations for the second, third and fourth quarters will give the weighted average price for the year as a whole:

Contract month	Nominal contracts	Discount factor	Discounted contracts	Market price ($/barrel)
Feb-98	19	0.981	19	20.99
Mar-98	33	0.981	32	20.90
Apr-98	28	0.981	27	20.81
May-98	10	0.981	10	20.72
1Q98	**90**		**88**	**20.87**
May 98	20	0.969	19	20.72
Jun-98	30	0.969	29	20.63
Jul-98	33	0.969	32	20.55
Aug-98	8	0.969	8	20.47
2Q98	**91**		**88**	**20.61**
Aug 98	20	0.957	19	20.47
Sep-98	32	0.957	31	20.39
Oct-98	32	0.957	30	20.31
Nov98	8	0.957	8	20.23
3Q98	**92**		**88**	**20.36**
Nov-98	20	0.945	19	20.23
Dec-98	35	0.945	33	20.15
Jan-99	27	0.945	26	20.10
Feb-99	10	0.945	9	20.05
4Q98	**92**		**87**	**20.14**
Totals	**365**		**351**	

Thus, the current market value of the discounted portfolio of futures contracts required to replicate a fixed price swap for calendar 1998 is:

Average price = ((88*20.87)+(88*20.61)+(88*20.36)+(87*20.14))/351

i.e. Calendar 1998 weighted average price= $20.50/barrel

If this price is acceptable to the producer, he would then instruct his broker to execute the order to sell the specified portfolio of contracts so as to lock in the fixed average price for the year.

The portfolio is then unwound during 1998 by buying back an appropriate number of contracts every month (an average of slightly more than one every trading day) in order to match the physical sale of 1,000 b/d of WTI production on the physical market. This is equivalent to the floating price index in the swap contract.

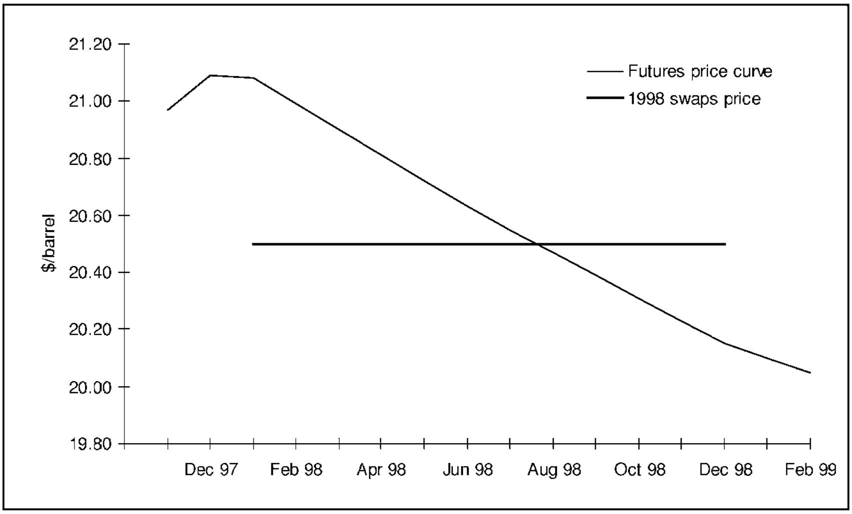
As with the swap deal, the eventual profit and loss from the sale and purchase of the portfolio of futures contracts is combined with the actual proceeds from the sale of WTI in the physical oil market to yield the fixed target price of $20.50 for 1998.

Factors affecting arbitrage with futures

There are, however, differences between the swap agreement and the portfolio of futures contracts which can affect the arbitrage relationship between the two markets.

First, there is the question of transactions costs. A swap is a single transaction that covers the entire period specified in the agreement. Although it may be more costly to negotiate initially than a futures contract because the swaps market is less liquid, it is less costly to operate and monitor once it has been set up as there are no further price risks associated with executing the contract. The futures portfolio, however, requires repeated daily transactions in each of the delivery months and must be monitored constantly to avoid the risk of adverse price movements, especially during the last few days of trading for each delivery month. The weighted average price obtained from the market must therefore be adjusted to allow for transactions costs, including brokers fees, which could amount to 1 or 2 cents per barrel.

Secondly, there is the question of margin calls. Futures contracts are marked to market on a daily basis and are subject to margin calls if the change in the futures price increases the financial exposure of the futures position. Although this is necessary in order to protect other futures market users against the risk of default, it does represent an extra cost for futures market users since it ties up cash that could be used for other purposes, which is why the number of futures contracts required to replicate a swap must be discounted to reflect the different payment schedules. These costs do not arise for a swap since these are not usually marked to market unless the swap provider is particularly worried about the financial standing of the swap purchaser. In the case of a portfolio of futures contracts that attempts to replicate a long-term swap the financial outlay associated with repeated



Source: Nymex, Intercapital

Figure 10.5 WTI forward curve and swaps price, 16 Oct 1997

margin calls can be substantial — as one trading company discovered in late 1993.

10.3.2 Term structure of prices

The most important factor determining the price of a swap is the term structure of futures prices in the market that is being used by the swaps providers to hedge their exposure in the swaps market.

The basic difference between swaps and futures is that a swap agreement offers a single fixed price for an entire period while the portfolio of futures contracts offers a sequence of different prices for each delivery month. Although it is theoretically possible for all the futures prices to be the same, it is more likely that the futures prices will be on a rising (in contango) or falling (in backwardation) trend. The relative value of the swap agreement compared with the futures portfolio therefore depends on the slope of futures prices and whether the swap user is hedging a long or short position in the physical market (see Fig. 10.5).

In the case of an oil producer, who has a long position in the physical market and wants to hedge his selling price, the floating price is likely to be above the fixed price during the early part of the contract period when the market is in backwardation as the term structure of futures prices is downward sloping. The swap user would therefore expect to make cash payments to the swap provider which he would otherwise be able to earn interest on.

Swaps are therefore potentially more costly for producers when the market is in backwardation as they entail an initial net cash outflow. The reverse is true if the market is in contango, since the term structure of futures prices is upward sloping, and it is the swap provider who suffers the initial cash outflow.

Example: The effect of term structure on swap pricing

The arbitrage relationship between swaps and futures contracts also depends on the term structure of prices in the futures market.

In order to compare the market value of the portfolio of futures contracts with the swap market price, it is necessary to make allowances for the different patterns of cash flows generated by the two types of instrument under different market conditions:

Net cash flow	Backwardation	Contango
Producer hedge	Negative	Positive
Consumer hedge	Positive	Negative

In the case of the WTI producer's hedge in the example above, the market was in backwardation (i.e. prices for nearby delivery months were above prices for future delivery months) when the swap deal was done. As a result, the producer would expect to pay cash to the swap dealer during the early part of the period as the floating price would be higher than the fixed price — assuming the market remains in backwardation. This net cash outflow represents a cost to the producer (and a benefit to the swap dealer) from the swap and the interest payments on the expected payments need to be taken into account when pricing the swap.

Swap period	Volume traded (barrels)	Average price ($/bl)	Price differential ($/bl)	Expected cashflow ($)	Interest @ 5% pa ($)
1Q98	90,000	20.870	+0.370	+33,333	139
2Q98	91,000	20.607	+0.107	+9,707	179
3Q98	92,000	20.365	–0.135	–12,454	127
4Q98	92,000	20.142	–0.358	–32,981	–10
			Net interest on swap payments:		**435**
			Annual average cost (cts/bl):		**0.12**

As can be seen, the net cost per barrel of interest on swap payments made by the producer to the swap dealer are very small when interest rates are low and the forward price slope is shallow.

However, they are important and can be significant if interest rates are high or the forward price slope much steeper.

Long-term price structures

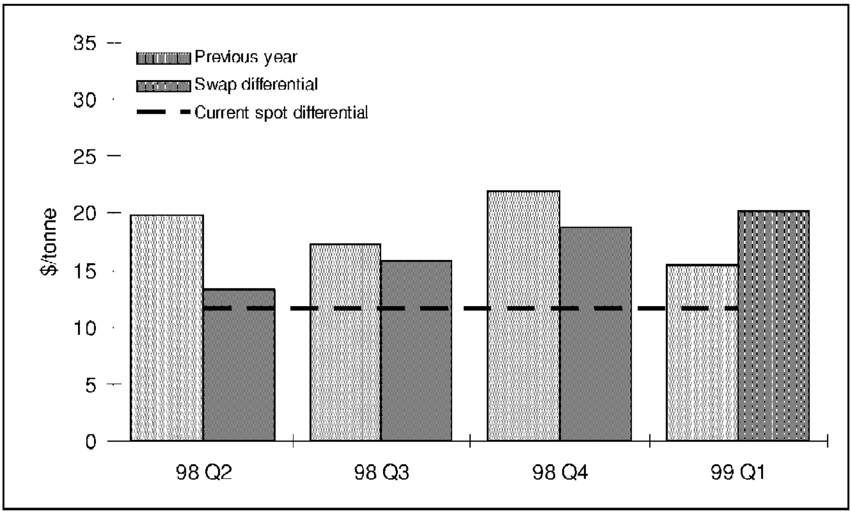
In the case of a short-term swap, covering a period of up to a year ahead, the term structure can easily be observed, since most futures markets for oil offer a number of contracts that are traded at least a year ahead. In addition, contracts such as Nymex Light Sweet Crude (WTI) are now traded six to seven years ahead providing a guide to the longer-term forward price structure in the oil market (see Chapter 8).

In the case of longer-term swaps which extend beyond the time horizon of the forward and futures markets, however, the term structure must be deduced (or assumed) by the swaps provider (see Chapter 11). One way of doing this is to create a synthetic contract by rolling forward a series of futures positions. In this way the cost of hedging depends on the cost of rolling over from one futures contract to the next.

10.3.3 Basis risk

Given that one of the primary attractions of swaps is that they can be tailored to meet the precise requirements of the swap user, it is not surprising that one of the greatest problems facing the swaps provider is basis risk.

Although the term structure of the underlying futures market



Source: Petroleum Argus, IPE & Intercapital

Figure 10.6 Jet swap premium over IPE gasoil futures is important in determining the price of a swap, the real exposure for the swaps provider comes from the basis risk between the commodity specified in the swap and the futures contract that is being used to hedge the swap position.

Assuming that there is a suitable reference price available for the grade of oil specified in the swap, there will be little or no risk for the swap user that the floating price will differ from the opportunity cost or value of the underlying physical position.

However, from the point of view of the swaps provider the equivalent futures portfolio will be exposed to the risk of changes in the price relationship between the grade of oil specified in the futures contract and the grade of oil involved in the underlying physical position. If the risk is great, then the swap agreement will be worth much more to the swap user, and the swap provider will need to charge a larger premium to cover his exposure.

Swap providers must therefore include a premium in the price of the swap that rewards them for taking the risk that the hedging instrument they choose is less than perfect. There is no "right" way of doing this since the size of the premium depends on assumptions about the future relationship between the price index used in the swap and the forward or futures contract used for hedging. In the early days of the swap market, swap providers relied mainly on past relationships as a guide, but with increasing liquidity and transparency the premium has come to be determined by the market itself (see Fig. 10.6).

10.3.4 Credit risk

Finally, there is the issue of credit risk. Unlike a futures contract, which is guaranteed by the futures exchange, a swap contract is not guaranteed by anybody and therefore involves a risk that the other party may fail to perform. Such risks may be magnified in the case of price swaps since the contract could cover a period of many years during which either party could go bankrupt.

However, counter-party risks are quite normal in the oil market, which involves a wide-range of over-the-counter trading instruments, and there are various standard methods of dealing with the problem of non-performance ranging from careful exposure management to letters of credit (see Chapter 13).

In addition, there are a number of specialist firms that will stand between two parties that do not wish to increase their mutual credit exposure in exchange for a fee. Nevertheless, credit risk can add up to 10 cents per barrel to the price difference between a portfolio of futures contracts and a swap agreement.

10.3.5 Sources of price information

Over the past ten years the price transparency of the swaps market has improved enormously. From being a largely private market in which a small number of highly tailored deals were kept secret by the close group of players, the swaps market has developed into a much more liquid and transparent market which can support regular price quotations for a range of standardised swap instruments. Although the swaps market still has a long way to go compared with the futures exchanges, participants accept that transparency is desirable if swaps are to be more widely used throughout the oil industry.

But, despite the obvious improvements in price transparency, there are still relatively few sources of regular and reliable price information outside the market itself. Within the industry price quotations can be obtained from both market makers and specialist brokers, but swaps prices are not reported to the same extent as physical, forward and futures market prices by the major price reporting organisations.

Price assessments for the more liquid swaps contracts such as WTI, Brent CFDs, Tapis, NW European gasoline, jet kerosine and high sulphur fuel oil can now be obtained from most of the major price reporting organisations (see Chapter 3). But a wider range of market quotations for swaps prices can be obtained from the following sources:

Petroleum Argus

Daily price assessments for Brent CFDs, paper Tapis, and a wide range of short-term product swap markets in NW Europe, the United States and Asia Pacific. Also a record of reported swap deals for a wide range of crude and products.

Saladin

Daily swaps quotations supplied by Intercapital Commodity Brokers Ltd together with a price history dating back to 1992. Coverage includes: premium unleaded gasoline barges fob Rotterdam, jet kerosine, diesel (EN590) and gasoil cargoes cif NWE, LSFO cargoes fob NWE, HSFO carges cif NWE and barges fob Rotterdam; kerosine, kerosine re-grade, gasoil and fuel oil fob Singapore, No. 6 residual fuel delivered New York Harbor and fob US Gulf Coast, Brent/WTI differentials and the Brent/gasoil crack spread NWE. Also futures strips for IPE Brent, IPE gas oil, Nymex WTI, Nymex heating oil and Nymex unleaded gasoline.

10.4 Using swaps

Price swaps have many potential applications in the oil market which helps to explain their success as a trading instrument. In the short term they provide an alternative to forward and futures contracts since they can be used to reduce or even eliminate basis risk. In the longer term they provide an extension to the forward and futures markets since they can be used to hedge prices far into the future beyond the time limits of existing contracts.

In addition, it is possible to use other OTC derivatives to vary the level of risk protection provided by creating more elaborate trading instruments that mimic the behaviour of options. Such variations can provide users with the additional benefits of highly complex trading strategies within the framework of a single transaction.

10.4.1 Short-term swaps

Short-term swaps typically cover a period of up to six months ahead and are widely used to hedge both outright price risks for crude oil and refined products and to lock in refinery margins or price differentials between crudes or products.

In some cases, swaps are used to fill a gap in the more limited range of futures contracts offered by the futures markets, and the level of liquidity is such that swap prices are quoted by the price reporting services alongside forward and futures prices. Trading activity in the product swaps markets is concentrated in the period from one to six months ahead, but deals are also regularly completed for periods of up to a year ahead. Swaps are usually quoted on a monthly basis in the near term and on a quarterly or annual basis in the longer term.

Table 10.1: Short-term swap markets

NW Europe	United States	Asia Pacific
Brent CFDs	WTI strips	Paper Tapis
Brent/WTI spread	Low sulphur residual	Naphtha
Brent/gasoil crack	High sulphur residual	Jet kerosine
Unleaded gasoline	Jet kerosine*	Kerosine re-grade
Naphtha	Heating oil*	Gasoil
Jet kerosine	Unleaded gasoline*	High sulphur fuel oil
Diesel (EN590)		
Low sulphur fuel oil		
High sulphur fuel oil	** US Gulf Coast*	

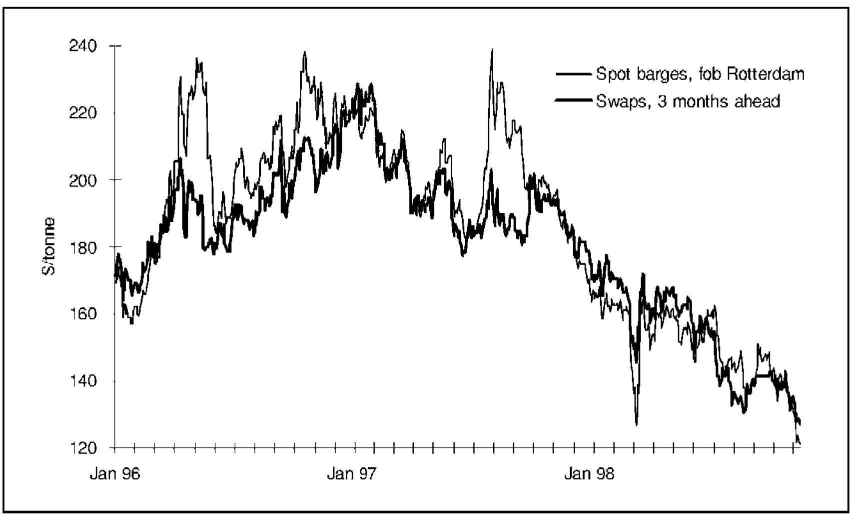
Northwest Europe

The gasoline swaps market is based on Rotterdam fob barge quotations for 95 RON unleaded gasoline and deals are usually done in 5,000 tonne lots. The naphtha and jet kerosine swaps market are based on NW Europe cif cargo quotations. The EN590 diesel swaps market is based on NW Europe cif cargo quotations. The low sulphur fuel oil swaps market is based on NW Europe fob cargo quotations and deals are usually done in lots of 5,000 or 10,000 tonnes. And the high sulphur fuel oil swaps market is based on Rotterdam fob barge quotations and deals are usually done in lots of 5,000 or 10,000 tonnes (see Fig. 10.7).

United States

In the United States, short-term price "strips" for WTI and other pipeline crudes are actively traded. Strips (or mini-term deals) are based either on the Nymex light sweet crude contract or on posted prices and allow companies to lock in a fixed price over a period of three to six months.

Refined product price swaps are traded for all main products at all major locations, but low sulphur residual and high sulphur residual swaps based on *Platt's* quotations are the most widely quoted and fill an important gap in the range of contracts offered by the US futures markets. The low sulphur (1 per cent) residual swaps market is based on New York Harbor price quotations, while



Source: Petroleum Argus, Intercapital

Figure 10.7 NW Europe unleaded gasoline barge swaps prices the high sulphur (3 per cent) residual swaps market is based on US Gulf Coast price quotations. The Gulf Coast market also trades unleaded gasoline, jet kerosine and heating oil swaps.

Asia Pacific

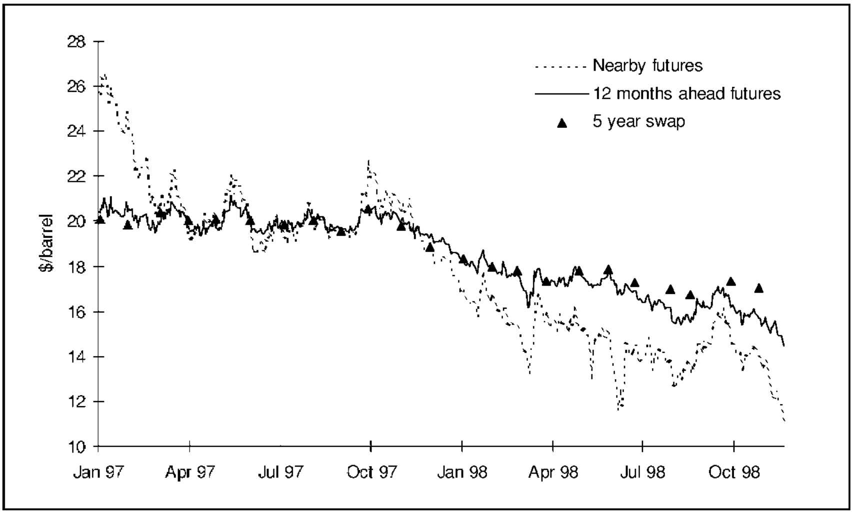
In Asia, light sweet crudes can be hedged using the so-called "paper" Tapis market. Despite its name, paper Tapis is actually a swaps market and not a forward paper contract. The market is not based on standardised quantities like most other short-term swap markets, but a typical paper Tapis deal would be for 100,000 barrels.

The paper Tapis market is based on the average of Tapis APPI (Asian Petroleum Price Index) price quotations for a given month and enables companies to fix the price of cargoes of physical Tapis and other similar regional crudes which are usually sold using a formula price which also includes the Tapis APPI price quotation (see Chapter 4). Since APPI price assessments roll-over in the middle of the month, the paper Tapis market for any given calendar month is always slightly out of line with the underlying physical market for physical Tapis delivered in the same month. In a backwardated market, the paper Tapis price for August will be lower than the spot price for August Tapis because the average of the published APPI price quotations for August will be based on a combination of August and September spot Tapis prices (see Chapter 18).

As far as refined products are concerned, price swaps are now the most popular method of hedging short-term price risks in the Asia Pacific market. Naphtha swaps based on fob Singapore cargoes are traded alongside the revived open-spec naphtha forward paper market for delivery c+f Japan (see Chapter 7). And price swaps for jet kerosine, gasoil and high sulphur fuel oil are also actively traded based on *Platt's* fob Singapore price quotations. The gasoline swaps market is no longer active as the region currently lacks a clear gasoline price marker (see Chapter 5).

10.4.2 Long-term swaps

Long-term swaps have no theoretical limit to their time-horizon but typically cover periods from six months to ten years ahead. At the nearer end of the market they are used to support supply decisions, but further out they are used to support investment decisions, such as developing a new oil field. Unlike shorter-term swaps, which are priced in relation to the futures markets, long-term swaps do not always have a clear pricing basis. Prices can therefore be more



Source: Nymex, Intercapital

Figure 10.8 Long-term WTI swaps prices

subjective since they may require swap providers to take a very long term view of oil price prospects and to extrapolate the forward price structure beyond the time horizons of the existing forward and futures markets (see Chapter 11).

The most active long-term swaps market is for WTI and the market is now sufficiently liquid to provide regular bid/ask quotations at least five years ahead (see Fig. 10.8). Since the market is based on the Nymex light sweet crude contract, which now trades up to seven years ahead, the slope of the long-term WTI swaps price profile is determined by arbitrage with the futures market. But further out, one of the factors determining the forward curve is the long-term interest rate curve. Other long-term swaps markets such as Brent typically trade at a differential to the WTI swaps price.

10.4.3 Over-the-counter (OTC) options

OTC derivatives can also be structured to provide various degrees of price protection. Swaps are the simplest type of OTC derivative — sometimes described as "plain vanilla" — since they are designed to transfer all the price risk from the swap user to the swap provider. But it is also possible to create many different "flavours" of OTC derivatives that provide, for example, an upper (cap) or lower (floor) limit to prices, or allow the user to confine the price exposure to a specified range (collar), and even "participate" in the profits if prices move outside a specified range.

These more elaborate derivatives include OTC options which can also be tailored to suit the user in exactly the same way as a simple price swap (see Chapter 9). Although similar hedging strategies can be devised using exchange-traded options, the user faces the same problems of basis risk that affect the hedging efficiency of futures contracts. As a result, price caps, floors and collars are now widely used by companies seeking effective and accurate control of their price exposure.

What is an OTC option?

There is no standard form of OTC option since the parties involved can choose from a variety of option types to structure their agreement. However, the most common form of OTC option used in the energy market is an *average price option* (APO), sometimes known as an *Asian option* to distinguish it from *American* and *European* options, which works in much the same way as a price swap.

Like an exchange-traded option, an OTC option confers on the buyer the *right*, but not the obligation, to buy (or sell) the underlying commodity at an agreed fixed price in exchange for an "insurance" premium that is paid up-front. But, instead of being converted into a futures contract if it is exercised by the buyer, an OTC option can either be converted into a cash payment from the option writer to the option buyer or into a swap (swaption). OTC options therefore remain purely financial transactions and, like price swaps, cannot be used to make or take physical delivery of the underlying commodity. Like price swaps, OTC options can also be applied to any asset for which a mutually acceptable pricing mechanism can be established.

Although the general principles for using OTC average price options are the same as for exchange-traded options, there are a number of important differences. First, the terminology is not quite the same. An OTC call option is generally known as a "price cap", while an OTC put option is known as a "price floor". Secondly, OTC average price or *Asian* options can only be exercised at their expiry date and are only exercised if the period average price is above (or below) the agreed cap or floor price. This distinguishes them from *European* options, which can only be exercised if the market price is above the strike price on the expiry date, and *American* options, which can be exercised if the market price goes above the strike price at any point up to and including the expiry date. Thirdly, OTC average price options are automatically exercised on expiry if they are in the money. This is not the case for exchange-traded options since there are sometimes tax advantages to be gained from not exercising in-the-money options or exercising out-of-the-money options. And finally, like a price swap, OTC average price options usually cover a longer period than a futures contract, for example, a quarter or a year.

Apart from these practical differences, however, the risk and reward profile of an OTC option is the same as for an exchange-traded option. An option buyer's exposure is limited to the premium that is paid to the option writer, while the option writer's exposure is unlimited.

How does a price cap work?

A company, such as an airline, that wants to set an upper limit to the price of its jet fuel requirements over the next quarter could purchase a price cap for the next three months from an OTC options market maker instead of using the futures market to hedge its jet fuel costs with exchange-traded options.

The OTC price cap agreement specifies that the market maker will pay the airline the difference between the price cap and the monthly average jet fuel price for an agreed quantity of jet fuel in any of the next three months in which the average monthly market price of jet fuel exceeds the level agreed for the price cap. In exchange the airline agrees to pay the market maker in advance a fixed and non-refundable premium for the same quantity of jet fuel over the entire period.

The market price of jet fuel is determined by the monthly average of the daily price assessment published by a mutually acceptable and reputable price reporting service. The option is automatically exercised by the market maker if the monthly average market price of jet fuel exceeds the level agreed for the price cap. The contract is settled, like a price swap, usually at the end of each month, by paying the difference between the fixed price and the period average floating price to the airline if the option is deemed to have been exercised. If the monthly average remains below the level agreed for the price cap, the market maker is not required to make any payments.

Since the contract does not involve physical delivery, the airline needs to make separate arrangements to purchase the jet fuel. If the monthly average market price remains below the level agreed for the price cap, the effective price paid by the airline will be the market price *plus* the premium paid to the market maker for the OTC option. If the monthly average market price goes above the level agreed for the price cap, the net payments from the market maker *minus* the premium paid can be used to offset the higher market price for jet fuel. In this way the maximum price paid by the airline is limited to the level agreed for the price cap *plus* the premium paid to the market maker for the option.

How are OTC options priced?

Like swaps, arbitrage between the OTC options market and the exchange-traded market ensures that average price options are priced in line with exchange-traded options contracts. However, since options are "non-linear" trading instruments it is not possible to replicate exactly the payoff from an OTC average price option with a portfolio of exchange-traded options — as it was in the case of a price swap (see Chapter 9).

Like exchange-traded options, the price of an OTC option will depend partly on the market's view of the expected price volatility for the commodity, partly on the current price level of the underlying strip of swaps prices, partly on the duration of the option, and partly on the strike price agreed for the price cap or floor (see Chapter 9). Market makers in the OTC options markets use a variety of pricing models, including modifications of the Black and Scholes options pricing model — originally developed for European options — to evaluate the premium they require to sell a price cap or floor. But everyone likes to use their own variations to fine-tune pricing models according to their views of how the market works.

In the short term the OTC options market tends to track the level of price volatility implied by the exchange-traded options market, but in the longer term the market forms its own view of the expected level of price volatility as there are no exchange-traded options available that far out to provide a guide (see Chapter 18).

Example: Hedging jet fuel with swaps and OTC options

A European airline specialising in holiday charter flights is considering using price swaps or OTC options to limit its exposure to fluctuations in the price of jet fuel during the winter ski-season. In order to fix prices in June 1998 for a new holiday brochure being prepared by a major travel company the airline obtains quotes for three types of swap deal that might be appropriate.

Simple (plain vanilla) swap

The simplest arrangement would be a straight-forward "fixed for floating" price swap for the period October to March based on *Platt's* quotations for jet fuel cargoes cif NW Europe. This could be done at $140/tonne in June 1998 and would guarantee the airline a fixed price for its jet fuel over the entire winter period. As long as

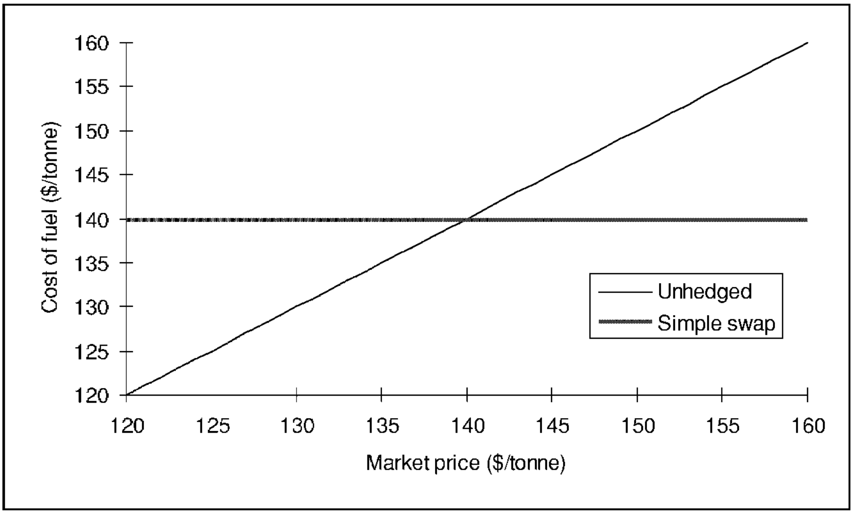


Figure 10.9 Result of hedging using a simple swap

the airline can buy physical jet fuel at prices equivalent to *Platt's* jet kerosine price quotations, the "plain vanilla" price swap will provide a perfect hedge whatever happens to jet prices over the six month period (see Fig. 10.9).

If the average monthly spot jet fuel price is higher than $140/tonne, the airline will receive a cash payment from the swaps provider equal to the difference between $140/tonne and the monthly average of *Platt's* jet cargoes cif NWE that can be used to offset its higher purchase costs on the physical market. And if the average monthly spot jet fuel price is lower than $140/tonne, the airline will have to make a payment to the swaps provider that will offset its lower purchase price on the physical market.

Price cap (ceiling swap)

An alternative, but rather costly, arrangement would be to purchase a price cap (or ceiling swap) for the same time period. This would allow the airline to set a maximum price for its jet fuel over the winter, while allowing it to benefit from lower fuel costs if the opportunity arises. Since it is an option, the cost of a price cap depends on how far "out of the money" the ceiling price is set (see Chapter 9). In June 1998, an *at the money* cap of $140/tonne would have cost $10/tonne, while an *out of the money* cap at $150/tonne would have cost $7/tonne. This premium, like any option premium is non-returnable as it is effectively an insurance premium against a price rise.

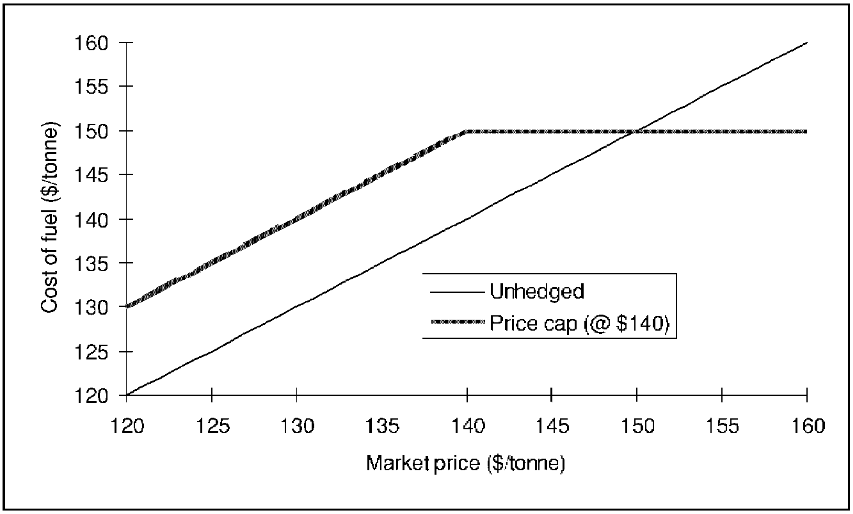


Figure 10.10 Result of hedging using a price cap

If the average monthly spot jet fuel price is lower than the price ceiling specified in the price cap agreement, the airline does not have to pay any more to the swap provider and simply buys its jet fuel on the spot market at the lower market price (see Fig. 10.10). But if the average monthly spot jet fuel price is higher than the agreed price ceiling, the airline will receive a monthly cash payment from the swaps provider equal to the difference between the ceiling and the monthly average of *Platt's* jet cargoes cif NWE that can be used to offset its higher purchase costs on the physical market.

Price collar (price range swap)

A cheaper alternative would be to purchase a price collar (or price range swap) which sets both a floor and a ceiling price. This would expose the airline to a specified (narrow) range of price fluctuations in the price of jet fuel, while providing insurance against very large price movements. It is cheaper than a price cap because the airline forgoes some of the downside benefits of lower oil prices in exchange for fixing a maximum price for its jet fuel over the winter. Like a cap, the price of a collar depends on how far "out of the money" the ceiling and floor prices are set, but the net cost of the two combined options is much lower because the swap provider's risk is limited on both the upside and downside (see Chapter 9).

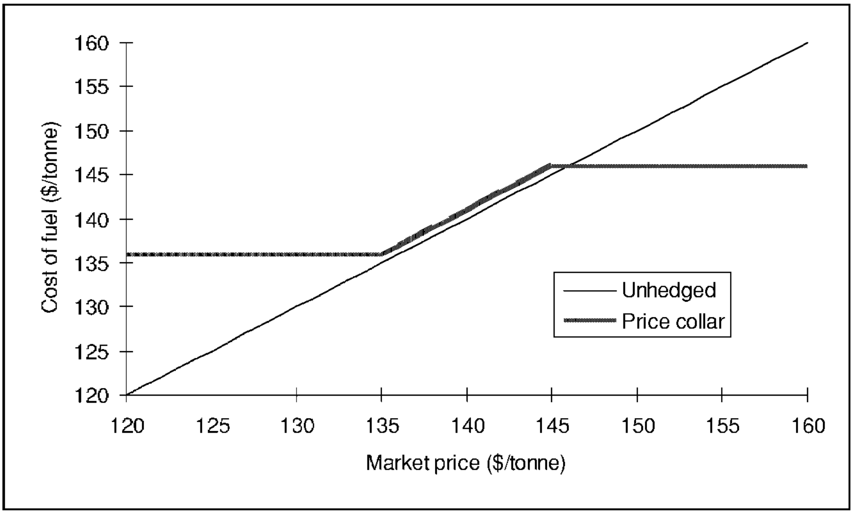


Figure 10.11 Result of hedging using a price collar

In June 1998, a price collar with a ceiling price of $145/tonne and a floor price of $135/tonne would have cost only $1/tonne. As before, the premium must be paid up-front and is non-returnable. With this type of price collar, the airline is only exposed to movements in the average monthly spot jet fuel price over a range of $10/tonne (see Fig. 10.11). If the average monthly spot jet fuel price rises above $145/tonne, the airline receives a monthly cash payment from the swaps provider equal to the difference between the ceiling and the monthly average of *Platt's* jet cargoes cif NWE that can be used to offset its higher purchase costs on the physical market. But if the average monthly spot jet fuel price is lower than $135, the airline will have to make a payment to the swaps provider that will offset its lower purchase price on the physical market.

10.5 Future developments

Swaps and other OTC derivative instruments remain the fastest growing sector of the oil market. The ease with which they can be tailored to match the individual price exposure of each participant continues to ensure their popularity. And the increased flexibility associated with a purely financial instrument has enabled them to capture most of the liquidity previously attracted to a wide range of informal forward paper contracts. In addition, the use of long-term swap contracts to reduce the risks of investing in major capital projects such as an oil field or a refinery has sustained the development of this important market for oil.

But the future expansion of the OTC market could be affected by uncertainty over the possible regulation of financial derivatives in the US. The rapid growth of derivatives trading throughout the financial sector has led to concerns about the scale of risk being assumed by the derivatives traders and there is growing pressure for more regulation and control of these markets. Although such moves are being strongly resisted by the financial services industry — and currently enjoy only limited support among the various regulatory authorities — the very large losses incurred by a small number of derivatives providers could force changes in the law, both in the US and elsewhere.

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11 Long dated oil markets

Frédéric Barnaud & Philippe Lautard

11.1 Introduction

The oil industry has always needed to take a long term view of investment. Geological risks, which characterised the risk and reward structure of the pioneering epoch in the second half of the nineteenth century, can be greatly reduced by the use of better techniques and technology, and — ultimately — by luck, but they cannot be managed. The management of risk in the oil industry depends on both time and prices: producing oil from a new oil field typically requires several years and a huge investment; while moving the oil from the well-head to the consumer requires several weeks and the use of many financially illiquid assets such as pipelines, ships, tankage, and refineries.

To ensure their success — or simply their survival — in such a difficult business environment, oil companies and producing and consuming countries have put into practice a wide variety of economic theories and have also tried some exotic solutions. These include vertical, horizontal or global integration, nationalisation of producing assets, national price control, swinging or controlling production, oligopolistic agreements, long term contracts, and netback pricing. And, since the early 1980s, the combination of events and people have triggered the emergence of spot and futures markets in oil. Modern financial techniques have turned the wet barrels of oil first into paper barrels and then into video barrels.

Methods of managing risk, especially in the context of highly erratic prices, have increased tenfold as a result of the new markets, which provide a focus for the expectations not only of the oil industry, but also of the other main economic agents. The standardised markets — futures markets such as the Nymex, the IPE and the Simex, or forward markets, such as dated Brent, Littlebrook Lottery or Russian Roulette — have now become a major factor in the pricing mechanism for short-to-medium term crude oil and refined products. This role was dramatically revealed to the world and then enhanced by the first "oil war" in the period August 1990 to March 1991.

Recently, a market for long-term oil has been jointly developed to meet specific requirements in the industry, to structure oil-linked transactions and to create new opportunities for speculators. This new over-the-counter market has brought together heavy weighted and highly ranked oil companies, banks and traders. Their external counterparts include oil producers and importers (countries as well as companies), end-users, financing institutions, large funds and small speculators. A typical long-term transaction ranges from 5,000 b/d to 50,000 b/d with a time horizon of three, five, seven or even ten years. In other words, the volume of oil involved is sizeable when compared to:

- the Nymex WTI Light Sweet Crude futures trading volume: 106 million b/d,
- world energy demand: 65 million b/d, with a forecast annual growth rate of more than 1 million b/d,
- Opec's current production quota of 25 million b/d.

This chapter gives a general overview of the long-term oil market. It portrays, first, the different actors in the market, and the way liquidity is generated and evaluated. Secondly, it presents the whole range of hedging and speculative instruments available to traders, producers and end-users. Thirdly, the main risks embodied in pricing and hedging long-term oil contracts and the ways they are modelled by market theoreticians are explained. Fourthly, the contractual environment, with legal, credit-risk evaluation and administrative aspects are reviewed briefly. And last, but not least, a broad analysis of long-term oil trading for producers is presented and illustrated by concrete hedging strategies and practical advice.

11.2 Market participants

11.2.1 Companies and countries exposed to oil prices

Large integrated oil companies have been involved in oil trading activities ever since the emergence of markets and they have set up trading subsidiaries to develop an expertise in modern oil risk management. These were first created for internal purposes, to manage, in a global way, the transfer of risk between affiliates. However, some of them have also developed an external independent clientele for diversifying their portfolio. Their presence in the long-dated oil market is characterised by:

- precise and global access to information, which is the nerve centre of any market,
- an opportunity to associate strategic group decisions with some transactions, with all the involvement in terms of pricing or hedging,
- an ability to work on long-term contracts with specific physical delivery clauses, or *Argus/Platt's* related terms,
- a good and high-level covering of their traditional counterparts, oil-exposed countries as well as oil companies.

Similarly, medium-size oil companies, for instance independent oil producers and refiners have been directly involved in physical oil trading as most of their incomes and some of their costs are linked to spot prices in the market. They have therefore followed — or even anticipated — the trend towards improved risk management and are increasingly willing to work on long-term transactions.

Within the large world of oil-price-exposed entities, oil importing and exporting national companies and countries only play a marginal role. Their vision of risk management often relies on global economic solutions rather than direct oil price hedging policies. This is especially true of the oil producing countries, which (reportedly) consider oil markets as a vehicle for speculation and an amplifier of price fluctuations. However, some oil exporting countries are said to have concluded long-term transactions at the end of 1990, taking advantage of high prices during the Gulf crisis. The oil importing countries, on the other hand, have traditionally sought solutions that are complementary to their economic situation. Their exposure cannot be controlled and there have been at least five oil crises with major price increases for one price fall.

But it can be managed. Their requirements obviously differ according to the structure of the oil industry in the oil consuming country. Depending on their refining capacity, they may be either a net importer of refined products, or a net importer of both crude oil and refined products, or a net importer of crude oil only, or even a net importer of crude oil and a net exporter of refined products. Prices may be locked into a national price control framework, or be related to world oil market prices.

These elements must be analysed and taken into account in order to define an appropriate long-term hedging strategy. Given the large volumes generally involved, it is often optimal to set up the hedging scheme regularly over a certain period of time and to monitor and manage the strategy continuously.

11.2.2 Banks and investment houses

The involvement of banks and financial investment houses in the market for long-dated oil has been an important factor in its development and liquidity. They have transferred financial techniques from interest rates and foreign exchange derivative markets to the oil market. This has been guided by their clients' need for global structured transactions, and also contributes to a strategy of risk diversification away from their traditional businesses. Their presence in the long-dated oil market is characterised by:

- extensive experience of financial derivative markets and administration,
- an opportunity to work on structured deals with complex payoffs, to propose global financing and combined risk management solutions,
- the existence of a highly captive clientele, with whom they generally have a long-term and stable relationship.

According to their portfolio structure, banks and investment houses may be divided into two main groups:

- some do not take on the specific oil price risk but separate it out from the main deal in order to swap it with other oil trading counterparts. As they are only present from time to time, they cannot be considered as true counterparts, but they bring a considerable amount of liquidity to the market.

- other banks and investment houses have chosen to manage the oil price risk and have created a sophisticated trading portfolio. But, possibly because of the difficulties facing a bank as an actor in the physical oil market, their core activity is mainly based on futures-linked deals, WTI and other Nymex or IPE references, and on medium and long term transactions.

11.2.3 Oil traders and Wall Street

The presence of traditional oil trading houses is not as important in the long-term oil market as it is for physical and medium-term markets. Some companies, however, have acquired diversified interests as a result of their structure: halfway between a trader and an oil company owning refineries or other assets or (sometimes) a share holding relationship with a bank. The involvement of traders in the long-dated oil market is characterised by:

- a traditional aggressiveness, due to their excellent knowledge of physical markets, access to information and their quick reactions,

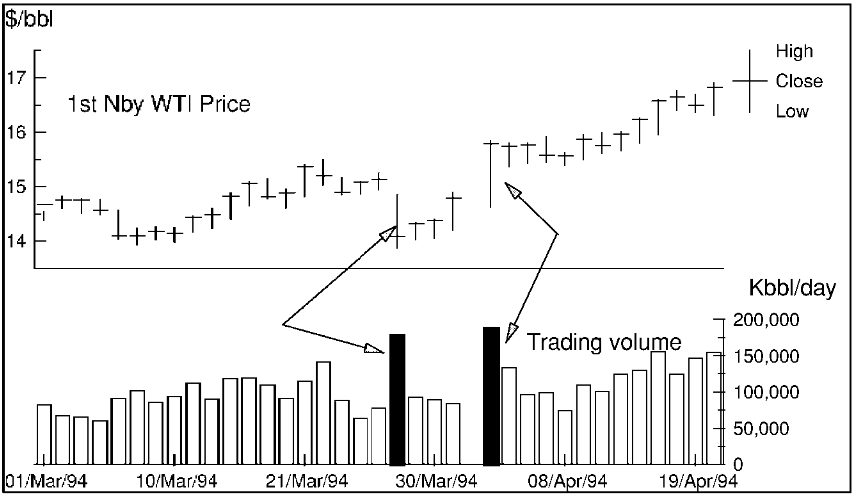
- the ability to work on instruments combined with physical delivery or *Argus/Platt's* risks.

11.2.4 Unexposed companies, funds and speculators

The development of the long-dated oil market satisfies the needs of many different actors for alternative risk management instruments. The interest of other types of companies — many of which are not directly exposed to oil price risks — such as large investment funds and large and small speculators, has been triggered by the fact that oil is a commodity that is strongly influenced by political and economic factors. Thus large funds may seek a long-term investment related to oil finance as a partial hedge to their interest rates and inflation risks, or as a portfolio diversification.

These other types of participant have played an important role in the market for long-term oil not only during the extreme price movements of the Gulf crisis, but also in response to the general uncertainty over oil prices, appearing either in a direct relationship with oil traders, or through their interest in instruments such as warrants or synthetic oil fields, which are quoted on secondary financial markets. Elf Trading's published work[1] shows that

[1] With the collaboration of the Oxford Institute for Energy Studies



Source: Elf Trading

Figure 11.1 Influence of funds on nearby WTI futures prices

speculators also respond to price volatility but, to a large extent, this response is in the nature of arbitrage with liquidity. This explains the large shifts of speculative interest from one market to another. As a result, the market for long-term oil appears more and more to be naturally integrated into the global framework of financial markets, equities, interest rates or foreign exchange.

An example of how fund activity can influence the level of oil prices in the short run is given by looking at the WTI price around March and April in 1994 (see Fig. 11.1). A first surge in activity, shortly after an OPEC production quota meeting, resulted in a sharp downward market gap. Subsequently, funds decided that the market was oversold and came into the market, boosted volumes and caused an upward market price spike.

(OIES) and its Director Robert Mabro, some Elf Trading research assistants have published work on energy markets:

Barnaud, F., 1990, *In Search of Liquidity: Hedging and Speculation in Oil Futures Markets*, OIES WPM 13,

Chassard, C. & Halliwell, M., 1986, *The Nymex Crude Oil Futures Market: an Analysis of its Performance*, OIES WPM 9,

Chassard, C., 1987, *Option Trading and Oil Futures Markets*, OIES WPM 11,

Gabillon J., 1991, *The Term Structure of Oil Futures Prices*, OIES WPM 17,

Trabia X., 1992, *Financial Oil Derivatives: from Options to Oil Warrants and Synthetic Oilfields*, OIES SP3.

11.2.5 Arguments for investing in oil

Lately, commodities have attracted increased interest as an investment instrument. The poor performance of traditional equity and fixed income investments, a positive fundamental outlook on commodities and portfolio diversification arguments have drawn institutional investors into the market.

Oil, being the pre-eminent industrial commodity, has the diversification and exposure benefits of more broadly based commodity indices, and offers the superior liquidity and transparency of its underlying futures market. Focusing on one strategic commodity also facilitates the investment decision process and allows a better economic fundamental understanding.

Modern portfolio theory (MPT) as prescribed by Markowitz, dictates that investors should allocate their assets across as wide a range of investments as possible (i.e. *the market portfolio*) in order to obtain an optimal risk-reward combination. The main benefit of investing in oil-linked instruments is thus to diversify traditional stock and bond portfolios and protect them from inflation.

Table 11.1 shows the degree of correlation between crude oil prices and a number of other major economic indices. The results were calculated using monthly data from January 1985 to January 1995 and the analysis was performed using rates of change.

Table 11.1 Correlations with Nymex nearby WTI futures

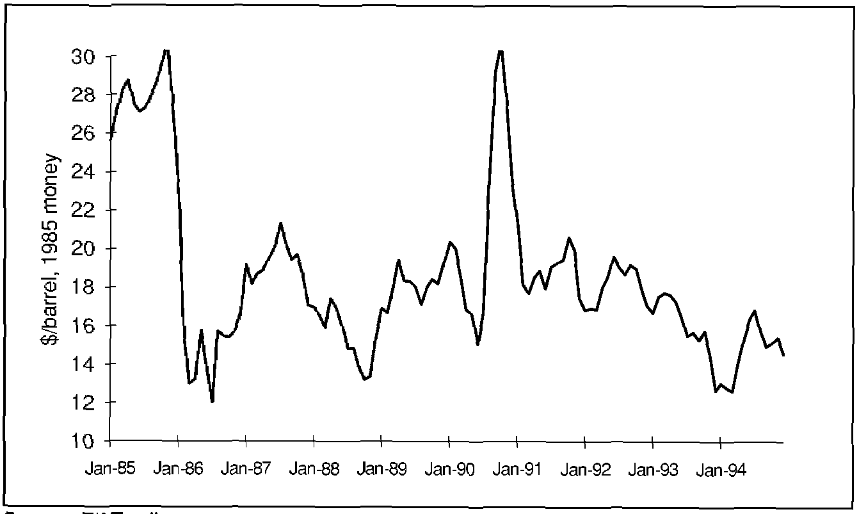
S&P 500 Stock Index	-29%
Salomon Brothers Treasury Bond Index	-30%
US Consumer Price Index (CPI)	43%
US Producer Price Index (PPI)	65%

Hedge against inflation

Worries about an overheating US economy and a subsequent rise in inflation were the underlying causes of depressed financial markets in 1994. The positive correlation recorded between oil and the consumer price index (CPI) and producer price index (PPI) means that adding an oil component to a portfolio can increase returns as inflation rises.

Portfolio diversification

Negative correlation recorded between oil and the Standard & Poor's (S&P) 500 index and the Salomon Brothers Bond Index



Source: Elf Trading

Figure 11.2 WTI price adjusted for inflation, 1985 dollars

means that adding an oil component will reduce the volatility of a portfolio and thus enhance its risk and reward characteristics.

Under performing asset class

Little evidence exists to support the argument that crude oil will continuously outperform traditional equity or fixed income instruments on a long-term basis. The fact, however, remains that inflation-adjusted crude oil prices currently stand at historically low levels (see Fig. 11.2). Continuously increasing world energy consumption combined with a tight Opec production ceiling remain as medium-term bullish factors and Middle Eastern political uncertainty offers the potential for price surges.

11.3 Market liquidity

11.3.1 Visibility

The long-dated oil market, being a typical over-the-counter market, where transactions may be negotiated at state level over a few months, often lacks visibility. With not much standardisation of terms, a global "private and confidential" basis and no reporting agency, there is no reliable way of measuring the long-term activity. For instance, nothing is known about deals made between the banks and their captive clientele, which leads to an underestimation of the market's size. Another example is the limited role of brokers: many long-term deals are conducted directly between counterparts, since they need time to structure most of the transactions, a precise credit-default risk evaluation and legal negotiations around a master agreement.

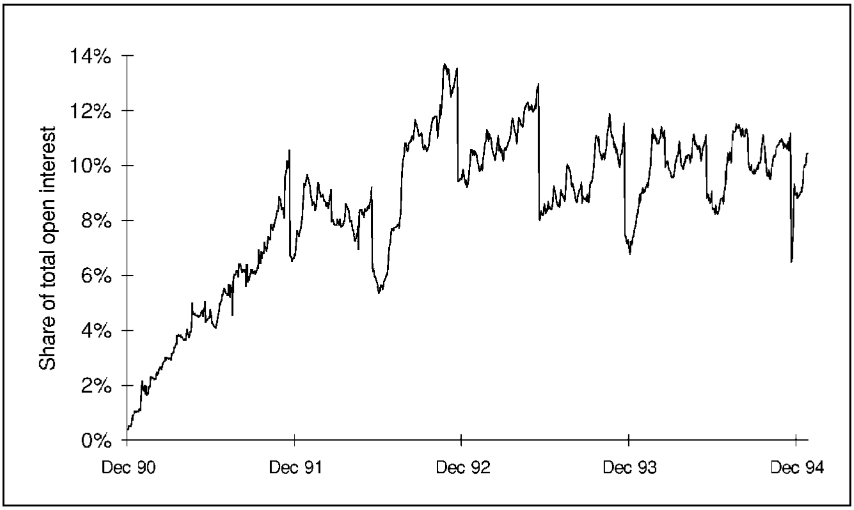
Both buyers and sellers must also be blamed for this opacity since every trader tries to keep deals as private and confidential as possible.

11.3.2 Liquidity

Although lack of visibility may be the essence of the long-term oil market, this does not prevent us from evaluating the liquidity of the market. If visibility is concerned with the activity of the market — the number of deals, average volume and maturity involved — the notion of liquidity is concerned with the opportunities for participants to turn over their portfolio quickly at low cost.

The liquidity of a derivative trading instrument can be indirectly evaluated by the liquidity of its ultimate hedging market, for example Nymex WTI futures for long-term crude oil swaps.[2] The Nymex provides market participants with many statistics: trading volume and open interest, information on futures contracts, and reports of large hedging and speculative interests. Figure 11.3 illustrates how this information can be synthesised to assess the growing size of the long-term oil markets. It shows the percentage of the Nymex WTI open interest for contracts with a maturity over

[2] For swap writers, it is important to note that the Nymex actually limits the open interest on the first maturity to any trading company and refuses a limit exemption on this first maturity for the purpose of swap hedging. Hedging computations have to take this into account and therefore use other maturities for covering large volumes.



Source: Elf Trading, Nymex

Figure 11.3 Share of WTI open interest 19 to 36 months ahead

eighteen months (back months). Hedging long-term transactions with futures contracts will usually increase activity in the back months in order to limit the risks of the maturity factor and the term structure of prices. The back months started trading in December 1990 during the Gulf crisis. Their success has been very impressive as, only a year later, they accounted for around ten per cent of the WTI futures total open interest, which represents a position of 40 million barrels.

However, to be fully relevant when analysed in terms of market liquidity, the figures provided by the Nymex and other exchanges have to be further processed. For example, it is important to understand the behaviour of market participants, mainly hedgers, speculators, locals, market makers, and their respective impact on volume and open interest. The evolution, either structural, seasonal or opportunist, of their requirements would change the pattern of liquidity in futures and derivative markets.

Understanding liquidity of the underlying hedging market can give a clue to the liquidity of a derivative market. Monitoring the bid/offer spreads of such instruments gives additional information and complements the analysis. The larger the bid/offer spread, the worse is the liquidity of the market, for it represents the instantaneous cost of reversing or closing out a position. For example, the spread for the first three traded maturities is only a few cents. But this increases to twenty cents for the Nymex back months, leading to a fifty cent bid/offer range for a classical five-year-maturity swap. Such a bid/offer spread is not constant over time nor across maturities. It would aggregate different components and have complementary characteristics.

Market participants' trading decisions are the first element that determines the size of the swap spread. They take into consideration how the swap would fit into their existing positions and directional views, how it would suit their long-term strategic decision process and whether they would like to make a tight market quote versus their competitors.

Other elements that could influence the spread are liquidity considerations, ongoing hedging or position rolling transactions, option-related trading activity, mathematical and modelling factors, and legal matters.

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11.4 Trading instruments

11.4.1 Long term trading instruments

The long-term oil derivative market is a modern market which provides trading participants with many diversified instruments. These may be based on straightforward swaps, include optional and synthetic payoffs, have physical delivery characteristics or be settled on any relevant *Argus/Platt's* index. Table 11.2 gives a general overview of the most frequently traded derivatives, and additional information is provided in Section 11.7 on using long-dated derivatives and the related Appendices. Built on these instruments, further sophisticated hedging strategies can be precisely tailored to the client's needs.

11.4.2 Oil warrants

Oil warrants are investment instruments offered to the public and can be used to speculate on different oil price and volatility scenarios. Even if both the issue and the secondary market's activity are difficult to monitor, it appears that this class of instruments is likely to flourish and enjoy considerable success during major oil price turmoil periods, like the Gulf crisis and war in 1990/91.

The structure of payoffs often includes some exotic components like American options on futures or nearby maturities, compound options on Asian options or look back options (see Chapter 9). But, apart from the theoretical difficulties and management decisions embedded in the initial pricing and hedging, the most important factor of a successful launch appears to be the timing and the marketing of the warrant. This is the major reason why such instruments have been mainly written by banks and financial institutions.

Deeper analysis has often shown that these so-called oil warrants are relatively expensive for oil traders, but are more suitable for the public to whom the oil market is not easily accessible.

11.4.3 Royalty trusts

Royalty trusts, like the Prudhoe Bay Royalty Trust issued by British Petroleum and Standard Oil, may be summarised as bonds whose yield is effectively based on the production and price of

Table 11.2 Main long term oil trading instruments

Type	Characteristics	Objectives
Swaps	Periodical financial settlement against the average of futures, a nearby or an *Argus/Platt's* index.	The simple direct hedge, tailored to minimise the client's basis risk.
Asian options	Periodical financial settlement against an average, over or under an agreed strike price. The buyer must pay an initial premium directly linked to price volatility and time maturity.	Being hedged on the risk side with the open opportunity to take advantage of favourable price moves. Buying an option is like buying an insurance policy.
American options	Opportunity to lock in hedging profits, if any, at any time during the life period of the option.	Added flexibility at a cost.
Combinations of swaps and options	Min-max swaps, collars, participation swaps.	Tailor-made flexibility over a swap with minimum basis risk.
Swaptions	Opportunity, for a certain time, to enter a swap at an agreed price. Initial premium paid by buyer.	Option-like flexibility over a swap with minimum basis risk.
Exotic payoffs	Options on spread values, e.g. WTI-Brent or time spread. Option on options, on min or max value.	No limit to the imagination of traders and marketers.
Physical delivery	Financial hedging combined with the delivery, optional or not, of physical crude oil.	The modification of traditional supply routes, when combined with hedging, may enable the client to eliminate the residual basis risk or convergence risk between the hedge and the physical.
Structured transactions	Global transactions, e.g. energy swaps and options written in any European currency. Loans and finance indexed on oil prices.	The ultimate design of a hedge; needs a deep analysis of the client's combined risks.
Wall Street financial oil instruments	Financial instruments which replicate the payoffs of an oil field, e.g. royalty trusts, synthetic oil fields. Public speculative instruments, e.g. oil warrants.	Give equity, forex, interest rate traders and the general public the opportunity to take part in oil trading and diversify portfolios.

physical oil. The return enjoyed by holders of the trust units depends partly on the reference oil price — Nymex WTI light sweet crude — and partly on other factors, the consumer price index, chargeable or production costs and taxes.

This highly successful trust issue brought the issuer fresh finance whose reimbursement was directly linked to the market price for the anticipated field production and sales, and therefore did not damage the long term financial structure of the company. Its main risks are the basis risk between the crude produced — Alaskan North Slope — and the price index used as a reference for the trust payoffs, and the political risk of changing environmental or production regulations.

But the main risks for the unit holders are not negligible. Beside the basis risk, they are also exposed to inflation. Since oil is an important component of international trade and industry, there is a high correlation between oil prices and the inflation rate. This helps to explain the success of this issue among pension fund managers. Most of the other large risks involve potential conflicts of interest between the field owner and operator and the trust holders over reserve estimates, and therefore production costs as defined in the trust contract.

The success of such trust issues hinges not only on excellent marketing but also on attractive pricing, depending on the need or will of the issuer to generate funds. Anyway the way is now paved for innovative oil companies to exploit a new source of exploration and production financing.

11.4.4 Synthetic oil fields

Some investment houses have issued synthetic oil field trusts as an alternative to royalty trusts designed to finance the physical development and operation of an oil field. Since they are engineered as a purely financial play, these long-term instruments do not create potential conflicts of interest over the assessment of production costs and the evolution of the regulatory and tax framework.

However, synthetic oil fields have no physical production to underwrite them and must be covered by the writer using the whole range of futures and derivative oil markets, which brings liquidity risks and costs when hedging in the back months, and maturity exposure when rolling forward positions. If the issuer sells all the trust units quickly, the real success comes from the secondary market, if it can generate its own liquidity and provide good arbitrage opportunities.

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11.5 Pricing models

Pricing is not the trickiest part of the deal when there is adequate competition — if not liquidity — in a derivative market. For example, a few elementary hypotheses and a large number of Monte Carlo[3] simulations can provide a price for any structure of future payoffs. Such techniques were frequently used to price average and exotic options before satisfactory pricing formulae were proposed by theoreticians. Classical random models and simple hypotheses are widely used in the literature and are sometimes adapted for use in the markets.

11.5.1 Log normality of outright prices

This is the main hypothesis underlying the theory of rational option pricing, as developed in 1973 by Black & Scholes[4] and Merton.[5] But the modern vision of prices as a random walk process was initiated years earlier by two French mathematicians, Louis Bachelier[6] in 1900 and Benoit Mandelbrot[7] in the 1960s. It is usually expressed in writing that the daily rate of return, for example, the daily official settlement prices provided by futures exchanges, follows a "brownian motion". In other words, it has a normal statistical distribution:

$$\mathrm{Log}(F_t/F_{t-1}) \sim \mathrm{Normal}(\mu,\sigma)$$

where, μ = commodity appreciation rate,
σ = price volatility.

One of the quickest ways to accept or reject such a model is to plot a graph of the statistical distribution of the daily rate of return of outright prices and compare it with the equivalent normal distribution, for example, the first nearby Nymex WTI futures

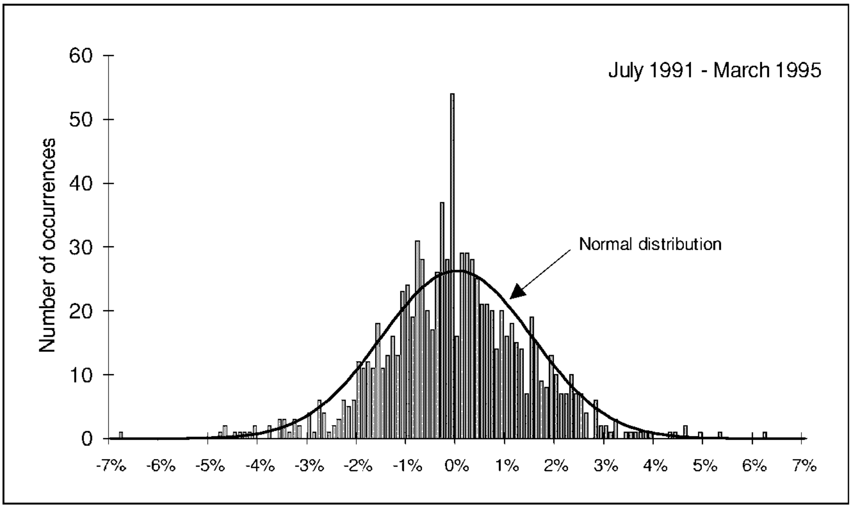
[3] Monte Carlo is a classical numerical analysis technique to value a risk by computing various simulations of adequate probabilities and measuring their statistical results.

[4] Black, F. & Scholes M., 1973, 'The pricing of options and corporate liabilities', *Journal of Political Economy, Vol.81, pp.637-659.*

[5] Merton, R.C., 1973, 'Theory of rational option pricing', *Bell Journal of Economics and Management Science, Vol.4, pp.141-183*

[6] Bachelier, L., 1900, 'Théorie de la spéculation', *Annales de l'Ecole Normale Supérieure, Vol.17, pp.21-86.*

[7] Mandelbrot, B., 1963, 'The variation of certain speculative prices', *Journal of Business, Vol.36, pp.394-419.*



Source: Elf Trading

Figure 11.4 Distribution of daily returns for WTI first nearby

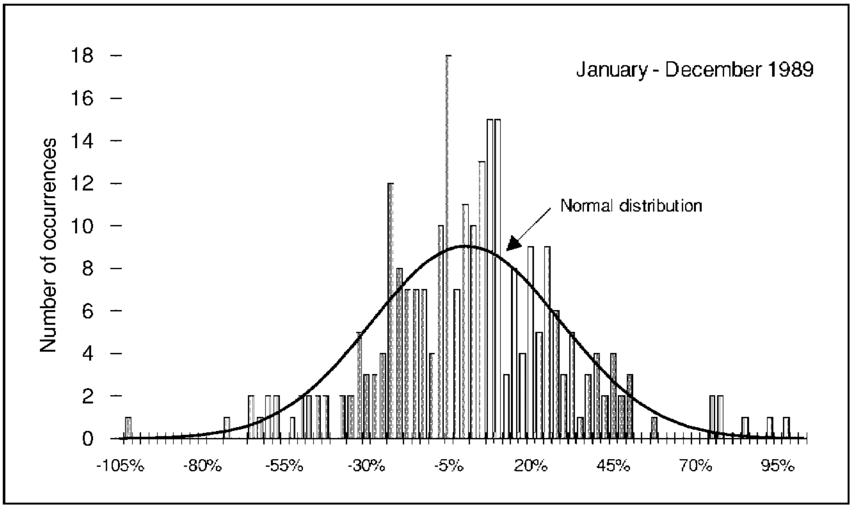
contract from July 1991 to March 1995 (see Fig. 11.4). Further analysis, using third and fourth moments, trends and seasonal adjustments, should be carried out if these statistics are to be used in genuine pricing models.

11.5.2 Normality of price spreads

In the same vein, quality spreads and time-spreads are also said to have a normal statistical distribution. However, price differentials tend to be just as — if not more — volatile than outright prices, and highly subject to seasonal and disrupting effects. The WTI-Brent first nearby spread distribution for 1989 (see Fig. 11.5) provides a quick insight of the reasonableness of such a hypothesis when differentials are not too erratic.

11.5.3 ARCH volatility

Another class of models, known as auto-regressive conditional heteroscedastic (ARCH) models — also GARCH and ARMACH — are frequently used to forecast price volatility for option pricing. These assume that conditional standard deviations are a deterministic function of past returns. Their attraction is that they relax the very restrictive Black & Scholes hypothesis of constant price volatility. Option pricing models can then be adapted successfully either for the very short term, say intra-day trading, or for longer term maturities.



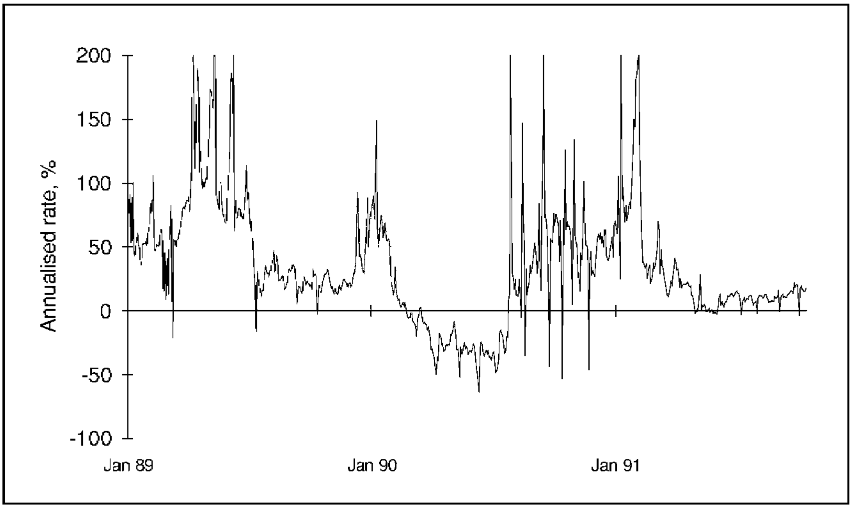
Source: Elf Trading

Figure 11.5 Distribution of daily returns for WTI-Brent spread

11.5.4 Market constraints

Like random models, historical simulations may be used to verify the stability of hypotheses and to evaluate the results of hypothetical pricing or hedging strategies. The relevant data have first to be processed to allow for the effects of physical squeezes and price jumps. But the main limit on such techniques is the lack of reference data, as the Nymex WTI futures contract has only been trading since April 1983, with eighteen maturities since mid-1989, and maturities up to three years since December 1990.

Moreover, the trader must be in the market and that cannot be captured by any mathematical or statistical model. A reliable and fair pricing model must be described in terms of market and not the reverse. Minor price differences can occur as a result of different profit expectations and evaluations of hedging risks. Apart from back-to-back transactions — where the trader has no risk exposure except credit and takes a few cents commission for matching the deals — most of the profits have to be generated by the hedging strategies and management. The initial bid/offer spread is not usually wide enough to cover the cost of an immediate and perfect hedge on the Nymex, even in a simple case.



Source: Elf Trading

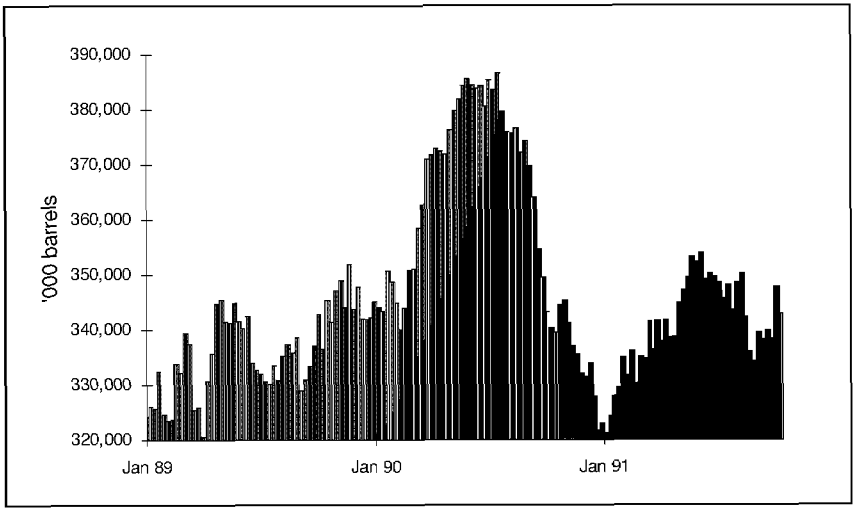
Figure 11.6 Convenience yield for nearby WTI futures

11.5.5 Prices, term structure and risks

As the Nymex provides futures contracts for maturities up to three years ahead, it can be used as a trading and hedging reference for short to medium-term liquidity. If most of the long-term risks included in the transaction the trader has concluded are transferred to the Nymex — or the IPE for hedges in Brent-related swaps — the remaining risks will lie in the time spread between the different maturities. As a result, movements in the term structure — backwardation or contango — of the market will create profits and losses on the resulting portfolio. The futures price, F, may be described using different parameters: the spot price S, financial interest rate r, the cost C_C of holding and carrying stocks and the convenience yield C_Y.

The convenience yield is the specific interest rate of the commodity. Because of the lack of reliable spot prices, the convenience yield may be better measured using homogeneous futures prices, for instance between the first two nearby contracts. The first month's convenience yield or intrinsic oil interest rate, expressed as an annual rate may move from –50 per cent in contango to +200 per cent in backwardation (see Fig. 11.6).

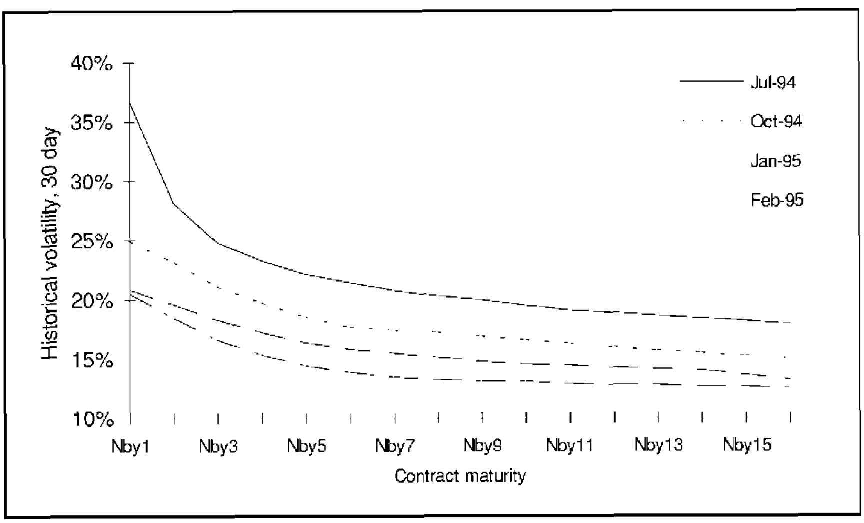
As it represents short to medium-term effects related to physical supply and demand unbalance, the convenience yield is not constant, nor stable over time. A contango market — with nearby prices trading at a discount to longer maturities — creates



Source: API

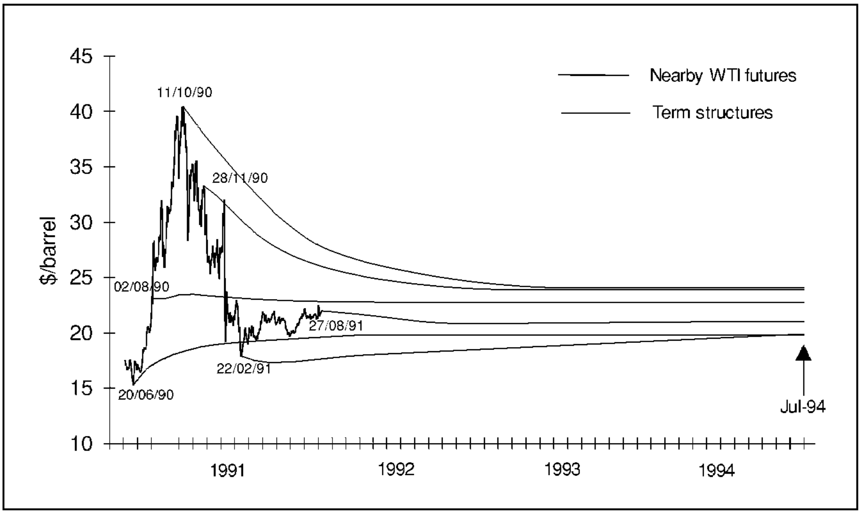
Figure 11.7 US crude oil stocks, end-week

opportunities for physical arbitrage (buy and store) and is theoretically limited unless there is no storage capacity available at marginal cost. But, since there are no real limits to the factors, either political or economic, which may affect the physical crude oil markets, there is no equivalent arbitrage opportunity to set a limit to backwardation.



Source: Elf Trading

Figure 11.8 WTI historical price volatility, 30 day period



Source: Elf Trading, Nymex

Figure 11.9 WTI term structure and the Gulf war

The fundamental characteristics of the behaviour of the convenience yield may be illustrated by comparing Fig. 11.6 with the American Petroleum Institute (API) weekly crude stocks (Fig. 11.7), a proxy largely used for the assessment of crude physical markets. For instance, very high stocks in the second term of 1990 lead to a stable contango and a very low convenience yield, though neither the correlation nor the causality are evident or stable.

Moves in long-term prices will depend, first, on the convenience yield and, secondly, on the way price moves in the short-term are transferred to the longer term. In order to view how price moves are absorbed by the term maturity, one may plot the historical forward volatility structure of Nymex WTI settlement prices, at the end of several months, calculated over the past 30 (working) days, from July 1994 to February 1995 (see Fig. 11.8).

Another example of term-structure moves and therefore risks, is to analyse the effects of the political, economic and supply/demand chaos induced by the Gulf crisis and then war from August 1990 to February 1991. We plotted the term structure of the Nymex WTI futures contracts (see Fig. 11.9), at different dates, on the same time-scale as the realisation of the first nearby prices. Extending futures prices to July 1994, using a simple linear extrapolation from the Nymex prices, illustrates the stability of medium-to-long-term prices, which move in a 20 to 26 dollars per barrel range while the first nearby prices move in a 17 to 40 dollars per barrel range in both a contango and a backwardated market.

Convenience yield and related models may shed light on moves of oil prices term structures and induce specific hedging actions. Gibson & Schwartz[8] developed a model of futures prices with a stochastic convenience yield. The spot price is assumed to have a log normal-stationary distribution and the convenience yield to follow a correlated mean-reverting process.

$$dS/S = \mu.dt + \sigma_s.dz_1$$

$$d\delta = k(\alpha-\delta) + \sigma_\delta.dz_2$$

$$dz_1.dz_2 = \rho.dt$$

This model provides the basis for a model of price term structure, however its hypotheses are too restrictive and its parameters are difficult to measure. A larger class of models can be obtained by assuming there *is* a long term price for oil. Both the spot price S and the long term price L, at infinity, follow a joint stochastic process:

$$dS = \mu_S(S,t).dt + \mu_S(S,t).dz_1$$

$$dL = \mu_L(L,t).dt + \mu_L(L,t).dz_2$$

$$dz_1.dz_2 = \rho.dt$$

To describe fully the term structures of futures prices and volatilities, and the associated boundary conditions, Elf Trading[9] defines a flexible form of marginal convenience yield:

$$C_Y(S,L,t) = \beta(t).Log(S/L) + \delta(t)$$

The assumption of a long term oil price is a strong one which still needs to be proved. However, it gives a useful guideline in pricing and hedging long term oil derivatives.

As pointed out above, the absorption of the convenience yield over time maturity must therefore be valued for any hedging purposes. For example, on futures, forwards and swaps, movements in inner months have a causal and correlated relationship with movements in outer months. Therefore the maturity exposure

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[8] Gibson, R. & Schwartz E., 1990, 'Stochastic convenience yield and the pricing of oil contingent claims', *Journal of Finance, Vol.16, No.5, pp.1011-1029.*

[9] See note 3.

induces a kind of dynamic hedging based on price and volatility term structure. However, the longer the maturity the more important will be other elements in the management of portfolio and contractual risks.

11.6 Contractual issues

11.6.1 Need for a master agreement

The market for long-term oil is still at an early stage of development when compared, for instance, to interest rate swaps, and its legal framework is not yet fully standardised. However banks and large oil companies are lobbying for the establishment of common or comparable rules of trading and therefore negotiate master agreements. Obviously there is still progress to be made as there is no reference master agreement such as the one provided by the International Swaps and Derivatives Association (ISDA) for financial derivatives. A master agreement should encompass different principles to simplify the work of traders and administrative staff, and allow them to expand the business and to globalize positions for credit risk. In this way, a master agreement helps to unify procedures in response to any change in markets, publications, or laws.

The aim of using a standardised master agreement is to provide liquidity in the market, as it ensures a certain degree of fungibility between transactions. Therefore it should shorten the bid/offer spread on classical swaps and options. This is in the interest of all participants, trading counterparts as well as clients and customers.

11.6.2 Evaluation of credit risk

The trend towards credit checking and management is very strong these days, especially in the long-term market for oil. Counterparts who are engaged to each other for periods of five, seven or ten years want to be secure on this point.

Also the credit manager would have — in relation to the trader and the general management — to evaluate the risk of the transaction, either absolutely or relative to the market and price volatility. Either way, the evaluation of the risk would have to be revised regularly for collateral needs.

11.6.3 Implications for administrative procedures

It is important to appreciate the sophisticated back-office accounting procedures and computer systems required for long-term transactions, especially when compared with dealing on the forward, futures or short-term derivatives markets. The addition of tailor-made clauses like physical delivery possibilities may also complicate the administration of the transaction.

Although a standardised master agreement eliminates the administrative constraints resulting from tailor-made contracts, its purpose is not to reduce the range of tailor-made strategies since it will never be able to provide for all the possibilities or the relentless creativity of the participants.

11.7 Using long dated derivatives

11.7.1 An oil producer's price exposure

A large oil company generally groups both exploration and production in its upstream activity. On the one hand, exploration is one of the most speculative businesses: the average cost of an oil drill is expressed in millions of dollars, and the average probability of failure is eight dry drills for nine exploratory ones. On the other hand, production requires a huge investment and has both a political and a strategic aspect. Therefore the 100 per cent hedge of the core exploration & production (E&P) businesses cannot be a goal in its own right.

For an oil producer — especially a small one — global economic analysis should define the hedging requirements and objectives in order to ensure both the financial stability (repayment of liabilities) and the profitability (distribution to shareholders) of the company, and the successful development of new projects (putting existing reserves on stream or discovering new ones). The duration and payoff structure of the hedging transaction would depend on the specific needs of the company:

- profitability over one or more accounting year(s),
- duration of liabilities if debtors require guarantee of repayments,
- ensure the return on investment for long-term projects.

Let us consider the following example. The objective of the producer is to guarantee his profitability for the next four years. The producer first determines the minimum quantity Q that he is certain to produce during this period, whatever the economic conditions and operational constraints.

Given his investments and costs, the producer can determine for the coming year and relative to this quantity Q, the cost of production per barrel P_c and the minimum profit per barrel B_m to reimburse creditors and to provide shareholders with a minimum profitability. The minimum price per barrel to achieve is therefore expressed by:

$$P_m = P_c + B_m$$

Among the various hedging strategies available to the company is one composed of two legs:

- a swap which ensures a P_{ho} fixed selling price, with P_{ho} greater than P_m, for Q_h barrels, and is aimed at reimbursing debtors,
- a put (option to sell) for a positive return on the remaining $Q-Q_h$ quantity, at a S_o strike price and Pr_o premium. In order to simplify the point, the put strike price is supposed to be equal to the cost of production: $S_o = P_c$.

It is obvious that if the realisable four-year swap price P_{ho} is not greater than P_m, there is no opportunity, at this time, of entering into a profitable hedge.

Then if, $P_{ho} > P_m$, Q_h will be determined at initiation by:

$$Q_h.(P_{ho} - P_c) = (Q - Q_h).Pr_o + Q.B_m$$

$$Q_h = \{(B_m + Pr_o)/(Ph_o - P_c + Pr_o)\}.Q$$

For example,

Cost of production: P_c = \$15/barrel,
Minimum profit B_m = \$1/barrel = > P_m = \$16.00/barrel

1st case: 4-year swap value P_{ho} = \$16/barrel

$$Q_h/Q = 100\ \%$$

2nd case: 4-year swap value P_{ho} = \$18/barrel
Cost of \$15/barrel put Pr_o = \$0.70/barrel

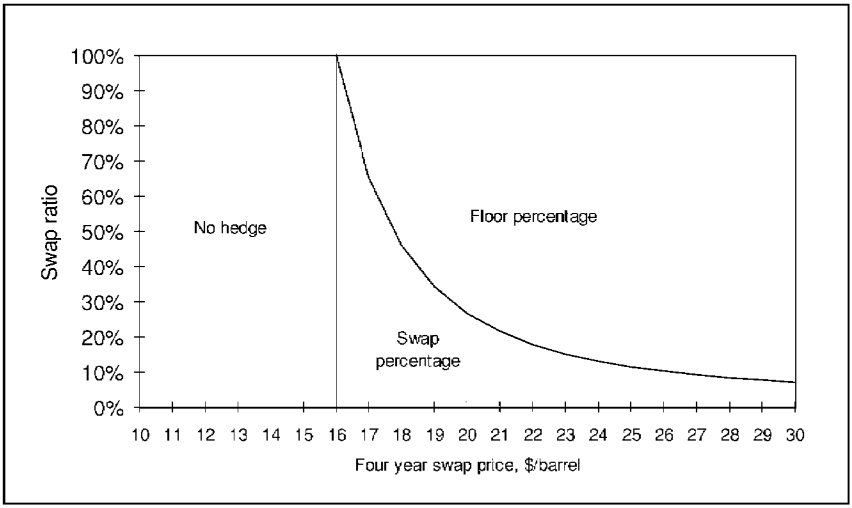
$$Q_h/Q = 46\ \%$$

3rd case: 4-year swap value P_{ho} = \$20/barrel
Cost of \$15/barrel put Pr_o = \$0.45/barrel

$$Q_h/Q = 27\ \%$$

4th case: 4-year swap value P_{ho} = \$23/barrel
Cost of \$15/barrel put Pr_o = \$0.25/barrel

$$Q_h/Q = 15\ \%$$



Source: Elf Trading

Figure 11.10 Producer hedging strategy with swaps and floors

This example, although simple, shows that once the market prices reflect the profits from hedging, the producer only needs to lock in a small part of his production at a fixed price in order to cover both his minimum financial profit and the cost of the options to insure the remainder. Thus he retains in a "naturally speculative" way, the potential profit expected from the rest of his production.

11.7.2 Using oil derivatives

Generally speaking, the financial settlement of derivatives is based on the average pricing of a reference index during one or several time periods. The index may be based on futures contracts, either as a reference to a specific maturity or as a forward rolling index. The concept of "nearby" is often used, the nearby N on each day being the Nth maturity currently traded for the futures contract. For an oil producing company, the usual hedge is the maturity closest to the physical market, i.e. the first nearby, except in cases where the sales and/or purchases are clearly based on another futures price. Typically, the last trading day of any futures contract is excluded from the first nearby reference price index, to avoid being caught in a purely technical spot-to-futures squeeze.

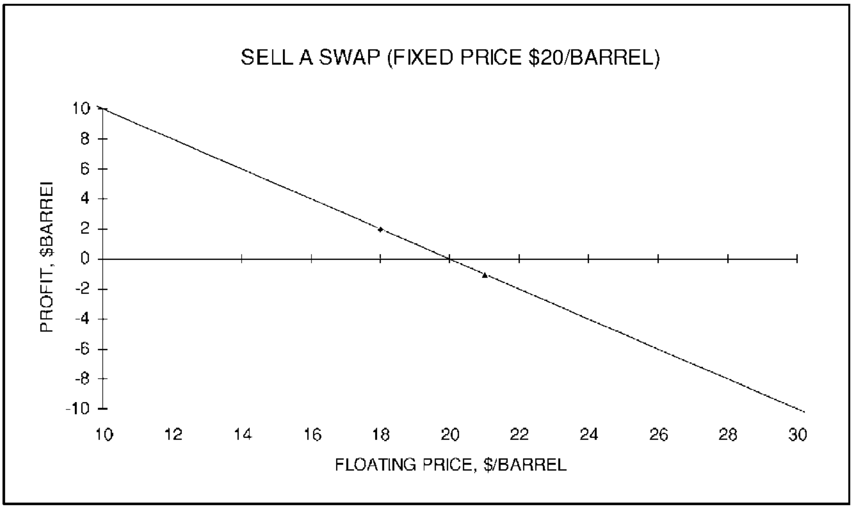
Assuming that the company needs to hedge the next accounting year, and that the average market value for the year is $20/bbl, some possible hedging strategies are described below (prices are indicative and may change according to conditions):

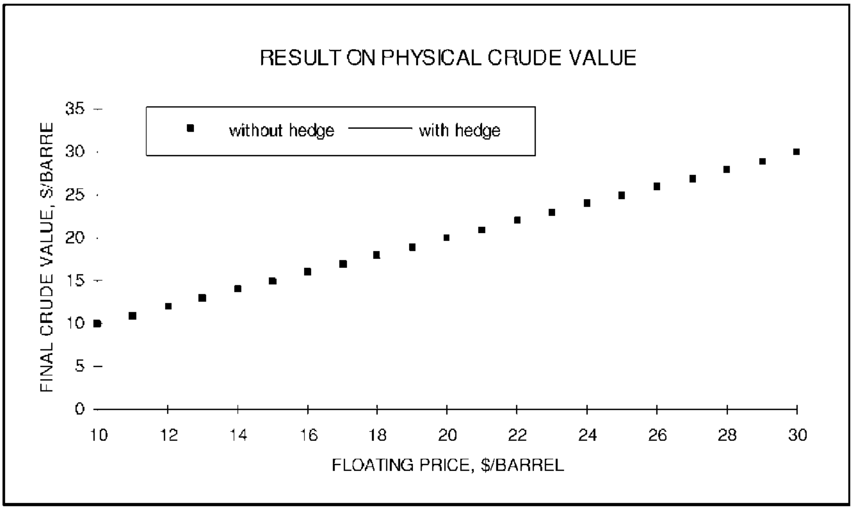
Sale of a swap (Appendix 11.1)

Selling a swap fixes the price for the producer, avoiding the risk of lower prices, but eliminating any profits from a future price rise.

- Fixed price $20/barrel.
- Strategy fully hedged.

If prices are rising and the producer wants to limit his "loss" from the swap, he should consider the possibility of getting partially or completely out of the hedge and must decide to do it in time. Alternatively, he could consider selling a min-max swap instead.





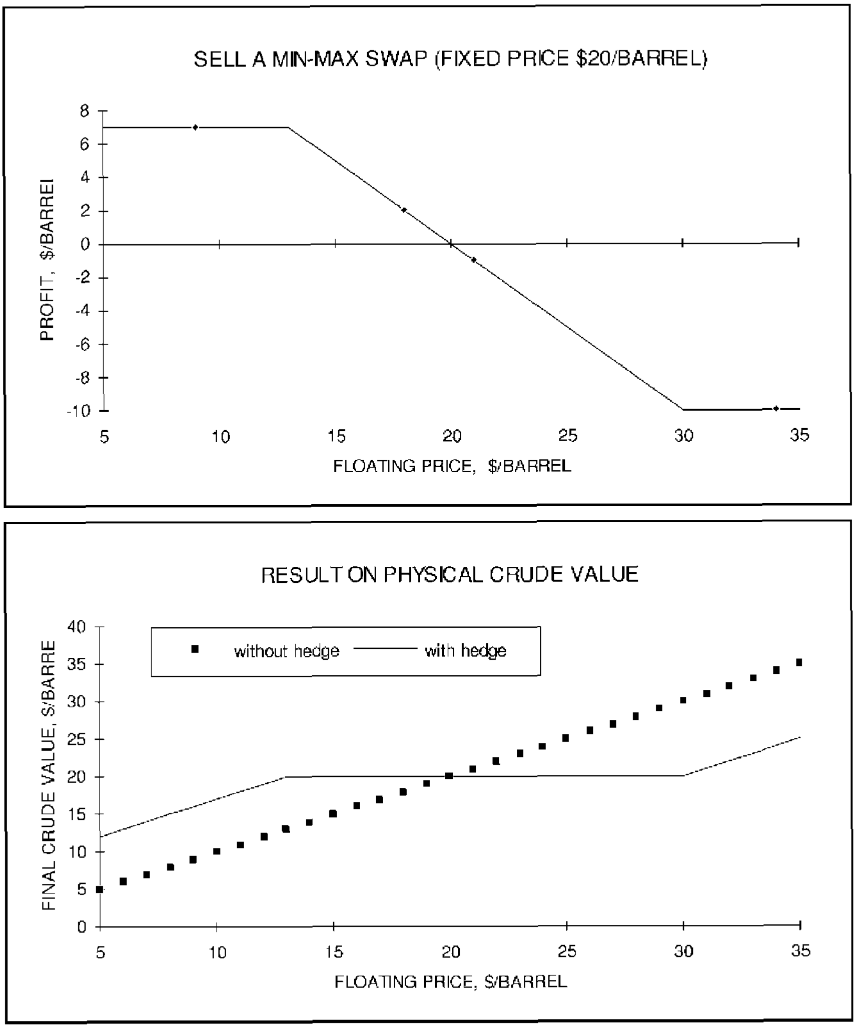
Source: Elf Trading

Figure 11.11 Sale of a swap

Sale of a min-max swap (Appendix 11.2)

Selling a min-max swap fixes the producer's price over a specified range, thus exposing him to the risk of very large price movements.

- Fixed price $20/barrel with limitation below $13/barrel and above $30/barrel.
- Strategy to fix a limit to the potential swap cost by accepting a limit to the potential profit at a bottom value.



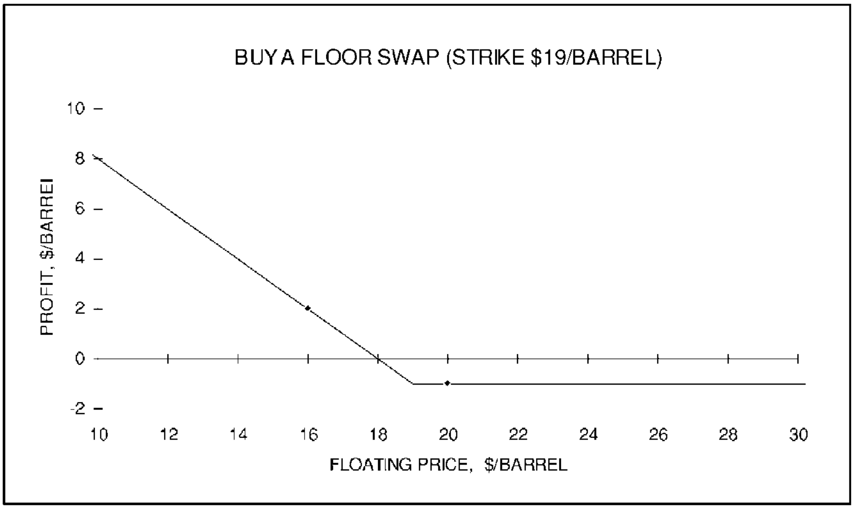
Source: Elf Trading

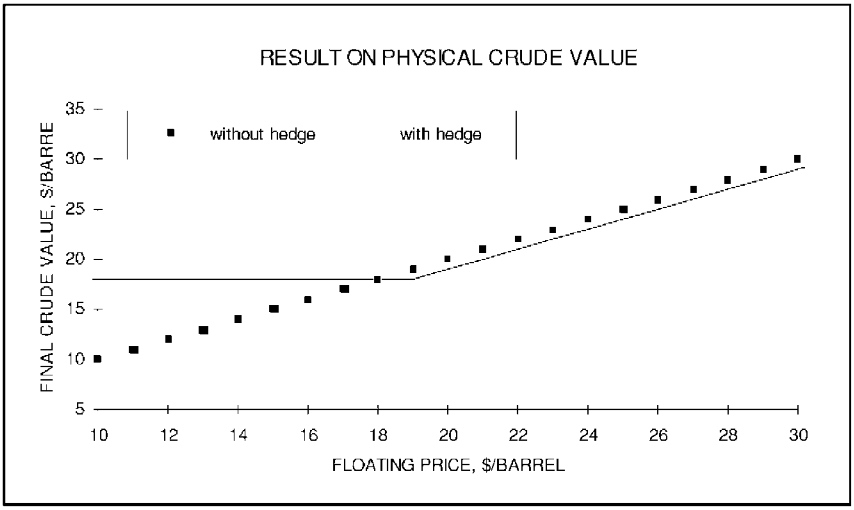
Figure 11.12 Sale of a min-max swap

Purchase of a floor swap (Appendix 11.3)

Purchasing a floor swap protects the producer from a fall in prices, but still allows him to profit from a price rise.

- Floor price $19/barrel, initial premium $1/barrel.
- Strategy to buy insurance against a price decrease and to keep the profits from any probable price increase. Choosing a floor price that is a little out of the money will minimise the premium paid.





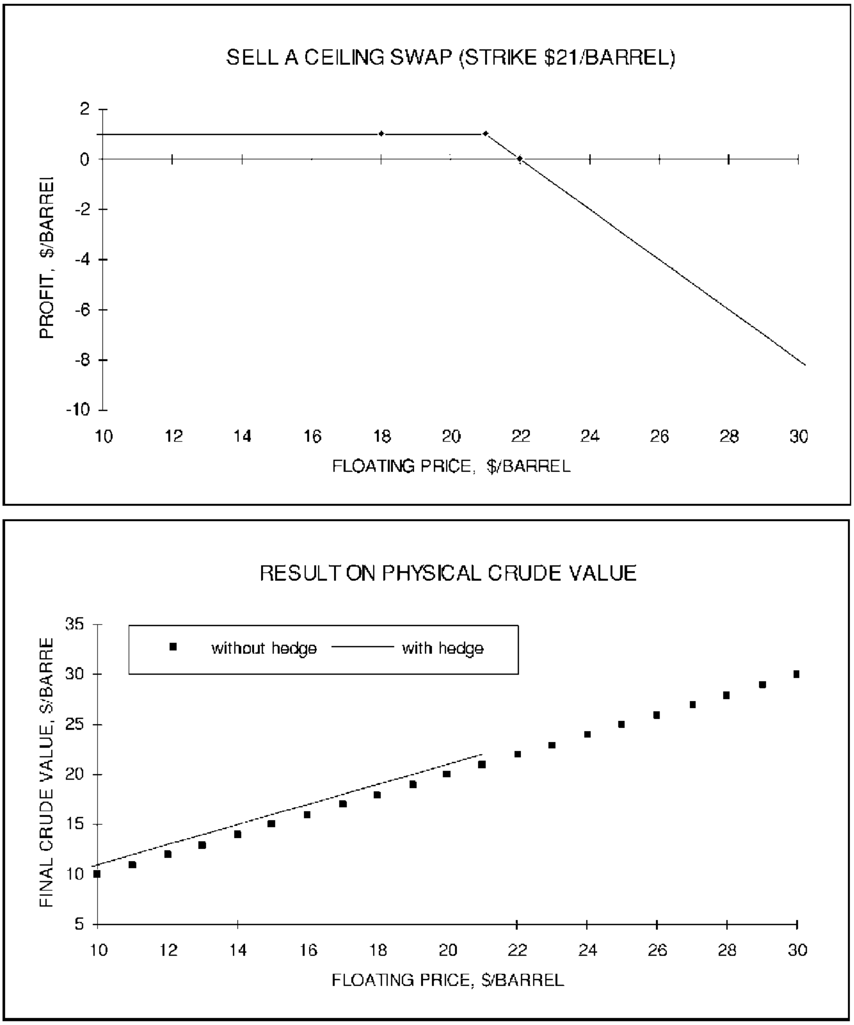
Source: Elf Trading

Figure 11.13 Purchase of a floor swap

Sale of a ceiling swap (Appendix 11.4)

Selling a ceiling swap enhances a producer's profit in a stable market.

- Ceiling price $21/barrel, initial premium $1/barrel.
- Strategy assumes that market prices will remain stable and below $21/barrel. In this case, the premium received increases the profit. But, apart from the $1/barrel initial income there is no hedge and no protection against a large price decrease.



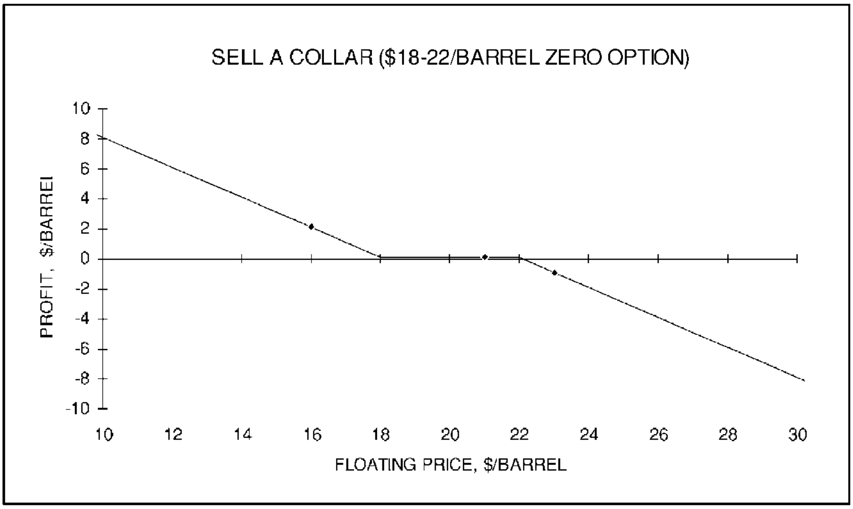
Source: Elf Trading

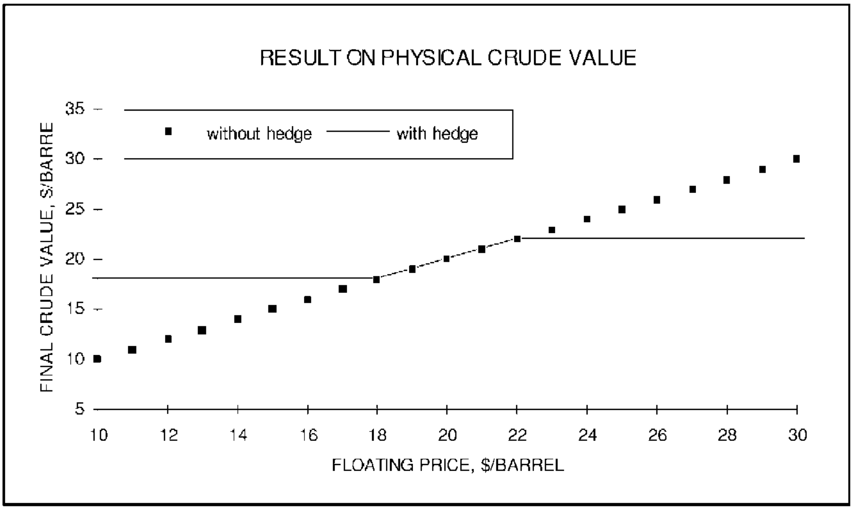
Figure 11.14 Sale of a ceiling swap

Sale of a collar (Appendix 11.5)

Selling a collar protects the producer from price movements outside a specified range, but exposes him to the risk of smaller price changes within the specified range.

- $18–22/barrel collar sold with no initial premium.
- Strategy protects producer below $18/barrel with no insurance cost, except that the global profit on the sales will be limited to $22/barrel. But such a collar gives a no hedge inside the $18–22/barrel price range.





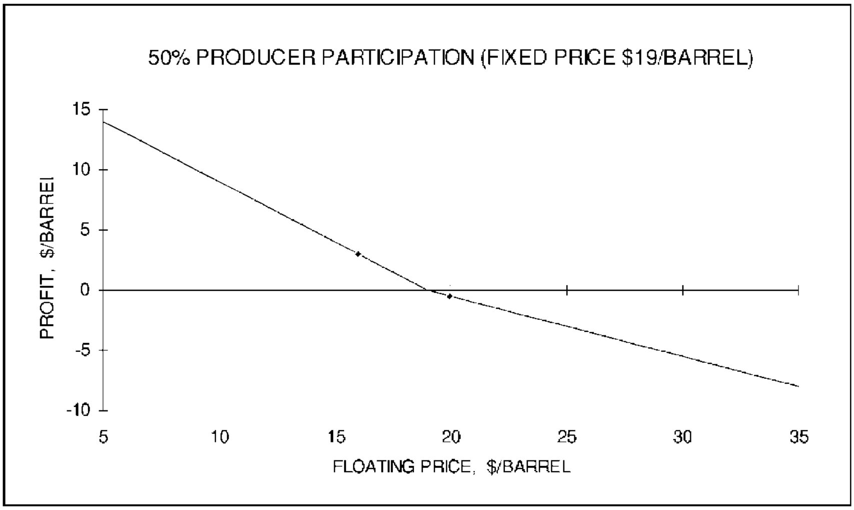
Source: Elf Trading

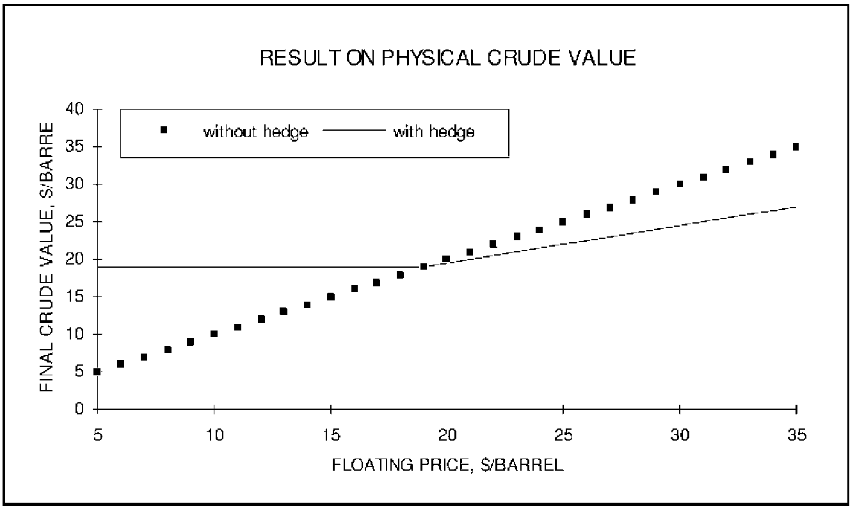
Figure 11.15 Sale of a collar

Producer participation (Appendix 11.6)

Selling a participation swap fixes the producer's price at an agreed minimum level, but allows him to enjoy a specified share of the profits from any future price rise.

- 50% participation, fixed price $19/barrel, with no initial premium.
- Strategy in the middle of the swap sale and the floor purchase.





Source: Elf Trading

Figure 11.16 Producer participation

11.7.3 Hedging strategies

Violent movements in the oil price market structure create a classic hedging problem: how does a producer respond to changes in backwardation and contango?

Backwardation

Spot prices are higher than longer term prices. Physical crude oil has an added value. The producer is under pressure to sell at prompt prices and not to support the backwardation spread. Any hedge using a future maturity will be equivalent to a forward sale below the spot price. It will eventually lead to a loss if market prices do not fall at the same rate. This was the case, for instance, during 1989 when the market was in backwardation all year long, locked in a trading range of less than three dollars per barrel.

The producer may be reluctant to hedge. The short-term benefits are not apparent, unless a market move or reversal in the price structure is expected. But a longer-term hedge could be much more attractive. The proportional effect of backwardation is reduced — there could even be a contango in the long-term — and long-term values can be very profitable indeed. Careful long-term analysis may yield good hedging opportunities, especially when there is a strong backwardation as a result of a major crisis.

Contango structure

Spot prices are lower than term prices. Physical oil has less value in an over-supplied market. The producer will face difficulties selling his crude, but he can sell on the futures market at a higher price. As he can fix his hedge or his future sales at a better price than the spot market, hedging will generate profits if market prices are not increasing at the same rate.

The short-term benefits from hedging are obvious, while a longer-term hedging strategy could be less advantageous — even if selling $2 per barrel above the spot seems to be very attractive. To put it simply, if the spot price is very low, $17 per barrel for example, selling the long-term at $19 per barrel should be regarded with caution.

Trend market

A trend often amplifies a backwardation or a contango. Thus, an upward trend may sustain or even increase the backwardation in the market, while a downward trend will have the same effect in a contango in the market — see, for example, the period from March 1990 to June 1990.

In a strongly trended market, the producer will be even more reluctant to hedge during a backwardation and even more inclined to hedge during a contango. It is important, however, to develop an approach to hedging that is in line with a company's short, medium and long-term objectives.

The ultimate question is whether to anticipate the reversal of a trend or simply to wait for the reversal and act just after it, even if the top or bottom of the market is history.

11.7.4 Tax issues

Taxes are complex and specific to each country, location and case. It is therefore important to analyse possible hedging strategies under different production and financial tax constraints. The following cases may shed light on such difficult issues.

Case 1: no specific taxes on crude production

In this case, the crude produced is treated in the same way as any other trading commodity. Profits or losses resulting from these physical sales, like profits or losses from trading and hedging, are part of the company's income. One does not need to separate the crude sales from the hedging for fiscal computations. Thus the hedging policy is straightforward and has to be planned on 100 per cent of the volume of crude produced. This is generally the case in the United States and US producers have no fiscal constraints on hedging their production over short or longer-term maturities.

Case 2: royalties

Royalties represent government or fiscal authority property rights to a percentage of the crude produced, either on a financial basis or in kind. In this case, the royalty share of the crude produced is not controlled at all by the producer and will usually be excluded in proportion for hedging purposes.

Case 3: petroleum or production tax

In the main producing areas, and especially in the UK, there is a specific production tax. Apart from any production royalty or transfers to government entities, there are additional taxes for the sale of physical equity crude, depending on specific fiscal rules, that do not apply to the hedging of paper crude. The financial results of any hedging strategy are therefore not directly comparable to the financial results from physical sales. To correct for this difference the hedge volume should be adjusted to reflect the fiscal environment, as illustrated in the example and formulae below. If such an adjustment is not made, the hedge volume is equal to the physical volume (100 per cent hedging ratio):

- if prices increase, the result is a physical gain and a hedge loss; but, as the strategy is over-hedged compared with after-tax computations, the result is a loss.

- if prices decrease, the result is a physical loss and a hedge gain; but the after-tax result will be a gain.

The main tax issues can summarised as:

- tax X % on production,
- tax Y % on company profits, including hedging profits.

Assuming the company is profitable at the current market price P, this translates into, for a prime cost of production P_c, a yearly production of Q barrels and a hedge over Q_h barrels at a P_h swap price:

- nominal after-tax sales = $(1 - Y).(1 - X).Q.P$
- production profits, if P is greater than the prime cost

$$P_c = (1 - Y).(1 - X).Q.(P - P_c)$$

- hedging results = $(1 - Y).Q_h.(P_h - P)$

To insure the next yearly company results,

$$R = (1 - Y).(1 - X).Q.(P - P_c) + (1 - Y).Q_h.(P_h - P)$$

one needs no price sensitivity,

$$\partial R/\partial P = 0$$

which is better expressed by the equation:

$$(1 - Y).(1 - X).Q - (1 - Y).Q_h = 0$$

Therefore, the company need not be fully hedged on the yearly Q production, but an under-hedge is enough, given these simple but reasonable tax constraints:

$$Q_h = (1 - X).Q$$

Example

Petroleum tax: 75 %
Company income tax: 35 %
Yearly production volume: Q = 6 million barrels
After-tax hedging volume: Q_h = 25 %, Q = 1.5 million barrels

Conclusion on tax issues

Any other system of official prices or taxes would have an impact on the hedging strategy. In some cases, one could decide not to hedge, or, to apply a global management hedging strategy disconnected from the physical production and sales, it being understood that, whatever taxes are, if prices fall the profitability of an oil producer is always reduced.

To summarise, taking into account tax and royalty issues leads to an under-hedged strategy.

Tax calculations are often obscure in advance and the stability of tax calculation methods are not guaranteed. It could be difficult to accept a long-term strategy based on these hypotheses, but this should not alter the decision process. Many other parameters, such as production and operational risks, are not completely certain. Approximations and hypotheses provide useful guidelines and the decision should always allow for an under-hedge compared to the "ideal" calculation.

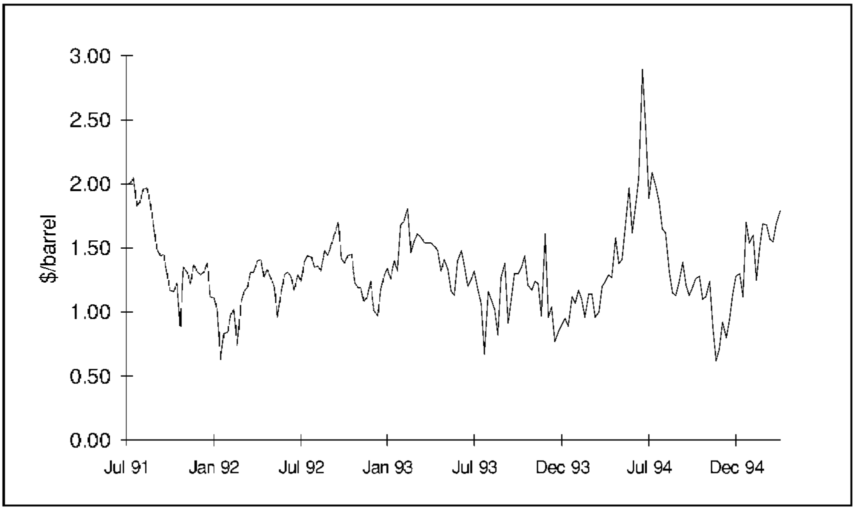
11.7.5 Basis risk

Several hundred different crude oil qualities are produced around the world. The price of a crude is mainly based on:

- the price levels for the related geographical production and selling areas,
- a price adjustment for quality.

The value of a crude depends on the market price for refined products obtained from the crude. A crude with a high yield of light products — kerosene, naphtha, unleaded gasoline — would therefore have a higher value on the market than a crude with a high yield of heavy fuel oil.

Geographical and quality differential risks have to be taken into account when analysing any hedging scheme. For example, long-term spreads between WTI and Brent may create interesting opportunities for crude arbitrage between the US and Europe.



Source: Elf Trading

Figure 11.17 WTI–Brent crude price spread, post Gulf war

Table 11.3 Trading characteristics of benchmark crudes

	WTI	**Brent**	**Dubai**
Exchange	Nymex	IPE	IPE/Simex
Maturity	22 traded maturities over 3 years	9 months	7 months
Average volume	105 million b/d	40 million b/d	not reliable
Average open interest	400-410 million barrels	120-150 million barrels	not reliable
Density @15°C	826 kg/m^3	867 kg/m^3	869 kg/m^3
API gravity	40	38	31
barrels / tonne	7.63	7.53	7.25
% sulphur	0.28	0.35	1.96
Pour point	–18°C	–1°C	–18°C
Viscosity @10°C	6 cst	7.5 cst	16.5 cst

The three main trading areas and crude benchmarks are:

- America with WTI as a reference,
- Europe and Africa with Brent as a reference,
- Asia with Dubai as a reference.

These three reference crudes are traded on futures markets but with very different scales of activity (see Table 11.3). Brent and Dubai are also traded on two active forward markets. Obviously these different scales of liquidity and trading maturities have an impact on derivative markets. The Nymex Light Sweet Crude Oil (WTI) contract with listed maturities of up to 36 months ahead, is the most active for very long-term maturities such as ten years. But Brent is gaining ever wider acceptance as the international benchmark crude, and is currently estimated to be used in the pricing of up to 65% of the world's crude oils and is now available on the Singapore exchange (Simex).

Given the evolution of crude oil production and new developments towards heavier grades, quality references could move to heavier indexes.

In order for the producer to avoid the expensive residual basis risk, it is often worth considering a hedging strategy directly indexed on any *Platt's* or *Argus* reference.

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11.8 Conclusions

Oil and gas are increasingly important primary sources of energy. Recent developments and future environmental constraints could even expand their role compared with other energy commodities, since nuclear power and coal are not regarded as safe or desirable alternatives. The long-term strategic role of oil therefore creates both basic and sophisticated requirements for risk management. Both the oil industry as a whole, and a number of other important economic agents, have recently started to re-appraise the impact of oil prices on their traditional businesses.

New market developments have always generated fear and suspicion concerning speculation and the risks involved. But oil futures markets and long-term oil derivative markets have proven their efficiency and their usefulness both as a stabiliser and as a shock-absorber throughout the extremely difficult market conditions of the recent Gulf crisis.

Long-term oil markets are continuing to expand and aim to satisfying a highly diversified range of hedging and speculative requirements. They are attracting more and more companies. This is the course of history. But, their presence is often temporary and the number of true and effective counterparts — large oil companies, trading entities, banks and traders — remains fairly stable over time, at around ten companies.

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Appendix 11.1

Sale of a swap

Terminology

Swap or fixed price swap:

Fixed price payer = "fixed price buyer"
Floating price payer = "fixed price seller"

Settlement calculation

The "Fixed Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Fixed Price.

The "Floating Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Floating Price.

If the Fixed Amount is greater than the Floating Amount, then the Fixed Price Payer shall pay to the Floating Price Payer the amount by which the Fixed Amount exceeds the Floating Amount; or

If the Floating Amount is greater than the Fixed Amount, then the Floating Price Payer shall pay to the Fixed Price Payer the amount by which the Floating Amount exceeds the Fixed Amount.

Example

Elf telex confirmation for a fixed price swap

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- FIXED PRICE PAYER:	ELF TRADING
- FLOATING PRICE PAYER:	PRODUCER
- COMMODITY:	WTI
- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- FIXED PRICE (OR FIXED PRICE PER DETERMINATION PERIOD): 20 $/BARREL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.

Appendix 11.2

Sale of a min-max swap

Terminology

Fixed price swap with limited variations. Equivalent to a call spread or a put spread without premium, the fixed price giving the equilibrium point. It is mainly designed to set a limit to the financial amounts to be exchanged.

Fixed price payer = "fixed price buyer"
Floating price payer = "fixed price seller"

Settlement calculation

The "Maximum Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Maximum Price.

The "Minimum Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Minimum Price.

If the Floating Amount is less than the Minimum Amount, then the Fixed Price Payer shall pay to the Floating Price Payer the amount by which the Fixed Amount exceeds the Minimum Amount; or

If the Floating Amount is greater than the Minimum Amount and less than the Fixed Amount, then the Fixed Price Payer shall pay to the Floating Price Payer the amount by which the Fixed Amount exceeds the Floating Amount; or

If the Floating Amount is greater than the Fixed Amount and less than the Maximum Amount, then the Floating Price Payer shall pay to the Fixed Price Payer the amount by which the Floating Amount exceeds the Fixed Amount; or

If the Floating Amount is greater than the Maximum Amount, then the Floating Price Payer shall pay to the Fixed Price Payer the amount by which the Maximum Amount exceeds the Fixed Amount.

Example

Elf telex confirmation for a fixed price min-max swap

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- FIXED PRICE PAYER:	ELF TRADING
- FLOATING PRICE PAYER:	PRODUCER
- COMMODITY:	WTI

- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- FIXED PRICE (OR FIXED PRICE PER DETERMINATION PERIOD): 20 $/BBL
- MAXIMUM PRICE (OR MAX PRICE PER DETERMINATION PERIOD): 30 $/BBL
- MINIMUM PRICE (OR MIN PRICE PER DETERMINATION PERIOD): 13 $/BBL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.

Appendix 11.3

Purchase of a floor swap

Terminology

It is an option designed to profit from any price decrease. The name "put" is preferably used for single options.

Floor price = strike price
Premium payer = option buyer
Premium receiver = option seller or writer

Settlement calculation

The "Floor Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Floor Price.

If the Floor Amount is greater than the Floating Amount, then the Premium Receiver shall pay to the Premium Payer the amount by which the Floor Amount exceeds the Floating Amount; or

If the Floating Amount is greater than the Floor Amount, then no payments shall be made.

In addition, the Premium Payer shall pay to the Premium Receiver the Premium on the Premium Payment Date.

Example

Elf telex confirmation for a floor swap

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- PREMIUM PAYER:	PRODUCER
- PREMIUM RECEIVER:	ELF TRADING
- COMMODITY:	WTI
- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- FLOOR PRICE (OR FLOOR PRICE PER DETERMINATION PERIOD): 20 $/BBL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.

- PREMIUM:	1 $/BBL
- PREMIUM PAYMENT DATE:	DATE DD + 1

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Appendix 11.4

Sale of a ceiling swap

Terminology

Again the terminology ceiling swap or cap is preferred to the call one which refers to a single option.

Settlement calculation

The "Ceiling Amount" in respect of a Determination Period shall be the product of the Relevant Quantity multiplied by the Ceiling Price.

If the Floating Amount is greater than the Ceiling Amount, then the Premium Receiver shall pay to the Premium Payer the Amount by which the Floating Amount exceeds the Ceiling Amount; or

If the Ceiling Amount is greater than the Floating Amount, then no payments shall be made.

In addition, the Premium Payer shall pay to the Premium Receiver the Premium on the Premium Payment Date.

Example

Elf telex confirmation for a ceiling swap

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- PREMIUM PAYER:	ELF TRADING
- PREMIUM RECEIVER:	PRODUCER
- COMMODITY:	WTI
- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- CEILING PRICE (OR CEILING PRICE PER DETERMINATION PERIOD): 20 $/BBL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.

- PREMIUM:	1 $/BBL
- PREMIUM PAYMENT DATE:	DATE DD + 1

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Appendix 11.5

Collar

Terminology

A Collar is equivalent to a call option minus a put option. It can be called a zero option if the strike prices are designed to cancel the premiums.

It is easier to consider that the buyer is the one whose resulting risk is long i.e. the call buyer and put seller. Then the premium payer is the one who has bought the most expensive option.

Settlement calculation

If the Floating Amount is less than the Floor Amount, then the Collar Buyer shall pay to the Collar Seller the amount by which the Floor Amount exceeds the Floating Amount; or

If the Floating Amount is greater than the Floor Amount and less than the Ceiling Amount, then no payments shall be made; or

If the Floating Amount is greater than the Ceiling Amount, then the Collar Seller shall pay to the Collar Buyer the amount by which the Floating Amount exceeds the Ceiling Amount.

In addition, the Premium Payer shall pay to the other party the Premium on the Premium Payment Date.

Example

Elf telex confirmation for a collar

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- COLLAR BUYER:	ELF TRADING
- COLLAR SELLER:	PRODUCER
- COMMODITY:	WTI
- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- FLOOR PRICE (OR FLOOR PRICE PER DETERMINATION PERIOD): 18 $/BBL
- CEILING PRICE (OR CEILING PRICE PER DETERMINATION PERIOD): 22 $/BBL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.
- PREMIUM: 0 $/BBL

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Appendix 11.6

Producer participation

Terminology

A participation is a mix of swap and option, or a mix of same strike prices options, in different proportions. For example, a X % producer participation is equal to [(1–X).swap – X.put] or to [(1–X).call – 1.put]. It includes a fixed price for calculation purposes.

Fixed price payer = "fixed price buyer"

Floating price payer = "fixed price seller" (the producer)

Settlement calculation

If the Fixed Amount is greater than the Floating Amount, then the Fixed Price Payer shall pay to the Floating Price Payer the amount by which the Fixed Amount exceeds the Floating Amount; or

If the Floating Amount is greater than the Fixed Amount, then the Floating Price Payer shall pay to the Fixed Price Payer the amount equal to the product of the amount by which the Floating Amount exceeds the Fixed Amount multiplied by the amount equal to 1.00 minus the participation rate.

In addition, if there is a premium, the Premium Payer shall pay to the other party the Premium on the Premium Payment Date.

Example

Elf telex confirmation for a producer participation swap

WE ARE PLEASED TO CONFIRM THE FOLLOWING SWAP CONCLUDED ON DATE DD WITH YOUR COMPANY:

- FIXED PRICE PAYER:	ELF TRADING
- FLOATING PRICE PAYER:	PRODUCER
- COMMODITY:	WTI
- EFFECTIVE DATE:	DATE DD
- TERMINATION DATE:	12/31/95
- DETERMINATION PERIODS:	FROM 01/01/92 TO 12/31/92
	FROM 01/01/93 TO 12/31/93
	FROM 01/01/94 TO 12/31/94
	FROM 01/01/95 TO 12/31/95

- QUANTITY PER DETERMINATION PERIOD: 1,500,000 BBL
- FIXED PRICE (OR FIXED PRICE PER DETERMINATION PERIOD): 19 $/BBL
- FLOATING PRICE: FOR EACH DETERMINATION PERIOD THE AVERAGE OF THE DAILY SETTLEMENT PRICES OF THE SECOND MONTH AS QUOTED BY NYMEX.

- PARTICIPATION RATE:	50 %
- PREMIUM (IF ANY):	0 $/BBL

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12 Operations and logistics

Robin Burley

Appendix

12.1 Introduction

In the past, the primary role of operations and logistics was to service the needs of the shipping system, moving production off-take, satisfying refining demands, managing pipelines and implementing marketing plans. Today, the requirement is also to add value to a deal, and to be creative. Nowadays, a trading organisation may rely on its operations personnel to monitor and, to some extent, control the activities of its traders besides providing support. The day of the easy oil trade is over – traders have to work for a living. And logistics has become all important to profitability.

In fact the logistics picture has become so significant, that many leading independent traders and oil companies have taken the additional step of interposing the operations or logistics management into the approval system for a deal – a trend welcomed, as, for a time, many operations personnel were regarded by the traders as a sort of appendage in the business, indeed almost subservient.

The word "operations" conjures up different views depending on experiences and attitudes within companies. In a producing company it may refer purely to the act of drawing up and executing a loading programme from a given set of production expectations. For the refiner, it may include the crude delivery programme and product off-take by whatever means. It may also include some input into the actual running of plant within the refinery – optimisation – depending on deliveries and prevailing prices. For many it will include a shipping, pipeline, rail, truck or storage interface.

Prior to the 1973/74 crisis, operations and logistics were concerned with cost-minimisation. Transportation was a significant element in the price of oil and the objective was cheaper shipping. Most aspects of company operational planning at this time were shipping oriented, since an integrated company's profits were linked to its shipping costs. Oil acquisition, facilities planning and even refining became ship driven. Vessels were fully employed and cargoes had to be found – or in the case of multi-products carriers fitted to meet vessel constraints. Operations personnel within companies were governed or even ordered by those who controlled the shipping. The short-term linear programming model for a refining system relied heavily for solution accuracy upon a mass of freight data. And companies operated tonnage exchanges to reduce inefficiencies based on ton-days or ton-miles of service.

After the first oil crisis, higher oil prices shifted the emphasis of operations on to supply management rather than costs. Hanging on to term arrangements became of primary importance, despite fears of increases in HGT (Host Government Take – sometimes known as "Higher" Government Take – hiking the price on a term deal – sometimes retroactively). Maintaining supply became the priority and shipping inefficiencies began to creep in the expense of the necessary acquisition of crude or product further disguised by the growing oversupply of shipping. In the case of the majors, many became decentralised allowing their overseas associates to run the business almost independently of the head office managing their own shipping and supply arrangements. The operator now focused on timing, location and grade exchanges, trading off what acquisitions he had made in order to have a stake in the play.

In the 1980s, changes in the nature of oil trading prompted a further shift in the role of operations and logistics. Falling world oil demand meant that term supply was no longer the sole route to survival. The growth of spot trading and the emergence of paper markets created a new method of doing business, weakening the influence of the OPEC pricing system. And the price crash of 1985/86 ushered in a more volatile world for oil trading in which players had to think fast on their feet; be capable of using all of the tools available whether paper or physical, wet or dry. Long term planning no longer ruled the logistics world.

12.2 Scheduling

12.2.1 Lifting order

An onshore production or loading system may have several partners. Substantial inventory may be available throughout the month. Via a co-ordinator, the partners can usually agree a lifting order for a month on a logical progression based on their total production. Partners may be invited to propose their liftings for a month and these are then sorted and a definitive set of windows (laydays) for lifting each cargo determined and issued by the co-ordinator.

Many of the earlier North Sea fields were offshore loaded, and some still are. A lifting order has to be determined to establish a loading programme – the subject of much debate in transportation agreements. The key questions in determining the rules for lifting are:

- What minimum stock a participant should have in order to qualify for a lifting?
- How far ahead should the lifting order be binding – in other words set in concrete, regardless of operational interruptions that may distort entitlements?
- Can the lifting order be changed under certain circumstances?
- If the weather is bad, can a tanker sail with a part cargo and, if so, what is the minimum acceptable from a safety and cargo trading aspect?

Many of these fields were developed at a time when the price of oil was becoming dynamic and neither the current price structures (e.g. marker-related pricing of many grades), nor price management tools such as futures and swaps existed.

Larger participants, invariably majors and refiners, were able to deal with changes in a programme by virtue of having the facility to exchange, sell or refine a cargo in their own systems or between themselves. Besides, if they lifted frequently, statistically they were less likely to take a price "hit".

Smaller companies, however, with fewer liftings and without the flexibility of the majors found themselves at the mercy of the weather, the market and in some cases the companies to whom they may have committed to sell. Such participants therefore had to make decisions on whether to go it alone – lift a full cargo or whatever cargo could be lifted if weather or other circumstances intervened – or amalgamate their entitlements with other larger participants thus sharing in more frequent liftings. The different fields and lifting systems had various rules for agreeing an amalgamation or revising it. Smaller participants were often driven into amalgamation through a bad experience and felt cornered by the purchase terms offered by the majors.

For example, take a field of three participants A,B,C, of share holding 46 per cent, 44 per cent and 10 per cent respectively in an offshore loading system, which is serviced by two tankers (one of 450,000 barrels capacity and the other 550,000 barrels).

Assume some simple rules for determining the lifting order, namely that the tankers load in rotation and there is always a buffer stock of say 500,000 barrels minimum. After a lifting, production is assumed to be made up to replace that lifted and the participant with the highest paper entitlement is projected to lift. If a tanker has loaded 60 per cent of cargo and cannot load more due to bad weather she may sail. The “binding” part of the programme may be for 2 months and there are 3 tanker liftings per month on average.

Company C may expect to lift number 7 – the first cargo in the month after the “binding programme” – but may find, due to the changed order of rotation of the liftings of the tankers or the fact that 1 or 2 liftings may have been short loaded, that they may be deferred by several liftings perhaps to number 10 and thus into another month.

As is obvious, this works to the detriment of the smaller company, perhaps in terms of price in a volatile market and certainly in terms of cash flow. Perhaps worse can be the case where the company gets the smaller tanker lifting or is short-loaded due to weather – their “turn” may not come around again for some time. Indeed the smaller the percentage share holding the greater the risk of this happening.

12.2.2 Production terminals

Production terminals have operational requirements determined by the producer or joint venture producers each of whom have an equity share in production. We will consider some of the operating aspects of the joint venture systems here.

Such systems are managed by a party (usually one of the equity participants) on behalf of the co-venturers. The operator has guidelines drawn up under a joint operating agreement which regulate the amount of stock each participant may hold both physically in the terminal and pipeline system, and on paper. The order of lifting and thus the lifting programme may be determined by a statistical method, a defined on-paper oil entitlement level triggering successive liftings in order, or may be a more gentlemanly arrangement where participants nominate when they require a lifting, or in some cases a combination of both.

In most cases, programmes for any month are usually defined during the first half of the previous month and advised as such to all participants.

The determination of stock entitlement to any participant may not be a simple matter since, in a complex collecting and distribution system, each field may have different qualities.

This is usually overcome by evaluating the quality and hence value of the individual inputting fields versus the final blend. This may be done by 1 of 2 distinct methods:

1. Negotiation

The participants will agree, perhaps on a quarterly basis, on the value of the inputting streams. This value will then either be related to volumes available to participants or result in a cash settlement between participants.

2. Mechanistic valuation

Samples of the crudes are taken over a period of time to form a composite sample – say one month – and then analysed. Again, varying methods exist: in a typical mechanistic valuation the agreement will have established rules for valuation usually based on particular cuts of the barrel.

For example these might be 3 distillation cuts from the liquids in the sample representing naphtha, gasoil and heavy fuel oil (the latter with adjustments for sulphur and viscosity). Each cut volume is then valued at market (based on published product prices from an agreed source) and a composite value for the crude drawn up – a sort of basic gross product worth. Rather than reimburse each other in money terms, adjustments to participants' stocks are made in equivalent volume terms of entitlement to the final blend.

Mechanistic valuation is used in crude production systems such as Brent and Forties and also in receiving and distribution terminals such as the Louisiana Offshore Oil Port (LOOP).

12.2.3 Scheduling products

The scheduling of products poses the operator with a different set of problems and is a function of refining which may be affected by crude input and capacity problems, interruptions, storage capability and of course the key factor – specification requirements.

Many products are finished by blending in tankage at a site which could be on or off the refinery. The operator may be involved in scheduling the blending procedure. At such time as a product may be loaded onto a tanker, the quality may be "off-spec" (not meet the specification required under the contract of sale or required for marketing into a particular area), at which point decisions have to be made:

- Can the cargo be re-blended up to spec on board the vessel?
- Will the cargo need to be pumped ashore for re-blending or treatment to meet spec?
- Can the cargo be sold off-spec as is to buyer without severe penalty?
- Can the cargo be sold as is to meet the requirements of another buyer or another country's specifications?

The final solution may depend on how familiar the operator is with the economics of the various options.

12.3 Bookouts

The 1980s witnessed the growth of paper markets. Such markets included forwards and futures. Operators were familiar with physical problems but the forward markets brought a new breed of problem not seen before.

In the first instance, operators had to come to terms with the bookout. Many people associate this with the Brent and other forward markets, although it has to be noted that settling differences has been a feature of other non-forward markets for some time, where trading of the same cargo has taken place. Nevertheless in our example we shall use the Brent market.

12.3.1 The Brent market

How does the bookout mechanism work? To illustrate this, it is best to look at the historical growth of the Brent market.

The original position of the British National Oil Corporation (BNOC) established in 1975 as a state oil company with production interests and subsequently a pricing role, the desire of producing oil companies to reduce North Sea tax exposure – the concept of tax spinning – and the eventual free market pricing of Brent Blend crude have all led to the development of the Brent forward or 15-day market. At times the chains of players involved in a single cargo have approached 50 or even 100. The need to make the market efficient and reduce the number of parties eventually involved in physical loadings led to the evolution of the bookout.

The mechanism of the Brent 15-day market requires that cargoes are nominated by the seller 15 days prior to the first of the laydays (a 3-day loading window) which appear in the loading programme for the month. The fact that there were 60 physical cargoes and initially some 400–600 transactions per month meant that the date nomination procedure, which is often carried out on the last possible day and which must by definition be completed by 17:00 London time on that day, had to be as efficient as possible.

In the early 1980s chains of transaction began to be apparent after the dates had been declared. So for example, for a particular cargo, an observer being a member of the "club" involved in Brent trading, could write down, after nomination of the date range in accordance with the conditions of sale, a series of transactions thus:

Let us suppose that Company X – an equity producer – has a defined date range for sale of a cargo (500,000 barrels ±10%).

If the cargo is declared down a chain then the result will be as follows:

X sold to Alpha
Alpha sold to Beta
Beta sold to Gamma
Gamma sold to Delta
Delta sold to Alpha
Alpha sold to Z (a refiner who wishes to lift the cargo)

Thus between X and Z, all transactions are of a paper nature with no interest in the physical item.

The actual timing of the bilateral sales transactions between the parties would have been irrelevant.

The first bookouts were thus carried out after chains had been identified. It was however realised almost immediately that players did not have to wait for chain nomination before completing a bookout. Indeed to improve the efficiency of the nomination procedure it was desirable to eliminate as many players prior to nomination as possible.

12.3.2 Executing a bookout

Let us therefore assume that this is the case and April 15-day Brent transactions have been identified between the parties. It is not necessary for the parties to know the price terms of other members of the bookout.

However, in order for us to appreciate the mechanism we will assume pricing as follows:

Alpha sold to Beta at	\$18.50
Beta sold to Gamma at	\$19.25
Gamma sold to Delta at	\$19.00
Delta sold to Alpha at	\$20.35

These parties can now execute a bookout. They will define a "base price" as probably being \$18.50 – although this is irrelevant to the outcome as we shall see, and Alpha has agreed to co-ordinate the bookout.

The procedure of a bookout involves the cancellation of the original agreements in exchange for a fee settlement between the members of the ring.

Suppose on 15 March, the four companies have verbally agreed to carry out a bookout – remember, no nomination of a cargo (wetting) has taken place to create the chain yet. They have agreed that the base price will be \$18.50. For an example of the telex issued by Alpha, see Appendix 12.2.

Note that in the telex the parties propose to settle some 51 days prior to the normal assumed payment date – deemed to be 30 days after the middle of the contract month (assumed to be the 15th day of the month) and a discounting mechanism is proposed.

Looking at the money flows before discounting:

Case A

The parties agreed the base price to be <u>\$18.50</u>:

Beta pays Alpha	500,000 × (18.50 – 18.50) = \$0
Gamma pays Beta	500,000 × (19.25 – 18.50) = \$375,000
Delta pays Gamma	500,000 × (19.00 – 18.50) = \$250,000
Alpha pays Delta	500,000 × (20.35 – 18.50) = \$925,000

Net result

Alpha	loss	\$925,000
Beta	profit	\$375,000
Gamma	loss	\$125,000
Delta	profit	\$675,000

Case B

If the parties had agreed that the base price should be <u>\$19.00</u>:

Beta pays Alpha	500,000 × (18.50 – 19.00) = –\$250,000
– in other words Alpha pays Beta	\$250,000
Gamma pays Beta	500,000 × (19.25 – 19.00) = \$125,000
Delta pays Gamma	500,000 × (19.00 – 19.00) = \$0
Alpha pays Delta	500,000 × (20.35 – 19.00) = \$675,000

Net result

Alpha	loss	\$925,000
Beta	profit	\$375,000
Gamma	loss	\$125,000
Delta	profit	\$675,000

In other words, the base price is not relevant to the outcome. It may be selected – as in Case A – as being the lowest of the prices and the money flows will be all from buyer to seller; or be chosen as in Case B where the size of the money flows is lower, but in one case, seller pays buyer.

12.3.3 Discounting for advanced payment

The procedure also allows for advanced payment – in this case 51 days. The accepted calculation for this is as follows:

$$\text{DISCOUNTED FEE} = \text{ORIGINAL FEE} \times \frac{100}{100 + (\text{LIBOR} \times n/360)}$$

where n is the number of days payment is advanced

For example,

A cargo of April Brent will be deemed to load 15 April. Normal terms would stipulate payment within 30 days. If the bookout settlement is to take place on 25 March then the advancement is 51 days. If LIBOR is 3.5%, then in our example in Case A above Gamma will pay Beta:

$$\text{DISCOUNTED FEE} = 375{,}000 \times \frac{100}{100 + (3.5 \times 51/360)}$$
$$= \$373{,}149.80 \text{ on or before 25 March}$$

The other payments made by the parties will also be adjusted accordingly.

Following the Brent market hiccups in 1986 and the UK Financial Services Act of 1988, attempts were made to incorporate a clause making the bookout mandatory where identified. This was eventually dropped and indeed turned around to include a clause allowing a party to decline a bookout without reason.

12.3.4 Reasons for bookingout

Financial

Reduction in the size of the transaction transfers by an order of magnitude – in other words sums normally of the order of up to $1 million as opposed to say $10 million per sale.

Early settlement of position

Where a Letter of Credit is required – avoidance of any problems such as delay or non-performance.

Declaration procedures

Avoidance of problems encountered in 15-day declaration – such as “5 o’clocking”. If a company receives a nomination at just before 5 o’clock on the last possible day, it does not have sufficient time to pass the nomination on to its buyer.

Oil production

Avoidance of risk of crude oil production interruption, resulting in a deferred or cancelled programme and hence deferment of settlement.

Shipment

Avoidance of: delayed vessel nomination
unacceptable vessel presentation
vessel problem alongside

12.3.5 Reasons for not bookingout

Trading losses

Deferring settlement of a losing position’s negative cash flow.

Use of loading tolerance to reduce loss or increase gain

Assuming tolerance will be taken by end-receiver which will reduce loss or maximise profit.

For example, a trader has a purchase at $19 and a sale at $18/barrel. In a falling market it may be assumed that the end receiver may aim to lift 500,000 barrels less 5% tolerance, in other words as close as possible to 475,000 barrels. Thus the trader would benefit by up to $25,000 by avoiding a bookout.

Trading opportunities

Taking the 15-day declaration as a physical, selling it as dated and going short the 15-day. Here a trader will take such a position when on a substantial loss even at the risk of opening up a premium on the 15-day market. Good examples of this occurred during the 1990/91 Gulf crisis.

For example, a trader has purchased at $29 and sold at $19/barrel. The market for April dated is now $19.00 with 15-day

Brent (April) at $19.10. It is now 4 April and the trader receives a nomination for a 15-day for 19–21 April loading.

Case A

Take bookout: loss $5 million

Case B

(i) Hang in chain; take 15-day declaration as physical; charter and sell CFR or sell as dated but with volume 475,000 barrels
(ii) Buy in 15-day to meet short position created by (i)
loss range on (i) $4.75 million
loss range on (ii) $0.0475 – $0.0525 million
total loss/barrel $4.7975 – $4.8025 million
net saving about $200,000

So far we have considered the Brent 15-day 500,000 barrel contract in our example of paper markets. During 1986, in response to traders wishes to play in smaller volumes than the 500,000 barrel lot, the concept of mini- or partial-Brent was launched whereby players were able to trade in 50,000 barrel lots. Originally this was linked to an over-the-counter hedging concept whereby players buying 500,000 barrel lots would be able to price in tranches of 50,000 barrels by predetermined trigger dates. Trade in this vehicle diminished with the launch of the successful Brent futures contract (1,000 barrel lot) in June 1988 but saw a resurgence in the 1990s.

12.3.6 Other forward markets

Although many forward markets have now been replaced by derivative trading instruments such as swaps (see Chapter 7), a small number still survive. The most important of these are for West Texas Intermediate (WTI), Dubai and Tapis crudes:

- WTI is based on delivery into Arco/Texaco pipeline at Cushing Oklahoma – in practice on 20,000 to 100,000 bbl lot sizes. The last quoted day in Platts is 25th of the month prior to delivery month. Other sweet crudes may be substitutable with premium or discount,
- Dubai is based on 500,000 bbl cargoes +/–5% FOB Fateh terminal. Physical production has diminished over the last few years to 12–15 cargoes per month

calling into question its validity as a major price determinant for Arabian Gulf crudes going East. Paper trades are of the order of 5–10 per day,

- Tapis is based on 600,000 bbl +/–5% cargoes FOB Kerteh. Physical volume is about 14–16 cargoes per month. Paper trades are about 5 per day.

In all of the above forward markets the nomination and declaration procedures differ from Brent.

Outright trades in all crude forward markets probably form less than one third of all paper trades done. Grade and time spreads are the most common use of these markets nowadays.

Forward markets do exist in products but these have tended to be used in the form of swaps over recent years since the forward market declaration mechanisms can, as we have seen, lead to uncertainties.

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12.4 Nomination and documentation

After a deal has been agreed or a lifting date confirmed the shipper will have to provide a vessel nomination to the seller and possibly loading co-ordinator – if necessary through a chain as far as the first FOB seller who may be the party at first interface with the loading terminal.

12.4.1 Standard documentation

Large companies have standard documentation schedules which may have coded letters to denote particularly types of information. Typically the following will be required:

- Vessel name or TBN (to be nominated)
- Date range of lifting (laydays)
- Cargo reference number if applicable
- ETA of vessel
- Quantity/quality of cargo to be lifted – this may include a tolerance, a minimum, a maximum or a target; or in some cases an exact figure if the nomination is part of a cargo that can be separately documented.
- Instructions on the taking of samples
- Instructions as to which independent inspector is appointed
- Advice on agent appointed (where relevant)
- Name of supplier/consignor
- Name of consignee to applied to bill of lading (B/L) together with any special instructions on B/L
- List of documents to be supplied and these may include for example:
    - Bills of lading (usually in triplicate)
    - Quantity/quality certificates
    - Origin/authenticity certificates
    - Cargo manifest
    - Vessel time sheets and ullage reports
    - Master's receipt for documents
- Master's receipt for samples
- Finally the names of parties to whom the documents are to be distributed

It is quite possible that the B/L may be made out (consigned) to the seller himself, and in any event there may be a long chain between sellers and buyers. The original B/L will be despatched to the named consignee. In the event that this consignee named on the B/L is not the last buyer, he will have to "endorse" the B/L to his buyer – literally stamp on the B/L: "Endorsed to BUYERCO by SELLERCO signed . . ." before sending them on to the buyer.

12.4.2 Letter of indemnity

In many cases, buyers may not receive the B/L (and hence evidence of title) in time for payment and in such cases they or their bank could refuse payment for the goods. In such cases the seller issues to buyer a Letter of Indemnity (in wording acceptable to buyer) to accompany the commercial invoice and thus release payment. (See Chapter 13 for an example of a Seller's Letter of Indemnity (LOI)). At such times as the B/L is endorsed and received in good order by buyer, the LOI will be cancelled.

12.4.3 Letter of credit

The job of credit department or treasury may be to control whether a buyer has to supply some form of payment guarantee. This may be in the form of a Parent Company Guarantee – a device which may be used when dealing with a wholly owned subsidiary of a parent company with which open credit would normally exist; provision of an Irrevocable Documentary Letter of Credit (L/C) or provision of a Standby Letter of Credit (Standby L/C) which may be invoked on the buyer's bank in the event that the buyer does not directly meet payment as specified. (See Chapter 13 for examples of these.)

Although aspects of these forms of guarantee of performance and or payment are covered elsewhere in this Manual, it often falls to the operations desk to chase up the associated documentation. Attention must be paid to detail in dealing with Letters of Credit as minor errors may cause invalidation.

Although a contract (FOB, CFR or CIF) may specify that the Letter of Credit (L/C) may have to be in place say 10 days prior to loading and failure may imply repudiation, deals are usually kept going and, by continuing to exert pressure on the buyer to comply with the contract, the documentation is usually provided. This may well be at the last minute when the vessel is being held up awaiting confirmation of an L/C. Lately, the Standby L/C has been more favoured by sellers because of its flexibility. Note in the case of a sale delivered ex-ship (DES), the L/C timing requirements may relate to discharge.

12.5 Inspection

The independent inspector has been likened to a field representative, investigator and policeman reporter and analyst. He may be appointed to attend a vessel at loading or discharge, or a terminal interfacing with ship, pipeline or refinery. The role the independent inspector has to play will depend on the instructions and involvement of the client in the shipment.

In attending a loading at a crude terminal where the client is an fob seller, the instructions may simply refer to attendance to ascertain quantity/quality loaded is as per instructions to terminal and vessel, and matches documentation produced. It may be a condition of the contract that inspection is either shared between buyer and seller or paid for by the party requesting it. A more complete set of instructions for inspection for a buyer/shipper in the case of a product loading is given in Appendix 12.1.

The role of the inspector is truly to be independent so it is worth establishing that the inspector so appointed has a record of providing a quality service. Most occasions the work of the inspector will provide back-up to other information. On the odd occasion – when there is an operational problem or in more extreme cases a dispute leading to litigation – the inspector will provide useful input.

In cases of cargo loss – determined by comparing the original B/L figures (i.e. usually shore tank measurements or metered quantity at the supply end) with the out-turn (the amount delivered to the receiver and usually measured in shore tank at the discharge) – the inspector's report will be valuable in ascertaining the role played by the ship.

It is critical that all parties – ship, shore, buyer, seller – are aware of the inspector's role. Simply put, an inspector's role is EITHER to act as witness to the quantity/quality determinations made by vessel and shore OR to actually determine quantity and quality himself. It is worth noting that the sales contracts of some major oil companies call for the inspector to be a witness in the cases of transactions at any terminal owned by that company with the Q/Q determination being carried out by the terminal, whereas if the company is buying or selling at a third party terminal they will request determination by the inspector.

12.6 Demurrage

Demurrage – charge for excess laytime incurred in loading or discharging a vessel – is a specialised subject and often assigned to a specialist. Operations will encounter demurrage as they may be the first company staff to see a vessel time sheet or sailing telex.

There are essentially two forms of demurrage:

1. *Supply or contract demurrage*: that associated with an oil sales contract or terminalling arrangement where a supplier or receiver of the cargo (or terminalling company as the case may be) has a duty to turn the vessel loading or discharging around within the specified laytime – typically 36 hours for a straightforward crude oil shipment. This may be related to the charter party demurrage rate (*see below*), or a rate to be determined by an accepted source – for example the London Tanker Brokers Panel, or a published rate such as AFRA. AFRA – Average Freight Rate Assessment – is published monthly by the AFRA panel and lists rates in Worldscale terms applicable to key tanker sizes. Access to AFRA rates is by subscription.
2. *Charter party* (*CP*) *demurrage* – that associated with the Charter party as specified between owner and charterer and typically 72 hours for the voyage. The exact terms (rate) will be specified in the CP.

There are occasions where the shipper may profit from demurrage. Take for example the case where the vessel takes 48 hours laytime at load port resulting from delays caused by the shore supplier but only 24 hours at discharge port. If 36 hours is allowed under a supply contract, the shipper may be able to claim 12 hours demurrage from the supplier but not be liable to any CP demurrage. In some cases, suppliers may insert a clause effectively limiting their liability to a portion of any CP demurrage incurred. Some suppliers do not pay demurrage at all!

Operations staff should be aware of the following. Many Charter party Demurrage clauses contain a time-bar – usually 60 or 90 days. In other words, a claim has to be launched in writing within a certain time of the event taking place. Also more companies are incorporating clauses defining payment of demurrage within a specified time after receipt of invoice and documentation. In the past this tended to be an area which was forgotten about and substantial sums can accrue. Demurrage claims are still overlooked, sometimes put at the bottom of the paper pile; but this can be an expensive practice.

12.7 Shipping operations

12.7.1 Risks and opportunities

In today's trading environment, even the simple purchase of a cargo of crude oil can generate a wide variety of options for the operations co-ordinator. For example, a West African cargo has been purchased fob. The objective is to trade it to the US Gulf. A company controlled vessel is ballasting to West Africa, which looks as though it could meet the scheduled lifting date range.

The crude price risk management aspects – hedging the purchase on Brent, covering the dated/forward risk with a contract for difference swap (*see Chapter 7*), hedging the WTI-based sale price – could all be put in place at the time of the deal or any time thereafter. But the physical transport of the cargo to the US offers both risks and opportunities.

In the 1970s, the pattern would have been predetermined by supplier and receiver planning. Now the combinations could be as follows, the selection of final delivery mode will depend on several factors and objectives:

- Sell the cargo fob; charter out the company vessel on the market.

If sufficient profit (which may be hedged) can be made between the initial purchase and fob sale, then no further involvement may be considered useful. Shipping involvement may not be seen as an advantage in this particular deal.

- Sell the cargo fob and charter out the company vessel to the buyer of the cargo.

A variation of the first case, again leaving the buyer with shipping responsibility.

- Load the cargo on the company vessel and sell CFR, CIF or DES.

A shipping involvement may appear to offer greater profit potential. Continued control up to the point of sale in the right kind of market may be beneficial. There may be an opportunity to profit from freight – for example by using a larger vessel than typical for the route and on which the landed market value of the oil is generally assessed. The company may wish to raise its profile as a seller of oil with delivery capability. The decision to go for CFR, CIF or DES then depends on the level of risk the company feels it wishes to take on versus additional profit potential, DES of course giving most risk on B/L versus out-turn volume.

- Charter in a vessel to load the cargo and sell CFR, CIF, DES; charter out the company vessel on the market.

There may be an opportunity to profit from the cargo size available for loading and add profit by loading on another vessel.

Nowadays many smaller trading companies combine oil and shipping operations; to some extent it is still fragmented in the majors for management reasons, but anyone who has worked in a small trading office will have recognised the value of combined operations. Knowledge of shipping movements provides useful intelligence on deals done and other companies' supply patterns. Additionally it should be noted that some companies specialise in providing a tanker tracking service.

12.7.2 Single voyage

Having liaised with chartering personnel to arrange a spot fixture, operations will have to talk to brokers/owners on the post fixture operations side, together with agents and terminal personnel. Voyage orders to chartered vessels will be sent via brokers through to owners and vessel. Although owners pay for agency in voyage charter, agents may, depending on the terms of the Charter party (CP), be appointed by charterer. In any event, the charterer may wish to appoint his own "protective" agents as in fact occurs occasionally with some fob sales on cargoes where there are a number of interests.

The significance of vessel ETAs (Expected Time of Arrival) in relation to a single voyage charter cannot be overstressed. If the vessel is, or is anticipated to be, arriving after laydays and thus, presumably, after the FOB purchase lifting window, this situation could create a breach of contract for the charterer as oil buyer. The charterer is then faced with several options to remedy the situation:

- get agreement from seller to defer the lifting window;
- find an alternative potential buyer with a vessel and carry out an exchange; or
- charter an alternative vessel to meet the lifting window – if possible.

Recovery from the tanker owner of any damages on the oil trading side is only likely if the vessel had misled the charterer over the ETA or was aware of circumstances that would alter the ETA and did not disclose them.

Consider also the implications for any hedging programme, which might as a result of delay on voyage require a rollover of a hedging month with consequent transaction costs or increase in basis risk. Again it is unlikely that the charterer will be able to recover these, provided that delay was outside the owner's control and ETAs were advised in accordance with the CP.

12.7.3 Time charter

Orders to time chartered vessels will be sent direct to the vessel and copied to the owners. The operator handling the time chartered vessel needs to ensure that agents are appointed and instructed for each port. From time to time, owners may prefer to appoint (and pay for) their own agents at a port to handle matters for owners' purposes such as crew change.

The agent will also be a source of up-to-date information on port conditions ranging from berth and harbour physicals dimensions to outlook for delay and port costs and requirements or restrictions.

The operator of a time charter vessel will be paying attention to services required by the vessel in addition to other cargo aspects – such as ballast facilities and bunkers. Although not directly responsible for owners and vessel needs, it is in his interest – as it may save problems and time later – to be aware of the supplies of stores and water and whether or not repair facilities are available or whether repairs can be carried out alongside.

All orders should include consignor and supplier, grade and quantity of cargo in compliance within Charter party (CP) terms, outward destination (port or area), name of consignee and receiver at discharge port (if known). The operations personnel will have to consider restrictions that may cause dead freight at load port (such as draft or cubic capacity of vessel), on passage (such as canals), and at discharge port, and evaluate whether these can be overcome most economically by, for example, lightering or short-loading. Care must be taken on routing if orders are to be changed (within CP terms) to ensure that the vessel is able to enter a different loadline zone with the cargo on board.

Operations personnel may also be required to keep an eye on a vessel's voyage performance as part of the ongoing performance audit process and with a view to inputting to a company database on tankers for future reference in chartering activity.

Such voyage performance will include the ability of the owner to react to the charterer's instruction without delay as well as Charter party performance aspects such as the speed and consumption of the vessel and discharging capability, which in the case of a time chartered vessel are essential in reviewing CP performance against description.

In the event that a vessel on voyage charter arrives at the discharge port and documents are not available, as frequently is the case in these days of chains, the master/owner will require a letter of indemnity – part of an example of which is given in Appendix 12.3. The wording is usually incorporated into the Charter party.

At this stage the LOI wording may incorporate a clause requiring the LOI to be issued by a first class bank (on behalf of the charterer) which is acceptable to the owner.

Delay in presentation of a B/L or LOI will be for the charterer's account.

12.7.4 Vessel arbitrage

Vessel arbitrage can take the form of improving timing or size with consequent freight savings.

In the case of the timing arbitrage, the player will re-let (charter-out) on the expectation that the rate he will obtain will be the same (perhaps improving his delay situation) or greater than that obtained for a similar vessel at the subsequent charter-in.

For example, a cargo has to be loaded 17–19 November. A company vessel shows an ETA at the load port of 14 November. If the vessel can be chartered out at Worldscale 70 for loading on 14 November and another vessel chartered in at Worldscale 70 for loading 17 November then 3 days delay will be saved.

The size arbitrage plays on the nominalization aspect of chartering can be seen in regionally established markets.

For example, if a 125,000 tonner (a vessel with cargo carrying capacity of 125,000 tonnes) will charter or trade (in the freight sense) at Worldscale 65, then a 130,000 tonner will be likely to trade at Worldscale 62.5.

In other words, tonnage multiplied by freight is a constant within reasonable bounds – in a given trade route and within a similar size and type category of vessel.

Thus all things being equal, if you have a 125,000 tonner and it fits a cargo, charter it out and replace it with a 130,000 tonner charter-in, then try to fill out the cargo, which may be available anyway on the purchase tolerance.

Of course there are other dimensional implications: does the vessel fit the discharge port? Will additional lightering be required – if so at what cost?

12.7.5 Alternatives on discharge

A player has loaded a cargo of Arabian crude for the West. Leaving aside cargo pricing ramifications he has decided to deliver to the US Gulf. The options could be as follows:

- Discharge at LOOP for on-shipment by pipeline assuming capacity through LOOP is available.

At around Worldscale 60 in 2001 terms the freight would work out at around $1.70/barrel. However, to this has to be added the cost of distribution through LOOP which would of course depend on destination and for local US Gulf area this could be $0.30–$0.60/barrel.

- Lighter in the US Gulf.

In 2001 terms, and assuming the lightering was a 12 day exercise, total delivery cost would approach $2.10/barrel.

- Hold in floating storage (vessel) and lighter as appropriate.

Cost as above plus floating storage charges, which would be about $0.30–0.50/barrel per month.

- Trans-ship across the jetty in the Caribbean to a shuttle ship delivering direct to the refinery on the Gulf Coast.

Assuming a shuttle cost of Worldscale 150, again at 2001 rates, this would work out at around $2.25/barrel.

- Put into storage in the Caribbean and shuttle as appropriate.

Total delivery costs would approximate to $2.30–2.50/barrel for say 10-day storage and would escalate with the storage period. Storage costs may work out between $0.15 and $0.30/barrel per month.

A word on the assumptions: there is also a small in-transit loss when any lightering or trans-shipment takes place (0.2 per cent based on typical industry averages) which is not included in the costs identified above. The Caribbean has been assumed to cover the area including the lower Netherlands Antilles to the Bahamas. The Bahamas may work out a few cents per barrel more than lightering for US Gulf delivery depending on the relationship between VLCC and shuttle freight costs. It is, however, particularly well placed for servicing the US Atlantic Coast refineries (such as Philadelphia).

12.8 Terminals, trans-shipment and storage

12.8.1 Terminals management

Involvement with terminals covers many aspects – production companies or joint ventures, receiving terminals for crude or products, intra-company storage and trans-shipment terminals and third party storage companies operating their own terminals. We have already addressed some aspects of production terminals.

A person sitting on the operational desk at an oil terminal or an oil company managing a terminal or a company wishing to execute terminalling deals requires a general all-round knowledge of oil deals, shipping deals and regulations, and of course storage arrangements.

If not a pure oil storage company, the operator's company may be involved as a principal in the oil arrangement, i.e. have title to the oil at some stage. In any event the terminal operations staff will be liaising directly with terminal technical and safety staff, marine staff, shipping agents, tankers and masters, independent inspectors, oil companies – all at operational level.

Key problems will be general inventory control, quality/quantity measurement and jetty occupancy. Back in the design days of many terminals – the early 1970s, considerable care went into the estimating of storage and jetty facilities, as the world – as we have said – was ship driven. Tankers turned up at a terminal and demanded to be served. Simulation studies were run using models to generate random or near random arrival patterns and evaluate them using queuing theory, and the cost of delay in terms of vessel demurrage due to constraints in tankage volume or jetty occupancy and tanker size.

With high freight rates, a tanker had to be turned around as expeditiously as possible and the discharge was continued apace sometimes at the expense of effective stripping of cargo.

In order to act as an incentive to quick turnaround, many terminals included in their conditions berth occupancy clauses, whereby if a tanker exceeded its expected residence time alongside for ship's reasons such as slow pumping/deballasting, then the terminal would penalise the user. This also acted as a revenue source to pay demurrage.

As the cargo became more valuable relative to freight and Crude Oil Washing (COW) became the norm (and indeed to some extent mandatory) as opposed to the exception, tankers stayed alongside for a greater period. Excess berth occupancy clauses were still being invoked, although there were additional allowances for excess berth occupancy for COW.

Clearly berth occupancy clauses worked in opposition to the general overview of oil economics, pollution control, safety and environmental interest. In the climate prevailing in the mid-1980s when many terminals all but went out of business due to slack demand, these clauses tended to lapse and many have not been reinstated.

12.8.2 Spot storage

Clauses which should be covered in a spot storage deal are as follows:

- *Term of storage*: number of days tanks are occupied from first barrel in to last barrel out.
- *Quantity*: maximum volume to be specified – may be gross.
- *Fees*: based on barrels capacity taken in storage – likely to be the maximum storage used in terms of integral tank sizes – may be net. In the mid-1980s actual volume stored may have been negotiated.
- *Heating*: whether required and if so whether cost is included in fees above.
- *Loss limit*: this is an important and often misunderstood clause. Some storage companies will specify best endeavours to redeliver all of the stored quantity. Others will guarantee no losses in excess of 0.2 per cent. Others will take the guaranteed loss amount and only redeliver 99.8 per cent regardless.
- *Storage conditions*: whether segregated, commingled with some of customer's own material or with third party material.
- *Title and risk*: usually for the account of the customer. Insurance may be taken by the storage company to cover his negligence only.
- *Measurement*: measured in-tank by terminal personnel. Independent inspection will usually be for the account of the storage user.
- *Payment*: invoice may be raised upon commencement. Payment may be specified within 5–30 days.
- *Applicable law*: usually the country of location.

12.8.3 Term storage

Other clauses applicable to term deals are:

- *Period*: monthly or annually; whether evergreen with a cancellation clause with suitable notice period.
- *Quantity*: a term deal may offer the user the flexibility of use of a terminal for storage or trans-shipment depending on the prevailing economics. Usually a deal will be structured on the rights of the user to a defined quantity of tankage either segregated or commingled within quality groups.
- *Nominations*: nomination procedures for vessels and off take (shipping or pipeline).
- *Use of jetty*: the deal may assume a specified number of jetty days aside from the tankage aspects.
- *Fees*: may be based on term use – monthly or yearly – of a specified quantity of tankage limited by number of turnovers (or throughput quantity). Incremental volume of tankage capacity or additional throughput may be specified at different rates.

12.8.4 Trans-shipment across jetty

Depending on traffic congestion, many terminals will offer the user the opportunity to trans-ship across the jetty to avoid additional handling losses in and out of tankage, which will attract lower fees than short term spot storage.

In the case of crude oil, this may also be useful as a replacement for lightering, being possibly more secure, although it may be more or less expensive depending on the overall logistics pattern of the vessels involved and freight rates.

Example: Cargo from Persian Gulf to Philadelphia

Route a) VLCC trans-ships across jetty at Bahamas into 80,000 tonners for Philadelphia.

	$/bl
VLCC Mid East Gulf to Bahamas @ W60 11.99/7.3	= 1.64
Shuttle Bahamas to Philadelphia @ W115	= 0.49
Across jetty fee	= 0.08
Total	= 2.21

Route b) 130,000 tonner moves PG to Philadelphia (via Suez)
130,000 tonner Mid East Gulf to Philadelphia @W100
= 2.50

12.8.5 Terminal regulations

Regardless of the type of deal, the Terminal Regulations will form part of the contract. These will include advice on areas such as:

- Pilotage and tugs.
- Availability of services: ballast, bunkers, stores, water, repairs etc.
- Vessel regulations, safety aspects, pollution control, liabilities.
- Nomination, ETA and NOR procedures.
- Laytime and demurrage – demurrage may be defined as dependent on parcels loaded, whether or not related to AFRA or another freight determination, whether limited to the charter party demurrage calculated or charged.
- Vessel routing – of increasing importance in a pollution conscious environment.

12.8.6 General points

Anyone involved in storage or trans-shipment on a regular or term basis should give consideration to an inspection of the terminal in the same way as one would inspect a tanker prior to chartering. Areas of particular importance are as follows:

- *Tanks:* number and size, whether or not fitted with bottom drain; some companies only provide gross in and out service; if a bottom drain is fitted, free water can be drawn off, roof drain provision given local climate conditions, whether heating and mixers are available.
- *Deballasting facilities:* whether clean ballast has to be pumped ashore.
- *Lines:* valve separation, external interfaces and metering.
- *Power supply:* whether self-generated or dependent on third party.
- *Marine facilitie*s: fire and pollution control.
- *Laboratory*: range of tests that can be performed, whether a truly independent inspection service is available.
- *Administration:* control room facilities, security and safety.

12.8.7 Discharge

Prior to a ship's arrival at the discharge port, the operators (shipper, buyer, seller as appropriate) should check the status of title documents and execution of any letters of indemnity that may be required and in the case of DES terms possibly any outstanding letter of credit requirements that should be fulfilled.

The vessel will have given ETAs under its charter party terms and the operators will have ensured that, with or without lightering as appropriate, the vessel is able to enter the port and proceed to a safe berth as agreed.

Once at berth the vessel has to discharge cargo, ballast and vacate the berth as expeditiously as possible. All this must be done with the interests of charterer, cargo receiver, cargo owners and ship owner in mind. The cargo owner may be concerned that the vessel strips as much cargo out as possible as he wants to ensure any losses are minimised. The cargo receiver may be concerned about contract demurrage liability; he may also have other vessels to service. The charterer may want the vessel turned around as quickly as possible to avoid any Charter party demurrage liability.

At this point it is also essential to establish that the vessel is aware of port regulations and practices. For example, the practice of crude oil washing may be limited for reasons of berth occupancy (in some cases charges may be made for excess berth occupancy) or limitation on loss of light cargoes. All parties and in particular the vessel must be aware of such practices in advance to prevent interruption that may be otherwise caused by the need for discussion with seller/receiver/buyer/shipper involved during the actual cargo operation. In this respect, whilst initially operators may rely on agents for early advice, the services of an inspector on the ground at discharge can be useful in ensuring the vessel meets local requirements and will provide valuable feedback to operations personnel for future movements into that port. Of course, in some cases, a company may have its own employees fulfilling this role.

Continuing on the theme of inspection, it is important that the samples of material on board the vessel at arrival, in any lines between vessel and tank, and in receiving tanks, are taken prior to discharge. In the case of product shipment this action is critical.

In the event of multiple port discharging, it is necessary to give the vessel advance notice of discharge quantities and grades at each port at the earliest opportunity. In the case of complex cargoes such as clean products and lubricants, the appropriate time may even be prior to loading.

In the event that a grade is discharged at 2 or more locations, depending on contractual arrangements, this may require the reallocation of Bills of Lading.

For example, a vessel loads 100,000 tonnes net of gasoil for discharge, 60,000 tonnes to a consignee at port A and 40,000 tonnes to a consignee at port B. Assume port A receives 60,500 tonnes based on out-turn and port B receives 39,300 tonnes based on out-turn. A total of 99,800 has been discharged yet on the face of it, A has made a 0.8 per cent gain and B a 1.8 per cent loss.

Clearly there has been an overall loss which should be borne equally. Reallocated bills of lading would pro rata this and show 100,000 tonnes loaded basis 60,621 tonnes for port A and 39,379 tonnes for port B. Thus this way A and B will both have experienced a 0.2 per cent loss on out-turn – a more equitable solution.

Finally, having completed discharge, the cargo owners and spot charterer will have no further interest in the vessel, save that regarding any claims follow up on cargo quantity/quality loss or demurrage. The vessel owner or time charterer will be looking to expedite port departure, as time without cargo means time without freight earnings.

Appendix 12.1 Instruction to inspectors

WE APPOINT XYZ SERVICES AS INDEPENDENT INSPECTORS AT .... TO WITNESS LOADPORT DETERMINATION AS FOLLOWS:

VESSEL NAME

LOAD PORT/BERTH/SUPPLIER

PRODUCTS DESCRIPTION, QUANTITIES AND QUALITIES

ETA

AGENT

VESSEL DWT AND OTHER RELEVANT PHYSICAL INFORMATION

FLAG

THE LOADING INSTRUCTIONS TO THE VESSEL HAVE BEEN GIVEN AS FOLLOWS:

E.G. LOAD PRODUCT A INTO VESSEL SEGREGATION OF CAPACITY . . . LOAD PRODUCT B INTO VESSEL SEGREGATION OF CAPACITY . . . ETC.

WE REQUEST BUNKER SAMPLES AND BUNKER GAUGING OF ALL BUNKER TANKS ON ARRIVAL AND DEPARTURE. SAMPLES TO BE RETAINED UNTIL FURTHER NOTICE.

THE FOLLOWING TESTS ARE TO BE PERFORMED ON EACH PRODUCT:

[LIST OF TESTS APPLICABLE TO SPECIFICATION OF PRODUCTS]

TANKS AND SHORE LINES TO BE TESTED AND SAMPLES TO BE RETAINED ON BOARD.

VESSEL TANKS AND LINES TO BE CHECKED BEFORE LOADING TO AVOID ANY POSSIBLE CONTAMINATION.

CHECK BOTTOMS ON VESSEL BEFORE LOADING. SAMPLES TO BE TAKEN AND RETAINED. ISSUE SUITABILITY CERTIFICATE AS REQUIRED.

PUMPING RATE FROM THE TERMINAL TO BE MAINTAINED AT ALL TIMES IN ACCORDANCE WITH VESSEL'S

CAPACITY TO RECEIVE. IF RATE DROPS AT ANY TIME, ISSUE A LETTER OF PROTEST.

REPORT CARGO TEMPERATURE IN SHORE TANKS AND VESSEL TANKS. VESSEL EXPERIENCE FACTOR TO BE APPLIED. PROTEST TO BE ISSUED IF DIFFERENCES EXCEED 2/10 OF 1 PER CENT BETWEEN B/L AND VESSEL'S ULLAGES.

COMPOSITE SAMPLE TO BE TAKEN FROM VESSEL AND RETAINED ASHORE WITH . . . (OR FORWARDED TO . . .).

PLEASE PROVIDE A SAILING TELEX COVERING B/L AND QUANTITY/QUALITY FIGURES, TIME ALL FAST, COMMENCEMENT, COMPLETION OF LOADING, HOSE DISCONNECTION AND SAILING TIMES.

NOTIFY US IMMEDIATELY IN EVENT ANY PROBLEMS ARISE. FULL INSPECTOR'S WRITTEN REPORTS TO BE SENT TO US AS SOON AS THEY ARE COMPLETED.

Appendix 12.2 Sample Brent bookout telex

TELEX DATED 15 MARCH 2001
FROM: ALPHA TRADING COMPANY PLC, ANDREW ASH
TO: BETA TRADING A/S, ATTENTION BJORN BLAND
COPY TO: GAMMA TRADING CORP., ATTENTION GRETA GROLSCH
COPY TO: DELTA TRADING LTD, ATTENTION DAVID DUNNIT

RE: BOOKOUT OF APRIL BRENT, ALPHA BOOKOUT NUMBER ABC123

IT HAS COME TO OUR ATTENTION THAT THE FOLLOWING SEQUENCE OF AGREEMENTS EXISTS FOR A CARGO OF BRENT SYSTEM CRUDE OIL WHICH IS TO BE DELIVERED IN APRIL 2001.

ALPHA TRADING PROPOSES THE FOLLOWING CANCELLATION AGREEMENTS FORMAT IN ORDER TO FACILITATE THE HANDLING OF THESE AGREEMENTS. THE LANGUAGE OF THE CANCELLATION IS AS FOLLOWS:

QUOTE
THIS AGREEMENT IS EXECUTED ON 15 MARCH 2001 BY AND AMONG

ALPHA TRADING COMPANY PLC	'ALPHA'
AND BETA TRADING A/S	'BETA'
AND GAMMA TRADING CORP	'GAMMA'
AND DELTA TRADING LTD	'DELTA'

WHEREAS ALPHA AND BETA ARE PARTIES TO A CONTRACT IN WHICH ALPHA HAS AGREED TO SELL AND BETA HAS AGREED TO PURCHASE:

VOLUME CRUDE TYPE	DELIVERY DATE	
500,000 BBLS	BRENT	APRIL 2001

WHEREAS BETA AND GAMMA ARE PARTIES TO A CONTRACT IN WHICH BETA HAS AGREED TO SELL AND GAMMA HAS AGREED TO PURCHASE:

VOLUME CRUDE TYPE	DELIVERY DATE	
500,000 BBLS	BRENT	APRIL 2001

WHEREAS GAMMA AND DELTA ARE PARTIES TO A CONTRACT IN WHICH GAMMA HAS AGREED TO SELL AND DELTA HAS AGREED TO PURCHASE:

VOLUME CRUDE TYPE	DELIVERY DATE	
500,000 BBLS	BRENT	APRIL 2001

WHEREAS DELTA AND ALPHA ARE PARTIES TO A CONTRACT IN WHICH DELTA HAS AGREED TO SELL AND ALPHA HAS AGREED TO PURCHASE:

VOLUME CRUDE TYPE	DELIVERY DATE	
500,000 BBLS	BRENT	APRIL 2001

THE ABOVE PARTIES HAVE CONCLUDED THAT IT WOULD BE IN THEIR JOINT INTEREST TO TERMINATE THE CONTRACTS IDENTIFIED ABOVE. NOW THEREFORE IT IS HEREBY AGREED AS FOLLOWS:

1.

IN CONSIDERATION OF THE EXECUTION OF THIS AGREEMENT TO CANCEL THE CONTRACTS ABOVE, THE ENTERING INTO THIS AGREEMENT TO PAY THE CANCELLATION FEE AS SET FORTH BELOW, EACH PARTY EXPRESSLY RELEASES THE OTHER PARTY AND THEIR SUCCESSORS, ASSIGNS AND LEGAL REPRESENTATIVES FROM ALL LIABILITIES, CLAIMS AND DEMANDS ARISING OUT OF THE CONTRACTS IDENTIFIED ABOVE, AND ALL OF THE ABOVE REFERENCED CONTRACTS ARE HEREBY RESCINDED, TERMINATED AND CANCELLED IMMEDIATELY.

2.

THAT IN ORDER TO CALCULATE THE CANCELLATION FEE PAYABLE BY EACH PARTY HERETO A BASE PRICE OF USD 18.50 PER BBL 'THE BASE PRICE' SHALL BE USED.

3.

EACH PARTY HERETO SHALL PAY ITS SELLER A CANCELLATION FEE EQUAL TO 500,000 MULTIPLIED BY THE AMOUNT, IF ANY, BY WHICH SUCH PARTY'S PURCHASE PRICE PER BBL EXCEEDS THE BASE PRICE PROVIDED ALWAYS THAT IF THE PURCHASE PRICE IS LESS THAN THE BASE PRICE, THAT PARTY SHALL RECEIVE FROM ITS SUPPLIER A CANCELLATION FEE EQUAL TO 500,000 MULTIPLIED BY THE DIFFERENCE BETWEEN THE TWO PRICES. THE DEEMED BILL OF LADING DATE SHALL BE 15 APRIL 2001, CANCELLATION FEE SHALL BE PAID IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE 25 MARCH 2001 DOLLARS DISCOUNTED AT A

RATE OF 3.5000 PER CENT (LIBOR) PER ANNUM INTEREST FOR 51 DAYS.

4.

ALL PAYMENTS HEREUNDER SHALL BE MADE IN FULL WITHOUT SET-OFF DEDUCTION OR COUNTERCLAIM.

5.

THIS CANCELLATION AGREEMENT SHALL BE CONSIDERED AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF ENGLAND AND SHALL CONSTITUTE THE ENTIRE AGREEMENT BETWEEN THE PARTIES AND SUBJECT TO JURISDICTION OF ENGLISH COURTS WITHOUT RECOURSE TO ARBITRATION.

6.

THE SIGNATORIES HERETO HEREBY WARRANT AND REPRESENT THAT THEY ARE AUTHORISED AND EMPOWERED BY THEIR COMPANY TO CONSENT TO THIS AGREEMENT.

7.

EACH PARTY HERETO EXPRESSLY WARRANTS AND REPRESENTS THAT THE DETAILS OF THOSE CONTRACTS TO WHICH IT IS A PARTY AS REFERRED TO IN THE ABOVE RECITALS ARE CORRECT AND ACCURATE IN ALL RESPECTS AND HEREBY ACKNOWLEDGES THAT THE OTHER PARTIES HERETO WHICH ARE NOT A PARTY TO SUCH CONTRACTS ARE ACTING ON RELIANCE OF THE ABOVE WARRANTY AND REPRESENTATION.

8.

THIS AGREEMENT SHALL COME INTO EFFECT WHEN ALPHA HAS GIVEN TELEX NOTICE TO ALL OTHER PARTIES TO THIS AGREEMENT, STATING THAT ALPHA HAS RECEIVED THE TELEX AGREEMENT OF SUCH PARTIES TO THE TERMS OF THIS AGREEMENT.

IN WITNESS WHEREOF THIS AGREEMENT HAS BEEN ENTERED INTO THE DAY AND YEAR FIRST WRITTEN ABOVE.

ALPHA TRADING COMPANY PLC
BY: ....
BETA TRADING A/S
BY: ....
GAMMA TRADING CORP
BY: ....
DELTA TRADING LTD
BY: ....
UNQUOTE

THE FOLLOWING TELEX SHOULD BE SENT TO ALPHA TRADING COMPANY PLC (LONDON OFFICE) AND ALL OTHER PARTIES.

QUOTE
REFERENCE NUMBER: ABC123
WE REFER TO THE CANCELLATION AGREEMENT DATED [INSERT DATE OF THIS TELEX] BY AND AMONG

ALPHA TRADING COMPANY PLC	'ALPHA'
AND BETA TRADING A/S	'BETA'
AND GAMMA TRADING CORP	'GAMMA'
AND DELTA TRADING LTD	'DELTA'

BY THIS TELEX WE, [INSERT COMPANY NAME] CONFIRM OUR AGREEMENT TO THE TERMS OF THIS SAID CANCELLATION AGREEMENT AND FURTHER CONFIRM THAT WE HAVE CALCULATED AND AGREED WITH OUR SELLER THE DISCOUNTED CANCELLATION TO BE PAID PURSUANT TO CLAUSE 3 ABOVE. WE FURTHER AGREE TO PAY, OR, AS APPROPRIATE, RECEIVE PAYMENT OF THE CANCELLATION FEE ON OR BEFORE THE AGREED DATE.
COMPANY NAME

BY:
UNQUOTE

ALPHA TRADING COMPANY PLC
BY:

Appendix 12.3 Sample letter of indemnity

– issued by charterer to owner

IN THE EVENT THAT THE VESSEL ARRIVES AT THE PORT OF DISCHARGE BUT ORIGINAL BILLS OF LADING ARE NOT AVAILABLE FOR PRESENTATION IT IS AGREED THAT CHARTERERS SHALL HAVE A RIGHT TO DEMAND THAT OWNERS DISCHARGE THE CARGO ON BOARD THE VESSEL WITHOUT CHARTERERS AND/OR RECEIVERS PRESENTING THE ORIGINAL BILLS OF LADING, ON THE FOLLOWING TERMS AND CONDITIONS:

IN CONSIDERATION OF OWNERS DELIVERING ANY CARGO UNDER THIS CHARTER IN ACCORDANCE WITH CHARTERER'S DEMAND WITHOUT ORIGINAL BILLS OF LADING DULY ENDORSED BEING PRESENTED TO AND RECEIVED BY THE MASTER OR OWNERS, CHARTERERS HEREBY UNDERTAKE TO HOLD OWNERS HARMLESS AND KEEP OWNERS INDEMNIFIED AGAINST VESSEL OR OWNERS BY REASON OF SUCH DELIVERY OF CARGO WITHOUT PRIOR PRESENTATION OF BILLS OF LADING, INCLUDING BUT NOT LIMITED TO ANY LOSS, DAMAGE OR EXPENSE CAUSED BY ANY ARREST OR DETENTION OF VESSEL.

CHARTERERS FURTHER AGREE TO PRODUCE AND DELIVER TO OWNER THE BILLS OF LADING FOR THE CARGO DULY ENDORSED AS SOON AS THESE DOCUMENTS HAVE ARRIVED.

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13 Credit control

Catherine Jago

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13.1 Why is credit control necessary?

13.1.1 Method of doing business

The oil industry works on the basis of a gentleman's agreement – my word is my bond – since almost all business, both futures and physical, is transacted over the phone. Deals worth millions of dollars are agreed between 2 parties many times every day, with each party trusting that the other will honour what has been agreed. This level of trust also feeds into the payment for the oil. Rarely is payment made for oil before it has loaded, or at the time of loading – although some countries from West Africa, Eastern Europe and the former Soviet Union use pre-payment as a method of financing the development of their oil industry infrastructure. Anybody who enters into this sort of pre-financed deal must be very confident that the oil will actually be delivered.

Payment may be made before discharge date, perhaps due to the contractual terms giving a limited number of days' credit, or perhaps the vessel has been delayed in discharging. Payment may be due anything up to 60 days, or even later, after bill of lading date. During this time events might take place which could put pressure on payment being made on due date, or even render the contractual party unable to make the payment.

Whilst traders may conclude deals which on paper make huge profits, these paper profits are meaningless if the other party, or even a party elsewhere in the chain, fails to perform either by not making the oil available or by not taking delivery of it, or by not having the correct financial arrangements in place. Credit and performance management therefore should be a vital part of any oil company's trading department.

Credit management in all walks of life is no longer a case of avoiding bad debts. Nor can a trading company always restrict itself to safe, low risk customers. Even if it did try to do this, oil companies can change overnight from an apparently rock solid financial risk, to one which creates a number of headaches. Open positions could amount to several million dollars, and that only on 1 or 2 cargoes! Routine financial insurance should feature in most oil transaction contractual terms.

13.1.2 Nature of the market

The oil market is not a static market in terms of the players in it, the trading mechanisms used and the amount of financial risk involved. When crude was priced at $5 per barrel, a cargo of crude would be worth approximately 2.5 million dollars. In the early 1980s when crude topped $40 per barrel, the value of a crude cargo went up correspondingly to 20 million dollars. So not only was there the increased risk of non-performance as trading partners reneged on heavy loss making deals, the absolute financial risk was considerably higher.

While there are some trading companies which have survived the rigours of the oil industry for a large number of years, many have not and new companies are continually being set up. A trader cannot avoid coming across these new players, and is likely to have to consider them at some time as possible trading partners, especially in a difficult market environment.

It is therefore vital that each trading company has a system for measuring the credit worthiness of new trading partners, and for monitoring business with existing trading partners. These systems must be able to react quickly to give an answer to a trader who may have only a short period of time during which he can conclude a deal with a new or existing trading partner. A delay of hours or days may mean that they will lose the deal. Any credit monitoring system must react quickly, must be easily used by traders and must be effective.

Different markets require different types of credit controls. Trading using regulated markets, such as futures and options markets in London, New York and Singapore, are already protected to some extent by the conditions set by the futures exchange for entry to the market. The costs, initial margin calls and brokers fees, are known in advance and, since the trading is done through the exchange, there is no performance risk and the exchange guarantees payment when due.

There is therefore no need to monitor the credit worthiness of other players using the regulated futures and options markets. Indeed, this would not be possible since a trader has no idea with whom he is transacting the business, only the broker with whom they agree the deal. It is then up to the exchange to work out the positions at the end of the trading monthly period and determine who owes oil into the system and who is owed oil, or money if the settlement is not by physical delivery.

However, when establishing a futures position a trader contracts with the broker who then in turn contracts with the exchange to take the futures position. The broker acts as the principal to the market. Thus it is the broker that receives the protection of the exchange, not the trader. The trader therefore has complete exposure to the futures broker of his futures position and any funds he may have placed with the broker. When choosing a broker with whom to transact futures business, one should consider very carefully the broker's financial position, and monitor this throughout the time of trading futures with this broker, considering, as best as possible, not only the positions you may have with the broker, but positions other customers may have with your broker also.

One way of limiting this exposure is to insist that margin money be held in a segregated account, separated from the broker's other funds. When negotiating brokers commissions, the fee charged is likely to be higher if a segregated account is used, and the interest rate payable on funds in a segregated account is likely to be lower than that offered for a non-segregated account. However, this small cost might be considered worthwhile for the financial security it gives you.

All other forms of oil trading expose the player to much more significant financial risk. This includes markets involving any over the counter (OTC) business such as swaps and options, forward paper trading and all physical transactions, none of which have such stringent entry requirements or are underwritten by a clearing organisation.

In theory, anyone could start ringing round potential players claiming to be interested in taking out a position. So long as they can prove that they have or will have ownership of oil to the satisfaction of the prospective purchaser, or that they have sufficient funds to pay for the oil, or perhaps just an on-going sale so that they only need to finance the margin, then anyone could become an oil trader. Should this individual be less than scrupulous, he could walk away from a deal, having agreed it over the phone, without the other side being able to receive any compensation, except through the courts, which are costly and laborious.

13.1.3 Risk management

The recent highly visible and serious losses incurred as a result of the use of derivatives have led the senior management in many oil companies to examine the effectiveness of their existing risk management practices, especially with regard to the control and reporting procedures for staff who regularly trade in these markets.

In 1993, the US-based organisation of senior bankers, academics and derivative market participants known as the "Group of Thirty" published an important set of recommendations based on best practice for companies involved in trading derivatives.[§] The G30 report addressed key issues including the role of management, the need to de-mystify derivatives, the measurement of market risks and the systems required. Any company involved in the oil market, especially those using the more elaborate derivative contracts that form such a large part of many oil traders' portfolio of activities, should look very carefully at its methods of managing and containing the risks associated with trading derivatives and satisfy itself that the necessary controls and reporting systems are in place.

The Group of Thirty continue to play a role in making recommendations of best practices for front, middle and back office functions and their reports can now be accessed via the internet.[*] These surveys of industry practice make interesting reading, demonstrating as they do that some companies are continuing to put their business at considerable risk by not following even the most basic of best practice recommendations. Additional information can be obtained from the Bank for International Settlements[†] and the International Swaps and Derivatives Association.[‡] These organisations, amongst others, are helping to co-ordinate the process following on from the G30 initial report.

An area of current contention is that of accounting practices for derivative business (*see Chapter 14*). Increasingly government tax authorities are insisting that all derivatives taken out as hedges are matched to the corresponding physical transaction at the time rather than claiming a derivative position was a hedge rather than speculative once the company gets to completing their accounts. Following on from this they are recommending that mark-to-market accounting is best practice, that is all outstanding positions are marked against today's price, rather than hedge accounting which they consider can manipulate and mask the true financial position of a company.

One particularly important area of risk management that requires considerable caution is that of the legal risk associated with doing business with government or municipality organisations. During the mid-1990s a number of municipal bodies decided they would use derivatives such as long term interest rate swaps to manage their finances and to make money. When

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[§] Derivatives: Practices and Principles, Group of Thirty Global Derivatives Study Group, July 1993

[*] www.group30.org

[†] www.bis.org

[‡] www.isda.org

these deals turned sour they claimed that they did not have the authority to conclude the deals, and the courts found in their favour. Trading companies should therefore be cautious in transacting with such bodies, and ensure that their counter-parties do indeed have regulatory approval for the transactions they wish to carry out.

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13.2 Assessing credit risk

When judging the credit worthiness of a prospective trading partner, there are a number of considerations and a variety of information which must be reviewed. Some of this will be background information which can be updated at regular intervals, for example company accounts if filed, staff, term contracts, types of business, capital assets etc. However, much of it will need to be updated more often, and even checked immediately before concluding a deal.

13.2.1 Amount of money at risk

If the amount of money at risk is relatively small in terms of oil trading deals, then the credit worthiness of the potential trading partner is not of such great concern. For example, a barge lot of 2,000 metric tonnes of fuel oil costing $60 per tonne would be worth in total $120,000. However, a one million barrel ULCC (Ultra-large Crude Carrier) of Dubai crude costing $20 per barrel would be worth $20 million. In the case of the latter deal, very carefully consideration should be made to the credit worthiness of the trading partner.

Having said that, though, to some small trading companies the barge deal could be a significant amount of money, and to a large trading company with assets in the millions, the ULCC of Dubai is just one of many deals they would transact in a day. So the size of the financial exposure should be judged against the prospective trading partner's own financial standing. Equally if your own financial situation is shaky, then any deal, however small, must be carefully checked for financial security.

13.2.2 Political and country risk

If a cargo of oil is being sourced or delivered into a part of the world which has been the subject of recent political instability, care must be taken to ensure that all the correct channels are used for negotiations and payments. Although much political risk cannot be prejudged since insurrections can occur without any prior warning, there are areas of the world which are known to be politically unstable. This risk has to be weighed up against the reward from concluding the deal.

A trader transacting much of his business in these more difficult parts of the world should take time to keep himself up to date with the political events, and to keep his ear to the ground about possible changes which might cause problems or even render his transactions worthless. Many Eastern European countries, for example, require that business be transacted via the correct governmental departments, and government controlled banks. Any trader looking to do business in these countries should make sure that he is fully aware of these correct channels and take advice from the appropriate trade bureaux.

13.2.3 Reputation of trading partner

Although the industry is an international one, the number of active players is relatively small for each part of the market, for example companies trading in Russian fuel oil might amount to only 20. Through these close knit groups, information about companies, especially if it is unfavourable such as reneging on a deal, gets disseminated quickly. Records should therefore be kept, having made attempts to confirm or refute any rumours, for future reference.

Other considerations include whether this potential trading partner is known to be experienced in the area of the market which he is now offering to do business in, or is this a new venture for him into oil per se or a different part of the oil market? Obviously traders need to diversify, and they will have to start somewhere before moving up the learning curve, but inexperienced traders may make mistakes or not be familiar with the importance of certain specifications. This can cause as many problems if you are the inexperienced trader as it can if you have the inexperienced trader on the other side of the deal.

If you are moving into a new market, you must familiarise yourself with the important factors involved in trading in that market. Otherwise, you could leave yourself open to being taken advantage of by more experienced and perhaps less scrupulous traders who might take advantage of your ignorance to off-load off-spec or otherwise incorrect cargoes. In this case a particularly careful eye must be kept on contractual terms, and operations.

Has the trader got sound supply contacts? If you are buying from a trader who is in turn buying it from someone else, if his seller reneges or supplies off-spec oil, you could inherit their problem in some form or other. Is the operations department of the company effective and reliable? A deal which can be making good profit on paper can end up being a loser if you have to spend a great deal of time and money on demurrage bills, quality problems and so on.

13.2.4 Financial standing of trading partner

Any good credit monitoring system should include as much base financial data on potential trading partners as possible. Included in this should be an indication of the size of the company, and a feel for the overheads. For example, a large trading company may have to cover overheads of $1 million per month for their office before they ever make money for the shareholders. This puts tremendous pressure on the company to do high volume, profitable business to cover these costs.

It is also important to know the extent of capital backing for the company, to gauge whether a bad position can be financed internally. Much of this information is extremely difficult to obtain for trading companies, since few are publicly quoted companies. Most are privately owned with no requirement to publish results or to divulge financial information which they tend to keep close to their chests.

13.2.5 Current exposure of trading partner

One of the more difficult evaluations that has to be made is to assess the current market exposure of a potential trading partner. While it is clearly important to avoid dealing with a company that might be over-exposed and therefore at risk from defaults by other companies, it is extremely difficult to obtain factual information on this issue.

If a potential trading partner already has a number of loss making positions, and its financial standing is not good anyway, you would be wise to avoid transacting business with the trader without very secure financial guarantees. Naturally, a trader does not want its position known on the market, since this would restrict its ability to trade out of its loss making positions. It is not going to divulge its book to anyone.

Information about traders' positions therefore has to be gleaned from other market sources, and collated so that a sensible estimate can be made. By necessity, this will be a guess and will be far from accurate. Indeed, with many traders hedging their positions on the futures markets or doing complicated spread and arbitrage business between various markets, it is always risky to second-guess traders' positions.

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13.3 Limiting financial exposure

Once an assessment of the various parameters affecting a potential trading partner's credit worthiness and the possible risks involved has been made, it is necessary to decide on the credit terms to be used in the contractual terms of any deal.

In some cases it may be decided that the credit worthiness of the company is so bad that it excludes the possibility of doing any business with the company. This is not unusual, since many companies have strict limits about the size of any companies they may do business with, and this may keep their list of possible trading partners short. As a result, some well known but small companies may be excluded from the list of potential trading partners that another company will deal with.

13.3.1 Open credit

If you are confident that the company concerned carries no financial risk in terms of guaranteeing payment for a deal, then you might consider doing business on open credit. In which case, the seller of the oil has no formal financial guarantee that payment will be made for the oil except that given by the company buying within the terms of the contract. Because of this, open credit is reserved generally for business done with oil majors and multinationals.

13.3.2 Parent company guarantee

If a trading company is part of a large organisation which has substantial funds, then business transacted by the trading company which is acting as the principal may be secured using a financial guarantee supplied by the parent company. Effectively this means giving the trading company open credit and care must be taken that the parent company has been carefully screened for its own credit worthiness. Some traders came unstuck in 1991 when a well known trader with whom people traded on parent company guarantee sent shock waves through the industry as its parent company faltered under fraud charges.

13.3.3 Letter of Credit

Much oil trading business is concluded using a Letter of Credit (LC) as a financial guarantee. Once in place, an LC guarantees that, so long as the correct documents, or a Letter of Indemnity

(LOI), are presented to the buyer's bank, the buyer's bank will honour the LC and make the appropriate payments due for the cargo.

The following documents are generally required by the buyer's bank before it will honour the Letter of Credit:

1. A signed commercial invoice indicating the destination of the cargo.
2. 3 out of 3 of the original Bills of Lading issued or endorsed to the order of the buyer.
3. A certificate of quality and quantity.
4. An insurance certificate.

A Bill of Lading is a legal document of title to the oil, and is essentially a receipt by the master for the cargo. Unless a buyer is in possession of a Bill of Lading he cannot claim a cargo. Originally when shipping moved considerably slower than now, three Bills of Lading were actually needed so that one could be sent on ahead, on board a faster clipper vessel. In order to collect the goods from the vessel, this advance copy of the Bill of Lading had to be presented to the master before he would release his cargo.

The documents must always be presented to the bank, and the Letter of Credit is always brought into effect in a deal financially guaranteed by the LC. A bank would normally charge between 0.10 and 0.15 per cent of the total value of the cargo, although there may be a fixed charge lower limit. These fees are negotiable and will be increased if the LC is confirmed by the bank of both parties. This may occur if the seller is unsure about the calibre of the buyer's bank or the country in which the LC opening bank is located.

The normal contractual phrase which would appear in the contract would state that "*the buyer is to open an irrevocable Letter of Credit in a format and from a Bank acceptable to the seller*". The seller would then be guided by his own bank who might suggest that they guarantee it as well in certain cases. In which case, the seller and buyer would have to come to some arrangement about sharing this additional cost.

The contract would normally stipulate that the LC be opened on nomination of the vessel, even specifying the time of the day by which it must be opened. If the LC is not opened in time, the seller has the right to declare the deal null and void, although under normal trading conditions they are unlikely to do so. However, if the market has subsequently moved up, the seller may well be looking for an opportunity of re-offering the cargo at a higher price.

One way of overcoming problems attached to the late set up of a Letter of Credit, in cases where both parties are keen for the deal to progress, involves each party's respective banks ringing the other to check whether the LC is being prepared, even requesting this statement in writing. In normal cases, the LC must be valid for 30–45 days after Bill of Lading or at least until 15 days, say, after payment is due.

Although a Letter of Credit provides an excellent guarantee, there are a number of pitfalls which can render the guarantee invalid if they are not handled correctly.

First, the payment will only be made if the correct documents are presented to the bank. If they cannot be presented to the bank then payment will not be made, unless some guarantee has previously been given that the seller has ownership of the cargo and will indemnify the buyer against all legal costs related to the loss of the documents. This is generally done in the form of a Letter of Indemnity (*see below*) and a Letter of Credit must always contain the option for payment to be made against a Letter of Indemnity.

Secondly, a Letter of Credit is issued by a bank. It is therefore only as secure as the bank. Thus it is vital that the LC should be issued by a first class bank, and contracts will normally specify this when stipulating that a Letter of Credit is necessary.

Finally, a Letter of Credit is a purely financial undertaking by a bank and therefore does not take account of changes in the actual specification of the contract or cargo. An LC is therefore a very powerful tool, particularly if it gets into the wrong hands. As well as committing the buyer's bank to make the payments due, it also ties the seller to do certain things.

For example, if the Letter of Credit specifies that the quality should be 1 per cent max, but the certificate of quality says 0.4 per cent, the bank may say that the documents are not in order and that they want a certificate of quality saying that the cargo loaded was 1 per cent max before making payment. In extreme cases you might lose the cargo value or it can cause considerable delays in receiving payments, which costs money.

The format of any Letter of Credit should therefore be scrutinised for any possible loop-holes in order to make it the effective guarantee that it should be if it is worded correctly (*see Chapter 17*).

13.3.4 Standby Letter of Credit

As an alternative to a full Letter of Credit, a standby Letter of Credit may be used. In the US this type of arrangement is referred to as a Guarantee. A standby Letter of Credit is also a guarantee given by a bank that payment will be made, on presentation of the correct documents, but is generally only called upon if payment is not readily made for some reason.

Unlike a deal guaranteed by the LC, the documents would normally be presented directly to the buyer rather than to the bank in order to generate payment. Only if for some reason payment is not made will copies of the documents go to the bank together with a statement saying that the invoice has been presented, but payment not made. The bank will then make the payment to the seller.

A standby Letter of Credit is a simpler document than a full LC. However, it is generally only used when the amount of money involved in the transaction is small, or the companies involved are very large and therefore likely to be more credit worthy. As a standby LC is not usually drawn, the fees charged by banks are slightly lower.

13.3.5 Letter of Indemnity

The purpose of a Letter of Indemnity (LOI) is to indemnify the buyer against the seller not having the necessary documents, especially the original Bills of Lading, to prove that he has title to the oil which he has sold. When a LC is used a LOI must be set up and incorporated as an option within the LC. Where a LC is not used, then a LOI is still required if documents are not available. The responsibility for issuing a LOI rests with the seller.

In most cases, unless one is dealing with a major oil company or a multi national, the LOI is countersigned by a bank for additional security. Among other things, the wording of the LOI says that "*the seller warrants that they have marketable title to the cargo free and clear of any lien or encumbrance*". This last phrase is important, because it ensures that the buyer inherits no problems from parties further up a chain. The LOI also indemnifies the buyer against all costs and damages from third parties claiming title. Thus all oil deals will be paid either against documents or a LOI.

A LOI expires when the correct documents are supplied to the buyer's bank. In cases of mislaid documents, or in cases of long chains, some of which have amounted to over 100 players, this can take a considerable length of time. The cost of setting up a LOI is negotiable, but is likely to be in the region of 0.05 per cent of the total value of the cargo, and is paid for by the seller. Fees for bank LOIs may be negotiated as a flat rate on a per annum basis.

13.3.6 Letter of Intent

A Letter of Intent is a document supplied by the buyer and sent to the seller's bank, expressly confirming that the buyer, has bought a specific cargo at a specific price or formula, and therefore will be paying this amount into the seller's bank on a particular day.

In terms of financial security such a letter means very little. However, it may serve to appease an anxious seller's bank. In most cases it also helps the seller to re-finance the transaction with his bank. It is generally used by major oil companies and multinationals, who would not expect to issue letters of credit.

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13.4 Methods of credit monitoring

13.4.1 Banks

Banks can be a good source of information and advice about credit monitoring and the credit worthiness of other companies. Your own bank is likely to have heard of many of the companies you are likely to do business with, and if they have not, they will be well placed to use the banking network to speak to other bankers to find out what information is available. Obviously it is in your bank's interest to help you maintain a good and effective credit monitoring system for all business you transact.

It is also possible for you to contact your potential trading partner's bank directly and ask pertinent questions. Whilst they are not obliged to answer all your questions, especially without consulting their client, they are likely to be able to supply you with information which will help you to reach a decision about whether to progress further with any business.

For example, a bank is not obliged to divulge ownership details, nor will they hand over financial information unless their client agrees, but much information can perhaps be obtained from what is not said, as much as from what is said. Banks obviously will only take clients on if they themselves consider them credit worthy. They will want to see their potential client's balance sheets, be supplied with extensive background information including ownership details, and will themselves perhaps contact a specialised credit monitoring organisation, who can supply information such as the reputation of the company and the traders in the company.

Depending on the outcome of these investigations, the running of the account with the bank will vary. For example, whilst realised losses might not be payable until the position is liquidated, some banks will ask smaller clients, especially those with perhaps offshore ownership, to post margins at intervals, rather than when the position is liquidated. Some might ask for an amount greater than the margins to be deposited, even asking for the full value of the cargo in some circumstances when the account is new.

However, while checks by banks on new clients are exhaustive, in most cases banks will leave their clients to do their own credit checks on their trading partners. They might recommend that they monitor credit on an ongoing basis, but would not insist that this be handled in a particular way.

It is an important legal protection for banks, that while they will advise, if requested, about the financial status of possible business partners, the ultimate decision about who to trade with is made by the client, the bank having no control over the activities of their clients. Though this has never been successfully legally tested, banks are concerned that a creditor of a bankrupt company might sue the company's bank on the basis that it had overall control. Most bankers will therefore insist that they do not participate or benefit from the business of their client, but assist their clients in concluding business. Whilst this assistance is not always free, much free advice can be obtained by regular communications and a good relationship with one's bank.

13.4.2 Specialist credit monitoring organisations

There are a number of different types of specialist credit monitoring organisations that can help you assess the credit-worthiness of a potential trading partner. These include:

Basic credit information suppliers

These are companies that spend their time collating readily available information about other companies, and supplying this information, for a fee, in a variety of different ways. Such companies only tend to have limited data on oil companies, especially those which are not limited companies, or the continental equivalent.

One example of such an organisation is **Dun and Bradstreet**, now trading as **D&B**. **D&B** was founded nearly 160 years ago and now holds business information on 65 million companies worldwide. Information is gathered in 214 countries. However, their coverage of information on oil companies is limited by the secrecy of these companies, many of which are privately owned and registered in countries where it is extremely difficult to obtain ownership details.

Most of the information that **D&B** supplies is published information which they collate and transmit in a user friendly way, including the internet.[§] However, they can serve a purpose for supplying the latest published financial information about some companies. **D&B** can also supply products and services tailor-made to your own requirements, such as competitor analysis or corporate analysis on a specific company covering ownership details and financial information.

[§] www.dnb.com

Other companies supplying similar information include **Graydon International,*** **Standard and Poor's,**† **Moody's,**‡ and **Equifax**** (now includes **Infocheck**).

Company accounts specialists

If the information required is mainly financial information about well known, and therefore well reported, companies, a company such as **John S. Herold**†† might suit your needs. They analyse and appraise the accounts of a specific but large number of oil companies in the US and elsewhere. As well as looking at the companies' annual accounts and their stock exchange values where appropriate, they will make estimations on the amount, value and life of oil and gas reserves owned by the company, estimate future operating profits plus many other factors. The information is supplied at regular intervals, and is not customer generated but a standard range of companies are analysed at differing times of the year. Thus this type of service is very useful for adding to one's own in-house monitoring system, but is of little use on its own for the immediate response to a trader's query "Is this company a suitable trading partner right now?"

Specialist company information suppliers

In order to meet more comprehensively the needs of an oil trading company which is conscientiously monitoring credit risk, one needs to turn to a specialist organisation set up specifically for the needs of the credit departments of oil companies, such as **MRC Business Information**.§ **MRC** is based in Oxford, England and offers a variety of services that draw on an extensive data-bank of international oil companies, including companies registered in sheltered tax havens.

MRC responds to clients' requests as well as supplying standard reports companies in the energy sector using a database of information on some 90,000 marine and related companies. The response to an enquiry is researched specifically for each client, with the information kept on a database updated each

* www.graydonint.com
† www.standardandpoors.com
‡ www.moodys.com
** www.equifax.com
†† www.herold.com
§ www.mrcinfo.com

time information on that company is requested. This means that the client can focus the research on the aspect of the company which is of most interest such as its Far East office or its trading in Russian oil, or ask **MRC** to investigate rumours such as "the company is very long in a falling market". The answers to queries can be written reports, verbal replies or even online for shipping companies.

Such a tailor-made service is, naturally, more expensive than the other services mentioned above, but costs must be weighed against the scale of the risks involved. It is also limited by the secrecy of some companies.

Another company which supplies similar reports, although mainly on shipping companies, is **Dynamar BV**§ in the Netherlands.

13.4.3 Credit associations

The **International Energy Credit Association (IECA)**,* is the largest association of petroleum industry credit and financial executives in the world, with membership covering oil trading companies spread over the United States, Canada and Europe. The IECA seeks to promote the interests of credit and financial professionals in the oil industry, and to assist members in acquiring up to date skills and techniques, so helping them to make improved contributions to their companies and to the well being of the industry.

The IECA organises annual conferences in the US attended by many members and which deal with matters of real and practical concern to the members through a mixture of speakers drawn from government, academia, banking, industry and the legal profession, and through informal discussion groups. Annual conferences are also held in Canada and Europe by the Canadian Credit Group and the European Division of the IECA. But perhaps the greatest benefit from membership of this organisation is the opportunity it provides for networking amongst the members, in particular through membership of the Association's Crude Oil and Refined Products Credit Group (CORP), which enables members to keep up to date with risk management developments.

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§ www.dynamar.com
* www.ieca.net

13.4.4 In-house credit monitoring

Like so many service industries, the services offered by the companies mentioned above could be handled in-house, by buying in the expertise and committing staff to the tasks involved. However, the information that a credit person working for an oil company can obtain is likely to be different, and may be more limited, than the information which can be obtained by a third party who has no vested interest in the information other than obtaining it and disseminating it to his client for a fee.

The organisations mentioned above spend their time researching and collating the information. To match this would require staff devoted to this task, and even then many companies would be less likely to talk to you as a potential competitor than they might an information gathering organisation. On the other hand, if one is making an enquiry about a company with a view to doing business with that company, they may well be happy to supply information to you about themselves, more so than they might supply to a credit monitoring company.

However, it might be very difficult for you to obtain information about the company from its trading partners. In addition, the staff in the information gathering companies are likely to have a bevy of contacts built up over a long period of time, all of whom can supply pieces of information which can then be put together in an easily usable format, thereby saving your staff considerable time and effort.

As a trader you will come across much useful information about other trading companies in the course of the day. In order not to waste this information, a system should be set up to allow for easy input of this to help build up an in-house database of existing and potential trading partners. It is vital that any system created should be user friendly otherwise it will not be used and therefore not regularly updated as information is obtained. At a more mundane level, it also helps if credit staff are physically located close to traders. This makes them not only easily accessible to traders to answer their queries, but also within earshot of traders' conversations from which they might well be able to glean snippets of information which might not otherwise be passed on to them.

Any in-house credit monitoring system should therefore use the full range of the services available, depending on the types of trading partners, the size of the business and the status of the company itself.

13.4.5 Internet credit sources

The massive rise in popularity of the internet as a source for information has provided interested parties with a wealth of online information about companies that is now relatively easy to access at the press of a button. Access to up to date company accounts is much easier and quicker. Gone are the days of waiting for the annual reports to be printed and posted out. Many company sites also have help pages where questions can be asked of the company. Searches on newspapers and specialist publications are also easier and faster.

In addition a number of specialist credit monitoring organisations make their services available on-line (*see 13.4.2 above*). Useful lists of credit reporting services are also compiled by internet-based companies such as **Creditworthy**.[§] However, it should be remembered that much can be implied through voice inflection which is totally lost through the internet or e-mail responses. Nothing can replace the quality of information, particularly around sensitive areas such as credit status, that people may be prepared to disclose either over the phone or face-to-face as opposed to in written or internet form.

[§] www.creditworthy.com

Appendix 13.1 Costs of credit control

Contractual terms	Cost	Who pays?
Open Credit	Nil	
Parent Company Guarantee	Nil	
Letter of Credit	0.1–0.15%	Buyer, the cost of his bank
Standby Letter of Credit	0.5–0.1%	Seller, the cost of his bank
Letter of Indemnity	0.05%	Seller
Letter of Intent	Nil	

Credit monitoring organisations	Approximate cost
Basic credit information	$50–100 per basic company profile
Company accounts specialists	$1,000–1,500 for 100 companies
Specialist company information	$750–1,500 per full company report

In-house: staff, computer systems, training courses, conferences plus purchased information.

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Appendix 13.2 Sample Letter of Credit for a CIF transaction

TO: SELLER
FROM: BUYER'S BANK

WE HEREBY OPEN OUR IRREVOCABLE DOCUMENTARY LETTER OF CREDIT NUMBER 000.00:

BY ORDER AND FOR ACCOUNT OF:	BUYER
IN FAVOUR OF:	SELLER
FOR AN AMOUNT OF:	TOTAL VALUE OF CARGO ± 10%
VALIDITY:	UNTIL 31 JANUARY 2002

AND AVAILABLE BY DEFERRED PAYMENT WITH VALUE 10 DAYS FROM/AFTER BILL OF LADING AT THE COUNTER OF OPENING OR ADVISING OR CONFIRMING BANK AGAINST PRESENTATION OF THE FOLLOWING DOCUMENTS IN ONE ORIGINAL AND 3 COPIES, UNLESS OTHERWISE REQUESTED:

1. – DULY SIGNED COMMERCIAL INVOICE (INDICATING DESTINATION OF CARGO)
2. – 3/3 ORIGINAL CLEAN 'SHIPPED ON BOARD' OCEAN BILLS OF LADING ISSUED OR ENDORSED TO THE ORDER OF BUYER OR BUYER'S BANK MARKED 'FREIGHT PREPAID' OR 'FREIGHT PAYABLE AS PER CHARTER PARTY' OR 'FREIGHT PAYABLE AS AGREED' OR 'FREIGHT PAYABLE AS ARRANGED'. B/L TO BE ORIGINALLY SIGNED BY MASTER OR VESSEL AGENT AT LOAD PORT.
3. - CERTIFICATE OF QUALITY ISSUED FOR LOAD PORT EVIDENCING PRODUCT IS NORMAL RUSSIAN GASOIL HAVING POUR POINT MAX -10 DEG C AND SULPHUR MAX 0.2 WT PER CENT (ALTERNATIVELY IF CARGO IS NOT RUSSIAN, THEN CERTIFICATE OF QUALITY ISSUED AND/OR COUNTERSIGNED BY . . . WOULD BE ESSENTIAL).
4. – NEGOTIABLE INSURANCE CERTIFICATE OR POLICY ISSUED BY XXXXX, FOR MINIMUM 100 PER CENT OF THE CIF INVOICE VALUE WITH PARTICULAR AVERAGE, SUBJECT TO PARAGRAPH 2 P2 OF THE TRANSPORT INSURANCE RULES, INCLUDING MIXING AND/OR CONTAMINATION INCLUDING LEAKAGE AND/OR SHORTAGE IN

EXCESS OF 0.5 PER CENT EACH TANK OR ON THE WHOLE AND/OR NEGOTIABLE WESTERN INSURANCE CERTIFICATE OR POLICY ISSUED FOR MIN 110 PER CENT OF CIF INVOICE VALUE AS PER BULK OIL CLAUSES INCLUDING THE RISKS OF LEAKAGE AND/OR SHORTAGE HOWSOEVER ARISING SUBJECT TO AN EXCESS OF 0.5 PER CENT TRADE ULLAGE ON WHOLE SHIPMENT, INCLUDING THE RISKS OF CONTAMINATION HOWSOEVER ARISING IRRESPECTIVE OF PERCENTAGE. ORIGINAL INSURANCE CERTIFICATE(S) TO BE ISSUED OR ENDORSED TO BUYER COMBINATION OF BOTH FOR AT LEAST 100 PER CENT OF CIF INVOICE VALUE ACCEPTABLE.

IF DOCUMENTS 2–4 ARE NOT AVAILABLE ON DUE DATE, PAYMENT WILL BE MADE AGAINST:

1. COMMERCIAL INVOICE AS UNDER DOCUMENT NO 1
2. SELLER'S LETTER OF INDEMNITY COUNTERSIGNED BY BANK . . . IN THE FOLLOWING FORMAT:

[SEE APPENDIX 4 FOR SAMPLE LETTER OF INDEMNITY]

COVERING: 19,224.354 METRIC TONS OF NORMAL RUSSIAN GASOIL ON M/T "THE GOOD SHIP LOLLIPOP" /SUB AVAILABLE EX SOVIET BALTIC SEA.

PRICE: $170 PER METRIC TON CIF ONE OR TWO SAFE BERTHS/PORTS HAMBURG - AMSTERDAM - ROTTERDAM - ANTWERP ON NON-EEC BASIS ON B/L QUANTITY.

DELIVERY: DURING THE PERIOD . . . IN SELLER'S VESSEL "THE GOOD SHIP LOLLIPOP" OR SUITABLE SUBSTITUTE AS PART CARGO CIF ONE OR TWO SAFE BERTHS/PORTS HAMBURG-AMSTERDAM-ROTTERDAM-ANTWERP WITH B/L DATED 5 JANUARY 2002 IN VENTSPILS.

SPECIAL CONDITIONS:
– PARTIAL SHIPMENTS AND TRANS-SHIPMENTS PROHIBITED
– PART CARGO ALLOWED
– CHARTER PARTY B/L ARE ACCEPTABLE
– DOCUMENTS PRESENTED LATER THAN 21 DAYS AFTER B/L DATE BUT STILL WITH THE VALIDITY OF THE CREDIT ARE ACCEPTABLE

– PHOTOCOPIES FOR COPY DOCUMENTS ARE ACCEPTABLE
– SHIPPING DOCUMENTS SHOWING LARGER OR DIFFERENT DISCHARGE RANGE THAN ALLOWED FOR UNDER PARAGRAPH DELIVERY HERE ABOVE ACCEPTABLE
– SPELLING MISTAKES IN VESSEL'S NAME ACCEPTABLE
– BILL OF LADING AND OTHER SHIPPING DOCUMENTS (EXCEPT INVOICE AND LETTER OF INDEMNITY) ISSUED BY THIRD PARTY ACCEPTABLE
– TELEX INVOICE, TELEX LOI, BOTH DULY TESTED, ACCEPTABLE

REIMBURSEMENT
UPON RECEIPT AT OUR (BUYER'S BANK) COUNTERS IN GENEVA OF DOCUMENTS ISSUED IN STRICT CONFORMITY WITH THE TERMS AND CONDITIONS OF THE PRESENT LETTER OF CREDIT, WE UNDERTAKE TO COVER YOU ON DUE DATE AS PER YOUR INSTRUCTIONS PROVIDED HOWEVER THAT SUCH DOCUMENTS REACH OUR BANK NOT LATER THAN 10 A.M. GENEVA TIME ON DUE DATE, OTHERWISE PAYMENT WILL BE EFFECTED WITH VALUE 1 BANK WORKING DAY.

UNLESS OTHERWISE STATED, THIS DOCUMENTARY CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS, I.C.C. BROCHURE NO 400 (1983 REVISION).

THIS TELEX MESSAGE REPRESENTS THE OPERATIVE CREDIT INSTRUMENT AND NO WRITTEN CONFIRMATION WILL FOLLOW.

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Appendix 13.3 Sample Letter of Credit for a FOB transaction

TO: OPENING BANK
FROM: BUYER

PLS. OPEN STILL TODAY BY TELEX FOLLOWING IRREVOCABLE DOCUMENTARY LETTER OF CREDIT NO . . . , WHICH PLS ADVISE TO BENEFICIARY WITHOUT ADDING YOUR CONFIRMATION:

BY ORDER AND FOR ACCOUNT OF: BUYER (FULL TITLE AND ADDRESS)
IN FAVOUR OF: SELLER (FULL TITLE AND ADDRESS)
FOR AN AMOUNT OF US DOLLARS: . . . PLUS/MINUS 10 PER CENT (IN WORDS UNITED STATES DOLLARS . . .)
PAYABLE 30 CALENDAR DAYS AFTER BILL OF LADING DATE AT OUR COUNTERS IN . . . AGAINST PRESENTATION OF THE FOLLOWING DOCUMENTS TO BE ISSUED IN ONE ORIGINAL PLUS 4 (FOUR) COPIES UNLESS OTHERWISE STATED:

1. SIGNED COMMERCIAL INVOICE
2. 3/3 (FULL SET) ORIGINAL MARINE BILLS OF LADING ISSUED OR ENDORSED TO THE ORDER OF . . . MARKED: “FREIGHT PAYABLE AS PER C/P” / “CLEAN ON BOARD”, SHOWING DESTINATION . . . , PLUS 6 NON-NEGOTIABLE COPIES
3. EEC-QUALIFICATION CERTIFICATE “T2L” ISSUED AND STAMPED BY CHAMBER OF COMMERCE OR CUSTOMS AUTHORITIES (DEPENDING ON ORIGIN AND DESTINATION – OTHER CASES REPLACED BY “CERTIFICATE OF ORIGIN ISSUED AND/OR COUNTERSIGNED BY . . .)
4. CERTIFICATE OF QUANTITY ISSUED AND/OR COUNTERSIGNED BY INDEPENDENT INSPECTOR FOR LOAD PORT
5. CERTIFICATE OF QUALITY ISSUED AND/OR COUNTERSIGNED BY INDEPENDENT INSPECTOR FOR LOAD PORT SHOWING THE PRODUCT MEETS THE FOLLOWING GUARANTEED SPECIFICATIONS:

[INSERT LIST OF SPECIFICATIONS HERE]

6. ULLAGE REPORT ISSUED AND/OR COUNTERSIGNED BY INDEPENDENT INSPECTOR FOR LOAD PORT (OPTIONAL)
7. TIME SHEET COUNTERSIGNED BY INDEPENDENT INSPECTOR AND MASTER (OPTIONAL)
8. MASTER'S RECEIPT FOR SAMPLES, COUNTERSIGNED BY MASTER
9. MASTER'S RECEIPT FOR COPY OF ALL DOCUMENTS MENTIONED HEREIN EXCEPT FOR DOC NO. 1

IN THE CASE OF NON-AVAILABILITY OF ALL OR PART OF THE ABOVE LISTED DOCUMENTS 2 TO 9, THE LETTER OF CREDIT MAY BE PAYABLE AGAINST PRESENTATION OF THE FOLLOWING DOCUMENTS:
1. COMMERCIAL INVOICE AS ABOVE
2. LETTER OF INDEMNITY ISSUED IN THE FOLLOWING FORMAT

[SEE APPENDIX 4 FOR SAMPLE LETTER OF INDEMNITY]

PRICE CLAUSE: . . .
COVERING: SHIPMENT OF . . . MTONS OF . . . (PRODUCT) FOB . . . DURING THE PERIOD . . . ON M/T "..."

SPECIAL CONDITIONS
1. CHARTER PARTY BILLS OF LADING ACCEPTABLE.
2. PARTIAL SHIPMENTS AND TRANS-SHIPMENTS NOT PERMITTED.
3. PHOTOCOPIES INSTEAD OF COPY DOCUMENTS ACCEPTABLE.
4. ALL BANK CHARGES AT OPENER'S BANK ARE FOR OPENER'S ACCOUNT. ALL BANK CHARGES AT BENEFICIARY'S BANK ARE FOR BENEFICIARY'S ACCOUNT.
5. TELEX INVOICE AND DULY TESTED TELEX LETTER OF INDEMNITY ARE ACCEPTABLE WITH HARD COPY TO FOLLOW.
6. THE L/C AMOUNT IS TO FLUCTUATE AUTOMATICALLY ACCORDING TO PRICE CLAUSE WITHOUT FURTHER AMENDMENT FROM OUR PART.
7. IN CASE 1/3 ORIGINAL BILL OF LADING AND/OR ORIGINAL "T2L" IS PLACED ON BOARD, THEN THIS IS ACCEPTABLE AND DOCUMENTS NO. 2, 3 AND 9 TO EVIDENCE SAME AND LETTER OF INDEMNITY TO REFLECT SAME.
8. DOCUMENTS PRESENTED LATER THAN 21 DAYS AFTER B/L DATE ARE ACCEPTABLE.
9. IF DUE DATE FALLS ON A SUNDAY OR MONDAY NY

BANK WORKING DAY, THEN PAYMENT TO BE MADE . . . (TO BE IN ACCORDANCE WITH CONTRACT).

THIS CREDIT EXPIRES AT OUR COUNTERS ON . . .

WE HEREBY ENGAGE WITH THE BENEFICIARY THAT DOCUMENTS DRAWN UNDER AND IN STRICT COMPLIANCE WITH THE TERMS OF THIS CREDIT WILL BE DULY HONOURED UPON PRESENTATION AS SPECIFIED.

UPON RECEIPT OF DOCUMENTS STRICTLY IN CONFORMITY WITH L/C TERMS WE UNDERTAKE TO COVER YOU AS PER YOUR INSTRUCTIONS WITH VALUE 30 CALENDAR DAYS AFTER BILL OF LADING SUBJECT TO RECEIPT OF DOCUMENTS LATEST 2 WORKING DAYS PRIOR TO DUE DATE. OTHERWISE PAYMENT WILL BE EFFECTED 2 WORKING DAYS.

THIS TELEX IS THE OPERATIVE INSTRUMENT AND WILL NOT BE FOLLOWED BY A WRITTEN CONFIRMATION.

EXCEPT SO FAR AS OTHERWISE EXPRESSLY STATED HEREIN, THIS CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1983 REVISION) INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NUMBER 400.

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Appendix 13.4 Sample Letter of Indemnity

TO: BUYER, C/O BUYER'S BANK
DATE:

RE: SHIPMENT OF XXXXX MT OF NORMAL RUSSIAN GASOIL PER MT " GOOD SHIP LOLLIPOP" / SUB B/L DATED IN VENTSPILS COVERED BY DOCCRED NR. XXXXX OF BUYER'S BANK.

DEAR SIRS,
ALTHOUGH WE, SELLER, SOLD THE ABOVE MENTIONED CARGO TO BUYER WE HAVE BEEN UNABLE TO PROVIDE YOU WITH THE ORIGINAL SHIPPING DOCUMENTS INCLUDING 3/3 ORIGINAL CLEAN ON BOARD BILLS OF LADING ISSUED OR ENDORSED TO THE ORDER OF BUYER AS REQUESTED BY DOCCRED NO. XXXXX OF BUYER'S BANK COVERING THE SAID SALE.

IN CONSIDERATION OF BUYER'S BANK FOR ACCOUNT OF BUYER PAYING US FULL PURCHASE PRICE OF US $ XXXXX WE HEREBY TRANSFER TITLE TO YOU AND EXPRESSLY WARRANT THAT WE HAVE MARKETABLE TITLE TO SUCH CARGO FREE AND CLEAR OF ANY LIEN OR ENCUMBRANCE AND THAT WE HAVE THE FULL RIGHT AND AUTHORITY TO TRANSFER SUCH TITLE AND TO EFFECT DELIVERY OF SUCH MATERIAL TO YOU.

WE FURTHER AGREE TO EXERCISE OUR UTMOST EFFORTS TO LOCATE AND SURRENDER TO BUYER'S BANK FOR ACCOUNT OF BUYER AS SOON AS POSSIBLE THE ORIGINAL SHIPPING DOCUMENTS INCLUDING 3/3 ORIGINAL CLEAN ON BOARD BILLS OF LADING ISSUED OR ENDORSED TO THE ORDER OF BUYER AS REQUESTED BY DOCCRED NR XXXXX OF BUYER'S BANK AND TO PROTECT, INDEMNIFY AND SAVE YOU HARMLESS FROM AND AGAINST ANY AND ALL DAMAGES, COSTS, COUNSEL FEES (INCLUDING REASONABLE ATTORNEY FEES) AND ANY OTHER EXPENSES WHICH YOU MAY SUFFER BY REASON OF THE ORIGINAL BILLS OF LADING AND OTHER SHIPPING DOCUMENTS REMAINING OUTSTANDING, INCLUDING, BUT NOT LIMITED TO, ANY CLAIMS AND DEMANDS WHICH MAY BE MADE BY A CONSIGNOR, A

HOLDER OR TRANSFEREE OF THE ORIGINAL BILLS OF LADING AND OTHER SHIPPING DOCUMENTS, OR BY ANY OTHER THIRD PARTY CLAIMING AN INTEREST IN OR LIEN ON THE CARGO OR PROCEEDS THEREOF.

THIS LETTER OF INDEMNITY SHALL BE CONSTRUED, INTERPRETED AND GOVERNED BY THE LAWS OF ENGLAND (WITHOUT LIMITATION AS TO ITS FORM CONTENTS, VALIDITY AND ENFORCEABILITY, BUT WITHOUT REFERENCE TO ANY CONFLICT OF LAW RULES).

THIS LETTER OF INDEMNITY SHALL EXPIRE UPON TENDERING TO BUYER'S BANK FOR ACCOUNT OF BUYER THE ORIGINAL SHIPPING DOCUMENTS INCLUDING 3/3 ORIGINAL CLEAN ON BOARD BILLS OF LADING ISSUED OR ENDORSED TO THE ORDER OF BUYER AS REQUESTED BY DOCCRED NR. XXXXX.

Appendix 13.5 Sample Letter of Intent

FROM: BUYER
TO: SELLER'S BANK
COPY: SELLER

CONFIRMATION OF PURCHASE
BUYER HEREBY CONFIRM TO HAVE PURCHASED FROM SELLER 25000 MT +/– 10 PER CENT NORMAL RUSSIAN GASOIL AT A PRICE OF (US DOLLARS) 170 PER METRIC TONNE. DELIVERY TO BE IN 1 FULL OR PART LOT CIF ARA BASED ON CURRENT ETS VENTSPILS . . . , ACCORDING TO THE TERMS OF THE VERBAL AGREEMENT AS REACHED ON . . .

THE AFORESAID AGREEMENT MAY BE SUBJECT TO AMENDMENT BY AGREEMENT BETWEEN THE PARTIES AT ANY TIME AND, ALTHOUGH THE ABOVE STATEMENT IS MADE IN GOOD FAITH, IT SHOULD NOT BE TREATED AS A REPRESENTATION BY US AS TO THE ENFORCEABILITY OF THE AFORESAID AGREEMENT AND IS GIVEN WITHOUT RESPONSIBILITY.

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14 Accounting

Hanif Barma
Rachel Leigh
Matthew Price

14.1 Introduction

An enterprise may enter into oil trading activities for a number of reasons. Oil companies engaged in the exploration and production of oil may wish to secure prices to be obtained from future production. A refiner may wish to secure prices to be paid in the future for refinery feedstock purchases or proceeds from future production. Other companies may be active in the market with different motives – traders may take positions in the market to make a profit. The position they take will clearly depend on the trader's or speculator's expectations of future price movements.

In the case of the producer or refiner, the motive for the transaction is essentially precautionary with oil trading activity principally carried out as a hedge. In the case of the trader, the profit motive underlying dealings indicates that the transaction is speculative. The accounting treatment adopted for oil trading activities will depend on the nature of the transaction. In particular, profit recognition will be affected by whether a transaction is entered into as a hedge or for speculation.

In this chapter, we review the principal aspects of accounting for oil related products. It will consider accounting guidance available in the form of accounting standards and industry best practice. The accounting treatment applicable to all the major oil trading products or instruments – forwards, futures, swaps, options and physical hedges – will also be considered in turn illustrated by detailed examples.

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14.2 Accounting guidance

The development of oil related trading instruments, like that for financial instruments, has been rapid, with various new and complex instruments having been developed in response to a perceived need. As a result of this fast changing environment, little authoritative guidance has been developed in the United Kingdom. Accounting practice for the industry has therefore drawn upon guidance from the United States.

The primary source of authoritative guidance in the US is drawn from Financial Accounting Standard (FAS) 133 *Accounting for Derivative Instruments and Hedging Activities*, issued by the Financial Accounting Standards Board (FASB) in 1998 and by FAS 138 *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of FASB Statement No. 133* issued in 2000. FAS 133 applies to all entities following US Generally Accepted Accounting Principles (GAAP) and to all instruments it defines as derivatives. FAS 133 supersedes FAS 80, 105 and 119 and amends FAS 107 to make it consistent with FAS 133's measurement provisions. In the UK, brief reference is made to oil trading activities in the Oil Industry Accounting Committee's Statement of Recommended Practice (No.4), *Accounting for Various Financing, Revenue and Other Transactions of Oil and Gas Exploration and Production Companies*. In addition, guidance may be drawn from the Statement of Recommended Accounting Practice (SORP) on *Off-Balance Sheet Instruments and Other Commitments and Contingent Liabilities*. Although issued for the banking industry, useful reference can be made to the SORP.

The accounting principles discussed in this chapter are drawn from the above sources where applicable. However, as a result of the lack of authoritative guidance in the UK, it is possible for two enterprises in similar circumstances to account for a transaction involving an oil related commodity or instrument differently, giving rise to differing reported results. This potential divergence demonstrates the need for adequate disclosure of accounting policies and the nature of transactions in the enterprise's financial statements.

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14.3 General principles

In order to apply the principles of hedge accounting, under both UK and US GAAP, a number of criteria should apply:

- The futures transaction must be designated as a hedge of an existing asset, liability or firm commitment, or a specific anticipated transaction.
- The relationship between the hedge and the hedged item must be highly effective in achieving the offset of changes in those fair values or cash flows that are attributable to the hedged risk.

Under UK GAAP, if the conditions for hedge accounting are fulfilled, then changes in the market value of the hedging instrument are not accounted for immediately in the profit and loss account. Rather, any gains or losses are deferred in the enterprise's balance sheet (normally as an adjustment to the carrying value of the item being hedged). These are recognised and included in the profit and loss account on the realisation of the underlying hedged item or transaction. However, under US GAAP (FAS 133) the accounting treatment for items designated as hedges is rather more detailed and is discussed in more depth in the rest of this chapter. For example, a fair value hedge under FAS 133 changes in the market value of the hedging instrument are accounted for immediately in the profit and loss account and offset the changes in the market value of the hedged item.

If the item being hedged is accounted for at market value the hedge instrument itself is also accounted for at fair value and the gains and losses of the hedged item and the hedging instrument are offset within the profit and loss account.

Where any of the two criteria mentioned above do not apply, then the instrument concerned is accounted for at market value. Marking to market implies that changes in the market value of the instrument are accounted for immediately in the enterprise's profit and loss account. All speculative transactions are consequently accounted for on the mark to market principle. Marking to market will result in the setting up of a pre-payment or accrual, as appropriate, in the balance sheet.

Under FAS 133, reference is made to a number of different types of hedge, which can be described as follows:

- Fair-value hedge – a hedge of the exposure to changes (that are attributable to a particular risk) in the fair value of a recognised asset or liability or an unrecognised firm commitment.

- Cash-flow hedge – a hedge of the exposure to variability (that is attributable to a particular risk) in the cash flows of a recognised asset or liability or a forecasted transaction.

FAS 133 also refers to foreign-currency hedges, although this chapter makes reference to fair-value and cash flow hedges only.

14.4 Futures contracts

A futures contract is a contractual agreement between a buyer and seller, traded on a regulated exchange, to accept or take delivery of a standardised quantity of a specified grade or type of commodity at a specified date in the future. Futures also provide for cash settlement as an alternative to delivery.

14.4.1 Accounting for margins

One of the major characteristics of the futures market is the regular – often daily – cash settlement to reflect changes in the market value of an instrument. Typically, on execution of the futures contract, an initial margin is paid over to the broker in the form of cash. This initial margin simply represents a deposit. As a consequence, the payment of an initial margin should be reflected in an enterprise's balance sheet as a debtor and not as an expense or cost to the enterprise. For example, the payment of an initial margin of $10,000 to a broker would be reflected:

Dr	Debtors – margin account	$10,000	
Cr	Cash		$10,000

In addition to initial margins, the enterprise will be involved in making daily cash settlements to the broker. These variation margins (which are based on the closing prices of the contract) represent adjustments to the deposits held by the broker. These daily settlements, which can result in an additional margin payment to the broker or in cash refunds from the broker are accounted for in the same way as the initial margin.

Margin deposits should not be included in reported cash balances. Nor should they be incorporated in the cost or carrying amount of the hedged asset or liability. Instead, margin deposits should be included within debtors in the enterprise's balance sheet.

14.4.2 Accounting for commissions

Apart from payments to brokers in the form of margins, commissions will normally be paid to brokers. Such commissions will need to be identified separately from margin payments and expensed separately in the profit and loss accounts.

In practice, commissions may be deducted from any remaining margin deposit prior to the margin being reimbursed by the broker to the enterprise. Regardless of the timing of payment, the commissions represent a transactional cost and should be expensed on execution of a futures contract. The accounting entries required on entering a futures contract would be:

Dr	Profit and loss account	$x	
Cr	Creditors – commissions payable		$x

On settlement of the commission (possibly by offset against margin deposits) the accounting entries required would be:

Dr	Creditors – commissions payable	$x	
Cr	Cash (or debtors – margin deposit)		$x

14.4.3 Accounting for hedges

The accounting for the futures contract under consideration will be dependent on whether the contract is treated as a trade or a hedge. If it is treated as a hedge, gains or losses on the hedge should not be recognised in the profit and loss account of the period in which the price change takes place, but deferred and included in the profit and loss account in the period during which the underlying transaction matures or the hedged asset (liability) is realised (crystallises).

For example, where a crude oil producer enters into a futures contract in January for July delivery, profits and losses on the contract would be deferred until July when production of the expected quantity of crude oil is produced and sold. The gain or loss on the futures contract would be included within oil and gas revenues or turnover in July. The gain or loss would not be classified below the gross profit line in the profit and loss account. In practice, under UK GAAP, there is no need for any balance sheet recognition of the hedging instrument in January because the hedge relates to a future production stream.

Similarly, where the hedge is for an existing asset or liability of the enterprise, gains or losses on the futures contract are deferred in the same manner. No accounting entries affecting the balance sheet or profit and loss account are required until the asset is sold or the liability crystallises. For example, if a futures contract executed in June for the sale of gasoil (for November delivery) hedges physical gasoil stock which is not expected to be sold until the winter, unrealised gains or losses are not initially reflected. The gain or loss arising when the futures contract is closed out in November is included within sales revenues in the profit and loss account in November. It should be noted that if the stock is written down below cost to net realisable value in accordance with generally accepted accounting principles, part of the profit on the futures contract must be recognised to the extent of the loss on the physical stock.

An alternative approach is to recognise an asset, or liability in respect of the gain or loss, with a corresponding adjustment to the underlying hedged asset or liability. This treatment is typically adopted where the underlying hedged asset or liability is accounted for at market value. Until maturity, the gains or losses on revaluation will also be included in the enterprise's balance sheet as such within debtors or creditors and will not be reflected in the profit and loss account (except for those hedges treated under FAS 133 where the gains or losses on revaluation are recognised in the profit and loss account immediately and used to offset against the gains and losses on revaluation of the hedged item). Unrealised gains and losses should not normally be offset against initial margins included within debtors. In addition, the deferred gains or losses should be classified appropriately as long term or short term, consistent with the expected timing of recognition of the hedged sale.

In order to qualify for hedge accounting, the futures contract must satisfy certain criteria:

- designation as a hedge,
- reduction of enterprise risk (not required under FAS 133),
- an adequate degree of effectiveness.

These criteria are considered individually in more detail below. Where any of these criteria are not fulfilled at inception, the futures contract will be regarded as speculative and should be marked to market. Gains and losses in this case are recognised immediately in the profit and loss accounts.

The use of futures contracts as a hedge can be illustrated by way of example. Assume that on 1 January, an enterprise enters into 50 IPE Brent crude oil futures contracts for the sale of 1,000 barrels each (total 50,000 barrels) for 31 March delivery at a price of $20 per barrel. The enterprise has entered into the contract to hedge March production. Its broker requires an initial margin of $150,000 and commission of $1,000 to be paid. The accounting entries required on initiation of the futures contract are as follows:

Dr	Profit and loss account		
	– commissions payable	$1,000	
Cr	Cash		$1,000

(to reflect payment of broker's commission)

Dr	Debtors – margin account	$150,000	
Cr	Cash		$150,000

(to reflect payment of the initial margin)

On 31 January, the price of a futures contract for 31 March delivery is $22 per barrel and the broker imposes a margin requirement as follows:

Case 1: 100 per cent cash requirement for the change in the price per barrel

Case 2: 20 per cent cash requirement for the change in the price per barrel

In the first case, the additional margin payable to the broker is a further $100,000 ($2 × 50,000 barrels). The following accounting entry will be made at 31 January:

Dr	Debtors – margin account	$100,000	
Cr	Cash		$100,000

(to reflect the payment of the variation margin),

Dr	Other assets – deferred loss on futures contracts	$100,000	
Cr	Debtors – margin account		$100,000

(to reflect the reclassification of the constituent parts of the margin account).

Both the margin account ($150,000) and the deferred loss on futures contracts ($100,000) will be shown as current assets in the company's balance sheet at 31 January.

If the enterprise had entered into the contract for speculative purposes, the accounting entries at 31 January would have been as follows:

Dr	Debtors – margin account	$100,000	
Cr	Cash		$100,000

(to reflect the payment of the variation margin)

Dr	Profit and loss account – losses on futures contracts	$100,000	
Cr	Debtors – margin account		$100,000

(to reflect the marking to market of the futures contracts)

At this date, the balance sheet would include only the initial margin within debtors.

In the second case the additional margin payable to the broker is $20,000 (20 per cent × $2 × 50,000 barrels). The following accounting entries will be made at 31 January:

Dr	Debtors – margin account	$20,000	
Cr	Cash		$20,000

(to reflect the payment of the variation margin),

Dr	Other assets – deferred loss on futures contracts	$100,000	
Cr	Debtors – margin account		$100,000

(to reflect the funded and unfunded deferred loss).

The enterprise's balance sheet at 31 January will need to reflect the unfunded liability arising on revaluation of the futures contract although this loss is deferred until maturity of the contract, on 31 March. However, if there is a right to offset, the margin account and unfunded liability can be disclosed net in the balance sheet. If unfunded liabilities exceeded the initial margin, a net creditor would arise.

If the contract had been speculative in nature, or failed to meet the criteria for hedge accounting to apply, the following entries would have been made:

Dr	Debtors – margin account	$20,000	
Cr	Cash		$20,000

(to reflect the payment of the variation margin),

Dr	Profit and loss account – losses on futures contracts	$100,000	
Cr	Debtors – margin account		$100,000

(to reflect the marking to market of the futures contracts).

14.4.4 Designation of transactions

In order for a futures contract to qualify as a hedge, the contract must be designated as a hedge at its inception. Designation demonstrates management intent in relation to the rationale for entering into a futures contract. In the absence of such designation, the contract should be deemed to be speculative for the purposes of accounting and is then accounted for on a mark to market basis.

Suitable backing documentation will need to be maintained by the enterprise to indicate which contracts that have been entered into are hedges, and indeed, which assets, liabilities, committed or anticipated transactions they are hedging. (This may be an onerous requirement and an enterprise wishing to reduce the operational burden involved with hedge accounting may decide to decline to designate its transactions as hedges, even where they operate as such, and mark to market instead. This will, however, not necessarily result in reported results reflecting the true nature of the underlying transactions.)

The supporting accounting controls should be robust enough to prevent manipulation of reported results by the re-designation of contracts from hedges to speculative transactions or vice-versa. Clearly, re-designation can have a potentially significant effect on the reported results of an enterprise through the deferral or acceleration of the timing of recognition of profits and losses. A contract should be designated as a hedge or as speculative on execution and maintained as such during the life of the contract. Circumstances such as lack of effectiveness may, however, dictate re-designation. Where this is frequently the case, the validity and appropriateness of hedge accounting is called into question.

14.4.5 Enterprise risk

Prior to the introduction of FAS 133, one of the criteria to be fulfilled, in order for a futures contract to be accounted for as a hedge, was that the item to be hedged must have exposed the enterprise to price risk. The hedge itself then needed to demonstrate a reduction in that price risk. Under FAS 133, the demonstration of enterprise or transaction risk reduction is not required – only the demonstration of a high effectiveness of offset in changes in the fair value or cash flows of the hedging instrument and the hedged item. High effectiveness is discussed further below.

14.4.6 Effectiveness

A further condition to be fulfilled under FAS 133, in order for hedge accounting to apply, is that the hedging relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in those fair values or cash flows that are attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. An assessment of this effectiveness is required at least every 3 months and whenever financial statements or earnings are reported by an enterprise.

The high-effectiveness requirement has been interpreted in practice, and by the Securities Exchange Commission (SEC), to mean that cumulative changes in the value of the hedging instrument should be between 80 per cent and 125 per cent of the inverse cumulative changes in the fair value or cash flows of the hedged item.

FAS 133 requires that an enterprise, as part of its designation of a hedging relationship, define up front how it will assess a hedge's effectiveness in achieving the offset of changes in fair value or the offset of cash flows that are attributable to the risk that is being hedged. In this regard, FAS 133 requires that, throughout the hedge period, an enterprise consistently use a defined method to:

- assess whether it expects the hedging relationship to be highly effective in achieving offset; and
- measure the ineffective part of the hedge.

FAS 133 does not limit an enterprise to specifying a single method to achieve the above objectives but does, however, require that the method of assessing effectiveness be reasonable and that the same method be used for similar hedges, unless different methods are justified explicitly.

FAS 133 requires that an enterprise specify initially whether it will include all or only a portion (i.e. a specified percentage) of the gain or loss or cash flows on a hedging instrument in its assessment of hedge effectiveness. FAS 133 permits an enterprise to exclude a component of the hedging instrument's gain or loss or cash flows from the assessment of hedge effectiveness only in certain circumstances, for example, if the effectiveness of a hedge with a forward or futures contract is assessed based on changes in the fair value attributable to changes in spot prices, the change in the fair value of the contract related to the changes in the difference between the spot price and the forward or futures price would be excluded from the assessment of hedge effectiveness.

In the case above, changes in the fair value of the excluded component would be included currently in earnings, together with any ineffectiveness that results under the enterprise's defined method of assessing effectiveness. Except for the three circumstances described above, enterprises are not permitted to exclude components of a hedging instrument's gain or loss from the assessment of hedge effectiveness.

An example of how an oil producer may assess hedge effectiveness would be to compare the entire change in fair value of a futures contract to the total price changes in oil stocks held. This would be in lieu of assessing the hedge effectiveness based on changes in only the "spot" component of the futures contract and the oil inventory.

Even though hedging relationships may be highly effective, in many cases the effectiveness will not be perfect, that is, the gains and losses on the hedging instrument will not be offset perfectly by the losses and gains on the hedged item. It is worth noting, however, that high effectiveness does not guarantee that there will be no earnings volatility resulting from hedge ineffectiveness.

Where the hedge is highly effective but not perfectly effective, there will be some volatility in earnings due to the ineffective portion of the hedge. This is because FAS 133 requires that the ineffective portion of the hedge be recorded in earnings. For example, an oil producer uses a futures contract as a fair value hedge for a holding of crude oil stock. If the future's fair value decreases by $10,000 but the stock's value increases by $8,000, a net loss of $2,000 will result when gains and losses on both the future and the stock are recorded in earnings as required by FAS 133.

14.4.7 Grouping of transactions

Apart from hedging individual assets, liabilities or transactions, it is permissible for an enterprise to group a number of like items and to designate a futures contract or a number of futures contracts as a hedge of the group of items. For example, an enterprise with stocks of different grades of crude may execute a single futures contract as a hedge. However, where the underlying items are dissimilar – such as stocks of crude and a range of product stocks – it is unlikely that it will be appropriate to group such stocks to be hedged by a single type of futures contract as adequate effectiveness may not be achieved.

By corollary, it would also be acceptable to group a series of futures contracts and designate this group of contracts as a hedge against an underlying asset, liability or transaction (or indeed, group of items). An enterprise may decide on this method of hedging where there is no single traded contract with an appropriate maturity to serve as a hedge.

An organisation may also elect to hedge a net inventory position. In this case, the enterprise will need to keep particularly detailed records in order to identify the amortisation or recognition of gains or losses on the relevant futures contract or contracts. The basis of amortisation must produce reasonable and sensible results and will be based normally on the enterprise's rate of inventory turnover.

FAS 133 permits portfolio hedging where the individual assets and liabilities share the risk exposure for which they are designated as being a hedge. However, there must be an expectation, both at the inception of the hedge and on an ongoing basis, that the fair value of each individual item in the portfolio will change proportionately to the change in the fair value of the entire portfolio for the hedged risk. For example, if the fair value of a portfolio of stocks was to increase by 10 per cent, the fair value of each component of stock should increase within a narrow range of 9 per cent to 11 per cent.

14.4.8 Anticipated transactions

Apart from hedging actual or existing assets, liabilities or contracted transactions, an enterprise may decide to hedge an anticipated transaction. In order for hedge accounting to apply to an anticipated transaction, two other criteria need to be met (in addition to the usual requirements of designation, enterprise risk and adequate effectiveness):

- the significant terms and characteristics of the anticipated transaction need to be capable of being identified, and
- it must be probable that the anticipated transaction will occur.

The significant terms and characteristics of the anticipated transaction would normally include the transaction date, the type or quality of the commodity involved and the expected quantity of the commodity to be bought or sold. For example, an oil producer will normally have a clear idea of the expected quality or grade of crude to be sold from one of its fields. It will normally have a firm idea of production or lifting dates and quantities (subject to unforeseen shutdowns), at least in the short term. Consequently, the producer will be in a position to hedge part or all of a future month's production using futures contracts and hedge accounting could be applied in such circumstances.

The likelihood that an anticipated transaction will materialise should be based on observable factors rather than merely considering management intent. These factors are likely to include:

- the frequency of similar transactions in the past,
- the length of time until the anticipated transaction is due to arise,
- the effect on the enterprise should the anticipated transaction not occur,
- the availability of alternative transactions or courses of action available to the enterprise, and
- the financial position of the enterprise and its ability to carry out the transactions.

If it becomes probable that, during the life of the hedge, the quantity of the anticipated transaction will be less than the quantity hedged originally, the deferred gain or loss should be prorated and an appropriate portion recognised immediately in the profit and loss account. The remaining gain or loss should continue to be deferred and recognised when the underlying transaction occurs. If it becomes probable that the quantity of the anticipated transaction will be greater than that hedged originally, hedge accounting remains unaffected as the hedge merely becomes a hedge of part of the anticipated transaction.

In addition to the above, a requirement of FAS 133 is that hedged anticipated transactions must be described with sufficient specificity such that, when a transaction occurs, it is clear whether that transaction is or is not the hedged transaction. For example, an enterprise that expects to sell at least 300,000 barrels of crude oil in its next fiscal quarter might designate the sales of the first 100,000 barrels in each month as the hedged transactions. It could not, however, simply designate any sales of 300,000 barrels during the quarter as the hedged transaction because it then would be impossible to determine whether the first sales transaction of the quarter was a hedged transaction. Similarly, an entity could not designate the last 300,000 sales of the quarter as the hedged transaction because it would not be possible to determine whether sales early in the quarter were hedged or not.

14.4.9 Early termination of hedges

The termination of a hedge will arise from the disposal of the underlying asset or crystallisation of the underlying liability. It will also terminate when the underlying firm commitment or anticipated transaction arises. However, a hedge may also be terminated early. It is important to understand the circumstances surrounding early termination since this will affect the accounting treatment adopted. Early termination may result from:

- a discretionary decision by management, and
- absence of effectiveness.

Management may decide on the early termination of a hedge and close out a futures contract by executing an equal but opposite contract to that designated originally as a hedge. This may be done even where the underlying asset (or liability) has not been sold (or crystallised) or where the committed or anticipated transaction has not yet occurred. Where this arises, the gain or loss on the futures contract should continue to be deferred until the underlying transaction occurs and included within the gain or loss on the underlying transaction itself. Management should not terminate hedges selectively and recognise profits and losses at their discretion as this could be taken to be an indication of speculative activity. Where the underlying item being hedged is an asset or a liability, the gain or loss on an early terminated hedge will simply be included within the carrying amount of the asset or liability.

On the other hand, where high effectiveness ceases to exist, previously deferred gains and losses should be recognised in the profit and loss account, but only to the extent that they have not been offset by changes in value of the item being hedged. Deferred gains and losses that have been offset by changes in value of the hedged item continue to be deferred. In spite of the lack of expected future effectiveness, management may decide not to close out the futures contract; as such, it becomes a speculative contract and is thereafter accounted for on a mark to market basis.

Significant changes in an enterprise's hedging strategy may raise the possibility that the requirement of high effectiveness has not been satisfied, or that it is not expected to continue in the future. Changes may reflect simply a change in management intent as to the exposure to price changes being hedged – there is no requirement to hedge a position or exposure completely. In order to account for futures transactions properly, the accountant should therefore have a clear understanding of the enterprise's hedging strategy.

A situation where hedge management is achieved through the repeated designation and re-designation of futures contracts as hedges or speculative contracts (rather than actually closing out contracts) would not be acceptable for hedge accounting.

14.4.10 Valuation issues

Although stringent criteria need to apply to permit hedge accounting, an issue common to both hedge accounting and accounting for speculative contracts is the valuation of the futures contracts. The latter requires valuation of the contract at market value at each period end for profit recognition purposes. The former requires valuation in order to determine the gain or loss to be deferred and included as part of the carrying amount of the underlying asset or liability that is being hedged.

Generally, determining the market value of a futures contract is not a problem as the contract will be traded on a recognised exchange. Most exchanges, however, impose daily limits on permitted price movements to attempt to ensure an orderly market. Unanticipated events, such as the commencement of the Gulf crisis with the Iraqi invasion of Kuwait in 1990, can result in the prices of futures contracts reaching the price cap or floor. Where this happens trading may temporarily cease and determining period end prices may be difficult if trading straddles the year end. In such cases, other sources may provide a more suitable basis for valuation.

14.4.11 Documentation

An enterprise engaging in significant futures hedging activity will, apart from maintaining adequate systems of control, need to maintain adequate documentation to support its hedging activity. This is required to demonstrate:

- the contracts as hedges,
- the mitigation of enterprise risk (not required under FAS 133), and
- an adequate level of effectiveness (which should be monitored on an ongoing basis).

Additionally, further documentation should be maintained where anticipated transactions are to be hedged to ensure that hedge accounting is suitable for such transactions – all this must be maintained in addition to that information required to record and monitor the underlying futures contracts themselves (which would also be required where the contracts are speculative).

Compared to pre-FAS 133 requirements, FAS 133 increases the requirements in terms of the degree of documentation and the quality of hedge effectiveness analysis that is necessary in order for a hedge relationship to qualify for hedge accounting. Since FAS 133's model does not require a specific type of test for hedge effectiveness, or that an enterprise use a specific hedge strategy for a particular type of hedge transaction, it places more emphasis on the documentation of an enterprise's approach to risk management. As a result, the hedge documentation must include, at a minimum:

- an identification of the hedging instrument, the hedged item and the nature of the risk that is being hedged;
- a description of how the hedging instrument's effectiveness in offsetting the exposure to changes in the

hedged item's fair value or cash flows that are attributable to the hedged risk will be assessed (must include an indication of whether all of the gain or loss on the derivative hedging instrument will be included in the assessment and must have a reasonable basis);

- a specification of the enterprise's intent for undertaking the hedge (for example, its risk management strategy); and
- evidence that, at the hedge's inception and on an ongoing basis, it is expected that the hedging relationship will be highly effective in achieving offsetting changes in the fair value or cash flows that are attributable to the hedged risk.

Clearly, hedge accounting potentially requires significantly more documentation and paperwork than where an enterprise simply marks to market. This is also a potentially onerous commitment or obligation, particularly for smaller enterprises. An enterprise may decide to account for all its futures contracts as speculative – by not designating them as hedges – thereby reducing the extent of the back office responsibilities. However, the impact of this approach on reported results will clearly need to be considered properly.

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14.5 Forward contracts

Forward contracts are contracts to buy or sell a specified quantity of a commodity for delivery at a particular time and place in the future. Unlike futures contracts, forwards are not traded on regulated exchanges. Such contracts may simply be a supply agreement between a refiner and purchaser of refined products to cover the purchaser's requirements for a period of time, such as for the next 12 months. In another situation, a non-operator with a small stake in a producing field may have an agreement to sell its share of production forward to the operator at a fixed price. Although these 2 examples illustrate forward contracts, they do not come within the scope of oil trading transactions being considered here. Forwards in this context normally refer to paper deals where physical delivery is not necessarily expected to result: such as trading on the 15-day Brent market.

14.5.1 Accounting guidance

There is no authoritative guidance for accounting for forward trading. However, the accounting rules which apply to accounting for futures trading also apply generally to forwards. Forward transactions may be entered into as hedges (of underlying assets, liabilities or transactions) or for speculative reasons. In order for hedge accounting to apply, the criteria discussed above relating to futures should also be met, namely:

- designation of the transaction as a hedge,
- mitigation of enterprise risk (not required under FAS 133),
- adequate degree of effectiveness.

Where all these criteria are met, the gains or losses on the forward contracts should be deferred and recognised in the profit and loss account in the period in which the hedged asset (or liability) is realised (or crystallises) or the hedged transaction occurs. However, where any of the criteria are not met, the forward contract should be regarded as speculative and price changes accounted for in the period in which the price change occurs by marking to market.

14.5.2 Accounting on a net basis

An issue which arises in relation to forward trading which does not arise in relation to futures contracts is whether to account for the transactions on a gross basis (as part of sales and cost of sales) or whether to account for the net profit or loss as part of other operating income or turnover.

Although there are arguments for recording forward sales and purchases that are undertaken as part of an enterprise's oil trading activities as part of turnover and cost of sales respectively where oil trading is not the principal activity of the enterprise (for example, an oil producer or refiner), the most appropriate basis is to account for such transactions net. To do otherwise would potentially distort turnover as a measure of the level of activity of the enterprise and distort any meaningful comparisons that could otherwise be drawn from the enterprise's gross margin.

Accounting for forward transactions is best illustrated by way of example. Assume an oil producer's next lifting of 500,000 barrels is due in 3 months' time, in April. To hedge this production, it sells 500,000 barrels forward on the 15-day Brent market at $20 per barrel. In March, it closes out the forward contract by purchasing 500,000 barrels forward (April delivery) for $22 per barrel. Its lifting in April is also subsequently sold, at market prices, for $22 per barrel. The accounting entries during the period would be:

Dr	Debtors	$10,000,000	
Cr	Forward sales		$10,000,000

(To record the forward sale in January),

Dr	Forward purchases	$11,000,000	
Cr	Creditors		$11,000,000

(To record the closing out of the original forward contract),

Dr	Debtors	$11,000,000	
Cr	Profit and loss account – turnover		$11,000,000

(To record the sale of the April lifting),

Dr	Profit and loss account – turnover	$1,000,000	
Dr	Forward sales	$10,000,000	
Cr	Forward purchases		$11,000,000

(to reflect the recognition of the gain or loss on the hedge).

Except where indicated, the above entries relate to balance sheet accounts.

If the forward transactions were recorded gross, the enterprise's turnover is shown as $21 million, notwithstanding the single lifting of 500,000 barrels. By recording forward purchases and sales net, turnover for the period shown is $11 million with a net loss on forward trading of $1 million. As the transaction was undertaken as a hedge, this would be offset against turnover to result in net turnover disclosed of $10 million.

If the enterprise entered into the forward transactions for speculative purposes, the $1 million loss on the trading transactions would not be offset against turnover but shown as other operating income/expense after the gross profit line.

Where an enterprise is long or short in forward transactions at the end of an accounting period, the forward transactions should be revalued at the period end. If the transactions are hedges, the gain or loss would be deferred and carried forward in the balance sheet as a deferred asset or deferred liability as appropriate. If speculative, gains or losses would be included within other operating income/expense in the profit and loss account.

Where forward trades are not strictly paper trades, but trades in physical cargoes, arguments can be framed for these trades to be accounted for on a gross basis. For gross accounting there should be a clearly identifiable cargo and legal title to the cargo should pass upon the trade. Additionally, settlement of the trade should be for the gross value of the transaction traded. Whichever basis is adopted, however, the accounting policy should be disclosed clearly to enable a proper understanding of the financial statements.

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14.6 Swaps

Unlike futures and forward contracts, which are frequently-traded commodity-backed instruments, swaps are a form of derivative instrument which are not traded on a "market". Generally, these are contracts entered into by an enterprise with a financial intermediary such as a bank, for the same motives as the enterprise enters into futures or forward contracts; either as hedges or for speculative reasons. Swaps can also be tailor-made to suit the enterprise's specific requirements and can provide hedges with a high degree of risk mitigation.

A swap exchanges an income stream that the enterprise would normally face, for another devised by the financial intermediary or bank. For example, an oil producer facing volatility in its income stream as a result of selling its production on the spot market may enter into a swap contract with a bank, exchanging its production for a fixed price. The bank therefore takes on the exposure to price fluctuation. However, the bank may be able to offset part or all of this exposure by entering into another swap with a refiner who faces price volatility in his cost of sales: crude oil purchases. As the nature and terms of one swap instrument may vary from another the accounting treatment will also vary. However, there are a number of basic swap instruments to consider:

- average price or basic swaps,
- floors,
- ceilings/caps,
- range forwards,
- participation hedges.

The accounting treatments for these instruments are considered by way of example.

14.6.1 Average price instruments

An oil producer enters into a swap of 100,000 barrels of crude per month with a financial intermediary at $20 per barrel for a 12 month period. The producer is expected to produce at least this quantity of crude per month. In practice it sells its production on the spot market. At the end of each month settlement takes place with the bank. This settlement will be defined by reference to a published source (such as *Platt's*, or prices quoted in the *Financial Times*). If the average price of crude exceeds $20 per barrel, a payment will be made by the producer to the bank. If the average price of crude is below $20 per barrel, a top-up payment will be made by the bank to the producer.

If the average price of Brent crude for the month is $22 per barrel, the accounting entries required will be as follows:

Dr	Cash	$2,200,000	
Cr	Turnover – crude oil sales		$2,200,000

(to reflect the sale of its production on the spot market, the producer having received $2,200,000, i.e. 100,000 barrels at $22 per barrel),

Dr	Turnover – crude oil sales	$200,000	
Cr	Cash		$200,000

(to reflect a payment of $200,000 by the producer to the bank, i.e. 100,000 barrels at $2 per barrel).

The net effect of these two entries will be to include $2 million in the producer's profit and loss account as turnover. In essence, the enterprise has fully hedged its production.

If the average price of Brent crude is $19 per barrel the following accounting entries would be made:

Dr	Cash	$1,900,000	
Cr	Turnover – crude oil sales		$1,900,000

(to reflect the sale of crude production on the spot market),

Dr	Cash	$100,000	
Cr	Turnover – crude oil sales		$100,000

(to reflect the payment by the bank to the producer).

The net result of these entries would also be to include $2 million in turnover.

In the above example, no initial payment was made by either party. If an initial payment of $12,000 had been made by the oil producer to the bank, this would be amortised over the life of the contract as follows:

Dr	Debtors – prepaid commissions	$12,000	
Cr	Cash		$12,000

(to reflect the initial payment made on entering into the swap).

At the end of each month, $^{1}/_{12}$ of this would be amortised:

Dr	Turnover – crude oil sales	$1,000	
Cr	Debtors – prepaid commissions		$1,000

As an alternative, the debit entry may be made to other operating expenses. If production is expected to vary each month, the amortisation should be calculated on a unit of production basis. In the case of futures transactions, the preferred treatment discussed in Section 14.4.2 above was to expense such costs as transactional costs. In the case of swaps such as those described here, amortisation of the up-front payment is acceptable as the swap can be viewed as a series of transactions that are being hedged. Normally, futures contracts are used to hedge only a single transaction. In the above example, the enterprise entered into the swap as a hedge. An identical contract could, of course, be entered into by a non-producer of oil.

In this case, the transaction would be speculative and the only entry required at the end of each month would be:

Dr	Cash	\$x	
Cr	Other operating income		\$x

with cash received from the bank where the average price falls short of the swap price, or

Dr	Other operating income	\$x	
Cr	Cash		\$x

with the cash payment made to the bank where the average price exceeds the swap price.

Where a transaction is speculative, the bank may perceive that it faces a different level of credit risks, with the result that the terms of the swap may vary.

14.6.2 Floors, caps and range forwards

A floor is an instrument which sets a minimum price to be received by the oil producer or other enterprise. If the average price prevailing in the market exceeds the floor price, no payment is made by either the producer or the bank. A floor will be attractive to a producer to minimise or reduce the downside potential of future price movements to be received for its production. However, a commission or premium will be required at the outset by the bank entering into the swap.

A cap is an instrument that sets the maximum price (ceiling) to be received by the oil producer or other enterprise. This limits the upside potential but does not limit downside risk. Such a transaction can only be speculative from the producer's point of view. Here, an initial payment will be made by the bank to the producer.

If prices exceed the cap price, a payment is made by the producer to the bank. If prices fall below the cap, no further payments are made between the producer and the bank.

A range forward combines the elements of both a floor and a cap by setting a floor price and ceiling price. For example, an oil producer (monthly production – 100,000 barrels) and bank may set a floor of $16 per barrel and a ceiling price of $21 per barrel. The per barrel difference in price will be settled between the 2 parties if the average price is outside the range set. If the average price is $15 per barrel, a payment of $100,000 ($16–$15 × 100,000 barrels) is made to the producer. The following adjustment is made to turnover, assuming the transaction is a hedge:

Dr	Cash	$100,000	
Cr	Turnover – crude oil sales		$100,000

If the average price rises to $25 per barrel the producer pays $400,000 ($25–$21 × 100,000 barrels) to the bank with the following adjustment to turnover:

Dr	Turnover – crude oil sales	$400,000	
Cr	Cash		$400,000

In both cases, the producer will have recorded the initial sale of its month's production as turnover at the prevailing market price. If the average price of crude is in the range $16 to $21 per barrel, no payment is made by either party.

14.6.3 Participation hedge

A participation hedge is similar to the swaps already described, except that the settlement between the bank and the enterprise will be based upon a proportion of the per barrel difference in oil price.

For example, an oil producer enters into a swap as a hedge with a bank on the following terms:

- 60,000 barrels per month are swapped for a year,
- monthly settlement is made based on a floor of $20 per barrel,
- if the average price falls below $20 per barrel, the producer receives a cash payment amounting to the difference between the average price and $20 for each barrel produced,

- if the average price exceeds $20 per barrel, the producer pays 20% of the per barrel difference in price for the volume hedged for each barrel produced, and
- there is no initial premium or payment.

In the example, if the average price of crude is $18 per barrel, a payment of $120,000 ($20–$18 × 60,000 bbls) will be made by the bank to the producer resulting in the following accounting entry being made:

Dr	Cash	$120,000	
Cr	Turnover – crude oil sales		$120,000

If the average price is $25 per barrel, the producer pays the bank $60,000 ($25–$20 × 20% × 60,000 bbls) with the following accounting entry being made:

Dr	Turnover – crude oil sales	$60,000	
Cr	Cash		$60,000

If an oil producer enters into a contract which provides for it to receive 20% of the price difference when the average price is below the floor but pay 100% of the difference in excess of the floor, the transaction is speculative in nature and cannot be accounted for as a hedge. But if the enterprise was a refiner acquiring crude for refinery intake, a contract of this nature would be a hedge, while the terms in the previous example would be regarded as speculative.

14.6.4 Swaps contracts and accounting periods

In the examples considered above, monthly settlements were made between the enterprise and the bank. Where the swaps were hedge transactions, the cash settlement is reflected as an adjustment to turnover. Where speculative, the cash settlement is not shown as an adjustment to turnover but within other operating income or expense (and therefore excluded from gross profit).

The terms of the swap may be such that an oil producer may hedge 12 months' production with settlement between the producer and bank taking place at the end of the year. If the contract year straddles an enterprise's financial year end, the gain or loss on the contract at its financial year end will need to be assessed.

For example, on 1 January the producer swaps annual production of 2,400,000 barrels for barrels at $22 per barrel, receiving or paying 100% of the per barrel difference. Settlement is at the end of the 12 month period. Its financial year end is 31 March, when it has produced 800,000 barrels receiving average proceeds of $20 per barrel. Its forecast production for the next 9 months is 1,600,000 barrels.

Although settlement will not be made until 31 December, the enterprise will have received revenues of $16 million (800,000 barrels × $20).

Dr	Cash	$16,000,000	
Cr	Turnover – crude oil sales		$16,000,000

It will make an adjustment to turnover at 31 March to reflect the unrealised gain of $1.6 million ($22–$20 × 800,000 barrels) on the swap contract at this date:

Dr	Debtors – unrealised gain on swap	$1,600,000	
Cr	Turnover – crude oil sales		$1,600,000

Where there are variations in volumes produced to date in relation to forecast production, or if there are variations in forecast production for the remaining contract period, consideration will need to be given to the determination of the adjustment to be made to revenues.

- If production for the period is 800,000 barrels but the forecast for the full year is increased to 3,200,000 barrels, it would be appropriate to regard the enterprise as hedging 75 per cent of its production. Consequently, the adjustment at 31 March would be reduced to $1,200,000.
- If production for the period remains at 800,000 barrels but forecast for the full year is reduced to 1,600,000 barrels, the adjustment to turnover at 31 March remains at $1,600,000. (This assumes that the swap contract is unaffected if annual production falls short of forecast).
- Variations in production for the period to date will result in corresponding changes to the adjustment to turnover, assuming that the forecast for the full year remains unchanged.
- If both production to 31 March and the full year forecast vary, the adjustment to turnover should be based

on actual production to date in relation to the revised full year production forecast. However, where the full year forecast production increases, the adjustment should be pro-rated appropriately.

In all cases, the terms of the contract will need to be considered as these may influence the accounting treatment adopted. For example, penalties for not meeting the agreed swap quantity should be recognised.

14.6.5 Requirements for hedge accounting

As with forward contracts, hedge accounting can only be employed if the swap contract meets the standard criteria of high effectiveness and hedge designation. Where any of these criteria are not met, the swap contract should be regarded as speculative and unrealised gains and losses should be recognised immediately in the profit and loss account and should not be deferred.

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14.7 Options

Option contracts are contracts that provide the owner with the right, but not the obligation, to purchase or sell a specified item at a fixed price during a specified period. The owner of an option pays a non-refundable fee (premium) to the seller of an option. Options, as with futures, may be traded on regulated exchanges or, as with forwards, may be traded directly with another party.

Accounting guidance for options can be drawn from FAS 133 which, as already discussed, relates to accounting for derivative instruments and hedging activities.

14.7.1 Effectiveness

Unlike futures and forwards which have two-sided risk and return characteristics, options have only one-sided risk and return characteristics. In the case of options, the enterprise can allow a put option to lapse if the current market price of the underlying asset is in excess of the strike price at maturity. In the case of a call option, the enterprise would not exercise its right if the current purchase price of an asset was below the exercise price of the option. In the case of futures and forwards, the enterprise does not have this choice and must settle the relevant contracts even if it is not to the enterprise's advantage.

One of the requirements for hedge accounting to apply under FAS 133, as discussed earlier, is for high effectiveness to be demonstrated. As mentioned above, an option contract provides the owner with the right, but not the obligation, to purchase or sell a specified item at a fixed price during a specified period and the owner pays a non-refundable fee (premium) to the seller of the option. The time value, that is the premium, for an at-the-money or out-of-the-money option contract represents a cost of the hedge and generally would not be effective in offsetting changes in the fair value or cash flows of the hedged item. Therefore, only the option's intrinsic value would be effective as a one-sided hedge of a hedged item and would be considered in the assessment of hedge effectiveness.

For example, assume that an enterprise is concerned with the downside price risk of stocks of crude oil and, therefore, purchases an at-the-money put option. Assume also that the enterprise assesses hedge effectiveness based on changes in the option's intrinsic value. The intrinsic value of the put option will be highly effective in offsetting the decreases in the fair value (below the option's strike price) of the stocks held. Any increases in the fair value of the stocks above the option's strike price, however, would not be included in the measurement of hedge effectiveness, because they were not intended to be, or designated as, the hedged risk.

As discussed earlier in respect of futures and forwards, FAS 133 requires that an enterprise specify initially whether it will include all or only a portion of the gain or loss or cash flows on a hedging instrument in its assessment of hedge effectiveness. FAS 133 permits an enterprise to exclude a component of the hedging instrument's gain or loss or cash flows from the assessment of hedge effectiveness only in certain circumstances, which are as follows:

- If the effectiveness of a hedge with an option contract is assessed based on changes in the option's intrinsic value, the change in the time value of the option contract would be excluded from the assessment of the hedge effectiveness.
- If the effectiveness of a hedge with an option contract is assessed based on changes in the option's minimum value, that is, its intrinsic value plus the effect of discounting, the change in the volatility value of the option contract would be excluded from the assessment of hedge effectiveness.

In each circumstance above, changes in the fair value of the excluded component would be included currently in earnings, together with any ineffectiveness that results under the enterprise's defined method of assessing effectiveness. Except for the 2 circumstances described above, enterprises are not permitted to exclude components of a hedging instrument's gain or loss from the assessment of hedge ineffectiveness.

14.7.2 Profit recognition

The recognition of gains and losses on options will depend on the underlying motive for entering into the option contract. Where criteria for hedge accounting apply any gains and losses should be deferred and recognised in the profit and loss in the same period as any profits or losses on the underlying hedged asset, liability or transaction. Where the hedge accounting criteria are not met, the gains or losses on the option should be recognised immediately in the period's profit and loss account. This would be the case where a transaction was entered into for speculative reasons. Strict accounting treatment would require the separation of an option premium paid – effectively the cost of the option – into its intrinsic value and time value, with the latter being amortised on a systematic and rational basis to maturity. However, in many cases, the time value element may not be a significant or material component and may not, therefore, warrant a different accounting treatment.

In line with futures and forwards accounting, the option should be carried in the enterprise's balance sheet at market value where the hedged item is also carried at market value. If it is carried at the lower of cost and net realisable value, the option should be carried at the higher of cost and net realisable value, as illustrated below. This applies whether the option is traded on a recognised exchange or not.

The one sided nature of an option can be illustrated by way of a simple example. An enterprise has an asset worth $100 which is accounted for at the lower of cost or net realisable value. To protect itself against adverse price movements, it acquires a put option to sell the asset for $100 at a fixed time in the future. The cost of this right to the enterprise is $10.

If the asset value falls to $80, the enterprise would write down its carrying value to this amount, which is the lower of cost or net realisable value. The value of the option rises from $10 to $30 and, by marking to market, the gain on the option offsets exactly the loss on the asset when the asset is ultimately sold and the option closed out. The gains and losses on both are recognised in the profit and loss account in the same period.

If the asset value rises to $120, the carrying amount remains at cost of $100. The option is carried at $10, being the higher of cost ($10) or net realisable value ($nil). However, if the asset was carried at market value (say the asset being hedged was a futures contract), the option would be revalued to a market value of $nil, the enterprise thereby recognising a profit of $10.

Where options are not traded on a recognised exchange, valuation of the option may become an issue and it may be necessary to derive a price using a theoretical model. In such a case, it may be appropriate to discount the price to reflect any lack of liquidity in the market.

14.7.3 Commissions and margin payments

Options trading will normally involve the payment of a commission or brokerage charge at the outset of the transaction. As this is a transactional-based charge, this is most appropriately expensed to the profit and loss account as incurred, regardless of whether or not the option is to be treated as a hedge.

Brokers may also require the payment of initial and variation margins in respect of options trading. As discussed earlier in relation to futures trading, these margins represent deposits with brokers and therefore are included appropriately within the enterprise's debtors, again regardless of whether or not the option is to be treated as a hedge.

14.8 Physical hedges

An enterprise may decide to hold physical inventories, rather than holding paper instruments such as oil futures, as a hedge against other assets held or against a firm commitment or anticipated transaction.

For example, a power generator may have a commitment to buy heavy fuel oil at prevailing market prices in the UK in 3 months' time. By taking advantage of currently low prices in another geographic market, say Singapore, the enterprise's Singaporean affiliate may acquire an equivalent quantity of heavy fuel oil on the spot market on behalf of the enterprise. In three months' time when prices have recovered, the enterprise acquires the heavy fuel oil it is contracted to purchase in the UK and sells the product previously acquired in Singapore.

The result of these transactions (ignoring the effects of foreign exchange movements and storage costs) is that the enterprise has hedged its commitment in the UK through the holding of physical inventories, albeit at a different location. Assuming stocks are sold in Singapore at similar prices to those paid in the UK, the net cost to the enterprise is the lower cost of the product originally acquired in Singapore.

14.8.1 Definitions

In the above example, the enterprise has effectively eliminated its price exposure on a firm commitment. However, for hedge accounting to apply, the usual hedge criteria must apply:

- designation of specific physical inventories as a hedge,
- adequate degree of effectiveness between the price of the physical inventories held and the underlying item being hedged, and
- the underlying transaction or item to be hedged must expose the enterprise to price risk (not required under FAS 133).

Where the acquisition of the physical hedge and its disposal take place within a single accounting period, the question of deferral of gains and losses will not be an issue. However, where an accounting period is straddled, the physical inventory held as a hedge should be carried in the balance sheet at market value. Any unrealised gain or loss at the period end should be deferred until the underlying hedged item crystallises.

In addition, as with forward contracts, an issue that arises is whether the purchase and sale of the physical hedge should be reported gross (as part of the enterprise's purchases and sales). To do so, however, would distort reported purchases and sales. Instead, the enterprise should determine the net gain or loss on the physical hedge and include this amount within purchases (in the case of a hedged purchase commitment) or sales (in the case of a hedged sales commitment).

In the absence of authoritative guidance, accounting for physical hedge transactions on a gross basis is considered acceptable. However, the physical assets used as the hedge should be clearly identifiable, legal title to these assets should pass to the purchaser, and settlement of the transaction should normally be based upon the gross value of the assets traded.

The enterprise should disclose adequately the nature of its physical hedging activities in its financial statements. These disclosures should include:

- the enterprise's accounting policy concerning physical hedges,
- the nature and level of hedging activity, and
- unrealised gains and losses at the period end.

14.8.2 FAS 133

FAS 133 does not permit an enterprise to apply hedge accounting when a non-derivative instrument is used as an economic hedge of an asset, liability, firm commitment or forecasted purchase or sale. In developing FAS 133, the FASB believed that hedge accounting generally should not be permitted for non-derivative instruments because an application of the provisions of FAS 133 would often override the established measurement method for those instruments, simply because they were part of a hedging relationship. Consequently, the non-derivative instrument should be treated as a normal item under the relevant accounting standard.

14.8.3 Speculative inventories

Physical inventories may also be held for speculative purposes. Where this is the case, or where any of the criteria for hedge accounting do not apply, the physical inventory held should be carried at market value. Any unrealised gains or losses should be recognised immediately in the enterprise's profit and loss account rather than being deferred. Such gains and losses should be reported within “Other Operating Income” and disclosed separately in the notes to the financial statements to enable a proper understanding of the enterprise’s financial statements and its accounting policy on physical inventories, together with disclosure of the nature and level of its trading in physical inventories.

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14.9 Disclosure requirements

In order to enable a user of a set of accounts to obtain a full and proper understanding of an enterprise's results for a period and its financial position as depicted in the balance sheet, it is necessary for the enterprise's accounting policies to be disclosed fully. Where oil trading activity is significant, it will also be appropriate to disclose the nature of the trading activity undertaken and items being hedged. The existence of material positions held, amounts included within income for the period and the extent of unrealised gains and losses included at the period end should also be disclosed.

14.9.1 United States

In the US, disclosure requirements are evolving as a result of the project by the Financial Accounting Standards Board (FASB)* to consider financial instruments and off-balance sheet financing. The latest phase of the FASB's work has resulted in the issue of FAS 133 *Accounting for Derivative Instruments and Hedging Activities,* issued in 1998 and revised in 2000 by FAS 138 *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of FASB Statement No. 133*. In addition, it should be noted that the Derivatives Implementation Group (DIG) established by the FASB have made an extensive series of pronouncements which address the application of the standard to particular scenarios.

FAS 133 supersedes FAS 80, 105 and 119, and amends FAS 107 to make it consistent with FAS 133's measurement provisions, and to include in FAS 107 the disclosure provisions in respect of concentrations of credit risk, taken from FAS 105. In particular, FAS 133 eliminates the previous requirements to disclose:

- the face, contract or notional principal amount for all derivative financial instruments held at the balance sheet date; and
- the average fair value of derivative financial instruments held for trading purposes.

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*Further information on FASB disclosure requirements and the work of the Derivatives Implementation Group can be found on the FASB website (www.fasb.org).

The key components of FAS 133's disclosure requirements are as follows:

- An enterprise that holds or issues derivative instruments (or non-derivative instruments that are designated and qualify as hedging instruments) needs to disclose its objectives for holding or issuing those instruments, the context needed to understand those objectives, and its strategies for achieving those objectives.
- Qualitative disclosures about an enterprise's objectives and strategies for using derivative instruments may be more meaningful if such objectives and strategies are defined in the context of an enterprise's overall risk management profile (the enterprise is encouraged but not required to provide such additional qualitative disclosures).
- For derivative instruments that have been designated and have qualified as fair value hedging instruments and for the related hedged items:

  i) The net gain or loss recognised in earnings during the reporting period, representing the amount of the hedges' ineffectiveness and the component of the derivative instruments' gain or loss, if any, excluded from the assessment of hedge effectiveness, and a description of where the net gain or loss is reported in the statement of income or other statement of financial performance.
  ii) The amount of net gain or loss recognised in earnings when a hedged firm commitment no longer qualifies as a fair value hedge.
- For derivative instruments that have been designated and have qualified as cash flow hedging instruments and for the related hedged transactions:
  i) The net gain or loss recognised in earnings during the reporting period, representing the amount of the hedges' ineffectiveness and the component of the derivative instruments' gain or loss, if any, excluded from the assessment of hedge effectiveness, and a description of where the net gain or loss is reported in the statement of income or other statement of financial performance.
  ii) A description of the transactions or other events that will result in the reclassification into earnings of

gains and losses that are reported in accumulated other comprehensive income, and the estimated net amount of the existing gains or losses at the reporting date that is expected to be reclassified into earnings within the next 12 months.

iii) The maximum length of time over which the enterprise is hedging its exposure to the variability in future cash flows for forecasted transactions (excluding those transactions related to the payment of variable interest on existing financial instruments).

iv) The amount of gains and losses reclassified into earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur.

It is worth noting that an enterprise may need to modify information systems to accumulate some of the data that they will need if it is to comply with FAS 133's disclosure requirements. For example, for fair-value hedges the net gain or loss recognised in earnings during the reporting period that represents the amount of the hedges' ineffectiveness and the component of the derivatives' gain or loss that is excluded from the assessment of hedge ineffectiveness have to be disclosed separately.

FAS 133 does not specify display requirements for reporting the effects of hedging transactions in the income statement. Consequently, diversity in practice may develop. Current practice has generally been to present the results on a combined, or net, basis. It is expected that, after adopting FAS 133, most enterprises will continue the current practice of presenting "net" all of the gains and losses of the hedging instrument and the hedged item, because this better conveys the economic results of the hedging activity. Financial statement users, however, may prefer a separate presentation of the ineffective portion of the hedge results. A net presentation should be acceptable, provided that the hedge relationship is highly effective. A net presentation, however, would not be appropriate for hedging relationships that are not highly effective.

It is worth noting that FAS 133 requires disclosure in the footnotes of all hedges' ineffectiveness, which will enable financial statement users to discern the amount of hedge ineffectiveness that has occurred, even though derivative gains and losses might be presented net in the income statement with the results of the hedged item.

For cash-flow hedging transactions, FAS 133 required that enterprises display, as a separate classification within other comprehensive income, the net gains and losses on derivative instruments that qualify as cash-flow hedging instruments. Enterprises must also disclose separately a roll-forward of the activity for such net gains and losses that are deferred in other comprehensive income.

14.9.2 United Kingdom

In the UK, Financial Reporting Standard 13, *Derivatives and other financial instruments: disclosures* (FRS 13) was issued in September 1998. It represents the first stage in the development of accounting standards covering financial instruments in the UK, and its scope includes certain commodity contracts. FRS 13 covers disclosure requirements only and applies to entities that have any of their capital instruments listed or publicly traded on a stock exchange or market. Although it is not mandatory for other companies, the requirements of the standard illustrate good practice disclosures for other companies where the use of financial instruments is significant.

The standard requires that entities to which it applies provide certain narrative and numerical disclosures of their financial instruments, including derivatives. The narrative disclosures describe the role that financial instruments have in creating or changing the risks faced by an entity; they also describe the entity's objectives and policies in using financial instruments to cover these risks. The numerical disclosures are intended to show how these objectives and policies were implemented in the period and provide information for evaluating significant, or potentially significant, exposures.

FRS 13 considers cash-settled commodity contracts to fall within the scope of the standard, although not all the disclosure requirements required for financial instruments more generally apply to such contracts. Contracts for the purchase of commodities (including gas) for actual or physical delivery and use in its business are not considered as cash-settled contracts and are outside the scope of FRS 13.

The narrative disclosures required by FRS 13 that apply to cash-settled commodity contracts are:

- an explanation of the role financial instruments have had during the period in creating or changing the risks that the entity faces in its activities. This should include an explanation of the objectives and policies for issuing or holding financial instruments, and the strategies that have been followed in the period for achieving those objectives;

- an explanation should be provided of how the period-end numerical disclosures shown in the financial statements reflect the objectives, policies and strategies; and
- if financial instruments are used as hedges, the transactions and risks that have been hedged should be described, including the period of time until they are expected to occur; the instruments used for hedging purposes should also be described, distinguishing between those that have been accounted for using hedge accounting and those that have not.

The numerical disclosures required by FRS 13 that apply to cash-settled commodity contracts are:

- fair value disclosures: an entity should group its financial assets and financial liabilities into appropriate categories and disclose, for each category, the aggregate fair value at the balance sheet date together with the aggregate carrying amount; the aggregate fair value of those items with positive fair values should also be disclosed separately from those with negative fair value amounts. In determining the categories into which the instruments are grouped, the entity should take into account the purpose for which each asset and liability is held and the type of asset or liability involved. The methods and assumptions used for determining fair values should also be disclosed;
- if the entity trades in financial instruments, disclosures should also be made about: the net gain or loss from trading in financial instruments that has been included in the profit and loss account during the period, appropriately analysed; period-end fair values of financial assets and, separately, of financial liabilities, held or issued for trading purposes (average fair values over the period should also be disclosed if the period-end position is unrepresentative); and
- where financial assets and liabilities are used as hedges, disclosures should include: the cumulative aggregate gains and losses that are unrecognised at the balance sheet date; the cumulative aggregate gains and losses carried-forward at the balance sheet date

pending recognition in the profit and loss account; the extent to which such gains and losses are expected to be recognised in the profit and loss account in the next period; and, the amount of gains and losses recognised in the current period's profit and loss account that arose in previous periods but were unrecognised or carried forward in the balance sheet at the start of the current reporting period. If instruments held as hedges have been re-designated during the period and are no longer held as hedges, the amount of gains and losses that arose in previous periods but are now recognised should also be disclosed.

Where an entity participates in an illiquid commodity market that is dominated by very few participants and disclosure of such information at the time financial statements are issued is likely to move the markets concerned significantly, FRS 13 allows the entity not to give the disclosures relating to such instruments. However, the fact that such information has not been disclosed and the reasons for non-disclosure should be given.

14.10 Conclusions

An enterprise may use a range of instruments – such as futures, forwards, swaps and options – to enable it to manage its exposure to the risk of both price and exchange rate volatility. The proper accounting for an enterprise's oil trading activities is dependent on a clear understanding of the enterprise's strategy and transactions. At present, under US GAAP, FAS 133 is prescriptive in its approach in relation to measurement issues and rules about hedge accounting, however, in the UK there is limited accounting guidance.

In order to comply with FAS 133's accounting and disclosure requirements, enterprises will need to develop information systems that can track and accumulate data on gains and losses related to each individual hedge relationship. Some enterprises may have to draw on considerable resources to accomplish this.

As a result of limited guidance in the UK, the potential diversity of accounting treatments makes disclosure of the nature and extent of transactions – and the accounting policies adopted – all the more important. The reported results of an enterprise in the UK may therefore differ considerably as a result of the accounting treatment applied to its oil trading activities. As a result, a proper understanding of the financial statements of a company engaged in oil trading is dependent on clear and appropriate disclosures of the accounting policies and the nature of the transactions it undertakes.

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15 Taxation of oil trading

Phil Greatrex

15.1 Introduction

The oil trading markets are now very sophisticated with many of the players trading 24 hours a day by having traders based in the three main time zones of North America, Europe and the Far East.

Most developed tax jurisdictions attempt, ultimately, to tax the profits generated in their location but it can be almost impossible with global oil trading activities to assess where particular profits are being generated. With traders in touch with each other and with the market constantly, the fact that a particular contract is made in, say, Europe which generates a profit does not necessarily mean that profit has been earned for the corporation in the European location as the contract could have been taken out to hedge a loss making position elsewhere in the world-wide group.

Tax jurisdictions use a number of mechanisms, to try and ensure they are able to tax the profits earned in their location, including the application of transfer pricing rules and the entering into of double taxation treaty arrangements. However, with the global nature of oil trading activities, it has become increasingly difficult to isolate profit or loss by location and it seems likely that increasingly tax jurisdictions will simply attempt to collect what they deem to be a reasonable amount of tax without trying to accurately assess the profits made in their location.

A global trading group will generally be concerned to ensure that double taxation does not arise and that the world-wide effective rate of tax borne by the group is not in excess of the home country rate. Typically groups will, therefore, be looking to minimise taxation outside the "home country" location. In these circumstances agreeing a commission or cost mark up basis of taxation in other locations can be attractive, as can locating the activities in a country which offers special incentives to oil traders.

The following sections set out the main principles for the taxation of oil trading activities in three of the main oil trading centres of the world, i.e. the UK, the USA and Singapore, and include a detailed description of the taxation of oil trading instruments in the UK and the operation of the UK Petroleum Revenue Tax (PRT) nomination scheme.

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15.2 United Kingdom

15.2.1 The Oil Taxation Office (OTO)

The Oil Taxation Office (OTO) is the technical division within the UK Inland Revenue responsible for all oil related activities so far as direct tax is concerned. The taxation affairs of most, but not all, oil trading groups are handled by the Oil Taxation Office. It has built up considerable expertise in the area of inter company transfer pricing and over the last decade has learnt a great deal about the way international crude and product operations are conducted.

The following is a description of the basic domestic legislation for the taxation of companies operating in the UK and how this may be affected by Double Taxation Treaties.

15.2.2 Scope of tax

A company which is resident in the United Kingdom is chargeable to UK corporation tax on its world-wide profits (**S.8 TA 1988**).

A non-UK resident company carrying on a trade in the UK through a branch or agency is also liable to corporation tax, but only on the profits attributable to the branch or agency (**S.11 TA 1988**).

The conclusion of contracts in the UK is a major, but not conclusive, factor in establishing whether a trade is being carried on in the UK. However, even when contracts are concluded outside the UK there may still be a trade being carried on in the UK, depending on the activities and influence of the personnel based in the UK.

The profits of activities carried on in certain controlled foreign corporations (CFCs) – i.e. foreign subsidiaries – of UK resident companies, may be taxed in the UK if the activities are based outside the UK for the purpose of avoiding UK tax and certain other conditions are not satisfied (**S.747 TA 1988**).

Supplies of goods situated in the UK or of services treated as supplied in the UK will generally be within the scope of VAT regardless of the residence of the supplier.

15.2.3 Residence

Since 1988 a UK incorporated company has been automatically resident in the UK for corporation tax purposes (**S.66 FA 1988**).

Non-UK incorporated companies may also be UK resident if their central management and control is situated in the UK.

Central management and control of a company is exercised normally where the Board of Directors meet and where the more important decisions regarding the running of the company are made. This is not necessarily the same as where the day to day management of the company is exercised although the two activities are often carried out at the same location.

It is possible for companies to be treated as resident in the UK under UK domestic law and resident elsewhere under the domestic law of another country. In these cases the relevant double taxation treaty will normally determine, for the purposes of the taxation of profits and application of the treaty, which of the two locations the company will be deemed to be resident in. Certain treaties such as the UK/US treaty, however, permit the company to be treated as resident in both locations.

Furthermore, under a double taxation treaty, if a company which is incorporated in the UK is treated as resident outside the UK, usually by virtue of being effectively managed outside the UK, it will also be treated as not resident under UK domestic law (**S.249 FA 1994**).

Residence is not generally important for VAT.

15.2.4 Differing trading entities

Representative offices of non-UK companies

A representative office will typically not be subject to UK tax on any service it supplies to its head office. The representatives will not be carrying on a trade or part of the company's trade and thus will be outside the scope of UK tax.

Some representative offices provide such a substantial level of service in information gathering etc. that the activity itself is regarded as the carrying on of a business in providing services. In this case the profit chargeable to UK tax is generally determined as a percentage of costs (i.e. the turnover is a mark up on costs incurred by the UK activity, resulting in the mark up being the profit).

The percentage mark up to be applied will vary with the level of service and expertise being provided. This 'cost plus' basis can only be agreed in advance, except in very straightforward cases, by way of a formal advance pricing agreement which can be very time consuming to complete. It is possible to obtain a post transaction ruling after the end of the accounting period that avoids any possibility of penalties applying, but generally companies must decide what is a suitable transfer price, document the basis of their decision, and file their return accordingly.

In addition, the UK has double taxation treaties with many countries which would normally, in any event, exempt from tax the activities of a representative office that was merely gathering information in the UK or otherwise performing a support function. To the extent the office is instrumental in introducing or effecting sales, however, a charge to tax will arise as with a branch or agency (*see below*).

A representative office will only remain completely free of tax if it is a branch of a non-resident company and genuinely only acts as an information gathering centre. If the representative office activity is put into a UK company, that company will be regarded as providing services for which it should earn an arm's length fee (again normally computed on the 'cost plus' basis mentioned earlier).

For VAT purposes a representative office will be a business establishment, albeit not one which is directly concerned with making supplies. As such it is not required to register for VAT but may do so on a voluntary basis if the company wishes to recover any UK VAT paid on business costs.

Branch or agency

A foreign company, trading in the UK through a branch or an agency, will be chargeable to corporation tax in the UK on any profits attributable to that branch or agency activity. (See the definition of business profits attributable to a foreign branch contained in the OECD model tax treaty in Appendix 15.1.) In this connection the term 'agency' can include a broker or other intermediary instrumental in carrying out the trading activities.

However, there are exclusions from any charge in the case of independent brokers and investment managers carrying out certain investment transactions.

In many cases the terms of a relevant double taxation treaty will exclude independent commission agents acting in the ordinary course of their business from being a permanent establishment (i.e. branch or agency of the overseas company) even if they have power to conclude contracts. The same is not true, however, for companies which are related. (See the definition of a permanent establishment in the OECD model tax treaty in Appendix 15.1.)

For VAT purposes the position is broadly the same. The existence of a branch or agency in the UK through which trading is undertaken will normally call for the VAT registration of the overseas company. Any supplies of services are normally treated as taking place at the location of the supplier. However, under oil trading contracts (particularly traded or over the counter options or price swaps) the supply is treated as taking place at the location of the recipient. Brokerage or agency services relating to over the counter deals may be treated as taking place where the underlying trade takes place. For contracts treated as supplies of goods, different rules apply based on their location at the point of delivery or appropriation.

UK subsidiary

UK resident subsidiaries are chargeable to UK corporation tax on their world-wide profits, wherever generated. A credit is, however, available against the UK liability for any tax suffered on the same profits in a foreign jurisdiction. To the extent that services are provided to non-UK resident affiliates, or non-UK branches of UK affiliates, arm's length prices have to be applied in computing taxable profits.

For VAT the position is basically the same as for a branch.

15.2.5 Taxation of income and gains

The rate of corporation tax is currently (1 April 2001) 30 per cent, although this rate may be reduced to the small companies rate (currently 20 per cent) where the profits charged to tax are small (currently less than £1.5 million) or 10 per cent if profits are below £10,000. However, these limits are reduced for group companies, by being divided by the number of active companies in the world-wide group. For large groups, these reliefs are generally of no significance.

Trading losses may be set off against other current year profits or gains and can be carried forward indefinitely for set off against future income of the same trade. Trading losses may also be carried back against previous year's chargeable profits and gains (**S.393/393A TA 1988**).

Capital gains are chargeable as part of the corporation tax profit. Capital losses brought forward and current year capital losses are set off against current year capital gains; there is no carry back of capital losses.

Profits from UK upstream oil and gas activities are "ring fenced" for corporation tax purposes such that losses and other reliefs from "non-ring fence" activities, such as oil trading cannot be utilised to reduce tax on ring fence profits.

The standard rate of VAT is 17.5 per cent with certain supplies, notably financial services, being exempt. Some commodity transactions treated as UK exchanges or involving exports are, however, zero rated (i.e. taxed at 0 per cent). Certain supplies of exciseable goods in bond are outside the scope of VAT.

15.2.6 Treaties

The UK has an extremely wide treaty network with fully comprehensive treaties in place with all major trading locations in the world. The list of countries with which the UK has a full treaty is as follows:

Algeria
Antigua
Argentina
Armenia
Australia
Austria
Azerbaijan
Bangladesh
Barbados
Belarus
Belgium
Belize
Bolivia
Botswana
Brunei
Bulgaria
Burma (Myanmar)
Canada
China (People's Republic)
Croatia
Cyprus
Czech Republic
Denmark
Egypt
Estonia
Falkland Islands
Faroe Islands
Fiji
Finland
France
Gambia
Georgia
Germany
Ghana
Greece
Grenada
Guernsey
Guyana
Hungary
Iceland
India
Indonesia
Ireland
Isle of Man
Israel
Italy
Ivory Coast
Jamaica
Japan
Jersey
Kazakhstan
Kenya
Kiribati
Korea
Kuwait
Kyrgystan
Latvia
Lesotho
Luxembourg
Macedonia
Malawi
Malaysia
Malta
Mauritius
Mexico
Moldova
Mongolia
Montserrat
Morocco
Namibia
Netherlands
New Zealand
Nigeria
Norway
Oman
Pakistan
Papua New Guinea
Philippines
Poland
Portugal
Romania
Russian Federation
St. Christopher & Nevis
St. Vincent
Sierra Leone
Singapore
Slovak Republic
Slovenia
Solomon Islands
South Africa
Spain
Sri Lanka
Sudan
Swaziland
Sweden
Switzerland
Tajikistan
Thailand
Trinidad
Tunisia
Turkey
Turkmenistan
Tuvala
Uganda
Ukraine
UAE
USA
Uzbekistan
Venezuela
Vietnam
Yugoslavia
Zambia
Zimbabwe

15.2.7 Administration

The corporation tax payable by a UK company or a UK branch of an overseas company is based on profits referable to its accounting period (which cannot in practical terms exceed one year since, where accounts cover a longer period, the results are time apportioned). Under the self assessment regime companies must return their profits (having adopted arm's length prices for any non-arm's length transactions) and compute the amount of tax due. The Inland Revenue will examine some returns, typically those of larger companies, which is likely to include most oil traders. On examination they may require that amendments be made to the return.

Tax for companies where the small companies' rate does not apply (*see Section 15.2.5*) is payable in four instalments – these being in months 7 and 10 of the year in question and in months 1 and 4 of the following year. Some transitional reliefs do, however, apply until 2001. For other companies tax is not due until 9 months after the end of the period.

A non-resident company may be assessable and chargeable to UK income tax or corporation tax in the name of the UK branch or agent. The UK branch or agent is charged and assessed in the same way as the non-resident company would be charged and assessed if it were UK resident (**S.126 FA 1995 et seq.**).

VAT is accounted for on the basis of VAT accounting periods, usually of 3 months. Formal VAT returns must be submitted, together with any tax, by the end of the month following. Delays in submission or payment or mistakes can incur substantial penalties (not deductible for corporation tax). Failure to register on time can also give rise to penalties.

15.2.8 Special considerations for oil traders

Many international trading organisations have set up offices in London and, by having all contracts concluded outside the UK, have sought to keep themselves outside of the UK tax net. They would argue that they have not carried on a trade in the UK. In many such cases people based in London will do all of the initial work of finding potential buyers or sellers and discussing price parameters to the point where a deal looks possible. Agreement of the terms will then be done from the tax haven location with the final contract documentation being sent from that location. Most companies with these operations have been able to agree with the UK Revenue a 'cost plus' basis of taxation (*see Section 15.2.4*).

However, such arrangements are becoming increasingly hard to operate. Firstly, the individuals based in London are usually traders by profession. They want to trade and for companies to use their expertise effectively they need to be able to trade. If, in reality, the trader takes a deal almost to its conclusion and then hands it over to a foreign location merely to implement it, the additional paperwork required puts an unwanted burden on the operations and it could be that the trader has effectively created a trading presence for the company even without formalising the contract.

Also, the Inland Revenue are becoming increasingly more adept at establishing where the true trading operation is being carried on and are able to extract much higher mark ups on cost, or perhaps establish that the foreign entity has traded in the UK.

Further, new technology and trading practices make it difficult for contracts not to be concluded in the UK. This is particularly the case in futures trading, where the prices at which contracts are traded are constantly changing and trading can in effect only be done over the telephone or on screen with confirmatory paperwork following later.

Where UK-based traders actively trade in the market the group will generally want to seek to agree a basis of taxation with the UK Inland Revenue which will provide some certainty and minimise the risk of double taxation.

Where the trading activity is substantial and contracts, when required, pass between trading offices at market values, the accounts for the UK branch or subsidiary will generally be used to determine the UK taxable profit.

However, where the activities are so intertwined with the global trading of the group and where the principal trader has the protection of a relevant double taxation treaty, the profit attributable to contracts entered into in the UK can sometimes be determined on a commission basis. The level of commission can often be agreed in advance with the Inland Revenue and the basis of taxation agreed may well include an element of ‘cost plus’ as well as a commission (*see Section 15.2.4*).

Where there is substantial speculative trading controlled by the UK traders outside the global network, the Inland Revenue will usually seek to isolate this to tax it separately.

For VAT, the position depends very much on the nature of what is being traded and the circumstances in which this takes place. As noted earlier, there is an important distinction between transactions which involve goods and those which represent services. This affects both the place of supply and, in some cases, the VAT liability.

In general, contracts, other than pure agency arrangements, which involve spot, forward or traded futures in tangible commodities such as oil or gas are supplies of goods. If the place of supply is in the UK the standard rate of $17\frac{1}{2}$ per cent will apply unless:

- the oil or gas is excisable and is sold whilst warehoused – i.e. in bond (when the supply is outside the scope of UK VAT);
- the oil or gas is imported and potentially subject to Customs duty and is sold while in bond (when it is outside the scope of UK VAT); or
- the oil or gas is physically located outside the UK (when it is again outside the scope of UK VAT); or
- the contracts are traded on an approved UK terminal market – in this case the IPE (when the supply is zero-rated).

Where goods are brought into the UK from abroad the buyer or consignee will generally have to pay or account for VAT on arrival unless the goods are taken into bond, when VAT generally becomes payable on removal for home use. This VAT can usually be deducted as input tax. This does not apply, however, to contracts which are not deliverable, such as contracts for differences, where the supply is seen as an exempt "monetary" financial service. However, it should be noted that for these purposes IPE Brent crude contracts are treated by Customs as deliverable.

In addition, goods removed from bond are subject to VAT at the standard rate.

Contracts involving options are treated as financial services for VAT. The place of supply, in broad terms, is where the recipient is established or has a place of business established to which the supply is made. If the place of supply is in the UK, the supply will be taxable at the standard rate unless the contract:

- is with a member of the IPE, when the supply is zero-rated; or
- is with a buying counterparty established outside the UK (when it will be outside the scope of UK VAT);
- involves contracts which are not deliverable, such as contracts for differences when the supply is seen as a basically exempt "monetary" financial service.

The treatment of brokerage or agency services will tend to follow the same broad principles as the underlying trade will generally be seen as taking place for VAT where the underlying trade itself takes place. In some cases it is possible that the existence of a UK desk in a foreign company managing a global book may mean that the company is established in the UK for VAT. This need not be restricted to a branch situation, but can also apply where this is operated by an affiliate, depending on the scope of what that affiliate does in effecting particular sale or purchase transactions. The result may have a consequential impact on VAT liabilities.

15.2.9 Petroleum Revenue Tax (PRT)

Petroleum Revenue Tax (PRT) is chargeable on the profits from the production of oil and gas under UK licences and any associated income generated from assets used in the production process. However, PRT was abolished in respect of fields which receive development consent after 15 March 1993. Oil trading profits are not subject to PRT although the activities of oil traders can influence the price on which production is subject to PRT (*see Section 15.5*).

15.3 United States

David Zimmerman & John S. Levin, Miller & Chevalier

The US has long been a trading centre within the global market for oil trading activities with significant amounts of trading taking place in New York, Houston and Chicago.

15.3.1 Scope of tax

US corporations

US corporations are taxed on their world-wide income. A corporation is treated as a US corporation if incorporated in the United States, regardless of where managed or controlled. US subsidiaries of a foreign corporation are taxed on their world-wide income in the same manner as other US corporations.

Generally, US corporate shareholders of a foreign corporation are not taxed on the earnings of the foreign corporation until it pays a dividend. The US tax system has various provisions that attempt to discourage avoidance of US tax by diverting income to a foreign corporation. They include controlled foreign corporation (CFC) provisions, foreign personal holding company provisions, foreign investment company provisions, and passive foreign investment company provisions. Although each of these provisions must be considered by any US corporation that owns stock in a foreign corporation, the most far-reaching of these are the rules dealing with CFCs.

A CFC is any foreign corporation with more than 50 per cent of

- (i) the total combined voting power of all classes of its stock entitled to vote, or
- (ii) the total value of its stock is owned, directly or indirectly, or through certain related parties, by US shareholders on any day during the taxable year of the foreign corporation.

US corporations owning 10 per cent or more of the voting stock of a CFC (US shareholders) are taxed on their share of the CFC's subpart F income, even if this is not distributed during the tax year. Subpart F income generally consists of passive income, including net gains from commodity transactions, such as oil and gas futures and forward transactions, unless substantially all of the CFC's business is as an active producer, processor, handler, or merchant of commodities. Subpart F income also generally includes interest, dividends, royalties, gain from the sale of certain property, including shares of stock, and certain other categories of income.

A tax credit is available to offset US tax liability on foreign source Subpart F income for foreign income taxes paid or accrued on that income.

Foreign corporations

Foreign corporations generally are taxed in the US as follows:

(1) Net income that is effectively connected with the conduct of a US trade or business are taxed at regular US corporate rates (a maximum rate of 35 per cent).
(2) Certain categories of US source income not effectively connected with the conduct of a US trade or business are taxed at a flat rate of 30 per cent of gross income (unless a lower treaty rate applies).
(3) Income of a foreign corporation's US branch is also subject to a 30 per cent branch profits tax (unless a lower treaty rate applies) imposed on:
    (i) the current earnings of the US branch that are effectively connected with the conduct of a US trade or business,
    (ii) interest paid by the US branch to a foreign lender, and
    (iii) interest expense attributable to the US branch that is deemed excessive.
(4) A foreign corporation's foreign income not effectively connected with a US trade or business is exempt from US taxation.

Whether a foreign corporation's US activities consist of a trade or business is determined under a facts and circumstances test.

Generally, all of a foreign corporation's US source income is treated as effectively connected with its US trade or business. Certain kinds of US source income, however, such as capital gains, interest, dividends, rents, and royalties are treated as effectively connected only if they are derived from assets used or held for use in the conduct of the US business or the activities of the US business were a material factor in the realisation of such gain or income.

Income from the sale of personal property, including oil contracts, by a foreign corporation is generally US source income if the sale is attributable to a US office or fixed place of business (US office) maintained by the foreign corporation. Such income is treated as US source income effectively connected with the conduct of a US trade or business.

Income is generally attributable to a US office if the US office is a material factor in the realisation of the income. A US office is a material factor in the realisation of the income if:

(i) the office actively participates in soliciting the order, negotiating the sale contract, or performing other significant services necessary for the consummation of the agreement, which are not the subject of a separate agreement between the buyer and seller, and
(ii) the income is realised in the ordinary course of the foreign corporation's trade or business carried on through the US office.

Under a special exemption for inventory property sold for use, disposition, or consumption outside the US, income from such sale is foreign source income not effectively connected with the conduct of a US trade or business if the foreign corporation maintained an office or fixed place of business outside the US that materially participated in the sale of the inventory property, even if the US office also materially participated in the sale.

Generally, a foreign corporation has a US office if it maintains a fixed facility in the United States where it carries on regular business activities. The office of an independent agent is not treated as the US office of its principal. The office of a dependent agent, however, can constitute a US office of a foreign corporation if the agent can negotiate and conclude contracts in the foreign corporation's name or the agent has a stock of merchandise from which it regularly fills orders on behalf of the foreign corporation.

Gains and losses from the disposition of US real property interests (USRPIs) are treated as effectively connected with a US business. Included in the definition of a USRPI are interests in real property located in the United States (including any interest in an oil well) and, generally, stock of a US corporation if USRPIs comprise at least 50 per cent of the corporation's total value.

A tax credit is available to foreign corporations engaged in a US business for foreign income taxes paid or accrued on their foreign source effectively connected income.

15.3.2 Residence

For US corporate income tax purposes, a company's country of incorporation rather than residency is used to determine income tax liability.

15.3.3 Taxation of income and gains

The regular US corporate tax rates are progressive for the first $100,000 of income, ranging from 15 per cent to 34 per cent. The tax rate increases to 39 per cent for income above $100,000 up to $335,000 and returns to 34 per cent for income in excess of $335,000 but less than $10 million. Income above $10 million is taxed at a rate of 35 per cent.

In addition to the regular US corporate income tax, foreign corporations conducting business in the United States are subject to a 30 per cent branch profits tax and a 30 per cent branch-level interest tax. These taxes attempt to equalise the taxation of income earned by US branches with income earned by foreign-owned US subsidiaries. Foreign corporations are subject to a 30 per cent branch profits tax on after-tax earnings connected with a US branch to the extent such earnings are not reinvested in the US branch. Foreign corporations are also subject to a 30 per cent tax on interest paid by the US branch and certain additional interest that is deductible against the branch's effectively connected income. The branch profits tax or the branch-level interest tax may be reduced or eliminated by a tax treaty.

Corporations may be liable for the alternative minimum tax (AMT). The AMT is calculated separately from the regular US corporate tax. Taxpayers pay the AMT in excess of the regular corporate tax. The AMT is intended to ensure that corporations with substantial economic income pay some minimum amount of US tax. The AMT is a flat rate tax of 20 per cent for corporations reduced by the AMT foreign tax credit for the taxable year.

Capital gains realised by corporations are currently taxed at a maximum rate of 35 per cent. Capital losses may only offset capital gains. Capital losses in excess of capital gains can be carried back three years and carried forward five years.

Net operating losses from US business activities can generally be carried back 2 years and carried forward 20 years in computing income subject to US tax.

15.3.4 Treaties

The United States has income tax treaties in effect with the following countries:

Armenia
Australia
Austria
Azerbaijan
Barbados
Belarus
Belgium
Canada
China (People's Republic of)
Cyprus
Czech Republic
Denmark
Egypt
Estonia
Finland
France
Georgia
Germany
Greece
Hungary
Iceland
India
Indonesia
Ireland, Republic of
Israel
Italy
Jamaica
Japan
Kazakhstan
Korea, Republic of
Kyrgystan
Latvia
Lithuania
Luxembourg
Malta
Mexico
Moldova
Morocco
Netherlands
New Zealand
Norway
Pakistan
Philippines
Poland
Portugal
Romania
Russia
Slovak Republic
Slovenia
South Africa
Spain
Sweden
Switzerland
Tajikistan
Thailand
Trinidad and Tobago
Tunisia
Turkey
Turkmenistan
Ukraine
United Kingdom
Uzbekistan
Venezuela

The United States also has income tax treaties in effect with Aruba, Bermuda, and the Netherlands Antilles that apply to limited items.

15.3.5 Administration

US corporations are required to file an annual income tax return.

Foreign corporations engaged in US business, or that have a permanent establishment in the US, any time during the tax year must file an annual income tax return. This rule applies even if the foreign corporation has no net income that is effectively connected with its US business. A foreign corporation that fails to make a timely return may not be able to receive the benefit of most of the deduction and credits otherwise allowed to it under the code.

Foreign corporations not engaged in US business at anytime during the tax year generally are not required to file an annual return if their US tax liability for the year is fully satisfied by US withholding taxes on income from US sources. A foreign corporation must file a return, however, for any year in which it claims treaty benefits or seeks a refund.

Foreign corporations engaged in US trade or business and US corporations that are at least 25 per cent owned (by vote or value) by foreign persons must file an annual information return reporting information about certain foreign related party transactions and must keep records concerning these transactions.

15.3.6 Special considerations for oil traders

Foreign corporations trading in commodities through a resident broker, commission agent, custodian, or other independent agent are not considered to be engaged in a US business as long as the foreign corporation does not have a US office through which the commodity transactions are effected.

Foreign corporations trading in commodities for their own account, regardless of how the trades are effected, are not considered to be engaged in a US business even if the foreign corporation has a US office. This exception, however, does not apply to foreign corporations that are dealers in commodities. In order for a foreign corporation to qualify for this exception, the commodities must be of a kind customarily dealt in on an organised commodities exchange and the transaction must be of a kind customarily consummated on such an exchange.

A foreign corporation taxable in the US that is a commodities trader may elect to report gains and losses from certain commodities and related contracts held at the close of the taxable year under a mark-to-market system. Under this system, the commodities and related contracts on hand at the end of the year are treated as sold for fair market value on the last business day of the year. Any gain or loss on the contracts subject to this elective mark-to-market system is treated as ordinary gain or loss. Commodities and related contracts subject to this mark-to-market regime include actively traded commodities, notional principal contracts with respect to an actively traded commodity, any evidence of an interest in, or derivative interest in, any actively traded commodity, including any option, forward contract, futures contract, short position, and any similar interest in such a commodity. Once made, this election can be revoked only with IRS consent.

A foreign corporation subject to US taxation that does not elect the broad mark-to-market treatment discussed above must nevertheless report gains and losses from regulated futures contracts and non-equity options held at the close of the taxable year on a mark-to-market basis. Under this more limited mark-to-market regime, the regulated futures contracts and non-equity options on hand at the end of the year are treated as sold for fair market value on the last business day of the year, and gain or loss recognised on such contracts is treated as 40 per cent short term capital gain or loss and 60 per cent long term capital gain or loss.

Oil traders may also be subject to loss deferral rules on certain straddle transactions. Generally, the straddle rules require that losses realised on one leg of a straddle be deferred until the gain on the offsetting leg is recognised. A straddle generally is defined as offsetting positions with respect to actively traded personal property. Certain hedging transactions are not subject to this loss deferral rule.

As with most tax jurisdictions the US has transfer pricing rules for transactions between related parties. It is, however, possible to obtain advance rulings in the US that could cover how profits from a global trading activity will be allocated to the various taxing jurisdictions for US tax purposes.

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15.4 Singapore

Alain Ahkong, Pioneer Associates Ltd.

Singapore is the third largest oil trading centre in the world today, after New York and London. It is also the most important oil trading centre in the Asia–Pacific region.

There are many factors which have contributed to the success of Singapore as a leading oil trading centre. Most notably is its ideal location at the tip of the Malayan Peninsula which provides for the close proximity to the major oil producers and markets in the Asia–Pacific region. The major oil producers in the region include Malaysia, Indonesia, China and Brunei, and the major markets comprise Japan, South Korea, Taiwan, Australia and India. The Singapore government is also committed to making Singapore an international oil trading centre. It introduced the Approved Oil Trader tax incentive scheme in 1989 and is committed to broadening the range of contracts (including energy futures) on the Singapore International Monetary Exchange (now part of the Singapore Exchange).

With effect from June 2001, the Approved Oil Trader Scheme was merged with the Approved International Trader Scheme – a similar scheme for trading in approved commodities and products – known as the Global Trader Programme. The benefits of the programme remain the same.

The physical trading of crude and finished petroleum products has been the backbone of the oil trading market in Singapore. However, the recent influx of oil brokers into Singapore has resulted in a growth of the paper market. Whilst the physical business conducted by the international oil traders should continue to increase significantly, the growth of the paper market is expected to outpace the physical market in the longer term.

There are currently more than 100 oil traders in Singapore and the list continues to grow. These traders range from the oil majors and refiners to independents and Japanese trading houses. In view of the Singapore government's actions to promote the oil and gas industry an increasing number of companies are expected to expand their oil trading operations into Singapore. As a result, the income tax laws and the taxation of oil trading in Singapore will invariably be important issues on the agenda of these companies.

15.4.1 Scope of tax

Singapore income tax is imposed on a resident company in respect of:

(i) income accruing in or derived from Singapore, and
(ii) income received in Singapore from outside Singapore (i.e. foreign source income received in or remitted to Singapore).

There is no capital gains tax in Singapore. However, gains from short-term real property transactions and gains from short-term transactions of shares in private real property companies are deemed to be "income" and chargeable to income tax.

A foreign source income is deemed to be received in Singapore from outside Singapore where:

(a) it is remitted to, transmitted or brought into Singapore;
(b) it is applied in or towards satisfaction of any debt incurred in respect of a trade or business carried on in Singapore; and
(c) it is applied to purchase any moveable property which is brought into Singapore.

A non-resident company carrying on business in Singapore through a branch is taxable on income accruing or derived from Singapore. It may also be taxed on income received in Singapore from outside Singapore only to the extent that the offshore income is directly attributable to the branch's operations.

15.4.2 Residence

For Singapore income tax purposes, a company is resident in Singapore if the control and management of its business is exercised in Singapore. The country of incorporation is not decisive in this respect. Generally, control and management is considered to be exercised at the place where the Board of Directors meetings are regularly held and important decisions taken.

A foreign company carrying on business in Singapore through a branch office is not likely to be considered resident in Singapore since the directors of the foreign company would in most cases exercise control and management outside Singapore.

15.4.3 Taxation of income and gains

For the Year of Assessment 2001, the corporate tax rate in Singapore is 25.5 per cent. With effect from the Year of Assessment 2002, the rate is reduced by 25.5 per cent with the following tax exemptions:

(a) three-quarters of up to the first S$10,000 of a company's chargeable income; and
(b) one-half of the next S$90,000.

Thus, the effective corporate tax rate in the Year of Assessment 2002 is as follows:

Tax on first S$10,000	6.125%
Tax on next S$90,000	12.25%
Tax on income exceeding S$100,000	24.5%

Trading losses can be carried forward to be utilised against future years' profits so long as the company meets the "substantial shareholders" test, that is, there is no more than a 50 per cent change in the shareholders and their shareholdings in the company as on the last day of the calendar year in which the losses arose compared with the first day of the year of assessment in which the losses are utilised.

Where a company fails to meet the above test, it may apply for a ministerial waiver if it can substantiate that the change in shareholders and their shareholdings was due to legitimate purposes not motivated by tax considerations. Under such circumstances, the losses can only be set off against profits from the same trade or business in respect of which that loss was incurred.

15.4.4 Differing types of entities

Representative offices of non-Singaporean companies

Foreign companies that have been granted procedural approval from the Singapore Trade Development Board to set up representative offices in Singapore are not permitted to undertake any business transactions in Singapore, including the conclusion of contracts and opening or negotiating letters of credit directly or indirectly on behalf of its head office. They have no legal corporate status in Singapore. A representative office's activities are strictly confined to promotional and liaison work for its head office. It is not therefore subject to Singapore tax.

Foreign companies are required to renew their representative office status annually.

Singapore branch

The chargeable profits of a Singapore branch are subject to tax at the same tax rate applicable to companies (*see Section 15.4.3 above*).

There is no withholding tax on the remittance of branch profits.

Singapore subsidiary

There is no withholding tax on dividends. Singapore operates a full imputation system. Under Section 44 of the Singapore Income Tax Act the income tax paid by a company resident in Singapore on its profits is fully passed on or imputed to the shareholders on payment of a dividend.

For a Singapore resident company, the amount of tax at the prevailing corporate tax rate deemed paid on the dividends to its shareholders may be credited against the shareholder's tax liability and any excess deemed tax credit is refundable. Dividends paid out of tax exempt profits or profits which have been subject to a reduced tax rate are not subject to the provisions of Section 44 and can be paid to the shareholders free of Singapore tax.

The provisions of Section 44 also do not apply to dividends paid by a Singapore resident company out of certain foreign income for which tax credit has been allowed against the Singapore tax payable.

A portion of the foreign income (computed in accordance with a prescribed formula) is credited to a special account and dividends paid out of the foreign income credited to this account are exempt in the hands of shareholders. Where the recipient of the tax exempt dividends is a Singapore holding company owning 50 per cent or more of the beneficial interest in the issued share capital of the Singapore resident company at the time it receives the tax exempt dividends, it can in turn distribute tax exempt dividends out of such tax exempt income to its shareholders. The "50 per cent" criteria may be relaxed under certain circumstances.

The tax exemption does not apply to dividends paid to holders of preference shares.

Singapore service company

A foreign company may incorporate a Singapore subsidiary which provides services in the normal course of its business for a fee.

The service company would provide administrative and information gathering services and would seek potential customers. Such a company cannot conclude contracts or control the pricing of products if it is to be a service company. Under current practice the Singapore tax authorities expect a minimum taxable income based on 5 per cent of the cost of providing the services.

15.4.5 Treaties

Singapore has concluded double tax treaties with the following countries:

Australia
Bangladesh
Belgium
Bulgaria
Burma (Myanmar)
Canada
China (PRC)
Cyprus
Czech Republic
Denmark
Egypt*
Finland
France
Germany
Hungary
India
Indonesia
Israel
Italy
Japan
Latvia
Luxembourg
Malaysia
Mauritius
Mexico
Netherlands
New Zealand
Norway
Oman
Pakistan
Papua New Guinea
Philippines
Poland
Portugal
South Africa
South Korea
Sri Lanka
Sweden
Switzerland
Taiwan (ROC)
Thailand
United Arab Emirates
United Kingdom
Vietnam

**awaiting ratification*

Singapore has also concluded an agreement on mutual tax exemption with:

- USA – on income derived from international operation of ships or aircraft;
- Saudi Arabia – on income arising from the business of international air transport;
- United Arab Emirates – on income arising from the business of international air transport;
- Chile – on income arising from international operation of ships;
- Bahrain – on income arising from the business of international air transport; and
- Oman – on income arising from the business of international air transport.

Residents of Singapore are eligible to enjoy the benefits accorded under the various treaties.

15.4.6 Administration

The Singapore tax year (known as the year of assessment) is the calendar year. The basis of assessment is the preceding calendar year's income. In the case of profits derived from a trade or business, where the accounts are made up to a day other than December 31, the profits assessable in a year of assessment from that trade or business are based on the accounts ending in the preceding year.

15.4.7 Special incentives for oil traders

In order to further encourage the growth of the Singapore oil trading industry and to encourage international oil trading companies to base their regional operations in Singapore, the Approved Oil Traders (AOT) Tax Incentive Scheme was introduced on 1 January 1989. The Minister of Finance has issued The Income Tax (Concessionary Rate of Tax for Approved Oil Trading Companies) Regulations 1992 in respect of the incentive. To date, 54 companies have been granted the AOT tax incentive. The features of the AOT tax incentive which is administered by the Singapore Trade Development Board are currently as follows:

Tax benefits

- Companies (both Singapore incorporated companies or branches of foreign companies) granted the status of Approved Oil Trader (AOT) are subject to a tax rate of 10 per cent on qualifying income from qualifying trading activities in approved oil products with non-residents and other AOTs.
- An approved AOT is not subject to the imputation system in respect of dividends paid to holders of shares of a non-preferential nature, out of income which has been taxed at the concessionary tax rate of 10 per cent.

  Note: Dividends paid to holders of shares of a preferential nature are subject to the imputation system where the AOT is resident in Singapore.
- The incentive granted will be for an initial period not exceeding 5 years and may be extended for such further periods, not exceeding 5 years at any one time, on a case by case basis.

Qualifying criteria

Minimum requirements
Potential AOT companies will be assessed on their trading headquarter functions and activities, world-wide networks and performance track record. In addition, the following factors will be taken into account:

1. annual turnover;
2. total business spending;
3. number of experienced oil trading professionals;
4. the quantum of its capital funds;
5. use of banking and other ancillary financial services in Singapore;
6. use of Singapore's trade infrastructure;
7. use of Singapore as a centre of arbitration in case of disputes in its international trade;
8. its contribution to the success of the oil futures market.

Qualifying income from qualifying activities

Qualifying income
The qualifying income is defined as:

1. profits from qualifying transactions; and
2. commission and fees from acting as a broker in physical trading between any of the following persons:
   - an AOT;
   - a person who carries on the business of petroleum refining in Singapore;
   - a person who is neither a resident of nor has a permanent establishment in Singapore; or
   - a branch office outside Singapore of a company resident in Singapore;

but excludes any income attributable to activities carried out in Singapore which add value to the petroleum or petroleum product by any physical alteration, addition or improvement, including refining and blending.

Qualifying transactions
Qualifying transactions for purposes of the Regulations are any of the following transactions carried out by an AOT in currencies other than Singapore dollars:

(a) Physical trading, i.e. trading in petroleum or any petroleum product on a spot or forward basis where the intention of the parties at the time of the transaction is that actual delivery of the petroleum or petroleum product is required, whether or not it is actually made, and where the petroleum or petroleum product is purchased by an AOT from and sold to:
- another AOT;
- a person who carries on the business of refining petroleum in Singapore;
- a person who is neither a resident of nor has a permanent establishment in Singapore; or
- a branch office outside Singapore of a company resident in Singapore;

but excludes any transaction in which the petroleum or petroleum product is purchased for the purposes of consumption in Singapore or for the supply of fuel to aircraft or vessels within Singapore.

(b) Petroleum futures trading, i.e. trading in futures contracts or options in petroleum or petroleum product on any exchange specified in the Regulations of the Singapore Income Tax Act carried out by an AOT in accordance with the rules and regulations or customs and practices of that exchange with:
- an Asian Currency Unit of a financial institution;
- a member of the Singapore International Monetary Exchange;
- a person who is neither a resident of nor has a permanent establishment in Singapore;
- a branch office outside Singapore of a company resident in Singapore; or
- another AOT company.

Note: The exchanges currently specified in the Regulations are as follows:
(i) International Petroleum Exchange
(ii) New York Mercantile Exchange
(iii) Singapore International Monetary Exchange

(c) Over the counter (OTC) hedging, i.e. any transaction, other than a transaction carried out on any specified exchange, in petroleum swaps or options including caps, collars, floors and swap options, where:
- the consideration or other payment in the transaction is calculated on the basis of the price of petroleum or any petroleum products;

- the transaction is in connection with and incidental to any physical trading; and
- the transaction is carried out by an AOT company with:
  - another AOT company;
  - a person who carries on the business of refining petroleum in Singapore;
  - a person who is neither a resident of nor has a permanent establishment in Singapore;
  - a branch office outside Singapore of a company resident in Singapore; or
  - an Asian Currency Unit of a financial institution.

Approved products
Qualifying petroleum products for the purposes of the Regulations are crude oil, asphalt or bitumen, aviation fuel, diesel oil or gas oil, fuel oil, fuel oil components, gasoline, gasoline components, heating oil, kerosene, liquefied natural gas, liquefied petroleum gas, low sulphur waxy residue, lube basestock or its derivatives, naphtha, paraffin wax and sulphur.

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15.5 United Kingdom taxation of trading instruments

Oil traders can use a number of different types of financial instruments in their trading activities. The most common would be options, futures, swaps, term contracts and forward contracts as set out in the earlier chapters of this manual. The UK tax system does not deal easily with any of these transactions, as they are fairly new on the commercial horizon, unless they are undertaken as part of a trade in such financial instruments. Taxation of these instruments in the UK has, therefore, developed in accordance with agreed practices and Inland Revenue concessions.

Sections 15.5.1 to 15.5.3 describe the general PRT and corporation tax treatments of trading instruments. Where the position is potentially different for specific instruments the treatment is described in Sections 15.5.4 to 15.5.7.

15.5.1 Petroleum Revenue Tax (PRT)

PRT is not chargeable on the profits derived from financial or trading instruments and can be disregarded for the taxation of oil trading activities (but see Section 15.6 on the impact of valuation for PRT purposes). Its impact has, however, to be borne in mind by traders seeking to hedge group exposures.

15.5.2 Corporation Tax

General

The corporation tax legislation does not adequately cover the use of trading instruments related to commodities, and the Inland Revenue consider that the tax consequences of each transaction depend on the specific circumstances and the motive for entering into the transaction.

If oil trading instruments are regularly entered into as part of a separate trading activity, all of the gains and losses will be treated as taxable or allowable as ordinary income. For pure oil trading companies, where this is their only activity, this is fairly easy to establish, but for oil companies who have an oil trading group the Inland Revenue are generally reluctant to recognise a separate trading activity. In this case, the rules regarding taxability are far from clear.

Because of this, the Inland Revenue have issued a Statement of Practice (14/1991) which gives some guidance regarding the general treatment of trading instruments.

Where the instrument has been entered into in connection with an underlying revenue transaction, the tax treatment of the instrument will be revenue in nature. Thus, for example, an oil company may hedge against the sale of its equity production and protect against a possible fall in price. The gain or loss on this instrument will then be treated as part of its general trading income (*see, however, the ring fence rules below*).

However, whilst the treatment of an instrument taken out in connection with a specified volume of oil should fall within the revenue category, this may not be the case where the volume of oil covered by the financial instrument is far in excess of the company's equity production or there is no direct match with an underlying transaction. In this case capital gains tax treatment is the most likely outcome.

15.5.3 The ring fence

A "ring fence" is placed around certain UK oil and gas activities covering most upstream operations conducted under UK licences. These ring fence activities are treated as a separate trade for all corporation tax purposes. The rules are designed to prevent reliefs and allowances from non-"upstream" activities being used against upstream profits. Thus, ring fence losses may be used to offset profits from non-ring fence activities, but losses from non-ring fence activities (which include most downstream operations including trading) may not be used to offset ring fence profits.

It is important, therefore, that costs incurred in connection with upstream activities achieve a ring fence tax deduction. Gains and losses on financial instruments would not normally be treated as part of the ring fence profits but providing a connection can be demonstrated ring fence tax treatment is achievable.

15.5.4 Capital gains

If an instrument is marketable and is not quoted on the stock market, a disposal or abandonment prior to its maturity will be a chargeable event for capital gains tax purposes. The wasting asset rules apply so that the base cost of the instrument is depreciated on a straight line basis over its life.

15.5.5 Spot and forward contracts

No specific rules apply for corporation tax purposes and the general rules described above will apply.

For VAT purposes, these contracts are for the supply of goods. The place of supply will be where the goods are located at delivery/appropriation. Thus, if they are in the UK they will be within the scope of VAT. Tax will be due at the standard rate unless:

(i) the goods are subject to duty and are sold in bond. This can potentially apply to crude oil or refined products but not gas. In the case of imported goods VAT is only paid if or when they are removed from bond. For goods produced in bond (e.g. after UK refining) all supplies in bond are disregarded except the last which is taxable; or

(ii) the goods are sold for export when the zero rate applies. This does, however, require proof of export and the seller must usually be the person arranging shipment abroad.

Goods sold abroad to which (i) above applies will still strictly be supplied outside the UK.

15.5.6 Futures contracts

No specific rules apply for corporation tax purposes and the general rules described above will apply.

For VAT, a futures contract for a physical commodity is also a contract for the supply of goods, provided that the contract can technically go to delivery, notwithstanding that the vast majority of such contracts do not go to delivery. The supply will take place where the goods are located at the time the supply takes place. In most cases, as a matter of practice Customs and Excise take this to be in the country in which the exchange on which they are traded is situated. IPE cargoes of gasoil are, for example, often loaded outside the UK in, say, Rotterdam but the supply will be treated as a matter of practice as being made in the UK.

Cash-settled futures contracts, which cannot technically go to delivery, are essentially exempt for VAT and are treated as supplies of financial services with the same treatment as financial futures. The rules for determining the value of the supply can be complicated.

15.5.7 Options

Options can be treated as capital gains tax assets in certain circumstances, but if the option is taken out in respect of a trading item the rules in the Statement of Practice (14/1991) outlined above should apply. Gains or losses on an option taken out as part of a genuine oil trading activity would normally be treated as part of the trading profit or loss of the company.

If an upstream production company used options to hedge its selling price of crude oil or gas, it is unlikely that the Oil Taxation Office would accept the option price as being applicable for PRT or ring fence corporation tax purposes unless specific agreement had previously been made.

In VAT terms, options, whether traded or over the counter, are supplies of financial services. Contracts for oil or oil products will be essentially taxable at the standard rate of 17.5 per cent unless the buyer (if a business) is established outside the UK or Isle of Man or otherwise outside the European Union. Similarly options acquired from someone outside the UK are taxed at 17.5 per cent on a self-supply basis. Traded options on UK exchanges such as the IPE may be zero rated if one of the parties is a member of the exchange. Options related to financial futures contracts on the other hand are normally exempt from VAT with a consequent possible restriction on the amount of input VAT to be recovered.

15.5.8 Swaps

The treatment of financial swap transactions, such as interest rate swaps or currency swaps, are subject to the regimes for the corporate tax treatment of foreign exchange gains and losses and financial instruments which are effective for accounting periods commencing after 23 March 1995. Whilst the legislation does not specifically deal with the distinction between ring fence and non-ring fence transactions, it generally follows the principles outlined above and thus the previous treatment is likely to continue.

Although the Oil Taxation Office is generally reluctant to accept that financing transactions fall within the ring fence, it is possible to get a prior agreement with the Revenue that, provided the transaction is demonstrably a hedge against a borrowing which falls within the ring fence, the profit or loss on the swap transaction will also be treated as within the ring fence.

Swaps in the oil trading sense, i.e. exchanges of cargoes of different crudes with or without a price differential are not within the new legislation, but any profit or loss would normally be treated as part of the trading activity of the company. For an upstream company swapping its own production, the disposal will be treated as a non-arm's length disposal such that the Oil Taxation Office market value has to be brought into account for both PRT and ring fence corporation tax purposes. Any profit or loss on the acquisition and subsequent disposal of the other half of the swap would not be within the PRT net and would be treated as a non-ring fence gain or loss for corporation tax purposes.

As the essence of a swap contract is the hedging of a price variation in the underlying product and given that the contracts are based on deemed purchases and sales, the treatment for VAT purposes is as an exempt financial service. The supply is recognised to the extent that money is received. It can be zero rated if the paying counterpart is established outside the European Community.

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15.6 The UK PRT nomination scheme

15.6.1 Outline

A major influence on oil trading in the UK is the PRT Nomination Scheme. The scheme was introduced in 1987 to counter perceived abuses by the majors, but impacts all companies (**S.61 & Schedule 10 FA 1987**). The scheme primarily influences traders in oil companies that are selling the group's equity crude.

Production of oil (and gas) is subject to PRT, in simple terms, on the market value of the oil produced. For third party arm's length sales, this will be the price achieved, but for other disposals a deemed market value is applied. To avoid companies abusing the system, if companies wish their third party crude sales to be taxed at the price achieved, rather than the deemed market value, the general rule is that the sales contract must be notified (nominated) to the Oil Taxation Office (OTO) of the Inland Revenue by 5 pm on the next business day after which the main terms of the contract are agreed by the traders (**S.61 & Schedule 10 FA 1987**). In practice, traders employed by oil companies to, *inter alia*, sell the group's equity production will need to be familiar with these rules. These rules currently only apply to sales of crude oil.

The deemed market price applied to all other disposals of crude is computed by the OTO based on third party sales data which is available to them. To this end, all UK oil companies and any of their world-wide affiliates can be required to supply details of all relevant transactions in UK crudes and traders who are part of oil producing groups clearly need to have systems in place to produce such data.

Only arm's length sales may be nominated. For non-arm's length sales the OTO market value price will automatically apply. For these purposes an arm's length sale is defined in the Oil Tax Acts as broadly one under a contract where the contract price is the sole consideration for the sale, the terms of which are not affected by any other commercial relationship between buyer and seller or their affiliates, and the seller has no interest in the subsequent resale of the product or any by-product.

Where arm's length sales are made under a long-term formula priced contract it is possible to nominate the contract itself, as opposed to each individual sale, under a "composite nomination" such that all sales under the contract will be treated as being nominated. A composite nomination can, however, only cover a maximum of two chargeable periods, and, therefore must be repeated at least annually. Similarly, should the terms of the contract be changed, a new composite nomination must be made. A long-term fixed price contract has, however, to be nominated when it is entered into on the same basis as a one-off spot sale.

A revision to the Nomination Scheme was introduced in December 1991 which permits companies to “opt out” of the scheme if they always sell on an arm’s length basis and do not trade anything other than their own equity production. The “opt out” scheme was amended as from 1 January 1994 such that companies must notify the wish to “opt out” before the start of the chargeable period to enable companies to “opt back in” to the scheme from the point when they no longer fulfil the criteria for “opting out”.

15.6.2 Calculation of market value

Where a company sells its equity production otherwise than at arm’s length (e.g. to an affiliate), a market value is imputed for tax purposes. A single market value for each blend of crude is arrived at for each month and applied to all relevant deliveries in that month. The market value of Brent crude is derived from a database maintained by the Oil Taxation Office and the source data consists of the prices realised on all known third party sales in that crude (from all sources), on contracts struck over a period commencing at the beginning of the calendar month prior to the delivery month and end in the middle of the delivery month; the 45 day period.

A weighted average price is arrived at for each day in the 45 day period and a simple average of all those prices gives the market value for that month. In a situation where the crude is not heavily traded and hence there is not enough data to compute a market value as described, the Brent database is used with the prices for other crudes being arrived at by adding or subtracting a market differential. Contracts based on trigger prices can distort the database since the trigger may be a future price level but the OTO database will bring in the eventual price gained as being achieved on the day of contract. The OTO have stated that they are continuing to keep these areas under review.

15.6.3 Tracking the database

A trader in Brent can track the OTO database with reasonable accuracy (subject to there not being too many trigger deals) and may well be able to take a view before the end of the 45 day period as to whether to sell an equity cargo to a third party or dispose of it on a non-arm's length basis.

In a falling market the trader would usually want to sell the cargo to a third party so that the actual price will stand for tax purposes. In this latter event details of the contract have to be notified to the OTO by 5 pm on the next business day after the sale was agreed under the nomination scheme, and if notification is not made then the higher of market value or the actual realisation is used as the taxable income.

In a rising market, there is an incentive for the trader to dispose of a cargo on a non-arm's length basis since the price derived from the 45 day database will be lower than the price which would be achieved on a sale towards the end of the period.

The tax system could therefore encourage companies to put more volumes into the market where prices are falling and withdraw them from the market when prices are rising.

15.6.4 The Revenue's response

There are anti-avoidance provisions (which have not been activated) which could potentially levy tax on a "penalty" valuation to the extent that there are both nominated equity deliveries in a month and other equity deliveries in the same month. There are, however, provisions protecting crude to be used for refining within the group. The provisions will only apply if, and when, the Government choose to activate them and are not currently believed to act very much as a deterrent against traders picking and choosing selling alternatives.

Most companies in the UK are conscious of the need not to abuse the current valuation system since tax legislation in the UK is likely to change again if the UK Revenue do not believe that they are collecting tax on a representative market value. However, where the market is particularly volatile there is a strong incentive for companies to use the flexibility in the tax system to maximum advantage and when it becomes known that some companies are seeking to maximise their after-tax return, others follow to maintain their competitive positions.

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Appendix 15.1

Articles from the OECD model tax treaty

Permanent establishment

1. For the purposes of this Convention, the term "permanent establishment" means a fixed place of business through which the business of an enterprise is wholly or partly carried on.
2. The term "permanent establishment" includes especially:
   (a) a place of management;
   (b) a branch;
   (c) an office;
   (d) a factory;
   (e) a workshop; and
   (f) a mine, an oil or gas well, a quarry or any other place of extraction of natural resources.
3. A building site or construction or installation project constitutes a permanent establishment only if it lasts more than twelve months.
4. Notwithstanding the preceding provisions of this Article, the term "permanent establishment" shall be deemed not to include:
   (a) the use of facilities solely for the purpose of storage, display or delivery of goods or merchandise belonging to the enterprise;
   (b) the maintenance of a stock of goods or merchandise belonging to the enterprise solely for the purpose of storage, display or delivery;
   (c) the maintenance of a stock of goods or merchandise belonging to the enterprise solely for the purpose of processing by another enterprise;
   (d) the maintenance of a fixed place of business solely for the purpose of purchasing goods or merchandise or of collecting information, for the enterprise;
   (e) the maintenance of a fixed place of business solely for the purpose of carrying on, for the enterprise, any other activity of a preparatory or auxiliary character;
   (f) the maintenance of a fixed place of business solely for any combination of activities mentioned in sub-paragraphs (a) to (e), provided that the overall

activity of the fixed place of business resulting from this combination is of a preparatory or auxiliary character.

5. Notwithstanding the provisions of paragraphs 1 and 2, where a person – other than an agent of an independent status to whom paragraph 6 applies – is acting on behalf of an enterprise and has, and habitually exercises, in a Contracting State an authority to conclude contracts in the name of the enterprise, that enterprise shall be deemed to have a permanent establishment in that State in respect of any activities which that person undertakes for the enterprise, unless the activities of such person are limited to those mentioned in paragraph 4 which, if exercised through a fixed place of business, would not make this fixed place of business a permanent establishment under the provisions of that paragraph.
6. An enterprise shall not be deemed to have a permanent establishment in a Contracting State merely because it carries on business in that State through a broker, general commission agent or any other agent of an independent status, provided that such persons are acting in the ordinary course of their business.
7. The fact that a company which is a resident of a Contracting State controls or is controlled by a company which is a resident of the other Contracting State, or which carries on business in that other State (whether through a permanent establishment or otherwise), shall not of itself constitute either company a permanent establishment of the other.

Business profits

1. The profits of an enterprise of a Contracting State shall be taxable only in that State unless the enterprise carries on business in the other Contracting State through a permanent establishment situated therein. If the enterprise carries on business as aforesaid, the profits of the enterprise may be taxed in the other State but only so much of them as is attributable to that permanent establishment.
2. Subject to the provisions of paragraph 3, where an enterprise of a Contracting State carries on business in the other Contracting State through a permanent establishment situated therein, there shall in each

Contracting State be attributed to that permanent establishment the profits which it might be expected to make if it were a distinct and separate enterprise engaged in the same or similar activities under the same or similar conditions and dealing wholly independently with the enterprise of which it is a permanent establishment.

3. In determining the profits of a permanent establishment, there shall be allowed as deductions expenses which are incurred for the purposes of the permanent establishment, including executive and general administrative expenses so incurred, whether in the State in which the permanent establishment is situated or elsewhere.
4. Insofar as it has been customary in a Contracting State to determine the profits to be attributed to a permanent establishment on the basis of an apportionment of the total profits of the enterprise to its various parts, nothing in paragraph 2 shall preclude that Contracting state from determining the profits to be taxed by such an apportionment as may be customary; the method of apportionment adopted shall, however, be such that the result shall be in accordance with the principles contained in this Article.
5. No profits shall be attributed to a permanent establishment by reason of the mere purchase by that permanent establishment of goods or merchandise for the enterprise.
6. For the purposes of the preceding paragraphs, the profits to be attributed to the permanent establishment shall be determined by the same method year by year unless there is good and sufficient reason to the contrary.
7. Where profits include items of income which are dealt with separately in other Articles of this Convention, then the provisions of those Articles shall not be affected by the provisions of this Article.

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16 Contracts

Denton Hall
Updated by Malcolm Groom and
Diyar Kanashev (Norton Rose)

16.1 Introduction

Oil trading deals can be subject to unforeseen problems and disputes even when the parties are expert, reliable and have no wish to cheat each other. The best way to avoid disputes is to conclude well-drafted, carefully designed contracts.

Oil trading disputes typically arise in the following areas:

- Failure to lift
- Failure (or delay) to deliver
- Problems with documents (not available or not acceptable)
- Problems with the quality or quantity of oil (including measurement issues)
- Problems with transport
- Failure (or delay) of payment
- Disagreements over insurance
- Bankruptcy of one party
- Questions of ownership
- Payment of import duties
- Disagreements with brokers
- Disagreements over terms and conditions
- Sovereign Immunity (in transactions dealing with state entities).

This chapter examines the key issues involved in drawing up oil trading contracts and looks at ways of reducing the risk and possibility of disputes by ensuring that contracts are properly drafted and agreed. It should not, however, be construed as proffering legal advice.

The review of contract terms concentrates mainly on spot or term contracts for physical oil and does not cover forward or exchange contracts, which are typically standard and non-negotiable. However, it highlights any relevant points of comparison with forward and exchange type contracts. Any views expressed about the examples of contract terms are those of the author and not those of the companies whose contracts are quoted in the chapter. Any extracts quoted remain the copyright of the companies concerned.

It is presumed throughout that the obligations are being assumed by the usual party, either the buyer or the seller, in a sale and purchase transaction in accordance with standard practice. Of course, the ultimate terms of any contract will depend on the facts of each case.

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16.2 General

16.2.1 Contract formation

The key to any deal is the negotiation and agreement of the contract terms and conditions that set out the rights and obligations of the parties involved. *How*, *when* and *where* a contract is formed are crucial aspects of the transaction that can be neglected once the price is agreed. This can result in the two parties ending up with widely different perceptions of the nature of the agreement that they have just entered into.

Oil trading contracts can be made in many different ways – either written or oral. However, any contract must comply with certain essential requirements to ensure that it is legally binding and enforceable. The English law requirements for a valid contract are summarised as follows:

(a) the parties must intend to enter into a legally binding contract. In the case of a commercial agreement such an intention will normally be presumed, however, this presumption may be rebutted where the agreement expressly states there is no intention to create legal relations. Similarly if the document is a statement of government policy this may not amount to a contract but rather an expression of intention;
(b) there must be an agreement, which comprises an offer and the acceptance of a promise. An offer has been defined as "an expression of willingness to contract made with the intention (actual or apparent) that it shall become binding on the person making it as soon as it is accepted by the person to whom it is addressed" and an acceptance "is a final and unqualified expression of consent to the terms of an offer".[1] Thus, under English law, a counter offer can never constitute an acceptance (as the mere making of a counter offer revokes the original offer);
(c) consideration (meaning something of value) for that promise must be given by the promisee or must be received by the promisor. If the promisee suffers a detriment at the promisor's request but the promisee confers no corresponding benefit on the promisor this

[1] Chitty on Contracts.

will still amount to consideration – for example by conferring a benefit on a third party at the promisor's request.

All these basic requirements may be applied to a standard physical oil contract. For example, the seller, who is an oil producer (the promisor), and the purchaser, who is an oil refiner (the promisee), intend to enter into a legally binding contract whereby the producer promises to deliver a cargo of crude oil to the refiner who has agreed to pay the producer for that cargo. However, it should be noted that offers can sometimes be made conditionally, for example, subject to specific circumstances or approval. In such cases, contracts are not binding if the conditions are not met unless the conditions are waived by the party imposing them. Since an oil contract need not be written – or in some cases where it is written, its terms are brief – the conduct of the parties is important in determining whether the contract exists. For example, acceptance of an offer may be by conduct. Acceptance is demonstrated where the purchaser accepts the cargo and uses the oil or, conversely, where the purchaser has offered to buy a cargo and the seller makes that supply.

In oil trading, parties typically deal over the telephone and oral contracts agreed over the phone (followed by an exchange of telexes or confirmation notes[2]) are standard practice, especially in the forward, swaps or over-the-counter options markets. Generally, traders will agree the key points (how much, when and what quantity) and may refer to a master agreement or standard terms.

To ensure the validity and effectiveness of such oral deals, traders should:

- ensure a clear offer and a mirror acceptance (not a counter offer),
- agree a price,

and should not leave anything to chance:

- make references to standard terms and conditions (provided that such standard terms are correctly and precisely identified),
- require confirmation in writing or by fax,
- if possible, document or record the conversation.

---

[2] Telexes are probably the safest option, compared to e-mails or faxes where the potential of an interference with the documents is possible.

It is important with oral contracts that a record is made not only so that there is an accurate record of all the agreed terms in the case of dispute, but also for the sake of clarity as there are often several conversations before a deal is finally agreed.

As a cautionary note, traders should be aware that, even where there has been an offer and acceptance, the contract may still not be valid. For example: the offer may have been terminated because it has been revoked by the promisor or on the basis of a counter offer made by the promisee. In addition, while the bare essentials for the formation of a contract have been fulfilled, satisfaction of such requirements does not alone mean that the contract is effective and enforceable. Contracting parties should be aware that there are circumstances, for example, where there has been a mistake, misrepresentation, fraud, duress or undue influence, which may affect the validity or enforceability of the contract. The parties should also be aware of the potential applicability of other legislative developments, that are not embodied in UK legislation, which may raise issues of illegality of the concluded contracts (e.g. under the scope of rules of the International Securities Lending Association or trading and energy related legislation, such as UN/US sanctions).

16.2.2 Carriage contracts

This section does not provide a detailed examination of maritime law but highlights the types of contracts for carriage which may apply.

Spot and term contracts for the purchase of oil will often involve contracts for carriage by sea, evidenced by bills of lading or contained in charterparties. The most common form of sale contracts for carriage by sea are "FOB" (Free on Board) or "CIF" (Cost, Insurance and Freight) contracts.[3] In the UK, contracts for the sale of goods will also be subject to the terms of the Sale of Goods Act 1979 (as amended by the Sale and Supply of Goods Act 1994 and by the Sale of Goods (Amendment) Act 1995) as well as certain international conventions. Where the parties consider the extent of liability arising out of or in connection with the contract or contemplate conferring of certain rights to a third party the scope of applicability of the Unfair Contract Terms Act 1977 and the Contracts (Rights of Third Parties) Act 1999 should be taken into account. In addition, where an entity benefiting from an

[3] See Chapter 17 for commentary on Incoterms.

exclusive right or which is state-owned is involved, EU procurement rules may need to be considered.

The main distinction between FOB and CIF contracts can be summarised as follows:

- FOB: the seller normally puts goods on board a ship nominated by the buyer who charters (or reserves space on) a vessel; the buyer also arranges insurance. Title usually passes on shipment;
- CIF: the seller arranges freight for carriage of the goods and the insurance. The seller tenders the appropriate shipping documents to the buyer, including a bill of lading and a certificate of insurance. Title normally passes on delivery of the shipping documents.

The key features of bills of lading and charterparties are:

- A bill of lading is evidence of goods having been received by the carrier for shipment and is issued by the carrier to the shipper. There may also be a charterparty in which case the bill of lading may act as a receipt.
- The bill of lading is – most importantly – a document of title. The carrier must deliver the cargo to the holder of the bill of lading and will commit the tort of wrongful interference with the goods if he delivers them to anyone else. If the buyer has no bill of lading, then he may be able to provide an indemnity to the carrier against which the carrier will deliver the goods. Similarly, because a bill of lading may arrive after the goods, it is common for the seller to issue a letter of indemnity that indemnifies the buyer against a failure to deliver documents with the buyer's payment (*see also Section 16.5.2 and Chapter 13*). Carriage contracts evidenced by bills of lading are transferable. Pursuant to 2(1) of the Carriage of Goods by Sea Act 1992 (which came into effect on 16 September 1992) the holder of a bill of lading has the right to sue under the contract of carriage as if he had been a party to it.

There are various types of charterparties but, unlike bills of lading, these are not documents of title and they are not transferable. The most common types of charter contracts are:

- *A time charter* – to charter the ship for a period of time on payment of a hire charge.

- *A voyage charter* – to charter the ship for carrying a cargo which is discharged on payment of freight.

There are also various types of "hybrid" charter which have features of both time and voyage charters.

Sometimes both a bill of lading and a charterparty may be entered into in respect of the same cargo, but different rights and obligations may arise under each document and therefore both documents will need to be considered when considering obligations such as insurance and questions of liability.

16.2.3 Sale of goods

Oil contracts may also fall within the scope of the UK Sale of Goods Act 1979 (*see also Section 16.4.1*) in which case certain terms (concerning the quality of goods) will be deemed to be implied terms. Under the 1979 Act (as amended by the Sale and Supply of Goods Act 1994) it is implied that the goods are of "satisfactory quality" when sold and, in certain cases, fit for the purpose for which they were bought. If the contract is not an "international supply contract", liability for breach of such an implied term may only normally be excluded as far as it is reasonable to do so. In the case of an international sale of goods contract – which is not subject to any reasonableness test in the drafting of its exclusion clauses – a seller may still expressly exclude an implied term in respect of quality.

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16.3 Express terms

Apart from the basic requirements of contract formation, there are a number of fundamental terms that should be included *expressly* in a physical oil sales contract. In the case of a term contract, these would include:

- Parties
- Date
- Definitions
- Quality
- Quantity
- Price
- Payment
- Title and risk
- Settlement or bookout
- Delivery
- Nominations
- Transportation
- Inspection and sampling (including measurement and verification of meters)
- *Force majeure*
- Restrictions
- Duties and taxes
- Assignment[4]
- Liability[5]
- Notices
- Governing law and dispute resolution
- Miscellaneous terms (e.g. sovereign immunity, minimum quantity (e.g. take or pay type clause)).

Such terms may also underlie other types of oil contract. Spot oil contracts would normally include a sub-set of the express terms listed above, in particular: parties, quality, quantity, price, payment, title and risk, delivery, nominations, inspection and sampling, *force majeure*, governing law and dispute resolution (*see sample contracts in Appendix to this chapter*).

It is preferable, wherever possible, to include express terms in a contract to show that basic contractual requirements have

[4] The impact of the third parties' legislation should be considered where applicable.

[5] Where multipartite – joint and several liability issues should be considered.

been met and to provide greater certainty as to what the terms of the contract are. It is desirable for a party to be able to rely on express terms rather than terms which may be *implied* or *incorporated.*

16.3.1 Parties

Purpose

To set out each party's details.

Content

The agreement should commence with a statement of who the contracting parties are. The contract should state:

- *Each party's full name and address*, so it is clear between whom the agreement is made and that the party named in the contract is the same as the party with whom the contract has been negotiated. Each party should then check that the other party is a separate legal entity and that it has the authority and capacity to enter into the contract. The parties may also be concerned about their counterparty's financial position (e.g. if there is an actual or threatened liquidation or administration or if a guarantee or a letter of indemnity has been issued, which can potentially affect the course of parties' dealing).
- *The registered (or principal) office and place of incorporation*, if either party is a company.
- *Which of the parties is the buyer and which is the seller* (and whether there is more than one of either). In more detailed agreements there may be a statement in the introduction describing the type of business that each of the parties is engaged in, for example: oil trader; refiner; electricity generating company.

The agreement can also contain *introductory words*, commonly called *recitals*, which briefly explain why the parties are entering into the contract. Such recitals do not necessarily form the terms and conditions of the contract but may be helpful in determining the parties' intentions at the time of entering into the contract should the contracting parties ever be in dispute. It should be noted that these are not usually employed in short form telex contracts such as spot oil trading contracts where an exchange of telexes will suffice.

Finally, at the end of the agreement there must be *a provision for the parties to sign the document* in order to make it a binding contract. The wording which appears beside each party's signature is commonly called an *attestation* and will vary depending on whether it is a company or individual who is signing the contract. The company's representative(s) should present an authorisation establishing that signing of the contract in question on behalf of the company is within his/her competence and as such making the contract binding on the company. In some cases there may be special requirements such as notarisation or the affixing of a seal.

Example

At the beginning of the contract:

> "This Agreement is made the [ ] day of [ ] 19[ ] BETWEEN:
>
> (1) [Name] of [Address] ('Seller') and
>
> (2) [Name] of [Address] ('Purchaser')".
>
> "Whereas:
>
> (A) The Buyer wishes to buy and the Seller wishes to sell [crude oil] on the following terms and conditions".

At the end of the contract:

> "Signed by [print individual's name]
>
> [SIGNATURE]
>
> for and on behalf of [print company's name]."

16.3.2 Date

Purpose

To specify the date of the agreement and when the contract takes effect.

Content

Sets out the date on which the contract is made, so there is no doubt when the contract was signed. However, there may be an "effective date" defined elsewhere in the text of the agreement which may be different from the date of signing.

Examples

This Agreement is made the [ ] day of [ ] 19[ ];

This Agreement has been entered into on the date first stated at the beginning of this Agreement; or

This Agreement takes effect as at the Effective Date.

16.3.3 Definitions

Purpose

It is common for *terms to be defined* in the first clause of a contract. This is useful for a number of reasons. Definitions will help to keep the contract concise and to avoid repetition of lengthy expressions that may be used several times. Definitions will also avoid a general meaning being applied where a more specific one is required. For example, the term “oil” may mean “Dubai crude oil” and not any other kind of crude oil or refined product.

Defining terms is particularly important where terms are intended to have some meaning other than their usual common meaning. For example, “year” might not mean a calendar year but some other twelve month period. The precise meaning of shipping terms is also of great importance when describing, in particular, transportation obligations of each of the parties.

Content

The clause may contain, preferably in alphabetical order, a list of terms in quotations with meanings or a cross reference to where those terms are defined subsequently in the contract.

Examples

Typical definitions in a spot or term contract for physical oil would include the following terms:

- *The agreement*: specify whether the agreement includes any general conditions of sale and refer to these clearly by name. For example, “Dubai Crude Oil General Terms and Conditions”, and the date of the relevant edition or any other special conditions agreed between the parties. It is not sufficient if a party merely prints its special conditions on the reverse of the contract without expressly stating that they apply.

- *Periods of time*: state whether a day is intended to mean 24 hours or a year is on a calendar year basis and when the time of a day/year is deemed to begin and end.
- *The product*: specify the commodity being bought. Terms such as "gas oil", "commercial butane" or "oil" are too vague unless further defined. "Oil" may mean feedstock and/or petroleum products, and "feedstock" and "petroleum products" will also require definitions. The definition may also refer to a quality specification elsewhere in the agreement which will provide for a more detailed description and specification.
- *Quantities and measurement*: define terms such as "cargo", "ton" and "barrel". Where terms of measurement are used it should be made clear if these are metric or imperial. There may be a cross reference to a more detailed provision contained in a separate quantity clause.
- *Shipping terms*: the following expressions are commonly defined in oil contracts: loading and discharge ports and terminals; commencement and completion of loading times; laydays; the vessel; working days; bill of lading; notice of readiness (NOR); waybill; delivery order; lighterage, demurrage.

Commentary

It is more likely that a term contract for the purchase of large quantities of oil at specified times – which is subject to many conditions as to quality, time of delivery and the obligations of the parties – will require and benefit from a detailed definition clause. By contrast a telex confirming a spot trading agreement may contain no defined terms at all, or simply refer to a published code or a previously negotiated master agreement which itself contains defined terms that the parties require to be incorporated into their agreement. For example, where the parties state that the contract shall be governed by an agreed set of terms and conditions, e.g. "Shell's General Terms and Conditions, 1990".

16.3.4 Quality

Purpose

The purpose of a quality provision is to state the specification required for a particular type of crude oil, refined product or feedstock and the procedures for and limitation on making a claim in respect of material that is off specification. It may contain a sliding scale cash adjustment for permitted variations within a band.

Content

Some of this may already have been dealt with in the definition of the product. The following points should be addressed:

- *Description:* this obviously depends on the type of oil. It would be appropriate to include a specification of the sulphur content, specific gravity, pour point and cloud filter plugging point (CFPP) for gas oil, but the origin, blend and API gravity for crude oil.
- *Warranties:* a buyer may require a warranty as to quality (and this should be expressed to be without prejudice to any statutory rights available to it), even if it is implied. A seller will want to limit this as far as possible. For example, only as far as the quality generally being supplied, at the time of loading in an FOB contract. Some warranty clauses include notice procedures and time limits for making a claim if there is a defect in quality.
- *Claims:* the inclusion of a procedure to notify the seller of defects can provide certainty for both parties. The following points may be addressed:
  - the specific matters for which the buyer may make a claim. For example, a shortage in quantity or a defect in quality. It may also contain potential limitation on type of claim (i.e. no consequential loss for offspec crude oil causing damage to buyer's facilities or loss of business, etc),
  - how the notice is to be given to the seller: in writing; with how much supporting information; within a certain time period (e.g. within so many days following the bill of lading date or on discovery of the defect); and whether the notice is to be followed up by a more formal claim within a certain time,
  - a limitation period during which the buyer may bring proceedings or issue a formal claim once the initial notice has been given,
  - the effect on the buyer of failure to comply with the procedure. It is in the seller's interests to state that

if no formal claim is received within a certain time the claim is deemed to have been waived.

- *Certificates:* the requirement to issue certificates of quality may be in both parties' interests in order to establish whether the oil was of the right quality at the time of delivery. The buyer often requires such documents against which payment may then be made (*see Section 16.3.13 on inspection and sampling*).
- *Testing:* both parties may wish to agree arrangements to test for quality. Provisions concerning rights of sampling and inspection are dealt with in Section 16.3.13.

Examples

"all statutory conditions or warranties with respect to the description, merchantability or quality of the oil or its fitness for any purpose are hereby excluded".[6]

"Notice of any claim by Buyer, either as to shortage in quantity or to defects in quality, shall be submitted to Seller, in writing, with full supporting documentation, within one hundred and twenty (120) days after the bill of lading date, or such shorter period as the Seller's supplier may require (as notified to Buyer in advance). Buyer's failure to comply with the requirements of this section shall be deemed a waiver by Buyer of any such quantity and/or quality claim. With respect to any such quantity and/or quality claim for which notice is given in accordance with this section, Buyer shall commence proceedings pursuant to Section NN within two (2) years from the bill of lading date or any such quantity and/or quality claim shall be forever barred. With respect to the oil sold and purchased hereunder, there are no representations, guarantees or warranties, express or implied, of merchantability, fitness, suitability of the oil for any particular purpose, or otherwise, which extend beyond the description set forth in the special provisions. Seller and Seller's supplier shall not be liable under this agreement for any special, indirect, or consequential damages."[7]

"Any notice of claim as to a defect in quality with respect to any cargo of oil shall be made in writing to Seller immediately after such apparent defect is discovered. Any such notice of claim shall be followed promptly by a formal written claim with all necessary details to promptly process such claim. IF NO FORMAL WRITTEN CLAIM IS RECEIVED WITHIN

[6] Shell FOB/CIF Contract.
[7] Amoco FOB Contract.

SIXTY DAYS AFTER DELIVERY OF THE OIL TO THE BUYER, THE CLAIM SHALL BE DEEMED TO HAVE BEEN WAIVED. . . . THERE ARE NO GUARANTEES, WARRANTIES OR REPRESENTATIONS, EXPRESS OR IMPLIED, OF MERCHANT-ABILITY, FITNESS OR SUITABILITY OF THE OIL FOR ANY PARTICULAR PURPOSE OR OTHERWISE WHICH EXTEND BEYOND THE DESCRIPTION OF THE OIL SET FORTH IN THIS AGREEMENT."[8]

"There are no guarantees or warranties, express or implied, of merchantability, fitness or suitability of the oil for any particular purpose or otherwise which extend beyond the description of the Oil appearing in the Special Terms and Conditions."[9]

"The quality of each grade of Oil shall be the usual production quality of that grade being sold by Seller at the time and place of delivery, unless specifications are prescribed elsewhere in this Agreement, in which case such specifications shall represent the only quality characteristics which the Oil is required to meet. THERE ARE NO GUARANTEES OR WARRANTIES, EXPRESS OR IMPLIED, OF MERCHANTABILITY, FITNESS AND SUITABILITY OF THE OIL FOR ANY PARTICULAR PURPOSE OR OTHERWISE, WHICH EXTEND BEYOND THE DESCRIPTION ON THE FACE HEREOF."[10]

16.3.5 Quantity

Purpose

To specify the amount of oil to be sold and purchased under the contract.

Content

The following points may be specified depending on the type of contract:

- *the number and type of relevant units*, these could be measured either by volume (e.g. metric tonnes) or by weight (e.g. US gallons or barrels),

[8] Chevron FOB Contract.
[9] Elf FOB Contract.
[10] Exxon FOB Contract.

- *delivery tolerances and at whose option*; for example "30,000 metric tons ? 10 percent in Seller's option",
- *in a CIF contract, the parties may allow for evaporation* where relevant and permit delivery within a stated percentage of the quantities specified in the bill of lading.

Examples

> "[Quantity] metric tons plus/minus 5 per cent Seller's option."[11]
>
> "Quality as determined by [original supplier] at loading port [load port]. Load port quality to be final and binding on both parties. Quantity for bill of lading shall be determined by an independent inspector [inspector name] or other mutually agreed inspector. The deemed b/l quantity shall be the average of the mother vessel's ship's figures and the receiving vessel's ship's figures. The resulting quantity, confirmed by the inspectors, will be considered as final b/l quantity, to be final and binding for both parties. Inspection costs to be shared 50/50 between seller/buyer."[12]

Commentary

In a term contract specify the lot size, for example: 10 lots of a specified number of metric tonnes each quarter.

Delivery tolerances should be made with respect to the buyer or seller's operational tolerance.

In the case of CIF contracts there has been much debate about whether 0.5 per cent loss by evaporation is or is not a "custom of the trade". Although courts on both sides of the Atlantic have recognised evaporation loss as an accepted occurrence, it is only in the USA that 0.5 per cent has been established as the level agreed by trade custom.

16.3.6 Price

Purpose

To specify the unit price by currency and by reference to units of the commodity. This may be either a "fixed and flat" price or a reference to a prevailing market price, for example a futures price

[11] Appendix 16.2 Sample FOB Contract (2).
[12] Appendix 16.2 Sample FOB Contract (2).

or a published price assessment (e.g. *Platt's* or an e-index for screen tradings).

Content

The following points should be included:

- *the currency* (usually US dollars or euros where the trading parties are from the Member States of the European Union participating in the common currency) per unit of measurement and, except where the price is fixed and flat, the basis for establishing the price by reference to a particular published marker and whether such a marker is chosen by reference to the same geographical region as the buyer or seller;
- if the price is to be established by reference to a published price (e.g. *Platt's*) then *specify the date or dates on which that price is taken* (often at or around the bill of lading date in the case of an FOB contract);
- what happens if the published price the parties have referred to *becomes unavailable or unascertainable*. In these circumstances, the parties may try and agree an alternative suitable index or take the nearest previously available index (the parties may need to take into account how often the index is quoted when deciding its suitability). Alternatively, it could be weighted against an average of a series of published prices. The parties will also need to agree on a provisional pricing mechanism, where there is a manifest error in the published price, whilst sorting out dispute (if any);
- any *differential* required to take account of quality of the oil and how that is to be determined, for example by formula or the parties' agreement or, failing this, expert determination;
- provisions to allow for *other events which may affect the enforceability of a price provision*. For example, there may be government regulations affecting the enforceability of a price (e.g. price freezing) which mean that a price determined under the contract will not be effective because to do so would violate a direction or request of a government. In such circumstances it may be appropriate to agree on an alternative course of action and, if the parties are unable to agree, provision will need to be made to permit suspension of performance with respect to the quantity of oil affected.

Examples

> "Unless otherwise specified in the special terms and conditions, the price of a shipment shall be that in force at the date of the bill of lading of such shipment."[13]
>
> "US dollars [price] fob [tankco] Amsterdam on EEC basis excluding any duties."[14]
>
> "Price: the five day arithmetic average of the mean of *Platt's* high and low quotations for Arabian Gulf fob high sulphur fuel oil 180 cst cargoes as published in *Platt's European Marketscan* plus [price differential] US dollars per metric ton. The five quotations used shall be the bill of lading date, two days prior and two days after the bill of lading date of the [seller's ship name] or substitute at the loading port [load port]. In the event that there is no *Platt's* publication on the bill of lading date then only four effective quotations shall be used, i.e. two before and two after the bill of lading date."[15]

Commentary

In a long-term contract, there may be a floor and/or ceiling price and the seller may try to negotiate a "hardship clause", which confers the right to terminate the contract if it becomes uneconomic, or the right to renegotiate the price in the event of material change of market conditions.

Prices may also be agreed by including a "netback" provision whereby the seller receives the price realised by the buyer after the buyer's costs for a sale have been deducted; or by a counter trade or barter whereby the product is processed and part of the processed product is returned to the seller to reduce the initial purchase price. These types of pricing arrangements are described in Chapter 3.

16.3.7 Payment

Purpose

To provide methods and procedures for payment[16] of the price of the commodity delivered:

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[13] Elf FOB Contract.
[14] Appendix 16.1 Sample FOB Contract (1).
[15] Appendix 16.2 Sample FOB Contract (2).
[16] For discussion concerning Letters of Credit and Parent Company Guarantees see Section 16.5.2 and Chapter 13.

Content

The following points should be included:

- *the currency in which payment is to be made*, if this has not already been stated in the price;
- *the chosen method of payment*, this is typically by telegraphic transfer or a letter of credit. In either case the seller may require payment to be supported by a bank/parent company guarantee or a performance bond;
- if payment is made by telegraphic transfer, *the time, date and place of payment*. For example, a contract may require that payment is to be made to the named seller's account at a bank on the due date of payment by a certain time (before the banks close) in the country of payment. The seller will usually also require that the payment is to be made in funds having good value on the day in question (i.e. cleared funds);
- *the due date of payment*. Examples of a due date are: a date as notified by the seller or a date within so many days either following discharge of the cargo at the discharge port or following the buyer's nomination. Where the due date of payment is not a business day then such payment should be required to be made on the next (or preceding) day which is a business day. "Business day" may typically be defined as a day on which the banks are normally open for business in the country in which payment is to be received. Strictly speaking, if it is not specified in the contract that if the due date is not a business day, payment must be made on the business day preceding the due date in order to meet the due date payment objectives, but most parties prefer to be specific;
- *procedures for the events of non-payment*, this would establish the amount of interest accruing on the overdue payments. They may also give to the seller the rights to terminate the contract or to suspend performance of its delivery obligations.

Examples

"Payment for each cargo shall be made by Buyers to Sellers against presentation of the following documents:

(i) full set of clean original Bill of Lading
(ii) invoice complying with the requirements of this Paragraph

within 30 days of the Bill of Lading date, free of all charges and without asserting at the time for payment any set-off, counterclaim or right to withhold whatsoever, in United States Dollars in New York to Seller's account number [ ] with [the Bank] (or to such other bank account as may be advised by Sellers to Buyers from time to time) quoting Seller's invoice number and Buyers' name; provided however that if any or all of the required documents are not available at the time payment is due hereunder Buyers shall pay against Seller's Letter of Indemnity for the missing documents."[17]

"Upon presentation of Seller's invoice and any other documents set aside in the Special Provisions, Buyer shall make payment for the Oil delivered hereunder, within the time designated in the Special Provisions, by telegraphic transfer in US Dollars to Seller's Bank identified in the invoice of immediately available ('same day') funds for Seller's use on due date prior to closing time of Seller's bank. In the absence of any time designated in the Special Provisions, payment shall be made to the Seller in accordance with the provisions of this Section within thirty (30) days after Bill of Lading date. If the payment due date falls on a Saturday or banking holiday other than Monday, payment will be effected on the preceding common bank business day. If the payment due date falls on a Sunday or Monday banking holiday, then the payment will be effected on the next common bank business day."[18]

"Payment for the Oil shall be made against Seller's invoice in US Dollars by telegraphic transfer of immediately available funds to Seller at [ ] account of [ ] Account No. [ ], or at such other address or depository as Seller may designate in writing. If the payment due date falls on a Sunday, or on a Monday which is a [New York] bank holiday, payment shall be made in immediately available funds to Seller on the next [New York] banking day after such payment due date. If the payment due date falls on a Saturday, or on a [New York] bank holiday other than a Monday, payment shall be made in immediately available funds to Seller on the last [New York] banking day prior to such payment due date."[19]

[17] Shell FOB/CIF Contract.
[18] Amoco FOB Contract.
[19] Chevron FOB Contract.

16.3.8 Title and risk

Purpose

To agree the point at which or time when title and risk (but not necessarily be simultaneous) passes from the seller to the buyer under the contract.

Content

A statement of the exact point at which title and risk passes from one party to the other.

Examples

> "as the oil passes the flange connection between the delivery hose and the vessel's permanent cargo intake manifold at the port of loading"[20]
>
> "The risk and property of the shipment delivered hereunder shall pass to the buyer as the crude petroleum passes the permanent hose connection at the port of loading."[21]

Commentary

Risk will normally pass at the same time as title and delivery, but it can pass at a different time. In FOB contracts this typically passes at the loading port and the exact point, normally the flange connection, at which it passes should be described.

Ex-ship contracts are different because the title and risk normally passes at the port of shipment. The seller bears the risks of the goods until the goods pass the ship's rail at the port of shipment (if the lighterage is required the parties should decide who is liable for such costs). Once the goods have effectively passed the ship's rail the buyer then bears all the risks of the goods. In either case the insurance obligations should reflect which party bears the risk for the oil.

In either an FOB or a CIF contract, a buyer may require that the seller gives a warranty that it has title to the oil and that oil sold and delivered is free and clear of all charges, liens and encumbrances.

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[20] Amoco FOB General Provisions for Purchase and Sale of Oil in Bulk.

[21] BP Oil International Limited, Conditions of Sale for Crude Petroleum FOB, Single Shipment (1986).

Provisions as to title and risk may however be incorporated or implied. Generally under English law property in identified goods is transferred to the buyer when it is intended to pass. Prior to 1995 property in unascertained goods could not pass under Section 16 of the Sale of Goods Act 1979. But the Sale of Goods (Amendment) Act 1995 amended the Sale of Goods Act 1979 by inserting Section 20A, which now allows for the passing of ownership where a specified quantity of unascertained goods forms part of an identified bulk for contracts entered into, on or after 19 September 1995.

Each case will vary depending on the facts, but the intention as to when property passes may be stated or implied from the terms of the contract or under Rules in s.17 of the Sale of Goods Act 1979 (if that Act applies). In addition, Incoterms provide terms in respect of risk (but not title) and the Carriage of Goods by Sea Act 1992 gives rights to the holder of a bill of lading (*see Section 16.4.2*).

16.3.9 Settlement or bookout

Purpose

To allow for a contract, which could form part of a continuous circle of transactions, to be settled by the payment of differences. If a party appears more than once in a chain of transactions, as often occurs, for example, in the 15-day Brent market, the contract may allow for the transactions to be "formed into a circle" and by agreement cancelled with the payment of the difference between the buying and selling prices. For example, a chain of transactions which involves Company C twice,

A—B—*C*—D—E—F—*C*—G—H

can be partly rearranged into a circle as follows:

```
A—B—C—G—H
   /  \
  D    F
   \  /
    E
```

This is known as a "bookout" and is described in more detail in Chapters 7 and 13.

Content

The following points should be included:

- *a definition of the settlement agreement*, which is normally an agreement between each of the parties involved in the circle pursuant to which no physical delivery of oil is made;
- *an obligation to enter into a settlement agreement* proposed by one of the parties to any of the transactions in the circle on condition that each party involved in the circle has given or gives a similar undertaking;
- *the type of oil to which the agreement will apply*, for example, Brent System crude oil;
- *a deemed delivery quantity*, for example, 500,000 barrels;
- *a deemed completion day of loading and deemed bill of lading*, for example, a specified day in a month or in a loading range;
- *terms of the settlement agreement* pursuant to which each party agrees to cancel its particular contracts in consideration of each party in the circle making payment to or receiving payment from (as the case may be) its supplier and its customer of such sums as shall be agreed between each seller in the circle and its customer. The parties may also consider provision for an adjustment mechanism dealing with the other party's trades or trades of unequal amounts of crude oil.

Example

Shell UK Limited's General Conditions for the Sale of Brent Blend Crude Oil on 15 Day Terms 1990 (Clause 20, Bookout) state that:

"(a) If after the date on which this Agreement is entered into it is found that the transaction which is the subject of this Agreement forms part of a series of transactions which can be shown by any party to any of such transactions to form a continuous circle of such transactions ('the circle') the parties hereto hereby express willingness to consider entering into any bookout agreement (as defined in Clause 20(b) below) that may reasonably be proposed by any party to any of the transactions in the circle provided always that each party involved in the circle has given or gives a similar undertaking, it being always understood that each party hereto retains all rights to decline to enter any such bookout agreement in its sole and unfettered discretion and without any obligation to give any reasons therefor.

(b) For the purpose of Clause 20(a) above, a bookout agreement shall mean an agreement between all parties to the circle in question pursuant to which each party in the circle agrees to forgo the receiving or making of physical delivery of Oil and to discharge its relevant contracts of purchase and sale in consideration of each other party in the circle undertaking to make payment to or receive payment from, as the case may be, its supplier and its customer of such sums as shall be agreed between each supplier in the circle and its customer. In determining the sums so payable Buyer and Seller agree that if the delivery in question is Brent System crude oil the following shall apply in any such bookout agreement:
   (i) there shall be a deemed delivery quantity of the Nominal Volume;
   (ii) there shall be a deemed bill of lading date of either the 15th day of the Specified Month or, if the Seller's declaration of the Laydays has been made pursuant to the Agreement, the middle Day of the Laydays; and
   (iii) discounting, if agreed, shall be based on the London Interbank Offer Rate for one month Eurodollars current on the date on which such bookout agreement is formally proposed by one party in the circle to all the other parties in the circle.

(c) The provisions relating to the method of payment in the bookout agreement shall, unless otherwise specifically agreed between the parties to the agreement, be as set out in the payment provisions hereof if the sum payable is to be paid by Buyer to Seller. If, however, such sum is to be paid by Seller to Buyer payment shall, unless otherwise agreed, be in accordance with such payment provisions as would usually be found in any sales by Buyer to Seller under sales contracts between them."

Should the parties agree to a bookout pursuant to Clause 20 above, a separate bookout contract would be drafted. The following is a sample of a standard Brent 15-day bookout contract involving three participants, "Company A", "Company B" and "Company C" booking out and netting off sales for February 2002 Brent 15-day. Although bookout circles for 15-day Brent more commonly involve four or five participants, in theory the number of participants in a bookout circle is only limited by the length of a sale chain and the number of matching buys and sells. Bookout circles involving as many as 12 participants where the same party may appear more than once have been known in the Brent 15-day market. Note that the contract below, which is sent to all the bookout participants, does not refer to the agreed price for each deal, as this information is confidential between each buyer and seller. The contract does however refer to a "base price", normally agreed at the time of the bookout, which is used as an adjustment mechanism for determining the invoice quantity to be settled on each party. Interest at a mutually agreed rate for the period between the bookout settlement date and the normally anticipated settlement date (e.g. 30 days after the Bill of Lading date) is usually discounted from the invoices. The bookout is not effective until such time as each participant agrees in writing to the terms of the bookout contract.

FEBRUARY 2002 BRENT CRUDE OIL BOOKOUT AGREEMENT

The following is a very recent example; terms for a cargo of Brent crude oil which is to be delivered during February, 2002 including the following provisions:

> Company A proposes the following bookout agreement format in order to facilitate the handling of these agreements. The language of the bookout agreement would read as follows:

QUOTE

This agreement is dated as of 15/02/2002 by and among Company A, Company B, Company C.

Whereas (A) Company A and Company B are parties to a contract dated 03/01/02 in which Company A has agreed to sell, and Company B has agreed to purchase a cargo of Brent crude oil. Such contract being briefly described as follows:

Volume	Crude Type	Delivery	Contract
500,000 bbls	Brent	February	03/01/02

and whereas (B) Company B and Company C are parties to a contract dated 24/12/01 in which Company B has agreed to sell, and Company C has agreed to purchase a cargo of Brent crude oil. Such contract being briefly described as follows:

Volume	Crude Type	Delivery	Contract
500,000 bbls	Brent	February	24/12/01

and whereas (C) Company C and Company A are parties to a contract dated 06/01/02 in which Company C has agreed to sell, and Company A has agreed to purchase a cargo of Brent crude oil. Such contract being briefly described as follows:

Volume	Crude Type	Delivery	Contract
500,000 bbls	Brent	February	06/01/02

and whereas (D) Company A and Company B and Company C have concluded and agreed that it would be in their respective best interests to terminate each of the contracts identified above.

Now therefore it is hereby agreed as follows:

1. In consideration of the execution of this agreement to terminate each of the contracts identified above and entering into this agreement to pay the cancellation fees as set forth below and subject as hereinafter provided each party hereby expressly releases each other party and their successors, assigns and legal representatives from all liability, claims and demands arising out of the contracts identified above and each of the above identified contracts is hereby terminated with effect from the effective date hereof as defined in Clause 8.
2. In order to calculate the cancellation fee payable by each party hereto a base price of US Dollars 21.0000 per barrel ("The Base Price") shall be used and a notional Bill of Lading date of 15/02/02.
3. Each party hereto shall pay to its Seller a cancellation fee equal to 500,000 multiplied by the amount, if any, by which such party's purchase price per barrel exceeds the base price. Each party hereto shall pay to its Buyer a cancellation fee equal to 500,000 multiplied by the amount, if any, by which such party's sale price per barrel is less than the base price. Each such cancellation fee shall be paid in US Dollars in immediately available funds on or before 22/02/02 and shall be discounted based on a 1.8400 per cent per annum interest rate for 23 days.
4. All payments hereunder shall be made in full without set-off, deduction or counterclaim.

5. This cancellation agreement shall be subject to and construed in accordance with the Laws of England and subject to the exclusive jurisdiction of the English Courts.
6. The signatories hereto hereby warrant and represent that they are authorised and empowered by their company to consent to this agreement.
7. Each party hereto expressly warrants and represents that the details of those contracts to which it is party as referred to in recitals (A), (B), (C) and (D) above are correct and accurate in all respects and hereby acknowledges that the other parties hereto which are not a party to such contracts are acting on reliance of the above warranty and representation.
8. This Agreement, issued by Company B, shall not come into effect until Company B has given telex notice to all other parties to this agreement, stating that Company B has received the telexed agreement of all such parties to the terms of this agreement. The date on which Company B gives the last such notice shall be the "Effective Date".

Please note that unless telex agreement to the terms of the proposed bookout agreement are received by Company B from all parties by 20/02/02, the above proposal shall lapse. The above proposal is made without prejudice to Company B's rights under its contracts referred to above, which shall remain in full force and effect unless and until the bookout agreement referred to above becomes effective.

Commentary

Problems can occur if there is bankruptcy in the circle and the potential consequences should be considered (e.g. if a liquidator has the power to disclaim bookout arrangements).

16.3.10 Delivery

Purpose

To ascertain when delivery of the goods to the buyer will take place.

Content

The terms of the contract will depend on the method of delivery. If the oil is being delivered FOB, the following points should be included:

- *the obligation of the seller to deliver*;
- *the quantity of oil to be delivered*, for example, whether it is in full or part cargo lots;
- *the place where the oil should be delivered.* This will typically be at the load port where vessels will normally be provided by the buyer. The loading port is normally specified if it has not already been defined;
- *the period or periods when delivery is to be made*. A mechanism for notifying when the seller is ready to deliver or when the buyer is ready to present its ship tank for loading will also need to be included. Such provisions are usually dealt with under the heading "nominations" or "loading conditions" and will not be specifically dealt with under the delivery obligation;
- *any particular criteria, consents or approvals*, for example environmental standards, that the seller requires the off take vessel to meet;
- *any terminal and/or operating procedures* that are to be complied with. These may be published and referred to in the contract or they may be expressly incorporated.

If the oil is being delivered ex-ship the following points should be included:

- *the seller's obligation* to ship the oil in a vessel assigned by the seller to the discharge port;
- *the buyer's obligation* to arrange for availability at the discharge terminal of a berth;
- the parties should provide for apportionment of liabilities related to port problems, which may give rise to *demurrage* (i.e. they will need to agree "allowed laytime");
- *the quantity(ies)* to be shipped and the number of shipments;
- *any specified loading port(s)*;
- *an obligation on the buyer to inform the seller* of matters relating to the discharge port such as restrictions, maximum draft and length, terminal procedures, and any customary requirements.

Examples

Delivery FOB

> "Delivery of the Oil shall be made to Buyer in full cargo lots or in substantial part cargo lots as mutually agreed, at the load port as the Oil passes the flanges connecting Seller's or Seller's supplier's delivery hoses to the loading connections of vessels provided by Buyer at the normal loading terminals for the Oil."[22]

> "the Seller shall deliver or cause to be delivered oil in bulk to the Buyer free on board tank vessels provided by the Buyer at the loading port."[23]

Delivery ex-ship

"(a) Seller shall ship the oil to Buyer in bulk in vessel(s) provided or arranged by seller, CIF or C&F (as appearing in the special terms) the discharge port, for discharge at the discharge terminal arranged by buyer to be available therefore. Buyer and Seller shall have agreed in the special terms as to the total quantity of oil to be shipped, the discharge port(s), and the period(s) within which Seller will arrange for the oil to be available at the discharge port(s), and the number of shipments to be made.

(b) Each shipment shall be made by Seller from such loading port(s) as it may determine in its discretion, unless particular loading port(s) are designated loading port(s), in which event the shipment may be made therefrom.

(c) Buyer shall provide at the discharge terminal a berth, mooring, or other area suitable for discharge of the oil from any of the seller's vessels otherwise conforming to the terms hereof. However, Buyer does not by this contract warrant the safety of any such place. Buyer shall furnish with reasonable dispatch, upon Seller's reasonable request therefor, all information readily available to it concerning restrictions applicable at the discharge port and the discharge terminal with respect to maximum draft, length, and the like, ter-

[22] Chevron FOB Contract.
[23] Amoco FOB Contract.

> minal procedures relevant to vessel operations, and special or non-customary requirements of governmental authorities at the discharge port with respect to vessel operations therein . . . [[24]]"

Commentary

Provisions for the delivery of oil will depend very much on the general nature of the contract and whether it is FOB or ex-ship or provides for delivery at mid-sea.

The obligation to "deliver" may be extended or be defined as including the obligation to "procure to be delivered" since the seller with whom the contract has been made may not always be the same person who makes the physical delivery of the oil.

In an ex-ship contract, instead of an obligation to deliver at the load port, the seller will be under an obligation to ship the oil to the discharge port. Typically the seller will provide (or arrange for) the vessel and transfer the oil and the buyer will accept the discharge at the berth which the buyer has provided. If transfer is ship-to-ship then the parties normally expressly incorporate appropriate ship-to-ship transfer rules (*see Appendix 16.2*).

16.3.11 Nominations

Purpose

To provide a detailed procedure for the notification of delivery or discharge of goods.

Content

Nomination terms are typically found under headings such as "Vessel Nomination", "Nominating Procedure" and "Presentation Date Range" and may provide for the following:

- *a notification procedure* whereby the buyer advises the seller at a certain time each month under a term

[24] Mobil CIF Contract. The clause continues with accepted date range provisions which are the same as for the FOB Contract (see above) except the Seller and Buyer have been transposed so that, for example, the Seller notifies the Buyer of the proposed date range and the Buyer has to respond promptly to each of the Seller's Notices etc.

contract (or in a spot contract by a certain time before the specified date range) when the buyer will be able to lift the cargo;

- *information that is to be contained in the buyer's notice* including, for example, the vessel's name, the flag, the crew nationality; size of vessel (capacity, length, beam, draught); the load port; the estimated time of arrival of load port within a certain date range (typically five days) and the number of loaders within that date range. If appropriate, it may also include the quantity and quality of the cargo and any other particular information which the seller may require relating to matters such as safety;
- *the time in which the seller may respond* to the buyer confirming or rejecting the nomination. Where the seller fails to respond then the seller may be deemed to have accepted the notification. Conversely, where the seller rejects the nomination then the parties may wish to include a provision for mutual agreement to a new time for notification;
- *a buyer's rights to substitute the vessel and to amend the nomination*. In both cases the seller may be concerned that such substitution and amendment rights are only exercised with prior notice to the seller;
- *a buyer's obligation to ensure that the vessel conforms to all the loading port's regulations*;
- *the seller's obligation to provide a safe berth for the vessel* at the seller's cost;
- *the seller's ability to inspect the vessel* to ensure it meets with safety and environmental requirements;
- *a provision dealing with cover for pollution incidents*. For instance, in an FOB contract the seller will be concerned that the buyer warrants that the nominated vessel is owned or demise chartered by a member of the International Tanker Owners Pollution Federation Ltd (ITOPF) and that adequate insurance has been taken out and the vessel carries on board a certificate of insurance as described in the 1992 Civil Liability Convention for Oil Pollution Damage;
- *timing:* it should be made clear if days are intended to be "working days" as sometimes port will not load after dark and what days are intended to be "working days" as port may not load on Fridays, Saturdays and/or Sundays. Both parties may wish to exclude public holidays in a specific country and for certainty it is advis-

able to refer to those excluded days expressly. Generally for the purposes of giving notices for notification and responding to such notices the actual time for the commencement of a date range may be helpful and to specify whether GMT or some other time of another country will apply. The parties should note that timing in the nomination procedure is very important. It was held that a buyer was entitled to cancel its contract where the seller substantially delayed its acceptance of the buyer's nomination of the vessel.[25]

Example

> "Unless otherwise agreed, Buyers shall at least fourteen (14) days before the first day of the agreed loading date range notify Sellers by telex of the name and summer deadweight tonnage of the vessel to be used and the expected date of that vessel's arrival at the loading port, and shall provide Sellers with any other vessel details necessary for the purpose of implementing the agreement. Sellers shall give notice accepting or rejecting any vessel nomination within two (2) London working days after receipt of such nomination, but shall not reject any such nomination unreasonably. In case of rejection, Buyers shall, as soon as possible, nominate to Sellers an alternative vessel for Sellers' prompt acceptance or rejection, and, in the case of the latter, the parties shall negotiate a mutually acceptable nomination . . ."[26]

Commentary

The above discussion has highlighted terms in an FOB contract. In an ex-ship contract the obligation to notify is reversed – the seller notifies the buyer of the vessel and date range.

It should be remembered that "time is of the essence"[27] with respect to such commercial contracts and in particular such fundamental procedures. Failure to make a timely[28] nomination, for example, can lead to cancellation of the contract. In such

[25] *Phibro Energy AG* v. *Nissho Iwai Corporation* and *Bommar Oil Inc.*, [1991] 1 Lloyds Rep 38 AC.

[26] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 7(1), Vessel Nomination.

[27] *Bunge Corporation* v. *Tradax Export SA,* [1981] Lloyds Report 7.

[28] or timeous (in Scottish law).

circumstances the innocent party may choose to cancel the contract because of changes in market price and is legally entitled to do so. But a party should seek legal advice before walking away from a contract to avoid a wrongful cancellation.

16.3.12 Transportation

Purpose

To specify conditions for loading or discharge at port.

Content

The provisions which are commonly found in term contracts under the headings of "loading conditions" or "lay time and demurrage". The following matters are normally dealt with in such provisions:

- *an obligation of the buyer to notify the seller* (or its representative) by giving a Notice of Readiness (NOR) as to when the vessel will be ready to load and when it will arrive at the port of loading;
- *an obligation for the seller to arrange for loading* at the berth which the seller is to provide free of charge;
- *the amount of laytime* – how long the vessel may take to load or discharge (as the case may be) after the "notice of readiness" (NOR) is given – either to the seller for FOB contracts or to the buyer for ex-ship contracts – that the vessel is ready to load or discharge (as the case may be). In the provision allowing for laytime the parties might consider whether to include any unused laytime at the discharge port and specify any particular exclusions, for example, where the vessel has broken down for reasons outside the seller's control or delays at customs etc. They may also provide for a risks allocation mechanism associated with the port risk events;
- *the demurrage rate* that will apply where a cargo is loaded by the seller and exceeds the laytime, and the buyer may require demurrage to be paid by the seller to the buyer at a particular demurrage rate. The seller may require that the buyer will compensate him for the costs incurred due to the late arrival of the ship (i.e. did not conform with NOR or arrived outside contract "window");

- *if the demurrage rate is not agreed* there may be reference to a published rate, for example, as published by the London Tanker Brokers' Panel. Such a rate may be determined by:
  (a) reference to total deadweight of the vessel multiplied by the relevant charter rate; or
  (b) if there are two or more sellers then an appropriate fraction of the total demurrage rate may be payable by each according to the amount of oil delivered by each seller;
- *a provision for reduction* where the delay has arisen as a result of a certain event, such as fire or some event outside the seller's control, which is specified as being an event of *force majeure* elsewhere in the contract;
- *a cap on the amount of demurrage payable* so that it does not exceed that amount of expense actually incurred by the buyer or the amount of demurrage the seller may in turn recover from its own supplier; although in the latter case, the seller should be obliged to recover from its supplier such demurrage claimed by the buyer;
- *the buyer's obligation to make a claim* within a certain time specified in the contract – for example, within 90 days from the bill of lading date.

Examples

> "Sellers shall provide or cause to be provided, free of charge, a berth or berths which the vessel can safely reach and leave and at which she can lie and load always safely afloat . . ."[29]

> "Laytime 48 hours plus 6 hours NOR. Demurrage as per performing vessel charter party terms and conditions. Laytime shall commence only upon the arrival of the seller's nominated vessel at the intended lightering position [location]."[30]

16.3.13 Inspection and sampling

Purpose

To provide a procedure for checking the goods at loading and/or discharge.

[29] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 8(3), Loading Conditions.

[30] Appendix 16.2 Sample FOB Contract (2).

Content

The following points should be included:

- *the appointment of an independent inspector* – this is normally a joint appointment by the seller and buyer – and a provision as to *whether the cost is to be borne equally*;
- *the individual right of either party to carry out such inspection at its own cost* – possibly with the ability to carry out such inspection by appointment of a representative;
- *the time of inspection* – whether both before and after delivery;
- *the method and standard of measurement and sampling*. For example, in accordance with "good standard practice at the port of loading" or "internationally recognised methods and practices";
- *a requirement for a certificate* to be prepared and signed by the suppliers as to the quantity and quality of the oil loaded upon completion of the loading of the cargo. The sellers may then be required to advise the buyers by telex of the details recorded on the certificate;
- *the effectiveness of certificates of quantity and quality* – whether such certificates will be conclusive and binding on both parties;
- *who is to bear the costs* caused by delays in the inspection and sampling procedure;
- the possibility for *reference of a dispute to an expert*, where there is dispute as to the results of sampling.

Examples

> "As ascertained at load port by independent inspector whose findings to be final. Costs at load port for Seller's account. At discharge port for Buyer's account."[31]

> "Where permitted by Seller's suppliers, Buyers may appoint a representative acceptable to Sellers and Sellers' suppliers to assist in the supervision of and to inspect the loading of each cargo . . . If any difference arises between Buyer's representative and Sellers' suppliers with regard to the loaded

[31] Appendix 16.3 Sample CIF Contract.

> quantity and quality, it shall be settled by an expert appointed under Clause 13."[32]
>
> "The cost of services of the expert, if appointed, shall be shared equally between Sellers and Buyers."[33]

Commentary

In order to inspect the cargo, the parties should consider at what times this needs to be carried out (before and after loading), by whom and at whose cost.

16.3.14 *Force majeure*

Purpose

To relieve a party from liability where it has failed to perform its contractual obligations normally as a result of an event which is beyond such party's control.

Content

The following points should be included:

- *a definition of force majeure* which means at least an event beyond a party's control. In some detailed *force majeure* provisions this clause may list a number of different types of events which are likely to frustrate or delay the contract as well as a general reference to "matters outside the control of . . .".

  The reference to an "Act of God" is sometimes left undefined but is commonly perceived to mean an accident due to natural causes without human intervention and which could not have been foreseen or resisted by human care and skill. Sometimes an attempt is made to quantify such events by reference to specific

[32] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 3(2), Measurement, Sampling and Testing.

[33] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 13(3), Appointment of Experts.

periods of time. In some cases some events may be expressly excluded; the drafting of the clause depends on how much protection a party views is needed and whether there are any particular circumstances which need to be addressed, such as extreme weather conditions or engine breakdown preventing the buyer's vessel arriving in time at the load port in an FOB contract;

- *a mechanism for the giving of a notice of force majeure* event to the other party, specifying the time in which such a notice must be given from when the party became aware of the event and any supporting information that such party should provide;
- *the obligations of a party once it has notified the other party* of that *force majeure* event. For example, the party may be obliged to use its endeavours to remedy the situation before it claims relief;
- *the consequences of force majeure*. If a party is entitled to relief from its contractual obligations by virtue of *force majeure* both parties may want a right to suspend or possibly terminate the contract if a *force majeure* event lasts more than a certain period of time;
- (if the seller) *that the buyer will be liable to pay* for any of the oil already delivered;
- (if the seller) *that force majeure covers delay or hindrance* so that if the seller's own supplier fails to perform the seller will be relieved from liability. Above all, the seller will need to ensure that the *force majeure* provisions with its buyer reflect those that it has in its own supply contract with its supplier.

Example

"Neither seller nor buyer shall be liable in damages or otherwise for any failure or delay in performance of any obligation hereunder other than obligation to make payment where such failure or delay is caused by *force majeure*, being any event, occurrence or circumstance reasonably beyond the control of that party including without prejudice to the generality of the foregoing, failure or delay caused by or resulting from Acts of God, strikes, fire, floods, wars (whether declared or undeclared), riots, destruction of the oil, delays of carriers due to breakdown or adverse weather, perils of the sea, embargoes, accidents, restrictions imposed by any governmental authority (including allocations priorities, requisitions, quotas and price controls). The time of seller to make, or buyer to receive,

> delivery hereunder shall be extended during any period in which delivery shall be delayed or prevented by reason of any of the foregoing causes, up to a total of thirty (30) days. If any delivery hereunder shall be delayed or prevented for more than 30 days, either party may terminate this contract with respect to such delivery upon written notice to the other party."[34]

Commentary

Force majeure is a commonly used term under English law, but it has no statutory or recognised legal definition. It is therefore up to the parties to agree a definition to be included in the contract. It will only be implied in law in the event that the contract is incapable of performance, for example, the seller's only source of supply – its only oil refinery – is destroyed in an explosion. By way of contrast, a strike does not necessarily render the contract incapable of performance as it is a temporary interruption to supply. This will be one of the most important terms because it may relieve a party from its liability to perform part or all of its contractual obligations.

If the contract is silent, or the circumstance so unenforceable or so destructive of the commercial purpose of the contract that it would be unjust to hold the parties to the contract, the law may recognise the contract as "frustrated", i.e. terminated without fault on either side. The English doctrine of frustration is, however, strict and narrow and may apply only in very limited circumstances such as destruction of the subject matter or supervening impossibility due to government interference. Certain provisions of the Law Reform (Frustrated Contracts) Act, 1943 (e.g. the extent of recoverability of expenditures incurred under frustrated contracts) may also be of concern to the parties. Thus it is advisable in respect of contracts subject to English law to consider the effect of the doctrine of frustration and draft a *force majeure* clause carefully in any oil trading contract.

16.3.15 Restrictions

Purpose

To specifically restrict a party from supplying a product from or to a particular destination.

[34] Appendix 16.2 Sample FOB Contract (2).

Content

The following terms may be included if required:

- *a specific restriction* may provide that oil may not be sold or delivered directly or indirectly to certain named countries or to any destinations which are "embargo destinations" at the time of disposal under the oil policy of the relevant government of production (e.g. the Arab boycott of Israel), process or manufacture. The effect of US/UN sanctions on Iraq should also be noted and their potential applicability taken into account;
- *rights may be included to suspend a contract* if by reason of government policy a party is unable to either supply or take delivery of oil produced (or products or feedstocks processed or manufactured) in a certain country;
- it may be appropriate for the contract *to provide for the parties to meet to resolve the difficulty* and then the seller may at its discretion suspend in whole or in part the supply;
- following delivery, the buyer may be required to provide the seller within a certain time period *a "certificate, sometimes called a certificate of discharge"*, which will show that the oil has been purchased under the agreement, and other relevant information such as the name of the loading and the discharge ports, the date of loading and discharge, details as to quantities and the vessel's name;
- a requirement specifying *to what extent the certificate of discharge should be an official document*. For example, whether it needs to be attested by customs or a local chamber of commerce;
- where there is *a failure to provide a certificate of discharge*, within a certain specified time. For example, within a certain period from the bill of lading date or within so many days after the seller's request, whichever is later. In the case of a term contract, the seller may wish to include the right to suspend further deliveries under the agreement.

Examples

(1) "It is a condition of the agreement that the oil purchased may not, in any event, be sold supplied or deliv-

ered, directly or indirectly, to any port or ports in the State of Israel or to any destination which at the time of disposal is declared an embargoed destination by the government of the country in which the oil is produced or a destination prohibited by the terms on which Sellers have acquired the oil, provided that if Buyers are, or are likely to be, prevented by any law, policy, demand or request to which they are subject to any governmental policy, demand or request by which Buyers reasonably consider they are bound from complying with the above, Sellers and Buyers shall meet and discuss the implications for Buyers and Sellers and, pending resolution of any difficulty which such law causes or is likely to cause, Sellers may at their discretion suspend in whole or in part supplies hereunder.

(2) Buyers shall provide Sellers with a certificate of discharge for the oil purchased under the agreement. The certificate of discharge shall be prepared on headed stationery by the vessel's agents at the discharge port and attested by an official seal and signature of the customs authorities or local Chamber of Commerce. The certificate of discharge shall reach Sellers within four months of the Bill of Lading date.

The certificate of discharge should include the names of the loading and discharge ports, the dates of loading and discharge, the grades and volumes involved, the vessel name, details of lightering or ship-to-ship transfer if applicable, and the names of the vessel's agents at the discharge port and the consignee. In the event that any specific detail is not available, Buyers will provide separate advice to cover such omission.

(3) Sellers shall have the right to suspend deliveries under this or subsequent or other agreements between Buyers and Sellers if satisfactory certification is not received from Buyers within four months of the date of the Bill of Lading of the cargo concerned."[35]

[35] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 10, Destination, Restrictions and Certification.

16.3.16 Duties and taxes

Purpose

To provide for which of the parties is to bear any of the taxes, duties or imposts or other charges in respect of the oil sold under the agreement.

Content

The following points should be included:

- *the buyer is normally responsible in an FOB contract* for all duties on the vessel and any taxes, duties, import fees on the oil after the oil has passed the vessel's permanent hose connection at the loading terminal, though sometimes the seller is prepared to take a wider obligation (see attached Shell General Terms and Conditions, for example);
- *the relevant costs provision* will normally cover any fees for formalities to be fulfilled to load/discharge the goods;
- *a statement as to which goods the duty or costs apply* and form part of the contract may be included if it is not clear from the terms of the contract. For example, in a long term contract where a number of shipments are to be made.

Examples

"(1) All taxes, duties and other imposts (other than those levied on the vessel) in respect of any oil sold under the terms of the agreement[36] in the country in which the loading port is situated shall be for the account of Sellers other than value added tax, goods and services tax or similar multi-stage consumption tax as Buyers are able to recover.

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[36] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 4(1), Risk and Property:

"The risk and property in the oil supplied under the terms of the agreement shall pass to Buyers at the loading port as the oil passes the loading vessel's permanent hose."

(2) All other such charges including any taxes arising as a result of interest becoming due in accordance with Clause 5(3) shall be for the account of Buyers."[37]

"Deliveries which, on request of Buyer, are made with exemption from excise duties, levies and/or taxes under cover of customs or excise documents issued by Seller, will take place at the exclusive responsibility of Buyer who is obliged to fully indemnify Seller for all duties, taxes, penalties, costs etc. which Seller might have to pay because of the absence of clearance of documents or other irregularities in the field of customs, excise and VAT legislation, national as well as foreign and EEC legislation, and regardless any fault chargeable to Buyer.

In case of resale Buyer will take care that new customs and/or excise documents are issued."[38]

Commentary

The liability will reflect the delivery arrangements. For example, up to the time of loading in an ex-ship contract it is normally the seller's responsibility to pay for all taxes, duties and other charges including export fees (other than those levied on the vessel) in respect of any oil sold under the terms of the agreement in the country in which the load port is situated in respect of the oil (except extra fees caused by ship, for example, lighterage).

16.3.17 Assignment

Purpose

To ensure that a party to the contract may not transfer its rights or obligations without either notifying or obtaining consent from the other party (under English law parties to a contract cannot assign their obligations and such intention will require novation: e.g. that the contract is not assignment of the old one, but a new contract between the non-assigning party and the incoming party. This may have significance if the non-assigning party does

[37] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 6(1), Taxes, Duties and Imposts.

[38] Appendix 16.1 Sample FOB Contract (1).

not insist on an indemnity from the incoming party in respect of all pre-novation liabilities – but they invariably do).

To provide a procedure for assignment of rights or a transfer of obligations.

Content

The following points should be included:

- *a provision as to whether either party should have the right to assign* with or without consent of the other party;
- *where there is assignment* (with or without consent) a typical provision would state that such assignment shall not be effective until the other party has been given written notice thereof;
- *where the right to assign is qualified* because it is subject to the other party's consent, the parties may wish to specify that consent should not be unreasonably withheld and whether there are any other conditions which need to be satisfied, for example, whether the assignment should be contingent on the assignee being suitable to perform the terms of the contract;
- *the consequences of assignment*. An assignment clause may also provide that the assignor (who is transferring the rights) will remain liable for the proper performance of the agreement (or guarantee the assignee's performance) even after the assignment. Such a provision is useful where the other party to the contract is concerned about the suitability of the assignee (including assignments to insubstantial affiliates).

Examples

"(1) Either party shall, having obtained the prior written consent of the other party have the right at any time to assign to another company all or part of the rights and obligations to sell and deliver or buy and receive the oil in accordance with the terms of the agreement. The assigning party shall remain responsible for the fulfilment of the terms and conditions of the agreement in accordance with paragraph (2) of this Clause 17.

(2) Any such assignment shall be effected by notice in writing from the assignor countersigned by the

> assignee to signify its acceptance of the obligations under the agreement. Upon the making of any such assignment, the assignor shall remain bound to perform or procure performance of the said obligations (as so accepted) by the assignee.'[39]

Commentary

Both parties should be concerned to specify what each party's rights to assign all or part of their respective rights (as opposed to their obligations) are under the agreement. If an assignment provision is not included then generally either party may assign all or any part of its rights without seeking the consent of the other party. It is of obvious importance to both parties that they know who has rights and obligations under the contract and against whom those rights may be enforced when there is a dispute.

Generally (as stated above) English law permits the assignment of rights but not the transfer of its obligations without consent and therefore if the identity of the party is crucial to the contract (e.g. its credit worthiness, competence or whether the assignee is a potential competitor) the parties may wish to consider whether the right to assign is to be either excluded or carefully qualified.

16.3.18 Liability

Purpose

To provide for the extent of each party's liability which may arise in connection with its obligations under the contract.

Content

The following points should be considered:

- the seller may be particularly concerned to include *limitations on its liability*, which shall not exceed the value of the product (e.g. for liability arising with respect to offspec crude oil or demurrage). The seller

[39] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 17, Assignment.

may also be concerned to limit liability caused by his inability to fulfil contractual obligations due to political restrictions/embargoes referred to in Section 16.3.15;

- both parties may wish to include *an exclusion for liability for any indirect or consequential loss*, specifying, for example, that neither party shall be liable for any direct, indirect or consequential losses or damages including, any special damages, loss of production or production of associated gas caused by non-offtake, any claims concerning reservoir damage caused by such shut-in, loss of profits, caused by non-offtake or business interruptions which may be suffered or alleged to have been suffered by the other party. The seller will be concerned to exclude its liability for polluting the port (if caused by the buyer);
- for the purposes of making a claim under the contract (notwithstanding the usual statutory period of limitation of six years) this period may be reduced by including *an express provision specifying a time limit in which claims may be made*.

Example

"(1) Neither party shall be liable for indirect, special or consequential damages.

(2) Any claim in respect of a shortage in quantity or defect in the quality of oil will only be considered by Sellers if notice in writing of such claim is received by Sellers within forty five (45) days after the date of the Bill of Lading (Bill of Lading date equals day zero) for the particular cargo and such notice is followed by a fully documented claim to be received by Sellers within sixty (60) days after the date of the Bill of Lading (Bill of Lading date equals day zero). If Buyers' fail to give notice of or to submit any such claim within the time limits, Buyer's claim is deemed to be waived and any liability on the part of Sellers extinguished. Buyers shall only be entitled to recover costs, losses or damages from Sellers to the extent that Sellers are able to recover costs, losses or damages from Sellers' suppliers and Sellers shall not be obliged to pay any amounts to Buyers in excess thereof. Sellers shall however use reasonable endeavours to recover from Sellers' suppliers costs, losses or

damages for which Buyers have presented a claim in accordance herewith.

(3) In respect of any other claims relating to the failure to supply or of delay in supplying any quantity of oil for which Sellers are responsible, Buyers shall not be entitled to costs, losses or damages exceeding the agreed selling price for the oil under the agreement. Any claim in respect of the foregoing will only be considered by Sellers provided that a fully documented claim is received within one year after the date of the occurrence."[40]

Commentary

As a general principle, it should be remembered that the rights and obligations of a contract may be enforced in the courts by bringing an action for damages where a party has suffered loss as a result of a breach of contract or by claiming specific performance of a contractual obligation. In addition to remedies arising from the rights and obligations specified in the contract, a person may also seek damages where a defendant has owed a duty of care towards that person and by his act or omission has caused some harm to that person.

16.3.19 Notices

Purpose

To provide how and to whom any notice or communication under the contract is to be given.

Content

The following points should be included:

- *the type of communications* to which the notice clause applies: whether it applies to all communications (e.g. all demands and communications including those relating to bills of lading) or only specified notices;
- *the method of communication*, and whether it will include post, hand delivery, telex, facsimiles or other

[40] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 16, Limitation of Liability.

means of data transmission; the parties may consider whether some terms of transmission are inappropriate because they are unreliable: they may be illegible or subject to broken transmission or there may be no answer back facility;

- *the chosen language of the notice*;
- *each party's details* (if not already stated), including address, telex and facsimile numbers which may be required;
- *a deeming of delivery provision* so that where a notice is given in a certain way it is deemed delivered (unless proved to the contrary) in a certain time, for example a telex is deemed delivered on receipt of answer back.

Example

"Unless otherwise specifically provided, all notices to be given hereunder by either party to the other shall be sufficiently given if in writing, by telex, cable or facsimile and delivered to the other party as follows . . ."[41]

16.3.20 Governing law and dispute resolution

Purpose

To determine which governing law shall apply to the contract and to provide a procedure for resolving any disputes that might arise.

Content

To determine the consequences of a breach of a contract the parties may specify the governing law of the contract, for example:

> "This agreement is governed by and construed in accordance with English Law".

It should be noted that the Contracts (Applicable Law) 1990 Act which became effective on 1 April 1991, brought into force the

[41] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 19, Notices.

Rome Convention which applies throughout the EU and changed the system of rules choosing the governing law of a contract where there is a choice between the laws of different countries.

This Convention does not apply to all contracts and there are special rules, which apply to bills of lading and charterparties. Article 3(1) states that the choice of law must be expressed or demonstrated with reasonable certainty. Where the parties fail to state the governing law, then the contract will be governed by the law of the country with which the contract is most closely connected – this is presumed to mean the country where the party who is to effect the performance which is characteristic of the contract has residence, or, in the case of a company, has a central administration at the time of the contract.

The agreement should further state how matters are to be resolved by adding, for example:

> "and the parties hereto agree to submit to the [exclusive/non-exclusive] jurisdiction of the English courts as regards any matter arising in respect hereof".

It should be noted that the use of the words "non-exclusive" are generally used where the parties wish to ensure that they can sue each other in the English courts and also retain the option to bring an action in the courts of another jurisdiction.[42]

A submission to jurisdiction provision will not be appropriate if the parties have agreed to refer all disputes to arbitration, unless of course only certain specified matters are to be referred in which case it may be helpful to specifically list them by reference to the relevant clause.

Where the parties wish to resolve a dispute by way of arbitration, an arbitration clause should be included to require the

[42] The use of the word "exclusive" means that the parties wish to ensure that they submit to the exclusive jurisdiction of the English courts. Unfortunately the result of the Civil Jurisdiction and Judgement Act 1982 (which brought into effect the EEC Judgements Convention), makes the effect of using the words "non-exclusive jurisdiction of the English courts" no longer clear. Commentaries on cases (*Kurz* v. *Stella* [1991] TLR 4 October, and *Meeth* v. *Glacetal S.A.R.L.* [1979] CMLR 520 European Court) formed the view that the "non-exclusive" wording would not have the effect of conferring jurisdiction upon the English courts to the exclusion of courts of other Contracting States. The other Contracting States, apart from the UK, are: Belgium, Netherlands, Germany, France, Italy, Luxembourg, Denmark, Greece, Ireland, Spain and Portugal.

parties to submit to arbitration either generally under the agreement or in respect of certain matters under the agreement. Such a provision may then refer to the Arbitration Act 1996, which controls the conduct of arbitrations (under English law), and/or to rules of a recognised arbitration agency (such as the International Chamber of Commerce). The ICC recommends the inclusion of the following standard clause:

> "All disputes arising out or in connection with the present contract shall be finally settled under the Rules of Arbitration of the International Chamber of Commerce by one or more arbitrators appointed in accordance with the said Rules."[43]

An example of a simple arbitration clause is as follows:

> "Any claim or dispute not settled by negotiation should be settled by arbitration in London before a single arbitrator, agreed upon by both parties or if not so agreed appointed in accordance with the English Arbitration Acts as amended from time to time".

Although terms may be implied by the Arbitration Acts, it is recommended that the parties make more detailed provisions in the agreement, and the following points should also be included:

- *the place of arbitration*;
- *the number of arbitrators* to be appointed and *the method of appointment*;
- *the procedure* (*i.e. voting*) to be applied by arbitrators while deciding upon matters;
- *the law applicable* to the merits of the dispute and the procedural law;
- *the language* to be used in the proceedings;
- *the timetable* for giving notice of arbitration, counter-notice, the submission of evidence, the appointment of arbitrators and the time in which responses are to be given. *The status of the arbitrator* (whether he should be qualified, for example, as a QC or as an engineer);
- where the parties are unable to agree on the appointment, *which independent body shall appoint the arbitrator* (e.g. the Institute of Petroleum);
- what should happen *in the event of an arbitrator having a conflict of interest*.

[43] ICC Incoterms 2000 Edition.

A detailed comparison of the different international venues and procedures for arbitration is contained in Chapter 17, Appendix 17.1.

The parties should also consider whether they may wish certain matters to be resolved by an expert. Based on submission of parties, the appointment of an expert is usually reserved for more technical matters, whereas an arbitrator exercises a judicial function – whether or not he is an expert on the subject. An express provision in the contract is necessary for the procedure for appointment of an expert in the absence of any equivalent statutes (such as the Arbitration Acts) which may otherwise be relied on to imply any procedure. The following points should be considered:

- *the types of matter in the contract which should be referred to an expert* if there is a dispute. For example, a dispute concerning sampling and inspection or a price differential which the parties are unable to agree;
- *how the appointment of the expert is to be made* – if there is no agreement between the parties, which body shall appoint the expert (for example, the International Chamber of Commerce or the President of the Institute of Petroleum in London);
- *how the costs of the expert's services are to be borne*;
- *any procedural rules for making submissions* to the expert and the time limit in which he is to render a decision;
- *whether the expert's decision is final and binding*. The parties may specifically provide for the expert's decision/determination to be non-binding in certain events (e.g. fraud, negligence).

It is up to the parties to decide whether arbitration is preferable to the courts. The advantages of arbitration include confidentiality and a limited right of appeal. However, arbitration may be slower than going to court or more expensive. It is also important to note that different jurisdictions have different rules for cost recovery.

16.3.21 Miscellaneous terms

Agency for service of process

Where one of the parties to the contract is resident outside England and Wales and the other party may wish to take proceedings against such party, then a form of appointment in England and Wales for the service of process should be included. This avoids unnecessary administration where it would otherwise be necessary to apply to the High Court for leave to serve a writ outside the jurisdiction. Such a clause should specify the name and address of a specific agent of the party who has been appointed for the purpose of service of process. If, however, the contract provides for arbitration, it is not necessary to have a service process agent provision.[44]

Sovereign immunity

Where a party to the contract is a sovereign state or a governmental agency, amendments to standard clauses will often be necessary in order to reflect the status of the sovereign party concerned. A form of waiver of sovereign immunity clause should provide that, to the extent that the sovereign state may be entitled in any jurisdiction to claim for itself or its property or assets immunity in respect of its obligations under the agreement from legal action, the sovereign state agrees not to claim such immunity to the fullest extent permitted by the laws of such jurisdiction.

Entire agreement

In some contracts, an entire agreement clause is included which will state that the agreement is the entire agreement made

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[44] Under the Arbitration Act 1996 (Section 14 (3,4,5)), in the absence of any agreement between the parties to the contrary:

(a) Where the arbitrator is named or designated in the arbitration agreement, arbitral proceedings are commenced in respect of a matter when one party serves on the other party or parties a notice in writing requiring him or them to submit that matter to the person so named or designated.

(b) Where the arbitrator or arbitrators are to be appointed by the parties, arbitral proceedings are commenced in respect of a matter when one party serves on the other party or parties notice in writing requiring him or them to appoint an arbitrator or to agree to the appointment of an arbitrator in respect of that matter.

(c) Where the arbitrator or arbitrators are to be appointed by a person other than a party to the proceedings, arbitral proceedings are commenced in respect of a matter when one party gives notice in writing to that person requesting him to make the appointment in respect of that matter.

between the parties and neither party has relied on any other representations or warranties outside the agreement in entering into the agreement.

Term and termination

Once the delivery obligations have been discharged by the seller, the buyer has paid for the oil and the contract has been performed it will not be necessary to terminate the contract formally. However, there may be reasons for which either party may want to terminate the contract prematurely – for example, because the contract has become uneconomic, or where one party has become insolvent or there has been a material breach by one party. It is highly preferable that the contract specifically provides for these instances to provide a termination procedure, rather than to leave the matter to be determined by litigation (e.g. requiring a warning notice provision before litigating or terminating).

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16.4 Implied terms

In addition to the express terms discussed above, there are also a number of terms that may be *implied* into a contract which confer rights and obligations that may not already be expressly stated in the contract. Express terms may seek to reduce the effect of such implied terms or exclude them as far as possible.

The statutory implied terms examined in this section are of particular relevance to a physical oil sales contract.

16.4.1 UK Sale of Goods Act

Brief reference to the UK Sales of Goods Act 1979 as amended by the Sale and Supply of Goods Act 1994 and by the Sale of Goods (Amendment) Act 1995 has already been made in the earlier sections on quality and title; this is because the 1979 Act lays down certain implied undertakings in a sale of goods contract which relate to matters such as title, description, quality and fitness of goods.

A sale of goods contract is defined by s.2(1) of the 1979 Act, as:

> "a contract by which the seller transfers or agrees to transfer the property in goods to the buyer for a money consideration, called the price".

While the key provisions are noted below, such implied terms may be excluded by the operation of express exclusion clauses. Exclusion of liability is however restricted under the Unfair Contract Terms Act (UCTA) 1977 although contracts which are classed as international supply contracts, a category which is particularly relevant to oil trading contracts, are not subject to the same restrictions (*see below*).

The following are examples of key terms which the 1979 Act[45] implies into a sale of goods contract:

- **Title (s.12)**. There is an implied term on the part of the seller that in the case of sale, he has a right to sell the goods, and in the case of an agreement to sell, he will have such right at the time when the property is

[45] The Sale and Supply of Goods Act 1994 has made minor and consequential amendments to the Sale of Goods Act 1979, which are reflected in the wording quoted.

to pass. If there is a breach of this section, the buyer of the goods is entitled to treat the contract as discharged and claim damages.[46]

- **Description (s.13)**. Where there is a contract for the sale of goods by description, there is an implied term that the goods will correspond with the description.
- **Quality and fitness (s.14)**. The goods supplied are of satisfactory quality and (subject to certain requirements) reasonably fit for the particular purpose for which they were bought.
- **Property and risk (s.16, s.17, s.20 and s.20A)**. Property will pass at such time as the parties intend it to pass. Such intention may be gathered from the terms of the contract or from the Rules in s.17 ("Property passes when intended to pass") of the 1979 Act.

Other implied terms relate to sales by sample, delivery obligations, rights of an unpaid seller, re-sale, rescission and actions for breach of contract.

If a party wishes to exclude a particular provision of the Sale of Goods Act 1979 (having regard to the Sale and Supply of Goods Act 1994 and Sale of Goods (Amendment) Act 1995) it must be aware of the effect of UCTA which precludes or restricts a party's right to rely on certain exclusion clauses. UCTA s.13 indicates that it applies to a wide variety of clauses. The restrictions to note – which correspond to ss.13, 14 and 15 of the Sale of Goods Act 1979 – relate to a seller's undertaking as to title, which may never be excluded, s.6(1)(a), and liability for breach of sale by description. Implied terms about quality or fitness for purpose and sale by sample may not be excluded as against a consumer and as against others only in so far as the clause satisfies the reasonableness test, ss.6(2) and 6(3).

In an oil trading contract, it is unlikely that either party would be acting as a consumer because each party will normally be dealing in the course of business. The reasonableness test will therefore apply. In s.11(1) of UCTA it is stated that:

> "the term shall have been a fair and reasonable one to be included having regard to the circumstances which were, or ought reasonably to have been, known to or in the contemplation of the parties at the time the contract was made".

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[46] This provision should be read in conjunction with the relevant provisions of Maritime legislation.

Thus a seller may only exclude a term which states that if he sells the oil by description the oil must meet that description if it is reasonable in all the circumstances to do so.

In many cases the oil trader is contracting with an overseas contractor. If the contract is then categorised under UCTA as an "international supply contract" the effect of UCTA is excluded. An international supply contract is determined by a twofold test under s.26. Such a contract is *either* a contract of sale of goods *or* a contract under or in pursuance of which the possession or ownership of goods passes and it is made by parties whose places of business (or, if they have none, habitual residences) are in the territories of different States.[47] A contract will meet these requirements if any of the following apply:

- the goods in question are, at the time of conclusion of the contract, in the course of carriage or will be carried from the territory of one State to another; or
- the acts constituting the offer and acceptance have been done in the territories of different States; or
- the contract provides for the goods to be delivered to the territory of a State other than that within whose territory those acts were done.

If the oil trading contract fulfils these requirements the protective provisions of UCTA will not apply. In this way, the Act recognises that parties in international trade are likely to be able to negotiate freely.

Although the 1979 Act is prima facie applicable to oil trading contracts, the exception to this rule is in the case of *contracts for differences (CFDs)*. Such contracts make no provision for delivery – because the cash settlement is made by reference to the movement of, say, the IPE Brent Blend price index. It is not a contract for sale, like other futures contracts such as gas oil and gasoline. The contract for differences is defined by the Financial Services Act 1986 and the contract rights are classified as an investment. If the contract is made on the exchange it may have the appearance of a wager and be unenforceable (s.18 of the Gaming Act 1845).

16.4.2 Maritime legislation

Since many oil trading contracts will also be contracts for the carriage of goods by sea, the provisions of the Carriage of Goods by

[47] The Channel Islands and Isle of Man are treated as different States from the UK.

Sea Act 1971 ("the 1971 Act"), which embodies the Hague–Visby Rules ("the Rules"), and the Carriage of Goods by Sea Act 1992 ("the 1992 Act"), which replaced the Bills of Lading Act 1855 and confirms (s.5) the continuing effect of the Rules, are relevant.

The Rules are contained in a Schedule to the 1971 Act and normally apply to a bill of lading or similar document of title in so far as such document relates to the carriage of goods by sea issued under or pursuant to a charterparty. Application of the Rules means they are incorporated into the contract. The Rules provide a minimum liability for the carrier and he cannot contract out although he may increase his liability.

Pursuant to the Rules the carrier has three main duties to the bill of lading holder. He must (Article II) exercise due diligence to:

(a) make the ship seaworthy;
(b) properly man, equip and supply the ship;
(c) make the ship fit and safe for the reception carriage and preservation of cargo.

In addition to the carrier's responsibilities the Rules also prescribe many instances (Article IV) where the carrier will not be liable provided that unseaworthiness has not caused the loss or damage – for example, as a result of an Act of God or an inherent vice of the goods. The carrier will not be able to escape liability if loss or damage resulted from unseaworthiness, although particular rules allow deviation – for example, where there has been an attempt to save life at sea.

The 1992 Act, which came into force on 16 September 1992, amended the position in respect of rights of suit relating to carriage of goods by contracts. This is an important amendment because prior to the 1992 Act only the party to the contract of carriage could bring an action. The 1992 Act updated on the position so that the holder of a bill of lading (or sea way bill or ship's delivery order) has transferred and vested in him all rights of suit under the contract of carriage as if he had been a party to that contract (s.2). Conversely, that person who now has the right to sue will also have liabilities if he had been a party to the contract of carriage (s.3).

16.4.3 The Vienna Convention

Parties to an oil trading contract also need to consider the effect of the Vienna Convention – its formal title being the United Nations Convention on Contracts for the International Sale of

Goods. This was signed in Vienna in 1980 and came into operation on 1 January 1988. The Convention applies to contracts of sale of goods between parties whose places of business are in different States:

- when the States are Contracting States; or
- when the rules of private international law lead to the application of the law of a Contracting State.

Although the UK has not ratified or acceded to the Convention, it may still apply to contracts because one of the contracting parties has a place of business in a state that has ratified or acceded to the Convention. The effect of the Convention on a contract may be significant – it contains numerous provisions that do not exist in the 1979 Act, which deal with the rights and obligations of both a seller and buyer.

For example, an obligation is imposed on the buyer to examine goods within as short a period as is practicable in the circumstances (Article 38) or where goods delivered do not conform to the contract, the buyer has a unilateral right to reduce the price in the same proportion as the sale of the goods actually delivered bears to that which the conforming goods would have had at the time of delivery (Article 50).

A number of important trading countries are parties to the Vienna Convention, including the USA, the Russian Federation, Belarus, Germany, Australia and China.

These countries are bound by the Convention's terms unless they have excluded it in whole or in part (Article 6). To determine the extent to which a contract will be subject to the Convention, where at least one contracting party is from a country that ratified or acceded to the Convention, and the law of the ratifying or acceding country is stated in the contract to apply, the national law will have to be considered in order to establish whether the Convention has been incorporated into that law in its entirety or if parts have been excluded. There is a risk that the Convention's provisions may apply because the parties have inadvertently failed to exclude it.

As a general rule the Convention seems to be tipped in favour of a buyer. If the parties wish to exclude it a simple clause may be used which states that:

> "the United Nations Convention on contracts for the International Sale of Goods (1980) shall not apply".

Another Convention that the UK has not ratified, but which may also apply, is the Convention adopting the United Nations

Conference on Prescription (Limitation) in the International Sale of Goods 1974 amended by protocol at the same time as the (Vienna) Convention. This replaces national laws, providing a limitation period of four years in which a buyer may bring its action for a contractual claim. Like the (Vienna) Convention there is a risk that even though a country has not ratified it, the Convention may still apply unless expressly excluded.

16.5 Incorporated terms

In addition to implied terms, the parties may also wish to *incorporate* terms that would otherwise not apply unless expressly incorporated into the contract. These differ from implied terms, which will always apply unless the parties exclude them. An obvious example of incorporated terms is where a party expressly incorporates its standard trading terms, for example, Shell's General Conditions for the Sale of Brent Blend Crude Oil on 15-Day Terms, 1990.

16.5.1 Incoterms

In order to interpret shorthand expressions, such as FOB and CIF, that are used in a contract – particularly when the parties are from different countries – the International Chamber of Commerce developed a set of rules called the International Rules for the Interpretation of Trade Terms. These are known as Incoterms and were first published in 1936, subsequently amended in 1953, 1967, 1976, 1980, 1990 and most recently amended in 2000.

The terms are divided into four different categories (*see below*) and set out buyers' and sellers' responsibilities and obligations under a particular type of contract.

If the parties wish to include a published set of Incoterms the contract should refer to the date of the edition; for example:

> "This Contract is subject to Incoterms 2000 Edition".

The contract should also state on what basis the goods are being sold, for example, "FOB" or "CFR" so that it is clear which rules apply, for example, "Incoterms 2000 FOB Rotterdam". It is not possible to "pick and choose" which terms apply to the contract – it must be the whole set under the particular category. In drafting a contract there may be other rules which the parties wish to apply in addition to the Incoterms such as the sellers' standard conditions of sale. Where such conditions of sale are expressly stated to apply then the order in which they, Incoterms and the contract terms prevail and priority in the event of conflict should be expressly addressed.

The four categories of Incoterms are called:

- "E Terms" (Ex works) whereby the seller makes the goods available to the buyer at the seller's own premises.

- "F Terms" (free carrier, free alongside ship, free on board) whereby the seller is called upon to deliver the goods to a carrier appointed by the buyer.
- "C Terms" (cost and freight, cost, insurance and freight, carriage paid to, carriage and insurance paid to) whereby the seller has to contract for carriage, but without assuming the risk of loss or damage to the goods or additional costs due to events occurring after shipment and despatch.
- "D Terms" (delivered at frontier, delivered ex ship, delivered ex quay, delivered duty unpaid, delivered duty paid) whereby the seller has to bear all costs and risks needed to bring the goods to the country of destination.

The obligations of the parties for each term are grouped under the same main headings of "the seller must" and "the buyer must".

There are ten obligations which may fall upon the parties and these are numbered with the headings as follows:

A1	Provision of goods in conformity with the contract	B1	Payment of the price
A2	Licences, authorisations and formalities	B2	Licences, authorisations and formalities
A3	Contract of carriage and insurance	B3	Contract of carriage
A4	Delivery	B4	Taking delivery
A5	Transfer of risks	B5	Transfer of risks
A6	Division of costs	B6	Division of costs
A7	Notice to the buyer	B7	Notice to the seller
A8	Proof of delivery, transport document or equivalent electronic message	B8	Proof of delivery, transport document or equivalent electronic message
A9	Checking-packaging-marking	B9	Inspection of goods
A10	Other obligations	B10	Other obligations

There is no legal obligation on the parties to include Incoterms and Incoterms will not cover all obligations in respect of delivery of goods, for example: there is no provision on the passing of title or *force majeure* or the applicable law of a contract. They do however provide a simple set of rules to regulate complex arrangements for the sale of goods which can be used in addition to a party's existing contract terms or conditions of sale (*see also Chapter 17*).

16.5.2 Letters of credit

The use of letters of credit may also require detailed provisions in the contract. There are three aspects of the letter of credit to consider: the obligation to provide the letter of credit, its terms and how the letter of credit is presented. The obligation to provide the letter of credit should specify:

- that payment under the contract is to be made by means of an irrevocable letter of credit in favour of the seller;
- with whom the letter of credit is to be opened or by whom confirmed; normally "an international bank acceptable to the seller";
- by when the letter of credit is to be provided – for example within so many days of receipt of a notice from the seller to the buyer;
- the currency of the letter of credit and its value; if the contract states "the total purchase price of the oil delivered hereunder" that may be unknown or too uncertain at the time the letter of credit is required;
- a statement that the buyer (normally) is to cover all costs, commissions, banks fees, etc., of obtaining the letter of credit;
- the effect of failure to provide the letter of credit; if the seller has already accepted a nominated vessel, is ready to load but has not received the letter of credit the seller will need to protect its position by stating that it shall not be obliged to commence loading the oil. The seller should also require an indemnity from the buyer for demurrage and any other costs, losses or damages which it incurs as a result of any delay in provision of the letter of credit.

In addition to the obligation to provide a letter of credit, the contract should provide for a procedure for presentation of a letter of credit stating:

- a requirement for confirmation from the bank providing the letter of credit to the seller that the letter of credit will not affect the validity of the contract;
- when the letter of credit is to be issued.

Normally, a letter of credit will be honoured by the issuing (or confirming) bank against the presentation of the seller's shipping documents – which will include the original bill of lading and certificates as to quantity, quality and (possibly) origin. If it is unlikely that the shipping documents will be available timeously, then the seller is normally obliged to issue a letter of indemnity. The form of letter of credit and letter of indemnity may be agreed in advance and attached in a schedule or appendix to the contract.

Examples

> "Payment shall be by means of an irrevocable Letter of Credit in favour of the Seller which the Buyer shall cause to be opened with or confirmed by an international bank acceptable to the Seller in the terms and by the time specified in clause [ ] and the currency specified for payment in clause [ ]"

> "Notwithstanding anything to the contrary herein or in the special provisions, Sellers shall be entitled at any time, including, but not limited to, circumstances falling within [ ] by written notice to Buyer to require Buyer to establish an irrevocable Letter of Credit in favour of Seller, in a form acceptable to Seller with a United States or international bank acceptable to Seller, for the total purchase price of the Oil to be delivered hereunder. All related opening, advising and confirming bank fees, commissions, costs, and expenses whatsoever shall be borne by Buyer. After the receipt of said notice from Seller, Buyer shall establish such Letter of Credit and cause the same to be received by Seller at least five (5) days before the scheduled loading of the Oil. Notwithstanding any vessel nominations or loading instructions which may have been submitted by Buyer and accepted by Seller hereunder, Seller shall not be obliged to commence the loading of any Oil, the payment for which Buyer is required to establish a Letter of Credit hereunder, until after said Letter of Credit is received, examined and found to be acceptable by Seller. Seller shall promptly make said examination and notify the Buyer of any deficiencies. In the event that such Letter of Credit is not established as required herein, the Seller shall have no obligation to deliver the Oil to Buyer and the Seller shall have no liability whatsoever to Buyer for non-delivery; Buyer shall indemnify Seller for demurrage or other costs, losses or damages incurred by Seller as a result of any delay or deferment of loading under this Section."[48]

[48] Amoco FOB Contract.

Payment may also be covered by the buyer providing a bank or parent company guarantee, although the payment will remain the primary liability of the buyer. In this way the guarantee is similar to the letter of credit. In either case, the seller should consider including a provision that the buyer will be required to provide a performance bond (in an agreed form) to be issued in the event of late or nonpayment.

Invoices will be prepared on the basis of the certificates of quality and quantity. The buyer should be required to pay against presentation of the issue of such documents or the seller's letter of indemnity if not all the shipping documents are available at the time of presentation.

16.5.3 Pollution

The International Tanker Owners Pollution Federation Limited (ITOPF) is a provider of a broad range of specialised technical services in the field of marine oil pollution (e.g. assessment of damage caused by spills and the resulting claims for compensation) to and on behalf of its tanker owner members and their P & I Clubs. The 1992 International Convention on Civil Liability for Oil Pollution Damage (the 1992 Civil Liability Convention) governs the liability of shipowners for oil pollution damage and creates a system of compulsory liability insurance. The 1992 International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage (the 1992 Fund Convention), which is supplementary to the 1992 Civil Liability Convention, establishes a regime, which in the event of oil spill, provides for compensating those suffering oil pollution damage who are resident in a State that is party to the 1992 Fund Convention when the compensation under the applicable 1992 Civil Liability Convention is inadequate. The International Oil Pollution Compensation Fund 1992 (the 1992 Fund) was set up under the 1992 Fund Convention. The levy of contributions is based on reports of oil receipts in respect of individual contributors. This applies whether the receiver of oil is a government authority, a state-owned company or a private company. Except in the case of associated persons (subsidiaries and commonly controlled entities), a person is not required to make contributions in respect of the oil imported or received by him in any year if the oil so imported or received in the year does not exceed 150,000 tonnes. The Merchant Shipping Act 1995 (Chapter 173) provides for oil importers to pay into the 1992 Fund.

The Merchant Shipping Act 1995 enables the UK to give effect to the International Convention on Civil Liability for Oil

Pollution Damage 1992. When oil escapes from a ship carrying persistent oil in bulk as a cargo the Act imposes strict liability on a ship owner for damage caused by oil pollution and also for the cost of measures taken to prevent or minimise such damage.

Example

Buyer warrants and undertakes that (for each vessel nominated to carry a cargo) the vessel is owned or demise chartered by a member of the International Tanker Owners Pollution Federation Limited (ITOPF).

> "Buyer shall exercise reasonable efforts to ensure that:
>
> (a) the vessel carries on board a valid certificate of insurance as described in the 1969 Civil Liability Convention for Oil Pollution Damage and the International Convention on Civil Liability for Oil Pollution Damage 1992;
> (b) the vessel has in place insurance cover for oil pollution no less in scope and amounts than the highest available under the Rules of P & I Clubs entered into the International Group of P & I Clubs.

If Buyer's vessel does not meet any of the above requirements Seller or Seller's suppliers may refuse to berth or load or continue to load the vessel with the scheduled loading."[49]

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[49] Shell International Trading Company General Terms and Conditions of the Sale of Crude Oil, FOB (1st January 1993) with amendments dated 25th November, 1999, Clause 7, Vessel Nomination.

Appendix 16.1

Sample FOB contract (1)

TO: SELLERCO, LONDON	ATTN: MR S. SELLER
TO: BUYERCO, ROTTERDAM	ATTN: MS B. BUYER

WE HAVE PLEASURE IN CONFIRMING THE FOLLOWING TRANSACTION:

01. SELLERS

[SELLER'S COMPANY NAME]
[REGISTERED ADDRESS]

02. BUYERS

[BUYER'S COMPANY NAME]
[REGISTERED ADDRESS]

03. INTERMEDIARY

BROKERCO, BROKERBURG

04. PRODUCT

LIGHT FUEL OIL ON EEC BASIS

05. QUALITY

SPEC. GRAV. /15 DEG C	0.9858
SULPHUR WT PCT	0.4
VISC. /50 DEG C CST	25.2
ASH WT PCT	0.04
CCR WT PCT	4.6
COLOUR	BLACK
FLASH POINT DEG C	67
POUR POINT DEG C-24	
SEDIMENT WT PCT 0.07	
VISC. /20 DEG C CST	125.3
TOTAL CHLORINE	4
WATER PCT VOL	<0.1

FURTHER NORMAL COMMERCIAL QUALITY

06. QUANTITY

CA. [QUANTITY] MT – TANK TO BE EMPTIED

07. LIFTING

PX TANK NNN TANKCO AMSTERDAM BY BARGES TO BE PROVIDED BY BUYERS FOR LIFTING BETWEEN [DATE RANGE] BOTH DATES INCLUSIVE.

08. PRICE

USD [PRICE] FOB TANKCO AMSTERDAM ON EEC BASIS EXCL. ANY DUTIES

09. PAYMENT

PAYMENT TO BE MADE IN FULL WITHOUT DEDUCTION SET OFF OR COUNTER CLAIM NET CASH IN USDLRS WITH VALUE LATEST FIVE CALENDAR DAYS AFTER B/L DATE AGAINST TELEX INVOICE, BUYERS TO OPEN AN IRREVOCABLE BANK GUARANTEE IN FAVOUR OF SELLERS WITH BOTH BANK AND TEXT TO BE ACCEPTABLE TO SELLERS.

10. DETERMINATION OF QUANTITY/QUALITY

AS ASCERTAINED BY LOADING INSTALLATION (QUALITY AS STIPULATED UNDER ITEM 05) IS BINDING FOR BOTH PARTIES.

11. GENERAL

A) OVERTIME, IF ANY NOT FOR ACCOUNT OF SELLERS.
B) ANY NOMINATION TO REACH BUYERS WITH AT LEAST TWO WORKING DAYS NOTICE.
C) LAYTIME AND DEMURRAGE AS PER TTN RULES.
D) INCOTERMS 2000 PLUS LATEST AMENDMENTS TO APPLY.
E) DELIVERIES WHICH, ON REQUEST OF BUYER, ARE MADE WITH EXEMPTION FROM EXCISE DUTIES, LEVIES AND/OR TAXES UNDER COVER OF CUSTOMS OR EXCISE DOCUMENTS ISSUED BY SELLER, WILL TAKE PLACE AT THE EXCLUSIVE RESPONSIBILITY OF BUYER WHO IS OBLIGED TO FULLY INDEMNIFY SELLER FOR ALL DUTIES, TAXES, PENALTIES, COSTS ETC WHICH SELLER MIGHT HAVE TO PAY BECAUSE OF THE ABSENCE OF CLEARANCE OF DOCUMENTS OR OTHER IRREGULARITIES IN THE FIELD OF CUSTOMS, EXCISE AND VAT LEGISLATION, NATIONAL

AS WELL AS FOREIGN AND EEC LEGISLATION, AND REGARDLESS ANY FAULT CHARGEABLE TO BUYER.

F) IN CASE OF RESALE BUYER WILL TAKE CARE THAT NEW CUSTOMS AND/OR EXCISE DOCUMENTS ARE ISSUED.

G) BUYER AGREES TO IMMEDIATELY INFORM SELLER OF THE DATE OF CLEARANCE AND THE CUSTOMS OFFICE WHERE THE CLEARANCE TOOK PLACE, AS WELL AS OF THE SUBSTITUTION OF THE CUSTOMS AND/OR EXCISE DOCUMENT.

WE THANK YOU FOR THIS DEAL.

REGARDS, BROKERCO.

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Appendix 16.2

Sample FOB contract (2)

[DATE]

TO: SELLERCO, SELLERTOWN ATTN: MR S. SELLER

WE ARE PLEASED TO CONFIRM THE RECENT TRANSACTION CONCLUDED UNDER THE FOLLOWING TERMS AND CONDITIONS:

01. SELLER:

    [SELLER'S COMPANY NAME]
    [REGISTERED ADDRESS]

02. BUYER:

    [BUYER'S COMPANY NAME]
    [REGISTERED ADDRESS]

03. COVERING:

    [QUANTITY] MTS PLUS/MINUS 5 PERCENT SELLERS OPTION
    [ORIGIN] STRAIGHT RUN FUEL OIL

04. QUALITY:

	UNITS	TEST RESULT	TEST METHOD ASTM
SP. GR. 60/60 DF		MAX 0.97	D-1298
VISCO RWI AT 100 DF	SEC	MAX 2500	CALCULATED
VISCO KIN AT 122 DF	CST	MAX 180	D-445
FLASH POINT	DF	MIN 140	D-93
POUR POINT	DF	MAX 75	D-97
SULPHUR TOTAL	WT PCT	MAX 3.5	D-1552
CARBON RES.	WT PCT	MAX 12	D-189
ASH	WT PCT	MAX 0.05	D-482
SEDIMENT BY EXT.	WT PCT	MAX 0.1	D-473
WATER CONTENT	VOL PCT	MAX 0.5	D-95
CALORIFIC VALUE	BTU/LB	MIN 18000	CALCULATED

05. SHIPMENT:
    BY SHIP TO SHIP OPERATION AT A SELLER DESIGNATED LIGHTERING POSITION OFFSHORE [LIGHTERING LOCATION] [COUNTRY] DURING THE PERIOD [DATE RANGE]. ALL COSTS RELATED TO THE

SHIP TO SHIP TRANSFER WILL BE ENTIRELY FOR SELLER'S ACCOUNT, I.E. SUPPLY OF FENDERS ETC.

06. PRICE:

FOB BY SHIP TO SHIP OPERATION [LIGHTERING LOCATION] EX SELLER'S VESSEL [SELLERS SHIP NAME] AND/OR SUBSTITUTE TO BUYER'S VESSEL [BUYERS SHIP NAME] OR SUBSTITUTE.

PRICE: THE FIVE DAY ARITHMETIC AVERAGE OF THE MEAN OF PLATT'S HIGH AND LOW QUOTATIONS FOR ARABIAN GULF FOB HIGH SULPHUR FUEL OIL 180 CST CARGOES AS PUBLISHED IN PLATT'S EUROPEAN MARKETSCAN PLUS [PRICE DIFFERENTIAL] US DOLLARS PER METRIC TON. THE FIVE QUOTATIONS USED SHALL BE THE BILL OF LADING DATE, TWO DAYS PRIOR AND TWO DAYS AFTER THE BILL OF LADING DATE OF THE [SELLERS SHIP NAME] OR SUBSTITUTE AT THE LOADING PORT [LOAD PORT]. IN THE EVENT THAT THERE IS NO PLATT'S PUBLICATION ON THE BILL OF LADING DATE THEN ONLY FOUR EFFECTIVE QUOTATIONS SHALL BE USED, I.E. TWO BEFORE AND TWO AFTER THE BILL OF LADING DATE.

07. PAYMENT:

IN US DOLLARS IN FULL WITHOUT DISCOUNT SET OFF OR COUNTERCLAIM TO SELLER'S NOMINATED BANK ACCOUNT BY AN IRREVOCABLE LETTER OF CREDIT AS DEFINED BELOW.

PAYABLE VALUE 15 DAYS FROM BILL OF LADING DATE. BILL OF LADING DATE FOR PAYMENT PURPOSES REFERS TO THE BILL OF LADING OF THE [SELLERS SHIP NAME] LOADING AT [LOAD PORT]. BILL OF LADING DATE TO COUNT AS ZERO AGAINST PRESENTATION OF COMMERCIAL INVOICE AND SHIPPING DOCUMENTS. IN THE EVENT NORMAL SHIPPING DOCUMENTS ARE NOT AVAILABLE, SELLER SHALL ISSUE A LETTER OF INDEMNITY TO THE BUYER BY WHICH PAYMENT MAY BE MADE.

IN THE EVENT PAYMENT DATE FALLS ON A SATURDAY OR BANK HOLIDAY IN NEW YORK OTHER THAN A MONDAY PAYMENT WILL BE EFFECTED PREVIOUS WORKING DAY. IN THE EVENT PAYMENT

FALLS DUE ON A SUNDAY OR MONDAY BANK HOLIDAY IN NEW YORK PAYMENT WILL BE EFFECTED THE FOLLOWING WORKING DAY.

BUYERS TO OPEN AN IRREVOCABLE LETTER OF CREDIT BY A FIRST CLASS WESTERN BANK ACCEPTABLE TO SELLERS AND IN A FORMAT ACCEPTABLE TO SELLERS. DUE TO TIME CONSTRAINTS IT IS IMPORTANT THAT SELLERS OPEN THEIR LETTER OF CREDIT AS SOON AS POSSIBLE AND THAT IT BE FIRMLY IN PLACE WITH ALL DETAILS TO SELLERS SATISFACTION BY NO LATER THAN [DATE BEFORE FIRST DAY OF LOADING DATE RANGE].

ALL COSTS RESULTING FROM OPENING THE LETTER OF CREDIT WILL BE FOR BUYER'S ACCOUNT WHEREAS COSTS FOR NEGOTIATION WILL BE FOR SELLER'S ACCOUNT.

IN THE EVENT THAT AN ACCEPTABLE DOCUMENTARY LETTER OF CREDIT IS NOT TIMELY RECEIVED BY SELLER AND AS A RESULT THE VESSEL LOADING OR DISCHARGING IS DELAYED, ALL ATTENDANT CHARGES INCLUDING DEMURRAGE INCURRED WILL BE FOR THE ACCOUNT OF THE BUYER.

08. LAYTIME AND DEMURRAGE:

LAYTIME 48 HOURS PLUS 6 HOURS NOR. DEMURRAGE AS PER PERFORMING VESSEL CHARTER PARTY TERMS AND CONDITIONS. LAYTIME SHALL COMMENCE ONLY UPON THE ARRIVAL OF THE SELLER'S NOMINATED VESSEL AT THE INTENDED LIGHTERING POSITION AT [LIGHTERING LOCATION].

09. DETERMINATION OF QUANTITY/QUALITY:

QUALITY AS DETERMINED BY [ORIGINAL SUPPLIER] AT LOADING PORT [LOAD PORT]. LOAD PORT QUALITY TO BE FINAL AND BINDING ON BOTH PARTIES. QUANTITY FOR BILL OF LADING SHALL BE DETERMINED BY AN INDEPENDENT INSPECTOR [INSPECTOR NAME] OR OTHER MUTUALLY AGREED INSPECTOR. THE DEEMED B/L QUANTITY SHALL BE THE AVERAGE OF THE MOTHER VESSEL'S SHIP'S

FIGURES AND THE RECEIVING VESSEL'S SHIP'S FIGURES. THE RESULTING QUANTITY, CONFIRMED BY THE INSPECTORS, WILL BE CONSIDERED AS FINAL B/L QUANTITY, TO BE FINAL AND BINDING FOR BOTH PARTIES. INSPECTION COSTS TO BE SHARED 50/50 BETWEEN SELLER/BUYER.

10. TITLE AND RISK:

    TITLE AND RISK SHALL PASS FROM SELLER TO BUYER WHEN CARGO PASSES BETWEEN SHIPS PERMANENT FLANGE CONNECTION AT LOAD PORT [LIGHTERING LOCATION].

11. LAW:

    THIS CONTRACT SHALL BE GOVERNED BY ENGLISH LAW WITH JURISDICTION IN THE HIGH COURT OF LONDON.

12. FORCE MAJEURE:

    NEITHER SELLER NOR BUYER SHALL BE LIABLE IN DAMAGES OR OTHERWISE FOR ANY FAILURE OR DELAY IN PERFORMANCE OF ANY OBLIGATION HEREUNDER OTHER THAN OBLIGATION TO MAKE PAYMENT WHERE SUCH FAILURE OR DELAY IS CAUSED BY FORCE MAJEURE, BEING ANY EVENT, OCCURRENCE OR CIRCUMSTANCE REASONABLY BEYOND THE CONTROL OF THAT PARTY INCLUDING WITHOUT PREJUDICE TO THE GENERALITY OF THE FOREGOING, FAILURE OR DELAY CAUSED BY OR RESULTING FROM ACTS OF GOD, STRIKES, FIRE, FLOODS, WARS (WHETHER DECLARED OR UNDECLARED), RIOTS, DESTRUCTION OF THE OIL, DELAYS OF CARRIERS DUE TO BREAKDOWN OR ADVERSE WEATHER, PERILS OF THE SEA, EMBARGOES, ACCIDENTS, RESTRICTIONS IMPOSED BY ANY GOVERNMENTAL AUTHORITY (INCLUDING ALLOCATIONS PRIORITIES, REQUISITIONS, QUOTAS AND PRICE CONTROLS). THE TIME OF SELLER TO MAKE, OR BUYER TO RECEIVE, DELIVERY HEREUNDER SHALL BE EXTENDED DURING ANY PERIOD IN WHICH DELIVERY SHALL BE DELAYED OR PREVENTED BY REASON OF ANY OF THE FOREGOING CAUSES, UP TO A TOTAL OF THIRTY (30) DAYS. IF ANY DELIVERY HEREUNDER SHALL BE DELAYED OR PREVENTED FOR MORE THAN 30 DAYS,

EITHER PARTY MAY TERMINATE THIS CONTRACT WITH RESPECT TO SUCH DELIVERY UPON WRITTEN NOTICE TO THE OTHER PARTY.

13. OTHER TERMS AND CONDITIONS:

    WHERE NOT IN CONFLICT WITH THE ABOVE, INCO TERMS 2000 WTH SUBSEQUENT AMENDMENTS TO APPLY.

14. MISCELLANEOUS:

    CERTIFICATES OF QUANTITY AND QUALITY WILL BE PROVIDED BY SURVEYOR IN ATTENDANCE. IT IS THE BUYER'S RESPONSIBILITY TO MAKE ARRANGEMENTS WITH THE ATTENDING SURVEYOR FOR ANY OTHER DOCUMENTATION WHICH MAY BE REQUIRED.

PLEASE CONFIRM YOUR AGREEMENT TO THE TERMS OF THIS CONTRACT.
REGARDS,

B. BUYER, BUYERCO.

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Appendix 16.3

Sample CIF contract

TO: SELLERCO, LONDON ATTN: MR S. SELLER
TO: BUYERCO, ROTTERDAM ATTN: MS B. BUYER

FROM: BROKERCO, LONDON ON BEHALF OF BROKERCO
WE CONFIRM THE FOLLOWING TRANSACTION:

01. SELLERS

[SELLER'S COMPANY NAME]
[REGISTERED ADDRESS]

02. BUYERS

[BUYER'S COMPANY NAME]
[REGISTERED ADDRESS]

03. PRODUCT

PREMIUM UNLEADED MOTOR GASOLINE

04. QUANTITY

[QUANTITY] MT +/– 5% SELLERS OPTION

05. QUALITY

PRODUCT TO MEET EN228 SPECIFICATION FOR PREMIUM UNLEADED CLASS 2 GASOLINE

06. DELIVERY

CIF BASIS [DELIVERY LOCATION] IN ONE LOT DURING THE PERIOD [DATE RANGE]. SELLER TO GIVE TWO WORKING DAYS NOTICE OF VESSELS ARRIVAL AT DISCHARGE PORT.

07. PRICE

US DOLLARS [PRICE] PER METRIC TON BASED ON B/L QUANTITY CIF [DELIVERY LOCATION]. PRICE TO ESCALATE DE-ESCALATE ON A DENSITY OF 0.7550 AGAINST ACTUAL CARGO DENSITY REPORTED ON THE B/L.

08. PAYMENT

US DOLLARS NET CASH BY TELEGRAPHIC TRANSFER WITH VALUE LATEST THREE WORKING DAYS AFTER DISCHARGE OR FIVE WORKING DAYS AFTER NOR TENDERED IN PORT (WHICHEVER FIRST) AGAINST SELLERS INVOICE AND USUAL SHIPPING DOCUMENTS OR SELLERS LOI FOR TEMPORARILY MISSING DOCUMENTS. BUYERS TO OPEN AN IRREVOCABLE LETTER OF CREDIT IN FAVOUR OF SELLERS WITH BOTH BANK AND TEXT TO BE ACCEPTABLE TO SELLERS.

09. DETERMINATION OF QUANTITY/QUALITY

AS ASCERTAINED AT LOADPORT BY INDEPENDENT INSPECTOR WHOSE FINDINGS TO BE FINAL AND BINDING. COSTS AT LOADPORT FOR SELLERS ACCOUNT. AT DISCHARGE PORT FOR BUYERS ACCOUNT.

10. LAYTIME

36 HOURS SHINC[50] PLUS 6 HOURS NOR.

11. DEMURRAGE

AS PER CHARTER PARTY RATE TERMS AND CONDITIONS.

12. OTHER TERMS AND CONDITIONS

A) THIS CONTRACT SHALL BE GOVERNED AND INTERPRETED BY ENGLISH LAW (WITHOUT CONFLICT OF ANY LAW RULES).
B) JURISDICTION: EACH PARTY EXPRESSLY SUBMITS TO THE JURISDICTION OF THE LONDON HIGH COURT.
C) SELLERS TO PROVIDE FIRST CLASS MARINE INSURANCE TO COVER ALL RISKS, LEAKAGE, AND OR SHORTAGE IN EXCESS OF 0.5 PERCENT FOR MINIMUM 110 PERCENT INVOICE VALUE.

WE THANK YOU FOR THIS BUSINESS.

BEST REGARDS, BROKERCO.

[50] SHINC: Sundays and holidays included. Also SHEXUU: Sundays and holidays excluded unless used.

17 Legal and regulatory issues

Blanche Sas
Updated by Malcolm Groom and Vince Mulvey (Norton Rose)

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17.1 Introduction

The legal issues relevant to oil trading break down into two fundamental categories: contractual and regulatory. As Chapter 16 has addressed contractual issues, this chapter will focus on the regulatory aspects of the oil market, although there are some very clear areas of overlap.

Regulation is primarily concerned with contracts and how they are traded, and with the companies who trade them and their behaviour. But state trading policies, for example tax, customs and export regimes, are also expressed in law. Moreover, general laws such as shipping laws, commercial laws or codes and banking laws are also relevant to the oil trading deal. In addition, there are other important laws that can only be ignored at huge risk, such as competition or anti-trust laws – all of which are relevant to the oil market.

All trading is regulated to a greater or lesser extent by states. Before 1970, the international oil industry was dominated by major vertically integrated oil companies who either produced, processed and sold their own oil products, or procured large amounts of oil under the long-term contracts. However, the emergence of independent producers and refineries and the events of the seventies led to the development of the spot market. Initially the spot market was only concerned with trading at the margin – rectifying supply and demand imbalances – but by the 1980s the spot contract, or spot price related contracts, had become the dominant form of trading. Term contracts became very short (less than a year), and spot contracts for the immediate delivery of specified cargoes at fixed and flat prices were the norm. But despite the rapid changes, all these contracts were still covered by normal legal regimes of the relevant states.

In the 1980s, however, new forms of oil contracts emerged: some to handle physical delivery risks, some to handle price risk management, and some as tax minimisation vehicles. And, as the range of risk management in oil trading increased, so did the variety of the market participants. In some cases, additional laws were required to regulate the operation of the new markets.

The current spectrum of oil trading contracts divides into two basic categories: those which are primarily concerned with physical delivery (“wet contracts”) and those which are primarily concerned with price risk management (“paper contracts”):

Wet contracts

- Long term
- Term
- Spot
- Physical forward
- Options on physical oil contracts
- Exchanges or swaps of physical oil
- Counter trade and barter deals

Paper contracts

- Paper forward
- Futures and options
- Swaps and swaptions
- Various contracts for differences (including bookouts)
- Financial instruments including spreads, box trades etc.

Many of the paper contracts are couched as physical delivery contracts, including most exchange-traded futures contracts. But they differ from wet contracts in that their prime purpose is price risk management and they are normally settled before delivery. As a result, most of the legal issues concerning oil trading are relevant to both paper and wet markets, although price risk management markets have, on occasion, come under significant additional regulatory control by those states in which the markets are primarily located.

Oil trading occurs at both the domestic and international levels. Oil is also traded against a variety of markers; these are defined by either the "type" of crude oil (for example Dubai, Brent, WTI etc.) or their geographical base (North West Europe, US Gulf, US East Coast, Singapore etc.).

This chapter will identify the key laws and how they affect oil trading. It is, of course, not an exhaustive analysis and is intended only to be a lay guide to the regulatory issues with respect to oil trading and should not be construed as proffering legal advice.

17.2 International

17.2.1 International aspects of oil trading

International law and practice has a significant impact on oil trading and its legal documentation, even though most contracts specify a national law as the governing law of the contract for the sale or carriage of oil. While much of the international law that relates to trade, shipping or finance is imported into domestic law by national laws, some is not and yet is applicable to international deals.

There are also trade terms and practices which have been developed by the international mercantile community, which, to a certain extent, have been standardised. Incoterms[1] and the UCP,[2] are examples of such standardisation. In some countries Incoterms or the UCP are given statutory force; in others they have been recognised as custom of the trade (and thus are considered to be part of domestic law); while, in still other countries, such as the UK, the terms must be expressly imported into the contract if the parties wish the definitions to apply (*see Chapter 16*).

17.2.2 Special trade terms

The terms of the contract that will be selected by parties to an international sale of oil will depend on the point at which the responsibility and title to the oil is to be transferred from the seller to the buyer. This determines the extent of the seller's responsibility with respect to loading, transportation, delivery, insurance, payment of duties and taxes, procurement of permits and licences for export or import and so on. The assumption or otherwise of such responsibilities and their associated costs clearly affects the sale price.

It is important for any sales contract for oil to make clear the meaning of any special trade terms used in the contract. This can be achieved either by expressly defining their meanings in the contract, or by referring to general terms and conditions of sale which already define it, or by referring to Incoterms. These were first published in 1936 and have been revised on a regular basis, the current edition being Incoterms 2000.

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[1] Incoterms – A standard set of definitions of trade terms drawn up by the International Chamber of Commerce.

[2] Uniform Customs and Practice for Documentary Credits (UCP).

The terms range from Ex-Works (Ex-Refinery) which is the most favourable export transaction for the seller to DDP which is the most favourable to the buyer. In earlier editions of Incoterms there was the trade term "Free on Rail". By the time the 1990 edition of Incoterms went to print it was thought that the term FCA would cover this and with Free on Rail not appearing in Incoterms 2000 the matter now seems settled. The most common terms used in oil trading at present are for sea-borne cargoes FOB and CIF and for rail and pipelines either FCA or DDP.

Incoterms

The current Incoterms are:

- EXW Ex Works
- FCA Free Carrier
- FAS Free Alongside Ship
- FOB Free on Board
- CFR Cost and Freight
- CIF Cost, Insurance and Freight
- CPT Carriage Paid To
- CIP Carriage and Insurance Paid To
- DAF Delivered at Frontier
- DES Delivered Ex Ship
- DEQ Delivered Ex-Quay
- DDU Delivered Duty Unpaid
- DDP Delivered Duty Paid

It should be noted that Incoterms only cover a limited range of issues and they should not be relied upon to answer all issues with respect to the sale. For example, they do not include any *force majeure* definition, destination restrictions, etc.

FOB

In a contract the term fob is followed by a named port (e.g. fob Augusta) or an agreed range of ports (e.g. fob ARA). In the basic fob oil sale contract the seller must, during the stipulated delivery period, put the oil on board a vessel nominated by the buyer at the agreed port named in the contract. The seller is responsible for all charges and risks up to the time the goods cross the ship's rail at which time the property and risk pass to the buyer.[3]

[3] Caution should be exercised in the US jurisdiction; see commentary in respect of the Uniform Commercial Code.

The buyer must nominate a ship and is responsible for all charges after the goods cross the rail, including stowage, freight, marine insurance, unloading charges, and import duties.

It should be noted that under English law, in addition to the obligations of the seller set out in Incoterms, a fob seller must, under s.32(3) of the UK Sale of Goods Act 1979, give the buyer – in circumstances in which it is usual to insure – due notice enabling him to insure the oil during sea transit. If the seller fails to do so the oil is deemed to be at the seller's risk during the sea transit.

The liabilities of the parties under a fob contract are also defined by a specific trade custom or custom of the port. For example in oil trading a trade usage exists according to which a fob buyer has to give the seller timely notice of loading.

It should also be noted that in the United States, the term fob is no longer solely related to vessels, and under s.2–319(1) of the American Uniform Commercial Code (UCC), fob has become a general delivery term, (like free delivery at named destination) which, on occasion, can cause some confusion. It has been said that the equivalent of a fob contract, as that term is understood in the UK and the Commonwealth, is "Fob Vessel" in the US.[4]

CIF

Under a cif contract the buyer pays a combined price covering the cost of the oil, an insurance policy covering its carriage and the cost of the carriage (i.e. freight cost) to the port/terminal of destination. The seller's obligations are performed by transferring to the buyer, in return for the price, the documents representing the goods: the invoice for the price, the insurance policy and the bill of lading received from the carrier during the contract period. This is considered to be equivalent to the delivery of the goods themselves.

The seller's obligations therefore include making all the necessary arrangements for the safe carriage of the oil to a named destination (e.g. cif Hamburg). This includes shipping the goods within the proper time under a reasonable contract of carriage and marine insurance policy (under which the buyer will be entitled to make claims and receive the proceeds of such claims in the event of cargo loss) and then tendering the documents to

[4] Schmitthoff's Export Trade, *The Law and Practice of International Trade;* D'Arcy, Murray and Cleave, Sweet & Maxwell 2000, p17 para 2-006.

the buyer who then in turn becomes obligated to pay the agreed price within an agreed time. Once the documents are accepted the title and risk pass to the buyer, and the buyer is then responsible for any import licences, import duties and subsequent costs of unloading, etc.

The utility of the cif contract lies not only in the fact that the buyer receives the documents and thus the oil with all expenses paid to their destination, but that the buyer may, before the oil is shipped or while afloat, resell it before it reaches its destination.

There are several variants on the cif contract, the most important in the oil trade is the cif out-turn contract developed in the US. Here, by means of a price adjustment, the buyer only pays for the actual amount of oil delivered, rather than the amount loaded as per bill of lading. Because this is intended only to relate to the determination of price, US courts have ruled that such clauses do not affect the character of the contract, which remains a true cif contract.

17.2.3 Standardisation of terms

The mandate of the United Nations Commission on International Trade Law (UNCITRAL) is the unification and harmonisation of international trade law. To date a number of major pieces of work have been completed including:

1. *The Convention on Contracts for the International Sale of Goods (CISG) 1980*, (*see Section 17.2.4*).
2. *The Convention on the Limitation Period in the International Sale of Goods 1974.* This establishes a limitation period of generally four years and attempts to harmonise the common law procedural approach and the civil law substantive approach to the issue of termination of rights of action. A 1980 Protocol aligned the provisions of the Convention with those of the 1980 Convention.
3. *The Convention on the Carriage of Goods by Sea 1978* (usually known as the "Hamburg Rules") which regulate international bills of lading (*see Section 17.2.7*).
4. *The Convention on the International Bills of Exchange and International Promissory Notes 1988* (*see Section 17.2.6*).
5. The United Nations Convention on Independent and Stand-by Letters of Credit, 1995.[5]

[5] This convention is currently only in force in five countries.

UNCITRAL has also adopted Arbitration Rules 1976 (*see Section 17.2.8*). Additionally, a number of "Model Laws", for instance, the UNCITRAL Model Law on International Credit Transfers (1992), have been produced which aim to provide a framework to assist states with the drafting and formulation of their own national legislation in a number of key areas.

17.2.4 International sale of goods

With the notable exception of the UK, many of the major oil trading countries – including the United States and Russia – are parties to the UN Convention on Contracts for the International Sale of Goods (CISG) 1980. This Convention relates only to *international sales of goods* and under Article 1 applies automatically to those contracts where the places of business of the parties are in different States and either (a) both States are Contracting States or (b) only one State is a Contracting State and private international law choice of law rules would lead to the application of the law of the Contracting State.

If the parties to an international contract wish to prevent the application of the Convention then under Article 6 they can expressly opt out of its application (*see Chapter 16*). Although it is clear that the parties may "opt out" of the Convention, care must be used in drafting a statement of exclusion as some authorities do not believe an implicit exclusion would be recognised by a court. Thus an exclusion clause should read something to the effect that:

> "this contract shall not be governed by the CISG 1980, but shall be governed by XXXXX law".

Articles 7–13 of the CISG deal with general principles and the interpretation of the CISG and the contract, including party conduct and trade usage (Article 9). Articles 14–24 deal with issues connected with formation of contract: what constitutes a contract, when it is formed, etc. Under the CISG there is no requirement of "consideration" for contract formation, unlike English law: merely that there be an offer and an acceptance of that offer. The CISG approach to acceptance is closer to the US approach – which holds that there must be no difference *in material terms* – than the English approach – which requires exact mirror acceptance. But on the question of when the contract is formed, CISG Article 18 states that the acceptance becomes effective when it is received by the offeror – like English law – and differs from the US "mailbox rule" – which states that the contract acceptance is effective from the time of dispatch of the acceptance.

Part III of CISG deals with the obligations of buyer and seller and the passing of risk. Interestingly, the CISG has a limited definition of delivery which only relates to transfer of possession and control. But this Part of the CISG also has some significant provisions, which are not necessarily part of US or English law. For example, under Article 41, the seller is obliged to deliver goods not only free from any encumbrance to their title but also free from any third party claim, i.e. "quiet possession of the goods". While, on other occasions, it leaves some issues unresolved. It is essential if the Convention is to apply that the parties *disapply*, as they may under Article 6, *any provision which is not appropriate*.

Part V contains provisions on anticipatory breach, damages and exemptions and avoidance of contract.

Many scholars are impressed with the flexibility of the Convention, such as its provisions relating to time limitations on giving notice in a timely manner (Articles 39 and 44). Others are concerned about its provisions which have been drafted as a compromise between legal systems. Whether or not a trader should allow the CISG to apply to an oil sales contract is a matter which should be discussed with his legal advisor. The easiest – but perhaps not optimal – approach is to choose as the governing law the law which the parties or the market normally use or are most familiar with.

17.2.5 General trade laws

European Union

In the European Union (EU) the provisions of the EC Treaty – and all the law which has been promulgated as a result – have had a significant impact on oil trading in EU member states. The EU is – among other things – a customs union and goods circulate freely between member states without quantitative or qualitative restrictions and without customs formalities or duties or charges having equivalent effect. The EU also establishes common customs tariffs *vis-a-vis* third states, as well as a common value added tax system. Frequently oil contracts specify EU duty paid.

The competition law provisions, Articles 81 & 82 of the Treaty, which prohibit certain anti-competitive or monopolistic behaviour, have particular importance to oil trading, oil futures exchanges – which periodically seek exemption from their application – and oil companies' behaviour. It is worth noting that EU competition law – like US anti-trust law – has extra-territorial effect. Thus traders who ignore the reach of Articles 81 and 82 may experience severe consequences in the form of fines up to 10 per cent of gross world turnover – although this is perhaps not as severe as the felony criminal sanctions and private treble damages actions found in the US. However, it is important to note that these Articles also render the offending contracts null and void.

EU legislation also covers environmental issues, specifying, for example, acceptable levels of sulphur, which in turn affects quality specifications in oil trading contracts.

World Trade Organisation

The World Trade Organisation ("WTO") was established in 1995. It is the successor to the General Agreement on Tariffs and Trade ("GATT") which was an institution which grew out of the agreement of the same name. The WTO is an international body (having approximately 140 states as members accounting for over 90% of world trade) which deals with the rules of trade between nations. At its heart are the WTO Agreements covering trade in goods, services and intellectual property. GATT, the agreement, has been amended and incorporated into the WTO Agreements and is the principal agreement dealing with trade in goods. The WTO, like its predecessor, aims to liberalise trade among states by reducing trade barriers such as tariffs, import quotas and other non-tariff barriers from international trade. WTO members agree to be bound by the WTO Agreements (Article II (2) of the Agreement Establishing the World Trade Organisation).

Article 1 of GATT requires each party to accord Most Favoured Nation (MFN) status to all the other GATT participants. MFN status under GATT means that a participant will not extend to any other country trade arrangements which are more favourable than those available to the other participants – although free trade areas are permitted. GATT also incorporates the practice of according national treatment to imported goods (Article III). Thus export goods of one participant are generally to be treated in no less favourable a way than the domestic products under its laws and regulations concerning sale, resale, purchase, transportation and use.

Article V of GATT creates a right of transit for goods, although it does not include pipeline transit. GATT also prohibits any use of quantitative restrictions, although it does allow non-discriminatory duties, taxes and other charges (Article XI) but their use is controlled (Articles X and XXVIII). It specifically prohibits quotas, import or export licences and other such measures. Under GATT negotiated tariff rates (tariff schedules) are agreed and are binding.

GATT does allow safety valves for states to protect domestic markets in specific circumstances, for example, those dealing with anti-dumping measures and countervailing duties.

National restrictions on the import or export of oil could breach GATT in the following circumstances:

- an import ban or quota (clearly not in line with Article XI unless an emergency); or
- a prohibition on importation of a good that fails to meet standards (e.g. safety or environmental). There is a 1979 Standards Code which sets the guidelines for how such requirements should be implemented; or
- a customs rule that under GATT would not be permitted.

Importantly, controls on exports (whether bans, quotas, or taxes) are not the subject of the provisions of GATT. Thus restrictions on exporting domestically produced oil, as for example, in the United States, are not covered by GATT provisions.

Unfortunately GATT and other WTO Agreements are multilateral agreements between member states only, and individuals and companies have no directly effective rights by which they can bring action in a dispute resolution forum. They must therefore approach the competent Ministry in their country and request that it take up their case and raise a complaint in accordance with the rules of dispute settlement. For WTO Agreements a new set of rules have superseded the previous dispute settlement rules used under GATT. These rules known as the Understanding on Rules and Procedures for the Settlement of Disputes are said to provide a more structured process with more clearly defined stages in the procedure than the rules under GATT provided. An example of how the WTO and its dispute resolution procedure can have importance in the oil trading business can be seen in the case that Venezuela brought before the WTO Dispute Settlement Body against the United States on 23 January 1995.[6]

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[6] World Trade Organisation Dispute Settlement Reports 1996 vol 1 (2000).

Energy Charter Treaty

The Energy Charter Treaty was signed in Lisbon on 17 December 1994, and came into force on 16 April 1998. Though it has not been ratified by the United States nor Canada (both of which were signatories to a document signed in the Hague on 17 December 1991 which was the precursor to the Treaty) it is nonetheless an important agreement that will have significant long-term implications for the trading of oil. This is partly because many of the ratifying states are from the former communist bloc – as well as all the states of the European Union and other trading states such as Japan. The Treaty is outside the WTO Agreements and seeks to promote co-operation in the energy sector, to open markets and to protect investment.

Many of its articles are aimed at the progressive opening of energy markets and the promotion of competition. Article 7 addresses the issue of transit and specifically transit through the transit state's pipeline system. Although Article 7 stops short of granting a right of transit it comes very close to it and ensures that transit oil should not be discriminated against in favour of domestic oil. The potential importance of the access to pipeline systems is clear. However, it should be noted that – while this is an international treaty between states – there is also a special provision allowing entities – as well as contracting parties – to resolve disputes under a special procedure set out in Article 7(6) and (7).

17.2.6 Financial issues

Although a simple contract for the sale of oil can be carried out in a straightforward way with the seller delivering the oil and the buyer paying the price, it is not always possible to do this in oil trading. Frequently, the buyers and sellers are in different countries, there is often an independent carrier, and there is a time delay between the seller loading the oil and the buyer receiving it. This raises many issues, including who wishes to tie up money in oil in transit.

For these reasons, a sophisticated system of credit has evolved to deal with international sales that is available through the banks, who organise the payment and assist in compliance with any currency or exchange control regulations.

Bills of exchange

The UK Bills of Exchange Act 1882, which codified the law governing bills of exchange, defined (s.3) a bill of exchange as "an unconditional order in writing addressed by one person to another, signed by the person giving it, requiring the person to whom it is addressed to pay on demand or at a fixed or determinable future time a sum of money to or to the order of a specified person or to bearer".

Like a cheque, a bill of exchange is a form of negotiable instrument. It is a document which acts as a substitute for money and is evidence of the right of the person legally entitled to possession of it (the holder) to claim a particular sum of money (often in specified circumstances).

Bills of exchange have some characteristics worth noting:

- the holder may sue on it in his name;
- the holder may transfer to a subsequent holder, either by delivery if it is payable to bearer or by endorsement and delivery;
- no notice of assignment is required;
- the value of them lies in the fact that by accepting a bill drawn down on him by the seller for the amount of the price, the buyer effectively gives the seller a document for which the seller can obtain immediate value; and
- often bills of exchange are "claused", which means it contains a number of additional provisions.

The purpose of a documentary bill is mainly to ensure that the buyer does not receive the bill of lading (and therewith the right to dispose of the goods) until the buyer has first accepted or paid the attached bill of exchange according to the arrangement set out between the parties.

Bills of exchange are used frequently in letters of credit arrangements. In order to obtain payment under a letter of credit the seller of the oil must attach what is called a "draft", or bill of exchange, to the documents required which the banks involved have agreed to honour if accompanied by a complete set of documents. This bill of exchange, or "draft", is written by the seller and drawn on the buyer or the buyer's bank for the amount of the contract price. The flow of goods, drafts and documents in a typical international oil sale is illustrated in Fig. 17.1.

The UN Convention on International Bills of Exchange and International Promissory Notes 1988 is an attempt to reconcile the two differing approaches to bills of exchange. It will come into force one year after there are ten parties to it and will create clear instruments and rules for international bills of exchange. Currently, however, only Guinea, Honduras and Mexico have acceded to the Convention.

Documentary letters of credit

In oil trading, due to the practicalities of the trade, the common method of payment (if not by open account) is by letter of credit. The ICC's "Uniform Customs and Practice for Documentary Credits" (UCP) has been very widely used, although it only has force when it is expressly adopted by the parties.

The current edition is UCP 500 of 1993. It covers documentary credits, including standby credits. It defines documentary credit to mean "any arrangement however named or described, whereby a bank (the 'Issuing Bank') acting at the request and the instructions of a customer (the 'Applicant') or on its own behalf:

i. is to make a payment to or to the order of a third party (the 'Beneficiary'), or is to accept and pay bills of exchange ('Draft(s)') drawn by the Beneficiary, or
ii. authorises another bank to effect such payment, or to accept and pay such bills of exchange (Draft(s)), or
iii. authorises another bank to negotiate against stipulated documents, provided that the terms and conditions of the credit are complied with."

The use and type of letter of credit will be specified in the oil sales contract. The buyer will then instruct his bank to open a credit for the seller. Normally the issuing bank will arrange through a corresponding bank in the seller's country to do this. Once the seller presents the documents specified in the sale contract to the corresponding bank he is entitled to payment.

There are several types of letters of credit which are briefly described below:

- *Revocable and irrevocable*
  A revocable letter of credit is one which can be cancelled or modified at any time prior to it being drawn on by the seller. Unless the contract stipulates to the contrary no notice of revocation is necessary. Not surprisingly therefore this form is not used in oil trading. Rather an irrevocable letter of credit, which cannot be thus cancelled or modified, is commonly used.
- *Confirmed or unconfirmed letters of credit*
  A credit is confirmed when the correspondent bank gives the seller its own undertaking to pay him on presentation of the required documents. Clearly it is in the seller's interest where possible to have a confirmed letter of credit, although the other side to this is that the buyer has to be prepared to meet the cost.

Where the corresponding bank does not give such an undertaking the letter of credit is unconfirmed.

- *Revolving letters of credit*
  When the buyer and seller have regular trading it is common to open what is termed a revolving letter of credit. Here a maximum amount of credit is fixed from which the seller can draw down, at the same time as the buyer replenishes it, usually by a standing order.

The bank's role

Under a documentary letter of credit the seller is paid against the presentation to the bank of the documents required by the contract for sale and specified in the buyer's instructions to the issuing bank. It should be noted (Article 3) that the UCP expressly states that letters of credit "by their nature, are separate transactions from the sales or other contracts on which they may be based and banks are in no way concerned with or bound by such contract(s), even if any reference whatsoever to such contract(s) is included in the credit".

In Article 4 of UCP it states clearly that in credit operations all parties concerned deal in documents and not with goods. Thus the banks are solely concerned with receiving documents that exactly comply with the requirements of the letter of credit. They are not concerned with commercial purposes and must accept or reject promptly. They are not concerned with custom/trade practice and must only examine documents with reasonable care on the face of the documents.

Thus a bank receiving non-conforming documents should reject them no matter how minor the discrepancy. An issuing bank which accepts unsatisfactory documents is in fact in breach of its contract with the buyer and, similarly, a corresponding bank which does so will not be entitled to payment by the issuing bank. However, even where the documents are forged a bank is not necessarily in breach of its obligations when it makes payment upon their presentation as it will depend on the facts whether the bank was negligent in accepting them. This view of the bank's role and the requirements for the documents are often described as the twin fundamental principles of letters of credit: the autonomy of the credit (Articles 3 and 4) and the doctrine of strict performance (Articles 13 and 14).

Documents
The documents that may be required for presentation include the following:

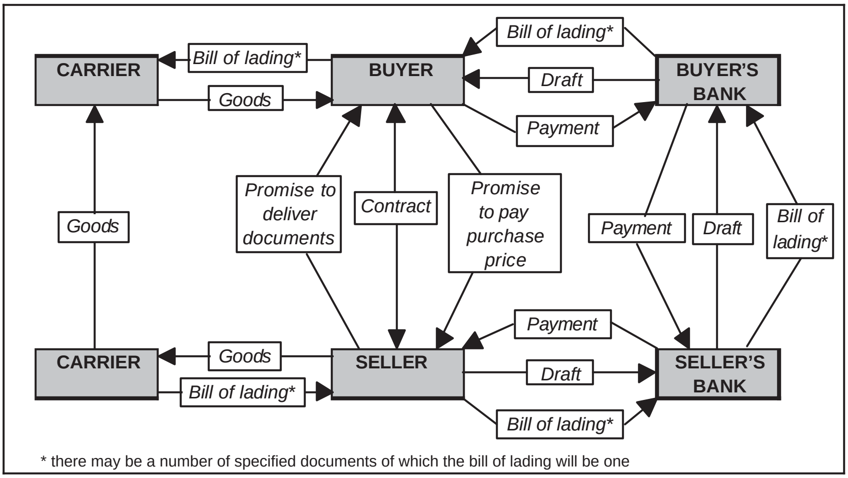

Figure 17.1 Goods and documents in an international oil sale

- commercial invoices;
- insurance policy, in negotiable form, in the currency of the credit;
- bills of lading;
- certificate of origin (*note*: be very careful with these);
- certificate of quantity; and
- certificate of quality.

Opening credit

Normally the oil sales contract will specify when to open the credit. The buyer has an absolute duty to open the letter of credit within the time specified by the contract. The credit is opened in accordance with instructions given by the buyer to the issuing bank which form the basis of the contract between them.

Figure 17.1 illustrates the links in the classic international documentary sale.

The steps are the following:

(1) Buyer and seller agree in oil sales contract that payment shall be by letter of credit.
(2) Buyer instructs issuing bank to open letter of credit in favour of the seller (the beneficiary) on terms specified by the buyer in his instructions to the issuing bank, probably including payment against presentation of specified documents.
(3) The issuing bank arranges with a bank in the seller's location (the advising bank) to advise the seller of the

credit (it may be confirmed) and to pay the seller's draft against delivery of the required documents by the seller.

(4) The advising bank informs the seller that it will pay his draft upon presentation with the required documents.
(5) On receipt of the goods for carriage the carrier gives the seller the bill of lading.
(6) The seller arranges all other documents required and together with them submits his draft to the advising bank.
(7) The advising bank makes payment and sends the documents to the issuing bank and receives payment from the issuing bank.
(8) The issuing bank gives the draft (paid) and all documents to the buyer and receives payment.
(9) The buyer presents the bill of lading to the carrier and receives the goods.

Assignment

A letter of credit is not a negotiable instrument. It can be expressly made transferable to a second but not to a third or further beneficiary under Article 48 of UCP.

The majority of letter of credit disputes in oil trading revolve around the following issues:

- non-compliance with the terms of the credit, especially with non-conformity of the documents;
- justified or unjustified bank refusal to perform its obligations;
- cases of fraud in the transaction; and
- cases where there is later non-conformity of the goods.

17.2.7 Shipping law

Bills of lading

There are two basic types of contract of carriage of goods by sea: those contained in "charterparties", and those evidenced by bills of lading. A charterparty is a contract between the ship owner and a party who wishes to use the ship to carry his cargo, "the charterer". Under the contract the charterer obtains the use of the vessel for a voyage (voyage charterparty) or for a stipulated time period (time charterparty). Most of the major oil companies and tanker owners have standard charterparties for both voyage and time.

Charterparties are normally governed by general national laws and the principle of freedom of contract applies to them. If the charterer loads the cargo on to the chartered vessel he will normally be issued with a bill of lading, but it should be noted that the bill of lading does not supersede the charterparty between the ship owner and the charterer. If the bill of lading is then endorsed to a third party, the relations between the ship owner and the third party are based on the bill of lading and not the charterparty.

Bills of lading are generally governed by specific national laws that usually fully or partially incorporate the international conventions relating to bills of lading, in particular the Hague–Visby Rules which are discussed briefly below (*see also Chapter 16*).

Bills of lading are normally issued in sets: each bill being valid until one of them is presented. The bill of lading has three important functions: it is evidence of the contract of carriage, a receipt for the goods and a document of title to the goods.

If the goods are not received in good order and condition the carrier or his agent may note this on the bill of lading, thus making it a "claused", rather than the "clean", bill normally required in oil trading.

In oil trading, the bill of lading is also used as a document of title as it represents the oil that has been bought and it can therefore be bought, sold or pledged as if it were the goods. It is not however a negotiable instrument and therefore the buyer can obtain only as good title as the transferor. Thus the transfer of a bill of lading will transfer the property in the oil, for instance while the goods are in transit between Rotterdam and New York, as long as the intention of the parties is that property should pass.

The issues of the passage of title and risk with respect to bills of lading have given rise to a number of major oil cases. In particular, a number of problems have arisen because of the mechanics of oil trading:

- problems relating to the passage of property, particularly because the oil is often shipped on large bulk tankers where it is unascertained cargo. Should any problem with respect to loss, contamination or the like occur there are major problems in the passage of property in unascertained cargoes under numerous national laws. For a long time this was the case under s.16 of the UK Sale of Goods Act 1979 until it was amended by s.20A of the Sale of Goods (Amendment) Act 1995; and

- problems because the bill of lading arrives after the oil has been discharged. Some companies put all the bills on board the vessel for delivery on arrival. This practice was challenged, but upheld by a UK court. Another oil trade practice to get around such problems is for the seller to issue a letter of indemnity to the buyer. Although traders and banks have voiced concern on their use, they appear to serve a useful and indeed essential role in ensuring that oil trading can function smoothly.[7]

Hague–Visby rules

The Hague Rules of 1924 (The Convention for the Unification of Certain Rules of Law relating to Bills of Lading 1924) which set out a uniform international regime to govern the respective rights and obligations of cargo-owners and carriers were relatively widely subscribed to by the major shipping nations. The Rules defined the basic obligations of the carrier and prescribe the maximum protection that can be derived from inserting exception and limitation clauses in the contract of carriage, but they did not create a comprehensive and self-sufficient code and were seen as offering a very limited protection to cargo owners. As a result, the Rules were revised and re-drafted in 1968 with one important amendment (Article 8) being that ship owners or cargo owners cannot contract out of the Rules. These 1968 Rules, known as Hague–Visby Rules, have however, been acceded to by fewer states.

The rules of 1924 and 1968 have been incorporated into some major legal systems, for example: the Hague–Visby Rules were fully incorporated into English law by the Carriage of Goods by Sea Act 1971; the Hague Rules are part of US law in the Carriage of Goods by Sea Act 1936; and the Merchant Shipping Code of the USSR 1968 (as amended) – which still applies to the Russian Federation – adopted many of the provisions of the Rules without wholesale incorporation.

[7] A useful article on the problems and issues arising from their widespread use can be found in [1990] 10 OGLTR 353.

Hamburg Rules

The UN Convention on the Carriage of Goods by Sea 1978 (the Hamburg Rules) came into force in 1992. Although important maritime States such as the UK have not yet become a party to the Convention – nor apparently are likely to do so in the near future – there is at least one major oil producing and trading country (Nigeria) which has.

The Hamburg Rules[8] are founded on the principle (enunciated in Article 5) that the carrier is liable unless he can prove that he was neither at fault nor negligent. In doing so they removed the necessity to elaborate in detail the carrier's duties and immunities, as were done in Article III and IV of the Hague Rules. They also introduced some important alterations to the Hague–Visby Rules, including the following:

- the extension of scope beyond bills of lading to all contracts of carriage by sea except charterparties;
- the extension of the period of liability of the carrier to the whole period during which the goods are in his charge;
- the abolition of the exclusion of limitation of the carrier's liability in case of error of navigation;
- the increase of the maximum levels of liability of the carrier and the fixing of them by reference to the special drawing rights of the IMF; and
- the making of a new distinction between the contractual carrier and the actual carrier. The contractual carrier is liable for the entire carriage and for the acts and omissions of the actual carrier, although the actual carrier is still liable for his own part of the carriage. Thus both, in principle, are liable to the shipper jointly and severally.

Marine insurance

While oil is being transported from the seller to the buyer it will be at risk and this risk is normally covered by insurance. There is no specific international law governing marine insurance. It is just an insurance contract and can, in its modern form, cover not only the sea transit but any other carriage associated with sea

[8] An overview of the Hamburg Rules can be found in [1992] 3 OGLTR 67.

travel. It is therefore governed by domestic laws and, in the UK, by the Marine Insurance Act 1906. This contains as its First Schedule the Lloyd's Ship and Goods Policy, which in 1982 was replaced by the Lloyd's Marine Insurance Policy and five Institute Cargo clauses. The key clauses are A, B and C and for oil trading the most important is the Bulk Oil Clause.[9]

With respect to liability for pollution from ship it is common in oil sales contracts to require that all vessels provided or arranged for making/taking delivery of the oil should be owned or chartered by a member of the International Tanker Owners Pollution Federation Ltd (ITOPF), and that the vessel carries on board a certificate of insurance as described in the 1992 Civil Liability Convention for Oil Pollution Damage (*see Chapter 16*).

17.2.8 Dispute resolution

Arbitration rules

Parties to oil sales contracts frequently agree to submit their disputes to various forms of dispute resolution. Technical disputes are usually put to the decision of an independent expert, while contractual disputes are often settled using venues and methods of resolving disputes different from the courts of the country whose law is the governing law of the contract. The most common of these is international arbitration. Litigation is often more expensive, takes longer than arbitration and does not have the advantage of privacy.

The venues for international arbitration include Geneva, Stockholm, New York, London and Paris (*see Appendix 17.1*). These arbitrations are conducted according to rules of procedure chosen by the parties to the contract. For example, with Russian oil sales contracts the chosen venue is often Sweden with Stockholm rules (the Rules of the Institute of Arbitration of the Stockholm Chamber Of Commerce). There are also international arbitration rules such as those drafted by UNCITRAL which are not linked to any national or international arbitration venue and the Rules of Conciliation and Arbitration of the International Chamber of Commerce whose Court of Arbitration is in Paris.

Each set of rules and venue has its perceived advantages and disadvantages. For example, Sweden – which has easily under-

[9] A very useful study on the Lloyd's policy and the clauses can be found in [1985] JBL 228.

stood rules, a good track record, is relatively quick and not too expensive – is seen as a neutral venue by the states of the former Soviet Union. The ICC, whose present Rules came into force on 1 January 1998, is seen as excellent in quality, but expensive and time consuming. The UNCITRAL Arbitration Rules are seen as a very fair and good set of rules especially for disputes between parties from various legal systems, but again arbitration under these rules is seen as lengthy and potentially expensive.

Enforcement

It is obviously important to the successful party to arbitration or court proceedings to be able to realise the award the tribunal or court makes. In some cases where the assets of the other party are not in the jurisdiction of the awarding body it may be difficult to realise the award.

Arbitral awards
Most countries are parties to the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards. Thus, in applying this Convention, most states will recognise an international arbitral award (in most circumstances).

Court judgements
Unlike the 1958 Convention there is almost no universal recognition of other countries' national court decisions. However, some European states do recognise the judgements of the courts of other parties to the 1968 Brussels Convention on Jurisdiction and Enforcement in Civil and Commercial Matters and the parallel EFTA Convention. It is always worth checking whether the states involved fall within these conventions.

17.2.9 Impact of national laws

There are also some laws that may affect the behaviour of the companies of a particular State, even though oil trading is not being carried out in the State in question. These include such laws as the US's Foreign Corrupt Practices Act (FCPA) 1977 and the UK's Protection of Trading Interests Act (PTIA) 1980.

The FCPA makes it criminally unlawful for any US company to make use of any means of interstate commerce "corruptly in furtherance . . . of the giving anything of value to . . . any foreign official . . . or any foreign political party for purposes of . . . influencing . . . or inducing . . . [action] . . . to assist . . . in obtaining or retaining business".

The PTIA allows, among other things, the UK government to require UK businesses to conform to directions of the UK government prohibiting them from complying with measures of other States which regulate or control international trade and which damage or threaten to damage the trading interests of the UK.

17.2.10 US and UN trade sanctions

Since the mid-1980s measures have been taken by the international community and, more notably, the US to impose restrictions on a number of commercial activities being carried out with or by certain states. These states are seen by those taking such measures as recalcitrant and as usually having acted as sponsors of state terrorism. The actions taken include the introduction of US legislation and the passing of United Nations Security Council resolutions providing for sanctions which aim to prevent, or at least restrict, companies from any country from being involved in transacting trade with these states. With three of the countries being targeted by these sanctions holding major oil and gas reserves – Libya, Iran and Iraq – the issues arising are of considerable concern to the oil trade business.

On 3 August 2001 the US Congress renewed for a second 5 year term the Iran–Libya Sanctions Act 1996 (ILSA).[10] Amongst other things, this Act places US sanctions on foreign companies that invest more than US$20 million annually in Iran or Libya. Executive Orders, issued by President Clinton in 1995, already prohibit any US company from either investing in Iran or purchasing any Iranian oil. There are arguments for and against the cost and effectiveness of the Act but for non-US companies the peril of acting contrary to its provisions has been summed up thus: "All we are doing is telling foreign companies that are willing to deal with Iran that they may have to pay a price when it comes to their dealings with [the US]".[11]

Following the invasion of Kuwait in 1990 the United Nations Security Council passed Resolution 661 requiring all member states of the UN to prevent, amongst other things, the import of all commodities originating in Iraq and to prevent their

[10] The renewing legislation being the ILSA (Iran–Libya Sanctions) Extension Act of 2001.

[11] The Chairman of the Subcommittee, Hon. Benjamin A. Gilman, speaking before the House of Representatives, Subcommittee on the Middle East and South Asia, Committee on International Relations, One Hundred and Seventh Congress on 9 May 2001.

nationals from exporting all commodities to Iraq other than limited medical products and, in humanitarian cases, foodstuffs. In 1995 UN Security Council Resolution 986 was passed permitting limited amounts of Iraqi oil exports in exchange for humanitarian aid; the so-called Oil-for-Food programme. There have been temporal extensions to Resolutions 986 as well as an easing of its terms since 1995. However, oil traders need to be careful to ensure they comply with the Resolution. The US has shown it is determined to police its terms as was demonstrated in April 2000 when the US Navy intercepted a Russian tanker in the Gulf which was found to be carrying a gasoil cargo, 20% of which was of Iraqi origin.

The implications for oil companies of these types of sanctions can be profound. Cargoes can be confiscated and, under the US legislation, financial pressures can be brought to bear on those who fail to operate within their parameters. With the new Bush administration signalling its intent to take a tough stand with those countries it eyes with suspicion, oil traders would be well advised to exercise caution when engaging even in an indirect way with any state against which sanctions have been imposed.

17.2.11 Sovereign immunity

Normally a foreign sovereign – the State including the government – is immune from suit in the national courts of other States. However, this doctrine could cause some problems where immunity is claimed by state-owned banks or state-owned oil companies.

Thus a number of States, in particular the US and the UK, have introduced State Immunity Acts which – while restating the general principle – create exceptions in cases where, *inter alia*, commercial transactions are entered into by the State, obligations of the State which by virtue of a contract fall to be performed wholly or partly in the legislating State, and matters relating to ships and cargoes used for commercial purposes such as oil (see s.3 of the UK State Immunity Act 1978).

The general impact of these laws is that the State agency/company/bank, unless acting in a "public" capacity, is put in the same position as a private legal entity.

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17.3 United States

17.3.1 Oil trading in the United States

As with all jurisdictions, United States law affects all contracts for the sale or purchase of oil that are made in the US or that are governed by US law. The relevant legislation includes general commercial laws relating to contracts and corporate behaviour as well as more specific laws relating to exports and imports, international trading, and forward, futures, options and swap contracts.

In the US, futures and options contracts fall under the scope of the Commodity Exchange Act (CEA) and are regulated by the Commodity Futures Trading Commission (CFTC) (*see Section 17.3.3*), while forward delivery and swap contracts appear to be excluded (at least in certain specified circumstances). The US approach to the regulation of oil trading activities is therefore different from that in the UK (*see Section 17.4*).

17.3.2 General commercial law

Uniform Commercial Code

The Uniform Commercial Code (UCC) is in effect in each State in the US and forms the legal basis of any oil trading contract under US law. The UCC is a codification of the law not only on the sale of goods but also on commercial paper, documents of title, negotiable instruments, and in fact touches almost all commercial transactions.

However, since the US is a party to the UN Convention on the International Sale of Goods 1980 (CISG), the US oil trader should not assume that the UCC is automatically applicable to his contracts – even if it is expressly governed by a US state's law – in cases where the places of business of both parties to the contract are in countries that are parties to the CISG.

It is important for the US oil trader to note that there are some important differences between the way the UCC and the CISG handle legal issues connected with the sale of goods. Some of these differences are:

- *Formation of contract: consideration*
  Under common law offer, acceptance and consideration are required for contract formation and will also be required under the UCC unless the requirement is

modified. Under the CISG there is no consideration requirement: offer and acceptance alone are necessary and sufficient. (Note however, that under the UCC, in respect of consideration, there are statutory modifications to the common law position. In these cases, for example, under §2-205 (a time limit is applied) and §2-209 (modifying agreements), there is less divergence between the UCC and the CISG.)

- *Formation of contract: effective time*
  Under the UCC the contract is formed when the acceptance has been dispatched (the "mailbox rule"), while under the CISG (Articles 18/22 and 23) the contract is formed when and where the acceptance reaches the offeror.
- *Revocation*
  The rules on revocation of offer differ. The UCC is more stringent. This could catch out a US buyer.
- *Remedies*
  To a practitioner familiar to remedies under the UCC, the CISG's remedies will seem slightly foreign, but would be considered quite acceptable except for that relating to price reduction.

Anti-trust legislation

The basic anti-trust statute is the Sherman Act 1890 (as amended). It is both broad and comprehensive in its scope. It creates criminal offences which are punishable by fines and imprisonment and it can also be enforced by civil actions by the government or by private triple damages actions.

Section 1 declares illegal and a felony "every contract, combination in the form of trust or otherwise, or conspiracy in restraint of trade or commerce amongst several states or with foreign nations . . .". Section 2 states that every person who shall monopolise, or attempt to monopolise any part of trade or commerce among several states or with foreign nations, shall be deemed guilty of a misdemeanour.

The breadth of these prescriptions means the courts in the US have over the years determined, to a greater or lesser extent what constitutes restraint of trade or monopolisation. The Sherman Act has been supplemented by a number of subsequent laws. The Federal Trade Commission Act 1914 set up the watchdog agency, the Federal Trade Commission (FTC) to implement the Act, and section 5 of this Act contained the general prohibition of "unfair methods of competition in commerce".

The Clayton Act 1914 is another very important law which declares illegal certain specified business practices where their ". . . effect may be to substantially lessen competition or tend to create a monopoly". The main practices with which the Act is concerned are: price discrimination (and elaborated by the Robinson Patman Act 1936), exclusive dealing contracts, and the acquisition of competing companies.

Such practices do not constitute criminal offences but can be enforced by cease and desist orders by the FTC. Unlike EU law there is no possibility to apply to the Commission to be exempted (at least in certain circumstances) from the application of US anti-trust law, although the courts have rather finely developed what is called a "rule of reason" for some of the prohibitions, which in some ways moderates the application of the law to some situations. Enforcement of these laws can vary widely from administration to administration.

Like EU competition law, US anti-trust law has been held to have extra-territorial effect and therefore can impact significantly on foreign trading. The Transnor case,[12] for example, involved an oil trader taking a triple damages action in a New York District court against five oil majors with respect to their trading of 15-day Brent outside the USA. Thus, traders should always be cautious with respect to anti-trust issues. Companies should have compliance guidelines and traders should be careful what they talk about and arrange between themselves and should document such arrangements appropriately in accordance with the guidelines.

Sovereign Immunity Act

The doctrine of sovereign immunity has its origins in international law. Basically the doctrine provides that a party cannot sue a sovereign (or an entity with sovereign attributes) unless it consents. The doctrine may be relevant any time a government trades, even through trading organisations or enterprises.

When the circumstances for its application occur, a court relinquishes jurisdiction over the state. In the US the nature, form and procedures relating to the defence of sovereign immunity are stated in the Sovereign Immunity Act (SIA) 1976.

Over the years the concept of absolute immunity has been watered down, particularly as states have increasingly entered into ordinary trading transactions. It came to be considered

[12] see [1990] 6 OGLTR 151.

unacceptable that a state could repudiate a deal and avoid its contractual obligations merely on the basis of its governmental status. On occasions it was very difficult for the courts to make the distinction between trading and governmental activities. The SIA was an attempt to set objective legal – rather than political – guidelines and procedures.

Who is a foreign state under US law? According to 28 USC[13] §1603(a) a foreign state includes "a political division of the state or an agency or instrumentality of the state". In turn under §1603(b) an "agency or instrumentality of the state is an entity which is a separate legal person, corporate or otherwise and which is an organ of the state or political subdivision thereof, or whose majority of shares or other ownership interest is owned by a foreign state or political subdivision thereof . . .". Thus a corporation wholly owned by the state can be for the doctrine's purpose a foreign state. In oil trading where state oil companies trade in the international markets this doctrine has clear relevance.

A central feature of the SIA is its specification of categories of actions for which foreign states cannot claim sovereign immunity in US courts. In particular there is a commercial activity exception to the rule (see 28 USC §1603(d) and 28 USC §1605(a)(2)).

Importantly, a foreign state may waive its right of sovereign immunity on entering into commercial transactions and this waiver will, under 28 USC §1605(a)(1), be recognised and enforced by the US courts. Given the narrow interpretation by US courts to the commercial activity exception, a carefully drafted clear waiver clause in a contract can be of some importance in contracts with state companies (*see Chapter 16*).

Foreign Corrupt Practices Act

The US Foreign Corrupt Practices Act 1977 was intended to eradicate the making of improper payments to government officials abroad to obtain commercial advantage. It makes it criminally unlawful for any US enterprise "To make use of the mails or any means . . . of interstate commerce corruptly in furtherance of . . . the giving of anything of value to . . . any foreign official or any foreign political party for purposes of . . . influencing . . . or inducing . . . [action] . . . to assist . . . in obtaining or retaining business".[14]

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[13] United States Code (USC)
[14] 15 USC §78dd-2.

Texas law

It is important in dealing with US traders to ensure that Texas courts do not have jurisdiction or apply Texas law. This is because – despite the repeal of the boldface statute (under which Texas jurisdiction was excluded only if it was expressly excluded in bold face type in the contract) – Texas courts have tended in the past to accept jurisdiction very liberally and to apply Texas law. It is therefore of no surprise that the jurisdiction and applicable law is defined in no uncertain terms in Shell's carefully drafted 15-day Brent contract which states that:

> "This Agreement shall be governed by and construed in accordance with English Law and the parties hereby submit to the exclusive jurisdiction of the English Courts without recourse to arbitration. The UN Convention for the International Sale of Goods (1980) shall not apply."

Corners and squeezes

Oil market participants, as well as the US Senate, have expressed concern about market manipulation, in particular corners and squeezes. The CFTC's single most important goal has been to prevent manipulation of commodity prices. Squeezes and corners occur in markets where one or more participants deliberately acquire a strategic amount of the commodity thereby creating a shortage of supply and thus artificially driving the price up.

Several sections of the CEA are directed at prohibiting manipulation of this sort: 5(b), 6a and 9. What constitutes a squeeze or a corner has been defined judicially by the US courts and the CFTC. The key to a CEA violation is the manipulative intent to bring about an artificial price. The sanctions for such manipulative behaviour include a trading bar as well as hefty civil sanctions against the individual(s) and the firm(s) involved.

17.3.3 Commodity trading law

Commodity Exchange Act

In the US the trading of commodity (including oil) futures is primarily regulated by the CEA and the CFTC is the statutory agency which is designated by 2a of the CEA with the exclusive jurisdiction to regulate commodities futures and options trading. Section 6(a) of the CEA declares it unlawful for any person to offer or to enter into a contract for the purchase or sale of a commodity for future delivery unless the transaction is: (i) conducted on or subject to the rules of a board of trade (i.e. an exchange) which has been approved by the CFTC as a “contract market” or a “derivatives transaction execution facility” for that commodity; or (ii) conducted on an exchange or market outside the US; or (iii) otherwise exempted by the Commission. The New York Mercantile Exchange is the only US “contract market” which is authorised to trade crude oil and oil products contracts.

The CEA’s precise scope has always been a little uncertain. In particular it has failed to provide a useful definition of a contract for future delivery. This lack of definition created widespread uncertainty as to the status of a number of trading instruments, including forward and swaps contracts.

After long debates in 1992 the Futures Trading Practices Act was passed. However, it did not introduce a comprehensive definition of what constitutes a contract for future delivery. Instead under s.502(a)(2) a new section (now section 6(c)) was inserted into the CEA which empowers the CFTC to exempt contracts from the application of the CEA “if the Commission determines that the exemption would be consistent with the public interest”.

This exempting power is hedged with a number of restrictions. An exemption may only be granted where it is considered by the CFTC not only to be in the public interest but also consistent with the purposes of the CEA, and it can be granted only when the exempted transaction is between “appropriate persons” (which are given a fairly wide definition).

Commodity Futures Trading Commission

The CFTC exercises its jurisdiction to enforce the provisions of the CEA, to protect investors, and to ensure the stability of the market. Because all exchanges must be registered, they must comply with all the requirements of the CFTC both for registration and subsequently to continue operations. The CFTC thus has final authority over the exchange’s rule books, exchange behaviour, and trading on the market. This mainly entails setting guidelines, giving approvals, monitoring to ensure compliance with the approved rules and an orderly market and (if necessary) taking enforcement action. It is envisaged that such contract markets would be more or less self-regulating with the parameters set by the CFTC.

Futures markets personnel fall into a number of categories and – except for traders trading on their own accounts – each must be licensed by the CFTC. There are also other control mechanisms such as reporting, record keeping and maintaining financial requirements. Exchanges have detailed rule books which set out the standardised contracts to be traded, the way trading is conducted on the exchange, the clearing system and many other aspects including dispute resolution procedures.

17.3.4 Specific contracts

Futures and options contracts

The New York Mercantile Exchange (Nymex) trades four oil futures contracts (WTI,[15] heating oil, unleaded gasoline and, a recent addition, the Brent crude futures contract). It also trades the following options contracts: WTI, heating oil, unleaded gasoline, Brent crude oil and two crack spreads; one for the differential between heating oil futures and WTI, the other for the unleaded gasoline/WTI spread).

Crack spread options can protect against the changing relationship between crude oil and refined products markets and provide a flexible hedge against variable refining margins. They differ from conventional options in that a single options position results in two futures positions when the option is exercised. A spread option is also available on the difference between Brent crude and WTI futures positions as a single options contract.

Nymex functions with an open outcry system and incorporates the usual settlement and clearing systems of futures exchanges (*see Chapter 8*). The exchange appears determined to continue with open outcry trading but has, since 1993, been operating an electronic trading system outside of the open outcry trading hours. Together the two methods combine to provide a 22 hour trading period each day.

There are two levels of regulation of futures trading in the US: the CFTC and the self-regulation by the exchanges themselves of trading activity of its members. The Nymex rule book detailing the contracts is available to the public.

Exchange of futures for physical (EFP)

An EFP can be described as a two legged bilateral transaction involving, first, a sale and purchase of a cash commodity and,

[15] for brevity WTI is used throughout, however, it would be more correct to refer to this contract as the Exchange's "light, sweet crude oil futures contract". WTI stands for West Texas Intermediate, the US benchmark grade and the principal crude oil deliverable under the light, sweet crude oil futures contract.

secondly, the non-competitive entry of related long and short futures positions on a futures exchange, which are subsequently closed out at an agreed price.

Although s.6(c) of the CEA prohibits "wash sales", fictitious sales and other similar transactions which are used to cause a price to be reported which is not a true and *bona fide* price, it does provide for the issuing of regulations that permit the use of EFPs. Under Nymex rules the parties agree an EFP at an agreed price and the exchange settles out the futures leg of the transaction.[16] The mechanics of EFPs are discussed in Chapter 8.

Forward paper contracts

Because of the lack of clear definition of what constitutes a futures contract in the CEA, there has been much debate about the legal status of the forward paper oil markets. Since the US District Court's finding in the Transnor case in April 1990 that Brent 15-day contracts fell within the scope of the CEA and, having been entered into for tax spinning purposes, were also wash sales, the issue of their legal status under the CEA has been a thorny one.

On 19 September 1990 the CFTC issued a "formal statutory interpretation" that, in its opinion, for a number of reasons, the Brent contract did not fall within the catchment of the CEA. This interpretation is not without problems, not the least of which is the fact that the CFTC is only a federal enforcement agency, not a branch of the US judiciary, so its statutory interpretations, though persuasive, are not binding. Furthermore, attached to the CFTC interpretation was a very strongly worded dissenting opinion of one of the commissioners which suggests that the interpretation may in fact be contrary to the public interest. However, the matter seems to have settled there and forward paper contracts continue to be traded without regulation under the CEA.

Swaps

The CFTC has always taken the view that swaps are not futures or options transactions and that therefore they fall entirely outside the CEA. In a policy statement in 1989 the CFTC clearly identified swaps contracts which will not fall within the catch-

[16] Rules 6.21, 150.14 (No 2 Heating Oil), 190.14 (Gasoline) and 200.20 (WTI).

ment of the CEA. It defined a safe-harbour for transactions which meet the following requirements:

1. individually tailored and negotiated terms, non-standard documentation;
2. obligations terminable only with the counterparty's negotiated consent (except in default);
3. absence of a clearing organisation and of a margin system;
4. that the transaction be undertaken in conjunction with the parties' business;
5. that there be no marketing of such transactions to the public.

Clearly such a statement could have been legally challenged in the courts and so the CFTC transformed this into Regulation in 1993 (see Part 35 of the General Regulations under the Commodity Exchange Act) under its 1992 new exemptive power, whose requirements differ from the safe harbour ones. Generally they include:

1. that the swap is entered into between "eligible" persons, which it defines;
2. that it is not part of a fungible class of agreement with standardised material economic terms;
3. that the parties' creditworthiness is a material consideration in the determination of the agreement's terms; and
4. that it is not entered into or traded on or through "a multilateral transaction execution facility" (i.e. an exchange).

Importantly, the requirement that the terms be non-standard remains and this is an important issue. Many experts believe such a requirement is contrary to business efficacy and that standardised documentation promotes efficiency, liquidity and high standards of conduct. However, this may not be as relevant to oil swaps as it is to financial swaps since the industry has not yet evolved a standard oil swaps contract, although companies do use their own standard swaps contract.

Given that swaps are traded off-market without the guarantee of payment provided through an exchange, there is a concern that companies involved in derivatives trading could sustain considerable losses which may in turn undermine the whole financial system. Consequently there is pressure for CFTC regulation in this area to be instituted. The recent demise of Enron may give further encouragement to those suggesting such a call.

17.4 United Kingdom

17.4.1 Oil trading in the United Kingdom

The UK legislation differs from US legislation in a number of important respects, adopting a different approach to international as well as domestic issues. In particular, it takes a different view of what constitutes a "futures" contract and in its treatment of swaps, both of which fall within the scope of the Financial Services and Markets Act 2000 (FSMA).

The introduction of the FSMA has brought with it significant changes to the regulation of the financial and trading markets in the UK. The Act, like its predecessor, the Financial Services Act 1986 (FSAct), covers the range of oil trading instruments, and will be of considerable interest to oil traders.

Oil trading carried out in the UK is subject both to UK law and – because the UK is a member of the European Union (EU) – to EU law. However, in recent years compliance with the regulatory legislation of the two jurisdictions has, in many respects, become more simplified as legislators move closer to harmonising the laws of the two. The enactment of the Competition Act 1998 in the UK is a case in point (*see below*).

17.4.2 General commercial law

Sale of Goods Act

All oil sales contracts which are governed by English law will be governed by the Sale of Goods Act 1979 (as amended). The Act addresses all aspects of the sale of goods: the definition of a contract of sale, contract formation, passing of property and risk, frustration of contract, delivery, implied terms, rejection and its consequences, acceptance, breach and remedies.

Section 16 of the Sale of Goods Act potentially poses special problems for oil trading and cif contracts. If a cif contract is fundamentally concerned with the passage of documents – i.e. if it is only a sale of documents – then, under 1 of the Sale of Goods Act 1979, the Act would not apply. However, it is clear from the case law that this is not the position and that the best way of viewing a cif contract is as a contract for the sale of goods to be performed by the delivery of documents.

A further problem with cif contracts under 16 of the Sale of Goods Act 1979 has now been corrected by the Sale of Goods (Amendment) Act 1995. Section 16 previously prevented property in unascertained goods from passing to the buyer – as might be the case in a cif contract where an oil cargo is loaded with other cargoes into a bulk tanker without segregated holds. This clearly defeated commercial expectations and places the buyer at risk. The buyer who has paid for the goods and has received documents specifying them in terms of weight or quantity finds that he does not have property rights in them and that the creditors of the seller may be preferred to him.

The problem was examined by the English Law Commission and their recommendations were brought into law by the Sale of Goods (Amendment) Act 1995, which now applies to transactions made on or after 19 September 1995. The new statutory rule (20A) allows for the passing of ownership in a specified quantity of unascertained goods forming part of an unidentified bulk. It should be noted that the provisions only apply to a specified quantity of goods and not to a fraction of a bulk and that the buyer needs to have paid the price for some or all of the goods which are the subject of the contracts and which form part of the bulk. Bulk is now defined by the Act as a "mass or collection of goods of the same kind which is contained in a defined space or area, and is such that any goods in the bulk are interchangeable with any other goods therein of the same number or quantity." This definition therefore covers oil in an identified storage tank or as cargo on a named ship.

Competition law

In addition to EU law, the competition law of the United Kingdom will also apply to oil trading activities. However, since the coming into force of the Competition Act 1998 on March 1, 2000, the UK law in this area now closely mirrors that of the EU with a stated principle of the Competition Act being to treat UK issues of competition law in the same manner as issues of competition law would be treated under EU law: see Section 60(1).

The object and thrust of the Competition Act are found in its two principle provisions, Chapters 1 and 2 of Part 1. Chapter 1 prohibits agreements which have as their aim or effect the prevention, restriction or distortion of competition within the UK. This follows similar wording of Article 81 of the EC Treaty which addresses the same issue at the EU level. Chapter 2, which reflects Art. 82 of the EC Treaty, aims to prohibit an undertaking attaining a dominant position in the UK market place.

The common law doctrine of restraint of trade also warrants mention. This doctrine means that the courts will not enforce a contract which is an unreasonable restraint of trade as to do so would be against public policy. With the combined EU and UK competition law the role of this doctrine may now be viewed as a residual possibility only, however, in the light of the *Esso Petroleum Co. Ltd* v. *Harper's Garage (Stourport) Ltd* case, it should not be forgotten.

Generally speaking, traders should avoid agreeing on practices which restrict market entrance, fixing prices, entering into exclusive sale contracts and other such behaviour, without careful consideration of the competition law issues. Under the UK legislation failure to heed the law can, under Chapter 3 of Part 1 of the Competition Act, find defaulting parties levied with fines of up to 10 per cent of turnover. This again follows the EU position.

Competition law and futures trading

Under the FSMA (as was the case with the FSAct) the rules, regulations, guidance, clearing arrangements and practices of recognised exchanges, like the International Petroleum Exchange (IPE), and recognised clearing houses, like the London Clearing House (LCH), are the subject of a special competition law regime. Such "recognised bodies" (as defined in 313 of the FSMA) will have their practices and regulatory provision (as defined in 302) exempt from the application of chapters 1 and 2 of the Competition Act (311 and s.312). However, they will be subject to the competition scrutiny provisions of Chapter 2 of Part XVIII of the FSMA.

Under this regime a prerequisite for recognition of exchanges and clearing houses is that their rules are provided to the Director General of the Office of Fair Trading for assessment as to whether they, or the practices of the exchange or clearance house, have "significant adverse effect on competition (303)". In addition the Director is to keep under review the regulatory provision and practices of any such exchange or clearance house once they are recognised (304). Reports are to be made by the Director and provided to the Financial Services Authority (FSA), the Treasury and the Competition Commission all of whom are to consider them and provide direction in respect of the same in accordance with the further provisions of Chapter 2 of Part XVIII. Under Chapter 2 of Part XVIII an application for recognition can be denied or recognition withdrawn in the circumstances described in the FSMA.

Carriage of goods by sea

The Carriage of Goods by Sea Act 1971 gave effect to the Hague–Visby Rules which identifies the substantive rights and liabilities of the parties to a bill of lading contract. Until 1992 this was supplemented by the Bills of Lading Act 1855.

However, the Bills of Lading Act 1855 proved to be inadequate in addressing all situations concerning the passage of rights under a bill of lading. In particular, under the Bills of Lading Act the transfer of property rights could only occur if property passed "... upon or by reason of the consignment or endorsement". A serious problem therefore arose under cif contracts in cases where the bill of lading had ceased to be a document of title before it was transferred to the endorsee and there were subsequent problems for the buyer. Just such a situation arose in the case of the *Delphini*, which was instrumental in highlighting the inadequacy of 1 of the Act and led to its amendment by the Carriage of Goods by Sea Act 1992.

The 1992 Carriage of Goods by Sea Act 2 now provides that a person who becomes the lawful holder of a bill of lading shall, by virtue of becoming the holder of the bill of lading, have transferred to and vested in him all rights of suit under the contract of carriage as if he had been a party to that contract. Thus it sorted out the ticklish problem which used to arise under cif contracts of how a consignee or endorsee acquires contractual rights of suit against the carrier for loss of or damage to the goods when it was the shipper and not the consignee or endorsee who concluded the contract of carriage originally.[17]

Finance and banking law

Bills of exchange are governed by the Bills of Exchange Act 1882 under English law. Although the UCP has not been incorporated into English law, the treatment of documentary letters of credit is – for the large part – identical under English common law based on court decisions. In fact, it is rarely necessary to ascertain the law governing a letter of credit because banks in most countries including those in England operate credits under the UCP, and the credit will specify the UCP in the choice of law clause.

Previously, under 3 of the Banking Act 1987, it was an offence to take a deposit in the course of carrying on what is called a deposit-taking business unless authorised by the FSA to do so. Clearly futures exchanges and clearing houses could have been constrained in receiving and holding money on behalf of members

[17] For two excellent analyses on this topic with respect to oil trading see [1988/1989] 7 OGLTR 171 and [1991] 1 OGLTR 25.

trading through them – for example, margin calls and marking to market – however, the taking of such sums was exempted as a deposit-taking under regulation 14 of the Banking Act 1987 (Exempt Transactions) Regulations 1988. With the coming into force of the FSMA the Banking Act and the 1988 Regulations have been repealed but the 3 offence is now subsumed in the FSMA's 19 general prohibition so the potential to offend against the provision remains. Now though, under Article 8 of the FSMA 2000 (Regulated Activities) Order 2001, by receiving sums in this manner RIEs and RCHs will not be offending against the general prohibition on this count as any such sum will be exempted from being classified as a "deposit" for the purposes of Article 5 of the Order (which specifies the taking of deposits as a regulated activity) and, therefore, accepting such sums will not amount to 22 regulated activity.

Protection of Trading Interests Act 1980
The Protection of Trading Interests Act 1980 provides, among other things, that a judgement of an overseas court for multiple damages – such as the US courts may make in triple damages anti-trust proceedings – is not enforceable in the UK. Moreover, a UK defendant who has paid such damages is entitled to recover, in the UK courts, the excess over the part attributable to compensation.

Arbitration and enforcement

The Brussels Convention (*see Section 17.2.8*) was incorporated into English law by the Civil Jurisdiction and Judgement Act 1982.

A foreign arbitration award may be registrable and enforceable in the UK under the Foreign Judgements (Reciprocal Enforcement) Act 1933 or under the Arbitration Acts 1950 and 1975, which give effect to the 1958 New York Convention (*see also Section 17.2.8*). The enforceability of an English arbitration award abroad will depend on the law of the country concerned and in particular whether that country is a party to the New York Convention.

State immunity

Under English law, the State Immunity Act 1978 restated the general principle that a foreign sovereign, including a government, has always been immune from suit in the English courts. However, it also created exceptions in cases of: commercial transactions entered into by the State, obligations of the State which, by virtue of a contract, fall to be performed wholly or partly in the UK, arbitration proceedings if the State has agreed in writing to arbitration according to the law of the UK, and matters relating to ships and cargoes used for commercial purposes (3). In the case of oil trading, the general effect of the Act is therefore to put state oil companies and countries tendering for oil supply in the same position as a private enterprise.

17.4.3 Financial services law

Financial Services and Markets Act 2000

Certain types of oil trading contracts fall within the category of "investments" as specified in the Financial Services and Markets Act 2000 (Regulated Activities) Order 2001 (FSMA (RA) Order). These include futures, options and contracts for differences. Under the FSMA an activity "which is carried on by way of business and . . . relates to an investment" (as so specified) is a "regulated activity" under section 22. As such under the general prohibition section of the FSMA, section 19, oil traders are required to be either an "authorised person" or an "exempt person" to carry on such a regulated activity.

Contravention of the general prohibition is an offence (23) and contracts made in breach of it are unenforceable against the non-offending party (26).

The Financial Services Authority (FSA) is empowered by the FSMA to regulate the conduct of those involved in financial services and markets and to grant direct authorisations, grant exempt person status, recognise investment exchanges and clearing houses, and make and enforce principles, rules and regulations with respect to regulated activities in the UK.

Futures exchanges and clearing houses

Futures exchanges and clearing houses can provide the venue and mechanisms for trading. Under Part XVIII of the FSMA they can apply for an order declaring them to be a recognised investment exchange (RIE) or recognised clearance house (RCH) which, when obtained, will exempt them from the general prohibition in respect of regulated activities (285). Each exchange or clearing house, such as the International Petroleum Exchange (IPE), has a set of exchange rules that must be complied with by the brokers and dealers trading at the exchange. To obtain recognition as a RIE or a RCH (as the case may be) these rules, amongst other things, must be provided to the FSA. If an applicant satisfies the recognition requirements (as provided by the Treasury) then the FSA may make a recognition order. RIEs and RCHs are required to comply with notification requirements of Part XVIII of the FSMA which include provisions dealing with changes in their rules. Section 297 confers on the FSA the power to revoke recognition and, hence, therein lies the regulator's control over RIEs and RCHs.

Recognition requirements

The recognition requirements were published by the Treasury on 15 March, 2001.[18] The criteria that must be met in order to be and remain recognised ensure exchanges meet principles and standards of conduct which assure integrity, fair dealing, skill, care and diligence, and subordination of the interests of the exchange to that of its clients. Areas dealt with in the regulations include:

- sufficiency of financial resources;
- fit and proper person standards;
- adequate and appropriate scale systems and controls;
- safeguards for investors; and
- effective disciplinary and complaint procedures and others.

The exchange must also "ensure that appropriate procedures are adopted for it to make rules, for keeping its rules under review and for amending them". Part II of the regulations requires the exchange to have in place "default rules" which enable appropriate action to be taken in the event that a member of the exchange is or appears to be unable to meet his obligations in respect of one or more market contracts.

International Petroleum Exchange

The IPE is a Recognised Investment Exchange. It was established in 1980 as a company limited by guarantee and owned by the members of the exchange.

In April 2000 the company was demutualised and ownership passed to a holding company, IPE Holdings plc, the share capital

[18] The Financial Services and Markets Act 2000 (Recognition Requirements for Investment Exchanges and Clearing Houses) Regulations 2001 (S.I. 2001 No. 995).

of which has now been acquired by Intercontinental Exchange Inc. Its affairs are managed by a board of directors, most of whom are elected from floor members. It operates from three trading rings around which representatives of the floor members trade by open outcry – that is, a bid or offer for lots must be made to the whole floor and may be accepted by a member but only openly on the floor. As a result, there is no undisclosed or selective trading on the futures exchange. This system though is set to change with the phased introduction of an electronic trading platform. As of February 2002 the IPE's public website advised that gas and power futures would be trading electronically by the summer of 2002 but a precise date had not been set for the move in trading its Brent and Gas oil contracts.

The trading floor, the procedures for trading, the traded contracts' terms, admission for membership and all aspects of the exchange are governed by its rule book.

The Floor Members also either are members of the London Clearing House (LCH) or have a clearing arrangement with a Clearing Member of the IPE as required by the rule book. Each Floor Member will own at least one seat on the IPE, each of which will entitle the Floor Member to have four traders transacting business on the market floor. The IPE rules require that every contract made on the IPE is registered with the LCH, through the established procedure. The LCH is a recognised clearing house under the FSMA. The importance of the registration of contracts and the clearing is that the performance of the contracts is then guaranteed.

This procedure "novates" the contract between buyer and seller by inserting the clearing house in two contracts, one with the seller as a buyer, and one with the buyer as the seller. The clearing house also operates the financial system of futures and options trading calling for initial margins (deposits) and "marking the contracts to market" (calling for margins to be paid or money to be paid into members' accounts depending on the movements of price). Thus the clearing house guarantees payment and delivery with respect to the futures contract made on the IPE.

Under the IPE rule book (section on arbitration rules) should a dispute arise it is referred to the directors for arbitration. The arbitration board consists of representatives of members and it should be noted that should they decide to call an oral hearing that generally neither party to the dispute may be legally represented. Only after the arbitration award may a dispute arising from exchange trading be actionable in court, except in certain limited circumstances.

Although the exemptions to UK competition and banking law automatically apply, the IPE has also obtained exemption (what is termed "negative clearance") from the application of EU competition law.

Sanctions

Disciplinary measures can be imposed on RIEs, RCHs and oil traders under the FSMA and also on members of RIEs by the RIE itself.

The principal sanction open to the FSA against RIEs like the IPE is the capacity to revoke recognition of the exchange under 297(2) of the FSMA. Such revocation will remove the exempt status of the exchange with the likely result that its trading activities will be in contravention of the general prohibition. The FSA can also direct the exchange to take certain steps (enforceable by injunction) to ensure compliance with the FSMA Part XVIII recognition requirements (296).

A prison sentence and a fine can be imposed upon conviction of contravention of the FSMA's general prohibition or for falsely holding oneself out to be an authorised or, in relation to a regulated activity, an exempt person (23 and 24).

Financial penalties can also be imposed on persons authorised to carry our regulated activities under Part IV of the FSMA of amounts that the FSA considers appropriate where such a person has contravened a requirement of the Act. Further the power to cancel an authorisation is also available to the regulator where a failure to maintain fit and proper person standards is established.

17.4.4 Specific contracts

Futures contracts

The IPE currently trades only two oil futures contracts: the gasoil and the Brent crude contract. A futures contract based on Natural Gas rights at the National Balancing Point has also been trading since 1999 (*see Chapter 8*). The gasoil contract is a contract for physical delivery, but the Brent crude futures contract is a contract for differences because it is settled against a price index (*see Chapter 8*). Unlike the other IPE contracts, the Brent crude contract is not a sale of goods and is therefore not subject to the Sale of Goods Act 1979.

Exchange traded futures contracts have standard terms and conditions – as listed in the exchange rule book – and are usually for standard small amounts of oil (lots), which contributes to their efficiency as hedging and/or speculative instruments. Every contract made on the IPE is expressed (upon the trader's signature of his daily dealing statement) to incorporate the IPE's rules and regulations.

15-day Brent

Because the 15-day Brent contract is considered to fall within the definition of a futures contract under the FSMA and the bookout contract could also fall within the definition of a contract for differences, persons who trade the Brent contract need to ensure that they are either authorised or exempted persons under the FSMA.

For oil traders a "light touch" regulatory regime was established under the FSAct. The principles established under the FSAct have been carried over into the FMSA and the light touch regime continues to apply to Oil Market Participants (OMPs).

This light touch regime results in a considerable amount of the FSA's Handbook of Rules and Guidance being disapplied to OMPs. However, in general terms, they are still required to have sufficient financial resources, exercise integrity and fair dealing, refrain from improperly manipulating the market or abusing market procedure, refrain from improperly or dishonestly misleading counterparties, fulfil legitimate expectations arising out of practice and avoid undisclosed conflicts of interest. A trader who violates these basics of market conduct may expect to have his authorisation reviewed and potentially removed.

Swaps

Oil swaps fall under the definition of an investment of the kind specified in Part III of the FSMA (RA) Order. As such trading in them is likely to be an activity that is a regulated activity for the purposes of the FSMA and in most cases authorisation will need to be obtained to trade in oil swaps. In certain circumstances the need for authorisation will not be necessary as the Order provides for certain exclusions, for example, where the swaps are entered into solely for the purposes of risk management (see Art 19). Again, however, swap traders, such as oil companies, who confine their business activities to the oil sector can avail themselves to the light touch regime applicable to OMPs.

17.5 Singapore

17.5.1 Oil trading in Singapore

In January 1989, in an effort to promote oil trading in Singapore, the Singapore Government introduced the "Approved Oil Traders (AOT) Tax Incentive" Scheme under which companies with such status are granted a concessionary tax rate of 10 per cent. The 1992 Income Tax (Concessionary Rate of Tax for Approved Oil Trading Companies) Regulations are applicable to the scheme, which is now known as the Global Trader Programme (GTP) and is described in more detail in Chapter 15. Also in 1989, the Singapore International Monetary Exchange (Simex) launched its first energy futures contract for high sulphur fuel oil (*see Chapter 8*). However, despite a re-launch in 1997 using different specifications, this contract, like others such as contracts for Dubai crude oil and gas oil, has not been a success. In 1995 the exchange started trading a Brent futures contract that is interchangeable with the IPE Brent futures contract. This arrangement allows the IPE Brent contract to trade over an 18 hour period.

The Singapore Exchange (SGX) (*see below*) now provides a facility to trade and clear Brent Crude futures under a Mutual Offset Agreement with the IPE. This allows positions opened through either the IPE or the SGX to be cleared and offset in either London or Singapore.

Futures contracts are governed by the Commodity Futures Act (Cap 48A) and the regulations thereunder as well as the Securities and Futures Act (SFA).[19] The Commodity Futures Act (Cap 48A) covers all commodities and all forms of commodities trading activities including commodity futures contracts: commodity forward contracts, etc. It also imposes mandatory licensing for firms and individual traders engaged in trading all forms of commodities and commodity trading activities.

17.5.2 The Singapore Exchange

The SGX is the first demutualised integrated securities and derivatives exchange in the Asia Pacific region. It was established

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[19] The Securities and Futures Act (SFA) was passed in October 2001. As of February 2002 the Minister has yet to appoint an effective date for the Act to come into operation. The Act aims to provide a comprehensive rule book on capital markets, create a flexible regulatory framework, facilitate the development of a disclosure-based regime and boost market enforcement.

in December 1999 by the merger of Simex with the Stock Exchange of Singapore and became a public-listed company in November 2000. Singapore Exchange Derivatives Trading Limited (SGX-DT) is a subsidiary of the Singapore Exchange (SGX) which has its roots in Simex. SGX-DT boasts the widest range of Asian derivatives in the world and the widest range of international derivatives in the Asia–Pacific region.

SGX-DT comes under the regulatory control of the Monetary Authority of Singapore (MAS)[20] through the Futures Trading Act. The Act requires, inter alia, the licensing of futures brokers and registered representatives to be subject to the approval of the MAS. It also sets minimum capital requirements for futures brokers.

As in London and New York, trading is conducted by open outcry in designated pits on the exchange floor and, additionally, a screen based electronic trading system (SGX-ETS) is used. The two trading methods complement each other to provide extended trading opportunities spanning different time zones. Clearing services are carried out by another subsidiary of SGX, the Singapore Exchange Derivatives Clearing System. It secures performance by the collection of margins and revaluing positions daily on a mark-to-market basis.

SGX-DT has a rule book which contains all the rules and regulations of the exchange, including the terms and conditions of all the oil futures contracts. Like the New York and London oil futures exchanges it also has rules governing the exchange of futures for physicals (EFPs).

[20] The MAS is the central bank of Singapore.

Appendix 17.1

Comparison of the procedures and rules of arbitral institutions

United Nations Commission on International Trade Law (UNCITRAL)

Rules	UNCITRAL Arbitration rules subject to modifications agreed by the parties.
Appointment of arbitrators	One or three arbitrators; parties agree on sole arbitrator, refer to appointing authority or in default to Secretary General of the Court of Arbitration at the Hague. If no agreement to appoint sole arbitrator, three arbitrators appointed, one by each party, and the president by the two appointed arbitrators. Challenges can be made if doubts as to impartiality or independence.
Venue for arbitration	Unless agreed by parties, determined by arbitral tribunal.
Language	Unless agreed by parties, determined by arbitral tribunal.
Documents to be submitted and preliminaries	Contract, written statements of claim and defence, submitted to tribunal. Further statements can be requested within 45 days.
Hearing and procedural matters	Oral hearing but affidavit evidence may be submitted. Arbitrators can appoint experts.
Award and its finality	Award to state reasons. It is binding but clerical errors can be corrected within 30 days. Public document only if both parties consent.
Jurisdiction	The tribunal has the power to rule on objections that it has no jurisdiction and the existence and validity of the arbitration clause.
Costs	Arbitrators' fees fixed by tribunal; must be reasonable taking the amount in dispute, complexity of subject matter, time spent and other factors.
Payment of costs in advance	Each party may be required to deposit an equal amount as an advance for costs.

The Stockholm Chamber of Commerce

Rules	Rules of the arbitration Institute of the Stockholm Chamber of Commerce or as agreed by the parties, as to procedure.
Appointment of arbitrators	One or three arbitrators; the Institute to appoint a sole arbitrator. If no agreement to appoint sole arbitrator, three arbitrators appointed, one by each party and the chairman by the Institute. Challenges may be made within 30 days to be settled by the Institute.
Venue for arbitration	Unless agreed by parties, determined by the Institute.
Language	Unless parties agree, determined by the tribunal.
Documents to be submitted and preliminaries	Written statements of claim and defence submitted. Further statements can be requested.
Hearing and procedural matters	Procedure determined by tribunal in accordance with parties' wishes. Oral hearing but affidavit evidence may be submitted on determination by the tribunal. Arbitrators can appoint experts unless parties provide otherwise.
Award and its finality	Made not later than one year after referral of case by a majority of arbitrators or by sole arbitrator. Reasons given: clerical errors can be corrected.
Jurisdiction	Rules silent.
Costs	Decide by the arbitral tribunal. Fees of arbitrators to be reasonable taking into account the amount in dispute, complexity of subject matter and time spent.
Payment of costs in advance	Security for anticipated costs.

Court of Arbitration of the International Chamber of Commerce (ICC)

Rules	ICC Rules of Arbitration.
Appointment of arbitrators	One or three arbitrators. Sole arbitrator by agreement of the parties and confirmation by the Court but in default, sole arbitrator appointed by Court. If agreement to appoint three arbitrators, one by each party and the chairman by the Court or the two other arbitrators. Challenges as to independence must be made within 30 days.
Venue for arbitration	Fixed by the Court unless agreed by the parties. Can be world-wide.
Language	Unless parties agree, to be determined by the arbitrator(s).
Documents to be submitted and preliminaries	Terms of reference are drawn up by the Court within two months of receiving the file then signed by the parties. Written statements of claim and defence submitted to Court.
Hearing and procedural matters	Procedure determined by Rules and as the parties may agree. Oral hearing but, if parties agree, by documentary evidence alone. Arbitrators can appoint experts unless parties provide otherwise.
Award and its finality	Court examines the draft award and can propose amendments. Made not later than six months from signature of Terms of Reference. The award is final.
Jurisdiction	Questions as to jurisdiction (or as to the existence or validity of the agreement to arbitrate) can be determined by the arbitrator.
Costs	Administrative and arbitrators' costs decided by the arbitral tribunal based on the amount in dispute with cumulative percentage charges in accordance with a scale fixed by the Rules.
Payment of costs in advance	Advance of anticipated costs required – fixed by Court. All costs payable before award is given.

International Centre for Settlement of Investment Disputes (ICSID)

Rules	Article 6(1)(a) of the Convention of the Settlement of Investment Disputes between States and Nationals of other States, 1966: The Rules of Procedure for Arbitration Proceedings adopted pursuant to Article 6(1)(b) and (c) of the Convention amended by the agreement of the parties. Can only be used where a State is a party.
Appointment of arbitrators	The number of arbitrators must be uneven and must be nationals of States other than the contracting State party to the dispute. Appointment by agreement between the parties or, in default, by the Chairman of the Administrative Council, who also nominates the President of the tribunal.
Venue for arbitration	At the seat of the Centre (Washington) or by agreement of the parties, elsewhere.
Language	English and French. (Spanish as soon as a Spanish speaking State becomes party to the Convention.)
Documents to be submitted and preliminaries	Request for arbitration and pleadings in the form of memorial and counter memorial.
Hearing and procedural matters	Procedure determined by Rules and as parties may agree. Oral hearings but, if the parties agree, by documentary evidence alone. Experts can be appointed.
Award and its finality	Award to be made promptly and contain reasons. It can be rectified, interpreted, revised and annulled by application to the Secretary General, ICSID.
Jurisdiction	The Tribunal may consider whether the dispute is within the jurisdiction of the Centre and its own competence.
Costs	Daily fee plus additional fee for any other services provided.
Payment of costs in advance	Advance payment of estimated costs required.

American Arbitration Association (AAA)

Rules	Commercial Arbitration Rules as amended by the parties.
Appointment of arbitrators	One or more arbitrators. Parties may agree on arbitrators or the AAA submits to each party an identical list of names allowing seven days to object. In default of appointment by parties, the panel will nominate someone from the list not removed by either party. Challenges as to impartiality, bias, financial or personal interest.
Venue for arbitration	Mutually agreed location or, in default, AAA will determine the location within seven days.
Language	Rules silent.
Documents to be submitted and preliminaries	Evidence by affidavit and filing of documents. Arbitrator may ask for statements of clarification.
Hearing and procedural matters	Oral hearing but parties may provide by written agreement for waiver of oral hearings. Conservation of property order possible.
Award and its finality	Award given promptly and no later than 30 days from close of hearing, or, if no oral hearing, from date of producing final statements and proofs. By sole arbitrator or majority.
Jurisdiction	Rules silent.
Costs	AAA is a non-profit making organisation and costs are according to a fixed fee schedule. Arbitrators serve without a fee, but in prolonged or special cases the parties may agree to a fee.
Payment of costs in advance	The AAA may require payment in advance.

London Court of International Arbitration (LCIA)

Rules	LCIA Rules as amended by the parties prior to the arbitration.
Appointment of arbitrators	A sole arbitrator will be appointed unless the parties have agreed otherwise or the Court determines that a three member Tribunal is more appropriate. The President or the Vice-President appoints all arbitrators. Challenges as to impartiality or independence within 15 days or on becoming aware of the relevant circumstances.
Venue for arbitration	Parties may choose the place of arbitration: world-wide. In default, London unless the Tribunal determines otherwise.
Language	That of the documents containing the arbitration agreement unless parties have agreed otherwise.
Documents to be submitted and preliminaries	Written statements of case and defence submitted to Tribunal with relevant documents.
Hearing and procedural matters	Tribunal encourages parties to agree arbitral procedure. Procedural rules at discretion of the Tribunal in absence of relevant Rules. Oral hearing unless parties agree on documents only arbitration. The Tribunal may in advance of the hearing submit list of questions meriting special attention. Experts can be appointed.
Award and its finality	Unless the parties agree otherwise, award to state reasons. The award is final and binding on the parties. Any clerical or other errors can be corrected on application to the Tribunal within 30 days.
Jurisdiction	The Tribunal has the power to rule on its own jurisdiction including any objections with respect to existence or validity of arbitration agreement.
Costs	Specified by the Tribunal in the award. Usually calculated on an hourly rate.
Payment of costs in advance	Deposits and security may be required.

18 Controlling financial risk

Françoise Deshusses

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18.1 Why risk control is important

18.1.1 What is trading risk?

When a trading company takes a position on the market it hopes to make a profit. But trading profits can never be certain and the company is also exposing itself to the risk of losing money. The value of a deal depends on market conditions, which determine its replacement value at any moment. Over time, the replacement value of a deal changes depending on specific market parameters such as price of the underlying commodity, the volatility of prices and the interest rate. Comparing the value at which a deal was initially transacted with its present replacement value therefore measures the profit or loss (P&L) made so far.

This chapter will examine the risk of financial loss associated with holding a wide range of trading positions and discuss methods of analysing the risk of trading derivative instruments whose underlying commodities are energy products. In order to assess the risks involved, it is important both to understand and quantify the conditions which might lead to a loss, and to be able to estimate the magnitude and probability of such a loss. Energy derivatives may have elaborate structures and determining the potential losses and risks from trading such instruments can be a complicated task. As recent experience has shown, inadequate control of trading risk can lead to losses on such a scale that even the most reputable companies may be jeopardised.

An effective risk control unit plays an important role in informing management and traders of the risk of potential losses that might occur as a result of current trading positions. Although it is impossible to predict future losses or gains, it is feasible to quantify the probability of extreme losses. Risk reports evaluating a company's potential exposure to financial loss from its trading activities are therefore an important tool for traders and senior management. The frequency at which such risk reports should be produced depends on factors such as the volatility of market prices, the level of trading activity, the identity of trading counterparties and the total size of the trading book.

18.1.2 Other potential sources of loss

Decreases in the value of a trading book due to market movements are not the only potential source of loss. A company can also be put at risk if its cash flow is compromised by offsetting payments and receipts that are due at different times. Although a set of trades for different maturities may have a positive value as a whole, the company may have to absorb losses from deals of a shorter maturity while waiting for the positive cash flows from deals with a longer maturity.

Cash flow problems can also occur with a pair of offsetting trades if these do not follow the same payment procedures, for example, a swap that is hedged on the futures market. Other risks include a defaulting counterparty, which could jeopardise the company's financial health if its total exposure to one trading partner is too large. And unchecked operational errors, such as failing to send invoices to counterparties, could also diminish a company's profit.

18.1.3 What are the functions of a risk controller?

One important task for the risk control unit is to monitor the replacement value of a trading book at regular intervals in order to allow traders and management to follow results. This valuation includes both the accounting for paid or received cash plus the valuation of open deals, although the latter might require complex valuation methods. Whether or not the controlling team actually calculates the P&L results, its function is to confirm the accuracy of the published figures. This includes controlling the valuation method used for each type of deal, checking market prices, volatilities and interest rates used, as well as auditing the accuracy of book entries made in the company's ledger.

In addition, the risk profile of the trading book should be analysed in order to provide traders with an independent risk break down. It is usual to analyse the effects on the P&L due to the variation in parameters such as market prices, volatilities, interest rates and the correlation between different market prices. Senior management needs a comprehensive risk report that they can use to guide their decisions.

This analysis should be followed up with discussions between managers, traders and risk controllers in order to ensure that the potential risks and rewards are understood and acknowledged by all.

18.2 Characteristics of the energy market

In the energy market a variety of derivative instruments are traded based on a wide range of underlying commodities. These trading instruments can be classified into two groups:

- those traded on a futures* exchange, and
- those traded over the counter (OTC).

The characteristics of exchange-traded futures and options are specified in detail by the exchange, including the quality of the underlying commodity, its maturity and delivery dates and procedures. Every futures or options contract can be traded for several months forward according to its specific calendar (*see Table 18.1*).

There are no formal rules regulating OTC trades, however legal contracts specifying the details of OTC deals – for example, a master agreement and subsequent confirmation for each deal covered by the master agreement – are generally exchanged by the two counterparties. The most commonly traded OTC energy derivatives are monthly, quarterly and yearly swaps, and monthly, quarterly and yearly Asian options. These derivatives are based on underlying commodities such as crude oil, refined products or natural gas whose reference price is given by an exchange or by a nominated trade publication. Financial instruments traded on the OTC market can also have more than one underlying energy commodity, for example the Brent-gasoil crack spread option which is described later in this chapter.

18.2.1 Sources of price information

Market prices are used to value deals traded on the energy market. Exchange contracts can easily be valued using prices from the relevant futures exchange, but OTC contracts are more difficult to value since only spot prices are quoted in most cases.

Futures exchanges publish settlement prices for all contracts and maturities currently traded at the end of every business day. Spot price assessments for a wide range of crudes,

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*To avoid confusion, the term “futures” will be used to refer to a contract to buy or sell a specified commodity for given maturity, while the term “forward” will be used to refer to a moment in time.

feedstocks, refined products and natural gas are published – either daily or at less frequent intervals – by a number of market reporting agencies such as *Platts* and *Petroleum Argus*.

Exchange futures and options prices

There are two futures exchanges around the world which trade energy products: the International Petroleum Exchange (IPE) in London and the New York Mercantile Exchange (Nymex). These exchanges offer futures and options contracts on a range of crude oils, refined products and natural gas (see Table 18.1). The

Table 18.1 Oil futures markets and contracts

Futures contract	Futures maturities	Options maturities
International Petroleum Exchange (IPE)		
Brent crude oil	12 consecutive months then quarterly out up to 24 months then half-yearly up to 36 months	6 consecutive months
Gasoil	12 consecutive months then quarterly out up to 24 months then half-yearly up to 36 months	6 consecutive months
New York Mercantile Exchange (Nymex)		
Light sweet crude (WTI)	30 consecutive months then long-dated futures initially listed 36, 48, 60, 72 & 84 months prior to delivery	12 consecutive months plus three long-dated options at 18, 24 & 36 months out on a June/December cycle
Brent crude oil	18 consecutive months	6 consecutive months
Unleaded gasoline, NYH	12 consecutive months	12 consecutive months
Heating oil	18 consecutive months	18 consecutive months
Propane	15 consecutive months	n.a.
Crack spread option, 1 : 1 heating oil : WTI	n.a.	6 consecutive months then 2 quarters on a Mar, Jun, Sep, Dec rotation
Brent/WTI crude oil spread option	n.a.	6 consecutive months

longest term futures and options maturities traded are for Light Sweet Crude Oil (WTI) on the Nymex. The Nymex now offers WTI futures contracts up to seven years forward.

Publications quoting spot prices

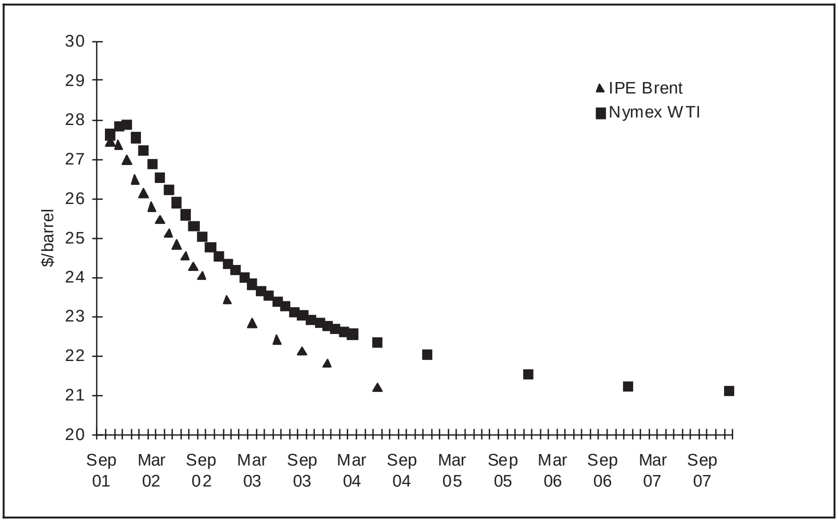
Spot price assessments for a wide range of energy products are available from daily publications such as *Platts Oilgram*, *Petroleum Argus*, *London Oil Reports* or from real-time screen reporting services such as *Reuters*, *FutureSource*, *Telerate* or *Bloomberg*. Many energy contracts refer to these publications for their settlement prices, although *Platts* is the most commonly used source for OTC contracts. Spot prices can be used as single quotes for option contracts, or averaged for swaps and Asian options.

Among the many derivative products traded on the OTC energy market, those based on prices quoted in trade publications include:

Platts refined products			*Platts*
NW Europe	US Gulf Coast	Singapore	crude oil
Pemium unleaded gasoline, cargoes CIF	Jet kerosene, 54 grade	Kerosene	Dated Brent
Premium unleaded gasoline, barges FOB	Unleaded gasoline, 87, 89, 93 MON	Unleaded gasoline, 97 RON	Dubai
Naphtha, cargoes CIF	Naphtha	High sulphur fuel oil, 180 cst	Forties
Gasoil, 0.2% sulphur	Residual fuel oil, 3% sulphur	High sulphur fuel oil, 380 cst	Ekofisk
Fuel oil, low sulphur, cargoes CIF			Statfjord
Fuel oil, high sulphur, barges FOB			

Some prices are not quoted

Estimating the replacement value of deals whose underlying commodity is not quoted on the market can prove difficult. Some OTC trades refer to crudes or products for which there is no



Source: Nymex, IPE

Figure 18.1 Forward price curves for WTI and Brent, 10/9/01

transparent forward market, for example, Tapis swaps, or to maturities beyond the time horizon of the relevant futures market, for example, Brent swaps for monthly periods that are not quoted (see Fig. 18.1).

One method often used to derive a corresponding forward price is to estimate the spread with a closely correlated exchange product whose forward price is known, for example, Nymex WTI. Although the spread between two products can be derived from historic data this process can prove hazardous since there is no guarantee that this spread will remain constant in the future. If a particular maturity has been recently traded on the OTC market, it may be possible to obtain market prices from traders or OTC brokers.

If the above methods are neither applicable nor satisfactory, then the controlling unit must rely on prices estimated by traders. We will see in a later chapter what is required from the controlling unit to quantify the potential consequences of mis-valued prices.

18.2.2 Term structure of deals

The energy market is very volatile compared with other markets and its price structure can move violently from backwardation to contango.

A market is in backwardation when spot prices are higher than longer term prices, and it is in contango when spot prices are lower than longer term prices (*see Chapter 6*). The crude oil market has been in backwardation for most of the past decade. Backwardation can be considered "normal" in a commodity market such as oil because end-users are usually ready to pay a premium for immediate availability, which is often referred to as the "convenience yield".

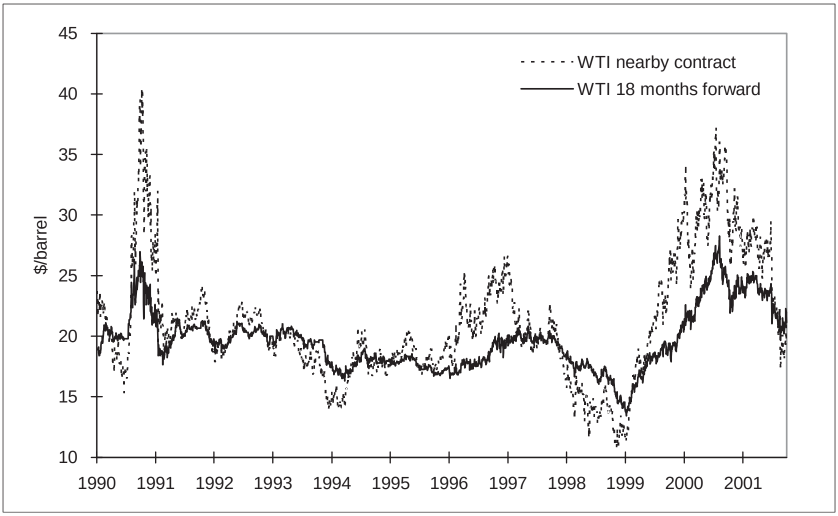
As John Maynard Keynes argued[1] "in the case of organised markets for staple raw materials there exist at any time two price quotations – the one for immediate delivery, the other for delivery at some future date, say six months hence. (...) If supply and demand are balanced, the spot price must exceed the forward price by an amount which the producer is ready to sacrifice in order to 'hedge' himself, i.e. to avoid the risk of price fluctuations during his production period. Thus in normal conditions the spot price exceeds the forward price, i.e. there is a backwardation. In other words, the normal supply price on the spot includes remuneration for the risk of price fluctuations during the period of production, whilst the forward price excludes this."

This argument applies to markets in which hedgers are predominantly either producers or companies handling the commodity who are therefore long in the physical market (short hedgers) and where a risk premium is necessary to entice speculators into the futures market to offset short hedging by producers and commercial operators.

During the last 10 years, the crude oil market has been in backwardation more often than contango and the forward spread has been very volatile (*see Fig. 18.2*). In late 1989, an early severe winter in North America saw a market with strong backwardation, the nearby WTI contract was at $23/barrel while the 18 month forward contract was at $19/barrel. However, the market changed from backwardation to contango during the first half of 1990 as Opec producers competed for market share. By June 1990, the WTI nearby contract was trading at under $16/barrel while the 18 month forward contract was still around $20/barrel.

But the contango was rapidly reversed following the invasion of Kuwait by Iraq and the backwardation strengthened to record levels. In October 1990 the WTI nearby contract reached $40/barrel but the 18 months forward contract only rose to just over $25/barrel. Early 1991 saw the Gulf War and the expulsion

[1] Keynes, J.M., 1930, "A treatise on money: Volume II: The applied theory of money", p. 143.



Source: Nymex

Figure 18.2 Term structure of WTI crude futures market

of Iraq from Kuwait, bringing prices back to more normal levels. From early 1991 to early 1993, the market remained broadly in backwardation with nearby WTI prices fluctuating in a range from $18 to 23/barrel. But from mid-1993 to mid-1994 the market was in contango with a weak spot price falling to around $14/barrel while forward prices remained above $18/barrel. Then after a period of unusually stable prices in the $18–20/barrel range from mid-1994 to late 1995, backwardation widened dramatically in 1996 as nearby prices exceeded $25/barrel while forward prices rose to around $20/barrel. But the backwardation collapsed again in early 1997 as mild weather and the start of the Iraqi oil-for-aid deal put an end to the shortage of prompt oil that had characterised 1996.

Prices started falling sharply towards the end of 1997 with the Asian economic crisis and the market moved into a deepening contango as the over-supply grew. By the end of 1998 prices were approaching $10/barrel, prompting defensive supply cuts by Opec and a small number of non-Opec producers in early 1999. After this oil prices started to rise again and the market returned to backwardation as industry stock levels began to fall. Prices continued to rise in 1999 and 2000 as increases in Opec production lagged behind rising demand and stocks continued to fall and the backwardation intensified. By October 2000, nearby WTI prices surged to over $35/barrel, pulling longer-term prices up with them. The backwardation eased and prices slipped back to just above $25/bbl in early 2001 after Opec boosted supply but weakening demand continued to undermine the market despite renewed supply cuts by Opec. And the market moved back into contango after the 11 September terrorist attacks in the US which sharply cut the demand for oil.

As described above, the term structure of energy prices is very volatile. This can have a major impact on the replacement value of deals involving a forward time spread since these are composed of a long position for a short-term maturity and a short position for a longer-term maturity (or vice-versa). It is important for the risk controller to be aware of this fact as a flat outright position may hide a short versus a long position held for different maturities. The potential loss on a forward spread depends on its time structure.

Example: Impact of changing term structure on a hedged deal WTI crude futures time spread, flat outright position

Action	Number of contracts	Contract maturity	Deal price	Market prices	P&L result
Buy	100	Jun, Year 1	23.50	22.10	(140,000)
Buy	100	Jul, Year 1	23.40	21.90	(150,000)
Buy	100	Aug, Year 1	23.20	21.70	(150,000)
Sell	(100)	Oct, Year 2	19.40	19.35	5,000
Sell	(100)	Nov, Year 2	19.30	19.30	0
Sell	(100)	Dec, Year 2	19.20	19.25	(5,000)
Total	**(0)**				**(440,000)**

Although the forward spread deal has a globally flat position, since the number of futures contracts purchased is equal to the number of contracts sold, it would be wrong to assume that variations in the WTI price curve would not affect its P&L. As the example above shows, changes in market price can result in a loss or a profit on a deal whose global position is flat.

OTC deal structure

Deals traded on the OTC energy market can have many different structures but the most common forms are swaps and Asian options. Over the last 10 years, the longest maturities traded have risen from 5 year contracts to up to 15 year contracts. Due to an even less transparent market, the valuation of very long-term deals is more difficult than that of short-term ones.

A swap is a contract in which a company buys or sells a specific product at a fixed price for a specific forward time period and then sells or buys the same quantity back at the average of the prices quoted during that period (*see Chapter 10*). These prices can be quoted on an exchange or in a trade publication.

Example: Swap

Company A sells to company B, 10,000 barrels of WTI per month for the next full calendar year, monthly settled, at a fixed price of $20.00/barrel and buys back at a floating price which will be the average of the first nearby WTI futures prices during each month.

Every month during the following year, the WTI first nearby prices are recorded and averaged. At the end of each month, the average is compared with the fixed price agreed in the swap contract. If the average is higher than $20.00/barrel, then company A will pay the company B the difference between the average and the fixed price times 10,000 barrels, but if the average is lower than $20.00/barrel, then company A will receive from company B the difference between the fixed price and the average times 10,000 barrels. This process is repeated for each month mentioned in the deal.

An Asian, or average price, option is a contract which gives a company the *right*, *but not the obligation*, to buy (or sell) a specific product at an agreed *strike* price (*see Chapter 9*). An option to buy is known as a *call* and an option to sell is known as a *put*. If the average price for the month is above the strike price then a company buying an Asian call option would exercise its right to buy as the option price is less. But if the average price is lower than the strike price, the company would not exercise its right to buy as the market price is less. Asian options are usually cash-settled.

Example: Asian option

Company A sells to company B a call option with a strike price $0.48/gallon at $0.051/gallon for 420,000 gallons of Gulf Coast Jet Fuel per month for the next full calendar year, monthly settled. The price is based on the mid-point of *Platts* quotations. The option premium of $21,420 is normally paid up front a few days after the option is purchased. Every month during the following year, the *Platts* Gulf Coast Jet Fuel quotation is recorded and averaged. At the end of each month, the average is compared with the strike price. If the average is higher than $0.48/gallon, the option is “in the money” and company A will pay company B the difference between the average and the strike price times 420,000 gallons, but if the average is lower than $0.48/gallon, the option is “out-of-the-money” and expires worthless, so no payment is due.

Although for both swap and Asian option contracts the average price is often based on a monthly period, shorter or longer periods can also be used.

In order to value these deals, several market parameters are required such as forward prices and, in the case of options, forward volatilities. However, this information is not always available from an official source. Besides, some deals can be more elaborate than those described above and require more complex valuation models (*see section 18.3 below*).

18.2.3 Cash flow specifications

OTC and exchange-traded deals do not follow the same payment procedures, which can create additional risks for companies that use both markets. Exchange deals are marked to market and settled on a daily basis via the margin call mechanisms. OTC deals do not have specific payment procedures although it is common that settlement only takes place at maturity. But companies might require security if the accumulated losses exceed a specific amount.

For example, a company may buy a swap on the OTC market and hedge it with exchange trades (*see below*). In this case, the company may have to pay money out in margin calls against the futures position before it receives any cash from the swap deal.

Example: Cash flow problems arising from deal structure
Purchase WTI swap and hedge by selling WTI futures

Counter-party	Notional quantity	Actual quantity	Maturity	Deal price	Market price	Cash flow
June, Year 1						
Buy: OTC	100	97	Jun, Y2	22.72	23.50	0
Sell: Exchange	(97)	(97)	Jun, Y2	22.72	23.50	(75,660)
July, Year 2						
Settle: OTC	100	100	Jun, Y2	22.72	23.50	78,000

Since the swap cash flow only occurs at maturity, it must be discounted to reflect its value when the contract is established. This is not the case with futures, which are marked to market every day. The hedge quantity therefore reflects the discounted notional value of the swap. Note that the hedge quantity must be adjusted as the time left to the maturity date decreases.

18.2.4 High volatility of prices

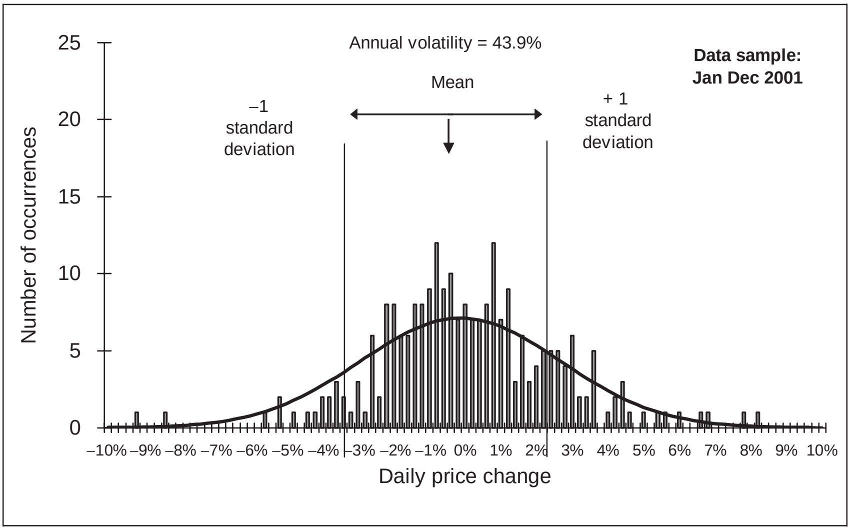
Price volatility is much higher in the energy market than in most other markets and the level of volatility can be difficult to assess.

What is price volatility?

Historical volatility is a statistical measure of the amplitude of past price changes. In order to calculate volatility, price movements are generally expressed as a percentage, i.e. $\Delta P/P$, or the compounded variation of daily price changes, i.e. $\ln(P_2/P_1)$.

If price movements are assumed to conform to a standard normal distribution, volatility can be measured by the standard deviation of the distribution. Volatility is usually expressed as the annualised standard deviation of percentage price changes (*see Fig. 18.3*).

This means that an underlying commodity with an annualised volatility of 25 per cent has a probability of 68.3 per cent, i.e. one standard deviation based on a normal distribution, that prices will move within a range of ±25 per cent during the course



Source: Cargill

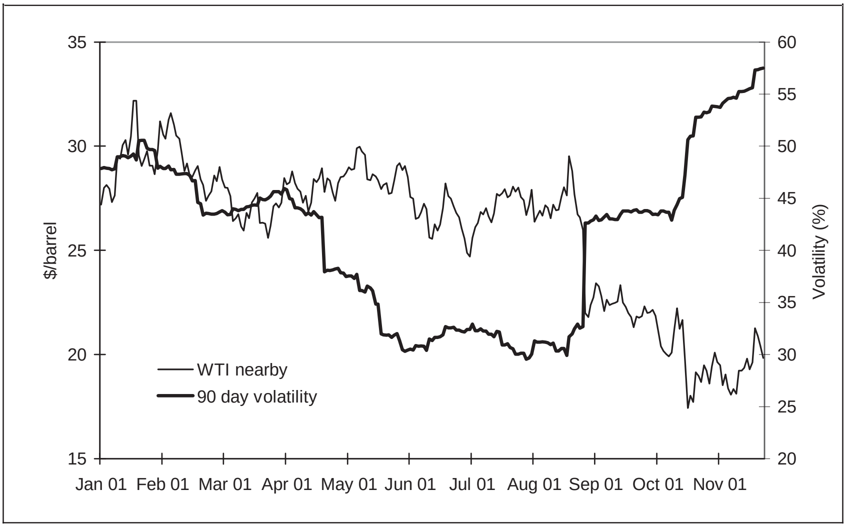
Figure 18.3 Measuring price volatility, WTI futures 2001 of a year. If the current price is \$100, this implies a likely price range from $\$100 \times e^{-0.25}$ to $\$100 \times e^{+0.25}$, i.e. \$77.88 and \$128.40.

Annualised volatility measurements can be converted into monthly volatilities by multiplying the annual volatility by the square root of the monthly fraction of a year, i.e. the square root of one twelfth. Similar calculations can be made for daily volatilities based on the number of trading days in the year, typically assumed to be 252 days.

How to measure price volatility

Unlike futures prices, volatility is not directly observable but has to be estimated. Two of the most commonly used methods are described below (*see also Chapter 9*).

Historical volatility
Historical volatility measures the past variability of prices over a specified time period. Estimates can be made using spot prices or any forward maturity and for any period of time, e.g. 5, 10, 20, 30, 60 or 90 days. Longer periods of observation will provide more accurate estimates for historical volatility, but they are less likely to correspond to current market conditions (*see Fig. 18.4*).



Source: Nymex

Figure 18.4 Historical volatility, WTI nearby futures contract

Implied volatility

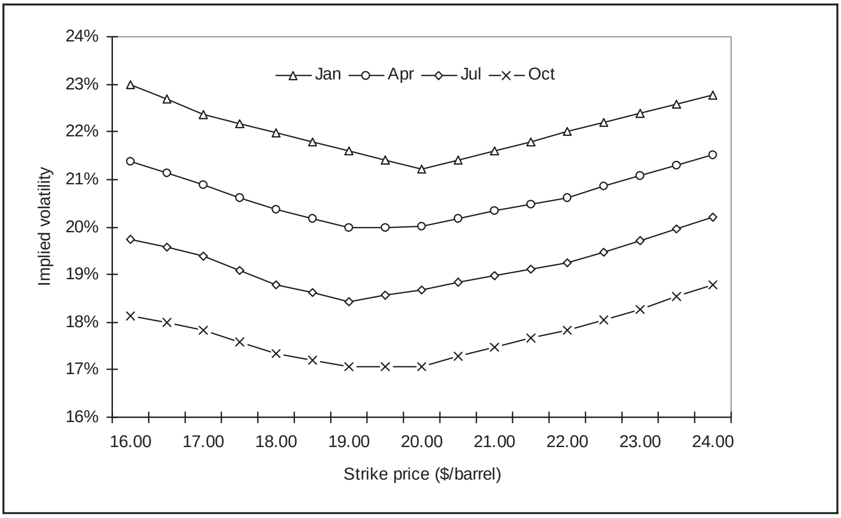
Implied volatility is the market's valuation of the future variability of prices which is embedded in the option premium. Estimates of implied volatility can be made using standard option pricing models, such as Black and Scholes, to derive the market's view of price volatility from the option premium and the other key parameters, namely the price of the underlying commodity, the time to maturity, the risk-free interest rate, and the strike price.

Description of smile

Options can be traded for different strike levels. Premiums will vary for each maturity at different strike levels. Implied volatilities derived from these premiums may not be the same for different strike levels for the same maturity (*see Fig. 18.5*). Usually, implied volatility "at-the-money" is lower than that for other strike levels. This indicates that extreme price moves are expected to be more frequent than the normal distribution would suggest (so called "fat tail").

Implications of high price volatility

In a highly volatile market, prices are likely to move over a wider range than in a less volatile market. This has important



Source: Cargill

Figure 18.5 Volatility smiles, WTI options implications for the P&L result for companies trading in energy markets, which typically have higher volatilities than many other markets.

In 1996, Nymex natural gas futures exhibited the greatest price volatility in the energy market with an annual average 20-day price volatility of 70 per cent. Nymex WTI crude oil futures were also much more volatile than all the other major market groups with an annual average 20-day price volatility of 36 per cent. After energy, metals markets are the next most volatile commodity. In 1996, the annual average 20-day price volatility in the LME copper market was 28 per cent. Soft commodities are typically less volatile than energy or metals, but are still more volatile than equities or currencies (*see Table 18.2*).

During the 1990s, the average 20-day price volatility of the nearby Nymex WTI crude oil futures contract has been just over 30 per cent. The highest annual volatility was in 1990 when the average reached 54 per cent and the lowest annual volatility was in 1992 when the average dropped to 19 per cent.

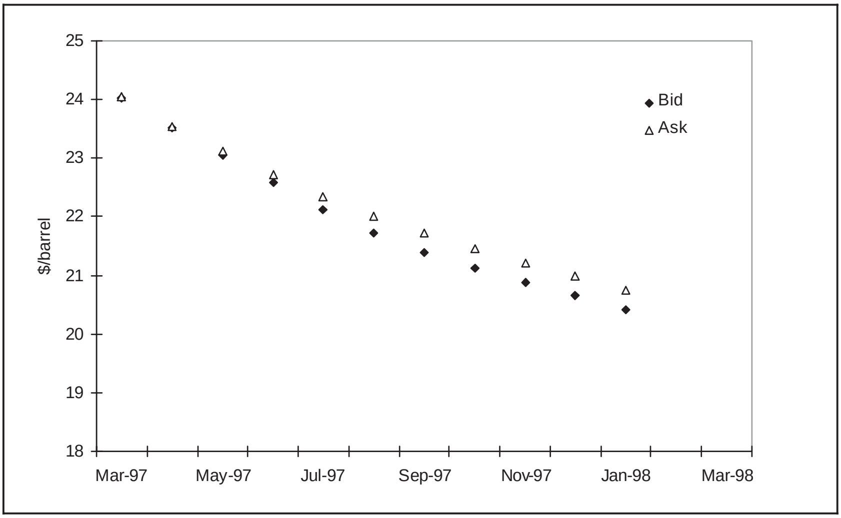
18.2.5 Lack of liquidity

WTI and Brent are the most liquid derivative contracts in the energy market. Liquidity is high up to 18 months forward for WTI and 6 months forward for Brent, but decreases for longer term exchange maturities. On the OTC market, depending on the products, liquidity is high for 3 to 6 months forward and for actively traded spreads, for example Brent/WTI or key maturities such as December. Lack of liquidity can be an important risk factor since it may hinder the closing of held positions. In order to measure this risk, the controlling unit can assess the bid-ask

Table 18.2 Average price volatility in various markets, 1996

Market	**Annual average price volatility (20-day)**
Nymex natural gas futures	70%
Nymex WTI crude oil futures	36%
LME copper	28%
CBOT soya bean futures	18%
Dow Jones share index	11%
Yen:$ exchange rate	7%
Gold	6%

Source: UBS



Source: Cargill

Figure 18.6 Bid-ask spread for WTI futures, 27 January 1997

spread of the market price and estimate the cost the company would bear should it wish to close its positions. This method is a good approximation, since the bid-ask spread increases with declining liquidity (*see Fig. 18.6*).

18.3 Valuation of trading positions

In order to keep track of trading profits and losses it is essential to know how much cash has been received from or paid out for completed deals and to estimate the current value of open positions. However, valuing open positions is not always straightforward and the process poses a number of problems for the risk controller. Nevertheless it is important to ensure that any valuation is as accurate as possible since some risk analysis procedures depend on comparing a range of valuations under different market conditions.

Settlement quotes are published for all exchange traded contracts at the close of each business day. These market prices should be used to value exchange traded deals for both futures and options. OTC deals whose underlying commodities are traded on a futures exchange should also be valued using these settlements.

But many OTC transactions are based on commodities or maturities that are not quoted on a futures exchange and, in order to value these deals, additional market parameters are required which might include the price and volatility of the underlying commodity. Estimating these parameters for specific commodities and maturities will be critical to obtain a reasonable P&L result and risk analysis.

18.3.1 Applying a valuation formula

The replacement value of a deal is calculated using a method specific to the type of deal. To estimate the current value of any deal it is therefore important to understand its payout scenario. The section below describes various methods of valuing some of the most commonly traded deals and discusses the problems that might be encountered. It is assumed that all the market parameters are known.

Valuation of quoted deals

The P&L of any exchange position is calculated by comparing the price of the initial purchase or sale with the current market price for the relevant contracts published by the futures exchange. All exchange-traded futures and options contracts should be valued in this way. However, due to lack of liquidity, the market may not provide up-to-date quotes for the required contract, maturity and strike price. Some market parameters will then have to be estimated in order to value the deal.

Valuation of a swap

The P&L of an OTC deal, such as a swap, is calculated by comparing the initial price agreed for the swap with its current market value based on the reference price stipulated in the swap contract. If the reference price is an exchange-traded contract, the value of a swap can be derived from its pay out scenario using the current market prices for the relevant contracts published by the futures exchange. But if the reference price is a spot market assessment published by a price reporting agency or a forward maturity that is not traded on the exchange, it will be necessary to estimate these parameters in order to value the deal.

Example: WTI swap, October, Year 2

Date of valuation	24 January, Year 1
Buy or sell	Buy
Type	Swap
Swap price	$20/barrel
Pricing period	October, Year 2
Product	WTI, first nearby contract
Payment date 7	November, Year 2
Quantity	30,000 barrels

On 7 November, Year 2 the calculation of the final invoice will be as follows:

$$Q \times (P_a - P_o),$$

where, Q is the quantity of oil purchased under the swap contract, P_a is the average of all the published first nearby settlement prices during the month of October, Year 2 and P_o is the original price agreed for the swap.

But the value of this invoice on 18 October, Year 1 is:

$$Q \times (P_a - P_o) \times D_f,$$

where, D_f is the discount factor for the period from 7 November, Year 2 back to 18 October, Year 1.

In order to calculate the current value of P_a on 24 January, Year 1 a market price is needed for each pricing day in the period specified by the swap contract. Since the swap reference price is the WTI first nearby futures contract, the average price will therefore be a weighted average of the closing settlement prices on 18 October, Year 1 for the November and December, Year 2

WTI futures contracts. The weights used are determined by the expiry date of the November, Year 2 contract, which will cease trading on 20 October, Year 2, after which the first nearby contract will become December, Year 2.

Pricing schedule for October, Year 2 WTI swap, 18 October, Year 1

Pricing date	First nearby contract	Market price
1 October, Year 2	November, Year 2	19.29
2 October, Year 2	November, Year 2	19.29
5 October, Year 2	November, Year 2	19.29
6 October, Year 2	November, Year 2	19.29
7 October, Year 2	November, Year 2	19.29
8 October, Year 2	November, Year 2	19.29
9 October, Year 2	November, Year 2	19.29
13 October, Year 2	November, Year 2	19.29
14 October, Year 2	November, Year 2	19.29
15 October, Year 2	November, Year 2	19.29
16 October, Year 2	November, Year 2	19.29
19 October, Year 2	November, Year 2	19.29
20 October, Year 2	November, Year 2	19.29
21 October, Year 2	December, Year 2	19.24
22 October, Year 2	December, Year 2	19.24
23 October, Year 2	December, Year 2	19.24
26 October, Year 2	December, Year 2	19.24
27 October, Year 2	December, Year 2	19.24
28 October, Year 2	December, Year 2	19.24
29 October, Year 2	December, Year 2	19.24
30 October, Year 2	December, Year 2	19.24

Thus, the current value of P_a on 24 January, Year 1 is:

$$(13 \times 19.29 + 8 \times 19.24)/21 = \$19.271/\text{barrel}$$

and, if the discount factor is 0.899, the P&L of the October, Year 2 WTI swap is estimated to be:

$$30{,}000 \times (\$19.271 - \$20) \times 0.899 = -\$19{,}661$$

Difficulties with different calendars

Since the various exchange contracts expire on different dates in the month, the mix of prices required to value swaps will be different in each case. Although there are only two exchanges offering energy contracts, the expiry dates are not standardised across commodities and together they represent a large number of different trading calendars regulating the maturities of the various contracts. This means that two products with similar physical characteristics, for example Brent and WTI, can be compared only if corrections for their differing calendars are taken into account.

As an example, a WTI swap for the calendar month of October will be settled using about two-thirds of its quotes from the November contract and one third from the December contract, while a Brent swap for the same calendar month will settle using about one half of its quotes from the November contract and one half from the December contract.

It is important to obtain calendars from a valid source and to be aware of changes. This is necessary in order to avoid errors in the calculation of replacement value and risk analysis.

Valuation of structured deals

In the last few years the energy market has seen an increase in "structured" deals including option combinations such as straddles and strangles, and knock-out, cap and floor options. Futures and swaps are linear instruments where the replacement value only depends on the price of the underlying commodity and the interest rate. But options are non-linear instruments and their replacement value also depends on the price volatility of the underlying commodity since they will only be exercised if the market price passes an agreed level. Like options, the value of the more complex structured deals also depends on assumptions about price volatility.

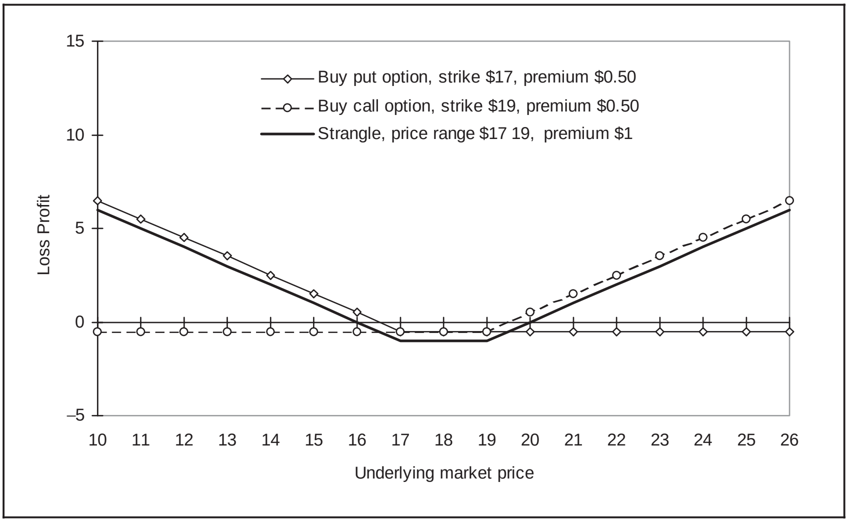
The presence of complex structured deals in a trading book increases the difficulty of calculating its replacement value and estimating the risk. In order to understand a structured deal properly, it is important to determine its payout scenario, which means calculating the P&L for every market level.

Example: Purchase of a strangle, price range $17–19/barrel

A structured deal such as a "strangle", which would pay out if prices move outside a specified range of (say) $17 to $19/barrel, can be broken down into two basic option deals whose pricing models are well established (*see Fig. 18.7*):

- buy a put with a strike price of $17/barrel
- buy a call with a strike price of $19/barrel

Once the complex or structured deal is broken down into its basic components, the replacement value of each component can be



Source: Cargill

Figure 18.7 Net payoff from buying a strangle

calculated using all the parameters required such as the forward price and market volatility. We have already seen the importance of selecting the correct forward price for the valuation of a swap. To value an option, in particular an Asian option, it is important to select the correct forward volatilities as well as the appropriate forward prices. These two parameters will affect the evaluation of both the replacement value of the deal and its risk parameters.

It is the role of the controlling unit to verify not only deal details but also that the appropriate valuation formula is being used. Similarly the controlling unit should check the decomposition of structured deals into their basic components.

Valuation of crack-spread deals

Valuing deals priced on more than one underlying commodity requires a reasonable degree of price correlation between each of the underlying commodities. For example, a crack spread option is an option on the price differential between crude oil and refined products which can be traded both on the futures exchanges and on the OTC market, e.g. Nymex WTI crude and heating oil or IPE Brent crude and gasoil. Correlation coefficients between the two underlying components can be estimated from past price behaviour. Longer time periods will usually produce more precise estimates, but could be out of step with current market conditions. Price correlations are also a critical factor in determining the "Value At Risk" of the global trading book (*see 18.4.4 below*).

18.3.2 Estimating prices not quoted on a market

The valuation of an OTC deal may require some market parameters to be estimated if the forward price or premium for the underlying commodity are not quoted on a recognised futures market. This can be the case either because the maturity of the deal is not quoted on the exchange or because the underlying commodity is only quoted on a spot basis, as is the case for *Platts* assessments used in OTC swap and option contracts.

The practical problems associated with estimating forward pricing parameters are illustrated below using the example of a Brent swap pricing from January, Year 1, to December, Year 3, a Tapis swap pricing during Year 1, and a strip of WTI options for the calendar Year 2. In the case of the WTI option strip, estimates are also required for the option premiums and associated market volatilities.

18.3.3 Forward price curves

The problem of estimating a forward price curve will be illustrated by a 10,000 barrel/month OTC Brent swap for three calendar years (Years 1, 2, & 3) which was originally purchased at $17.50/barrel. In order to value the swap, prices must be estimated for maturities that are not quoted by the exchange. The IPE publishes consecutive Brent prices for only twelve forward maturities, but the Nymex publishes WTI prices for maturities up to seven years ahead and these can be used to extend the forward curve for Brent (*see Table 18.3*). Although the IPE also lists selected longer-term Brent contracts up to 36 months ahead (*see Table 18.1*), they are traded infrequently and only the first twelve months are used in Table 18.3.

The prices used in this example do not relate to any particular day, but the valuation is being carried out at the start of Year 1 and the results have not been discounted.

In order to calculate the replacement value of the Brent swap market prices will be needed for 37 forward maturities from February, Year 1 to February, Year 4. Exchange prices can be used for the quoted maturities, but suitable market prices will need to be estimated for the remaining maturities. Estimated prices can be based on another closely related futures market such as Nymex WTI which is quoted for longer maturities and whose

Table 18.3 Contract prices for Brent and WTI futures, $/barrel

Contract	Year 1		Year 2		Year 3		Year 4	
month	**Brent**	**WTI**	**Brent**	**WTI**	**Brent**	**WTI**	**Brent**	**WTI**
Jan	*n.q.*	*n.q.*	19.69	21.01	*n.q.*	19.64	*n.q.*	*n.q.*
Feb	24.80	26.68	*n.q.*	20.80	*n.q.*	19.59	*n.q.*	*n.q.*
Mar	24.19	26.00	*n.q.*	20.63	*n.q.*	19.54	*n.q.*	*n.q.*
Apr	23.58	25.30	*n.q.*	20.46	*n.q.*	19.50	*n.q.*	*n.q.*
May	22.95	24.60	*n.q.*	20.31	*n.q.*	19.47	*n.q.*	*n.q.*
Jun	22.33	23.93	*n.q.*	20.05	*n.q.*	19.35	*n.q.*	*n.q.*
Jul	21.78	23.25	*n.q.*	20.08	*n.q.*	*n.q.*	*n.q.*	*n.q.*
Aug	21.30	22.75	*n.q.*	19.99	*n.q.*	*n.q.*	*n.q.*	*n.q.*
Sep	20.88	22.25	*n.q.*	19.92	*n.q.*	*n.q.*	*n.q.*	*n.q.*
Oct	20.53	21.75	*n.q.*	19.85	*n.q.*	*n.q.*	*n.q.*	*n.q.*
Nov	20.22	21.34	*n.q.*	19.50	*n.q.*	*n.q.*	*n.q.*	*n.q.*
Dec	19.94	21.16	*n.q.*	19.59	*n.q.*	19.25	*n.q.*	19.35

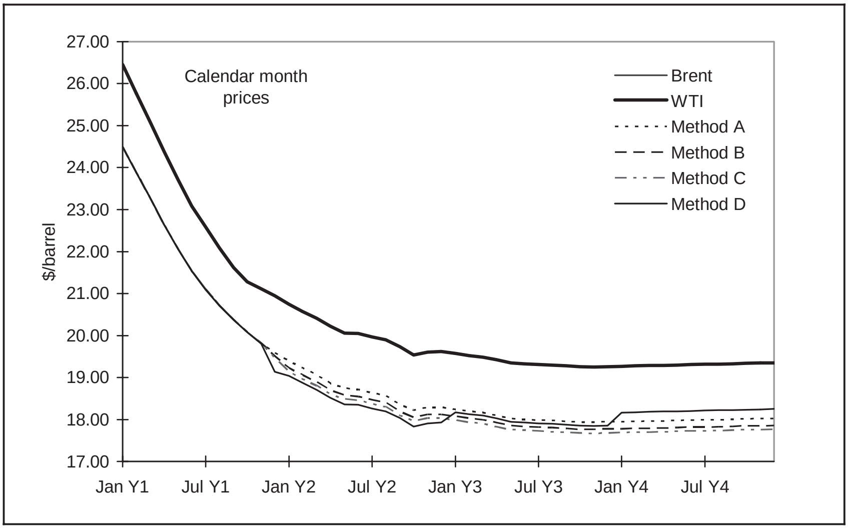
n.q. = price not quoted by exchange

prices are fairly closely correlated with Brent. All market prices used to estimate the swap value are estimated on a calendar basis. Several different approaches can be used to extend the forward curve for Brent futures:

A) apply the last quoted WTI-Brent spread to all unquoted maturities: $1.32/barrel,
B) apply the average WTI-Brent spread observed for all quoted maturities to all unquoted maturities: $1.49/barrel,
C) apply the average historical first nearby WTI-Brent spread from the last 12 months to all unquoted maturities: $1.58/barrel,
D) apply OTC market quotes from traders or brokers for the forward WTI-Brent spread to each unquoted maturity: $1.80/barrel for the unquoted Year 2; $1.70/barrel for unquoted Year 3, and $1.40/barrel for the unquoted Year 4,

and the results are shown in Fig. 18.8.

Since WTI prices are not quoted for maturities from July to November, Year 3, and from January to November, Year 4, it will also be necessary to estimate WTI prices for these forward contract months. The simplest approach, which is used in this example, is linear interpolation between the WTI exchange



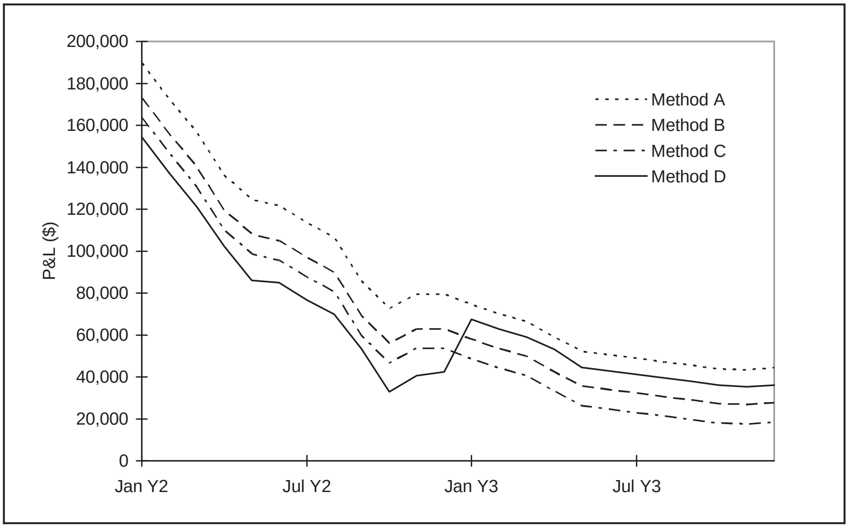
Source: Cargill

Figure 18.8 Estimated forward curves for Brent futures

quotes, although it should be recognised that this might not reflect OTC market prices, which may show seasonal variations. The controlling unit should be aware of the effect of such price estimates on the replacement value of the swap and should assess any potential impact on the P&L results.

Monthly replacement values for the Brent swap are then calculated using the estimated forward price curves (A, B, C, and D in Fig. 18.8) and the resulting P&L is shown for each case in Fig. 18.9. To further simplify this example, the Brent calendar price for each month has been approximated by averaging the prices for the first and second nearby contracts rather than using exact weights based on the IPE Brent trading calendar. The graph only shows the P&L impact of the different forward price estimates from January, Year 2 onwards since the results are identical for earlier calendar months as the valuation of the Calendar Year 1 Brent swap was based on quoted prices in every case.

It is not possible to predict which estimation procedure will provide the best reflection of the market, but it is essential that the controlling unit is fully aware of the potential impact of the method chosen. The controlling unit should therefore try alternative pricing methods and observe their effect on replacement values. A range of scenarios can be run for global trading positions and the results analysed and described in a risk control



Source: Cargill

Figure 18.9 Brent swap value using different price estimates

report. Such reports are essential for management to appreciate fully the extent to which reported results are dependent on estimated market prices and on market price movements.

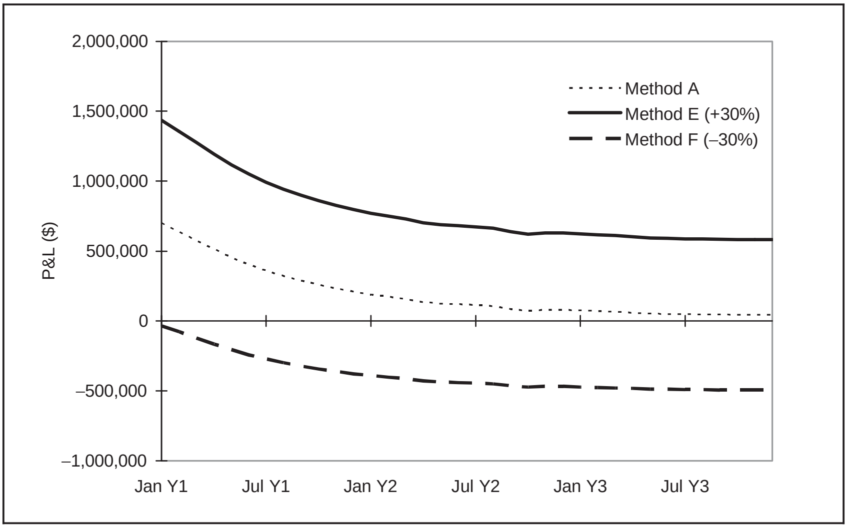
The risk control unit could also decide to analyse the potential impact of the Brent swap on the company's P&L by shocking Brent prices up and down. Such worst case scenarios can indicate to the management what the maximum loss might be if prices were to move strongly in either direction. In order to test this two additional forward price curves need to be prepared:

E) increase all Brent prices (based on method A) by 30%,
F) decrease all Brent prices (based on method A) by 30%,

and the impact on the company's P&L is shown in Fig. 18.10.

18.3.4 Price spreads and correlations

Estimating the forward curve for an OTC product such as a Tapis swap, for which only the spot price is quoted, creates further difficulties for the risk controller. To illustrate the problem, the purchase of a 10,000 barrel/month Tapis swap at a price of $17.85/barrel for the calendar Year 1 will be examined. The



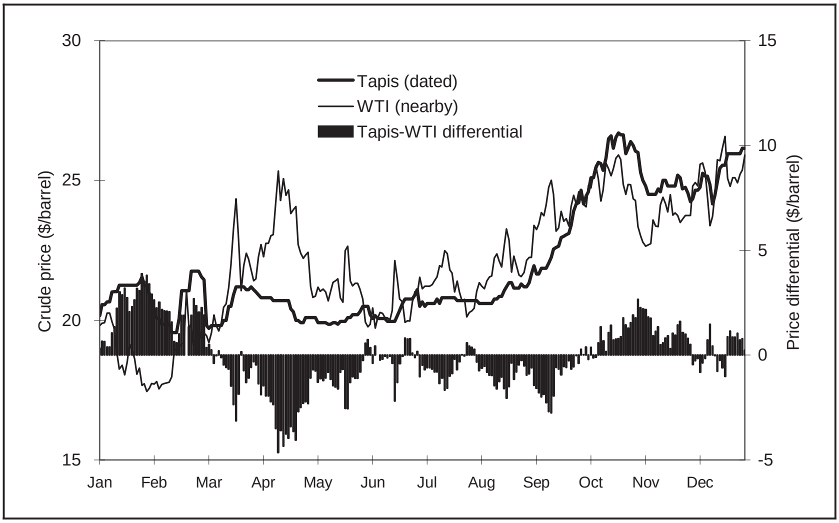
Source: Cargill

Figure 18.10 Impact of price shocks on Brent swap value

pricing basis for the swaps is the monthly average of the weekly or twice weekly spot assessments published in the Asian Petroleum Price Index (APPI) for Tapis. The replacement value of the Tapis swap is more difficult to determine since only spot prices are quoted by APPI. As a result, the replacement value of the Tapis swap requires estimated prices.

Since the prices for WTI and Tapis crudes behave similarly (*see Fig. 18.11*), the WTI forward curve can be used to derive a forward curve for Tapis prices. However, it is important to convert the WTI contract prices into calendar prices before applying a spread. Once again, there are several different methods that can be used (the prices do not relate to any particular day):

A) apply the last quoted Tapis-WTI spread (spot Tapis minus February, Year 1 WTI) to all unquoted maturities: $0.50/barrel,
B) apply the average historical Tapis-WTI spread from the last twelve months to all unquoted maturities: $0.10/barrel,
C) apply OTC market quotes from traders or brokers for the forward Tapis-WTI spread to each unquoted maturity: +$0.50/barrel for 1QY1, –$0.30/barrel for 2QY1, –$0.10/barrel for 3QY1, and +$0.40/barrel for 4QY1.



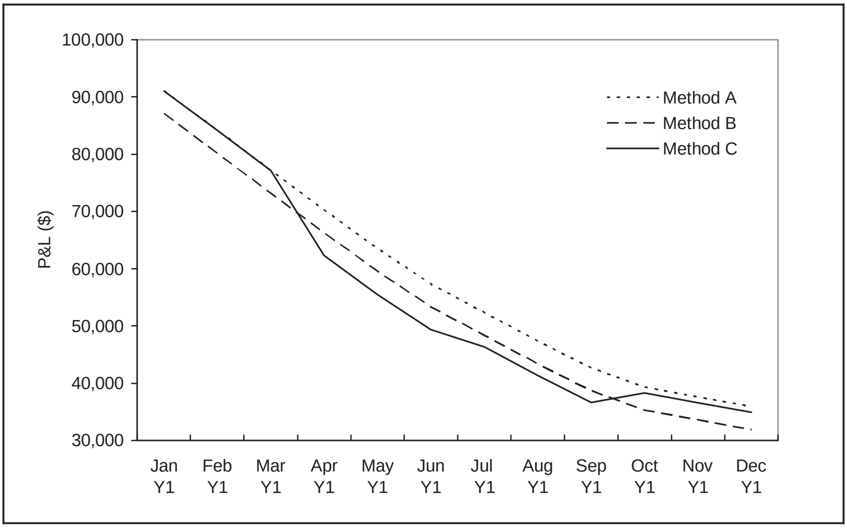
Source: Cargill, Nymex, Petroleum Argus

Figure 18.11 Correlation between spot Tapis and nearby WTI

Using the same forward WTI curve as before, the three methods generate different forward curves for Tapis since each assumes a different price spread between Tapis and WTI. Method A uses the current $0.50/barrel spread throughout the year, but method B uses the much narrower historical annual average spread from the previous year. And method C applies a seasonal pattern to the spread based on the pattern observed in the previous year, which varied between a premium in 1Q and 4Q and a discount in 2Q and 3Q.

Monthly replacement values for the Tapis swap are calculated using the spot price for January, Year 1 and the estimated forward prices for maturities from February to December, Year 1. No weighting is necessary as the swap is settled using the average of the Tapis spot price assessments published during the calendar month. As Fig. 18.12 shows, the P&L impact of the three pricing scenarios is very different, particularly for Method C which assumes a seasonal pattern for the price spread between Tapis and WTI.

Hedging the Tapis swap with an offsetting WTI swap raises further problems. Although Tapis prices are estimated from the forward curve of WTI prices, it would be wrong to conclude that the overall position would be independent of WTI prices. The risk control unit should therefore use the relevant shocking parameters to track the true exposure created by the trading



Source: Cargill

Figure 18.12 Tapis swap value using different price estimates

position. For example, WTI prices and the Tapis-WTI spreads can be shocked together, or the Tapis-WTI spread shocked separately.

Studying the correlation between different underlying commodities based on historical data provides an indication of which quoted prices can be best used to derive the forward price curves necessary for valuing OTC derivatives based on spot market quotations. But it should be remembered that they are only estimates and there is no guarantee that the market will move towards them. The controlling unit should be aware of the estimation procedures that are being used and run scenarios by shocking estimated parameters in order to evaluate the risks for management and traders.

18.3.5 Long-term price volatilities

Valuing OTC options, which may involve strike prices, maturities or underlying commodities that are not quoted on a futures exchange, poses a different sort of challenge for the risk controller. Exchange options are quoted on the market and should therefore be valued using market premiums, but the valuation of many OTC options will depend on estimated premiums.

Standard option valuation models, such as Black and Scholes, are used to calculate an option premium from:

Table 18.4 WTI forward curve and option premiums, $/barrel

	Year 1			Year 2		
Contract month	**Closing price**	**Strike price**	**Option premium**	**Closing price**	**Strike price**	**Option premium**
Jan	*n.q.*	*n.q.*	*n.q.*	20.60	20.50	1.44
Feb	*n.q.*	*n.q.*	*n.q.*	20.35	20.50	1.45
Mar	24.33	24.50	0.50	20.16	20.00	*n.q.*
Apr	23.91	24.00	0.84	19.98	20.00	*n.q.*
May	23.41	23.50	1.04	20.05	20.00	*n.q.*
Jun	22.97	23.00	1.16	19.93	20.00	1.04
Jul	22.54	22.50	1.31	19.83	20.00	*n.q.*
Aug	22.15	22.00	1.33	19.75	20.00	*n.q.*
Sep	21.78	22.00	1.36	19.68	19.50	*n.q.*
Oct	21.41	21.50	1.39	19.62	19.50	*n.q.*
Nov	21.14	21.00	1.40	19.56	19.50	*n.q.*
Dec	20.90	21.00	1.42	19.50	19.50	*n.q.*

- the current price of the underlying instrument,
- an estimate of the future price volatility of the market,
- the time remaining to expiry,
- the risk free interest rate, and
- the strike price of the option.

Conversely, the Black and Scholes formula can also be used to search for the market's view of future price volatility that is implied by a given option premium (*see Chapter 9*).

For example, valuing a strip of WTI call options for Year 1 using the price data shown above in Table 18.4 will require estimates of the option premium for the unquoted maturities from March to May, Year 2, and from July to December, Year 2. The strip of call options has a strike price of $20/barrel and was originally purchased at a premium of $1.00/barrel.

Estimating the missing option premiums requires careful analysis of the known market parameters for each of the unquoted maturities. Implied volatilities can be calculated for each of the quoted maturities from the option premia, using an option pricing formula adapted to an American option, for example, a binomial tree.

Implied volatilities for maturities lying between quoted maturities (i.e. March to May, Year 2) can then be derived using a simple linear interpolation. But implied volatilities for maturities beyond the last quoted option premium (i.e. July to Decem-

Table 18.5 WTI option premiums and implied volatilities

	Year 1			Year 2		
Contract month	**Option premium ($/barrel)**	**Time to expiry (years)**	**Implied volatility (%)**	**Option premium ($/barrel)**	**Time to expiry (years)**	**Implied volatility (%)**
Jan	*n.q.*	*n.q.*	*n.q.*	1.44	0.9699	17.85
Feb	*n.q.*	*n.q.*	*n.q.*	1.45	1.0548	18.89
Mar	0.50	0.1315	16.53	*n.q.*	1.1315	*n.q.*
Apr	0.84	0.2219	19.82	*n.q.*	1.2192	*n.q.*
May	1.04	0.2986	21.46	*n.q.*	1.2959	*n.q.*
Jun	1.16	0.3836	21.01	1.04	1.3990	11.99
Jul	1.31	0.4712	21.31	*n.q.*	1.4685	*n.q.*
Aug	1.33	0.5507	19.62	*n.q.*	1.5569	*n.q.*
Sep	1.36	0.6411	21.48	*n.q.*	1.6411	*n.q.*
Oct	1.39	0.7205	20.28	*n.q.*	1.7178	*n.q.*
Nov	1.40	0.8027	18.21	*n.q.*	1.8027	*n.q.*
Dec	1.42	0.8822	19.32	*n.q.*	1.8877	*n.q.*

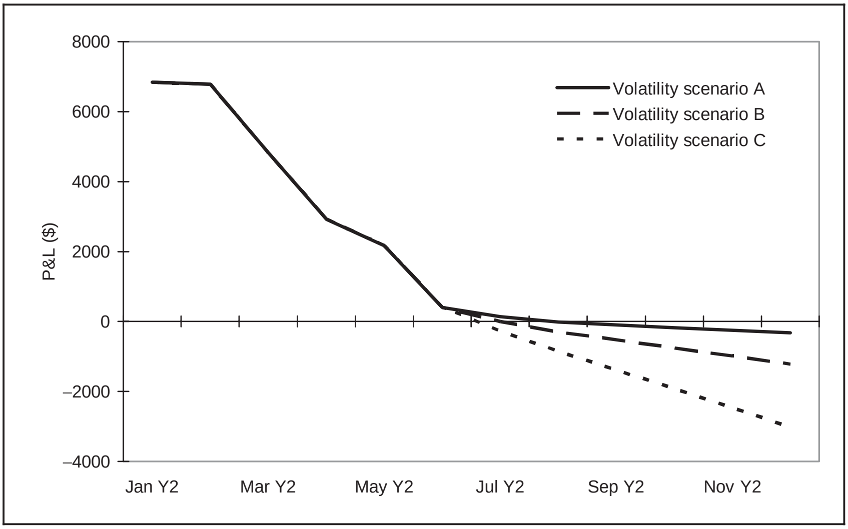
ber, Year 2) must be estimated. Some guidance can usually be obtained from traders or OTC brokers who may be able to provide assessments of current market levels for unquoted maturities, otherwise it will be necessary to assume a volatility profile for the remaining maturities.

In this example, three different volatility profiles have been used to extrapolate option premiums for the unquoted maturities:

A) volatility declines by 0.05 percentage points per maturity,
B) volatility declines by 0.2 percentage points per maturity,
C) volatility declines by 0.5 percentage points per maturity,

and the impact of these three different assumptions on the replacement value of the strip of WTI options is shown in Fig. 18.13.

It can be seen that several assumptions, such as the choice of option pricing formula, linear interpolation and forward volatility profiles, have had to be made in order to estimate premiums for the unquoted maturities. Other assumptions would lead to different valuations and it is important to keep this in mind when calculating the replacement value of an OTC options contract whose market premium is not quoted.



Source: Cargill

Figure 18.13 Value of WTI call option, $20/barrel strike price

In this example, implied volatilities were derived using option premiums that were "at-the-money", i.e. premiums for strike prices nearest to the settlement price of the underlying futures contract. This is also a simplification since the "smile" effect means that the energy market assigns higher implied volatilities for strike prices that are in- or out-of-the-money.

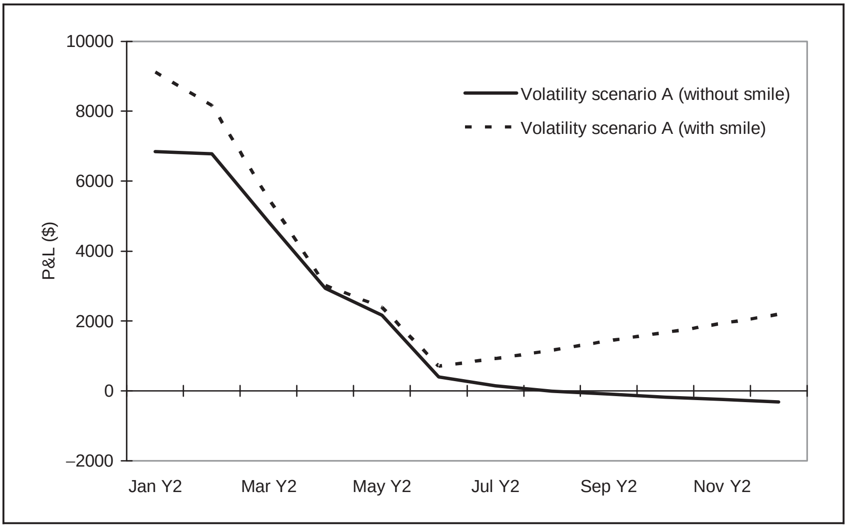
In order to introduce a "smile" into the valuation of a strip of options, the implied volatility should be derived from the premium of the market traded option at the appropriate strike level. If suitable premiums are not available, then the implied volatility will need to be estimated.

A simple formula can be used to construct a "smile" using market quotes for at-the-money premiums:

$$V_s = \text{ABS}\ (S - F) \times \alpha + V_m$$

where, V_s is the implied volatility at the strike price S,
F is the settlement price of the underlying futures contract,
V_m is the implied volatility at-the-money, and
α is a scaling coefficient measured in per cent per $/barrel which is set to 0.01 in this example.

There are many different methods that can be used to build up a smile, of which the one presented above is the simplest.



Source: Cargill

Figure 18.14 Effect of a smile on the value of a WTI call option

What is important is to select an estimation procedure that fits the current available market data and traders' assessments. Once again, it is important for the risk control unit to be aware of the method used to construct a smile in order to test the impact of any assumptions on the valuation of an option.

Applying a smile to the option premiums used to value the WTI call option strip increases the size of the premiums since the implied volatilities are higher for the maturities that are in- or out-of-the-money and therefore increases the replacement value of the option (*see Fig. 18.14*).

Valuing an OTC option for which the underlying commodity is only quoted on a spot basis, for example *Platts* price assessments, is even more subjective since it requires the estimation of both forward price curves and implied volatility.

These examples demonstrate how complex the valuation of OTC options can become. In many cases, a large number of parameters have to be estimated and these might not reflect true market levels. The risk control unit must be aware of the implication of any assumptions used for portfolio valuation and a range of scenarios should be run to assess the impact of changes in key parameters.

However, since the number of scenarios will rise rapidly as the number of estimated parameters multiplies, it is essential to select the most relevant parameters in order to provide timely risk analysis. Typically, traders and management expect to receive risk reports by the following business day. As market conditions change, any risk analysis quickly becomes obsolete and it is more important to keep up-to-date with market conditions than to carry out exhaustive tests of every possible combination of valuation parameters.

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18.4 Determination of risk

18.4.1 Different approaches to risk

When a company holds a portfolio of trading positions it is important to be able to analyse the risks that are involved and to assess whether changes in market conditions could lead to losses. There are several standard methods for evaluating potential losses and estimating the risks associated with a trading book.

The most common method is to investigate the sensitivity of individual trades to changes in a number of key market parameters. In the case of options, the key parameters are derived from the standard Black and Scholes options pricing model. These risk parameters are usually represented by a letter from the Greek alphabet, each Greek letter measuring the sensitivity of the deal's value to a specific market factor such as the underlying price, volatility or time to expiry. The "Greeks" for several deals can then be aggregated together and presented in a concise report which summarises the risks inherent in the trading book.

Another common method is to make changes to the most important market parameters and recalculate the value of the global trading portfolio as a result of price or volatility shocks. Several different shock scenarios can be created depending on which market parameters are most relevant to a specific trading book. Such fine tuning requires a thorough knowledge of both the structure of the trading positions in the global book and the behaviour of the underlying markets.

More recently, a method of risk analysis has been introduced called "Value at Risk" or VAR. VAR shocks the price of the underlying commodity and any other relevant risk factors for each open position in the book and then aggregates the results across all maturities, commodities and markets to provide a single global estimate of the trading risk for the entire company. The shock applied to each position is a statistical estimate of the potential price change in the underlying commodity calculated from historical data and is usually based on a confidence interval of 95.4 per cent (i.e. two standard deviations).

18.4.2 Greeks

Greeks measure how much the value of a financial instrument is likely to change as a result of variations of market conditions. They are derived from the Black and Scholes options pricing model and there is a specific risk parameter for each of the key components required for the valuation of financial instruments, namely the price of the underlying commodity, the volatility of the market, the time to maturity and the risk-free interest rate.

Greeks are used to assess the potential risk of the trading portfolio and indicate the direction and likely extent of changes in the value of the portfolio following changes in market conditions. Greeks are normally presented based on standard movements for the various market parameters, for example, a change of $1 in the underlying price, a change of 1 percentage point in market volatility, or a change of 1 day in the time remaining to expiry.

Delta

Delta measures the sensitivity of the value of a trading instrument to small variations in the price of the underlying commodity. In mathematical terms, it is the first partial derivative of a function representing the value of any financial instrument with respect to its underlying price. For options it only holds for small variations in prices because the function is non-linear.

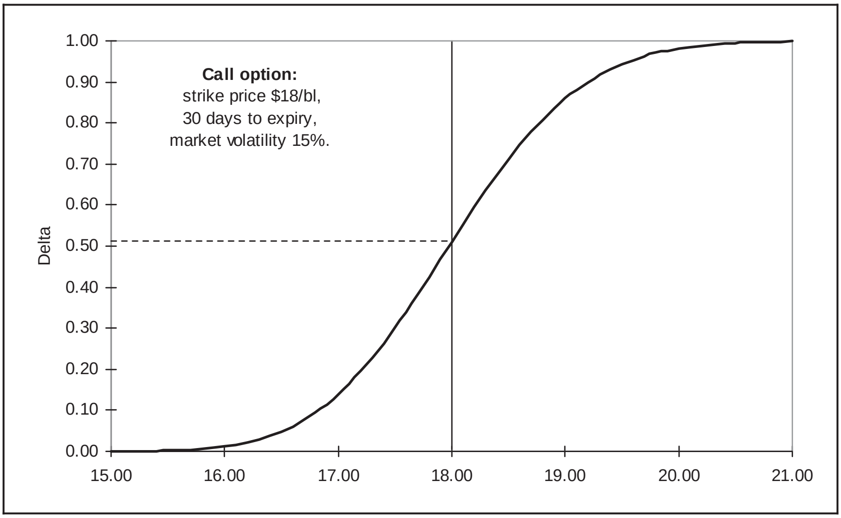
The value of delta varies between –1 and +1. The delta of a linear instrument such as a future is 1 – which implies that the replacement value of the instrument will move by the same amount as a change in the underlying price – while the delta of a swap is the current discounted value of 1. But the delta of a non-linear instrument such as an option can lie anywhere between –1 and +1 depending on whether it is in- or out-of-the-money.

The delta of a call option varies from 0 for a call that is far out-of-the-money, to +1 for a call that is deep in-the-money (*see Fig. 18.15*). The delta of a put option varies from 0 for a put that is far out-of-the-money, to –1 for a put that is deep in-the-money.

Table 18.6 Greeks, a summary

Greek name	**Greek letter**	**Risk parameter**
Delta	Δ	Sensitivity of value to change in underlying price
Gamma	Γ	Sensitivity of *delta* to change in underlying price
Vega*	n.a.	Sensitivity of value to change in market volatility
Theta	Θ	Sensitivity of value to change in time to expiry
Rho	Ρ	Sensitivity of value to change in interest rate

* *sometimes known as Lambda(Λ), Kappa(Κ) or Sigma(Σ).*



Source: Cargill

Figure 18.15 Changing value of delta for a call option

At-the-money options have a value of around +0.5 for a call option and around –0.5 for a put option. For example, a WTI call option which is just in-the-money might have a delta of +0.6, which means that the value of the option premium will rise by 6 cents if the underlying WTI price rises by 10 cents (everything else being equal).

If necessary, the delta of an OTC trading instrument should be discounted to reflect its different type of payment schedule. Exchange-traded futures always have a delta of 1 since the contract is marked to market and the variation margin is paid every day. But the delta of a swap or an OTC option should be discounted back from the payment date specified for the instrument to the day on which the replacement value is being calculated.

Example: Calculating delta for a simple trading portfolio

A company holds the following portfolio of WTI contracts:

Buy 95 lots October swaps, delta ratio = 0.947
Buy 150 lots December calls, delta ratio = 0.38
Buy 160 lots November puts, delta ratio = (0.65)
Buy 20 lots November futures, delta ratio = 1
Sell 65 lots December futures, delta ratio = 1

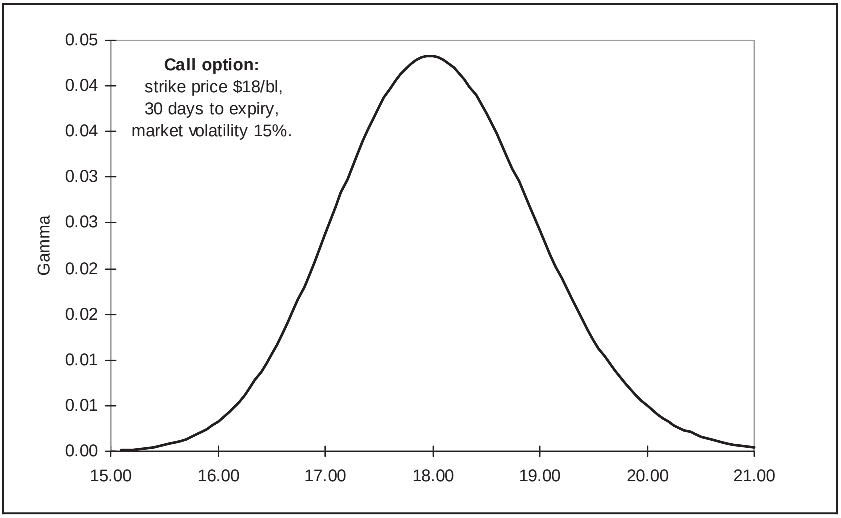
	Swap	Call	Put	Futures	Total
Delta equivalent position by contract month (quantity × delta ratio)					
November	60	0	(104)	20	**(24)**
December	30	57	0	(65)	**22**
Estimated P&L for a rise of $1 in the underlying price, $ '000					
November	$60	$0	$(104)	$20	**$(24)**
December	$30	$57	$0	$(65)	**$22**
Estimated total P&L impact, $ '000					
Total	**$90**	**$57**	**$(104)**	**$(45)**	**$(2)**

Combining the deltas for several deals gives an estimate of the global delta of the trading book. The delta of this combination of deals is short 24 lots of WTI for the November contract and long 22 lots of WTI for the December contract. This provides a global risk analysis which can be used to estimate the change in the total value of the book further to changes in market prices.

The short delta of 24 lots for November indicates that the value of the book will decrease by $24,000 if the market price goes up by $1 (and vice-versa). The long delta of 22 lots for December indicates that the value of the book will increase by $22,000 if the market price goes up by $1 (and vice-versa).

It must be emphasised that these results are only valid for a very small variation in the underlying price. The example given above uses a relatively large change of $1 and is unlikely to provide sensible results for non-linear instruments such as options. However, the delta gives a very good indication of the total size of the trading book exposure and provides good P&L risk estimation for all linear instruments.

The delta for each maturity can also be aggregated. In the example above, the November delta and December delta are added to give a global delta equivalent position of a book that is short 2 WTI lots. Although this conveniently summarises the global exposure of the trading book, it conceals the fact that there is a forward time spread. If the November and December prices were to move in opposite directions, the P&L effect cannot be correctly deduced from the global delta position. For example, if the November price goes up by $0.60 and the December price goes down by $0.40, the global P&L impact will be a loss of $23,200. Thus the aggregated delta does not warn of the risk of a potential loss if prices for the different maturities in a portfolio do not move in parallel.



Source: Cargill

Figure 18.16 Changing value of gamma for a call option

Gamma

Gamma measures the sensitivity of *delta* to small variations in the price of the underlying commodity. In mathematical terms, it is the second partial derivative of a function representing the value of a financial instrument with respect to the underlying price. Like delta, it only holds for small variations in prices.

The gamma of a linear instrument such as a futures contract or a swap is always 0, since its delta never changes. But the gamma of a non-linear instrument, such as an option, is always positive for a long position as its delta changes in response to changes in the underlying price (*see Fig. 18.16*).

Gamma is close to zero for options that are either far out-of-the-money (i.e. when delta approaches 0) or deep in-the-money (i.e. when delta approaches ±1) and rises to its highest value for options that are at-the-money. For example, if a WTI call option has a gamma of 0.1, this means that the delta of the option will increase by 0.1 if the underlying price goes up by $1.

Example: Calculating gamma for a simple trading portfolio

A company holds the following portfolio of WTI contracts:

Buy 95 lots October swaps, delta = 0.947, gamma = 0

Buy 150 lots December calls, delta = 0.38, gamma = 0.03

Buy 160 lots November puts, delta = (0.65), gamma = 0.05
Buy 20 lots November futures, delta = 1, gamma = 0
Sell 65 lots December futures, delta = 1, gamma = 0

	Swap	Call	Put	Futures	Total
Delta equivalent position by contract month (quantity × delta ratio)					
November	60	0	(104)	20	**(24)**
December	30	57	0	(65)	**22**
Delta change for a rise of $1 in the underlying price					
November	0	0	8.0	0	**8.0**
December	0	4.5	0	0	**4.5**

It can be seen that gamma provides additional insights into the effect of a change in the underlying price on the value of the trading book. The full P&L impact of an increase of $1 in both the November and December contract prices can be calculated by combining all the partial derivatives of a function representing the value of a financial instrument with respect to the underlying price. In mathematical terms this sum can be approximated using the Taylor expansion:

$$P(x + a) = P(x) + [P'(x)/1!] \times a + [P''(x)/2!]a^2 + \ldots$$

where, x is the value of the trading instrument, and
a is the change in the underlying price,
which gives in this example:

$$P(x + 1) = P(x) + (-2) + (+12.5/2).$$

Thus the total impact on the P&L is +$4,250.

	Swap	**Call**	**Put**	**Futures**	**Total**
Delta equivalent position by contract month (quantity × delta ratio)					
November	60	0	(104)	20	**(24)**
December	30	57	0	(65)	**22**
Estimated P&L impact from delta component, $ '000					
November	$60	$0	$(104)	$20	**$(24)**
December	$30	$57	$0	$(65)	**$22**
Estimated P&L impact from gamma component, $ '000					
November	0	$0	$4	0	**$4**
December	0	$2.25	$0	0	**$2.25**
Estimated total P&L impact, $ '000					
Total	**$90**	**$59.25**	**$(100)**	**$(45)**	**$4.25**

In this example, the gamma component has more impact on the P&L than the delta component. But, in practice, all combinations are possible.

Once again, it must be emphasised that these examples use a relatively large change in the underlying price of $1 and that the contribution of gamma has been simplified since the "square" of 1 is 1. Like delta, the results given by gamma are only precise for small variations in the underlying. However, gamma still indicates the potential change in delta as a result of changes in market prices. This allows traders to adjust their hedges dynamically in response to market circumstances.

Like delta, gamma can be aggregated across maturities, however, it should be remembered that this will also conceal the existence of any forward time structures in the global trading book.

Vega

Vega measures the sensitivity of an option premium to changes in the price volatility of the underlying commodity. The value of vega is always positive, which means that an option premium always increases with an increase in the volatility of the underlying market price. The vega of linear instruments such as futures or swaps is always zero since volatility does not affect their valuation.

A high vega indicates that an option is very sensitive to small changes in volatility and a low vega indicates that an option is relatively insensitive to volatility changes. Vega is at its highest for options that are at-the-money and lowest for options that are far out-of-the-money or deep in-the-money. For example, if a WTI call option has a vega of $0.44/percentage point, it means that an increase in volatility of 1 percentage point from (say) 18.5 per cent to 19.5 per cent, would lead to an increase of $0.44 in the option premium.

Example: Calculating vega for a simple trading portfolio

A company holds the following portfolio of WTI contracts:

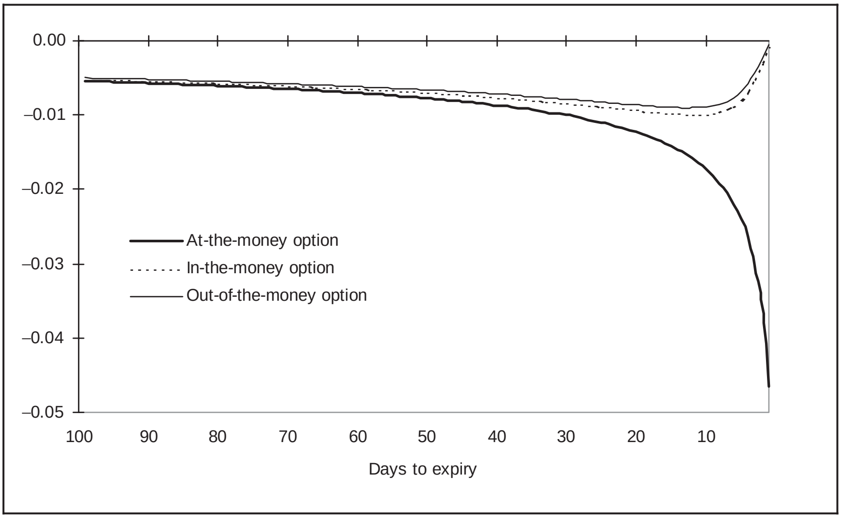
Buy 95 lots October swaps, vega ratio = 0
Buy 150 lots December calls, vega ratio = 0.44
Buy 160 lots November puts, vega ratio = 0.28
Buy 20 lots November futures, vega ratio = 0
Sell 65 lots December futures, vega ratio = 0

	Swap	Call	Put	Futures	Total
Notional quantity by contract month					
November	63	0	160	20	
December	32	150	0	(65)	
Estimated P&L change for an increase of 1% in price volatility, $ '000					
November	0	0	$45	0	**$45**
December	0	$66	0	0	**$66**
Estimated total P&L impact, $ '000					
Total	**$0**	**$66**	**$45**	**$0**	**$111**

Once again, the vega of individual deals can be combined to give an overall vega for the trading book as a whole, but this will conceal the existence of forward time spreads.

Theta

Theta measures the sensitivity of the price of an option to a change of one day in the time remaining to the expiry date of the option. The value of theta is nearly always negative and only changes slowly when an option is far away from expiration, but becomes rapidly more negative for an at-the-money option during the last 30 days as it approaches the expiry date. Options that are at-the-money have a more negative theta than options that are in- or out-of the-money (everything else being equal).



Source: Cargill

Figure 18.17 Changing value of theta for a call option

For example, a WTI call option which is at-the-money with around 60 days to expiry might have a theta of –$0.005 per day, which means that the value of the option will decrease by $0.005 between today and tomorrow. But the same at-the-money option with 10 days to expiry would have a theta about three times this size (*see Fig. 18.17*).

Example: Calculating theta for a simple trading portfolio

A company holds the following portfolio of WTI contracts:
Buy 95 lots October swaps, theta ratio = 0
Buy 150 lots December calls, theta ratio = –0.005
Buy 160 lots November puts, theta ratio = –0.002
Buy 20 lots November futures, theta ratio = 0
Sell 65 lots December futures, theta ratio = 0

	Swap	Call	Put	Futures	Total
Notional quantity by contract month					
November	63	0	160	20	
December	32	150	0	(65)	
Estimated P&L change for a decrease of 1 day in the life of the option, $ '000					
November	0	0	$(0.32)	0	**$(0.32)**
December	0	$(0.75)	0	0	**$(0.75)**
Estimated total P&L impact, $ '000					
Total	**$0**	**$(0.75)**	**$(0.32)**	**$0**	**$(1.05)**

Rho

Rho measures the sensitivity of the price of a trading instrument to changes in the interest rate, but it is not very widely used in the energy market since the impact of variations in the interest rate is a second order effect compared with the variation of the other risk parameters.

Aggregation of Greeks

Once the full set of Greeks have been calculated for all the individual deals in the trading book, they can be aggregated according to different criteria in order to create a summary report for traders and senior management. For example, the Greeks could be added together across all maturities for each underlying commodity and presented as follows:

	DELTA	GAMMA	VEGA	THETA
FUEL 1%				
FUEL 3%				
WTI				
NAPHTHA				
BRENT				
GASOIL				
JET, GULF COAST				
TOTAL				

Although the overall risk is clearly represented for each underlying commodity, the time structure is not shown.

Alternatively, Greeks can be aggregated together for each maturity across all commodities, and presented as follows:

	DELTA	GAMMA	VEGA	THETA
JAN				
FEB				
MAR				
APR				
MAY				
JUN				
JUL				
TOTAL				

Although the time spread is clearly represented, the spread between the different commodities is hidden.

However, these tables require careful preparation since the various underlying commodities do not have the same units and need to be converted into a common unit so that they can be added together.

A more complete report, which is not too large but still contains information about the time spread and commodity mix, might be organised like this:

	DELTA		GAMMA		VEGA		THETA	
	Crude	Product	Crude	Product	Crude	Product	Crude	Product
1 month								
2 months								
3 months								
6 months								
1 year								
2 years								
TOTAL								

It is important to devise a report that will provide the trader with all the relevant information. A good compromise would be to keep the report as concise as possible without losing too much information by aggregating across products and maturities.

The main advantage of Greeks is that they are relatively easy to calculate. They are also relevant to traders since they conveniently summarise the global trading positions held for selected groups of commodities or maturities. However, it is important to remember that some risks, such as forward time structure or commodity spreads (i.e. basis risk), might be hidden by an aggregated report.

Greeks also provide senior management with a useful overview of global positions taken by the trading unit. For practical reasons, a more concise report might be required for senior management with a higher degree of aggregation so that fewer commodities and maturities are presented on the report. If managers receive reports from several trading units they will not want to read a document that is several pages long.

18.4.3 Scenarios

Another method of estimating the potential loss associated with a trading portfolio is to change the market conditions used to value the book and see the effect on the P&L. A number of different parameters can be shocked in order to determine the precise impact of specific market movements, after which the value of the whole book is recalculated. In the energy market, the emphasis is usually on shocking prices and volatilities rather than interest rates since these only have a negligible impact.

Deciding which market parameters should be shocked, by how much, and in what direction can be done in various ways. If management, traders or the risk control unit have a strong view about market trends, the key variables can be shocked accordingly. Or a range of scenarios can be run corresponding to different views about the market. Using a scenario which goes against the positions held in the trading book provides a useful indication of the likely magnitude of any potential losses. Other scenarios may be based on the biggest historical moves observed in the market. Once several scenarios have been run, it is important to know how to present the results to both managers and traders.

Scenarios are also used by the futures exchanges to monitor the risks of default. For example, the London Clearing House (LCH) – which guarantees the futures and options contracts on the IPE – runs sixteen scenarios every night after the close of business shocking market parameters for each underlying commodity in order to determine the maximum loss that can be expected for each clearing member's overall position. This "worst case" scenario represents the maximum potential loss that one counterparty could incur on the following trading day and is used to determine the initial margin that has to be deposited by the client as a guarantee against default.

The main advantage of the scenario method is that it is mathematically more precise than Greek analysis, especially for large market movements since the value of the trading book is actually recalculated in each case. It is also more flexible since prices and volatilities can be changed by a much larger amount than is possible with the Greeks.

However, selecting scenarios can be difficult. It needs to be done in a very systematic way if it is to provide a useful result. Depending on the size of the trading book, it may also be time consuming and even cumbersome to shock a large number of prices and volatilities and then recalculate the value of the book. In many cases, certain scenarios are only run infrequently, say once a month. One of the main determinants of the number of scenarios that can be run is likely to be the flexibility of the computer system, which may limit how many parameters can be shocked and how frequently scenarios can be run.

Nevertheless, scenarios are an important risk management tool and the assumptions and results should be discussed by risk controllers, traders and managers so that they all understand and accept the risks being taken and the scale of the potential losses involved.

18.4.4 Value at risk

Neither of the two previous methods provides any guidance in selecting realistic potential market moves. An alternative method, is "value at risk" or VAR. Like scenario analysis, VAR shocks each position held in the book, but the likely movement is determined from historical changes in price, volatility and correlation factors for each market parameter and for each maturity using a range of two standard deviations (i.e. 95.4 per cent of all past movements if price changes conform to a normal distribution).

These market moves are then applied to each position in the trading book in order to provide an estimate of the maximum potential loss (within a pre-defined confidence limit) for all commodities and maturities individually, usually over a period of one day. With VAR, the results for different commodities and maturities are then aggregated using correlation factors which are also based on historical data. This aggregation provides a global estimate of the total value at risk for the entire trading book.

The potential loss that the book will face the following trading day is on average smaller than the maximum loss estimated by the value at risk calculation, although there is a small probability (2.3 per cent if a range of two standard deviations is used) that the *loss* will be higher. Another way of looking at this is to say that potential loss incurred by the current positions in the trading book is only likely to exceed the value at risk estimate on about 6 days in the next trading year (there are about 256 trading days in a year). Using a price range of three standard deviations (99.7 per cent confidence limit) for the value at risk estimates will reduce the uncertainty to less than 1 day in the trading year. This analysis, of course, assumes that all the chosen market parameters behave in line with the historical data sample that was used.

The main advantage of VAR is that it provides a simple, objective and concise report for management. It is especially useful for the management of a company which is active in a range of different markets (e.g. precious metals, energy, forex . . .) and needs to compare the risk exposure of the different trading units. It is also easier for management to interpret a single result rather than having to analyse several different “Greek” reports.

In order to monitor and control financial risk, management can set a limit based on value at risk for individual trading units. As a result, management can be confident that the trading loss over the next day should not exceed the value at risk figure on more than 6 days in the year if the calculation is based on two standard deviations. However, management should be aware that value at risk does not show the losses that the company would bear if the market should move drastically in one direction or another, i.e. outside the two standard deviation range on which the calculation is based.

18.4.5 Other tools for risk control

Another tool that is used to help management control the risk of a specific trading book is to set a limit for each trading unit in terms of delta equivalents for particular aggregations of commodities and maturities. Limits can also be set for each risk measure that is applied to the trading book. It is up to the management to decide which limits are needed to control the risks being taken by the various trading desks or individual traders.

It is also important to estimate the costs that a company would bear should it wish to close all its positions. Since all positions are usually valued at the mid-point of market quotes, this exercise values the impact on the company's P&L of buying at the high and selling at the low end of the bid-ask spread. In order to make a complete estimate, any commission, operational costs and management costs should also be taken into account.

18.5 Operations

18.5.1 The role of operations

Inputting and confirming deals

In order to be able to reconcile a company's trading activities with its financial records, *all* deals must be entered into a deal database. This can be done directly by the traders themselves or by the backoffice, either on the day they are transacted or not later than the following day. Once the trades carried out on a particular business day have been recorded, the deal database should be checked for any errors or omissions.

Exchange trades:
All exchange deals should be compared with the summary provided by the company's clearing broker and any discrepancies investigated immediately. Nowadays this process can be carried out electronically. Once all the deals have been confirmed, traders can be informed of the positions they hold with the exchange for each contract and maturity.

A margin call is agreed and settled daily between the clearing broker and the company after all the contracts have been "marked to market" using the closing prices for the previous business day. Companies trading in oil futures and option contracts must pay an initial margin determined by the exchange on any open position, which may change according to circumstances, and then pay a daily variation margin, which represents the change in the market valuation of their open positions from one day to the next. The size of the margin call from the clearing house should match *to the cent* the amount calculated using the company's own internal deal and pricing database. This is a good way of ensuring that all exchange trades and settlement prices are properly recorded.

OTC trades:
All OTC deals should be confirmed with the relevant counterparties. Confirmation procedures vary and it will be necessary to involve the company's legal department in order to ensure that the appropriate documentation is exchanged with clients in due time.

Inputting market prices and volatilities

Since market prices and volatilities are required to calculate the replacement value of deals it is essential to maintain a comprehensive and accurate database of settlement prices and option premiums. While the prices of most exchange-traded contracts and a number of the most widely-used OTC reference prices, such as *Platts* Brent dated, can be downloaded electronically from sources such as *Reuters*, other market price data might have to be entered by hand.

Calculating invoices and following up payment

Settlement prices need to be recorded to allow the calculation of averages which are used to settle OTC contracts such as swaps and Asian options. A sophisticated data-handling system might automate this process, including the generation of invoices. Once the invoice is calculated, the operations department needs to ensure that the correct amounts are paid or received by the company for each deal.

Calculating ledger P&L

At the end of each month, the operations department should prepare a P&L report which combines the valuation of open trading positions with the company's ledger for closed positions.

18.5.2 Input errors

Data input errors
Nowadays, companies rely more and more on electronic feeds to data-handling systems, either from in-house sources or external suppliers. However, some data is still entered by hand and the consequences of an input error can be serious for a company. For example, a trader might take a bad hedging decision as a result of the wrong information about trading positions. This could easily arise if data on prices or quantities are entered incorrectly, for instance recording a deal as a purchase instead of a sale (or vice versa).

Although the margin call check will highlight mistakes made on exchange trades, it is more difficult to spot errors that occur while inputting OTC trades. Errors can be identified by double-checking the input, by monitoring the confirmations exchanged with counterparties, or by noticing that an invoiced amount disagrees with that calculated by the client.

In the case of linear instruments, such as futures or swaps, data input errors will only have an impact on the company's P&L. However, in the case of other, non-linear, deals such as exchange-traded options, OTC Asian options or any exotic "structured" deals, data input errors might also affect the company's risk parameters (Greeks) as well as its P&L.

Incorrect invoices

It goes without saying that the amount invoiced for a deal must correspond to the amount used for the P&L calculation, unless the invoice is incorrect.

Another important responsibility for the operations department is controlling the company's cash flow. This means verifying that every invoice or margin call is properly settled and that the company pays or receives the correct amount at the right time. Failing to do so can jeopardise the company's cash flow.

Double-checking is probably the best way to minimise these sorts of errors.

18.5.3 Missing tickets

One of the most difficult areas for the operations department to control is missing or superfluous tickets, which can be a problem for OTC trades. For example, there may be extra tickets for non-existent trades or missing tickets for trades that have taken place, which could be either the result of fraudulent activity or genuine omissions by traders. The only way to detect that the trading records on the company's system are incomplete or incorrect, is when confirmation is received from clients. Experience shows that a thorough comparison of confirmations received with deals recorded on the database helps to expose gaps in the company's knowledge of specific transactions. However, spotting missing trades depends on whether the company sends the confirmation out or receives it.

18.5.4 Settlement errors

Wherever possible, market prices should be downloaded from existing sources in order to minimise input errors. However, some quotes are not available from official sources and have to be entered manually. Incorrect prices or volatilities will result in the company using the wrong delta equivalent for options, and trading decisions will be based on the wrong assumptions since the book will be marked to market incorrectly and therefore provide inaccurate risk parameters.

Input errors with prices will have different consequences depending on whether the price is being used for valuing positions or whether it is being used for calculating averages. Prices used to value the trading book at a specific date are regularly updated for each valuation, therefore mistakes should be noticed whenever a new valuation is performed. However, prices used to construct an average are accumulated and errors in recording a spot price settlement may not be noticed at the time and will generate incorrect averages and therefore the wrong invoice amounts.

It is important that price information is shared by a maximum of number of units and users in the company in order to increase chances of spotting inaccurate market parameters.

18.5.5 Controlling operations

Senior management and traders base some of their decisions on the risk analysis and P&L reports. One of the important functions of the risk control unit is to confirm the accuracy of these reports. In order to ensure this, the following steps should be taken:

- The operations department and the risk control unit must agree on all the procedures necessary to provide the information required by the risk control unit.
- The risk control unit must define which operational controls need to be in place in order for it to feel confident when signing off P&L or risk analysis documents. Some checks might be performed randomly and some at regular intervals. Checks on prices and deals could be controlled randomly, while a regular data check should be performed, for example, at the end of the month.
- The systems used to help with the valuation of a trading book may vary, however it is usual to have a single system to value realised and unrealised positions. The valuation report must tie up with a result which combines cash received or paid (ledger) plus the valuation of open positions.
- The risk control unit also needs to sign the ledger P&L. In order to do so, accounting procedures must also be known to and approved by the risk control unit.

18.6 Conclusions

Risk should be reported on a regular basis – normally daily – both to traders and to managers. Traders need a more detailed risk report to manage their positions effectively, but managers want a concise report which provides an overview. Both traders and managers need to understand which criteria and levels of aggregation have been selected for specific reports.

Traders are expected to comment on risk reports, especially pointing out any P&L result or "Greeks" that look incorrect. Although it is up to the controlling unit to initiate risk scenarios, traders can also request specific scenarios based on their view of the market. Managers also can request specific scenarios to be run, especially those which have an interaction with other trading units. There should be regular discussions between traders and management in order to ensure that risk reports are properly acknowledged.

Any trading entity should make sure that it obeys and conforms to the rules and regulations of the different regulatory authorities, such as the US Commodity Futures Trading Commission* (CFTC), the UK Securities and Futures Authority† (SFA), and the Bank for International Settlements§ (BIS). All regulatory authorities require specific information at regular intervals which the controlling unit should be responsible for preparing and supplying (see Chapter 17).

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* www.cftc.gov

† www.fsa.gov.uk/sfa

§ www.bis.org

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