GTM

Gas Trading Manual

WOODHEAD PUBLISHING LIMITED

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Gas Trading Manual is dedicated to the memory of Geoff Moore who, sadly, did not live to see the first edition printed. Despite his illness, Geoff was very determined to see GTM through to completion, and it has benefited from his insights and attention to detail right up to the final proof stages. His clear ideas and wealth of experience helped to shape GTM. We will all miss him.

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Gas Trading Manual

Edited by David Long and Geoff Moore

Second edition
Edited by David Long and Gay Wenban-Smith

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Introduction

The natural gas industry is undergoing far-reaching changes as governments seek to create a more liberalised market structure. End-use markets are being opened up to competition, requiring new ways of doing business and creating opportunities for new participants. Short-term trading is replacing long-term contracts and companies are no longer allowed to occupy monopoly positions. Pricing has become more transparent and new risks have been created as the supply chain is broken up into its constituent parts. As a result, gas is becoming much more of a commodity business, acquiring many of the same features as its associated hydrocarbon, oil.

Gas Trading Manual (GTM) — like its sister publication, *Oil Trading Manual (OTM)* — therefore sets out to provide a comprehensive guide to the many different aspects of the evolving gas market that is accessible to all those involved in the business, whether they are gas industry professionals, commodity traders, accountants, lawyers, bankers, fund managers, consultants or utility managers.

GTM is divided into four complementary parts. The first part, Introduction to gas trading, covers the fundamentals of the gas market, geography, market structures and the new gas trading instruments, including weather derivatives. The second part, European gas markets, examines the key role of the EU Gas Directive in changing the structure of the European gas market and deals in detail with the UK traded gas market, the prospects for competition in Continental Europe, the IPE natural gas futures contract, OTC gas trading contracts, the On-the-day Commodity Market (OCM) and the Network Code, take-or-pay contracts and gas pricing. The third part, Administration, deals with the essential 'back room' aspects of gas trading operations, including internal control frameworks, accounting for derivative instruments, and the taxation of gas trading. And the fourth part, Gas and electricity, looks at the role of gas in power generation and the growing convergence of the gas and electricity markets.

Although GTM focuses initially on the UK and the developing European gas markets, it is intended that future updates will extend its coverage to the highly-developed market in North America and the other emerging gas markets.

We hope that you will find it useful.

David Long
Geoff Moore
Editors

Acknowledgements

Compiling *Gas Trading Manual* presented many challenges, not least the rapidly-evolving gas market itself. Particular thanks are therefore due to our fellow contributors who have not only maintained their enthusiasm for the project throughout, but also provided the necessary updates as new developments occurred.

Thanks are also due to Martin Woodhead and Neil Wenborn at Woodhead Publishing for suggesting the idea of a sister publication to *Oil Trading Manual* for the gas market and providing us with the opportunity to work together. And to Mary Campbell and Cheryl Nice for their diligent and supportive copy-editing.

We would also like to thank all those who have generously provided us with maps, illustrations, data for graphs (including prices), and other materials used to enhance the text.

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GCM

Preface to second edition

Much has changed in the gas market since the first edition of *Gas Trading Manual* was published. Some of these changes were to be expected, others came as a complete surprise. Progress has continued towards greater market liberalisation, but the balance of power has shifted. European gas and electricity markets are gradually being opened up to competition and EU energy ministers have finally agreed to speed up the process, setting a new target date of July 2007 by which all consumers must be able to choose their supplier. However, the nature and identity of the participants is changing. The collapse of Enron forced everybody to re-evaluate the role of trading in their business and many have scaled back their activities. At the same time, mergers and acquisitions are restructuring the corporate landscape, creating big new multinational utility companies with different priorities. Nevertheless, trading is here to stay – even if it no longer leads the way – and the opening up of the European gas and electricity markets continues to foster the development of new market structures wherever they are needed.

We would like to thank all our contributors – and those who have generously provided us with maps, illustrations, data for graphs (including prices) and other materials – for their support in preparing the second edition of *GTM*. Geoff Moore's experience of and insights into the changing market for gas ensured that we have a sound foundation for this and future editions, making our task easier than it might have been. We would also like to thank Neil Wenborn at Woodhead Publishing for his extensive help and support in preparing this second edition, and Mary Campbell and Alex Harrington for their careful copy-editing.

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In order of appearance

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Before his untimely death in July 2001, Geoff Moore was a Senior Associate Consultant at Gas Strategies, working on gas trading operations and the progress of liberalisation in Europe. He worked in the UK gas industry for most of his employed life, always at the 'sharp end', dealing with UK gas supply contracts, foreign trade and the major political issues. He spent many years in a senior role at British Gas analysing and negotiating gas purchase agreements. In recent years he was involved closely with the UK-Continent Interconnector pipeline and developments in the competitive gas market in both the UK and North America. He spent a year with Natural Gas Clearinghouse (NGCH) in Houston before joining Accord Energy Ltd (a major market maker in spot gas) back in London, where he worked as an employee and, subsequently, as a consultant for several years.

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Abbreviations

ACQ	Annual Contract Quantity
AEEG	L'Autorita per l'energia elettrica e il gas
AMT	alternative minimum tax
AOT	Approved Oil Trader
APX	Amsterdam Power Exchange (Netherlands)
APX	Automated Power Exchange (UK)
BCC	British Coal Corporation
Bcf	billion cubic feet
Bcm	billion cubic metres
BG	British Gas
BGC	British Gas Corporation
BGT	Britsh Gas Trading
BOM	balance of the month
BP	British Petroleum
BSGM	British Spot Gas Markets
Btu	British Thermal Unit
C	Centigrade
CCGT	combined cycle gas turbine
CDD	cooling degree day
CEGB	Central Electricity Generating Board
cf	cubic foot
CFC	controlled foreign corporation
CFD	contract for difference
CFM	Compagnie Française de Methane
CHP	combined heat and power
cm	cubic metre
CME	Chicago Mercantile Exchange
CNG	compressed natural gas
CP	contract price
CV	calorific value
DCQ	daily contract quantity
DFN	daily flow notifications
DG-Comp	Competition Directorate of the European Commission
DGGS	Director General of Gas Supplies
DG-IV	former name of DG-Comp
DM	daily metered
DQ	quantity of gas traded on a given day
DSEC	daily system entry capacity
DTI	Department of Trade and Industry
EC	European Community
ECJ	European Court of Justice
EdF	Electricité de France
EDP	Electricidade de Portugal
EDSP	exchange delivery settlement price

EEC	European Economic Community
EEX	European Energy Exchange
EFET	European Federation of Energy Traders
EFP	exchange of futures for physical
EOR	enhanced oil recovery
ESB	Electricity Supply Board (Ireland)
ESGM	European Spot Gas Markets
ETM	energy trading and marketing
ETS	Energy Trading System
EU	European Union
F	Fahrenheit
F&D	finding and development
FAS	Financial Accounting Standard
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission (US)
FGD	flue gas desulphurisation
FM	Flexibility Mechanism
FRS	Financial Reporting Standard
FSA	Financial Services Authority (UK)
FSU	Former Soviet Union
GALP	Petroleos e Gas de Portugal
GCC	Gas Consumers Council
GCV	gross calorific value
GdF	Gaz de France
GDP	Gas de Portugal
GFU	Gasssforhandlingsutvalget, Norway
GJ	Gigajoules
GME	Gazoduc Maghreb Europe
GOAL	Generator Ordering and Loading
GRP	gas reference price
GSO	Gaz de Sud-Ouest
GWh	Gigawatt hours
HDD	heating degree day
H-gas	high calorific value natural gas
HSA 99	Hub Services Agreement, 1999
HSA 2001	Hub Services Agreement, 2001
ICE	Intercontinental Exchange
ICF	incomplete combustion factor
IEA	International Energy Agency
IMO	independent market operator
IOSCO	International Organisation of Securities Commissioners
INS	Incentivised Nominations Scheme (UK)
IPE	International Petroleum Exchange
IPP	Independent Power Producer
ISDA	International Swaps and Derivatives Association
J	Joule
Kcal	Kilocalories

KCBT	Kansas City Board of Trade
kWh	kilowatt hour
LCH	London Clearing House
LDC	local distribution company
LDZ	Local Distribution Zone
LIBOR	London Interbank offered rate
LIFFE	London International Financial Futures and Options Exchange
LME	London Metal Exchange
LNG	liquefied natural gas
LNOC	Libyan National Oil Corporation
LPG	liquefied petroleum gas
LPX	Leipzig Power Exchange
LTI	long-term index
LTS	low-pressure transmission system
Mcf	thousand cubic feet
Mcm	thousand cubic metres
MMbtu	million British Thermal Units
MMC	Monopolies and Mergers Commission (UK)
MMcf	million cubic feet
MMcm	million cubic metres
MSEC	monthly system entry capacity
MV	market value
NBP	National Balancing Point (UK)
NCV	net calorific value
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NGL	natural gas liquids
NGTA	New Gas Trading Arrangements
NGV	natural gas vehicle
NTPA	negotiated third-party access
NTS	National Transmission System
Nymex	New York Mercantile Exchange
OCGT	open cycle gas turbine
OCM	On-the-day Commodity Market
OFFER	Office of Electricity Regulation
Ofgas	Office of Gas Supply
Ofgem	Office of Gas and Electricity Markets
OFT	Office of Fair Trading
OTC	over-the-counter
OTM	Oil Trading Manual
OTO	Oil Taxation Office
PES	Public Electricity Supplier
PGNiG	Polskie Gornictwo Naftowe i Gazownictwo
PGT	Public Gas Transporter
PJ	Petajoules
PPA	Power Purchase Agreement
PPI	producer price index

PPP	Pool Purchase Price
PPX	Polish Power Exchange
PRT	Petroleum Revenue Tax
PSP	Pool Selling Price
RbD	reconciliation by difference
REC	regional electricity company
RGTA	Reform of Gas Trading Arrangements
RIE	Recognised Investment Exchange
RMC	risk management committee
RPI	retail price index
RV	remaining contract value
SDP	seller default price
SEC	Securities and Exchange Commission
SG	specific gravity
SES	Stock Exchange of Singapore
SG	shortfall gas
SGX	Singapore Exchange
SI	Soot Index
Simex	Singapore International Monetary Exchange
SMBP	system marginal buy price
SORP	Statement of Recommended Practice
SPP	Slovensky Plynarensky Priemysel
Tcf	trillion cubic feet
Tcm	trillion cubic metres
TCO	Trading Control Officer
TGSA	Troll gas sales agreement
th	therm (100,000 Btu)
th	*(also)* thermie
THT	tetrahydrothiophene
TTF	Title Transfer Facility (Netherlands)
UAE	United Arab Emirates
UF	Union Fenosa
UK	United Kingdom
UKCS	UK Continental Shelf
UKPX	UK Power Exchange
US	United States
USA	United States of America
USRPI	United States real property interest
VAT	Value Added Tax
VLDMC	very large daily metered customers
VV-gas	Verbandevereinbarung für Gas
WACOG	weighted average cost of gas
WPI	wholesale price Index
ZBT 99	Zeebrugge Natural Gas Trading Terms and Conditions, 1999
ZBT 2001	Zeebrugge Natural Gas Trading Terms and Conditions, 2001

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1 Changing nature of the gas trade

Geoff Moore and Gay Wenban-Smith, Independent Consultants

1.1 Prologue

There has been a commercial transformation in the gas industries of some of the major consuming countries that is as radical as some of the great technical revolutions – for example, the conversion from manufactured gas to natural gas, or the development of Liquefied Natural Gas (LNG) for long-haul gas transportation.

Because this commercial revolution has taken place over a number of years, and because, in some senses, it has been a government administered process, it has not always been seen as having world-wide application. However, like many commercial activities in a world of reasonably free trade, it is spreading from its originating economies of North America to Europe via Great Britain changing the organisation of the natural gas industry, creating opportunities for entrepreneurs and establishing new market structures for trading gas.

In Britain, a short-term traded gas market must now be regarded as established. There is a recognised 'market price' for gas that is now also being used in longer-term gas purchase contracts. And there is considerable interest in developing gas trading markets in the Continent of Europe and beyond wherever the gas market is liberal and competitive – at least at the wholesale level – as it is, for example, in some of the Mercosur countries of South America.

But there has not yet been a complete transformation in Europe. Although some countries have grasped the new ideology with enthusiasm, some have not. And some individual industry players are large enough to obstruct changes that threaten their interests. The European Union is finding that it cannot single-handedly enforce new regimes, and that it has opponents within.

Gas Trading Manual (GTM) is about this transformation and the development of gas trading, which constitutes a very major part of it.

1.2 Definitions

Gas Trading Manual (GTM) is indeed a 'manual' – a work of reference rather than bedtime reading. Its loose-leaf format is designed for updating as time goes on and as the world gas industry changes at a quickening pace. It is compartmentalised so that any topic of interest can be clearly identified and used selectively. Though no one chapter can stand entirely on its own without some prior knowledge of the industry, it is intended that the cumulative effect of selective reading will give a thorough grounding in the chosen subject of 'gas trading'.

By 'gas' we generally refer to natural gas, mainly methane, which is defined and described in detail in **Chapter 2** *Fundamentals of the gas market*. The days of manufactured gas are not entirely over as significant pockets of its use remain. Indeed a man-made substitute for natural gas may well be required in the future. The convenient properties of gas as a form of energy and the vast investment in the gas infrastructure will work to prolong its use when exhaustion of reserves becomes an issue.

The word 'trading' is used generally in the manual in its widest form – almost synonymous with 'commerce'. However, the main emphasis of GTM is a slightly narrower meaning that identifies and concentrates on the radical reform that the gas market is experiencing in many parts of the world. Trading here is used with the meaning of short-term, innovative, even speculative trading as is familiar in 'spot markets' for other commodities. This meaning is similar to that attached to oil trading, characterised and explained in our sister publication *Oil Trading Manual* (OTM).

1.3 Gas market structures

1.3.1 International gas trade

The conventional view, at least until the last decade, was that gas did not travel well. Gas, being less dense than oil, is comparatively expensive to transport. It does not figure in world trade in the way that oil does, despite the fact that its points of production and consumption are very similar to those of oil. This is not surprising as gas is – to a large extent – a joint product with oil and the energy hungry parts of the world are also natural markets for gas.

Though gas travelled thousands of miles in liquefied form well before the last decade, this was an expensive and somewhat freaky activity. Bulk long-haul gas transportation by pipeline always seemed to be associated with, or attributed some element of subsidy, reflecting – perhaps – the perceived riskiness of investing in transportation infrastructure. Some evidence to support the view is to be found in the statistic that only 22 per cent of world gas production enters international trade, compared with 59 per cent for oil[1].

Along with the view that gas is an essentially local activity was a belief that long-term contracts were endemic to the gas industry to give security of supply for importers and, as discussed further below, to justify the investment in infrastructure. The so-called conventional view is challenged, if not debunked, in **Chapter 3** *The geography of gas,* and it is proposed that these long-term contract structures must inevitably adapt as economics and attitudes develop.

1.3.2 Influence of infrastructure

Another, perhaps dated, view is that gas infrastructure is so costly and largely immovable that it requires a monopoly or franchised structure to bring it into existence and regulation to prevent abuse of that monopoly and to protect those who have no short-term substitute fuel available. Very often, the incumbent monopoly is state owned rather than private in order to maintain control and to make sure the strategic nature of the initial investment is taken into account.

Frankly this is still the model for most developing or 'greenfield' gas markets and grids though, as GTM describes, some mature gas markets are putting aside monopolies and their regulation to allow market forces to motivate and rule the gas chain from well-head to point of consumption. It is uncertain whether newly competitive markets will send sufficient market signals and incentives to ensure sufficient investment in infrastructure. Particular difficulties might occur in the

[1] BP Statistical Review of World Energy, 2002.

period of transition between secure monopoly markets and stable liberalised structures.

A new form of regulation has emerged which, though sounding a contradiction in terms, is regulation *of* competition (or *for* competition) – replacing, in time, the regulation of the incumbents. This makes the word deregulation, often applied to the process of liberalisation, a little misleading.

1.3.3 Industry structure

Early gas industries round the world have usually been structured as regional private companies, set up to manufacture gas from coal or other hydrocarbons and to distribute it through a small local network, covering an area perhaps only as large as a town. The advent of natural gas in large quantities led to economic supply over an integrated national infrastructure network. Because the supply of these volumes of gas involves considerable investment and long-term planning, as well as the national interest, in most countries the natural gas industry has ended up in the hands of very few large players, often state-owned or controlled.

The next development from this situation was the realisation that not all parts of the gas business formed a natural monopoly. The start of the gas trading story was the break up of the great monopoly structures and the opening of markets to competing players. Today in the US and UK, and to a lesser extent in Continental Europe, there are now many companies actively involved in the different parts of the gas supply chain.

The traded gas market is a secondary or wholesale market, largely in short-term gas, and gas trading, which is the subject of this Manual, can be an effective method of dealing with the new situations that have opened up as a result of the commercial revolution. It has attracted a number of entrepreneurs, who could see good business opportunities arising from liberalising markets.

As with most commercial processes, changes have not always been smooth, and power playing among some of the entrepreneurs has led to turbulent times. One major trading company, Enron, has already gone bankrupt and others have been under investigation by the US regulatory authorities. Some have been forced to sell substantial assets to avoid bankruptcy. The weakest firms have had their credit lines cut and lending terms tightened – even before the current chaos most energy traders only just got an investment grade credit rating and now some are junk-rated.

The splitting of national monopolies into a number of smaller parts, as has happened in Great Britain, has also led to many changes of ownership of companies and assets. Market volatility has reinforced the importance of cash flow and credit lines to staying afloat in competitive seas. Together with recent trading problems, this makes it even harder than usual to perceive the realities and make effective long term projections.

However, one positive outcome of the turmoil in the gas trading business is that new and different participants are entering the market, including banks with the necessary deep pockets. All the authors in the Manual are convinced that the future of gas trading is assured, or, at least, only dependent on the progress of the liberalisation revolution.

1.3.4 Long-term contracts

Markets for *natural* gas are generally of two main forms, depending on whether there was a pre-existing gas market and infrastructure. Where a gas industry exists already – as it did in some parts of Europe and North America – the infrastructure is usually based on the manufactured gas technology with gas retailing managed by a single large wholesaler, the Local Distribution Company (LDC). In this case, natural gas has to be introduced by a process of conversion of gas-burning appliances and a considerable refurbishing of gas mains and storage facilities.

The expense and complexity of this task generally led in the past to pressure for long-term contracts of some considerable longevity (20–30 years) to justify the investment. Generally speaking, both producers and buyers were agreed on the desirability for such contracts for their respective investment needs.

In completely greenfield areas, where gas is being introduced for the first time, there is also a tendency to require long-term supply arrangements. In order to bring about a fast build-up of contracted quantities, there is usually a very large consumer, or two, involved. In many parts of the world, a contract to supply a power station or a fertiliser plant is an integral part of the infrastructure development, contracts with LDCs following on at a later stage.

Such customers are sometimes also very important or essential to the first model described above – conversion from manufactured gas. In many markets, therefore, the wholesale price of gas is established (often by secret negotiation) between a producer oligopoly and a buyer monopoly/oligopoly.

In either model, it is not unknown for the producers to aspire to supply the larger customers directly by becoming, to a large extent or exclusively, the bulk pipeline entity. Their desire to enter public distribution has generally been much less. Continental Europe is a good example of producer participation in pipelines but not, generally, LDCs. Producer participation, however, resulted in less than full-scale competition in the end-use markets.

In Britain, too, the producers saw more potential profit in supplying the larger industrial customers but politics dictated that a pipeline and distribution monopoly should be maintained – for a while at least. Indeed, some sympathy may be due to a monopoly or franchised company that was deemed necessary to carry out the organisation and investment in infrastructure for the introduction of natural gas, only to be dismembered and replaced by competition by many players once the network was safely in place.

Views on this will, of course, depend on the acceptability of their behaviour while acting as the incumbent. The fact remains that no widespread gas infrastructure has been built on the basis of a short-term market, though such infrastructure, once built, might well be maintained on that basis. US and UK experience suggests that not all new gas field developments require a long-term contract for sale as long as a liquid short-term market exists.

Some would argue that this may be because both the markets and the gas infrastructure in these countries are already mature, lowering the risk for new investments requiring only incremental expenditure. But this observation would not necessarily apply to gas entering long distance international trade, which traditionally has required the guarantees provided by long-term contracts. Owners of existing pipelines can be remunerated as transporters or carriers but a question remains whether large-scale new projects would be undertaken.

Evidence from North America is mixed, but recently constructed pipelines have mostly been underwritten (in theory at least) by long-term ship-or-pay contracts. Recent ten-year contracts between Centrica in the UK and Statoil in Norway and Gasunie in the Netherlands also demonstrate that, even in the seriously liberalised UK, there are still needs that can be best fulfilled by longer term arrangements.

The different markets for gas in Europe and their state of development are the subject of **Chapter 4** *The different markets for gas.*

1.4 Developing trading markets

1.4.1 Origins

Short-term traded markets develop in economies where there is competition – that is, new players can enter and there are enough potential counterparties for there to be a liquid and transparent market. The first short-term traded gas market was created in the USA, where there was already competition at the level of bulk pipelining – though it must be accepted that the process was initiated and aided by government policy. In Britain, the former predominantly uncompetitive, franchised structure has been replaced – through government intervention – by a more competitive environment that has both supported and encouraged the development and growth of short-term traded gas markets.

Chapter 5 *Gas trading instruments* covers the basics of gas trading together with the more sophisticated trading instruments now in use, i.e. derivatives of the physical short-term gas market. **Chapter 6** *UK traded gas market* sets out what happened in the UK, and why it did. In Continental Europe, the process is less well advanced, and **Chapter 7** *Prospects for competition in Continental Europe* outlines the developments so far and speculates about future trends.

1.4.2 Gas trading activities

There are several reasons for the emergence of short-term trading in the gas market. Most immediate is the need for shippers to balance their supplies and demands as traditional long-term contract structures are replaced with less flexible and more competitive short-term arrangements. Producers may also have short-term gas to place in the market. Associated with these physical trades are forward paper trades, as traders and gas professionals seek to manage the price and volume risks created by the new competitive market structures. In addition, there are opportunities to make margins by more speculative commodity trading.

Gas 'trading' in the narrower sense set out above is now well established in North America and the UK. It is also beginning to be seen in Europe and in South America. GTM describes the newer type of traded market contracts, as they apply in the UK, for both over-the-counter (OTC) and exchange traded markets. Exchange traded contracts in the UK are dealt with in **Chapter 8** *IPE natural gas futures*. **Chapter 9** *UK gas trading contracts* covers the UK and Zeebrugge OTC markets and includes sample contracts.

Gas trading developments are, naturally enough, heavily influenced by the regime governing the use of the pipeline system. Particular points of interest are the costs and ease of transaction, the services provided by the transporter and the input and output balancing requirements of the gas shippers. In the UK, for example, trading has been boosted by the Transporter (Transco) facilitating trading On-System, at what is called the National Balancing Point (NBP). Whether Continental transmission companies will do the same could have an enormous impact on the trading prospects in Europe. **Chapter 10** *OCM and the Network Code* explains the UK regime.

1.4.3 Gas prices and contracts

In the most developed short-term markets, the changes have been associated with a decline in long-term contracts. Nevertheless, as described above, long-term contracts still appear to have an important role to play even in the UK, and they will remain the norm in less liberalised regimes. GTM describes the famous take-or-pay provisions of these long-term contracts and discusses their enforceability and their relatively complex price provisions in **Chapter 11** *Take-or-pay contracts* and **Chapter 12** *Gas pricing arrangements*.

1.4.4 Commercial aspects

The development of short-term gas trading has also created a demand for new operational and managerial information and control systems. As well as dynamic 'front-office' traders, companies need effective 'back-office' procedures to keep track of the deals that are being done and to measure and monitor their impact on company profitability, risk exposure and tax liabilities. These, more practical aspects of the traded gas market, are dealt with in **Chapter 13** *Running a gas trading business*, **Chapter 14** *Accounting*, and **Chapter 15** *Taxation of gas trading*.

1.5 Gas and electricity

1.5.1 Gas in power generation

By far the fastest growing market for gas worldwide is in power generation. This is because of the favourable economics brought about by the high efficiency of combined-cycle gas turbines (CCGTs) and the environmental advantages of using natural gas in that application. **Chapter 16** *Gas in power generation* is devoted to this subject.

From a gas trading viewpoint, this development has the potential for a huge impact. Gas powered generators have been an 'engine' for the developing trading markets and have opened up the opportunity of arbitrage between the two products. The prices, adjusted as they must be, by efficiencies in use and other physical characteristics, have hardly converged even in the most advanced markets but the possibilities must be kept under review by participants.

1.5.2 Forces for convergence

There are many parallels between developments in the gas market and the electricity or power markets. These are not confined to the evolution of trading. In countries where gas has been, or is being, liberalised it has been natural to see the same process in power as in gas, indeed it would seem inconsistent if this were not the case. Therefore, there is a tendency to adopt the same legislative/regulatory regime.

In some countries, gas seems to have led electricity in terms of timetable (for example, the USA) and in others the first major steps were in electricity (European Union countries as a whole). In the UK, the power market was reformed before gas, but the shortcomings of that reform seem now to have left gas as the leader in terms of the desired market structure.

The development of competition has had the effect of reducing margins and making unit cost reduction critical to success. As a result, companies that were retailers or wholesalers of gas or electricity have attempted to spread their overheads and make the best use of their equipment and data bases by joint marketing of gas and electricity. Many have also extended their reach to other conventional utility services, such as telecommunications, and commercial services such as finance and insurance. Where downstream companies are marketing both gas and electricity, they are, only to a faintly lesser extent, trading in both.

The trading and marketing techniques are tending to converge except when the essential differences in product prevent this. The cultures of the respective industries have also changed in a similar way. Under the old regimes of monopoly franchises and public ownership both the gas and electricity industries tended to be engineering dominated and this was reflected in top management.

The focus is now changing much more to customer interfacing and the commercial aspects of the business. Large multi-utilities, which are both horizontally and vertically integrated, are beginning to dominate commercially in some areas as the synergies and similarities between energy, water and telecommunications are fully recognised. The traditional municipal multi-utility (or LDC) may experience an escape from the patronage (or patronising!) of the old incumbent pipeline or grid company to be embraced by a wholesale multi-utility supplier.

In a separate development, there have been several joint ventures between gas shippers and end-users. Because of the way the UK Network Code and On-the-Day Commodity Market (OCM) work, there are often opportunities for large customers such as power generators to agree with their shipper to divert gas supplies to the OCM.

As the business approaches and personnel of gas and electricity companies come together, the culture as well as the trading and marketing methods and technology are converging also. This convergence is reflected in the competitive regime with regulators working more closely together or, in some countries, merging. The market changes and implications are covered by **Chapter 17** *Convergence of gas and electricity markets*.

2 Fundamentals of the gas market

David Long, Oxford Petroleum Research Associates

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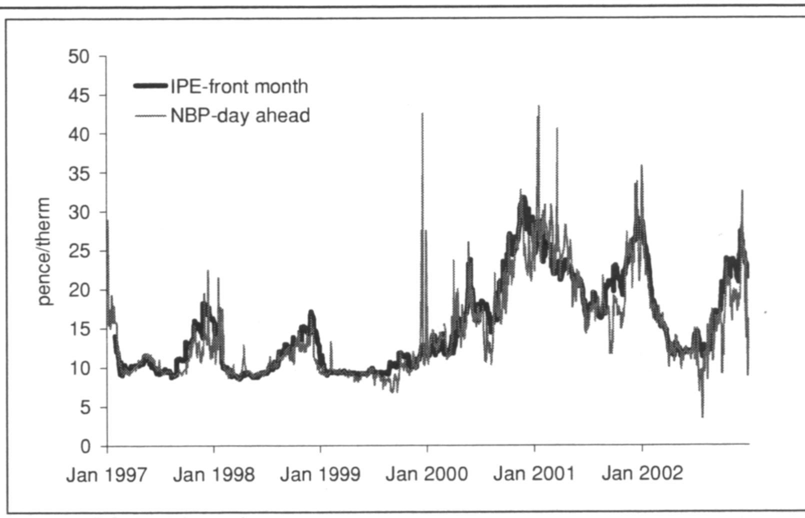
2.1 Characteristics of the gas market

The natural gas market – in most parts of the world – is in transition from a long-term contract, natural-monopoly utility market to a much shorter-term competitive energy commodity market. These important structural changes, which started in the US in the late 1970s and in the UK during the 1990s, are being driven by government policy rather than the gas industry itself. In recent years they have been spreading to Continental Europe with the implementation of the EU Electricity and Gas Directives. As a result, natural gas prices are now being determined in the short term by over-the-counter (OTC) trading and futures exchanges rather than by formulas linked to the price of oil or other competing fuels – but the link to oil still remains in many long-term contracts, upstream joint production and downstream inter-fuel competition, especially in power generation.

The advent of gas trading, combined with physical and technical constraints combine to make natural gas prices very volatile in the short-term (see Fig. 2.1). Gas demand is highly variable, both within the day and throughout the year, and depends crucially on the weather. Although these variations are predictable in a general sense – for example, at seasonally normal temperatures – the inherent uncertainty of the weather (both for heating and cooling demand) makes precise forecasting impossible, even over as short a time horizon as a day ahead.

Demand uncertainty alone would not necessarily make for a volatile market if gas supply was sufficiently flexible to cope with unexpected variations in demand. But gas supply is relatively inflexible



Source: IPE, Petroleum Argus

Figure 2.1 Gas price volatility

partly because it is limited by production constraints, but primarily because of fixed existing pipeline capacity, the time taken for molecules of gas to travel down a pipeline (not the case for electricity) and limited local storage opportunities. As a result, natural gas prices are more volatile than oil prices but less volatile than electricity prices, where storage opportunities are very limited indeed. Compared with other commodities and the wider financial markets, natural gas prices are highly volatile and managing price volatility is now a primary concern for companies operating in the new competitive gas markets.

2.2 Natural gas

2.2.1 What is natural gas?

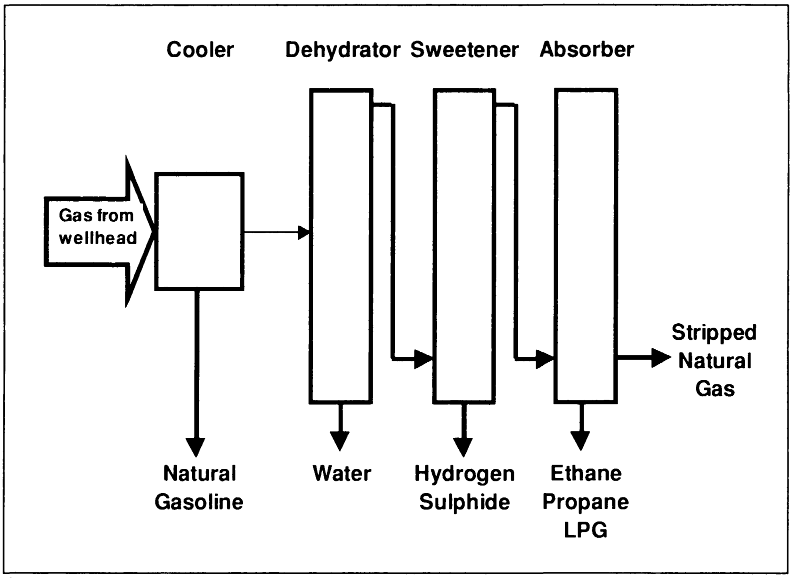
Natural gas is a clean fossil fuel with many uses. Its key constituent is methane – the simplest form of hydrocarbon molecule, comprising one carbon atom attached to four hydrogen atoms – which combines with oxygen when burnt to form carbon dioxide and water. Methane is a colourless, odourless gas which usually burns with a blue flame, but if there is not enough oxygen present for complete combustion the flame turns yellow indicating the presence of soot (pure carbon) and the poisonous by-product, carbon monoxide. The characteristic smell of natural gas as sold to the consumer is added, either by the pipeline transmission company (as in the UK, where National Grid Transco also owns the local grid) or by the local distribution company (as in the US and Continental Europe), to make it easier to identify leaks.

Pipeline gas is not a uniform product since the heat released by burning (its calorific value) depends on the proportions of its other constituents – mainly carbon dioxide, nitrogen and hydrogen – which depend on where the gas comes from. Increasing amounts of carbon dioxide and nitrogen that dilute natural gas reduce its calorific value. Calorific value is a key quality constraint for entry to gas pipeline networks and producers must be able to supply natural gas which meets the relatively narrow quality specifications laid down by pipeline operators (see below).

Natural gas, like crude oil, is produced by drilling into underground reservoirs where hydrocarbons were trapped millions of years ago. It generally occurs at high pressure and does not require secondary recovery (as with oil), although it may require compression for onward transmission via pipelines. Natural gas and oil are usually found together, albeit in very different proportions – all natural gas produced has some liquid hydrocarbons associated with it and all crude oil contains some natural gas – but there are three main forms:

- associated gas, produced with crude oil and separated at or close to the well-head, also known as casinghead gas, oilwell gas or dissolved gas;
- gas condensate, a two-phase mixture of light hydrocarbons from which natural gas can be separated; and
- dry (or non-associated) gas, light hydrocarbons in gaseous form.

In addition methane is also recovered from coal deposits (coal-bed methane), tight sandstones, shales, decomposing biomass, landfill sites and animal waste gases. About three-quarters of the natural gas



Source: Industry

Figure 2.2 Natural gas processing

produced in the US now comes from dry gas fields. Associated gas production rates are usually relatively inflexible and determined by oil field economics (although there are exceptions), but dry gas fields can be operated much more flexibly and are often used for swing production as an alternative to storage to meet the seasonal variation in gas demand.

Once natural gas has been recovered from an underground reservoir it needs to be treated (refined) to remove sand, impurities such as water and hydrogen sulphide, and to recover any other heavier gaseous and liquid hydrocarbons that might be present and which can be sold separately as 'natural gas liquids' or NGLs (see Fig. 2.2). With growing natural gas consumption, NGLs have become an important source of liquid petroleum, providing around 7 per cent of total world oil supply and over a quarter of US domestic oil liquids production. NGLs are used to produce liquefied petroleum gases (LPGs) such as butane and propane, as motor gasoline blending components and as raw materials for the petrochemical industry.

The composition of natural gas varies widely from reservoir to reservoir although the basic hydrocarbon constituents are usually the same – mainly methane together with significant amounts of ethane and propane, also small amounts of heavier hydrocarbons such as butane, pentane, hexane and heptane – all of which can be recovered by simple processes which rely on the different physical properties of each type of hydrocarbon (see Table 2.1). Natural gas with a relatively high proportion of liquefiable heavy hydrocarbons is described as 'wet' or 'rich', while gas with a low proportion of heavy hydrocarbons, or gas that has been processed to remove liquefiable heavy hydrocarbons, is described as 'dry' or 'lean'.

Table 2.1 Typical composition of natural gas (by volume)

Methane	CH_4	70-90%
Ethane	C_2H_2	
Propane	C_3H_6	0-20%
Butane	C_4H_{10}	
Hydrogen	H_2	nil
Carbon dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace quantities

Source: Harker & Allen, Fuel Science

Natural gas may also contain water, carbon dioxide, hydrogen sulphide, nitrogen and helium and so requires treatment before the gas can be sold or transported via a pipeline system. Sulphur-rich gas is commonly called 'sour gas'. Pipeline quality specifications vary from system to system, creating potential problems where gas is transferred from one system to another (for example, the UK-Continent Interconnector), but the basic requirements are very similar. Excess water is removed to prevent the formation of hydrates and freezing in pipeline systems. Hydrogen sulphide is removed because it is both poisonous and corrosive, and it is usually processed further to recover sulphur. Most of the carbon dioxide is removed to prevent corrosion and is sometimes re-injected into crude oil reservoirs to maintain pressure as part of an enhanced oil recovery (EOR) programme. Helium, which is a useful inert gas, is sometimes recovered for commercial reasons.

2.2.2 Measuring natural gas

There are various different ways of measuring natural gas depending on the purpose of the measurement and the practice adopted by the local gas supply industry in a particular country or region. The two most important functional measures are by volume as a gas (usually for gas production and supply) and by energy content (usually for sale and consumption), although natural gas can also be measured by volume or weight as a liquid (usually for liquefied natural gas (LNG)).

But the number of measurement units in common use is further complicated by the fact that there are two possible measurement systems – imperial and metric (SI) – and a rather confusing mixture of non-standard abbreviations for multiples of a thousand which are not used consistently throughout the industry. Rates of flow or usage are usually quoted per day or per year, and per hour for transmission purposes.

Volume

Volume measurements for any gas must be made at a pre-defined temperature and pressure in order to provide a consistent measure since the volume occupied by a gas expands as the temperature rises and the pressure falls. There are various measurement conventions in use:

- Standard units, measured at a temperature of 15°C and a pressure of 760 mm mercury or 1013 mbar;
- Normal units, used mainly in Europe, measured at a temperature of 0°C and the standard pressure;
- Russian units, measured at 20°C and the standard pressure.

The most common international (metric) unit for volume measurement is the cubic metre, either abbreviated as m^3 or (slightly confusingly) as cm. A cubic metre measured under standard conditions is usually abbreviated as scm (or ncm for measurements under normal conditions). Volume measurements in North America are usually made in imperial units, namely cubic feet or cf. Cubic feet are usually measured under standard conditions, but are sometimes referred to as standard cubic feet or scf. Standard cubic feet can be converted to standard cubic metres by dividing by 35.3.

Since the basic volume measurement units are very small, gas requires large multipliers to yield useful quantities. These are inconsistent, quirky and sometimes confusing. The basic multiplier is a thousand, denoted by the Roman numeral M. Thus,

One thousand cubic metres is 1 Mcm (or 1 Mscm)

One thousand cubic feet is 1 Mcf (or 1 Mscf)

and, by doubling up

One million cubic metres is 1 MMcm (or 1 MMscm)

One million cubic feet is 1 MMcf (or 1 MMscf)

but, after this the Roman numerals disappear

One billion cubic metres is 1 Bcm (or 1 Bscm)

One billion cubic feet is 1 Bcf (or 1 Bscf)

and

One trillion cubic metres is 1 Tcm (or 1 Tscm)

One trillion cubic feet is 1 Tcf (or 1 Tscf)

The gas industry, like the oil industry, uses the US definition of a billion (10^9) and a trillion (10^{12}).

Further complications are introduced by different editorial styles in the various gas industry publications, some of which use lower case m and mm for the Roman numeral, M, and some of which even use m or M to represent a million (as in b or B for billion and t or T for trillion) so it is always very important to check the context of any abbreviation quoted.

Gas can also be measured by volume as a liquid when it is being transported as liquefied natural gas (LNG). Natural gas becomes a liquid at a temperature of –162°C, which reduces the volume by around 600 times compared with the standard conditions of temperature and pressure. But LNG is more usually measured by weight in metric tonnes. One metric tonne of LNG is equivalent to 1.38 million cubic metres (MMcm) or 48.7 million cubic feet (MMcf) of natural gas at standard conditions. In the case of LNG it is important to distinguish between feed gas (i.e. the input to a re-gasification plant) and re-gasified LNG (i.e. the output from a re-gasification plant) since about 30 per cent of the feed gas is consumed in the liquefaction process and about 10 per cent is lost on re-gasification (see section 2.2.4 below).

Energy content

Energy content measurements for natural gas are similarly varied and idiosyncratic since they also represent the accumulation of past practice in different countries and regions, but with growing competition between natural gas and other fuels in electricity generation, metric (SI) units such as kilowatt hours (kWh) and Joules (J) are becoming increasingly common. It is also important to remember that there is no standard conversion factor from volume to energy content since the calorific value of natural gas differs widely from one region to another and, in some cases, from one pipeline system to another. Nevertheless, like oil, there are some commonly used factors which give a rough and ready conversion based on an 'average' calorific value for natural gas (see below).

The most common unit for measuring the energy content of natural gas in North America is the British Thermal Unit or Btu, usually expressed in million Btu or MMBtu, while the UK has traditionally used the therm (usually abbreviated to th), which is 100,000 Btu. The legal definition of a therm is very slightly different in the US and Europe[1]. Energy content is also occasionally measured in thermies (also confusingly abbreviated to th), which are a heat measure used by

[1] This is because there are several very slightly different definitions of the Btu, which is the amount of heat required to raise the temperature of one pound (weight) of water by one degree Fahrenheit. The definition varies slightly with the temperature of the water. In the US the legal definition of a therm is 105.4804 MJ, in Europe it is 105.5060 MJ (see Chapter 9, Appendix 9.1).

European engineers. One thermie represents the amount of energy required to raise the temperature of one tonne of water by 1 degree Centigrade. A thermie is equivalent to 1,000 Calories (kcal). There are 25.2 therms to a thermie. But Continental Europe commonly uses SI units, either kilowatt hours (kWh) or Joules, usually expressed in GigaJoules (GJ) or units of a million Joules, although Australian gas statistics are expressed in PetaJoules (PJ).

Calorific value (CV) measures the amount of heat produced when any fuel is burnt. There are two possible measurements:

Gross calorific value (GCV), which assumes that all the water created during the combustion process is fully condensed;

Net calorific value (NCV), which assumes that the water created during the combustion process remains as a vapour.

The difference between the two measures is the latent heat of condensation of the water vapour created during combustion. The gas industry typically uses gross calorific values for accounting purposes, while net calorific values are used in energy balances for comparing the heat content of different fuels.

The heat content of fuels is usually compared using net calorific value since the latent heat of condensation cannot be captured by most appliances. Net calorific values are therefore lower than gross calorific values and the difference depends on the amount of water produced in the combustion process. In the case of natural gas, the gross calorific value is 9–10 per cent higher than the net calorific value compared with around 5 per cent for oil and coal. Gross calorific values for a range of high (H) and low (L) calorific value natural gases are shown in Table 2.2 below.

Table 2.2 Gross calorific values (GCV) of natural gas

Source	GCV MJ/m^3	Type
Groningen, Netherlands	35	L-gas*
Ekofisk, Norway	44	H-gas
Sleen, Netherlands	19	L-gas
Distrigas, H-gas system	42	H-gas
Transco, NTS	36.9-42.3	H-gas

Source: Gasunie, Transco, Distrigas   ** also known as G-gas*

The heat content of natural gas is important since a typical gas burning appliance with fixed jets cannot tolerate a wide range of calorific values without burning inefficiently and dangerously (see below). Some gas fields produce low calorific value natural gas (also known as L-gas), which contains a significant amount of inert gas such as nitrogen (e.g. Groningen in the Netherlands which contains 14% nitrogen) or carbon dioxide (e.g. Sleipner in Norway). When the source of supply is very large, as in the case of Groningen, separate distribution systems are required with appliances specifically designed for burning low calorific value gas, otherwise gas from different sources is blended to meet the necessary pipeline quality specifications. In the Netherlands, for example, very low calorific value gas from fields such as Sleen is mixed with high calorific value gas to match the Groningen specification (see Table 2.2 above). Similarly, the heat content of very high calorific value gas can be reduced by adding extra nitrogen.

Conversion factors

Converting from one set of units to another is not always straightforward since the appropriate conversion factor may depend on the purpose of the exercise. In some cases, approximate conversion factors will give a satisfactory result, while, in other cases, much greater precision is required.

For natural gas, volume conversions are commonly made using the following conversion factors (which assume the same measurement conditions and conventions for the respective units):

1 cubic metre = 35.31 cubic feet, and

1 cubic foot = 0.2832 cubic metres.

Different measurement conditions would, of course, require slightly different conversion factors. For example, 1 cubic metre, Metric (dry at 1013.25 mbar, 15°C) is 35.2898 standard cubic feet, Imperial (dry at 1015.92 mbar, 60°F).

Converting from volume to weight is even more complicated since it also depends on the density of the material concerned since,

Density = Mass/Volume

but, many sources quote approximate conversion factors for converting a 'typical' natural gas measured by volume into a 'typical' crude oil. For example,

1 cubic metre of natural gas = 0.00083 tonnes of oil

1 tonne of oil = 1,110 cubic metres of natural gas

1 cubic foot of natural gas = 0.000024 tonnes of oil

1 tonne of oil = 39,220 cubic feet of natural gas

The picture is further complicated once measures of heat content are used. Conversions from one unit of heat measurement to another are straightforward as long as it is clear whether the measurement refers to gross or net calorific value. Typically, heat measurements refer to net calorific value. Thus,

1 British thermal unit (Btu) = 1.05506 kilojoules (kJ),

or more conveniently

1 million Btu = 1.05506 gigajoules (GJ).

Other commonly used conversion factors for natural gas heat units are summarised in Table 2.3 below.

Table 2.3 Conversion factors for heat units

	1 MMBtu	1 therm	1 GJ	1 kWh
multiply units in left hand column by factors below to convert to units above				
1 MMBtu	1	10	1.05506	293.1
1 therm	0.1	1	0.1055	29.31
1 GJ	0.9478	9.478	1	277.8
1 kWh	0.00342	0.0342	0.0036	1

A precise conversion from heat to volume strictly depends on the calorific value of the natural gas concerned, but once again most sources quote approximate conversion factors for 'typical' fuels. For example:

1 MMBtu = 965.9 cubic feet (cf) = 27.66 cubic metres (cm)

1 therm = 96.59 cubic feet (cf) = 2.766 cubic metres (cm)

1 kWh = 3.3367 cubic feet (cf) = 0.094515 cubic metres (cm)

1 GJ = 950 cubic feet (cf) = 26.25 cubic metres (cm)

and,

1 cf = 0.2997 kWh = 0.0011 GJ = 0.0102 therms = 0.00102 MMBtu

1 cm = 10.58 kWh = 0.381 GJ = 0.362 therms = 0.0362 MMBtu

Similarly, converting from natural gas heat units to oil volume or weight units uses conversion factors for 'typical' fuels,

1 MMBtu (gas) = 0.024 tonnes (oil) = 0.04 tonnes (coal)

1 therm (gas) = 0.0024 tonnes (oil) = 0.004 tonnes (coal)

1 kWh (gas) = 0.0000855 tonnes (oil) = 0.00014 tonnes (coal)

1 GJ (gas) = 0.022 tonnes (oil) = 0.036 tonnes (coal)

Although, in practice, the heat content varies between the different types of oil and coal fuel, for example:

Petroleum (therms/tonne)

crude oil (428);

heavy fuel oil (406);

heating oil (431).

Coal (therms/tonne)

power station (232);

domestic (285);

anthracite (316).

Finally, converting prices from one set of units to another can lead to confusion as prices are expressed as \$ *per* million Btu or pence *per* therm. This means *dividing* instead of multiplying when applying the relevant conversion factor. For example, converting 4 MMBtu into therms involves multiplying by a factor of 10,

i.e. 4 MMBtu x 10 = 40 therms,

but converting \$/MMBtu into \$/therm involves dividing by a factor of 10,

i.e. \$4/MMBtu ÷ 10 = \$0.40/therm = 40 cents/therm.

2.2.3 Pipeline quality gas

In order to ensure consistent burning characteristics for natural gas supplied to consumers, to avoid damage to pipelines and compressor stations, and to guarantee safe operations, gas transport and distribution operators need to define key quality specifications for any gas that they may accept from producers (see, for example, Appendix 2.1 for Transco's Network Entry Quality Specifications for the UK National Transmission System). These will vary from area to area depending on the type of gas available from producers and can cause compatibility problems where two independent transmission systems come together.

Compatibility problems range from whether the gas is already odorised to differences in calorific value, which may require separate high-pressure pipeline systems. Gas with very different calorific values is transported separately and then blended to meet consumer specifications before it is transferred to the local low pressure distribution systems.

The widely different specifications for pipeline quality gas could inhibit the growth of international gas trading and third-party access in Europe until the various pipeline operators develop the necessary procedures for dealing with the problem. Gas trading in Europe already distinguishes between high calorific (H) gas, low calorific (L) gas and Russian gas (which falls between H- and L-gas in terms of heat value), but other quality specifications will also be important for some buyers.

The key pipeline gas quality parameters include:

- Wobbe index
- Hydrocarbon dew point

- Water content
- Hydrogen sulphide (max)
- Mercaptan sulphur (max)
- Total sulphur (max)
- Temperature (max and min)
- Oxygen (max)
- Total inert gases
- Carbon dioxide (max) – separately from inert gases
- Radioactivity
- Odorisation

Wobbe index

The most important of these is the Wobbe index (or number), which is an indicator of the burning characteristics of the gas in relation to a particular type of appliance. It measures the heat input to an appliance, which depends on the heat content of the gas, the size of the jet(s) delivering the gas, and the pressure of the gas supplied to the appliance.

The Wobbe index is calculated by dividing the gross calorific value of the gas by the square root of the specific gravity:

$$\text{Wobbe Index} = \text{Gross Calorific Value}/\sqrt{(\text{Specific Gravity})}$$

Specific gravity (SG) is the density of the gas relative to air, which has a specific gravity of 1. The higher the specific gravity, the heavier the gas and so the slower the flow of gas through a burner jet at a constant pressure. A heavy gas with a higher specific gravity must therefore have a higher heat value if it is to provide the same energy output as a light gas with a lower specific gravity.

Town gas or manufactured gas (a mixture of hydrogen and carbon monoxide) – widely used in Europe and the US before natural gas took over – has a Wobbe index that is about half that of natural gas, which is why appliances had to be modified when natural gas was introduced. Coal-bed methane has a slightly lower Wobbe index than natural gas. In the UK, for example, gas supplied to the National Transmission System (NTS) must have a Wobbe index that falls within the 48.14 to 51.41 MJ/m^3 range (see Appendix 2.1).

A high Wobbe index may cause over-heating of the appliance, the leakage of combustion products into a room instead of up the flue, and (possibly) incomplete combustion resulting in excessive carbon monoxide. A low Wobbe index may produce an unstable flame, causing pilot lights to go out and creating dangerous accumulations of unburnt gas. It may also cause increased carbon monoxide. If two different gases have the same Wobbe index they will produce the same amount of heat and combustion products and will require the same amount of air for burning.

Hydrocarbon dew point

The hydrocarbon dew point is the temperature at which liquids begin to condense out of the gas. If the hydrocarbon dew point is high, liquid may accumulate in pipelines helping to form hydrates, which could damage flow regulating and measuring equipment, potentially causing a local loss of supply. If these liquids get into the local distribution system they could damage meters and consumer appliances. Liquid hydrocarbons also absorb odorant and the mixture can damage rubber seals.

Water content

Water content and water dew point are controlled because excess water can produce solid hydrates – an ice-like mixture of water and hydrocarbons – that can block or damage meters, regulators or even the pipeline.

Hydogen sulphide

Hydrogen sulphide is a poisonous gas which corrodes pipelines and can encourage stress fractures in steel pipelines. It also causes problems in compressed natural gas cylinders.

Mercaptan sulphur

Mercaptan sulphur does not cause any safety problems but is very smelly like the odorising agent and may lead to an excessive number of leak reports if the usual amount of odorising agent is added to gas which already contains mercaptan sulphur.

Total sulphur

High levels of sulphur compounds in natural gas produce excessive amounts of sulphur dioxide when burnt, adding to air pollution and reducing indoor air quality.

Temperature

Extremes of temperature damage pipelines. Prolonged periods of high temperature cause stress cracking and damage valves, seals and corrosion protective coatings. Low temperatures can have disastrous effects on low grade steel pipelines causing brittle failure.

Oxygen

Oxygen and carbon dioxide can cause pipelines to corrode and in the unlikely event of an excessive amount of oxygen, the mixture of gas and oxygen is explosive.

Inert gases

Inert gases include nitrogen, helium and argon. They do not constitute a safety hazard in themselves, but high concentrations of inert gases are associated with high concentrations of non-methane hydrocarbons, such as ethane and propane, which create soot in appliances even if the Wobbe index of the gas supply is correct.

Odorisation

The aim of odorising natural gas is to create a warning that is noticeable at concentrations well below the lower explosive limit for natural gas. If too much odorant is added, large numbers of minor leaks that pose no threat may be reported. The most common odorant is tetrahydrothiophene (THT), although tertiary butyl mercaptan (TBM) or mixtures of these two compounds are also used.

Pipeline quality

Gas quality specifications are usually monitored continuously by the pipeline operator at the system entry points. Trigger levels are set for each of the pipeline quality parameters at which measurements must be confirmed and then notified to the supplier. If any of the parameters is exceeded the gas is designated as 'out-of-specification' and the supplier must take action to remedy the problem. If the problem cannot be solved within a specified time period, the supplier must stop injecting gas into the pipeline system until the quality problem has been solved. Serious breaches of pipeline quality standards may require action by transporters or consumers to compensate for the problem. Appendix 2.1 gives Transco's pipeline quality specification for entry to the UK NTS.

2.2.4 Liquefied natural gas (LNG)

Natural gas is more costly to transport than coal or oil because it requires specialised and expensive facilities – either pipelines or liquefied natural gas (LNG) plants and ships – to move the gas from the well-head to the end-user. Pipelines are the most cost-effective method of transporting gas over land, unless the terrain is very difficult or the market is very small. But, under the sea, pipelines are more costly than LNG after about 2,000 km, because of the very small marginal cost of transporting LNG additional distances (see Chapter 3). LNG is therefore the preferred option for moving natural gas over long distances at sea, for example from the Middle East to Japan, or Nigeria to Europe and North America. LNG is also used as an alternative to shorter distance pipelines, especially to supply peak-shaving generation plants that would otherwise incur high delivery costs either because the demand is small or the terrain very difficult for pipes, and to provide emergency supplies and guarantee pipeline system operations under extreme demand conditions (see Section 2.3.4 below). In some cases, pipeline gas is liquefied to fill LNG storage used for peak shaving and supply security.

Moving natural gas as LNG involves three distinct stages. First, the gas is cooled to very low temperatures (–260°F or –162°C) in a liquefaction plant, which must be built at or close to a suitable port if the LNG is to be transported by sea. Secondly, the liquid gas is kept in well-insulated tanks either on land or at sea in specially designed ships (see Fig. 2.3). Thirdly, it is converted back into a gas from a liquid in a re-gasification plant at or close to the delivery port, after which it can be delivered into the local gas pipeline system or supplied directly to a large consumer such as a power plant.

Each of these facilities – the liquefaction plant, insulated storage tanks and LNG carriers – are very expensive to build, which means that LNG is not usually a cost-effective option for short distances. But, once the investment has been made, the costs of moving an LNG carrier are relatively low since so much natural gas can be transported in a small volume and the 'boil-off' gas used for autorefrigeration (see below) can also be used as a tanker fuel, which is why LNG becomes competitive for long-distance movements at sea. LNG is also moved in insulated road tankers to supply smaller industrial and utility consumers.

Source: Woodside Energy

Figure 2.3 LNG tanker

LNG occupies 1/600th of the space required for the same volume of natural gas. Its density is less than half that of water. It is odourless, non-corrosive and non-toxic and is not explosive either as a liquid or a vapour in an *unconfined* environment – although serious explosions have occurred in the past where LNG vapour has been ignited accidentally in a confined or restricted area. LNG vapour is, of course, highly inflammable and burns easily in air. Liquefaction removes many of the impurities such as sulphur, water, carbon dioxide, oxygen and nitrogen that are normally found in pipeline quality gas, producing nearly pure methane if required.

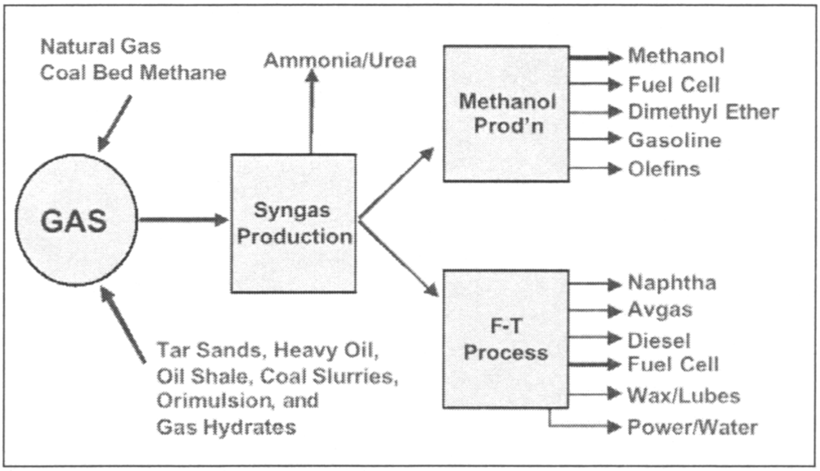
LNG storage tanks are double-walled and highly-insulated as LNG must be kept at a temperature of –162°C or below if it is to remain a liquid. But insulation alone is not sufficient to keep the temperature so low. LNG is therefore kept permanently 'on the boil' so that the latent heat of evaporation cools the liquid – this process is known as 'autorefrigeration'. The temperature of the LNG liquid is controlled by allowing the LNG vapour to leave the storage tank, thus preventing a rise in pressure. In large LNG storage tanks the pressure is kept very low. Smaller volumes are sometimes kept at higher pressures in vacuum-jacketed storage vessels.

LNG represents about a quarter of the international trade in natural gas, totalling 143 bcm in 2001. The Asia Pacific region accounts for nearly three quarters of the international LNG trade. The main use of internationally traded LNG is for electricity generation, especially in the Asia Pacific region. LNG is also widely used for peak shaving, either seasonally or to meet unexpected surges in demand. And, with rising demand for compressed natural gas (CNG) as a motor fuel to replace diesel and gasoline, LNG also has a potential market in the transport sector.

2.2.5 Gas-to-liquids (GTL)

Natural gas can be converted by chemical processes into a number of liquid products. These include methanol, dimethyl ether (DME), petroleum products such as naphtha and diesel, waxes, lubricants and specialty chemicals. Although the processes for converting gas into a liquid were developed many years ago, the cost of doing so was – until recently – too high to make it a commercial proposition except in exceptional circumstances. But improvements in gas-to-liquids (GTL) technology mean that it now provides a viable alternative method of developing remote gas reserves that might otherwise be too costly to bring to market by pipeline or LNG tanker.

The marketing of gas requires major investment in transportation infrastructure. Sometimes gas reserves are considered unsuitable for commercial development, because they are very distant from potential markets and far from the sea and opportunities for LNG shipping. In this case, it may be possible to convert the gas to marketable (and



Source: Gaffney,Cline & Associates

Figure 2.4 Gas-to-liquids alternatives

transportable) liquid products. The economics may be considerably improved if the cost of the gas is low (for example in the case of flared gas) or the market for petroleum products is particularly good (for example in more remote parts of the world where it is difficult or expensive to import petrol). There may also be centres of demand which could be accessed more easily by GTL vessels than LNG ships.

The starting point for all GTL processes is the manufacture of 'synthesis gas' or 'syngas' – which is a mixture of carbon monoxide (CO) and hydrogen (H_2) – from methane (CH_4). Syngas is then used either to make methanol or as a feedstock for the Fischer-Tropsch process, which yields a range of oil products depending on the process conditions (see Fig. 2.4). The Fischer-Tropsch process was invented in 1923 by Franz Fischer and Hans Tropsch and was used by Germany during World War II to make gasoline from coal. The same process has also been used by Sasol, the South African energy company, since 1955 to produce liquid fuels from coal.

Syngas can be made from methane either by steam reforming or by partial oxidation. Most syngas manufacture involves a combination of these two processes. Steam reforming is an energy-intensive process that combines methane and water vapour to produce syngas. But it requires high temperatures and high pressures, which makes it expensive if the heat has to be purchased at commercial rates. Adding oxygen to the reaction not only boosts the yield of syngas but also provides a useful source of energy from the partial oxidation of the methane. However, oxygen is also expensive if it has to be supplied at commercial rates.

In the Fischer-Tropsch process, the syngas is then blown over a number of possible catalysts to produce a mixture of synthetic petroleum products. The precise mix of oil products depends on both the choice of catalyst and the temperature of the reaction. At higher temperatures (330-350°C) more light products such as gasoline are produced, while at lower temperatures (180-250°C) heavier products such as middle distillates and waxes are produced. Like crude oil, the output from the Fischer-Tropsch process has to be refined in order to separate the various types of oil products. One important advantage of the Fischer-Tropsch process is that it produces very low sulphur liquid fuels, which helps the economics now that most countries have reduced the sulphur content required for oil products to very low levels indeed.

Table 2.4 Gas-to-liquids plants

Year	Operator	Location	Capacity (b/d)	Products
Operating				
1955	Sasol	South Africa	124,000	Light olefins, gasoline
1991	Mossgas	South Africa	22,500	Gasoline, diesel
1993	Shell	Malaysia	12,500	Waxes, chemicals, diesel
Proposed				
	Rentech	USA	1,200	Waxes, liquid fuels
	Syntroleum	Australia	10,000	High margin products
	Sasol	Qatar	34,000	Liquid fuels
	ExxonMobil	Qatar	100,000	Liquid fuels
	Sasol/Chevron	Nigeria	33,000	Liquid fuels
	BP	Alaska	100,000	Liquid fuels
	Sicor	Ethiopia	20,000	Liquid fuels
	PDVSA	Venezuela	15,000	Liquid fuels
	Shell	Qatar	150,000	Liquid fuels

Source: Gaffney,Cline & Associates, GTM

Technological progress has greatly improved the economics of GTL over the past decade, cutting costs by around a half. As a result, there are a number of commercially viable projects being developed around the world (see Table 2.4). Current estimates suggest that large-scale projects require a sustained oil price of $20-25/barrel over the life of the project to yield an economic return. At present, there are only three large-scale GTL projects in operation producing synthetic oil products: Mossgas in South Africa, Shell Bintulu in Malaysia, and a methanol to gasoline plant in New Zealand. But companies are working hard to reduce costs and further improvements in technology are likely to make many more projects viable over the next decade, especially for remote gas deposits that cannot be developed by more conventional means.

2.3 Demand, supply, and storage

Natural gas is relatively cheap to produce but relatively expensive to transport and deliver to market since it must be moved either by pipeline or in insulated storage vessels. Developing new gas fields or new markets for gas usually requires investment in new transport facilities, which represent a significant proportion of the cost of supplying new gas. In the past, new developments could only be justified by linking suppliers and customers with long-term take-or-pay contracts that guaranteed a satisfactory rate of return on the capital invested in new facilities. As a result, there was no short-term market for natural gas since all the gas produced was sold under long-term contracts, which prevented independent gas producers, shippers and marketers from gaining access to gas supplies and pipeline capacity.

But the gas industry is gradually being forced to provide guaranteed third-party access to pipeline capacity as part of an international drive to open up energy markets to greater competition. The process began in the US in 1978 with the Natural Gas Policy Act. In the early 1980s, local distribution companies were allowed to break long-term supply contracts with pipelines and the removal of price controls on well-head sales of natural gas. This was followed by the forced 'unbundling' of gas transportation and marketing activities in the early 1990s, giving independent producers, shippers and marketers access to spare pipeline capacity and spot supplies of natural gas. At the same time, in the UK, the government began to break up the British Gas Corporation's monopoly control of the downstream UK gas market, giving other gas suppliers access to Transco's pipeline network and (ultimately) allowing competition for all consumers. Now that the EU Gas Directive is being implemented, the same process is gathering momentum in Continental Europe.

Despite government moves to create a competitive market for gas in the US, UK and now Europe, access to pipeline capacity represents the main constraint on gas supply and it can therefore play a key role in setting gas prices. Long-term contracts between producers and consumers still limit the amount of pipeline capacity that is available to third-parties, especially in Continental Europe where the former monopoly operators are very reluctant to concede access. The cost of access is either set through bi-lateral negotiation and market forces (negotiated access) or by published tariffs controlled by national regulatory bodies (regulated access).

2.3.1 Sources of demand

Natural gas is primarily used for generating heat, for commercial and domestic heating and cooking, or for industrial processes, or in power stations for generating electricity. It is also used in the petrochemical industry, providing an alternative to oil-based feedstocks such as naphtha and gasoil. And a small, but increasing amount, is used in the form of compressed natural gas (CNG) as an automotive fuel, substituting for diesel in urban markets for vehicles such as buses and taxis.

Natural gas now supplies about a quarter of the world's primary energy needs and demand rose at an average rate of just under 2 per cent a year during the 1990s, compared with around 1 per cent for total primary energy demand, boosting its market share relative to other fuels. The driving forces behind faster growth in gas demand were a combination of lower prices and convenience, which encouraged substitution away from oil and coal, and the opening up of the power generation market to natural gas. Gas used to be regarded as a 'noble fuel' and some governments legislated against the use of gas in power generation, but growing supplies of natural gas, improved generating technology and environmental concerns have forced a change of mind.

Gas demand has also been encouraged by the liberalisation of natural gas and electricity markets, especially in North America and Europe. During the 1990s, gas ceased to be a monopoly business as first pipelines and then end-user markets were opened up to competition. As a result, natural gas prices fell sharply as pent-up supply was released onto the market, encouraging substitution. Demand for gas was further enhanced by the liberalisation of the electricity generation market, which brought independent power producers (IPPs) into the business, almost all of whom chose to build combined cycle gas turbine (CCGT) units (see Chapters 16 and 17).

Power generation

Electricity generation is the fastest growing demand sector in the natural gas market. In the UK, for example, the number of gas-fired power stations connected to the NTS increased from only one in 1991 to 32 in 2001, boosting gas' share of the power generation market to around 37 per cent[2]. The short investment lead times and lower capital costs for CCGT electricity generation units combined with the opportunities for new entrants created by the early liberalisation of the UK electricity market both contributed to the rapid growth in gas demand from the power sector.

Future demand for gas from the power sector is expected to follow the same rapid upward trend, especially in the US and Europe where the liberalisation of electricity markets is proceeding apace. Environmental concerns, as well as economic factors, make gas the preferred fuel for new generating capacity. Burning natural gas has two key environmental advantages, it contains virtually no sulphur and it creates less carbon dioxide for each unit of energy produced. With

[2] Gas' share of power generation fell in 2001 due to higher gas prices, cheap imported coal and greater availability of nuclear plants.

governments concerned to reduce sulphur dioxide emissions to improve air quality and carbon dioxide emissions to comply with the Kyoto Protocol commitments on greenhouse gas emissions, natural gas is clearly favoured over oil or coal.

Industrial and commercial

Environmental concerns have also supported steady demand growth for gas from the industrial and commercial sectors. Large scale industrial processes such as cement making and chemicals which used to use coal and high sulphur fuel oil to provide process heat have switched to natural gas to meet pollution reduction targets. Natural gas is also used as an alternative feedstock for the petrochemical industry.

Demand for gas from industrial and commercial users is also rising as more companies get involved in small-scale power and heat generation as a result of the liberalisation of electricity markets. Since companies can now sell surplus power to the electricity grid in both Europe and the US, small scale generation is becoming an increasingly important source of gas demand, competing for supply with the major generators. In the same way, growing numbers of combined heat and power (CHP) projects are adding to industrial and commercial gas demand.

Domestic

Domestic (or residential) use of gas for heating and cooking remains one of the largest components of natural gas demand, but the market is close to saturation point in countries with a well-established gas market as most consumers have already switched from coal or oil. Over 85 per cent of homes in the UK have central heating and three-quarters of these use natural gas. While improved building insulation and boiler efficiency is likely to limit the growth of this market in countries like the UK, there is still room for greater market penetration in countries that are new to gas or still have scope for substitution as low-pressure distribution networks are established.

Automotive

Natural gas vehicles (NGVs) are a small but growing component of world gas demand. They are a well-established niche market in Europe, North America, Australasia and Argentina with over 1 million vehicles now in use worldwide. Since natural gas is a clean burning fuel with low emissions, it provides an attractive and cost effective alternative to diesel or petrol, especially for fleet vehicles such as buses and taxis in urban areas where limited refuelling options are not a problem.

NGVs use compressed natural gas (CNG) which is stored in high-pressure cylinders carried by the vehicle. NGVs are more expensive to buy than conventional vehicles but cost less to run because of lower maintenance costs and fuel taxes. Some vehicles are either dual-fired (run on a mixture of diesel and natural gas) or bi-fuel (run on either natural gas or gasoline). Liquefied natural gas (LNG) can also be used to power NGVs, although much higher costs mean that it is currently used for only heavy-duty vehicles.

Demand drivers

Since natural gas is mainly used to provide heating or electric power for final consumers, demand is both strongly seasonal and closely related to weather conditions. The weather therefore plays a central role in the operations of most gas supply systems since gas is usually expensive to store and the distribution system must be able to provide an instantaneous response to fluctuations in consumption.

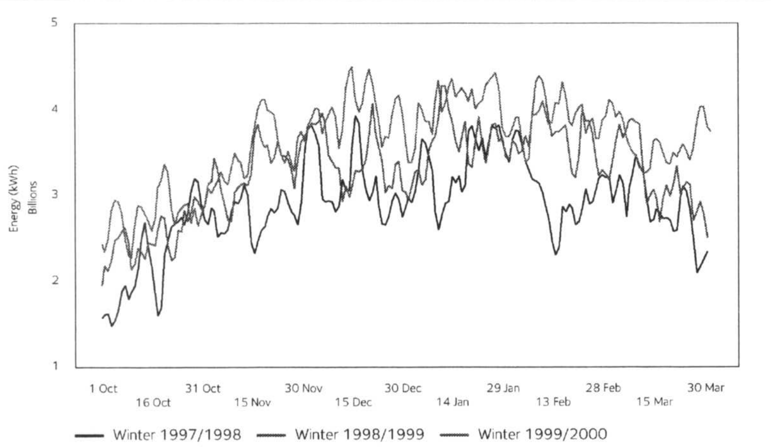
Weather forecasts and weather monitoring are essential tools for running gas pipeline operations (see Section 2.3.3 below). Long term weather patterns are used to predict seasonal demand, for example Transco's composite weather variable, but other trends such as global warming need to be taken into account. In the UK, Transco applies a mild weather trend correction factor which was recently increased to 3.5 per cent.

Relative prices are also important both in the longer term, when they will influence the rate at which gas is substituted for oil and coal, and in the short term, when they will determine which fuel is burnt in dual-fired power stations. In the past, gas and oil prices were closely linked through indexation clauses in long-term supply contracts. This linkage was weakened as liberalisation released unsold gas reserves onto the market, but can still be influential when oil prices rise or gas supplies tighten.

With the growing importance of gas in power generation, relative prices and the position of gas fired stations in the generating 'rank order' – base-load, intermediate, or peak – can have important implications for both the level and volatility of gas demand. In addition, power utilities are increasingly using their operational flexibility to arbitrage between the gas and power markets, buying extra gas when the economics favour generation and selling gas back into the market when high gas prices make generation uneconomic (see Chapter 17).

2.3.2 The gas supply system

End-user demand for natural gas is highly variable, both within the day (diurnal) and throughout the year (seasonal), creating a major technical and economic challenge for the gas supply system. The main determinants of gas demand are the temperature, economic activity, behaviour patterns, the price of gas and other competing fuels, and government policy. Since end-users cannot easily store gas – as they can oil or coal – the gas supply system must be able to cope with the full range of variation in demand, allowing the majority of consumers to turn appliances on, or off, as required. Predicting and managing the



Source: Transco

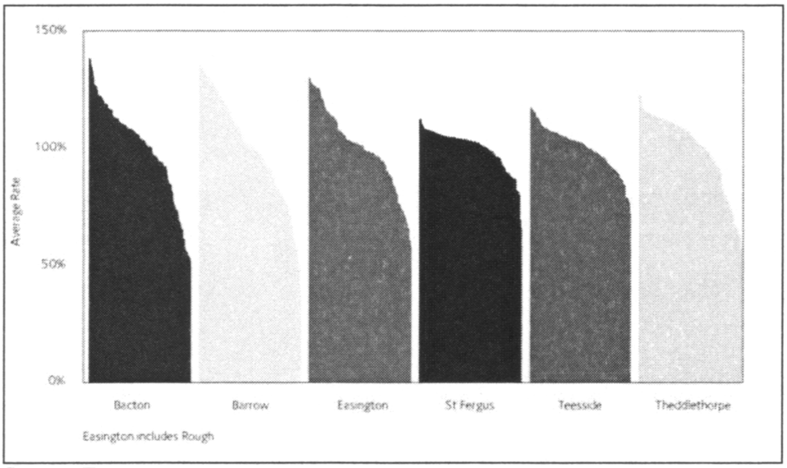
Figure 2.5 Daily variation in UK gas demand, 1998-2000

variations in demand is therefore central to the operation of the gas supply system and the market structures that have grown up to support it with greater liberalisation.

In the UK, the gas supply system is designed to deliver a 1 in 20 year peak day demand in order to ensure that customers will not go short. This means that for most of the time the system is operating well below its capacity. In 2001, for example, Transco's average annual operational load factor was around 54 per cent based on a forecast 1 in 20 year peak day demand of 540 mcm. On the maximum flow day in the 2001/02 gas year (2 January 2002), 427 mcm entered the National Transmission System, while on the minimum flow day (17 August 2002) only 165 mcm was required – a ratio of two and a half to one. On the maximum flow day 55 mcm came from storage facilities.

System efficiency should improve as load factors are expected to increase in the future as more gas fired power generation plants come into operation and more gas is exported through the Interconnector, but much of the peak comes from domestic consumers rather than industry or power generation. Nevertheless, bottlenecks do occur and accidents – such as the temporary loss of an entry terminal – can cause problems.

Some idea of the daily variation in demand facing gas suppliers can be gleaned from Fig. 2.5 which shows total gas demand in the UK over three winters – 1997/98, 1998/99 and 1999/2000. Although the general seasonal pattern of demand is the same from year to year, the daily ups and downs are very different since they depend largely on the temperature. In the short term, weather forecasts are getting more accurate, allowing the system operator to predict day-ahead and within-day demand with reasonable accuracy, but longer term forecasting



Source: Transco

Figure 2.6 Swing provided by UK entry terminals, 1999-2000

remains very uncertain, creating the conditions for a highly volatile gas commodity market.

Most of the variation in gas supply in the UK comes from production rather than storage, with many North Sea producers increasing and decreasing production as required. Such variations in production are known as 'swing' and many gas supply contracts include agreed swing parameters. Older UK gas supply contracts signed before privatisation had much greater swing factors. This was partly because the early gas supplies came from dry gas fields in the southern North Sea, which are relatively shallow making additional wells cheap to drill, and partly because the (then) British Gas Corporation was a monopoly buyer and could dictate terms. In addition, producers are now able to use derivative trading instruments such as options to capture some or all of the economic value placed on swing by the market (see Chapters 5, 6 and 8). Gas fields still have a seasonal production profile, but different gas supply packages may be bought by different customers.

Swing production usually comes from dry gas fields since the volume of associated gas produced from oil fields cannot be easily varied. During the winter of 1999/2000, the swing provided by UK entry terminals varied between 37 and 138 per cent of the average delivery rate (see Fig. 2.6). The greatest swing was provided by terminals such as Bacton, Barrow, Easington and Theddlethorpe, all of which are supplied by mainly dry gas fields or storage facilities, such as Rough. The two northern terminals, St Fergus and Teesside, which are supplied mainly from the associated gas fields of the Central and Northern North Sea, provide less swing.

2.3.3 Pipeline operations

Running a gas pipeline supply system is a challenging and highly technical balancing act requiring continuous and meticulous attention from the system operator. As well as providing for the safe physical delivery of a potentially explosive commodity, the gas pipeline system must also monitor and guarantee quality and manage any short term imbalances between supply and demand. In the UK, the NTS requires suppliers to balance their inputs on a daily basis, leaving Transco, the system operator, to handle within-day imbalances. But many Continental system operators require suppliers to balance their inputs every hour.

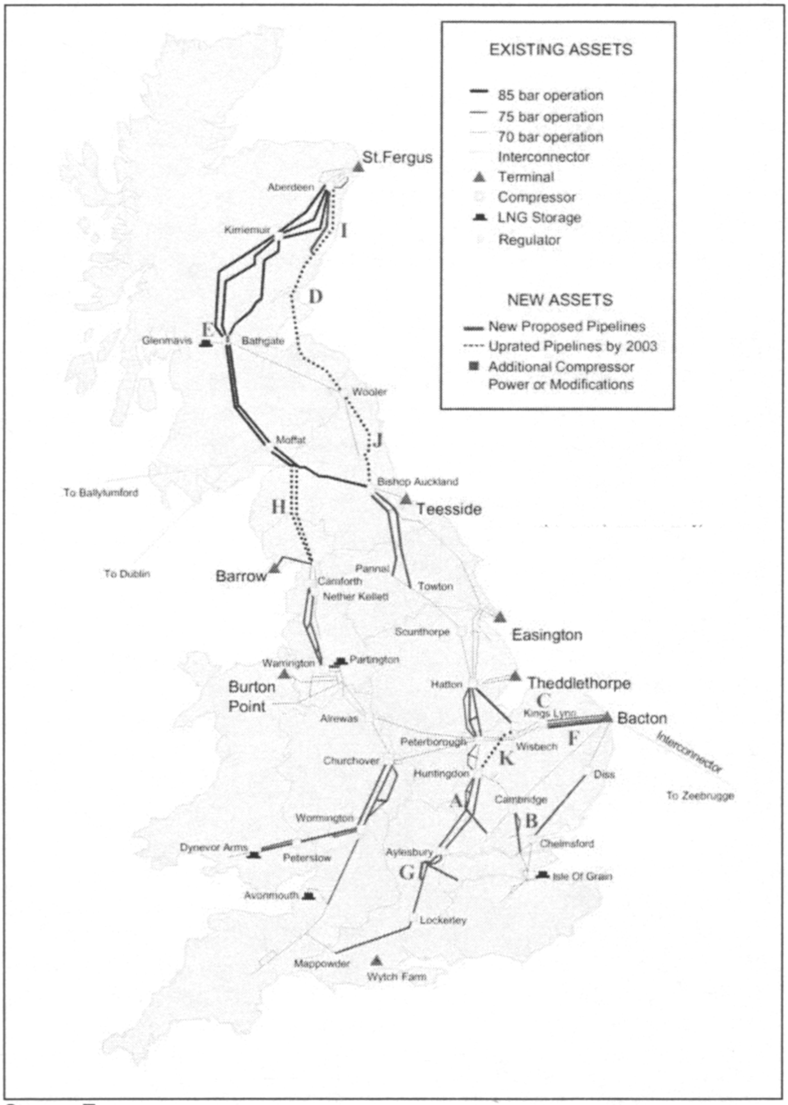
Managing the flow

Natural gas moves along a pipeline down a pressure gradient. It comes out of the ground at a very high pressure and is delivered to end-users at a very low pressure. Between the producer and consumer lies a complex network of entry terminals, exit terminals, high-pressure pipes, low-pressure pipes, compressor stations, pressure-regulating stations, monitoring stations, blending stations and storage facilities – all of which are managed by the system operator using a mixture of local automatic and centralised computer control systems (see Fig. 2.7).

Most gas pipeline systems are in two distinct parts, a high-pressure system for long-distance or large volume movements, and a low-pressure system for local distribution to domestic or commercial consumers. Large industrial consumers and power stations will be connected directly to the high-pressure system, usually via medium-pressure feeder pipes, while smaller industrial or commercial users and households will be connected to the low-pressure system. Typically, new gas supply systems are developed first to meet the needs of large users, for example power stations, and subsequently to supply smaller users once the cost of installing the high-pressure network has been recouped. But this was not the case in the US or Europe where existing town gas domestic supply networks were converted to natural gas.

The high-pressure network uses large steel pipelines, usually between 18 and 48 inches (45–120 cm) in diameter and operates at pressures of 40 to 85 bar (normal atmospheric pressure is 1 bar, so 75 bar is 75 times normal atmospheric pressure, about 1088 psi). Natural gas usually comes out of the ground at much higher pressures, 200 bar for example, but system operators set an upper limit to the pressure of gas supplied to the system. In the UK, the upper limit accepted by Transco is 75 bar, although some northern parts of the network operate at 85 bar to help move gas to the south where the majority of the consumers are. In the Netherlands, natural gas from the Groningen field is supplied at a pressure of around 65 bar and the pipeline systems operate at pressures from 40 to 65 bar.

The low-pressure system mainly uses much smaller polyethylene pipes (although some cast iron pipes are still in use) and operates at pressures of 8 to 10 bar in order to keep the gas moving towards the network of small pipes that supply the end-user. By the time it reaches the domestic consumer, the gas pressure has dropped to around 25 millibar, which is the pressure at which household appliances such as cookers and central heating boilers are designed to operate.



Source: Transco

Figure 2.7 UK National Transmission System (NTS)

The high-pressure and low-pressure systems are linked by feeder pipelines which operate at intermediate pressures of 16–40 bar. Medium pressure feeder pipelines are also used to supply power stations and large industrial users. In most gas supply networks, the feeder pipelines and low-pressure systems are operated by regional or local distribution companies (LDCs) and are not the responsibility of the main (high-pressure) system operator. For example, the UK high-pressure grid (see Fig. 2.7), operated by Transco, has more than 150 offtake points from which it supplies gas to 31 power stations, eight large industrial consumers, and 13 Local Distribution Zones (LDZs).

The transfer of gas from the high-pressure main pipeline system to the lower pressure feeder pipelines is managed by automatic pressure-regulating stations at the system offtake points. Governors control the transfer using pneumatic feedback from the low pressure network. Safety valves are installed on the downstream side in case a governor fails to prevent high-pressure gas entering the low-pressure system and parallel systems are installed to ensure that the flow of gas is not interrupted. Pressure-regulating stations at offtake points are also used on the Continent (and in the UK since the UK-Continent Interconnector pipeline) to odorise the gas before it enters the low-pressure network.

Gas is pushed through the high-pressure network using a combination of entry pressure and strategically placed compressor stations. The speed at which the gas flows through the network is not constant, but depends on the level of demand. In the summer, when demand is low, the speed of the gas drops to a walking pace. But in winter, when demand is high, the speed can rise to over 50 km/hour. As a result, compressor usage rises sharply in winter as more assistance is needed to keep the gas flowing at the rate necessary to match demand. The UK NTS has 22 compressor stations powered by Rolls Royce and Orenda jet engines, generating up to 33,000 horse-power. These are designed to work as quietly as possible and use about 0.5 per cent of the total system throughput to generate the necessary power. Typical winter compressor usage is double summer levels.

Compressors are also needed to keep gas flowing down long pipelines as friction (or drag) slows the rate of transmission. High-pressure systems typically have compressors spaced roughly 100 km apart. The relationship between pressure, speed and distance is non-linear since the drop in pressure is proportional to the square of the velocity of the gas multiplied by the distance travelled, which means that pipeline pressure falls off rapidly after a relatively short distance if the gas is travelling fast. There are several methods of calculating the rate of gas flow down a pipeline, but the best known is the 'Panhandle formula' which is widely used when designing and operating gas pipeline networks that operate at high pressure and high velocity.

Panhandle formula

$$Q = 18583 \times \frac{(P_1-P_2)^{0.5394}}{(T_f \times L)^{0.5394}} \times \frac{D^{2.6182}}{G^{0.4606}}$$

where,

Q is the gas flow in cubic feet/day,
P_1 is the initial gas pressure in psi,
P_2 is the final gas pressure in psi,
T_f is the average gas flowing temperature in degrees R,
L is the pipeline length in miles,
D is the pipe diameter in inches,
G is the specific gravity of the gas relative to air.

An alternative formula is the Weymouth formula.

Weymouth formula

$$Q = 36.926d^{8/3}[(p_1^2 - p_2^2)/L]^{1/2}$$

Where,

Q = cubic feet of gas per hour, standard gas pressure, temperature, and specific gravity;
d = internal diameter of pipeline, inches;
L = length of pipe, miles;
p_1 = inlet pressure, pounds per square inch absolute;
p_2 = outlet pressure, pounds per square inch absolute.

Since maintaining the flow of gas is one of the essential objectives for the gas supply system, national high-pressure pipeline networks are constructed in the form of a ring main so that gas can be sent by a different route to the consumer if part of the system is disrupted or out of service. Local storage also plays an important role in maintaining supply, especially at the extreme end of the network. The UK NTS uses a number of small LNG facilities to hold emergency reserves of gas for this purpose, which are also used to meet extreme peak demand levels (see Section 2.3.4 below). In certain cases, system operators may have to take advantage of interruptible contracts, cutting off supply to large customers who are willing and able to switch to alternative fuels, for example dual-fired power stations or industrial users.

System operators such as Transco in the UK, Gasunie in the Netherlands or Distrigas in Belgium use very sophisticated computerised central control systems to manage the gas supply network. Sensors all over the high-pressure network relay information to the central control system, which combines this with information from suppliers about gas availability, large consumers and local distribution companies about gas demand, and weather forecasters and weather stations to take decisions about system operation and balancing activities. Unexpectedly cold weather will require prompt action to maintain supply as millions of gas boilers start up automatically, calling on swing contracts, using gas from storage, or notifying interruptible contracts that supply is about to cease. Similarly unexpectedly mild weather will require action to postpone supplies or put gas into storage.

Ensuring quality

As well as guaranteeing physical delivery, the system operators are also responsible for ensuring that pipeline gas quality remains within prescribed limits for both safety and performance reasons. This is achieved partly by specifying minimum quality standards for entry to the high-pressure pipeline system and partly through frequent monitoring and (in some cases) quality correction on the way to the exit points linking the high and low pressure systems.

In the UK, entry terminals play an important role in moderating and controlling quality, creating opportunities for blending or adjusting gas with different characteristics from a variety of fields. But the UK only operates a single pipeline quality specification (see Appendix 2.1) and suppliers have to find or accept ways of meeting that specification if they want to sell gas through the NTS. In contrast, Continental European countries may have several different high-pressure pipeline supply networks for gas with widely different burning characteristics. The Netherlands currently has three different high-pressure pipeline systems for high calorific (H) gas, low calorific (L) gas and Groningen (G) gas.

In the Netherlands, G-gas is the quality supplied to domestic users since this is the natural quality of the huge onshore Groningen field, and H-gas to power stations and some large industrial users. H-gas from other offshore or onshore fields or import sources such as Norway is also blended with either nitrogen or L-gas to create G-gas. Nitrogen is manufactured from air either by cryogenic distillation (similar to the LNG process) or as a by-product from industrial processes like steel making which use a lot of oxygen.

Monitoring the heat (calorific) value of gas in the pipeline system is important for safety, operational and economic reasons. Gas supplied to consumers must conform to a fairly narrow range of calorific values as defined by the Wobbe Index, since this is what determines how the gas will burn in a specific appliance (see Section 2.2.3 above). In the UK, the NTS will accept gas with a Wobbe Index which falls between 48.14 and 51.41 MJ/m^3, but suppliers are only allowed a variation of ± 1 MJ/m^3 around an agreed value within that range for operational reasons (see Appendix 2.1).

In Continental Europe, for example in the Netherlands and Belgium, there are separate transmission systems for H-gas and L-gas, each of which has its own entry quality requirements. The two types of gas may then be blended to meet the burning specifications required by consumer appliances (G-gas). H-gas is either mixed with nitrogen to reduce its calorific value or sold direct to large consumers with the right type of burner. Monitoring the calorific value of gas as it enters the system and moves through the high-pressure network allows the system operator to make the right blending decisions when required and to guarantee the quality of gas supplied to end-users.

Knowing the calorific value of gas is also important for economic reasons since gas is priced and sold to end-users on a heat basis. Gas contracts specify prices in pence/therm, eurocents/kilowatthour or $/mmbtu and this is how gas is traded on the physical, OTC, futures and other derivative markets. Customer invoices also specify the amount of energy supplied to the end-user as well as the volume of gas delivered. Keeping track of the calorific value of gas as it moves through the system is therefore central to the financial and accounting side of the business.

Pipeline gas quality monitoring stations also check for and track the presence and concentration of contaminants such as hydrogen sulphide, sulphur, hydrogen, other hydrocarbons, water, solids, and inert gases, as well as temperature and pressure, all of which are specified in the system entry quality specifications. Excessive concentrations of any of these may affect pipeline operations and/or safety (see Section 2.2.3 above).

2.3.4 Storing natural gas

In the UK gas supply network, storage is provided by several different means. Since the UK lacks suitable natural geological features, such as aquifers, for local storage daily (diurnal) variations in demand are managed through a combination of line pack and local storage in gasholders because this is the only way of meeting instantaneous demand. Line packing involves raising the pressure in the pipeline to hold more gas in the same space, this is then drawn down by reducing the pressure as demand rises.

The UK low pressure transmission system (LTS) provides around 26 mcm of storage through line pack. It is the least-cost method of providing diurnal storage and is gradually replacing low-pressure gas holders, which are expensive to maintain. There are still 460 operational gasholders in the UK, providing around 24 mcm of storage. Other storage facilities available for meeting diurnal variations in demand include high-pressure storage in buried pipe arrays and 'bullets' and low pressure salt cavities, both providing about 3 mcm of capacity each. Some additional storage capacity is also available from line pack in the high-pressure National Transmission System (NTS), providing nearly 10 mcm of potential capacity.

Longer term gas storage is provided by either the depleted Rough offshore field or nine high-pressure salt cavities at Hornsea; both sites are now operated as independent commercial storage businesses (see Chapters 4, 6 and 8). The Rough field can hold very large volumes of gas (30 TWh or 1,000 million therms) and allows injection and re-injection at relatively short notice and high rates so that companies can manage both daily and seasonal variations in demand or supply. The Hornsea salt cavities provide 3.4 TWh of storage that can be used at very short notice. In addition, extra gas supplies can be obtained at short notice from five LNG storage facilities located at the extreme limits of the high-pressure pipeline network at Avonmouth, Dynevor Arms, Isle of Grain, Glenmavis and Partington, which are used by the NTS operator, Transco to supply 'top-up' gas to balance the system and guarantee its operational integrity.

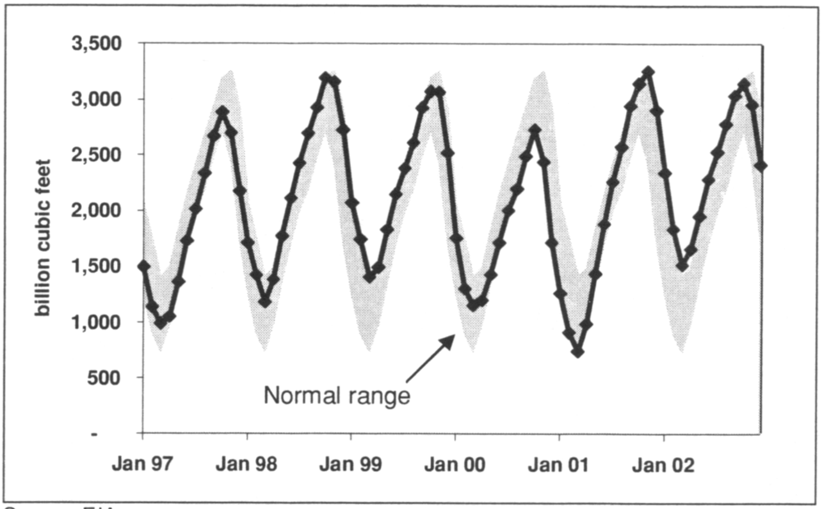
Storage is much more important in the North American gas market because the gas has to travel through very long pipelines and it is not economic to operate the pipes below capacity. As a result, the volume of gas held in storage, and seasonal injection and withdrawal rates, are closely watched by the industry, playing much the same role in gas pricing as stocks of crude oil and petroleum products in the oil market. There are more than 400 underground gas storage sites in the US and Canada, providing in excess of 3 quadrillion (10^{12}) Btus of capacity. Three types of underground storage are common in the US:

- depleted oil or gas reservoirs;
- natural aquifers;
- salt caverns.

In addition, small amounts of gas are stored in gas holders and as LNG, and extra capacity is available from line packing. Peak demand can also be met with synthetic gas, propane and other natural gas liquids.

Each storage medium has different characteristics. Depleted oil and gas fields, which provide the majority of the storage capacity in the US, and natural aquifers tend to be used to meet the seasonal fluctuations in demand as they are filled up and drawn down over a relatively long period of time. But salt caverns, which can be filled and drawn down very rapidly, are used to meet peak demand, for system balancing, and to provide emergency supplies, making them important trading tools in the highly competitive US gas market.

Seasonal storage is filled up during the non-heating season from April to October (214 days) and drawn down in the heating season from November to March (151 days). Average drawdown rates are 71 days for aquifers and 64 days for depleted oil and gas fields. Most facilities are therefore designed for one injection and withdrawal cycle each year. High-deliverability storage, such as salt caverns, can be filled in 40 days or less and drawn down in 20 days or less. Salt caverns can therefore operate several injection and withdrawal cycles in each year.



Source: EIA

Figure 2.8 US natural gas inventory cycle

Natural gas inventories in the US show a clear seasonal pattern, usually reaching a peak at the end of the annual injection cycle in late October or early November before falling through the heating season to a low point in late March or early April (see Fig. 2.8). In a 'normal' year, the inventory cycle covers a range of nearly 2 Tcf, from a low of 1 Tcf to a high of nearly 3 Tcf. Since each storage facility must a hold certain amount of 'base' or 'cushion' gas to maintain operations, stocks cannot be drawn down below a minimum level except for very short periods. Storage gas is then injected in addition to the base volume.

Like the oil market, the level of natural gas inventories plays an important role in shaping prices. Seasonal demand patterns, the annual storage cycle, and the costs of storage help to determine the slope of the forward price curve. Non-heating season prices are usually at a discount to heating season prices, and this enables injection to take place. In the same way, stocks above the seasonal norm tend to depress prompt prices, while stocks below the seasonal norm tend to boost prompt prices – as was demonstrated by the rapid rise in gas prices during 2000 as demand outstripped supply, limiting injection rates and keeping stocks at record lows both before and during the heating season (see Fig. 2.8 above).

2.3.5 Supply hubs and market centres

The liberalisation of the natural gas markets, first in the US and UK, and now in Continental Europe, has encouraged the development of gas supply hubs and market centres potentially offering a wide range of operating and financial services to gas market participants. These services include storage, balancing, peaking, wheeling, parking, loaning, exchanges, compression and, sometimes, blending of quality (see Table 2.5 below). Hubs have also become gas market trading centres and pricing points, facilitating changes in ownership, promoting price discovery, and offering risk management services. In some cases these services are provided by 'virtual' hubs, which provide the same operational or financial outcomes without the need for physical facilities.

Hubs are typically located at the junctions between different pipeline systems and were originally designed to handle the physical transfer of gas from one pipeline system to another (wheeling). These hubs (also known as headers) were often associated with gas storage and gas treatment facilities, thus providing the physical underpinning for the various operational and financial services now offered by commercial hubs and market centres. There are several different types of hub. The simplest type of hub operation moves gas from one pipeline system to another without providing more sophisticated services. These are often located in a supply area and provide an interface between the gas gathering pipelines of various producers and the first stage of a national or inter-state transport system.

Hubs are now beginning to develop in Continental Europe, driven first by supplies of gas through the UK-Continent Interconnector pipeline, and then by trading opportunities at various points in northern Europe. However, the liberalisation process is not yet generally sufficiently mature to facilitate full hub gas markets and services.

Table 2.5 Hub services

Wheeling Essentially transportation service. Transfer of gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over the transmission of a market centre pipeline.

Parking A short-term transaction in which the market centre holds the shipper's gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in line pack.

Loaning A short-term advance of gas to a shipper by a market centre that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.

Storage Storage that is longer than parking, such as seasonal storage. Injection and withdrawal operations may be separately charged.

Peaking Short-term (usually less than a day and perhaps hourly) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.

Balancing A short-term interruptible arrangement to cover a temporary imbalance situation. The service is often provided in conjunction with parking and loaning.

Gas Sales Sales of gas that are used mainly to satisfy the customer's anticipated load requirements or sales obligations to others. Gas sales are also listed as a service for any market centre that is a transaction point for electronic gas trading.

Title Transfer A service in which changes in ownership of a specific gas package are recorded by the market centre. Title may transfer several times for some gas before it leaves the centre. The service is merely an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic Trading Trading systems that either electronically match buyers with sellers or facilitate direct negotiation for legally binding transactions. A market centre or other transaction point serves as the location where gas is transferred from buyer to seller. Customers may connect with the hub electronically to enter gas nominations, examine their account position, and access E-mail and bulletin board services.

Administration Assistance to shippers with the administrative aspects of gas transfers, such as nominations and confirmations.

Compression Provision of compression as a separate service. If compression is bundled with transportation, it is not a separate service.

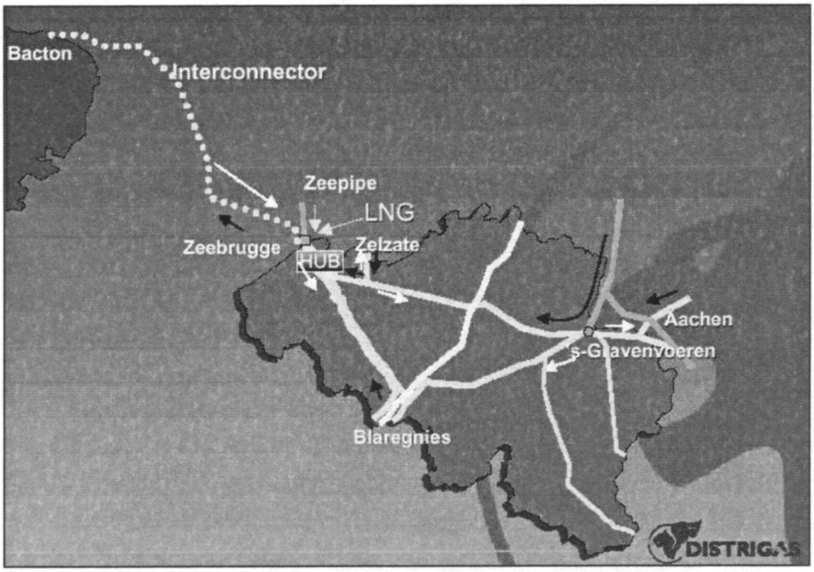
Risk Management Services that relate to reducing the risk of price changes to gas buyers and sellers, for example, exchange of futures for physicals.

Hub-to-Hub Transfers Arranging simultaneous receipt of a customer's gas into a connection associated with one centre and an instantaneous delivery at a distant connection associated with another centre. A form of 'exchange' transaction.

Source: FERC in EIA, Natural Gas Issues and Trends, 1996

More sophisticated services are provided by 'market' hubs which also offer storage, balancing, peaking, parking, loaning, exchange and compression services based on the physical facilities at their disposal. But hub services can also be provided by market centres which do not necessarily have all the physical facilities concentrated at one location. Market centre hub services are typically provided by pipeline supply companies that can utilise the flexibility in their network operations to offer the same facilities as a physical hub. In addition, gas trading companies can now offer 'virtual' hub services without the need for any physical facilities at all.

The best known is Henry Hub, located in southern Louisiana, which provides the pricing basis and physical delivery point for the Nymex natural gas futures contract. But Henry Hub is only one of over 40 supply hubs and market centres operating in the US and Canada. Other key hubs are the Waha and Katy hub areas in Texas, and the Sabine and Ellisburg-Leidy market centres in Pennsylvania. The Kansas City Board of Trade natural gas futures contract is based on the Waha Hub, while the Nymex has also tried, unsuccessfully, to launch alternative natural gas futures contracts based on the Permian Basin Pool, Texas and Alberta, Canada hubs (see Chapter 5). The development of supply hubs and market centres as commercial



Source: Distrigas

Figure 2.9 Zeebrugge hub connections

operations was encouraged and promoted by the US Federal Energy Regulatory Commission (FERC) under Order 636 as part of the liberalisation of the US pipeline market.

Commercial hub operations are a relatively new phenomenon in Europe, but will be essential to the development of an effective 'international' liberalised gas market within the European Union. The UK traded gas market has managed to evolve without the creation of separate physical or commercial hub services, partly because there is only one system operator, Transco, but mainly because of the use of a single, notional, delivery point – the NBP – for all system transactions.

In some senses, the entire UK NTS and its associated markets could be regarded as a market centre since it can – potentially – provide many of the services traditionally associated with a commercial hub. Also some of the beach entry points have the potential to become market hubs, but – until now – they lacked the flexibility and storage capacity to provide the full range of hub services. However, this may well change following the unbundling of BG's storage operations, the proposed trading of linepack services, and the creation of links to the European market.

The first truly commercial hub operation in Europe is at Zeebrugge, Belgium, where the landing point for the UK-Continent Interconnector pipeline intersects with the Zeepipe from Norway, the Distrigas LNG import terminal and the Distrigas high-pressure pipeline network, which has onward links to France, Germany, Luxembourg and the Netherlands and thus to most of Continental Europe (see Fig. 2.9). This complex of physical facilities has become the focal point for the first traded gas contract in Continental Europe following the opening of the UK-Continent Interconnector in October 1998 and is now a fairly liquid market offering a limited range of hub services[3] (see Chapters 4, 6, and 9). Although many of the initial trades were at the Interconnector flange rather than the Distrigas[4] hub, trading has now widened to include the hub itself.

Other European supply hubs are beginning to be used as a basis for gas trading as third-party access to the European gas pipeline network becomes easier as a result of the EU Gas Directive and any of these could become the focal point for a wider traded gas market in Europe in the future. Early candidates included: the Bunde/Oude Statenzijl hub on the Dutch-German border near Emden, Zelzate and Aachen (see Chapter 6). Of these, Bunde/Oude has emerged as the front-runner with regular OTC trades for spot and forward delivery periods taking place at this location. But there are two competing proposals for commercial hub services on either side of the border. On the Dutch side, Gastransport Services (the new Dutch system operator) is offering title-transfer and transportation services at Oude Statenzjl, Bunde and Emden through its subsidiary EuroHub[5]. While, on the German side, HubCo[6] – a joint venture between Ruhrgas, BEB and Statoil – is offering similar services for the Bunde-Emden area. At present, there is no standard contract for gas trading at Bunde/Oude, but there are plans to adapt the EFET[7] – European Federation of Energy Traders – gas master agreement for use at this location.

[3] Zeebrugge hub services are provided by Huberator (www.huberator.com).
[4] Fluxys is now the Belgian system operator (www.fluxys.net).
[5] www.eurohubservices.com
[6] www.nwehub.com
[7] www.efet.org

Appendix 2.1

Transco Network Entry Quality Specification[8]

For any new Entry connection to the Transco System, the connecting party should notify Transco as soon as possible as to the likely gas composition. Transco will then discuss whether this is feasible, on a case-by-case basis. In some cases, network analysis may be required and this will be based on the existing system taking into account Transco's existing statutory and contractual obligations. Therefore, due to continuous changes being made to the system any undertaking made by Transco on gas quality prior to signing a NEA will only be indicative. Transco's ability to accept gas into the system is affected, inter alia, by the gas quality, by the location of the entry point on the system, by the volumes entered and by the quality and volume of gas already being transported on the system. In assessing the acceptability of any proposed gas composition, Transco will take account of:

a) Its ability to continue to meet its statutory obligations with respect to gas quality (including, but not limited to, the Gas Safety (Management) Regulations 1996).

b) The implications of the proposed gas composition on system running costs, and

c) Its ability to continue to meet its contractual obligations.

For indicative purposes, the specification set out below is usually acceptable for most locations.

1. Hydrogen Sulphide

- Not more than 5 mg/ m^3

2. Total Sulphur

- Not more than 50 mg/ m^3

3. Hydrogen

- Not more than 0.1% (molar)

[8] Source: Transco Transportation Ten Year Statement 2002

4. Oxygen

- Not more than 0.001% (molar)

5. Hydrocarbon Dewpoint

- Not more than -2°C at any pressure up to 85 bar g

6. Water Dewpoint

- Not more -10°C at 85 bar g (or the actual delivery pressure)

7. Wobbe Number (real gross dry)

- Within 48.14 to 51.41 MJ/m^3 range, and
- In compliance with ICF & SI limits listed below

8. Incomplete Combustion Factor (ICF)

- Not more than 0.48

9. Soot Index (SI)

- Not more than 0.60

10. Gross Calorific Value (real gross dry)

- A value will be set within the band 36.9 to 42.3 MJ/m^3, in compliance with the Wobbe Number, ICF and SI limits described above, subject to a 1MJ/m^3 variation

11. Inerts

- Not more than 7.0% (molar) subject to
  - Carbon Dioxide: not more than 2.0% (molar)
  - Nitrogen: not more than 5.0 % (molar)

12. Contaminants

- The gas shall not contain solid or liquid or gaseous material that may interfere with the integrity or operation of pipes or any gas appliance (within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998) that a consumer could reasonably be expected to operate

13. Delivery Temperature

- Between 1°C and 38°C

14. Odour

- Gas delivered shall have no odour which might contravene the statutory obligation not to transmit or distribute any gas at a pressure below 7 bar g which does not possess a distinctive and characteristic odour

15. Pressure

- The delivery pressure shall be the pressure required to deliver natural gas at the Delivery Point into the Transco Entry Facility at any time taking into account the Transco System back pressure at the Delivery Point as the same shall vary from time to time
- The entry pressure shall not exceed the Maximum Permitted Operating Pressure (MPOP) of the system into which the gas is delivered.

Note that the Incomplete Combustion Factor (ICF) and Soot Index (SI) have the meanings assigned to them in the Gas Safety (Management) Regulations 1996 Schedule 3 (GS(M)R).

3 The geography of gas

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3.1 Introduction

Natural gas now provides almost 25 per cent of the world's primary energy supply. It has become the most sought-after fuel — not only for domestic, commercial and industrial space heating but also for power generation — putting it well ahead of its two other hydrocarbon competitors, coal and oil, in terms of conversion efficiency, capital cost, and speed and flexibility of power station construction.

At a policy level, gas is also favoured for its environmental cleanliness, not only in terms of reduced air pollution but also for its lower level of carbon dioxide emissions. Traditional concerns about security of supply, scarcity and remoteness have been overcome by the development of new, diverse and often competing sources of gas. The world now has five large regional supply envelopes, each capable of delivering sustained high volumes of natural gas to consuming centres at competitive cost, commensurate with an adequate return on the producers' capital investment.

On a longer time horizon, gas may also provide a feasible technical option for the production of sulphur-free liquid automotive fuels at prices that are competitive with conventional refining processes. At the same time, even a modest view of the trade-off between economic cost and the problem of air pollution could give the gas-fuelled vehicle an entry to the world's road transport fuels market, which has been dominated for so long by products derived from crude oil.

3.2 Supply envelopes

3.2.1 Forces for change

Apart from a long-standing reputation for convenience of use and environmental cleanliness there are three factors which — in varying degrees across the world — have greatly enhanced the position of natural gas as one of the world's major primary fuels.

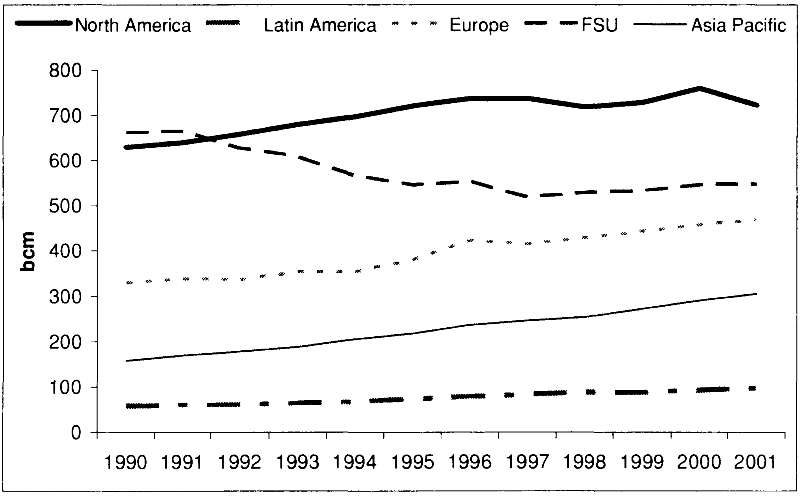
First, the technology of combined-cycle power generation — with its large comparative advantage versus coal and oil in terms of conversion efficiency, capital cost and construction time — has made gas the first choice for power generators when considering new capacity, and even for substitution with existing coal fired stations when faced with increasingly stringent environmental pollution controls.

Secondly, the new exploration opportunities which have been opened up to the oil and gas companies over the past 10–15 years have radically changed perceptions about natural gas, which is no longer seen as being in relatively short supply, or too remote and expensive to bring into centres of consumption.

In addition to the traditional 'core' gas resources in the United States, Canada, the Netherlands, Russia, Algeria, Indonesia and East Malaysia, supplies are now available from Trinidad, Argentina, Peru, Colombia, Norway, the United Kingdom, Egypt, Burma, Vietnam, Thailand and West Malaysia, all of which have substantial proven and developed reserves of gas. Furthermore, Venezuela, Nigeria and the Mideast Gulf all have huge, if more expensive (in delivery terms), supplies of gas available.

Looking further ahead, there are also possibilities for major developments in Mexico, Libya, Tunisia, Iran and the central Asian republics of Turkmenistan, Uzbekistan, Azerbaijan and Kazakhstan as well as further Russian gas developments in Eastern Siberia and the Russian Pacific Far East. As a result, natural gas is now potentially available at an economic cost compared with alternative fuels to all major centres of consumption in the world.

A third, and no less potent, factor which has acted as a powerful link between the supply of and demand for gas — particularly in the power generation sector — has been the trend to open up energy markets through privatisation and liberalisation. In particular, the creation of the 'Independent Power Producer' or IPP has ensured a much sharper focus on cost and efficiency. This, in turn, has reinforced the growing preference for gas as a fuel input to new power stations. With hundreds of projects of this type currently being developed across the world, the IPP acts as a major catalyst creating substantial initial high-loading gas demand and ensuring the necessary long-term supply of gas.



Source: BP Statistical Review of World Energy

Figure 3.1 Gas consumption by geographical area

Since the market value of gas can be measured and established directly in relation to competing fuels — and the economics of power generation are very similar in all regions across the world — there is beginning to be a convergence of valuation and pricing for natural gas, subject, of course, to differences in regulation policy, the degree of competitive market efficiency and the extent of competition between alternative gas supply sources. It is no longer either true or necessary to categorise gas as being 'different' or a 'by-product' whose value is difficult to determine. It is now central to the world's energy requirements, it is accessible and in competitive supply, and its value can be compared directly against competing fuels.

3.2.2 Demand and supply

The potential growth in demand for gas over the next 10–15 years is considerable. For example, in Europe — including the countries of Eastern Europe — demand grew at an average of 3 per cent during the 1990s, reaching 470 bcm in 2001 and could rise to over 700 bcm by 2010, an increase of more than 230 bcm (see Fig. 3.1).

Demand is also growing rapidly in the Asia-Pacific region and is expected to reach almost 400 bcm by 2010, an increase of around 100 bcm compared with 2001. Even in North America, which is a more mature gas market, consuming some 720 bcm in 2001, demand is expected to grow by 180 bcm by the year 2010. And Latin America, whose gas industry is still very much in the nascent phase, is expected to more than double demand to 225 bcm by 2010.

Wider access to potential hydrocarbon producing areas, as seen over the past 15 years, should ensure that there are adequate supplies to meet this rapidly growing demand — subject, of course, to reasonable terms being offered by producer governments to provide sufficient incentive to companies to drill up the gas, as well as reasonable pipeline tariffs and taxes in consuming countries to allow fair competition with other fuels. But just how this is to be managed needs to be examined in some detail and requires comparisons with its sister liquid hydrocarbon fuel, crude oil, in order to understand how gas resource developments respond to demand pressures.

3.2.3 No longer an anomaly

It used to be said that natural gas is fundamentally different from oil because oil is widely traded on an international market, whereas gas is confined to disparate and segmented markets because it is 'local' to an area, or even country specific. Gas was therefore seen as occupying a curious position in the international energy market with no 'world price' of natural gas to refer to, and a market so thin and inflexible that each deal must be tailor-made.

As a result, there was no single standard in the gas industry for how gas costs should be calculated in order to make easy and valid comparisons, either with the costs of alternative energy investments or with the benefit of the gas investment.

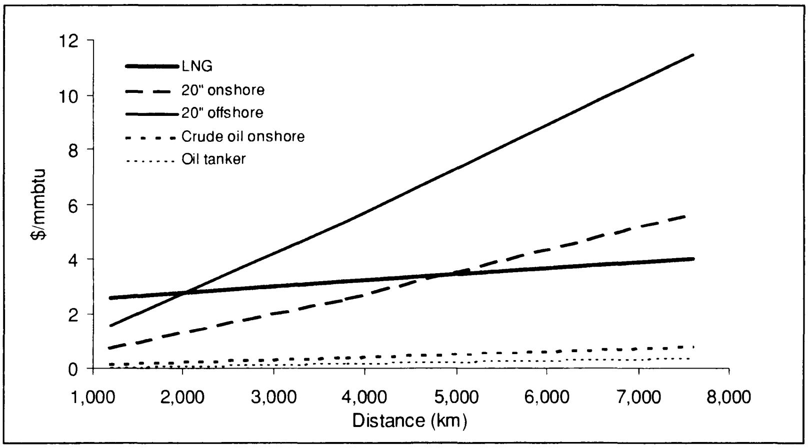
But this view of natural gas, as a curious anomaly in the energy business, is no longer either appropriate or helpful to the analysis of gas as a global energy fuel. With sizeable reserves of gas available at an economic cost to all the major gas consuming regions of the world, and the growing convergence of gas prices around the world through competition with other fuels in the power generation sector, gas markets are becoming both more standardised and more transparent.

3.2.4 Distance and transport costs

It is certainly true that gas is considerably more expensive to move than oil — in unit terms its cost is almost five times that of oil over distances up to, say, 2,000–3,000 km and, using an LNG tanker, is up to ten times more expensive in moving equivalent amounts of energy over long distances (see Fig. 3.2).

Nevertheless, gas is moved very large distances to centres of consumption, either in large-diameter long-distance high-pressure transmission lines or even longer distances in LNG carriers. Although gas is undoubtedly more expensive to move in the form of LNG, it is equally true that there is virtually nowhere in the world that LNG cannot be delivered at — or below — opportunity cost.

There is, however, no need to do so as, for the most part, the large number of competing supply sources, coupled with a well distributed pattern of sizeable gas fields, ensures that the market is cleared at a fully competitive price before more remote sources are required. In the same way, the overwhelming proportion of Asian oil consumption is



Source: World Bank, PEL

Figure 3.2 Costs of transporting oil and gas

derived from local and Middle Eastern crude supplies, while most US consumption is derived from 'local' i.e. US, Canadian, and Latin American or Atlantic basin crude oil supplies.

Finally, the obvious fact that, either as a heating fuel or as a power generation fuel, gas has to compete with coal and oil has led to a steady convergence of gas prices around the world — particularly where incremental power requirements are being met from combined-cycle gas turbine (CCGT) power stations.

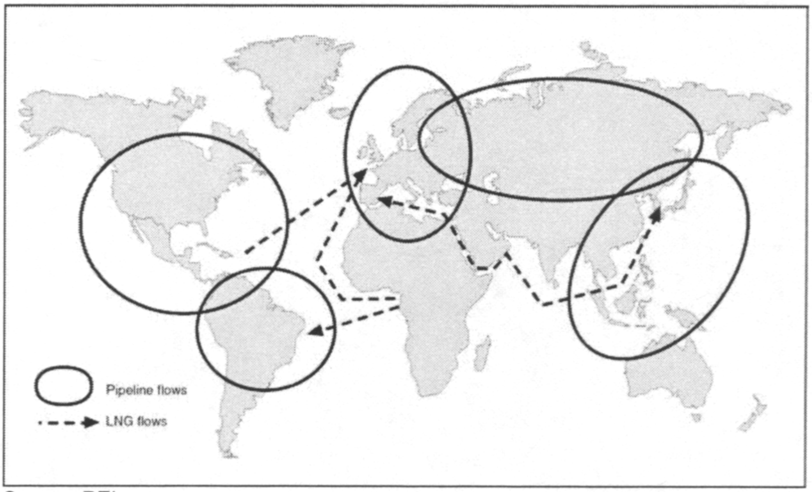
3.2.5 The supply envelope concept

Natural gas is subject to the same form of commercial and economic evaluation as any other energy project. That it is a complex industry, that the product itself is more costly to move than oil — that the industry is certainly fascinating — are all true statements, but that it is an anomaly in the energy market, that it varies from project to project and that it is 'different' in each country are becoming less valid descriptions.

The world gas supply system has now evolved into five major supply envelopes — North America, Europe, the former Soviet Union (FSU), Asia, and Latin America — each of which is defined by the ability to deliver gas at a competitive price into the major areas of consumption within that envelope (see Fig. 3.3). In addition, there is a sixth envelope beginning to be established linking Middle East and potential central Asian supplies with markets in the Indian sub-continent.

The wide variety of national sources and the high level of available gas reserves within each supply envelope is summarised in Table 3.1.

All these supply envelopes have the capability of delivering gas on an incremental economic basis along a transport radius of 2,000–3,000 km into areas of consumption to compete successfully in heating and power generation markets with oil and coal.



Source: PEL

Figure 3.3 The world's gas supply envelopes

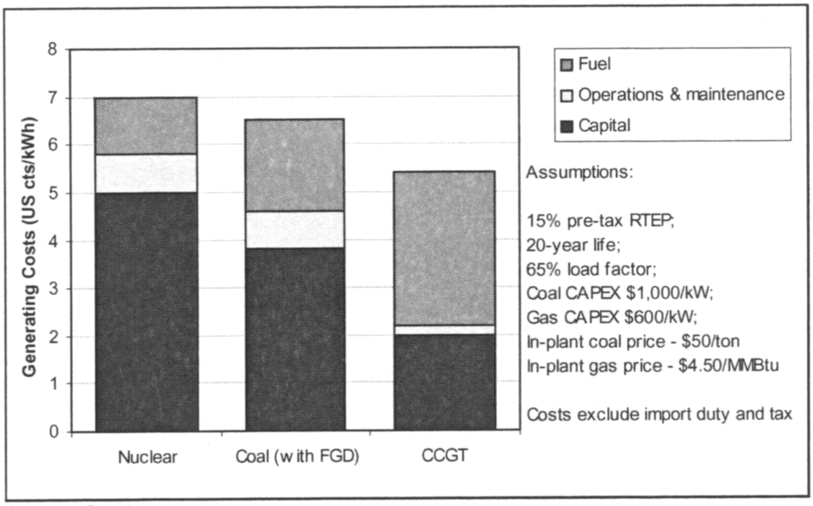
Within these envelopes, the common nodal price of gas is increasingly determined by its use as a fuel for power generation, for which the economics are well known and fairly standardised across all the industrialised regions of the world and designed to generate electricity within a price range of 3.5–5.0 cents per kilowatt hour (¢/kWh).

The concept of the gas supply envelope brings together development cost, transport cost and competitive pricing against alternative fuels. These envelopes are now fairly well established around the world and at least one, North America, has the commercial and regulatory framework to make it a fully operating competitive market with all the associated trading and financial instruments required to ensure a market equilibrium.

Table 3.1 World gas reserves, 2001

	Reserves (Tcm)	**Production (Bcm)**	**R/P ratio (Years)**
North America	7.55	762.1	10
South America	7.16	100.1	72
Europe	4.86	292.5	17
Former Soviet Union	56.14	677.3	83
Middle East	55.91	228.0	>100
Africa	11.18	124.0	90
Asia Pacific	12.27	254.8	44
Total World	**155.08**	**2464.0**	**63**

Source: BP Statistical Review of World Energy



Source: Shell

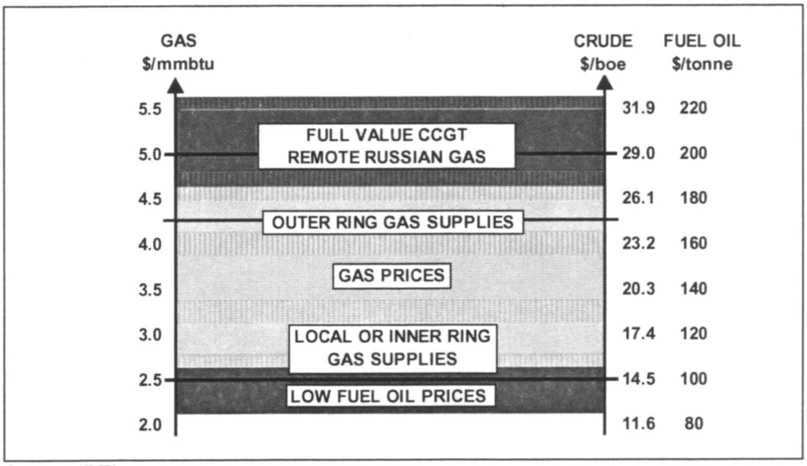
Figure 3.4 Costs of power generation using different fuels

The competitive market allows price signals within the envelope to determine both its geographical reach and whether incremental reserves within it should be brought forward into production. Many of these aspects are dealt with extensively elsewhere so they will not be pursued further here in any detail. At the same time no sensible appreciation of the supply of gas in its geographical and regional context is possible without understanding how these elements fit into the whole market mechanism.

It is no exaggeration to say that the advent and widespread application of combined cycle gas technology has elevated gas to an energy fuel of worldwide significance and transformed the way in which it is evaluated commercially.

At the same time the wave of privatisation and encouragement of private sector finance into utility development has produced an IPP sector that both operates to strict commercial criteria and develops new projects within international standards of cost and price. In a sense, therefore, the convergence of the world power price within a band of 4–6 ¢/kWh is, in turn, forcing the same process on gas pricing.

This is illustrated in Fig. 3.4 which clearly demonstrates the benefit of both higher fuel conversion efficiency and superior environmental performance which gas bestows on power generation. Coal can be used here as a proxy for oil since they have broadly the same calorific conversion ratios (both being confined to single cycle power generation systems). The immediate advantage of gas can be seen and that even at a price of $4.50/mmbtu ($26/bbl, crude oil thermal equivalent) it is the preferred fuel to coal or oil for new power stations. At prices below



Source: PEL

Figure 3.5 The gas price range (thermal equivalent basis)

this — until recently it was $2.50-3.50/mmbtu — in Europe the economic advantage of gas becomes irresistible.

The feasible area for a gas supply envelope can be mapped out by relating distance and price as shown in Fig. 3.5. The diagram clearly shows the amount of 'rent' obtained by a power producer when gas prices are low as well as the willingness to pay a higher amount should local or even 'inner ring' supplies not be sufficient to meet demand.

The diagram also illustrates the dilemma of LNG, which although it can be transported almost anywhere in the developed world at a fully valued CCGT price, is nevertheless excluded from nearly all the major supply envelopes where a lower price obtains. Since gas reserves are fairly evenly distributed around the world, LNG is most competitive in those areas such as Japan or Taiwan, or the East coast of China, that cannot be connected to a source of natural gas supply by pipeline.

At current and anticipated levels of demand forecast for the medium term there are sufficient economically-recoverable reserves of gas that can be supplied at prices well within the full CCGT value of gas. In Europe, for example, incremental Algerian gas can be delivered into Spain, Italy and southern France for $2.50/mmbtu and still show a satisfactory return. Things become more difficult — offshore lines are naturally more expensive per kilometre — as reserves in the Norwegian Sea are brought into play, but supplies could still be provided comfortably at $3.50/mmbtu. While a higher price of $4.50/mmbtu would bring in remote Russian gas, this is at the very outer edge of the envelope.

3.3 Europe

3.3.1 The European supply envelope

Europe is well supplied with natural gas from a variety of sources and backed by large additional reserves to meet future requirements (see Table 3.2). In the south, Algeria is in the process of expanding supplies to meet future consumption growth in Italy, Spain and France. In the north, Norway and Russia have been actively competing to move incremental gas into Europe's markets, and Norway has even sold gas to Italy, Spain and Eastern Europe — although the latter two areas are on the boundaries of economic return at current gas prices. Fully-incremental long-range Russian gas will not be needed for some years to come and, indeed, today could not be economically justified at current prices at the German border.

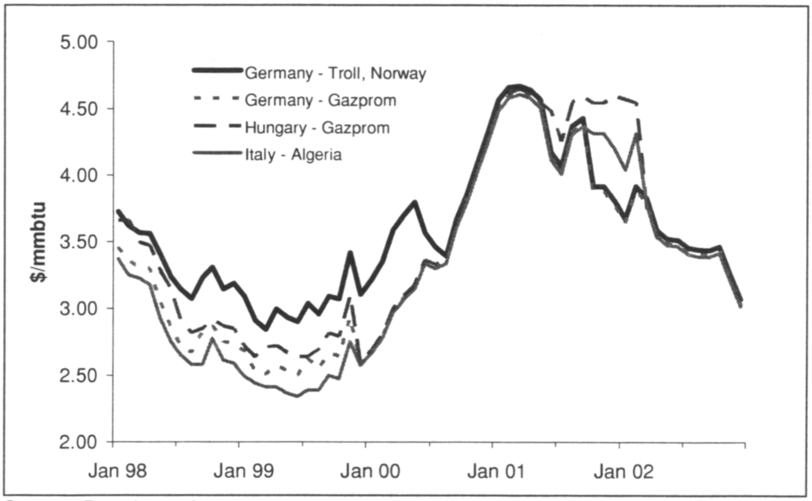
Table 3.2 Continental European gas supplies, 2001

Production	bcm	Pipeline	bcm	LNG	bcm
Denmark	8.4	Russia	107.7	Algeria	20.1
Germany	17.0	Norway	47.1	Libya	0.8
Hungary	2.7	UK	12.4	Nigeria	5.6
Italy	15.5	Algeria	30.6	Qatar	0.9
Netherlands	61.4			Trinidad	0.5
Romania	12.6			Oman	0.9
Other Europe	11.6			UAE	<0.1
Total	**129.2**	**Total**	**197.7**	**Total**	**28.7**

Source: BP Statistical Review of World Energy

Incremental long-range Russian gas, however, is not necessary since there are adequate reserves of gas from existing sources, although some de-bottlenecking of the gas pipeline system — particularly across the Ukraine — will be needed to move additional supplies. The UK — via the Interconnector — also supplies gas into mainland Europe. Southern basin North Sea supplies, however, are essentially limited and additional supplies from new discoveries west of Shetland, or imports from Norway, will be required in due course to meet both UK and continental European consumption. How economic this route will be in comparison with Norwegian supplies from northern Norway — the large Haltenbanken reserves — has yet to be tested.

For the next ten years, Europe is comfortably supplied with gas but, thereafter, prices may need to rise to bring in incremental supplies from deep Saharan Algeria, west of Shetland, the Norwegian Sea and west Siberia. At that stage, Middle East gas also becomes a possibility, but the formidable political obstacles of moving it by pipeline across so many politically sensitive borders will be difficult to overcome.



Source: Petroleum Argus

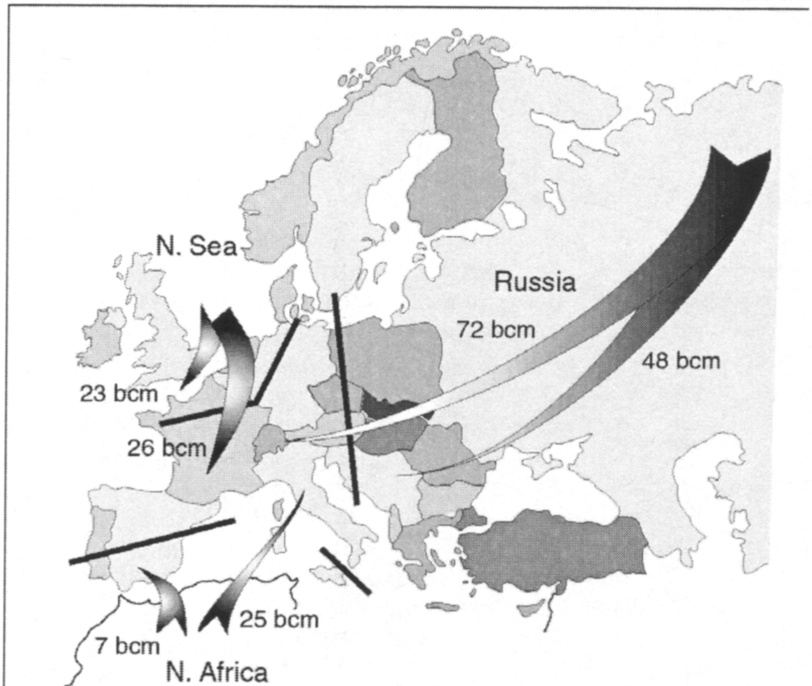
Figure 3.6 Border prices for European gas supplies

Supply competition into the European power market is intense. Gas flows into the European market from Russia, Norway and Algeria together with some small-scale LNG imports from Trinidad and Nigeria and some new supplies from the UKCS southern basin via the Interconnector pipeline which became operational in 1998. These sources supply the bulk of Europe's requirements and define its overall supply envelope.

Although the delivered supply costs from all these sources are subject both to varying degrees of government regulation and utility margin variation, the fundamental upstream or 'border' price is the *lingua franca* of the European gas business and probably has the largest single effect. It is here, rather than at the end of the national and local reticulation systems, that producer competition is both exerted and observed amongst producers in terms of new contracts and market share ambitions.

The pricing boundaries of these supply envelopes are shown in Fig. 3.7 below. Until recently, border prices — whether for Russian gas delivered to Germany, Algerian gas delivered to Italy or Norwegian gas to France — have been in the range \$2.50–\$3.50/mmbtu, moving in sympathy with the crude oil and fuel oil price markers which are employed in most gas contracts (see Fig. 3.6).

While it is understandable that most of the major European gas contracts have been established against their equivalent calorific value markers expressed as fuel oil and crude oil prices, there is nothing immutable about this system. With both the changing uses for gas, particularly in power generation, and the development of new competitive sources of gas, for example the Norwegian drive to market



Source: PEL, BP Statistical Review of World Energy

Figure 3.7 European gas supply envelope

gas in competition with incremental Russian and Algerian supplies, the pricing system for gas in Europe looks set to become rather more fluid and responsive to these factors.

Although, theoretically, if gas were fully valued in terms of its use as a power generation fuel, its price at the delivery point could go up to \$4.50/mmbtu and still compete successfully with either coal or oil, the degree of competition between alternative supply sources has ensured over the past few years — and possibly for some time to come — that the border price of gas will be set at levels between \$2.50 and \$3.00/mmbtu. This allows North Sea gas — both UK and Norwegian — and Groningen gas to be produced and sold quite profitably on an incremental basis.

For example, Algerian gas is sold fairly cheaply in Italy but, despite the cost of the undersea trans-Med line, is still likely to yield a net profit to Sonatrach of around \$0.60/mmbtu and a tax to the Algerian government of roughly \$0.70/mmbtu against a delivered price of \$3.00/mmbtu. This would also be true of Norwegian North Sea gas, although the higher cost of offshore development and offshore pipelines would probably reduce the overall take to around \$1.00/mmbtu, which is still quite adequate to pay off the project on commercial terms and leave a reasonable amount of producer rent for the government to enjoy. Even small field developments in the UK southern basin, either for consumption in the UK or for landing in Europe via the Interconnector, pay off quite handsomely against current price levels since a combination of proximity to the market and a well-established infrastructure reduce transport costs to a fairly low level.

3.3.2 More remote gas supplies

A considerable amount of incremental gas can be produced from this 'inner circle' of fairly proximate gas reserves, but since it is expected that Europe could be consuming an additional 300 bcm of gas between 2000 and 2010, it is important to examine the economics of delivering gas from closer to the rim of Europe's supply envelope. For example, Algeria can produce up to, say, 60 bcm of gas from the giant Hassi R' Mel field but, to avoid losing pressure on its valuable liquids production, it must look to deep Saharan gas a further 500–1,000 km from the main gathering centre to produce sustained volumes above this level.

Equally, the Norwegian North Sea sector although enormously prolific, particularly from the giant Troll field, is unlikely to produce much more than 70–80 bcm without endangering plateau levels. Significant incremental supplies can only be gained by moving further north to the Norwegian Sea. To get gas from Haltenbanken to, say, the northern Italian border is a distance of almost 3,000 km, implying a transport cost of over $2/mmbtu plus the development cost of offshore fields of, say, $1/mmbtu.

These costs would not leave much for producer rent and it is interesting to see that the Norwegian government is now considering rather carefully whether they should commit to major developments from this area without any certainty as to what the future price level for gas in Europe is going to be. Certainly, their own actions in aggressively pursuing a market for Norwegian gas — although successful in the short term — have helped to keep the price of gas below the level of fully-valued power generation, and their efforts to secure sales at Gazprom's expense in Eastern Europe appear to have set a most unfortunate price precedent of around $2.50/mmbtu. Such a low price will barely, if at all, cover the cost of fully incremental Haltenbanken gas and certainly provide no economic rent for the Norwegian government.

A similar problem is likely to be encountered by Algeria. The incremental cost of new gas field developments in southern Saharan Algeria, coupled with the cost of a major new line to Hassi R'Mel, will still allow an acceptable overall return when evaluated at its current sales price into Italy of around $2.70/mmbtu. Any comfort zone, however, is likely to be eroded if, as is increasingly the case, they turn to foreign oil and gas companies to share in these new projects by bringing in both their technology and their capital.

Given the perceived level of risk and the vast array of additional opportunities open to international oil and gas companies, the Algerian government's take may have to be reduced to accommodate the level of return required by the international financial community for projects of this type — rather than some nominal national internal rate of return. Furthermore, competing with increasingly aggressive sales by Gazprom in Italy, Yugoslavia, Greece and Turkey is likely to be difficult at current price levels without reducing Algeria's producer rent yet further.

3.3.3 The Russian position

Accordingly, this leaves the Russian position as being critical, not so much in terms of price as in volume. As with their oil exports, the Russians have always been content to maximise their profits by never wittingly underselling the Rotterdam oil price. If they sensed, therefore, that incremental Norwegian — or, indeed, UKCS — gas were at full stretch and beginning to need a price rise to induce incremental supplies, they would clearly wish to benefit from this position.

At the same time, Russia will also wish to satisfy her volume ambitions, not only to improve total revenue from current producing fields, but also to establish a sales platform from which to develop long-term plans for the full incremental expansion of West Siberian gas fields through and up to the Yamal peninsula. These are likely to be right at the edge of the European supply envelope economics of $4–$4.50/mmbtu delivered to Western Europe.

Equally, the Russians are never going to reach that point by engaging in a protracted price war with other producers, sending out a lower price signal than is needed long term. Of the additional 300 bcm of supply required by Europe in the next 10–12 years, the Russians may wish to secure half (150 bcm). Although the Russian supply system is highly complex and imperfectly understood, it would appear that an incremental 50–75 bcm — a huge volume — is potentially available at variable cost.

De-bottlenecking will be needed, in particular, of the southern trans-Ukraine pipeline system which has the potential capacity to carry much more gas than at present, although this would be a modest expense relative to full scale incremental expansion of Russian supplies.

3.3.4 Ultimate reserves of remote gas

There are several projects which can provide backstop — but economically more marginal — supplies of gas into the European supply envelope. Nigerian and Trinidadian LNG are two such examples, as indeed are further expansions of Middle East gas. Ultimately, the reserves of Central Asia and the Middle East (that is Azerbaijan, Kazakhstan, Turkmenistan, Uzbekistan, Iran and Iraq) can provide giant fallback reserves — even at today's price levels.

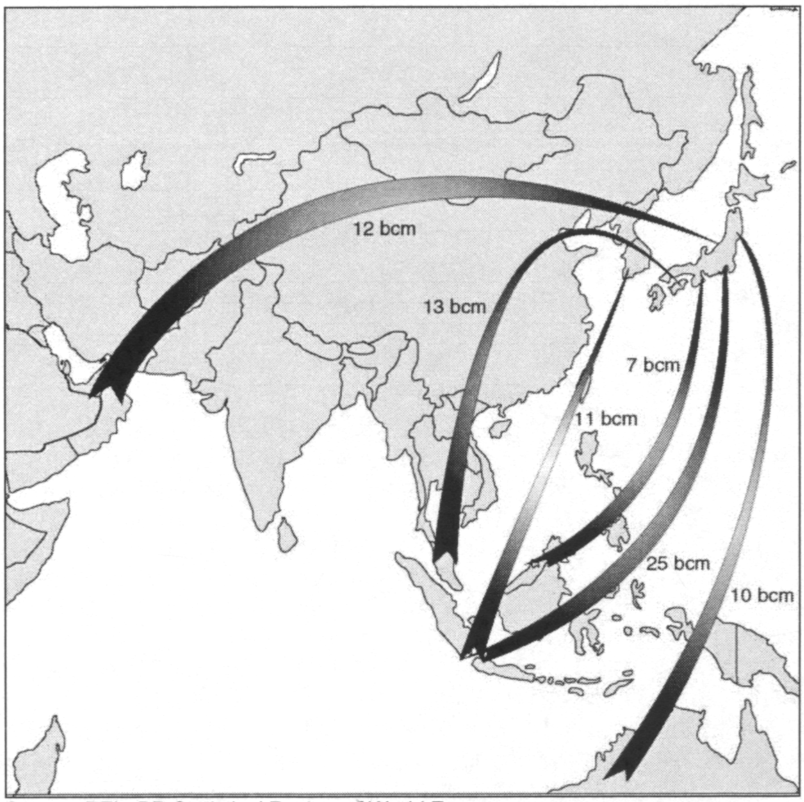
3.4 Asia

Asia is a vast area which should be divided into two sub-envelopes — East and West Asia. As more gas resources are developed across Asia this division will become more obvious and visible. A further, distinct, sub-envelope is also likely to develop as Northern Asia starts to draw in East Siberian gas and the more southerly Asian gas fields are linked to the rapidly industrialising markets of South East Asia (see Fig. 3.8).

3.4.1 Northern Asia

Historically, the Japanese market was the driving force behind the LNG business and it is still true that 80 per cent of the LNG sold in Asia goes to Japan.

But the future direction of the gas business in Northern Asia is more difficult to evaluate, largely because of the huge unknown factor of China and how it will direct its own energy policy over the next 10–20



Source: PEL, BP Statistical Review of World Energy

Figure 3.8 Asian gas supply envelopes

years. If China continues to use its extensive domestic coal reserves, then the prospects for a major expansion in gas seem limited. Nevertheless it is not clear, given the logistical difficulties of supplying China's vast market, whether coal can compete with long distance gas pipelines from, say, East Siberia or imported LNG into the East Coast of China from Australian and Indonesian sources.

Equally, the huge reserves in Sakhalin could provide substantial additional quantities of gas to the region but, as yet, it is not clear whether Sakhalin gas will be moved as LNG into Japan or whether the Japanese will connect it by undersea line to Northern Japan. In addition, an onshore pipeline could be constructed economically to bring gas into Northern China and Korea as well.

3.4.2 South East Asia

Gas supplies are abundant within the South East Asian envelope. Traditionally, it has been liquefied and shipped to Japan from Australia, Malaysia and Indonesia. But the industrial development of Malaysia and the opening up of Vietnam, which also has sizeable, if not huge, offshore gas reserves of its own, has led to the development of a substantial pipeline business which, in time, will cover all of South East Asia bringing in Laos, Cambodia and Burma (Myanmar) as well as a domestic home market for power and industry in Indonesia.

3.4.3 West Asia

Historically, Middle East gas has been consumed locally and exported as LNG from Abu Dhabi to a single buyer, Tepco, in Japan. More recently a number of LNG projects have been proposed and developed — Qatar, Oman and Yemen — with the original intention of supplying Northern Asia, Japan, Korea and Taiwan.

With LNG linked to the volatile price of crude oil, however, the economic viability of these schemes is brought into question, since the combination of high bank financing charges and the transport cost of a long sea voyage account for almost 50 per cent of the total delivered cost of the gas, reducing the profitability of these schemes when oil prices are low.

Instead, attention has turned to developing sales in the nearby Indian market. Numerous import schemes have been proposed, and some may even be built as India slowly gathers confidence and financial strength.

An earlier scheme to link the Indian sub-continent with an undersea gas line from Oman failed to materialise. Although construction would have been a major technical challenge this might well have been more economic than importing LNG. Over time, substantial competing sources of pipeline gas could be made available from Iran and the prolific gas fields of central Asia in Turkmenistan and

Uzbekistan, but the political risks of constructing multi-border pipeline routes present formidable challenges.

3.5 North America

The United States is the biggest gas market in the world, consuming 616 bcm (21.7Tcf) in 2001. Over 80 per cent of US domestic gas consumption is produced in the US, the remainder is imported by pipeline from Canada and Mexico and by LNG tanker from Algeria, Trinidad, Qatar, Australia, Malaysia and the UAE.

3.5.1 Reserves and production

Although not in the same league as Russia or the Middle East, the US has substantial reserves of gas which are concentrated in the south of the country, mainly in the South Central and Mountain regions (see Table 3.3). Seven areas in particular account for three-quarters of US gas reserves: Texas (24%), the Gulf of Mexico (15%), New Mexico (10%), Wyoming (9%), Oklahoma (8%), Alaska (5%) and Louisiana (5%).

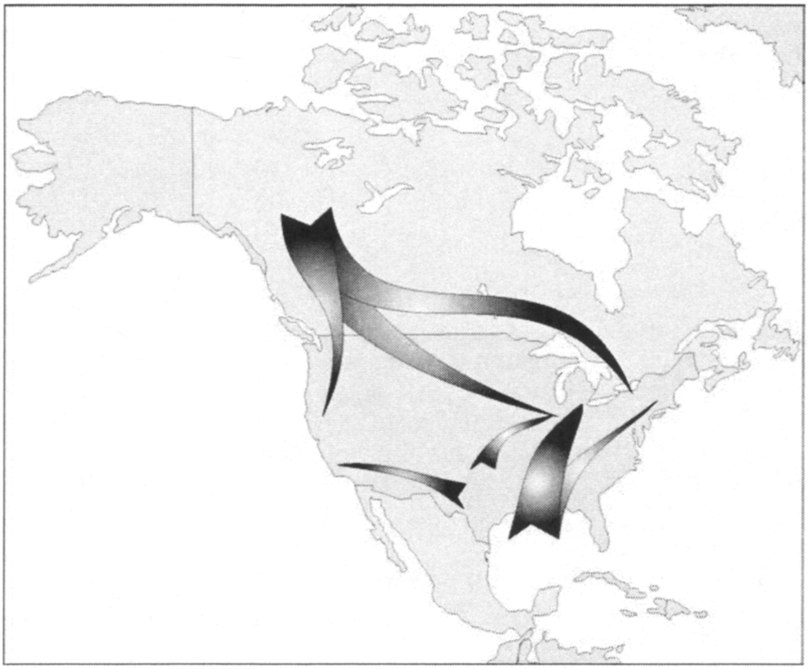
Table 3.3 North American gas supplies, 2001

	Reserves (Tcf)	Production (Tcf)	R/P Ratio (Years)	Consumption (Tcf)
North East	2.1	0.2	10	3.1
South East	4.7	0.3	16	1.9
North Central	9.6	1.0	10	5.0
South Central	99.3	13.8	7	6.7
Mountain	49.0	3.9	12	1.1
Pacific	12.7	0.8	16	2.9
Total US†	**177.4**	**19.6**	**9**	**21.7**
Canada	59.7	6.1	10	2.6
Mexico	29.5	1.3	24	1.2
North America	**266.7**	**26.9**	**10**	**25.5**

Source: EIA, BP Statistical Review of World Energy
† US Census Division data relate to 2000

Unlike many other gas producing areas, the R/P ratio is fairly low at 9:1 but nevertheless reflective of a market that is both fairly mature and also in competitive equilibrium where the discounted 10 year price of gas more or less equates to the finding and development (F&D) cost of drilling up additional gas. Despite the fact that cumulative production over the past 20 years has been almost 150 Tcf current reserves of 177 Tcf are, more or less, at the level they were then.

The process of proving and drilling up additional reserves is widespread and intensive across the country's reserve areas. It is estimated that gas well activity will rise from around 9,000 per year now to almost 17,000 per year by 2015. Lately there has been intense interest in the deep off-shore Gulf of Mexico and it is projected that around 40 per cent of total incremental production will come from this



Source PEL, EIA

Figure 3.9 North American supply envelope

source which is so prolific that each offshore well, on average, is likely to produce almost 6,000 onshore wells! At the same time, interest has switched to very deep gas drilling — down to, and even below, 15,000 ft — particularly in the mid-continent.

The growing shortfall between US demand and supply will be met principally from Canadian imports, which have increased greatly over the past 10 years from modest levels to over 80 bcm per year. Canada has large, relatively untapped reserves of 70 Tcf and Chicago acts as the major import gateway to supply the US and mid-west and north-eastern areas.

As yet there is no pressure to import gas for the southern and western part of the US, although there is a regular two-way trade with Mexico. In the longer run, however, substantial quantities of gas could be imported from Mexico, Venezuela or even Colombia either by pipeline, or, as LNG should it be needed.

Historically there were LNG imports from Algeria but the relaxed supply position did not create a sufficiently strong price climate to induce more LNG imports until recent years. With more LNG export schemes now online around the world the opportunities for LNG trade with the US have increased, adding Australia, Nigeria, Qatar, Trinidad and the UAE to the list of suppliers. And more companies are considering LNG imports after natural gas prices rose sharply in 2000 because of a temporary shortfall in supply due to the collapse in upstream drilling activity after the oil price collapse in 1998–99. Should the situation require it, Algeria, Venezuela or Nigeria could all provide additional LNG supplies for the US market. The geographical pattern of imports and exports of natural gas is shown in Table 3.4 below.

Table 3.4 US natural gas trade, 1996-2001

Mcf	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Imports - pipeline						
Canada	2,883	2,899	3,052	3,368	3,543	3,762
Mexico	14	17	15	55	12	10
Imports - LNG						
Algeria	35	66	69	76	47	65
Australia		10	12	12	6	2
Nigeria					13	38
Qatar				20	46	23
Trinidad				51	99	98
UAE	5	2	5	3	3	
Total imports	**2,937**	**2,994**	**3,152**	**3,586**	**3,768**	**3,998**
Exports - pipeline						
Canada	52	56	40	39	73	157
Mexico	34	38	53	61	105	140
Exports - LNG						
Japan	68	62	66	64	66	66
Mexico		†	†			
Total exports	**153**	**157**	**159**	**163**	**244**	**364**

Source: EIA *† small quantities*

3.5.2 Pipeline infrastructure

As might be expected of this market there is a huge pipeline system to carry the enormous volume of gas involved, particularly for the interstate trade. If demand continues to increase steadily, even an apparently modest projection of 2 per cent per annum on such a large base implies substantial extra volumes — with a parallel need to build more pipeline capacity. In fact, over the next 15 years incremental demand may be of the order of 9 Tcf requiring an additional of 16 bcfd of pipeline capacity to the US national transmission network in the first two years alone!

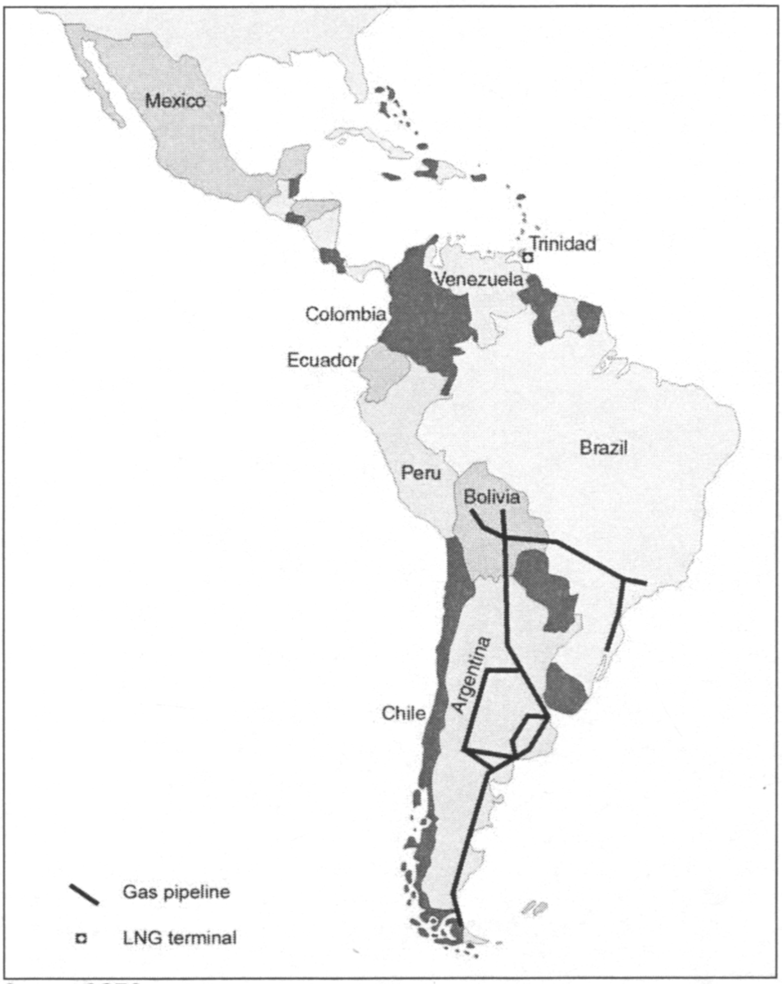
Admittedly much of this is to accommodate long distance pipeline imports from Canada much of it coming through the Chicago transit hub. Although much of this demand increase is already designated for power generation this could increase enormously if there is a national U.S. policy switch from coal to gas fired generation. Currently almost 60 per cent of US power generation is fuelled by coal, which in turn takes almost 90 per cent of US coal production. The scope for switching — and the consequent impact on the fuels concerned — is, therefore, considerable.

3.6 Latin America

3.6.1 The Latin American supply envelope

Latin America provides one of the best examples of supply envelope economics. The demand for gas is being driven principally by new power generation units using CCGT technology. Projected rapid economic development and industrialisation will result in significant growth in electricity demand over the next decade or so.

It has been estimated that $20 billion per year will be needed to provide the necessary generating and infrastructure facilities and



Source: CGES

Figure 3.10 Latin American supply envelope prevent the shortages in power supply which could hold back economic development and living standards. In particular the region's historical over-reliance on hydro-power has revealed an increasing vulnerability to seasonal water shortages.

The key success factor will be the economic attractiveness of creating highly reliable and sustainable gas supplies. Supported by government encouragement for the participation of international power generation industry, a large number of gas supply options are being developed — many of which depend on a new and more open attitude to cross-border trade, interlinking pipeline systems and competitive pricing regimes.

Latin America has a large number of gas supply options following the discovery of major gas fields over the past five years in Colombia, Peru and Bolivia, with Mexico, Venezuela, Argentina, Trinidad and Brazil already possessing significant indigenous supplies (see Table 3.5).

Table 3.5 Latin American gas supplies, 2001

	Reserves (Tcm)	Production† (Bcm)	R/P ratio (Years)	Consumption (Bcm)
Argentina	0.78	38.4	20	33.2
Bolivia	0.68	4.1	>100	1.3
Brazil	0.22	7.7	29	10.9
Chile	0.10	1.1	91	5.6
Colombia	0.12	6.1	20	6.1
Ecuador	0.10	0.1	>100	0.1
Mexico	0.84	34.7	24	33.7
Peru	0.25	0.4	>100	0.4
Trinidad	0.66	12.9	51	9.3
Venezuela	4.18	28.9	>100	28.9
Others	0.07	0.4	>100	1.3
Total	**8.00**	**134.8**	**59**	**130.7**

Source: BP Statistical Review of World Energy, EIA
† excludes gas flared or recycled

Despite the availability of sufficient reserves of commercially exploitable gas, the region is huge and the terrain extremely difficult for pipelines. Nevertheless the problem of constructing commercially viable east-to-west trans-Andean transmission lines appears to be being solved (just!) and the Mercosur area economic agreement is starting to establish an extensive north-to-south system linking Argentina, Paraguay, Uruguay and Brazil (see Fig. 3.10).

How and when the northern 'tier' of supplies in Ecuador, Colombia and Venezuela can be tied in remains to be seen but active domestic markets based on indigenous supplies are developing rapidly and Venezuelan LNG into north-east Brazil could become a competitive option.

3.6.2 Power and gas demand

It is estimated that by, say, 2010 gas demand in Latin America will have risen to around 220 bcm from its current level of 135 bcm. Of the total increment of around 100 bcm, almost 50 per cent will be for gas fired power generation. This, in turn, is based on the projection that, during this period, some 100 GW of generation capacity will be required of which — conservatively — at least 40GW will be for gas fired plant.

On the face of it there appears to be a future for gas suppliers, but their confidence in making investments to bring forward supplies has to be tempered by a residual level of uncertainty concerning eventual off-take levels. Although the IPP sector has generally been welcomed in Latin America, it is nonetheless the case that governments are becoming less willing to provide sovereign underwritten Power Purchase Agreements.

Accordingly, many IPP developers look at the prospect of building merchant plants in the face of dominant — ex-national — generators with considerable misgivings. Indeed, the international financial community's appetite for investment under these conditions is rather lukewarm. Such uncertainty over future off-take levels within 'take-or-pay' contracts is ominous for potential gas suppliers.

Supply envelopes with long pipelines are very sensitive to off-take volatility. But if the supply envelope is made too small then key projects cease to be 'bankable' which could well upset or delay the construction of the basic pieces of infrastructure which collectively form the eventual regional transmission grid.

3.6.3 Brazil

Brazil is leading the way in changing the direction of power generation in Latin America with a huge transitional move announced in Electrobras' current 10 year plan to substitute thermo-electric plants for hydro power. Within a total projected increment of 7000 MW of generating capacity more than 5000 MW will use gas, whether from indigenous sources or imported from Bolivia and Argentina.

The centre piece of the associated gas infrastructure projects is the Bolivia-Brazil pipeline (BBPL) which will eventually carry up to 15–20 bcm of gas into southern and eastern Brazil supplying all the growing industrial and power requirements in that area.

3.6.4 Argentina

Argentina has adequate indigenous reserves to meet its own requirements as well as exports to its immediate neighbours Brazil and Chile. Some of these export lines are rather modest in capacity which creates a potential problem. To support a serious long distance export capacity, Argentina's reserve base will have to expand to create confidence that a sustained high level of off-take can be maintained to make the projects pay.

3.6.5 Peru

The Camisea natural gas development is the major project in Peru's gas industry and, with at least 370 bcm of proven and probable reserves in place, has sufficient capacity to push Peru's domestic market forward to a higher level of development. The project tender has been awarded and price caps for Camisea gas have been set at $0.90/mmbtu for electricity generation and $1.20/mmbtu for other uses.

3.6.6 Colombia

Gas has been discovered by Amoco and Enron has built a pipeline to move it south towards the centre of the country. This has been further reinforced by big new reserves of gas found by the BP-led consortium in the east of Cusiana, Cupiagua and Volcanera. In addition to a plan to construct up to 4000 MW of new gas fired plant over the next 10 years, the government is encouraging the development of local distribution networks to serve industrial and residential needs.

3.6.7 Venezuela

Venezuela has huge (4 Tcm) reserves of natural gas for which it has only fairly recently formally established a national plan for its exploitation. Previously, the main thrust was for LNG export but the so-called Christobal Colon LNG project plan was shelved and has only recently been revived with probably the north-eastern Brazilian market as a main target.

3.6.8 Mexico

Mexico has very large gas reserves, but production growth is constrained by the fact that over three quarters of reserves are associated gas. State company Pemex is undertaking a large programme to raise production; developing non-associated gas fields and reducing flaring and venting will be immediate priorities. In 1999 5.9 bcm of Mexico's gross gas production was flared and vented.

Domestic demand is growing strongly. Mexico has experienced an annual average growth rate in natural gas consumption of 6 per cent since 1995. It is expected that this expansion will continue for the rest of this decade, underpinned by strong electricity demand growth. Mexico both exports to and imports gas from the United States for largely geographical reasons, but was still just a net importer in 1999 (see section 3.5 above).

3.7 Liquefied natural gas (LNG)

Since its early development in the 1960s, when liquefied natural gas (LNG) was first moved from Algeria to the UK and from Brunei to Japan, the LNG business expanded rapidly from 18 bcm in 1977 to 143 bcm in 2001. LNG, however, still occupies a very specialised niche within total world gas consumption of just over 2,400 bcm since it was developed to supply the Japanese gas market where no alternative pipeline gas is, as yet, available. Indeed, the Asia-Pacific LNG sector is almost ten times as large as the rest of the world and, of that, almost 80 per cent of the LNG still goes into Japan.

Over the years, the LNG supply base has broadened considerably. The trading pattern on a global basis is summarised in Table 3.6 below.

Table 3.6 LNG trade movements (bcm), 2001

	USA	Trinidad	Oman	Qatar	UAE	Algeria	Libya	Nigeria	Australia	Brunei	Indonesia	Malaysia	**Imports**
USA		2.62	0.34	0.64		1.84		1.08	0.07				**6.59**
P. Rico		0.58	0.05										**0.63**
Belgium						2.32		0.08					**2.40**
France				0.15		9.80		0.50					**10.45**
Greece						0.50							**0.50**
Italy						2.25		3.00					**5.25**
Portugal								0.26					**0.26**
Spain		0.45	0.91	0.78	0.02	5.20	0.77	1.71					**9.84**
Turkey						3.63		1.20					**4.83**
Japan	1.79		0.83	8.30	6.89				10.05	8.20	22.74	15.27	**74.07**
S. Korea			5.30	6.67	0.17				0.08	0.80	5.77*	3.04	**21.83**
Taiwan											3.70	2.60	**6.30**
Exports	**1.79**	**3.65**	**7.43**	**16.54**	**7.08**	**25.54**	**0.77**	**7.83**	**10.20**	**9.00**	**31.80**	**20.91**	**142.95**

*Source: BP Statistical Review of World Energy *0.4 bcm re-exported by Taiwan*

The future momentum of the LNG industry will depend on the cost of liquefying and transporting the gas from fairly remote sources in expensive ships compared with the growing availability of pipeline gas from closer sources. With a growing availability of local pipeline gas to meet South East Asia's future gas demand there appear to be only four — admittedly huge — areas of consumption left for the LNG trade to exploit.

Japan

With a high opportunity cost against alternative power generation fuels, the gas market could continue to grow even if not as fast as it has done historically. However, if the Sakhalin projects are developed as pipeline gas then an undersea pipeline into northern Japan is likely to be a more economic long run proposition.

Eastern China

Eastern China could be an attractive outlet for South East Asian and Australian LNG but East Siberian gas could well be competitive in cost terms providing the politics of large scale pipeline imports from Russia into China can be accommodated.

India

India seems an ideal potential market for Middle East LNG, which will continue to struggle for growth in the Japanese and Korean markets. A deep-sea offshore pipeline is possible — indeed, was originally proposed from Oman — but the technical difficulties are considerable and the size of the investment and large initial off-take volumes involved might well permanently inhibit such a scheme, thus creating a long-term future for LNG in the Indian sub-continent. Similarly, the possibilities of moving large volumes of Central Asian gas to India are obvious, but the political problems facing the pipeline routes seem insurmountable.

Brazil

Brazil's east coast could be a large potential market for Venezuelan and Nigerian LNG in the absence of major indigenous discoveries and the inevitable cost problems involved in long distance trans-Andean pipeline transport.

Other than these four areas, LNG will tend to struggle to create or maintain a market position not because it is uneconomic as such, but rather due to the availability of less costly pipeline gas well inside the outer rim of the respective supply envelopes. That said, the LNG industry has started to rise to the challenge over the past two to three years and unit costs are falling in all parts of the supply chain. Trinidad's Atlantic LNG project, in particular, has led the way and other new projects will undoubtedly reflect these improvements in cost efficiency.

4 The different markets for gas

Philip Nutman, PricewaterhouseCoopers

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4.1 Introduction

The natural gas industry is undergoing a far-reaching transformation in many countries as government-sponsored regulated market structures replace the historic utility services supply monopolies that existed previously in many countries. Although the pattern and timing of liberalisation is different from country to country and region to region, the same process is at work throughout the world, and this is creating new competitive market structures for the gas and electricity supply industries.

The process of change began in the United States during the 1980s and it has now spread via the UK to Continental Europe, largely as a consequence of the European Gas Directive (see section 4.2.3 and Chapter 7). But the way in which change occurs depends on the commercial structures existing in each country, the pattern of supply, demand and trade, the pipeline infrastructure, and the nature and ownership of the incumbent monopoly companies. This chapter examines how the individual characteristics of the natural gas industry in each country are both changing and affecting change.

4.2 Continental Europe

The driving force for change in Continental Europe is the desire for a single European market in both gas and electricity. The European Gas Directive requires the European gas industry to create new competitive market structures over a ten year period from 1998 to 2008. In order to achieve this, national governments are expected to adopt legislation requiring transmission and distribution companies to allow third-party access to their pipeline systems and giving consumers the right to choose their suppliers. Since Continental Europe is a major importer of natural gas and the incumbent companies have made significant investments in the supply infrastructure, change is not always welcome and progress towards the single European market is slow in some countries – especially as new investment will be required to meet the future growth in gas demand.

4.2.1 Supply and demand

Sources of supply

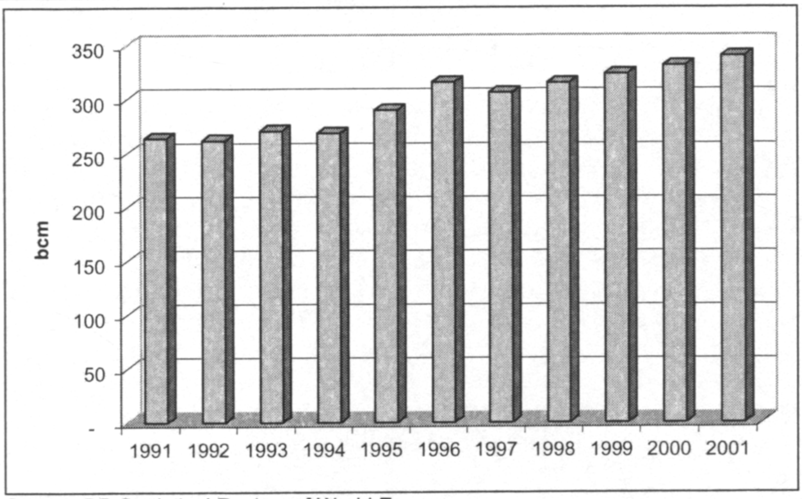
The countries of Continental Europe[1] are heavily dependent on imported supplies to meet their natural gas requirements. In 2001 total gas supplies in Continental Europe were approximately 350 bcm, of which 65 per cent were imported. The four main suppliers to the region in the year were Russia, Algeria, Norway and the Netherlands. Germany, Denmark and the UK provided additional pipeline supplies, while around 29 bcm of liquefied natural gas (LNG) was imported from Algeria, Qatar, Nigeria, Trinidad and Tobago, Libya and Oman. The breakdown of imports in 2001 is shown in Table 4.1.

Table 4.1 Continental European gas supplies, 2001

Production	**bcm**	**Pipeline imports**	**bcm**	**LNG imports**	**bcm**
Denmark	8.4	Russia	107.7	Algeria	20.1
Germany	17.0	Norway	47.1	Libya	0.8
Hungary	2.7	UK	12.4	Nigeria	5.6
Italy	15.5	Algeria	30.6	Qatar	0.9
Netherlands	61.4			Trinidad	0.5
Romania	12.6			Oman	0.9
Other Europe	6.6				
Total	**124.2**	**Total**	**197.7**	**Total**	**28.7**

Source: BP Statistical Review of World Energy

[1] In this Chapter, "Continental Europe" is taken to be Austria, Belgium, Luxembourg, Bulgaria, Czech Republic, Denmark, France, Germany, Greece, Hungary, Italy, the Netherlands, Poland, Portugal, Romania, Slovakia, Spain and Switzerland.



Source: BP Statistical Review of World Energy

Figure 4.1 Continental Europe natural gas consumption

In 2001, Continental European indigenous production of natural gas reached approximately 124 bcm; this was down from a peak of 154 bcm in 1996. Most of this was produced in the Netherlands, while other significant producers included Italy, Germany, Romania, Denmark and Hungary.

It is likely that Continental Europe will become increasingly dependent on imported gas in the future. Whilst Russia and Algeria will remain important sources of supply, there are development plans for new imports from the Caspian region, the Middle East and other North African countries in particular. The EU is beginning to take an active interest in the implications for security of supply.

Demand

From 1991 to 2001, natural gas consumption in Continental Europe grew by 25 per cent to reach 340 bcm/year at the end of the period, accounting for 22 per cent of the primary energy mix. Annual consumption over the decade is shown in Fig. 4.1 above.

Growth in natural gas consumption over the period has been driven by three main factors. First, liberalisation of the electricity markets in the region, which began in the 1990s, has resulted for commercial reasons in a shift in fuel use away from coal and oil to gas (although recent high gas prices have slowed this trend). Secondly, environmental considerations and the need to reduce carbon dioxide and other emissions have promoted the use of gas, which is a relatively 'clean' energy source. Thirdly, the greater availability of natural gas, arising from the significant expansion of both domestic and international transmission and distribution networks, has been an important driver of demand for residential, commercial and industrial consumers.

Table 4.2 Continental European gas consumption, 2001

	bcm		bcm		bcm
Austria	7.4	Germany	82.9	Portugal	2.5
Belgium*	14.7	Greece	1.9	Romania	17.5
Bulgaria	2.6	Hungary	11.9	Slovakia	7.4
Czech Republic	8.9	Italy	64.5	Spain	18.2
Denmark	5.1	Netherlands	39.3	Switzerland	2.8
France	40.7	Poland	11.4		
				Total	**339.7**

Source: BP Statistical Review of World Energy **includes Luxembourg*

In 2001, the largest consumers of natural gas in Continental Europe were Germany, Italy, the Netherlands and France, which collectively accounted for around 67 per cent of total demand. The national breakdown of natural gas consumption in 2001 is shown in Table 4.2 above.

The high growth rate in gas demand experienced over the last decade is forecast to continue in the future. This is expected for a number of reasons: the expansion of natural gas infrastructure that is currently under way; greater inter-fuel competition arising from the ongoing deregulation of national gas markets; the continuing liberalisation of electricity markets and increasingly important environmental considerations. It is anticipated that most of this increase in demand will come from the countries of Southern Europe, such as Italy, Spain, Portugal and Greece, and countries in Central and Eastern Europe, such as Poland, because they must substitute natural gas for coal and oil in order to comply with EU environmental standards.

4.2.2 International trade

The countries of Continental Europe are heavily dependent on imported supplies to meet their natural gas requirements. The chief sources of supply for the region are Russia, Norway, Algeria and the Netherlands.

The European gas trading network

The high growth in natural gas consumption in recent years coupled with the import dependency of the region has given rise to significant investment in international transmission infrastructure over the past decade. In addition, many new pipelines are currently under construction or are at the planning stage. The principal international pipelines that are currently in operation are summarised in Table 4.3.

Table 4.3 Principal international European gas pipelines

Pipeline	**Date**	**Length (km)**	**Diameter (inches)**	**Capacity (bcm/yr)**
Norpipe	1977	442	36	14
Zeepipe 1	1993	800	40	12.6
Midal	1993	600	32, 36, 40	8
Scotland/Eire	1994	300	30	3.5
TransMed (extension)	1994	2,100	48, 26	24
Europipe 1	1995	620	40	13 (initial)
Bulgaria – Macedonia	1995	165	-	0.8
Norddeutsche Erdgas-Transversale (Netra)	1996	292	48	16 to 18
Zeepipe Phase IIA	1996	303	40	17.2
Zeepipe Phase IIB	1997	249	40	18.5
Maghreb–Europe (Phase I)	1996	2,150	48, 22, 28	9.5
Hungary–Austria (HAG)	1996	120	28	4.5
Bulgaria to Greece (Burgas) to Alexandropoulis	1996	870	36, 30, 24	7
Wedal (Westdeutschland–AnbindungsLeitung)	1998	300	40, 48	11
UK-Continent Interconnector	1998	238	40	20
Franpipe	1998	840	42	16
Artère des Hauts de France	1998	185	44	15
Yamal–Europe (Polish section)	1998	670	56	10 to 14
Europipe II	1999	658	42	21.7
Vesterled	2001	45	32	12-13

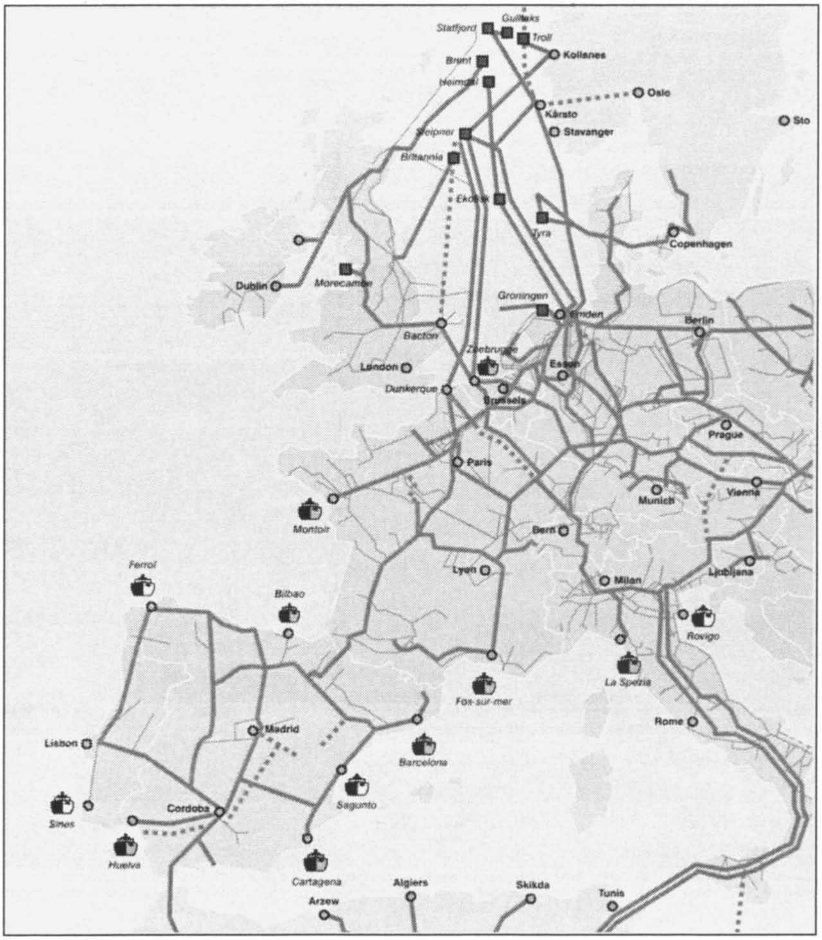
A map of the European Natural Gas Grid in 2001 is shown in Fig. 4.2 below.

Russia

Russian gas deliveries to Continental Europe averaged 108 bcm in 2001 accounting for just under a third of total gas supplies and slightly less than half of total imports. Russia currently supplies most of the countries in the region, with the largest amounts imported by Germany, Italy, France, Hungary, Slovakia, Czech Republic and Poland.

As Russia is expected to remain a vital source of supply for the foreseeable future, the Russian gas export route needs to expand significantly over the next few years to meet the forecast growth in demand. Construction of the Jagal pipeline was completed in October 1999 and makes an important contribution to the Trans-European network. It takes Russian gas from the Yamal line, which runs 4,000 km from the Yamal peninsula, into Germany and Western Europe.

There have been three further recent developments, which are expected to contribute to the expansion of Russian trade over the next few years.



Source: Eurogas

Figure 4.2 European natural gas grid, 2001

First, in May 1998, Gazprom signed an agreement with Ruhrgas of Germany, for the supply of between 13 and 20 bcm of natural gas per year from 2008. In return Ruhrgas agreed to allow Gazprom to use its pipelines, which will help Russian gas to penetrate the developing gas markets beyond Germany, although this might be affected by E.ON's purchase of Ruhrgas.

Secondly, in October 1998, the German east-west 320 km Wedal pipeline came into operation as did the Bacton-Zeebrugge Interconnector. The Wedal is operated by Wingas, a joint venture between Germany's Wintershall (65%) and Gazprom (35%). The line provides an important link between infrastructure bringing Russian gas into Germany from the East with pipelines bringing North Sea gas from the West, effectively connecting Russian gas supplies with Britain.

Thirdly, the 1,213 km Blue Stream pipeline, which runs under the Black Sea linking Russia to Turkey, began operations in early 2003.

Norway

During 2001-2002 Norway implemented changes to its offshore infrastructure operations to bring it in line with European liberalisation policy. As part of a complex new package of arrangements, all gas is now sold separately by individual field owners, not jointly under the auspices of the Gas Negotiating Committee or Gasssforhandlingsutvalget (GFU) as previously. These changes will make a significant difference to Norwegian gas sales contracts in future. Further, all offshore arrangements involving third party transportation are operated by a new state owned company, Gassco. All the pipelines listed below are now operated by Gassco (Norpipe from January 2003).

In 2001 Norway supplied 49 bcm of natural gas to Continental Europe, delivering the bulk to Germany and France and smaller amounts to the Netherlands, Belgium, Spain, Austria and Italy. Norway has several main export pipelines to the region, which are summarised below.

Norpipe Gas first flowed from the Ekofisk facilities to Emden via Norpipe in 1977. It is a 442km line with a carrying capacity of 14 bcm/year. It also carries gas from the Statfjord area (see Statpipe below), and at Emden it links up with Europipe.

Statpipe Commencing operations in 1995, the Statpipe system is an 880 km network comprising a 9 bcm/year rich gas pipeline from the Statfjord area to Karsto, processing plant at Karsto and dry gas pipelines connecting Heimdal to Draupner, Karsto and Ekofisk. At Ekofisk it links with the Norpipe line, which delivers supplies to Emden in Germany.

Zeepipe In operation since 1993, Zeepipe, which transports gas from the North Sea to Belgium, has been developed in a number of phases.

Phase I links the Sleipner area in the North Sea to Zeebrugge, Belgium and includes a connection to the Statpipe and Europipe I pipelines. At 800 km long, the line has a capacity of 12 and 13 bcm/year along its two stretches.

Phase II consists of two lines. Zeepipe IIA runs from the Troll gas treatment plant at Kollsnes near Bergen to the Sleipner areas; while Zeepipe IIB connects Kollsnes to Draupner E in the Europipe I system. Gas transit through Zeepipe IIA and IIB commenced in October 1996 and October 1997, respectively. Both Zeepipe IIA and IIB are 304 km long and have an annual capacity of about 18 bcm/year.

Europipe I and II The 620 km, 13 bcm/year Europipe I line links the Draupner E platform in the North Sea to Dornum, Germany and commenced operations in October 1995. The 658 km, 21 bcm/year Europipe II commenced operations in 1999.

Franpipe The 840 km line (formerly known as *Norfra*), which started deliveries in October 1998, is the longest sub-sea pipeline in the world. With a capacity of 16 bcm/year it transports natural gas from Norway's Troll field to Loon Plage, near Dunkirk, France.

Vesterled This short pipeline is connected to the Norwegian Frigg pipeline, enabling gas to flow from Heimdal to St Fergus in the UK. It provides third party access via an internet site, and together with the Bacton-Zeebrugge Interconnector it increases the options for Norwegian gas to reach the Continent.

With the recent expansion in export infrastructure, Norwegian natural gas deliveries to Continental Europe are forecast to increase by about 50 per cent from 2002 levels, to reach approximately 70 bcm by 2005.

Aside from the emerging markets in the South, Norway has also targeted markets in Central and Eastern Europe – potentially a very substantial new area for Norway, despite the competition from Russia. Norwegian gas already flows to the Czech Republic (1.7 bcm in 2001) and to Poland (0.4 bcm in 2001), delivery being made through Germany's pipelines. More ambitiously, Norway has considered plans for a direct pipeline connection to Poland – with the possibility of an extension to supply the Baltic States. However, a proposed sale of 74 bcm through this pipeline, delivered over 16 years from 2008, now looks very uncertain, due to changing politics in Poland and the effect of lower Polish gas demand forecasts on the economics of the pipeline.

Algeria

In recent years, Sonatrach, the main Algerian supplier, has focused on reinforcing its position in its nearest and growing markets of Southern Europe, in particular Italy and Spain.

Algeria sells 95 per cent of its gas exports to Europe, where they comprise 88 per cent of Portuguese gas supplies, 64 per cent of Spain's, 38 per cent of Italy's, and 24 per cent of French gas supplies, with smaller proportions in other countries. In 2001, this amounted to a total of just over 50 bcm.

There are two main pipelines that link Algerian supplies to the markets of Continental Europe. The first is the 2,100 km Transmed line which has been operating since 1983. This line is a principal source of supply for the Italian market and has been used to transport around 20 bcm of natural gas a year to Italian gas importer Snam, under long-term contracts which began in 1983. The capacity of Transmed is being nearly doubled from 13 bcm to 24 bcm and will provide Italy with some of the additional supplies that are required to meet its growing needs over the next decade and beyond.

The second major pipeline is the 1,400 km Maghreb line, which runs from Algeria's Hassi R'Mel field to Cordoba, Spain and which was completed in 1996. In February 1997 a 750 km extension to the Maghreb line from Cordoba to Portugal enabled Algeria to penetrate the developing Portuguese gas market. The Maghreb line has a capacity of 8 bcm, which will be expanded to 11 bcm when a compressor station is added to the Algerian section of the pipeline. System capacity may eventually reach 18.5 bcm, if plans to add four compressor stations in Algeria and three in Morocco are implemented.

There are plans for another export pipeline from Algeria to Spain under a project development involving Spanish oil and gas company Cepsa, France's TotalFinaElf and Algerian producers Sonatrach.

In addition to the increase in capacity of the Maghreb system, there are also new projects to bring gas by pipeline from Algeria to Spain, for sale to new players and possibly transit through to France.

Aside from its pipeline supplies, Algeria exported around 20 bcm of LNG to the region in 2001. Algeria is currently the principal supplier of LNG to Continental Europe, accounting for around 90 per cent of supplies. Major consumers of Algerian LNG in 2001 were France, Spain, Belgium and Italy.

Netherlands

The Netherlands is the main exporter of natural gas located within the Continental European region, supplying consumers in Germany, Belgium, France, Italy and Switzerland. In 2001, the Netherlands exported 42 bcm of gas accounting for 19 per cent of total Continental European gas imports in the year. Because of the Netherlands' huge onshore gas reservoirs, Dutch export contracts can offer considerable volume flexibility. Natural gas is exported from the Netherlands to bordering countries via 17 export stations.

4.2.3 Regulation and competition

Most of the national gas markets in Continental Europe traditionally have had either one integrated monopoly which controls the extraction/import, transport, distribution and supply of gas or have one dominant integrated player with several companies, often municipally owned, involved in the distribution of gas. But this is now changing with the implementation of the European Union (EU) Gas Directive.

EU Gas Directive

The EU Gas Directive, which requires EU members to open their markets to competition, was adopted on 22 June 1998 and came into force on 10 August 2000. A key aim of the Directive is to introduce third-party access (TPA) to transmission and distribution, providing gas companies and large consumers (such as power utilities) with the right to enter into or negotiate agreements for use of the gas transport system in the various member states. The ultimate objective of the Directive is to create a single European market in gas through the phased opening of individual state gas markets to competition (see also Chapters 7, 11 and 12).

EU members were given a two-year period in which they had to translate the Gas Directive into their respective national legislation. Minimum obligations mean that by August 2000 large consumers with consumption per site of more than 25 MMcm/year must have been able to enter into direct contracts with independent suppliers for their gas supplies. After five years (August 2003), this consumption threshold will fall to 15 MMcm/year and after 10 years (August 2008) to 5 MMcm/year. The initial 25 MMcm/year threshold equates to an average opening of the market, by volume across the EU, of 33 per cent.

The 33 per cent target is not imposed on individual states, which each face targets for minimum market openings of 20 per cent in the first stage (2000), 28 per cent in the second (2003) and 33 per cent in the third (2008). Rules do allow however, for some exceptions (known as derogations) to take account of the fact that gas markets in some countries (e.g. Greece and Portugal) are far less developed than in others.

The current status of the implementation of the EU Gas Directive is summarised in Table 4.4 below. Further information about progress towards full implementation can be found on the European Commission Energy website for the Internal Market for Gas[2]. Some countries – France, Germany – are still behind schedule and the Commission is taking legal action to enforce compliance with the Gas Directive.

The Commission has tried to accelerate the liberalisation of the gas market with a further Directive that sets an earlier target date of 2005 for full market opening for all consumers, bringing changes in the convergent gas and electricity markets closer into line. The revised Directive also hoped to abolish the option of negotiated TPA, requiring pipeline companies to publish standard tariffs for access, insist on the legal separation of activities rather than just the unbundling of accounts, and make the appointment of an industry regulator mandatory rather than voluntary. But strong opposition from Germany and France delayed EU attempts to introduce this new Directive.

EU Energy Ministers finally agreed on 25 November 2002 to revise the Gas and Electricity Directives with the aim of opening up to competition all industrial and commercial markets from 1 July 2004 and all household markets from 1 July 2007. The new Directives will also require the legal unbundling of gas and power grid operators from entities selling gas and electricity. Legal unbundling must be completed for transportation operators by July 2004 and distribution operators by July 2007 to coincide with the market opening dates.

[2] Thematic Site for Energy (europa.eu.int/comm/energy/index_en.html).

Table 4.4 Implementation of EU Gas Directive, October 2002

	Market opening	Eligibility threshold	Full opening	Unbundling transmission	Network access
Gas Directive	*Minimum 20% by 10/8/00*		*Date*	*Accounts*	*Regulated negotiated or a hybrid*
Austria	100%	-	2002	Legal	Regulated
Belgium	59%	5 mcm	2003/6	Legal	Regulated
Denmark	35%	35 mcm	2004	Legal	Regulated
Finland	Derogation (single supplier)				
France	20%	25 mcm	-	Accounts	Negotiated
Germany	100%	-	2000	Accounts	Negotiated
Greece	Derogation (emergent market)				
Ireland	82%	2 mcm	2005	Management	Regulated
Italy	96%	0.2 mcn	2003	Legal	Regulated
Luxembourg	72%	15 mcm	-	Accounts	Regulated
Netherlands	60%	1 mcm	2003	Management	Hybrid
Portugal	Derogation (emergent market)				
Spain	79%	1 mcm	2003	Ownership	Regulated
Sweden	47%	35 mcm	2006	Accounts	Regulated
UK	100%	-	1998	Ownership	Regulated

Source: European Commission, Second Benchmarking Report, 2002

Emerging market trends

The implementation of the EU Gas Directive and anticipation of competition in the markets of Continental Europe is already giving rise to a number of changes in these markets as companies seek to mitigate the risks associated with competition and ensure security and diversity of supplies (see Chapter 7).

Many companies have entered into strategic alliances both with companies within their own domestic market and with foreign players. Spanish firms Gas Natural and Endesa's strategic agreement reached in October 1998 provided an example of the kind of domestic agreements being made. Gas Natural itself has been formally split between its trading and transportation activities, and is now limited to a 35 per cent stake in Enagas. Similar changes have been actioned in the Netherlands, where Gasunie's trading activities are being hived off to its private shareholders – ExxonMobil and Shell – leaving the transmission system in public ownership. More recently, in the UK the infrastructure businesses of National Grid (electricity) and Transco (gas) have merged to form the new entity National Grid Transco.

Russian firm Gazprom's agreement with Germany's Ruhrgas, under which Gazprom extended its 20 bcm/year supply contract to

Germany in return for unspecified access to Ruhrgas' transportation system, provides an example of the cross-boundary agreements being made in the region.

Innovative transit deals have emerged, for example the swap agreement reached between Italy's Enel and France's GdF concerning Enel's Nigerian LNG supplies from NLNG.

In addition, Continental European companies are becoming integrated through merger and takeover. Major gas companies have also begun to diversify their activities into other areas of the energy markets, principally the electricity sector, and related utility and network industries such as water and telecommunications. In late 2001/early 2002 a number of major equity transactions were announced bringing the ownership of Central European gas utilities such as Transgas (Czech Republic) and SPP (Slovak Republic) under largely German and French ownership.

Finally, the establishment of a 'gas trading hub' at Zeebrugge[3], Belgium, has led to hopes of a new era of trade in Continental Europe. Further hubs are developing on the Dutch/German border, and more are expected to emerge as competition progresses, international connection continues to improve and long-term take-or-pay contracts expire, releasing pipeline capacity and enabling spot trading.

The UK-Continent Interconnector

Since 1 October 1998, gas has flowed through the 235 km Interconnector pipeline which stretches from Bacton in the East of England to Zeebrugge on the Belgian coast. UK gas is then transported through the Belgian network to the German, Dutch and French borders. However, contrary to expectations price differentials between the UK and Continental markets have led to gas flowing in the opposite direction for significant periods.

The line can transport up to 20 bcm of UK exports and contracts covering an annual 15 bcm were in place when operations began. In addition, the line has the capacity to carry 8.5 bcm of natural gas each year in the opposite direction, from the Continent to the UK. However, Interconnector (UK) Ltd has now received enough firm financial commitment from some of its shippers to proceed to install additional compressors that will increase the reverse flow rate to 16.5 bcm/year in 2005.

Linking the UK with Continental Europe to join two very different gas cultures, the Interconnector has served as a catalyst for the development of gas hubs in Continental Europe.

[3] Zeebrugge hub services are provided by Huberator (www.huberator.com).

Gas trading hubs

Broadly defined, a gas hub is a physical location that has:

- commercial arrangements in place to enable spot trades;
- several and diverse sources of gas supply;
- good connection to international markets both for the receipt and sale of gas (and capacity available for spot trading); and
- good storage facilities.

While short-term spot trading is well established in the UK, where energy markets are fully liberalised, gas hubs are only now beginning to emerge in Continental Europe. This is the consequence of the changing nature of gas markets. In the past, lack of competition in Continental European markets and the sale of gas under long-term take-or-pay contracts have served to restrict the supply, transmission capacity and demand for gas sold under spot terms.

Zeebrugge, on the Belgian coast, which currently has the capacity to handle 40 bcm of natural gas per year, has emerged as the first gas trading hub in the region (see Chapters 6 and 9). Its importance is expected to grow as Zeebrugge is situated at the meeting point of two principal European gas routes. The first of these routes runs east-west from Siberia to Scotland while the second runs north-south between Norway and southern Europe.

Apart from Zeebrugge, several other locations may emerge as gas hubs over the next few years. These include two separately-owned hubs[4] at Bunde/Oude Statenzijl on the Dutch/German border, where OTC trading is already established, Eynatten on the German/Belgian border, Zelzate in Belgium, Miltenberg in Germany, Emden on the Dutch/German border, Waidhaus in eastern Germany, and Baumgarten in Austria. Locations on the Italian/Swiss border as well as the Spanish/French border may also emerge as hubs, as these are the points at which gas supplies from the south, including LNG from Algeria, meet supplies from the north and east.

4.2.4 Germany

Germany is the largest user of natural gas in Continental Europe, consuming 83 bcm of natural gas in 2001. Germany has indigenous natural gas reserves of 340 bcm, producing around 17 bcm in 2001. However, it is a net importer, relying on imports for 90 per cent of its requirements in 2001. Major suppliers of natural gas to the country in

[4] EuroHub (www.eurohubservices.com) and HubCo (www.nwehub.com).

2001 were Russia, the Netherlands and Norway while smaller amounts where imported from the UK and Denmark.

At 21 per cent, the share of natural gas in the German energy mix is average for Continental Europe as a whole. Natural gas in Germany is used primarily by the residential and commercial sectors, industry and also (to a lesser extent) in power generation. According to forecasts commissioned by the oil industry the market share of natural gas should continue to rise slowly for the foreseeable future.

Most growth in demand over the past few years has come from the east of the country and has been derived from demand for space heating in the residential and commercial sectors and consumption for district heating purposes. Much of this growth has been associated with the substitution of natural gas for lignite, a feature of the industrial regeneration of the former East Germany.

Natural gas demand for the country as a whole is expected to expand by around 20 per cent to exceed 95 bcm by 2010. This corresponds to an average annual growth rate of approximately 1.5 per cent, which is around half the average annual rate of growth witnessed over the past 10 years. The slowdown in growth is expected as the residential and commercial markets become saturated and because of the current drive to improve efficiency in energy utilisation for environmental reasons.

The implementation of the new German Energy Law in April 1998 (Energiewirtschaftsrecht) put an end to the monopoly enjoyed by the country's one thousand public utilities over their demarcated markets. The new law incorporated the bulk of the recommendations of the EU Directive and called for a total liberalisation of the German gas market. However, the government did not appoint a regulator to oversee transportation arrangements, and it was left to the industry players to organise them themselves. A lack of progress on third-party access (TPA) to pipelines has led to a serious delay in the introduction of real competition.

Negotiations between the national association of gas suppliers – the Bundesverband der deutschen Gas- und Wasserwirtschaft (BGW) – and the association of industrial gas users – Verband der Industriellen Energie- und Kraftwirtschaft (VIK) resulted in the VVI German Association Agreement (Verbandevereinbarung für Gas or VV-Gas) on TPAs in March 2000, which introduced a three level tariff structure for self-regulated and negotiated third-party access, namely import/transmission, regional and local levels. The document was, however, heavily criticised for being too complex and government put pressure on the German gas industry to come up with a workable agreement for pipeline access or face the imposition of a regulator.

German gas industry participants finally signed an agreement Verbandevereinbarung II (VVII) on the provision of pipeline access for the year beginning 1 October 2002 on 3 May 2002. This has at least deferred the appointment of a regulator by the Economics Minister.

Nonetheless, in spite of the new agreement there remains a lack of regulation to oversee gas companies' access to other companies' gas transportation grids and hence a potential stifling of competition in the market. Although transportation pricing is now more transparent, different operators offer very different tariff packages. The new system is based on distance related pricing, rather than the more commonly accepted exit-entry charging, which is now being pushed in the negotiations for VVIII.

Main participants

There are around 650 companies operating in the German gas industry. However, this number is expected to decline significantly over the next few years as companies consolidate to survive in the competitive environment. The sector is currently dominated by Ruhrgas, whose shareholders include Bergemann GmbH (60%), BEB Erdgas und Erdöl GmbH (25%) and Schubert KG (15%), who are in turn owned by a number of major German and international companies. Ruhrgas has a controlling interest in the domestic pipeline network and a 70 per cent share of the natural gas market. Ruhrgas is also the largest importer of natural gas in the world. The German conglomerate E.ON has recently taken steps to take over Ruhrgas, but this was subject to a dispute which appears to be settled in February 2003 and will involve the divestment of some of their gas supplies and activities.

The most significant companies in each component of the sector are summarised below.

Exploration and production

Indigenous producers include BEB Erdgas und Erdöl GmbH, Erdöl-Erdgas Gommern GmbH, Mobil Erdgas-Erdöl GmbH, Preussag Energie GmbH, RWE-DEA AG and Wintershall AG. With the exception of RWE-DEA AG and Wintershall AG most producers are subsidiaries or associated undertakings of the international oil and gas majors, Shell and ExxonMobil.

Import, transmission and wholesale supply

While there are around 20 firms involved in this part of the sector, it is dominated by Ruhrgas, which has opposed liberalisation plans. There are two additional significant integrated utilities involved in the importation, storage, transmission and wholesale supply of gas. The first is Wintershall, which through its subsidiary Wingas – a joint venture between Wintershall (65%) and Gazprom (35%) – now has a market share of about 20 per cent. This may be assisted by the proposed auction of contracted gas volumes as part of an agreement to allow the merger of E.ON and Ruhrgas to proceed. The other significant player is the former East-German integrated utility Verbundnetzgas (VNG), which was created to be Gazprom's German marketing company.

Distribution and retail supply

The main player in distribution and supply is Thyssengas AG which is one of the oldest companies in Germany. Its activities cover all operations in the gas industry buying gas domestically and abroad, transport and supply to municipalities in industry and power stations. Most other distribution and retail supply activities are carried out by regional players, some of whom are now at least partly owned by international companies.

4.2.5 France

France is the fourth largest consumer of natural gas in Continental Europe, consuming 41 bcm in 2001. It has minimal remaining indigenous reserves and is therefore heavily dependent on imported supplies to meet its domestic requirements. The chief suppliers of natural gas to France in 2001 were the Russian Federation, Norway, Algeria and the Netherlands.

Over the past decade, French natural gas consumption has been growing at around 4 per cent per annum, from a relatively low base. This was twice the average rate of growth for Continental Europe as a whole and twice the rate of growth of total primary energy consumption in the country.

Nuclear power and oil are the dominant fuels in the French energy mix at present. While natural gas consumption is forecast to continue to grow over the next decade or so, nuclear power in particular is expected to retain its primary position in the country's energy mix.

In the broader regional context, for the foreseeable future France is likely to grow in significance as a transit route rather than as a key consumer of natural gas. This is expected given France's:

- geographic proximity and established ties to the high growth areas in southern Europe, such as Italy and Spain;
- excellent domestic transmission infrastructure; and
- continually improving international connections, such as the Franpipe line which came into operation in October 1998 and which will raise Norwegian import capacity by 10 bcm from 2005.

Since August 2000, large gas consumers have been able in principle to negotiate a gas supply from a third party. GdF tariffs have discouraged some new suppliers from competing in the market, but a number of large sites are now benefiting from third party supply.

Gaz de France (GdF), the dominant player in the French gas sector, has made a number of moves in recent years to exploit France's advantageous position. In 1997 the Italian Electricity Company, Enel, got into difficulties because it committed to take LNG from Nigeria but was unable to build its planned receiving terminal, for environmental reasons. GdF entered into an emergency swap agreement with the Enel, for the exchange of 3.5 bcm/year of natural gas from 1999. Under the agreement, Nigerian LNG destined for Enel is delivered to GdF at the Montoir-de-Bretagne terminal in France, while Algerian LNG is delivered to Italian Gas Company Snam's terminal near Panigaglia. Enel receives the remaining supplies from Russian pipeline supplies delivered to Gaz de France at Baumgarten, Austria. More recently, GdF agreed to a long-term commitment for LNG from Egypt and new reception facilities at Montoir. GdF has a strategy to acquire/develop sufficient upstream gas reserves to meet 20 per cent of its market needs.

Main participants

Indigenous production of natural gas in France is principally the task of Elf Aquitaine Production, which operates the Lacq deposit, situated in the southwest of the country. However, this gas field is nearly fully depleted.

Before August 2000, the gas transportation network was owned by the state, which gave concessions to three companies, GdF, Gaz du Sud-Ouest (now owned by TotalFinaElf and GdF), and TotalFinaElf as operator of the Lacq field. The country's three main networks have now been sold to Gaz de France and TotalFinaElf, and Gaz de France. Gaz de France still dominates transmission and distribution in the sector, with 90 per cent and 96 per cent shares, respectively.

Local distribution is undertaken jointly by GdF and Electricité de France (EdF), the French electricity monopoly, through 98 Distribution Areas. 17 non-nationalised distribution companies are responsible for distribution in the 4 per cent of the market that is not controlled by GdF. However, in order to guarantee continuity of supply to the nation as a whole GdF is responsible for co-ordinating the movement of gas throughout the entire French transmission network. Plans for the partial privatisation of GdF were delayed by union opposition, but the French government is now planning to go ahead with this.

Only a new gas-bill can eliminate GdF's official monopoly and open the way to privatization. But France's CGT, the leading gas and energy trade union, wants a merger of GdF and EdF into a joint 50-50 company to produce and transport energy and forge alliances with other countries and companies.

4.2.6 Italy

Italy is the second largest consumer of natural gas in Continental Europe, with total consumption reaching nearly 65 bcm in 2001.

Domestic consumption of natural gas has risen steadily over the past 10 years, growing by just over 3 per cent a year from 1991 to

2001. This growth rate appears set to continue for the foreseeable future with consumption forecast to reach more than 90 bcm by 2010.

Over the next decade, natural gas consumption will be driven by a number of factors, the most significant of which are summarised below:

Liberalisation of the power sector

As a consequence of the ongoing liberalisation of the market and forecast growth in electricity demand of 2 per cent per annum until 2010, the Italian electricity sector is likely to contribute the most to growth in natural gas consumption over the period. Plant economics in conjunction with national and local environmental policy force any (non-renewable) capacity conversions and additions to be gas-fired.

Environmental legislation

Stringent environmental policy, which on the whole aims to encourage the use of natural gas vis-à-vis other fossil fuels, should also stimulate growth in demand for natural gas from the Industrial sector as a whole over the next few years. In particular a levy on fuel consumption introduced in January 1999, which aims to control carbon emissions by encouraging the substitution of natural gas for oil and coal, is likely to become of increasing importance in this context.

Deregulation of the gas sector

According to the EU Natural Gas Directive, passed in June 1998, member states must open their natural gas markets to competition. The Italian government unveiled plans for its liberalisation process in May 2000, and directed that no single company could supply more than 50 per cent of the natural gas sold to final users by 2003. No company could send more than 75 per cent of natural gas put into the transmission system beginning in 2002 (apart from gas required for own generation), and this will be reduced to 61 per cent by 2009. The legislation also required corporate and accounting separation of natural gas storage and transport activities. Snam retained control of Italy's 30,000-kilometre (almost 19,000-mile) pipeline natural gas grid, but parent company ENI was forced to split Snam's pipeline transport activities from commercial and sales activities.

Italian consumers currently pay amongst the highest prices for natural gas in Europe and therefore domestic demand is likely to receive a boost from the downward pressure on prices that competition is expected to exert. Freedom of the gas market has been delayed by fears of inflation, however, and in September 2002 the government announced a cap on tariff prices. While this keeps prices lower, it discourages the development of competition, not least by loss of confidence in the independence of the regulatory system.

Italy is the third largest producer of natural gas in Continental Europe (after the Netherlands and Germany), producing just under 16 bcm of natural gas in 2001 accounting for a quarter of the country's requirements. While there has been a recent rise in domestic exploration and production after a slow period of several years, Italy looks set to become increasingly reliant on imports.

In the past few years, Italian companies have entered into new contractual agreements with existing and alternative sources of supply. Traditional suppliers include Algeria, the Russian Federation and the Netherlands, while new supplies have recently been secured from Norway, Nigeria and Abu Dhabi. Major import contracts that are currently in place are summarised in Table 4.5 below.

Table 4.5 Italy, major gas import contracts

Exporting country	Buyer	Contracted volumes (bcm)	Expiry date
Netherlands	Snam	6	2010
Russia	Snam	7	2010
Russia	Snam	8	2008
Russia	Snam	5.5	2015
Russia (from 2000)	Snam	8	2005
Algeria	Snam	19.5	2020
Algeria (LNG from 1997)	Snam	2	2015
Norway (from 2000)	Snam	6	2025
Netherlands (from 2001)	Snam	4	2020
Algeria	Enel	4	2014
Nigeria	Enel	3.5	2018
United Arab Emirates (from 1998)	Edison	0.4	June 1999

In July 1999, ENI's subsidiary Agip North Africa BV announced an agreement with the Libyan National Oil Corporation (LNOC) for the development of Libyan gas, condensate and oil reserves. The agreement also provides for the construction of a 600 km, 32 inch pipeline, stretching from the Libyan coast to Sicily, which will transport around 8 bcm/year of natural gas to the market. Deliveries are expected to commence in the summer of 2003.

In Algeria, Sonatrach and BP Amoco have given a green light to the $2.5bn project to develop seven Saharan gas fields in the In-Salah region. The project will supply some 9 bcm/year to southern Europe, starting in 2003. Italy's Enel has provisionally agreed to take 4 bcm. Italy's independent Edison group is expected to take 4 bcm/year. The field's estimated reserves are capable of producing between 9 and 11 bcm/year over 35 years.

In order to meet the growing requirements of the market, Italy's gas transmission and distribution infrastructure has been expanding rapidly in recent years, with major enhancements taking place in Southern Italy and the Italian islands in particular. From 1993 to 1997, ENI's primary and secondary networks grew by 12 per cent and 11 per cent respectively over the period as a whole. International networks were augmented in 1995 with the expansion of the Trans-Mediterranean pipeline, which transports Algerian supplies to Italy. In addition, in 1997 after two years of upgrading, the Panigaglia LNG terminal (the only LNG terminal in the country) resumed operation.

Main participants

ENI currently accounts for around 90 per cent of indigenous production, while various operators produce the rest, the most important being Edison with a 7 per cent share.

While the state-owned electricity company, Enel and Edison Gas independently import some of their supplies, ENI's subsidiary Snam is the main importer and sole transporter of natural gas in Italy. From July, 2001, Snam SpA transmission, dispatching and regasification activities were conferred on Snam Rete Gas SpA, 40 per cent of which was subsequently sold to a range of private investors in November 2001. From February 2002, Snam SpA and Somicem SpA were merged into ENI SpA, and the new Gas and Power Division of ENI became responsible for managing its natural gas activities.

The principal local distributor is Italgas, which has a 34 per cent share of the market and is 41 per cent owned by ENI[5]. Remaining local distribution and supply is the responsibility of numerous regional (primarily municipally owned) entities, operating under long-term concessions.

In November 2002, BG announced that it had obtained planning consent for its proposed LNG import terminal at Brindisi. Meanwhile, Gas Natural of Spain has set up a new company Gas Natural Vendita SA to be a gas wholesaler in Italy.

4.2.7 Netherlands

The Dutch natural gas industry is the longest established in Continental Europe. This is partly because of its considerable indigenous reserves and partly because of the high level of state involvement in the sector that has encouraged sustained investment in exploration and production and ensured security of supply. Dutch gas exploration, production and exports have been relatively tightly controlled by the Government, with the Ministry of Economics having the power to

[5] ENI has offered to buy the remaining shares in Italgas (December 2002)

earmark gas of Dutch origin for domestic use. Revenues from gas production form an extremely important part of the government's finances.

In absolute terms, with consumption of 39 bcm in 2001, the Netherlands is the fourth largest consumer of natural gas in Continental Europe. Natural gas currently accounts for 42 per cent of the Dutch energy mix, twice the average for Continental Europe as a whole. Over the past 10 years, natural gas consumption has grown very slowly, reflecting the maturity of the Dutch natural gas sector.

In accordance with the EU Gas Directive, the Netherlands is moving towards market liberalisation. The Government's proposals, which were announced in 1998, provided for immediate, non-discriminatory "negotiated" third-party access to Gasunie's transmission networks. The threshold level for customers free to choose their supplier was reduced to 1 million cubic metres a year in 2002. Access terms are now subject to regulatory control, so that a hybrid access system is now in place[6].

An important factor in the development of competition in the Netherlands was the completion of the UK Bacton to Zeebrugge terminal Interconnector pipeline, which enabled new gas supplies to be brought from the UK to the Dutch market. In 2001, the Netherlands imported 7.5 bcm of gas from the UK. Gasunie now plans to build its own direct link to the UK, following its agreement to sell gas to Centrica in the UK under a long-term sale agreement.

Main participants

Control over production and exports is divided evenly between private companies and the Dutch Government. The main private companies are Shell and Exxon, partners in Nederlands Aardolie Maatschappij (NAM), the company which developed the Groningen gas field, the largest field in the Netherlands. Collectively, NAM and Energie Beheer Nederland (EBN) – which holds the Government's interest in gas fields – account for 85 per cent of Dutch natural gas production.

Ownership of Gasunie, the Dutch transmission and export company which had a de facto monopoly of these functions, was evenly divided between Shell, ExxonMobil, the Dutch Government (through EBN) and directly by the Ministry of Economy. While Gasunie bought natural gas from a large number of producers, NAM was its principal source of supplies. As a consequence of the liberalisation changes, Gasunie has now been split, and transportation has been taken over by the state owned company Gastransport Services. The trading activities of Gasunie are to be split between Shell and ExxonMobil.

Recently there have been many purchases of gas distribution companies by power utility companies. These include Maatschappij Tot

[6] A new access regime with delivery based on a virtual 'Title Transfer Facility' (TTF) similar to the UK's NBP is being introduced in 2003.

Gasvoorziening Gelders Rivierengebied (GGR-GAS) bought by Dutch utility Nuon, the merged electricity distributor, the gas utility Nutsbedrijf Haarlemmermeer (NBH) bought by the German power utility VEW (now merged with the German multi-utility RWE) and Obragas by RWE. However, the new Dutch Government has now imposed a ban on any further stakes in gas distributors being sold for the time being.

4.2.8 Spain

Although gas consumption per capita in Spain is still relatively low, the Spanish gas sector is in the midst of a strong phase of development. Over the past decade, natural gas consumption in Spain has grown at the second highest rate in Continental Europe, trebling over this period to reach 18 bcm in 2001.

The high growth in consumption over the period has been largely driven by the price competitiveness of natural gas in relation to other fossil fuels. Natural gas prices for Spanish industrial, residential and commercial consumers are currently among the lowest in Continental Europe. This has been attributed to Spain's efficient gas infrastructure and its purchase of imported supplies at extremely competitive prices.

The high consumption growth is expected to continue with demand forecast to reach 33 bcm by 2012. As in Italy, the Spanish power sector will be the main driver of demand for natural gas over the period. New capacity requirements in the electricity sector are expected to cause gas demand for power generation purposes to rise from 0.5 bcm in 1998 to reach 10 bcm in 2012.

With minimal indigenous resources, Spain relies heavily on imported supplies, both by pipeline and LNG tanker. Algeria and Norway are the two pipeline sources, providing about half Spain's needs. But LNG imports from Algeria, Nigeria and Trinidad are almost as important. Spain currently has the largest number of regasification terminals in Continental Europe (at Barcelona, Cartagena and Huelva) with more planned by new entrants, who have contracted new supplies from Egypt and Nigeria and Middle East Gulf states, among others.

Spanish natural gas importer Enagas's current supply contracts are summarised in Table 4.6 below.

Table 4.6 Spain, Enagas's supply contracts, 2000

Source	Annual volume (bcm)	Total volume (bcm)	Expiry date
Algeria	6.00	138.53	2020
Algeria (LNG)	4.18	25.38	2004
Libya (LNG)	2.13	23.37	2008
Nigeria	1.50	37.50	2024
Norway	1.92	62.29	2030
Trinidad & Tobago (LNG)	1.43	28.60	2018
Inland production	0.33	1.70	2003

Spain passed its Hydrocarbon Law in 1998 to comply with the EU Gas Directive and, as of April 1999, all sites with a consumption rate equal to or more than 5 MMcm/year were eligible to choose their supplier – opening up nearly 70 per cent of the market to competition. From January 2003 all customers, regardless of their level of consumption will be entitled to choose their supplier.

About 30 companies are registered as suppliers into the contestable (liberalised) market, but only a handful are as yet active. In order to make gas available to new players, the government ordered the release of 25 per cent of Algerian gas contracted to Enagas and supplied through the GME pipeline. This gas was offered via a competitive bidding process to new entrants for the period 2002 - 2004, and BP and Iberdrola each won 25 per cent of the gas on offer, and Union Fenosa 20 per cent, Endesa 18 per cent and Shell 2 per cent.

Gas trading has not yet properly developed in Spain, apart from swapping of quantities in storage (i.e. LNG tanks) to optimize costs, but with the increasing volumes of gas sold by new players, real wholesaling could well start in the winter of 2002/2003.

Main participants

The Spanish natural gas market is dominated by the Repsol group affiliates, Gas Natural (which supplies around 90 per cent of the market) and Enagas (the main importer of natural gas in the country and national transporter). These two companies had been operating under a single management team but in May 2000 announced their intention to demerge, although some degree of cross-ownership (limited to 35 per cent) is maintained.

Endesa, the national electricity company also has limited distribution assets in the gas sector and in October 1998 entered into a strategic agreement with Gas Natural. As a result of this agreement, Gas Natural will supply Endesa with the gas required to fuel its planned 2,500–3,000 MW of new power stations at competitive prices. In effect, Endesa is committed to buying the great bulk of its future gas needs from Gas Natural. The two companies have together built four combined cycle power plants, each with a capacity of 400 MW, in Cadiz and Barcelona, owning two apiece. Endesa has also entered the gas market, and is supplying a number of large gas customers (it has for some time had a share of gas distribution interests in some regional gas industries). In addition to its gas supply from Gas Natural and gas awarded in the release programme, it continues to supply further marketing needs through spot purchases of LNG.

Union Fenosa (UF) is at an advanced stage of plans to bring gas to Spain from a liquefaction plant in Egypt at a cost of $1bn. The plant will guarantee supplies of gas for around 2,000 MW of combined cycle plant to be completed by 2005, and UF will also be able to sell to third parties in Spain and Europe. The amount of gas covered by the deal is equivalent to around 25 per cent of Spain's current gas usage. It has taken a stake in two new regasification terminals, and is a partner in the Reganosa project. UF also won 20 per cent of the released Algerian gas (0.85 bcm). However, these activities have been very ambitious for UF, especially the Egyptian plant, and it was forced to put half of its gas business up for sale[7].

BP is a leading new player in the Spanish gas market and has a strategic alliance to pursue power opportunities with Repsol, principally in Spain but also in Latin America. Further Spanish power projects – beyond the planned 800 MW facility in Bilbao – are likely in the near future. BP is involved in the development of Trinidadian gas and in shipping the LNG to Spain, regasification and delivery to downstream power projects. In addition to its release gas, BP has recently announced the purchase of a total of 1.5 million tonnes per annum of LNG from Adgas and Qatargas. In future, it is also likely to have access to Egyptian gas through its joint venture with Sonatrach in In Salah.

Another challenger to Gas Natural is the Italian company ENI, which has several interests in Spain and recently announced plans to buy 0.74 million tonnes per annum for 20 years from Rasgas. It has agreed to sell 1.5 bcm/year of LNG to Iberdrola,

Another notable new gas player is CEPSA, which is partly owned be TotalFinaElf, and which with Sonatrach has led plans for the new Medgaz pipeline from Algeria. It has recently sold shares in some of its gas and electricity interests to Sonatrach, which is interested in moving downstream in Europe.

4.2.9 Greece

The Greek natural gas industry is in the early stages of development and is expected to grow considerably over the next decade or so. The industry only came into existence in 1988, when the state-owned public gas corporation, DEPA, was created in an attempt to reduce the country's reliance on oil. As a consequence, natural gas currently has only a very small share of the country's energy mix.

The Greek Government plans to raise natural gas's share of the primary energy mix to 7 per cent by 2010. The International Energy Agency (IEA) describes this target as "conservative". DEPA itself has projected that natural gas demand could be in the region of 7-8 bcm by 2020, accounting for an estimated 15 per cent of the country's energy mix.

In 2001, Greek natural gas consumption was around 2 bcm. Considerable growth in natural gas demand is expected as investment in expanding the country's natural gas infrastructure enables power sector and industrial consumers to be connected to the system.

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[7] ENI bought a 50% stake in Union Fenosa Gas in December 2002

Significant work is currently underway to expand the country's natural gas transmission and distribution infrastructure. Most regions in Greece are currently without a local distribution network. Athens was the first city to have a gas distribution system and in 1997 supplied a total of 8,000 customers and this was expected to rise to around 30,000 in 2000.

Following privatisation of the distribution sector, Italgas won the right to lead the development of the gas market in Thessaloniki and Larissa. The third identified area, Athens, is being developed by a joint venture between Shell and Cinergy. The process to privatise the next two or three distribution areas is expected to start in 2003.

Before 1998 all of Greece's gas demand was met from the country's limited indigenous supplies. Prospects for further development of indigenous resources are limited and therefore nearly all of the growing market's requirements will be met by imports.

As can be seen from Table 4.7 below, Greek gas supply is currently based on the import of Algerian LNG as well as Russian pipeline supplies. In 2010 import requirements are estimated to reach 4.1 bcm/year.

Table 4.7 Greece, gas supply contracts 2000

	Russian gas	**Algerian gas**
Nominal annual quantity (bcm)	2.4 ± 0.6 *a)*	0.57
Year of first deliveries	1997	1999 *b)*
End year	2016	2020 *c)*
Take-or-pay clause	Yes	Yes

Notes: a) Russian contract quantities are expressed in bcm at 20 degrees Celsius and 1.013 bar. The quantity increases over time to reach a plateau; b) Projected c) Deliveries are not guaranteed after 2015.
Source: DEPA/IEA

Russian supplies are delivered through the Greco-Russian pipeline, which commenced operations in January 1997. The pipeline was developed as a joint project between the two countries and took a decade to complete. The pipeline is projected to deliver at least 2 bcm/year of natural gas for a period of 25 years and will eventually be extended to reach the Albanian border.

In the middle of 1998, the EU approved a planned US$ 600–800 million natural gas pipeline, which would run from the port of Otranto, southern Italy, to Igoumenitsa/Parka, in western Greece. This 70 mile sub-sea pipeline will have a capacity of around 5 bcm/year and was scheduled to commence operations in 2002 although construction has not yet commenced. This line is thought to be of strategic value as it will boost security of supply by opening the market to gas sources in Western Europe and will provide extra flexibility.

Greece is considered to be an emerging market under the EU Gas Directive and therefore under no obligation to open to full competition before the year 2008. Nevertheless, steps are being taken to introduce some competition into the sector before this date.

Main participants

The domestic gas market has been characterised by a strong degree of Government control with DEPA, the Public Gas Corporation, that imports, markets and transports gas in Greece, 65 per cent in state hands. The other 35 per cent is owned by Greek oil company Hellenic Petroleum (in which the government holds a 23.17 per cent stake). The sale of Hellenic Petroleum to Lukoil and National Grid Transco is currently under discussion.

The Greek Gas Law stipulates that the State should be the controlling owner of the gas supply companies. However, private sector presence is needed in order to meet the significant investment requirements of the sector. A further 35 per cent stake in DEPA has now been put to public offering. Eleven companies have expressed interest, including Algerian Sonatrach and the usual European energy majors.

Italian gas company Italgas, subsidiary of ENI, won two 30-year concessions to build and operate city gas distribution networks in the northern Thessaloniki region and for the smaller central Thesally region. Italgas will manage the network operations and have a 49 per cent stake in the state-controlled companies that will own the networks.

The award of the gas network concession for Athens, however, was delayed because, although Italgas submitted the highest bid, under legal rules designed to promote competition, the Greek government cannot award all three concessions to the same company. Subsequently, a joint venture between Shell and Cinergy was awarded the mandate.

Greece is an important potential transit site for energy exports from the Caspian/Caucasus regions. Recent improvements in Greek-Turkish relations are facilitating discussions of energy cooperation. For instance, Greece and Turkey agreed in July 2000 to work together to develop connections between their natural gas networks. This commitment was reaffirmed at "The EU and Black Sea economic cooperation conference" in September 2001 by the Turkish officials. Senior Greek and Turkish officials have signed an agreement at EU headquarters to study how best to develop natural gas connections.

The two countries have agreed to work with the EU-sponsored Interstate Oil Gas Transport to Europe (INOGATE) project, which provides technical assistance to modernize oil and gas transport in central Europe and Asia in order to work toward European pipeline linkage to Caucasus and Asian oil and gas. In March 2001, Greece signed an agreement with Armenia and Iran to strengthen economic and energy cooperation. Discussions included the possibility of an EU-subsidized natural gas pipeline from Iran through either Armenia and Ukraine or Turkey and Greece.

4.2.10 Portugal

Portugal is the last major European country to introduce natural gas to its energy mix and has recently made significant efforts to catch up with other countries in the region, consuming just over 2.5 bcm in 2001. The share of natural gas in the country's energy mix is expected to grow significantly to reach 20 per cent by 2010.

Gas demand is forecast to more than double between 2000 and 2015. Future demand growth is likely to be driven principally by the electricity generation and industrial sectors. Demand will be boosted particularly by plans to expand infrastructure in order to make natural gas available to 75 per cent of the population and 85 per cent of businesses.

As in Greece, the Portuguese gas industry is in the early stages of its development and hence efforts in recent years have focused on developing the country's transmission and distribution networks and securing supplies. In spite of difficulties associated with the geography of the country, domestic natural gas infrastructure has expanded significantly over the past few years. By the end of 1997, Portugal was operating approximately 680 km of high-pressure pipeline, connected to the Gazoduc Maghreb Europe (GME) pipeline.

Most Portuguese gas comes from Algeria via Spain through the GME pipeline. The first deliveries of Algerian gas took place in January 1997. Transgas, the State-owned Distribution Company, contracted with Algerian supplier Sonatrach for up to 2.5 bcm of gas each year up to 2002. Algerian imports are projected to reach 4 bcm each year thereafter. A new LNG receiving terminal is being built near Lisbon at Sines, and it should be operational by December 2003.

Transgas has contracted with Nigeria to purchase 350 mcm of LNG each year from 1999 to 2021. Until the Sines terminal becomes operational, the LNG will be delivered to Spanish firm Gas Natural's LNG re-gasification facility at Huelva, southern Spain, from where it will be piped to Portugal. In addition, ExxonMobil has put forward an open-ended offer for the supply of LNG and for the construction of a terminal, which could receive LNG supplies from Nigeria, Qatar or Trinidad.

As an emergent market, Portugal is not yet subject to the requirements of the EU Gas Directive. Portugal is expected to establish a common energy policy and an independent regulator will be created to oversee competition.

Main participants

In an effort to bolster the embryonic gas market in the run up to liberalisation, the Portuguese government created a national energy holding company, bringing together the state's interests in the oil and gas sectors. The new holding company, Petroleos e Gas de Portugal (GALP) became operational through the merger of the national gas holding company, Gas de Portugal (GDP), the oil group Petroleos de Portugal (Petrogal) and the national gas transmission company, Transgas.

The European Commission recently approved Italian energy group ENI's purchase of 33.3 per cent of Portugal's oil and gas company, GALP. The Portuguese state retains 48.3 per cent with the remainder held by Portuguese electricity firm Electricidade de Portugal (EDP) and Spanish utility Iberdrola.

4.2.11 Poland

While coal is expected to remain the dominant fuel in the Polish energy mix for the foreseeable future, it is clear that natural gas will have a growing role in the country's expanding economy. The largest consumers of natural gas currently are the industrial and residential sectors of the economy.

Natural gas consumption was 11.4 bcm in 2001 and, although it is not currently increasing as rapidly as earlier projected, it is forecast to reach between 22 and 27 bcm by 2010. This high growth is expected as Poland is substituting natural gas for coal in order to comply with the environmental standards that it must meet to achieve EU member status. Much projected growth will therefore be driven by the industrial and electricity sectors, in particular demand from the latter is forecast to grow by 40 per cent over the period.

Poland currently has proven indigenous natural gas reserves of between 150 and 160 bcm (with the methane content varying from under 20 per cent to 98 per cent). It produced around 37 per cent of its natural gas requirements in 1998, with the remaining 63 per cent of supplies imported mainly from the Russian Federation, with smaller amounts supplied by Germany and the Czech Republic. While the Government plans to meet future gas requirements partly by increasing indigenous exploration, it is thought that Poland will become increasingly reliant on imported supplies.

Until 1996 supplies from Russia were based on short-term contracts. In September 1996, however, the state-owned gas company, Polskie Gornictwo Naftowe i Gazownictwo SA (PGNiG), and Gazprom signed an agreement for the delivery of 250 bcm of natural gas from Russia to Poland over the next 25 years. The gas will be shipped through the Yamal pipeline. According to the Polish Government, Yamal gas will account for between 29 per cent and 43 per cent of total Polish demand for natural gas.

Poland has made various attempts to diversify its sources of supply. However, they have been undermined by political difficulties and the modifying of Polish gas demand forecasts.In May 1999, the

Polish Oil and Gas Company, PGNiG, finalised terms to purchase 500 MMcm/year of natural gas from Norway from 2001 to 2006, to be initially delivered to Emden in Germany, from where PGNiG would be responsible for its onward transportation.

A number of options exist for the transportation of the Norwegian supplies to Poland, including a pipeline which may be built by Ruhrgas of Germany in a joint venture with a Polish firm, Bartimex and a joint venture project including the Danish company, DONG. In addition, another firm, Verbundnetz is also reported to be considering building a pipeline.

In July 2001, an agreement was signed with Dansk Olie og Naturgas (DONG) of Denmark to import 16 billion cubic metres (565 Bcf). This would be done through the planned $330-million, 250km BalticPipe pipeline, which should have been commissioned in 2003, but will not be ready before 2005. The pipeline's capacity, 283 Bcf per year, is four times the volume that PGNiG will import from DONG annually, prompting some to question whether the pipeline will be financially viable. This project has now been put on hold, pending a government review of the energy sector.

In September 2001, PGNiG and Norway's (now defunct) Gas Negotiating Committee (GFU) agreed to the delivery of 74 billion cubic metres (2.6 Tcf) over 16 years starting in 2008. This replaced the previous contract with Norway for 500 million cubic metres (18 Bcf) per year until 2006. These Norwegian exports to Poland would require the construction of the $1.1-billion, 683-mile Austerled pipeline. Given probable increasing domestic natural gas production and flat demand, it will be very difficult for Poland to maintain its Russian, Danish, and Norwegian contracts in their present state. In addition, the new government has already signalled that it will probably amend or even cancel some or all of these contracts. Statoil has recently indicated that the Polish market appears very unfavourable compared with markets further west, particularly the UK.

The national transmission grid currently supplies 3,000 localities including 510 cities. The main system is for high methane gas (13,109 km), with smaller systems for low methane gas (3,104 km) and coke oven gas (367 km). All three systems have almost 17,200 km of high pressure gas pipelines. The coke oven gas system has been gradually decommissioned and in 1995 around 120,000 coke oven gas consumers were converted to high methane gas.

The distribution network currently consists of 87,500 km of medium and low pressure distribution lines and is constantly being extended (by between 2,000 and 3,000 km p.a.) to satisfy the demand of new consumers (around 200,000 consumers are being connected each year). Some 60,000 km of new distribution pipelines are planned by the year 2010.

Main participants

At present, all onshore natural gas production, importation, transmission, storage and distribution is carried out by the state owned oil and natural gas company Polskie Gornictwo Naftowe i Gazownictwo SA (PGNiG). PGNiG is one of the few fully-vertically integrated gas monopolies that remain in Europe. PGNiG has 24 separate branches operating (in principle) with their own budgets, although a restructuring plan is in place to be enacted prior to the proposed privatisation of the sector (see below).

Recently French utility Gaz de France (GdF) has unveiled an industrial and commercial co-operation agreement with Polish oil and gas company PGNiG. Upstream, the agreement encompasses joint development of Baltic Sea gas reserves and closer collaboration on underground natural gas storage.

In 1991, PGNiG was forced to withdraw from oil and gas exploration in central and eastern Poland. Some of these areas have now been licensed to foreign companies through international tenders.

Privatisation and restructuring

Poland's plans to liberalise the country's gas market are proceeding slowly. The target date set by the Polish Government to open up the gas market is 2005[8].

4.2.12 Czech Republic

Over the past 10 years natural gas consumption in the Czech Republic has grown by a half (the highest growth in Central and Eastern Europe) to reach nearly 9 bcm in 2001. This is especially significant given the fact that primary energy consumption has declined by 31 per cent over the period. Natural gas demand is expected to increase by between 5 and 7 per cent p.a. over the next few years, continuing to be driven by the substitution of natural gas for coal due to environmental and economic considerations.

Lacking significant natural gas resources, the Czech Republic has to rely on imports to meet its requirements. Until recently, Czech natural gas demand was met primarily by imports from the Russian Federation, with smaller amounts supplied by Norway and Germany. The Czech Republic has recently undertaken efforts to diversify its energy sources, including:

- A 20-year contract to import larger quantities of gas from Norway. Under the contract, Norway could deliver as much as

[8] The EU summit meeting in December 2002 agreed to the expansion of the EU to include the Baltic states (Estonia, Latvia and Lithuania), Poland, Hungary, the Czech Republic, Slovakia, Slovenia, Malta and Cyprus by May 2004, subject to certain conditions.

53 bcm of gas to the Czech Republic. This contract strained relations between the Czech Republic and the Russian Federation.

- A deal with German companies BEB and VNG for the supply of up to 3 MMcm/ day of natural gas during the winter months. These additional supplies will be delivered at Sayda/Hora Sv. Kateriny on the German-Czech border.

In addition, in mid 1998 Russia and the Czech Republic entered into a 15-year contract, under which Gazprom will deliver between 8 and 9 bcm of natural gas to the Czech Republic each year from January 1999. This is the first long-term contract of its kind between the two countries. Both parties agreed that the contract would be automatically extended for an additional 10 years provided that it was implemented to the satisfaction of both sides.

Furthermore Russia reached an agreement with the Czech Republic to transport Russian gas intended for export to Western Europe through the Czech gas network. The deal runs to 2020 and is unprecedented in the Czech Republic.

Main participants

Transgas, the state-owned import and transmission monopoly is the sole importer of natural gas in the Czech Republic. Its infrastructure comprises four pipeline sections built between 1972 and 1988, with a total annual capacity of 2.6 trillion cubic feet. There are 8 main gas distribution companies whose shares are held partly by the state (around half of each company, shares held either directly or via Transgas) and partly by private investors/municipalities.

A plan for the privatisation of the energy sector was submitted in April 2000. At the beginning of 2002 the Czech government decided to sell the Czech gas utility Transgas and eight regional gas distributors to Germany's RWE Gas for CZK 134 bn (EUR 4.1 bn). RWE was the only bidder to meet the government's privatisation criteria. Other bidders – the E.ON/Duke Energy consortium and the consortium of Ruhrgas and Gaz de France – had apparently raised objections to some provisions of the purchase contract. The major contract provision concerned a 10-year ban on the re-sale of privatized assets.

The date set for the opening of the gas markets is 2008. The rules governing liberalisation will be defined in the proposed Energy Act currently before Parliament.

4.2.13 Slovakia

Natural gas consumption in Slovakia has grown by a third over the past ten years to reach 7.4 bcm in 2001. As in the Czech Republic, this growth has been achieved in spite of an absolute fall in primary energy consumption of 16 per cent over the period. Natural gas has a relatively high share of the country's energy mix.

The strong growth in natural gas consumption over the past 10 years has been attributed to strong economic growth (which has averaged 4.3 per cent p.a. since 1993) and the availability of natural gas in the country. Currently over 85 per cent of the population have access to natural gas supplies.

The Slovak republic has indigenous natural gas reserves, however domestic production is minimal and the bulk of the country's requirements are imported from the Russian Federation. In addition, the Slovakian gas company, Slovensky Plynarensky Priemysel (SPP), has long-term transit contracts (expiring in 2008) with Gazprom to transport gas destined for other European companies through its network.

Most domestic supplies are transported through two pipelines, "Brotherhood" and the international transit system, Slovtransgas, which consists of four parallel gas pipelines. The use of Brotherhood, which commenced operations in 1968, to supply domestic requirements is declining as more gas is being transported through Slovtransgas.

The expansion of Slovtransgas is part of an extensive investment programme being carried out by SPP which provides for the development and upgrading of other parts of the country's transmission and distribution network. In addition, SPP plans to diversify its activities into the power sector with the construction of a number of combined cycle co-generation plants.

Regulatory developments

The Slovak Government has begun the process of privatisation of the country's energy sector. One of the first entities to be privatised was SPP, which was given clearance to sell 49 per cent of its shares to Ruhrgas and Gaz de France in June 2002.

Main participants

The Slovak gas sector is dominated by Slovensky Plynarensky Priemysel (SPP), an integrated gas company responsible for the procurement, transmission, distribution and supply of natural gas for the domestic market and the international transit of gas across Slovakian territory on behalf of foreign companies. In 1997, SPP had 240 km of long-distance pipeline and over 2,100 km of distribution pipelines. SPP is currently the largest fully independent international transporter of natural gas in the world.

Exploration, production and underground storage of gas is the responsibility of a private joint-stock company, Nafta a.s. Gbely. SPP purchased 45 per cent of this company in 1999.

4.3 United Kingdom

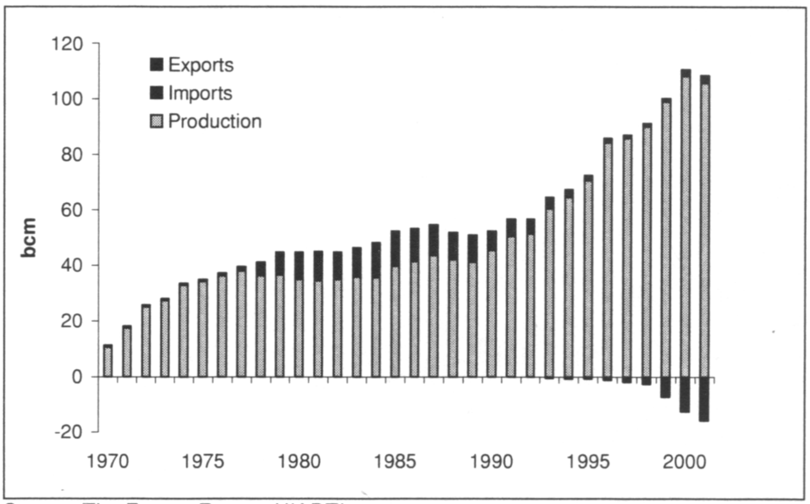
Along with the United States, the United Kingdom (UK) is a pioneer of the new liberalised market structures for natural gas. The privatisation of the British Gas Corporation in the mid-1980s not only set the scene for the gradual introduction of competition into a monopoly supply industry but also for the creation of new commodity markets for natural gas. Since the UK is – at present – broadly self-sufficient as far as natural gas supplies are concerned with many independent producers operating offshore in the North Sea, there was also strong pressure from the producers for the development of a more competitive end-user market and the removal of British Gas' monopoly over purchase and supply.

4.3.1 Supply and demand

Sources of supply

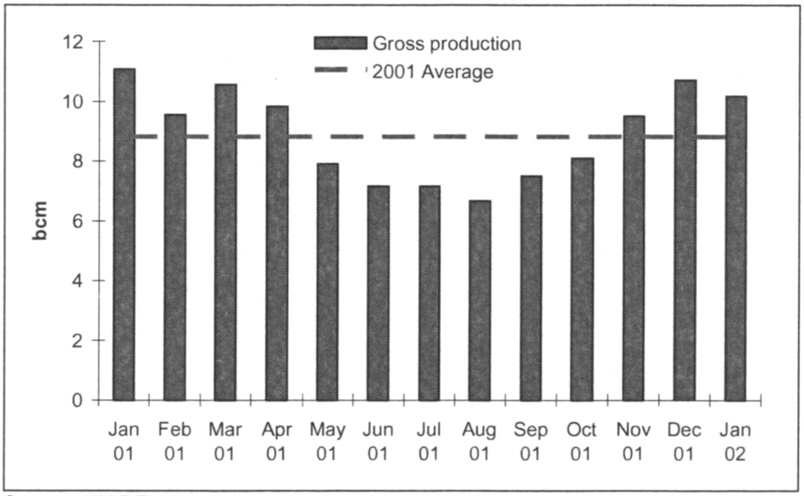
The UK had the largest natural gas output in Europe in 2001, producing a total of 106 bcm. The UK has been largely self-sufficient in natural gas since it was first introduced in the late 1960s, though it also purchased some imports from Norway, particularly during the early 1980s.

Figures for the remaining gas reserves in the UK Continental Shelf (UKCS) have remained steady since 1990 despite large increases in production as shown in Fig. 4.3 below. Gas production as a proportion of reserves has more than doubled since 1984. There are now,



Source: The Energy Report, UK DTI

Figure 4.3 UK natural gas production and trade, 1970–2001



Source: UK DTI

Figure 4.4 Seasonal pattern of UK gas production

however, concerns that the UK may need significant volumes of imported gas within five years or so. The timing will depend on the level of gas prices and the volume of gas exploration and development investment that is undertaken, but supplies from indigenous reserves are known to be running down, and the present low level of off-shore activity in the North Sea suggests that this will continue. Centrica has already signed contracts to buy long term supplies of gas from Norway and from the Netherlands, and there are several new projects to build gas import infrastructure.

Natural gas production in the UK is highly seasonal, as can be seen from Fig. 4.4 above, which shows monthly gas production from the UKCS in 2001. The effect of seasonal variations in demand may be clearly seen, with average mid-winter production representing twice the volume for mid-summer. In fact, the swing variation is somewhat less dramatic than in the past as the base-load gas-fired generating plant load dampens the more peaky seasonal requirements of household consumers.

Main producers

Gas production from the UKCS is concentrated amongst a small number of companies. In 2000, out of a total of nearly 60 gas producing companies, the top five – BP, Centrica, ExxonMobil, Shell and Conoco – produced around two-thirds of UKCS output (see Table 4.8).

Table 4.8 UK gas producing companies, 1998 to 2000

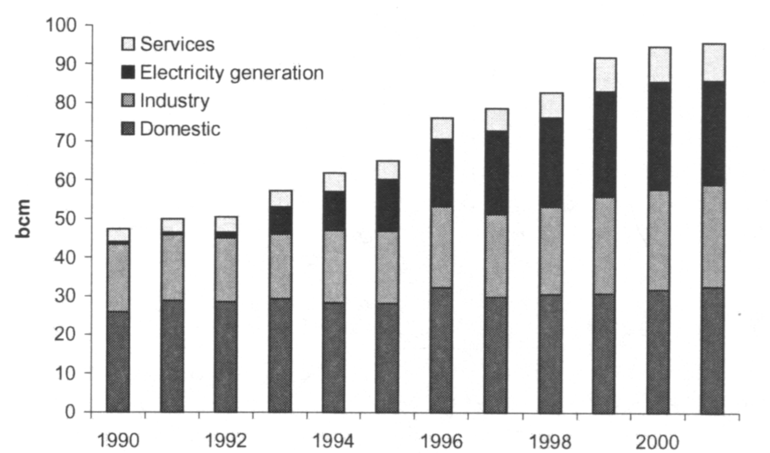
	2000	Share	1999	Share	1998	Share
	bcm	%	bcm	%	bcm	%
BP	17.5	16.4	14.0	13.9	13.5	14.7
Centrica	15.8	14.8	11.4	11.3	9.4	10.3
ExxonMobil	13.7	12.9	9.2	9.1	7.9	8.6
Shell	11.0	10.3	9.1	9.1	7.9	8.6
Conoco	7.7	7.2	6.7	6.7	4.4	8.6
BG	7.9	7.4	6.3	6.3	6.4	4.8
TotalFinaElf	6.5	6.1	4.2	4.1	4.1	7.0
Others	26.4	24.8	26.3	26.8	24.5	26.8
Total	**106.5**	**100.0**	**100.8**	**100.0**	**91.7**	**100.0**

Source: Wood Mackenzie

Structure of demand

Primary energy demand in the UK has remained almost static over the past 30 years, but gas' share of primary energy consumption rose from 5 per cent in 1970 to 38 per cent in 2001.

Figure 4.5 shows how gas consumption has increased from 1990 to 2001 by different customer sectors. Total gas consumption in the UK has doubled since the 1980s when it was already one of western Europe's largest gas markets. The most noticeable increase in demand for gas began in 1991 when Combined Cycle Gas Turbine (CCGT) stations first came onstream. Around 34 per cent of gas demand in the United Kingdom in 2001 was for households, while demand for gas for electricity generation was 28 per cent. The growth in gas consumption



Source: The Energy Report, UK DTI

Figure 4.5 UK natural gas consumption, 1990–2001 for electricity generation is primarily attributable to the substitution of gas for coal over the period. The shift towards gas in the power sector arose from both environmental and commercial considerations.

Until recently it was expected that the demand for gas would continue to grow at the same high rates experienced over the last decade or so. In late 1997, however, in its review of fuel sources the British Government raised concerns over the fuel diversity and security of supply issues in the power sector. As a consequence of this review, the Government announced a moratorium on planning consents for new gas-fired generation to protect the British coal industry, which was then undergoing a periodic crisis. Various government reviews of the power sector have identified distortions in the market which have hindered the ability of coal-fired generation to compete with gas (see Chapter 16).

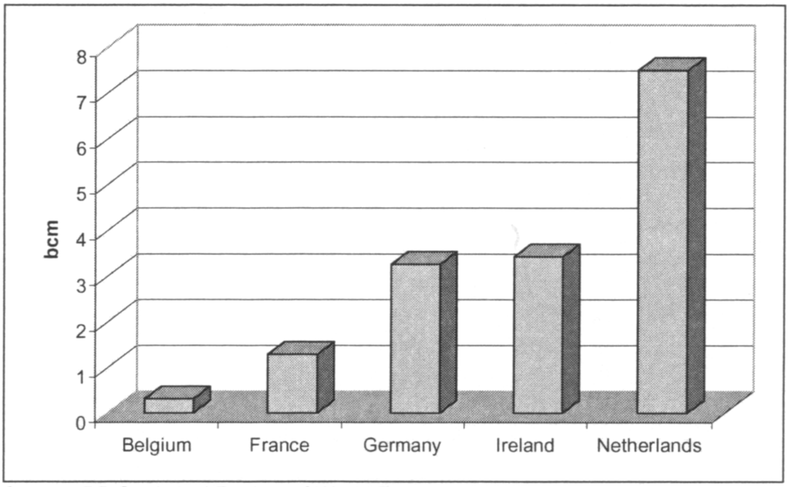
The moratorium was formally lifted in November 2000, and a number of gas-fired projects were eventually granted their planning consents. However the relatively high gas prices since then, caused primarily by oil indexation in European contracts, together with the impact of low electricity prices after the introduction of the New Electricity Trading Arrangements (NETA), have raised questions over the comparative economics of these new-build projects against other existing forms of power generation and many developments have been put on hold.

Northern Ireland

A gas pipeline, the Northern Ireland Interconnector provides a significant new market for UK gas. The Interconnector, which runs from Scotland to Northern Ireland, was completed in 1996, with the first gas arriving in Northern Ireland in September 1996. Prior to the development of the Interconnector, Northern Ireland had no natural gas supply as the economics were deemed to be unfavourable. This position changed when British Gas purchased Ballylumford power station in 1992. Ballylumford provides Northern Ireland with around 50 per cent of its power needs and was converted from oil to gas-firing as part of the restructuring and privatisation of the Northern Ireland Electricity Supply Industry, which began in 1991. The downstream gas market in Northern Ireland is being developed by Phoenix Gas, which is owned by BG, Keyspan and East Surrey Holdings.

4.3.2 International trade

The UK exported 15 per cent of production (15.8 bcm) in 2001. As shown in Fig. 4.6, the main destination of UK exports is the Netherlands followed by the Republic of Ireland, although increasing volumes are moving to Zeebrugge in Belgium through the UK-Continent Interconnector pipeline. The UK exports a significant volume of gas to Eire (70% of national consumption in 2000) through a separate pipeline



Source: BP Statistical Review of World Energy

Figure 4.6 Destination of UK natural gas exports, 2001

owned by BGE, with a second parallel pipeline now under construction to increase gas volumes and improve security of supply.

Imports of natural gas are primarily from Norway.

4.3.3 Regulation and competition

The introduction of effective competition into the UK gas supply market has required both time and heavy regulatory intervention, mainly as a result of the absence of precedents for such an endeavour. Before privatisation, the transmission, demand and supply of natural gas in Great Britain were controlled by a national public monopoly, the British Gas Corporation. The British Gas Corporation was privatised in 1986 and became known as British Gas plc.

The supply, transportation and shipping of gas in Great Britain is now the subject of a licensing and regulatory regime established by the two Gas Acts and largely overseen by the Director General of Gas Supply (DGGS). This section outlines the principal aspects of the legislative and regulatory framework for the gas industry in Great Britain.

The Gas Act (1986)

The Gas Act (1986) enabled the privatisation of the British Gas Corporation and created the regulatory framework for the newly privatised British Gas to operate in. British Gas was granted an authorisation (licence) by the Secretary of State as a public gas supplier to supply gas through pipes to any premises in Great Britain. This was for a minimum period of 25 years, with provision for revocation under certain circumstances.

The initial Authorisation covered separation of accounts; restriction of prices to tariff customers and standing charges; requirement to publish maximum prices for contract customers and a statement of principles upon which connection charges would be payable; provision of information to the Director General of Gas Supply and the Gas Consumers' Council (GCC); requirement to publish guidance on charges for conveyance of gas for others; provision for supply of back-up gas and emergency services; requirements for a code of practice for tariff gas supplies and of services for pensioners and the disabled; and provision for the promotion of the efficient use of gas and payment of fees. The Secretary of State, having granted an authorisation to a public gas supplier, could not modify it, other than to remedy any adverse effects found by the Monopolies and Mergers Commission (MMC) during an inquiry under the Fair Trading Act or the Competition Act.

According to the Gas Act (1986) British Gas was responsible for developing and maintaining an efficient, co-ordinated and economical system of gas supply. It also had to comply, as long as it was economical to do so, with any reasonable request for a supply of gas to any premises. British Gas had an obligation to supply gas on request, to any premises within 23 metres of a relevant main (i.e. distribution pipeline) or connected to a main, unless the supply was in excess of 25,000 therms a year. It was obliged to charge for such supplies on a tariff basis. Above the 25,000 therms level customers were free to buy from any authorised supplier. This was referred to as the non-tariff market. British Gas had no monopoly in the supply of gas to non-tariff customers, other suppliers being entitled to use British Gas pipelines for this purpose. However, the legislation offered no guidelines for the terms of any transportation of other suppliers' gas. The Gas Act (1986) recognised no difference between British Gas as a supplier of gas and as an operator of the transportation system.

The Gas Act (1995)

The Gas Act (1995) set out the framework for the removal of British Gas's remaining monopoly of supply and the introduction of competition in domestic gas supply. It came into force on 1 March 1996.

The Gas Act (1995) changed significantly the regulatory regime for the gas industry. The legislation now provides for three types of licence: a public gas transporter's (PGT) licence, a gas supplier's licence and a gas shipper's licence.

The Gas Act (1995) introduced a scheme by which on 1 March 1996 the assets and liabilities of British Gas's supply business were transferred to a wholly owned subsidiary, British Gas Trading, leaving the transportation and storage business with British Gas. Since March 1996 British Gas's authorisation as a public gas supplier has had effect as a PGT licence deemed to have been granted to British Gas; and a gas shipper's and gas supplier's licence granted to British Gas Trading.

Director General of Gas Supply

The Director General of Gas Supply (DGGS) is appointed by the Secretary of State for a term not exceeding five years. The Gas Acts also provided for the establishment of the Gas Consumers' Council (GCC). The DGGS' duties are set out in section 5 of the Gas Act (1986). The DGGS has a duty to exercise his or her statutory functions in a way that is best calculated to secure:

- that all reasonable demands for gas are met;
- that licence holders are able to finance their authorised activities; and
- effective competition between suppliers and between shippers.

Ofgas and Ofgem

Ofgas, the Office of Gas Supply, was the independent gas regulatory office. It was set up under the Gas Act (1986) to regulate British Gas, the newly privatised monopoly, and to promote competition in gas supply to industrial customers. In 1999, it was merged with the Office of Electricity Regulation (Offer) to form the Office of Gas and Electricity Markets (Ofgem). Ofgas had a staff of 130 and was headed by the Director General of Gas Supplies. Its principal functions, which were taken over by Ofgem, were:

1. to continue to regulate the monopoly or dominant elements in the gas industry;
2. to work actively to increase the scope of competition in the industry; and
3. to act as a competition authority for those parts of the industry that are competitive.

Stages of market opening

The gas market in Great Britain is now fully competitive. All 20 million premises connected to the gas mains, whether industrial, commercial or residential and in all consumption levels, can choose between competing gas suppliers. The competition was introduced in stages starting from large industrial customers, then medium and small industrial and commercial customers and finally the domestic customers (see Table 4.9 below).

Table 4.9 Liberalisation of the UK gas market - Key dates

1986	British Gas privatised
	The Gas Act 1986
	Liberalisation of the over 25,000 therms pa market
1989	90/10 Ruling
1991	Release Gas
1992	Competition and Service Utilities Act
	Liberalisation of the over 2,500 therms pa market
1994	British Gas accounting separation
1995	Gas Act 1995
1996	British Gas demerger
	Domestic market deregulation Phase I
1997	Domestic market deregulation Phase II
1998-99	Domestic market deregulation Phase III

The first phase of competition in domestic gas supply began in the south-west pilot area (Cornwall, Devon and Somerset) in April 1996 and the second phase in February 1997. The third phase included 6 stages when the competition was introduced into the rest of Great Britain.

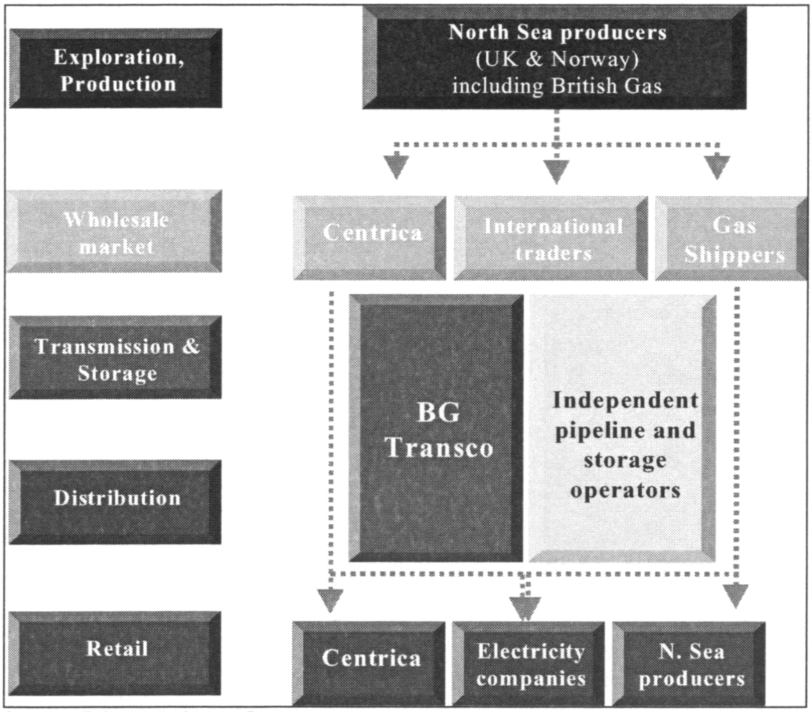
4.3.4 Market structures

The evolution of competition has altered the structure of the market in many different ways. Figure 4.7 below outlines the environment in which the current market operates.

Transmission

The national gas transmission network is controlled by a private sector national monopoly, National Grid Transco plc, operating its transmission business under a public gas transporter's (PGT) licence granted by Ofgas (now Ofgem). Until recently, this activity was undertaken by Transco, a subsidiary of Lattice plc, and a descendant of the original British Gas, but a strategic merger took place between the British gas and electricity transportation and distribution companies (Lattice and National Grid).

As an incumbent monopoly National Grid Transco faces a price-cap on its charges for the use of its transport network. To permit gas-on-gas competition in the supply of gas in the UK, it is obliged to follow 'Network Code' under which others may use its pipeline system on an open and non-discriminatory basis (see Chapter 10). Other licence conditions imposed on the transporter include an obligation to make effective arrangements for the provision of emergency services to the public; and an obligation to establish standards of performance and to provide compensation if these are not met.



Source: PricewaterhouseCoopers

Figure 4.7 Structure of UK gas industry, 2000

Other Public Gas Transporters (PGTs) have similar licence obligations to National Grid Transco, although their respective networks are much more localised with limited numbers of connected customers.

Storage

The demand for gas varies both within each day and seasonally. Domestic use of gas for space heating makes the demand for gas sensitive to temperature. During peak days in winter, demand for gas exceeds the supply of gas available at the beach terminals. One primary method used to balance supply and demand is to place gas in storage when supply exceeds demand (i.e. during summer months), and extract it when the reverse happens (i.e. at winter peak periods).

Dynegy purchased the non-LNG gas storage facilities from BG in 2001, but sold them again in 2002. There are two different kinds of storage facility (see also Chapter 8):

- **Rough** - The Rough facility is a depleted gas field off the Yorkshire coast into which gas can be injected and from which gas can be withdrawn. It is much larger than any of the other facilities, being capable of storing 100 bcf of gas and meeting around 10 per cent of current peak day demand, with a delivery rate that can be sustained for more than two months.

- **Hornsea** - At Hornsea, in east Yorkshire, gas is stored in underground salt cavities. It is a considerably smaller facility than Rough but has the advantage of shorter lead times for injection and withdrawal, which render its services attractive to customers wishing to use storage for very short-run balancing purposes. Similar facilities are now also being developed by other parties.

The Hornsea facility was sold to Scottish and Southern and Rough to Centrica (subject to regulatory clearance).

In addition, National Grid Transco continues to operate a number of liquefied natural gas (LNG) facilities which are situated at the extremes of the system far removed from the points of entry. There are five such sites at which gas is stored in liquefied form. They are characterised by high rates of deliverability relative to space (if gas were delivered at the maximum rate the facilities would be empty after five days) and by their locations, which are close to demand centres and relatively distant from NTS entry points. National Grid Transco operates these facilities both on account of their own need for system security and balancing and also on behalf of third parties trading and/or supplying gas.

Shippers

Shippers are companies involved in the wholesale purchase and/or production of gas that they then transport through National Grid Transco's national high pressure transmission network for sale to gas suppliers and/or final consumers. Shippers are licensed by Ofgas (now Ofgem) and, under the terms of their shipping licences, face obligations regarding the use of National Grid Transco's pipeline systems.

Among the standard conditions included in a shipper's licence are the following:

- an obligation to act in a reasonable and prudent manner in the use of a PGT's pipeline;
- provisions relating to dominant players in a flexibility/balancing market;
- in the event of an emergency, an obligation to secure the safety of the system;
- provisions relating to the information about premises which must be given to the PGT and suppliers; and

- provisions relating to certain information requested by a PGT or relating to gas illegally taken and restricting the disclosure of information from a PGT's record of meter point numbers.

Gas shippers must sign the network code of any PGT through whose network they ship gas. Shippers pay PGTs transportation charges for the use of their pipes. Many shippers are also licensed as gas suppliers although they can act as a shipper for gas suppliers who have chosen not to hold a shipper licence.

Suppliers

Only companies that have been granted a licence by Ofgas (now Ofgem) are allowed to supply gas. Every licensed company will have to meet certain conditions. These standard supplier's licence conditions include the following:

- An obligation to supply domestic customers whose premises are connected to a relevant main as soon as is reasonably practicable; to continue to supply as long as a supply is required; and to offer a new contract to a current customer no later than 30 days before a supply contract expires (Condition 2). Contracts must conform to published terms (Condition 3).
- An obligation to submit to the Director General details of arrangements to comply with the following licence requirements: provision of energy efficiency advice; provision of special services for pensioners, disabled or chronically sick people free of charge and provision of information about such customers to the PGT; provision of special information about billing and meters and about provision for enquiries or complaints to the blind and deaf free of charge; and provision of billing arrangements for domestic customers with payment difficulties (Conditions 15 to 19). Subject to certain conditions, suppliers can, from 2000, request compensation from a PGT to compensate for having a disproportionate number of older, disabled, chronically sick or indebted customers (Condition 6).
- A provision that the supplier is only required to comply with its supply obligations if a customer takes gas through an acceptable meter with acceptable meter-reading arrangements (Condition 8). Obligations to provide appropriate meters for registering the quantity of gas supplied and to operate a 'must read' policy which ensures actual meter inspection at least once every two years, and

report any leaks or evidence of theft to the PGT (Conditions 22, 23 and 28).

- In the event of a gas escape or pipeline emergency, an obligation to use best endeavours to comply with all reasonable requests from a PGT to avert or reduce danger to life or property and to secure the safety of the pipeline system (Condition 31).

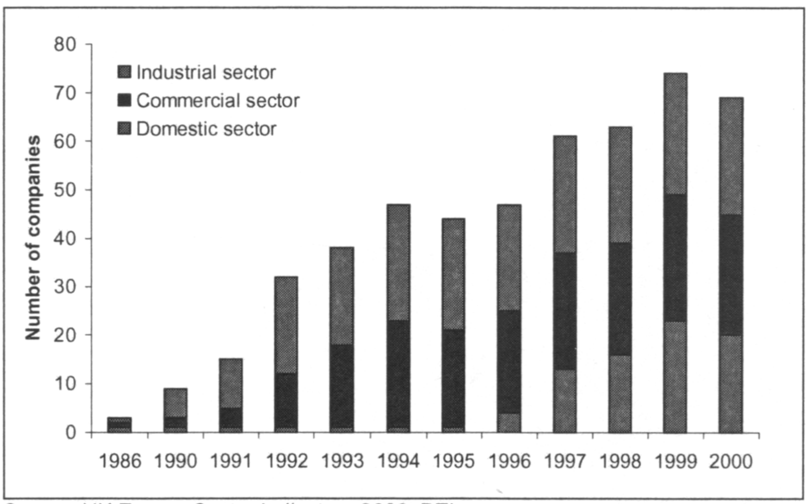
Having met these and other conditions, companies are free to offer a wide range of other services and prices.

The number of companies supplying gas has increased noticeably since 1990 (see Fig. 4.8 below). There are effectively four competitive sectors – sales to the electricity generators, the industrial sector, the commercial sector and the domestic sector. With domestic sector competition beginning in mid-1996, it lags some four years behind the other three sectors.

Industrial and commercial sectors

The number of companies supplying gas to industry increased from 10 in 1991 to 24 in 2000. Significant changes to market share occurred between 1991 and 1995 with British Gas losing substantial market share to competitors. Since then the situation has stabilised. More recently, the number of companies entering the market to supply industrial customers has been matched by mergers among existing suppliers.

It is interesting to note that the top six suppliers in this market all



Source: UK Energy Sector Indicators 2000, DTI

Figure 4.8 UK gas suppliers (excluding power generation) have considerable interests in North Sea gas production. Electricity suppliers offering a dual fuel capability dominate the remaining players.

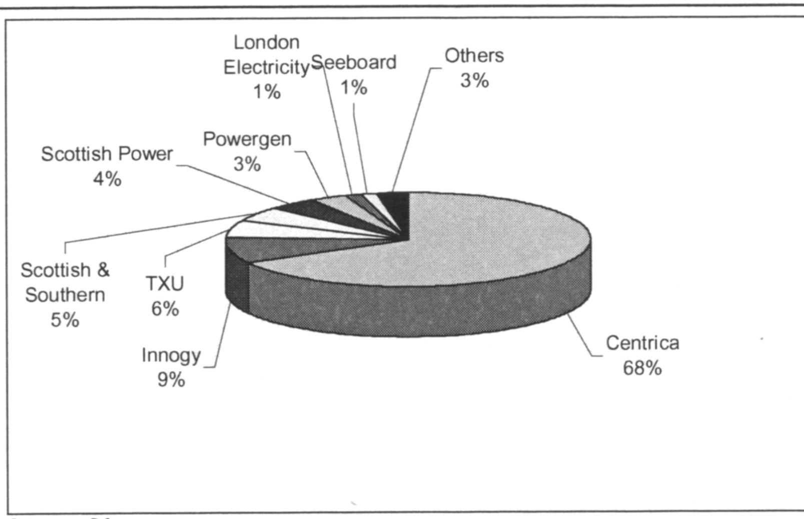
Table 4.10 Industrial and commercial suppliers, September 2001

Company	Market share	Company	Market share
ExxonMobil	16%	GDF (Agas/Elf/Total)	8%
BP Gas	14%	Amerada Hess	7%
Innogy (YE/Northern)	13%	Eastern TXU	3%
Shell	11%	Powergen (Kinetica)	3%
Alliance (Statoil)	10%	Others	14%

Source: John Hall Associates

Domestic sector

The number of companies supplying gas to the domestic sector increased from 16 in 1998 to 20 in 2000 but most of them had been selling gas to this sector for less than a year, reflecting the staged opening of the domestic gas sector. The dominance of Centrica (British Gas Trading, BGT) in this sector is expected to decline. In early 1998 Centrica's market share was 80 per cent, representing 15.9 million domestic customers. By the year-end Centrica announced that it had 14.8 million customers, representing 73 per cent of the market and including 1.2 million new customers or customers returning to Centrica. At the beginning of 1998 Centrica applied for and was granted a licence to supply electricity in the competitive electricity market in the UK. By the end of 1999 Centrica had signed up 2.8 million electricity customers.



Source: Ofgem

Figure 4.9 Market share of UK domestic market (by volume)

Since then BGT's market share has continued to fall in terms of both volume and customer numbers. By September 2001 BGT had a market share of 68 per cent of the domestic gas supply market measured by customer numbers, although its market share measured by the volume of gas supplied is lower. That shows that it has lost relatively more customers consuming higher volumes of gas. This is to be expected as competitors seek to 'cherry pick' the most profitable customers. Fig. 4.9 above shows the market shares by customer numbers in September 2001. The main rivals to BGT amongst other gas suppliers, based on market share gained, are the former Public Electricity Suppliers (PES) and electricity generators, some of which have now merged to form bigger multi-utility enterprises.

Significantly, the upstream gas producers have so far shown limited appetites for the domestic sector, perhaps reflecting their lack of experience in dealing with the large databases required for this sector.

5 Gas trading instruments

Sally Clubley, Arktauros

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5.1 Introduction

The liberalisation of the gas market has created a need for new and more flexible trading instruments to replace the longer-term asset-based contracts traditionally used by the industry. Gas trading is evolving from a physical imbalance market to a price risk management market and these changes are likely to continue, particularly in continental Europe where competition has been slow to develop despite the EU Gas Directive. Fixed-price term deals and take-or-pay contracts are coming under pressure as the gas industry adopts practices from oil and other industries and may ultimately be replaced by a fully-functioning commodity market for gas.

In the UK, as in the US, there was remarkably little resistance to the commoditisation of the gas industry. This is probably due in part to the fact that many of the companies involved are also in the oil industry and have become accustomed to futures, options and other derivative instruments. The rest of Europe has been much slower to follow, but the opening of the Interconnector in October 1998 brought a single European market closer and means that practices in different countries have begun to converge, within the limitations imposed by the different pace of liberalisation in the various countries (see Chapters 4 and 7).

Liberalisation is also changing the relationship between gas prices in continental Europe and the UK. Historically, there was no direct relationship between UK and mainland European prices, other than the fact that they were both linked – in different ways – to oil prices through long-term contracts (see Chapters 11 and 12). There was no direct physical connection and gas could not move from one market to another, creating price linkages between the two markets. But the summer of 2000 saw prices in the UK and mainland Europe move much closer. As European prices, which are linked through price indexation contracts to the lagged price of oil, moved sharply higher, UK producers were able to achieve higher returns by exporting gas through the Interconnector. This, in turn, reduced supply in the UK system raising prices there. Price links between the UK and Europe are likely to strengthen in the future during periods when the pipeline capacity and direction of flow allow effective arbitrage. This link was particularly noticeable at the beginning of 2001 when continental European prices rose sharply as a result of the oil indexation, drawing UK gas through the Interconnector and leading to a 50 per cent increase in UK prices in less than a week.

The spot market and, in particular, more accurate price reporting, also makes a derivatives market possible and futures trading has seen good growth since the introduction of natural gas futures, which were launched in the US in 1990 and in the UK in 1997. But the over-the-counter (OTC) derivative market has been somewhat more patchy in its development, with options and swaps so far attracting little interest for much of the year.

Historically, UK OTC gas trading was concentrated in short time periods around the renewal of medium- and long-term contracts, especially leading up to the start of the 'gas year' in October, and for shorter term contracts in April. All markets need to reach a certain level of liquidity before they start to attract new entrants, creating a virtuous circle of rising activity and improved liquidity. The UK and continental European markets have yet to reach an adequate level of activity consistently enough to enable traders to operate in the same way as their colleagues in the US.

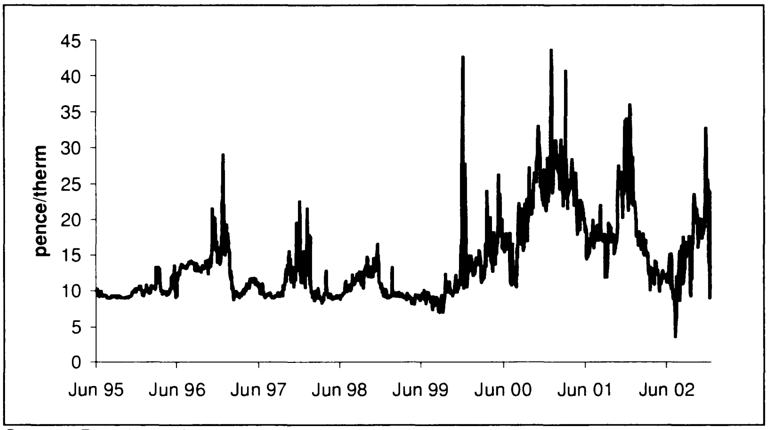
Enron had made a major contribution to the gas and electricity market liquidity in all markets and it is still too early to see what the lasting effect of the company's collapse will be. It may take some time for the European markets to make up for Enron's absence (see Chapter 6).

5.2 Spot contracts

The gas spot market in the UK, which was the first country in Europe to create a competitive market for gas, has existed, in effect, since 1992 when electricity generators first began trading gas amongst themselves. It had its origins in the need, at the time, for shippers to balance their production and sales on a monthly basis. At the same time, the electricity supply industry began to privatise and independent power producers appeared on the market. This was followed by the 'dash for gas' as around 20 gas-powered generators were built. All of this helped the growth of the nascent spot gas market.

Initially, the dash for gas helped raise spot gas prices by around 50 per cent to more than 20p/th by 1993. By 1994, however, suppliers began to find that they had excess unsold gas. A true market was beginning to develop. The following years saw spot gas prices fall back to around 13p/th (see Fig. 5.1), encouraging a second, smaller, dash for gas which was ended by the UK government imposing a moratorium on new gas-fired power stations in 1998. The moratorium, which was imposed to protect the UK coal industry, prevented the building of gas-powered generation plants for a period of three years, although permissions have been granted in recent years (see Chapter 17).

The gas market now trades delivery periods ranging from one day ahead to several years ahead. A fixed quantity of gas is normally traded, though there are occasional swing contracts, which allow the buyer to vary the amount of gas delivered during the contract period by an agreed amount. The contracts traded include spot contracts for physical delivery in the near future, and forward contracts, for delivery



Source: Petroleum Argus

Figure 5.1 Day ahead prices, Bacton terminal 1995-2002 further into the future. Forward contracts with fixed prices are often used for risk management rather than to ensure physical supply. Physical contracts often have prices linked to publications such as *European Spot Gas Markets*, *Platts*, *Petroleum Argus* or the IPE natural gas futures contract.

In addition to normal outright sales or purchases, traders now use time spreads and terminal spreads as well. Time spreads involve the simultaneous purchase of gas for one time period and sale of the same quantity for a different period. This is normally done to take advantage of price differentials between different time periods, particularly if the forward price structure allows for gas to be bought at current prices, stored, and sold for delivery in the future at a profit.

Similarly, a terminal spread is the simultaneous purchase of gas from one terminal and sale at another. The main reason for this is to allow companies to deal with any locational imbalances in their supply portfolio, and to take advantage of any short-term deviation in prices that would allow gas to be taken from one location to another profitably.

Gas companies also trade the On-the-day Commodity Market (OCM) — formerly the Flexibility Market — which provides the balancing mechanism for the UK gas pipeline system. As markets develop in other European countries, similar trading activities and mechanisms will evolve.

Capacity trading, or the trading of pipeline capacity, is an active market in the US and is growing in the UK. Traders can buy capacity in a pipeline for a period (e.g. one month or one year) and then, if they don't need it for their own transportation needs, they can trade it with the market. Capacity trading is part of the balancing mechanism in some markets and is a function of good third-party access arrangements (see Chapter 10).

An important part of a successful spot market is price transparency. There are now a number of daily and weekly price reporting services quoting gas prices and, importantly, enough trading being done to ensure that prices are readily available and accurate.

In the UK there are three major publications in use. *PH Energy*[1] launched a weekly report in 1994, following it up with daily reports the following year. This publication, now called *European Spot Gas Markets (ESGM),* was joined by daily reports from *Platts*[2] and *Petroleum Argus*[3], the two major oil price reporting services. In the US, there are reports from *Gas Daily*[4] and, twice a month, from *Inside Ferc*[5] — Ferc, the Federal Energy Regulatory Commission, is the US regulator — published by McGraw-Hill.

1 www.heren.com
2 www.platts.com
3 www.petroleumargus.com
4 www.gasdaily.com
5 www.platts.com

These reports give details of actual deals done, where they can be identified, and, more importantly, assess prices for a series of standard contracts on a daily basis. This provides a continuous and independent source of prices that can be used as an index in physical supply contracts. For example, ESGM publishes assessments of the price for gas traded at the UK National Balancing Point (NBP) and at the Zeebrugge delivery hub for a range of delivery periods, such as: gas for delivery the next day; gas for delivery in the next few calendar months; and gas for delivery in the winter and summer.

But the introduction of futures contracts both in the US (1990) and the UK (1997) made the greatest contribution to price transparency. Prices on futures exchanges are for actual deals done rather than assessments as supplied by the publications.

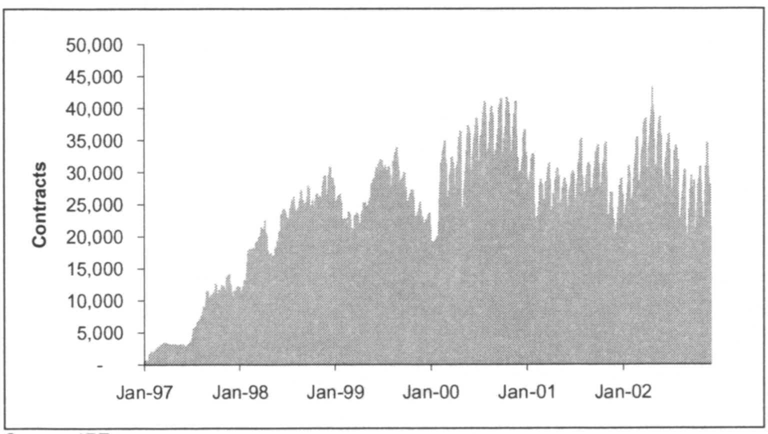
5.3 Futures and forward contracts

The establishment of a successful UK gas spot market has led to a growing market in futures, forwards, options and other derivative trading instruments. With the emergence of gas and power trading, the differences between futures and forward contracts are beginning to blur, although there remain certain key distinctions for operational and regulatory purposes. For the purposes of this chapter, futures are defined as contracts traded on a registered exchange and cleared and margined under the rules of the associated clearing house, while forwards are defined as contracts traded over-the-counter (OTC) and negotiated bilaterally between two counterparties.

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. 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



Source: IPE

Figure 5.2 Open interest, IPE natural gas futures 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.

The IPE's gas futures contract[6] (see Chapter 8) began trading in January 1997 and quickly achieved acceptance among gas trading companies. Each lot is 1,000 therms/day for the period of delivery, but the lots must be traded in multiples of five (i.e. 5,000 therms/day). The IPE's contract followed the record-breaking Nymex natural gas futures contract[7] for delivery at Henry Hub, which was launched in 1990.

When the Nymex contract was introduced it was the fastest-growing contract in history during its first few months. It is now an integral part of the US natural gas market. There have been a number of other gas contracts introduced by Nymex with various delivery points, but none has matched the success of the Henry Hub contract. The IPE gas futures contract did not see such rapid growth, but its liquidity was sufficient to keep its users interested and both trading volumes and open interest have gradually increased, receiving a boost after the Interconnector joining the UK to Continental Europe opened in October 1998 (see Fig. 5.2). Although futures trading volumes have since levelled off, the industry still sees the IPE contract as a useful tool and an essential contributor to price transparency.

One major difference between the two gas futures contracts is what happens when the contract expires. Nymex gas futures contracts cease trading on a given day of the month and all outstanding contracts are settled through the Henry Hub delivery system. Buyer and seller are committed to receive or deliver gas throughout the delivery month.

But on the IPE, it is still possible to trade gas futures using the balance of the month contract after the monthly delivery contract expires. For example, when October gas futures cease trading two business days before the end of September, it is possible to continue trading it through October as a depleting balance of the month contract. The balance of the month contract trades the total number of days outstanding in the current delivery month until two business days before the end of the month of delivery. There are also daily contracts available for seven days into the future, expiring the day before the delivery has to take place (see Chapter 8).

Both the IPE and Nymex have benefited from traders' tendency, since the Enron collapse, to prefer cleared contracts. The added security of the futures markets, with their contracts guaranteed by the clearing mechanism, has contributed to significantly higher volumes in 2002.

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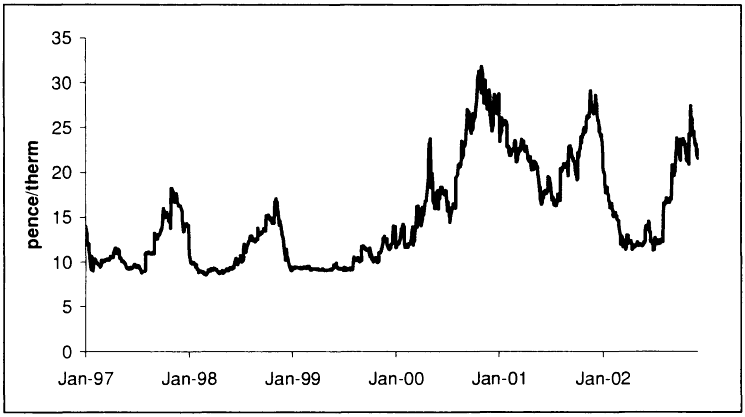
[6] www.ipemarkets.com

[7] www.nymex.com



Source: IPE

Figure 5.3 First month IPE natural gas futures prices

Both the Nymex and IPE gas futures contracts are used primarily, like all futures contracts, for hedging purposes, but they both see higher levels of delivery than their oil counterparts. This is particularly true of the IPE contract. The Nymex contract has around twice the proportion of contracts delivered as the crude oil contract, but it is still less than half of one per cent.

In its early days, the IPE contract frequently saw delivery rates of around 10 per cent, though this has now fallen to around 3 per cent. The reason for this high level of delivery is good compatibility between the IPE delivery mechanism and the normal physical market delivery in the UK. Gas market participants put in and take out gas according to their contracts, but buyers and sellers of individual parcels do not need to be matched up. There therefore need be no direct contact between buyer and seller and in the IPE delivery system, which takes place through the London Clearing House[8] (LCH), there is not. Buyers' and sellers' identities are not revealed to each other.

Gas traders use the futures markets for both hedging and trading purposes, with spreads and outright trades being done. Gas is different from many other commodities because gas storage is, in most countries, scarce and more expensive than for many commodities. The exception is the US, where gas storage is plentiful and the market is well developed. In the UK, the gas storage market is just beginning to get off the ground after British Gas was forced by the regulator to spin off its gas storage activities as a separate company, BG Storage, which has now been sold. BG Storage was initially purchased by Dynegy, but the storage facilities were sold on to Centrica (Rough) and Scottish and Southern (Hornsea). Several companies also offer "virtual" storage

[8] www.lch.com

contracts, which are intended to provide the same financial benefits as physical storage without the need to inject and withdraw the gas.

There is also some sort of balancing mechanism in all gas markets whereby producers must put in and take out the same quantity of gas on a daily, or other, basis. In the UK the daily balancing mechanism is governed by the Network Code, a framework agreed by the industry and the regulator (see Chapter 10).

But in terms of price risk, there is little difference between gas and any other commodity — although gas prices are more volatile than most commodities because of the high cost and scarcity of storage and the need to balance supply and off-take in a fairly inflexible time frame (see Fig. 5.3). Companies operating in the gas market therefore need to use derivative trading instruments to hedge against price risks.

The simplest hedging example is for a gas company which is either long or short of gas and takes the equal and opposite position on the futures market. For example, a producer that wants to protect itself from falling prices can sell futures. When the time comes for the physical delivery to be priced the futures can be bought back or the gas can be delivered through the exchange mechanism.

Example

Producer hedge

A gas producer wishes in June to fix the price of 25,000 therms/day of its August output. The physical gas has been sold on a floating price basis to one of its regular customers, but the producer is concerned that prices will fall and would like to lock in to today's price on the IPE for August gas of 18p/therm.

The producer therefore sells 25 lots (each of 1000 therms/day) on the exchange. The producer then buys back the futures contracts at the time when the price of the physical gas sale is fixed. The physical gas is then delivered during August to the regular customer under the normal contract terms.

Date	**Futures**		**Physical**	
June	Sold at	18p/th		
End July	Bought at	17p/th	Sold at	17p/th
	Futures gain	*1p/th*		

Net selling price = physical sales price + futures gain
= 17p/th + 1p/th
= 18p/th

Instead of buying back the futures contracts, the producer could enter the IPE's delivery mechanism. The producer would have to put 25,000 therms/day into the system and the LCH would allocate a buyer (i.e. someone who has open buy contracts) who would take it out.

Payment would be made through the IPE. If, at any time during the month, the producer wished to close its position it could buy back all contracts for the balance of the month.

For example, the producer might deliver 25,000 therms/day on each of the first six days of August and then decide it would rather not deliver for the rest of the month. It could go onto the IPE and buy back 'balance-of-the-month' futures, thus removing its obligation.

Should the producer choose to use the IPE delivery mechanism, the transaction would not have provided a hedge against its existing physical gas supply contract since this would still need to be met.

Another way of using the futures market is through the EFP or exchange of futures for physical mechanism. This is extremely popular on most other futures markets and its use is growing on the natural gas futures.

An EFP is a means of separating price and supply, enabling two companies to make a physical supply contract which leaves them both free to fix the price of the deal at some time in the future. All terms of the contract are agreed in the normal way, except the price. Instead of agreeing an absolute price, the two companies agree to price using the futures market. The month to be used must be agreed, and written into the contract, and so must the date by which the EFP will be registered with the exchange.

The buyer then goes onto the exchange at a time of its choosing and buys futures contracts for the agreed month. The seller similarly sells contracts when it feels the time is right. On the agreed date the exchange is notified and the two deals are, in effect, closed out against each other. The seller delivers the gas to the buyer. The seller has thus exchanged its short (sold) futures position for a physical sale and the buyer has exchanged its futures purchases for a physical delivery.

Example

EFP

A producer and its customer wish to negotiate a supply contract for 100,000 therms/day of natural gas during March. They can agree all the terms except the price. Instead of agreeing a spot or fixed price, they decide to do an EFP and price the contract against March futures. They agree to register the EFP on February 24. EFPs can be registered at any time up to the expiry of the contract and for a few hours afterwards, depending on the different contract rules.

At some point between the time the contract is agreed and the expiry of March futures, the producer will enter the market and sell 100,000 therms/day March futures at, say, 17p/th, and — at a different time — the customer will buy 100,000 therms/day at, say, 16.5p/th. On February 24 the exchange is notified by the parties that an EFP has taken place. An EFP registration price has to be agreed between the two, say 16p/th. Both futures positions are then closed out at 16p/th, the registration price and the seller invoices the buyer at the same registration price. It is therefore of no significance.

The purchase and sale prices can then be calculated as follows:

	Buyer	p/th	Seller	p/th
	Buys futures at	16.5	Sells futures at	17.0
Feb 24	Sells futures at	16.0	Buys futures at	16.0
	Futures loss	0.5	Futures profit	1.0
	Invoiced at	16.0	Invoices at	16.0
	Futures loss	0.5	Futures profit	1.0
	Net purchase price	16.5	Net sales price	17.0

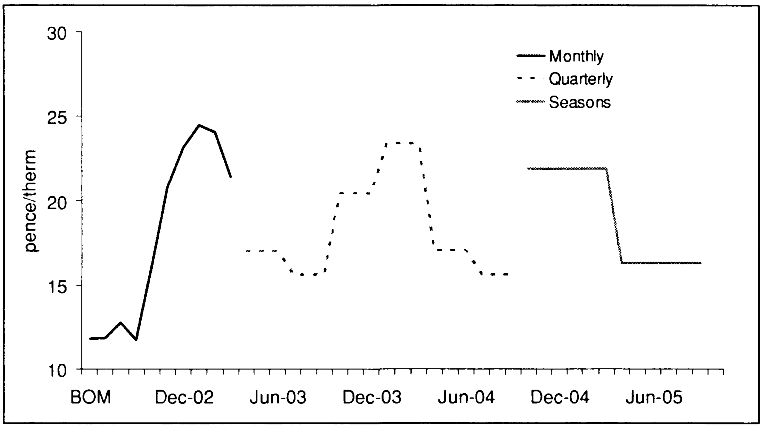
Whatever the EFP registration price, the calculation will always be that the buyer's net price is the price at which it bought futures and the seller's the price at which it sold.

This example assumes that the gas being delivered is at the same location and with other terms the same as the futures contract. If that is not the case, a differential to account for any differences between the terms of the futures contract and the physical agreement can be agreed. This differential is then applied to the EFP registration price when the invoice is sent. Both buyer and seller would then have a net price equivalent to the futures purchase or sale price plus or minus the differential.

The main advantage of the EFP mechanism is that the price of the contract can be completely separated from the physical supply. There need be no negotiation over price, unless there is a differential to be agreed, as buyer and seller will each fix their own. Long-term contracts can be entered into, ensuring supply or an outlet for production, without locking either side into price terms which can become unattractive. Such deals are common in some of the oil markets, for example the gasoline export market from Europe to the US.

Although the use of futures for hedging has the same effect, EFPs have the advantage that there is no need to unwind the hedge. This reduces the trading risk. Although, in theory, futures hedges are unwound at the same time as a physical deal is priced, this may be difficult to achieve in practice. Liquidity in the markets varies from day to day and within the day. By using an EFP the risk that the market might move between the time when the physical deal is priced and the hedge lifted is eliminated.

Similar mechanisms exist on the over-the-counter (OTC) market where they are known as trigger pricing or price fixation deals. They are particularly useful for companies that are not allowed to use the futures markets or who wish not to.



Source: IPE

Figure 5.4 IPE forward price curves 7 June 2002

Spreads are also actively traded on the futures markets. A spread is the simultaneous purchase of one contract and sale of another. In the case of gas, with its uniform quality, the most common spreads are time or calendar spreads, where one month is bought and another sold.

Gas traders use spreads primarily for speculative purposes. When the difference in price between two months appears too wide the trader will sell the higher priced one and buy the lower priced. When the spread is too narrow the opposite trade will be done. When trading spreads the overall movement in price is not important, it is only the differential which is significant. Arbitrage between gas futures contracts for different delivery horizons helps to ensure that prices along the forward curve remain consistent with each other and that any differences in price reflect genuine differences in market perceptions of the value of gas at different delivery dates in the future. Such differences include the strong seasonal pattern displayed by the forward price curve for IPE natural gas futures (see Fig. 5.4).

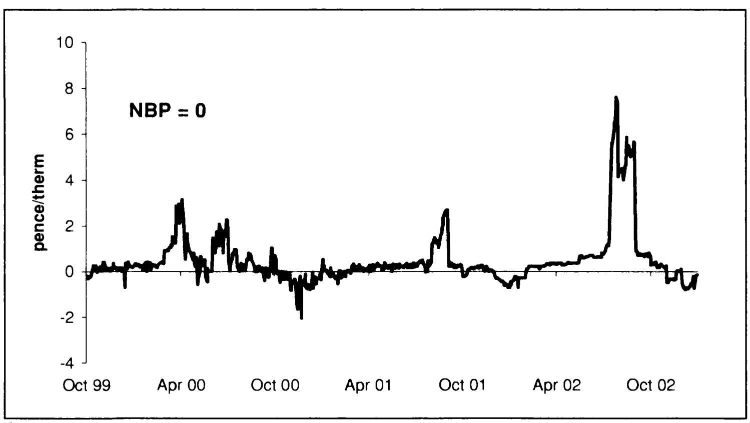
5.4 OTC derivative contracts

In addition to exchange-traded futures contracts, there are a number of derivative contracts traded over-the-counter (OTC). Any contract not traded on a futures exchange but agreed bilaterally between the two parties is an OTC contract. OTC contracts include forward contracts, swaps, contracts for difference, and options — although options are also traded on the futures exchange.

Gas forward contracts are actively traded in the UK and are beginning to be traded in continental Europe. Almost all the UK gas forward contracts are traded on the basis of the National Balancing Point (NBP), though it is also possible to use any of the beach terminals if both sides agree. The NBP is a notional trading point within the UK gas pipeline system that is used as a theoretical delivery point for gas. Gas actually enters the system at various terminals around the UK, known as entry points, and can also be traded for delivery 'on the beach' — see Chapters 6 and 9.

The forward contract sizes vary by negotiation with most being for 25,000, 50,000 or 100,000 therms/day of gas. As with all forward contracts there are standard terms and conditions: the price is the only real point of negotiation, subject to agreement on the delivery location. One major advantage of a liquid forward contract market is that it contributes greatly to price transparency and enables the providers of energy derivatives to offer various gas instruments.

Following the start-up of the UK-Continent Interconnector, a gas forward market is also developing based on delivery at the Zeebrugge hub, but much of the trading is related to UK NBP prices (see Fig. 5.5).



Source: Petroleum Argus

Figure 5.5 OTC prices: Zeebrugge first full month minus NBP

Many contracts were priced in pence/therm rather than Euros/therm, which are used in the physical market in the region.

Both forward and futures contracts have grown rapidly in the last few years. The two are complementary with many traders 'converting' futures into forwards and vice versa using the EFP mechanism. Futures and forwards have similar uses for those trading in the gas market: the choice of instrument will largely depend on market conditions at the time.

5.5 Swaps

Over-the-counter (OTC) instruments are developing quickly in the gas markets in the US and the UK. With the continental European market now physically integrated with the UK market the integration of the trading techniques must surely follow, but as yet there is little activity.

After forwards, swaps are the simplest of the OTC instruments. They have essentially the same effect as futures contracts, though they differ greatly in operation. A swap is a financial transaction, settled out by a cash payment from one party to the other rather than a physical transfer of gas. All swaps are contracts for differences (CFDs) because of this financial settlement and are sometimes called CFDs instead.

A swap allows a trader to fix a buying or selling price for a known time in the future. When that time comes the swap is reversed at the prevailing market price: a cash adjustment is then made.

It is known as a swap because the user can exchange a fixed price now for a floating price at a pre-determined time in the future. This floating price is the prevailing market price at the time. If used for a hedge, this floating price will be the same, or very close to, the price paid or received on the physical market.

Gas traders can trade swaps either by direct negotiation or they can use the Intercontinental Exchange (ICE), which lists several gas contracts in Europe and the US on its electronic platform[9].

Example

Swap

Company A wishes to fix the purchase price of July gas during February. It is offered a price of 16p/th to be reversed at the IPE index* price for July. This price is 17p/th.

	OTC		**Physical**
Feb	Price fixed at	16p/th	
July	Swap reversed at	17p/th	Gas bought at 17p/th
	Company A receives	1p/th	

The net purchase price paid by Company A is therefore 17p/th minus the 1p/th received from the swap provider, or 16p/th. This is the same as the price originally fixed using the swap.

*The IPE index is the average settlement price of the front month (i.e. the nearby contract), calculated daily from the day that the previous contract expires.

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[9] www.intercontinentalexchange.com or www.theice.com

5.6 Options

Options are available on the gas market but are not widely traded. Options on futures are available on the Nymex contracts, but not on the IPE. They are also traded over the counter (OTC). Gas price volatility is significantly higher than most commodities and because of this options are generally considered expensive.

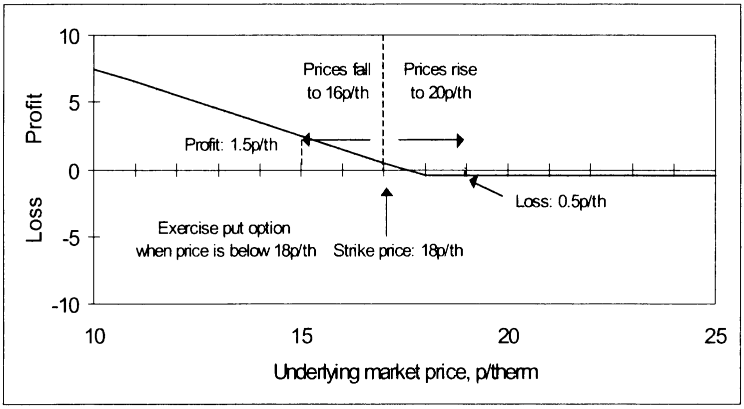
An option gives the buyer (holder) the right to buy (call option) or sell (put option) gas at a fixed price (the strike price) at some time in the future. In return for this right the buyer pays a premium. The seller (writer) of an option has the obligation to meet the buyer's rights, should the buyer choose to exercise them. In return for this, the seller receives the premium. Options are effectively insurance policies: they protect buyers against unwanted price movements. Unlike futures or swaps, however, options allow the buyer to benefit from improving prices.

As with other contracts, options traded on exchanges will have all their contract terms set by the exchange. The only negotiation is on price, which — in the case of options — is the premium. By contrast, OTC options can be traded for a wide range of commodities and the two parties can negotiate all the terms, strike prices, expiration dates and all the other elements of an option.

Exchange traded options expire on a single day and exercise will depend on the price of the underlying commodity on that day. OTC options will normally be exercised against an average price over a month, or other period as agreed with the seller.

A put option can be used by a producer of gas — if prices fall below the strike price, it will give the same protection as a futures or forward price hedge. The profit on the hedging instrument will offset the fall in price on the physical market. But if prices rise above the strike price, the producer will be able to benefit from the higher market price for its output — which would not be the case with a futures or forward contract since this would lock the producer into a single fixed price (see Fig. 5.6).

A call option, or option to buy, provides similar protection for someone concerned about rising prices. While the market remains below the strike price the gas buyer pays the market price and the option expires worthless. If the price moves above the strike price the buyer has a long position which will give a profit to offset the higher price being paid in the physical market. The maximum purchase price for a trader using a call option is the strike price plus the option premium. A gas buyer can therefore establish a maximum purchase price while still benefiting from any fall in market prices below the strike price (see Fig. 5.7).



Source: Arktauros

Figure 5.6 Buying a put option

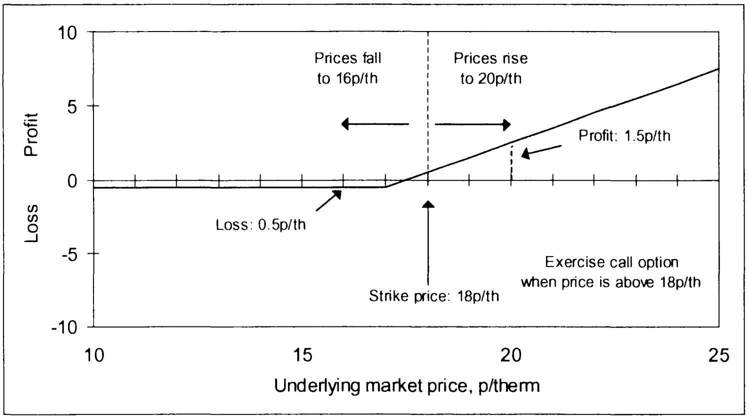
Example

Buy a put option

A gas producer wishes to protect itself against falling prices in October. Rather than sell futures or fix the selling price using a swap, it wishes to buy a put option so that it can benefit from rising prices. It therefore buys an 18p/th put option for 0.5p/th.

If the price remains above 18p/th the option will not be used by the producer. The option will expire worthless, and the producer will sell its gas at the higher market price. If, however, prices fall below 18p/th the producer will exercise the option. This will give it a short futures position at 18p/th. It can then buy back the resulting futures position at the lower price, say 16p/th, taking 2p/th profit. Its physical gas will be sold for 16p/th, giving a net price of 18p/th, less the 0.5p/th paid as a premium. If prices fall further, the net effect will be the same: the profit on the option will be added to the physical sale price to give a net price of 17.5p/th, the strike price less the premium paid.

Option premiums are dependent on a variety of factors, all relating to the likelihood of the option being exercised. Premiums can be broken down into two parts: intrinsic value and extrinsic or time value. The first of these is a measure of the inherent value of an option deriving from the difference between the current market price and the strike price. Only an option which would be profitable if exercised immediately has an intrinsic value: thus a call option with a strike price below the market and a put option with a strike price above the market have intrinsic value. They are known as in-the-money options. An option with a strike price at the current market level is known as an at-the-money option and puts with strikes below the market and calls with strikes above as out-of-the-money options.



Source: Arktauros

Figure 5.7 Buying a call option

Example

Intrinsic value

A call option has an intrinsic value when the strike price is below the market price. For example, if the strike price is 18p/th and the market price is 20p/th, the intrinsic value of the call option is 2p/th.

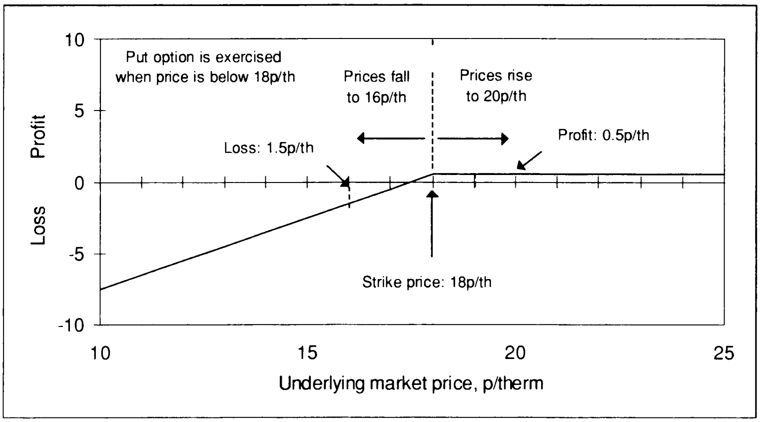
Conversely, a put option has an intrinsic value when the strike price is above the market price. For example, if the strike price is 18p/th and the market price is 16p/th, the intrinsic value of the call option is 2p/th.

Option values: underlying market price 18 p/th, 30 days left to expiry

Strike	Calls		Puts	
price	**Premium**	**Status**	**Premium**	**Status**
16 p/th	2.11	*in the money*	0.11	*out of the money*
17 p/th	1.28	*in the money*	0.28	*out of the money*
18 p/th	0.65	*at the money*	0.65	*at the money*
19 p/th	0.28	*out of the money*	1.28	*in the money*
20 p/th	0.11	*out of the money*	2.11	*in the money*

The other part of the option premium, the time value, is dependent on a variety of factors: the time to expiry, the volatility of the market, interest rates and the supply and demand for the option.

There are a number of mathematical models for establishing theoretical option premiums. These are useful as a starting point, but options are like any other market: an option price is determined by the willingness of buyers and sellers to trade at a particular price. The models use the historical volatility of a market to determine premiums, whereas in fact the market determines the premiums — which allows



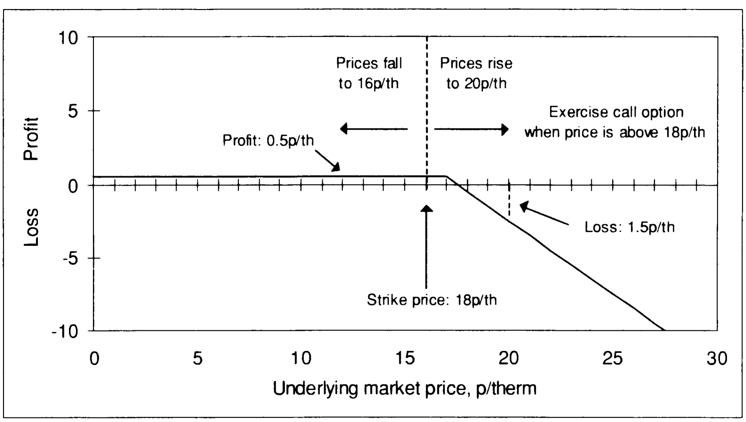
Source: Arktauros

Figure 5.8 Selling a put option

traders to determine the implied volatility of the market. Implied volatility gives a measure of the market's expectation of price movement, though not of the direction of that movement.

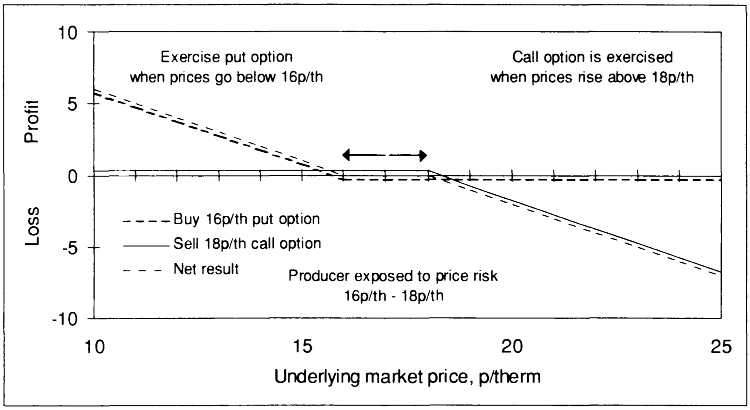
Time is a significant factor in the value of an option, especially as it approaches expiry. An option is a wasting asset: if nothing else changes an option will be worth increasingly less as time passes since the probability of the market price reaching the strike price will decrease with fewer days to go to expiry. In the early part of an option's life this is less important: each day that passes is highly insignificant for an option with, say, six months to run. But as an option approaches expiry each day represents a major part of the remaining option value.

Exchange traded options can be exercised at any time between



Source: Arktauros

Figure 5.9 Selling a call option



Source: Arktauros

Figure 5.10 Option strategies: zero-cost collar

purchase and expiry, but in practice they are never exercised early because of the time value. If an option is in-the-money and the buyer wishes to take its profit it will receive a better return by selling the option back to the market, thus retrieving some time value, than by exercising the option and getting only the intrinsic value. OTC options cannot be exercised early.

Option sellers receive the premium in return for which they have to meet their obligations to the buyer. If the option expires worthless the seller will have received the maximum possible profit: the option premium. If the option is exercised the seller will have the opposite position to the buyer, so the seller of a call option would have a short position and the seller of a put option a long position.

Because the buyer will only exercise when it is to their advantage, these positions will always be to the seller's disadvantage. Option buyers therefore have a risk that is limited to the premium paid, but unlimited profit potential. The reverse is true for option sellers: profits are limited to the premium received, but losses are potentially unlimited.

The seller's potential losses are the same as those for any other trader with a long or short position. This exposure can be hedged, but it is important to remember that a sold option retains a high exposure to risk. Short option profit/loss profiles are shown in Figures 5.8 and 5.9.

All option strategies are combinations of puts and calls, sometimes with futures or physical exposure included. There is a wide range of strategies for trading with options, but perhaps the most popular is the collar (known as a fence on the futures exchanges).

A collar allows the option buyer to reduce, or eliminate, the cost of the premium by selling a different option (see Fig. 5.10). For example, a gas producer, needing protection against falling prices, can sell a call option to finance the purchase of a put option. The effect of this is that the producer has the protection against falling prices but will not benefit fully from rising ones. Between the two strike prices of the sold call and bought put the buyer will have to pay the market price. If prices fall below the put strike the profit on the option will reduce the cost of the physical gas sale to the strike price plus any premium paid. If prices rise above the call strike, however, the producer will not benefit from the higher physical price because there will be a loss on the call option.

Collars are often traded at zero cost, i.e. there is no premium paid by the option buyer to the option seller. If the call and put options have strike prices that are equidistant from the current market price for the relevant delivery horizon, they should have the same premium. Thus the net cost of buying one and selling the other will be zero. In practice, OTC market-makers also build their fee into the net premium so the strike prices are adjusted slightly to create the zero-cost collar.

When there is a premium to pay for a collar it is because the premiums required to achieve the two strike prices are not equal and so do not offset each other.

In addition to the various types of options, puts and calls, there are different styles of option. The most common are European, American and Asian options. European options can only be exercised at expiry, which is the case for most OTC options. American options can be exercised at any time up to and including expiry, which is the case for all exchange traded options. It is not normally advisable to exercise options before expiry — the option holder will receive both the intrinsic value and any outstanding time value if the option is sold back to the market, but will only receive the intrinsic value if the option is exercised.

Asian options are average price options. Many OTC options are Asian or average price options. The strike price is the average price over a month and any profit is paid when the average market price over the month exceeds the strike price for a call option, or is less than the strike price for a put option. Premiums for Asian options are normally lower than for so-called 'bullet price' options, which depend on the price at a single moment. This is because the volatility of monthly average prices is much lower than the volatility of prices day by day.

5.7 Weather derivatives

In recent years there has been rapid growth in the field of weather derivatives. They are mainly traded on the OTC market, though the Chicago Mercantile Exchange[10] (CME) and London's International Financial Futures and Options Exchange[11] (LIFFE) offer temperature-based futures and the CME also offers temperature-based options. Any industry which is dependent to a greater or lesser degree on the weather can use weather derivatives to insure against falling sales or changing prices caused by different weather patterns, but the main users so far are energy utilities, which use them to protect sales revenues against unexpectedly cold or warm temperatures.

Most (more than 90 per cent of) weather derivatives traded are based on temperature, but it is also possible to trade rain, snow or wind-based products. In the US, where most of the business to date has been done, the concept of degree days has been well established for many years. The benchmark for a degree day is 18°C (65°F). If the average of the high and low temperatures for any day is higher than this it is a cooling degree day (CDD) and if it is lower it is a heating degree day (HDD).

Weather swaps and options are both traded on the OTC market. Weather swaps are normally based on a specified payment per degree day. The number of cooling degree days over any given period is the average temperature over the period (i.e. the average of the high and low for each day) minus 18°C, while the number of heating degree days is the opposite. Weather swaps and options are typically based on an accumulation of heating or cooling degree days over a calendar month, but the LIFFE weather futures contracts are based on a monthly average temperature index.

Many of the weather options traded are binary options. This means that the potential profit for the buyer of the option is a stated amount, similar to an insurance policy. The payout does not depend on the actual difference between the strike price and the actual outcome. Maximum or minimum temperature digital options can be used to hedge against the additional cost of bringing peak generation units on line to meet unexpected demand.

Although there is only limited liquidity in the market so far, particularly in Europe, the weather derivatives market has large potential because of the diverse nature of its potential users. Apart from energy companies, industries as diverse as construction, brewing and theme parks are affected by changes in the weather.

There has long been an active weather insurance market, but much of the business in this sector is one-way: all the users are

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[10] www.cme.com
[11] www.liffeweather.com

insuring against the same outcome, such as a hurricane. Weather derivatives have potential users on both sides of any market. For example, gas producers may prefer cold winters but retailers prefer warm ones. One effect of this is that weather derivatives are normally priced against average outcomes whereas insurance buyers have to pay a risk premium.

One problem that may hamper the growth of the market is the local nature of weather and the consequent lack of any potential international benchmark. Even within small geographical areas there can be widespread variation in the weather pattern over a season. The CME, for example, quotes futures and options for 11 US cities, but none of the contracts is liquid.

One of the attractions of weather derivatives is that they can be used to hedge unknown quantities. The gas and power industries have a risk management problem unknown in most other commodities: they cannot hedge by using a conventional equal and opposite position on a derivatives market because they don't know what volume they are going to produce or require.

But they can make a judgement that certain weather conditions will have a specified effect on their business and seek a weather derivative to manage that risk. US figures show that the gas price is the energy price most closely correlated with the weather. Gas producers have used derivatives to hedge against warm winters, when they can be adversely affected by both lower volumes and weak prices.

Examples of weather derivatives

Weather swap

An electricity utility could use a weather swap to protect itself against below normal sales due to mild weather during the winter period. The swap would be based on an expected average number of heating degree days (HDD) for a particular period. If the weather is colder than expected, then the utility will pay the swap provider increasing amounts for every heating degree day accumulated above the level set for the swap. If the weather is milder than expected, the swap provider will pay the electricity utility an increasing amount for every heating degree day below the level set for the swap. In this way the utility can guarantee a given revenue for the winter period.

Weather option

A heating oil distributor could use a weather option to protect itself against the cost of holding higher stocks in order to guarantee supplies to consumers in the event of a cold winter. The distributor could establish a heating degree day (HDD) floor level by purchasing a put option. The put option strike level would be based on the expected number of heating degree days for the winter period for which the distributor would pay a premium to the option provider. If the weather is colder than expected, the HDD put option would not be exercised since the heating oil distributor would be able to sell the excess stocks. But if the weather is milder than expected, the option would be exercised and the option provider would pay the heating oil distributor for every accumulated heating degree day below the strike as compensation for the cost of holding higher stocks.

Appendix 5.1

Glossary of gas trading terms

American option	An option which can be exercised at any time up to expiry. All exchange options are American.
Arbitrage	The simultaneous purchase and sale of the same quantities of same or similar products in two different markets.
Asian option	An option exercised against an average price.
At-the-money	An option with a strike price at the current market price.
Backwardation	The price differential between two delivery months when the nearer month is at a premium to the further one.
Basis	The difference in price between the futures or other derivative instrument and the physical price of the commodity being hedged.
Basis risk	The risk that the basis will change during the lifetime of a hedge.
Bid	Price where buyers are willing to buy.
Binary option	Option which pays a fixed sum if the conditions are met and nothing if they aren't. Also known as a digital option.
Broker	Someone who acts as a paid intermediary to arrange a deal between two parties (see also derivatives broker, futures broker).
Call option	An option giving the buyer the right to be long at the strike price.
Cap	A call option (normally over the counter).
Clearing broker	A futures broker who is a member of the futures clearing house and holds positions on behalf of its clients.
Clearing House	The agency with which all futures contracts are registered and which guarantees the performance of all contracts.
Clearing member	A broker or other company who is a member of the futures clearing house and can hold positions with the clearing house. Large users of the market often

become clearing members to reduce fees and keep all their futures positions in one book.

Collar — An option trade involving the purchase of calls and sale of puts or purchase of puts and sale of calls. Normally called a fence if traded on an exchange.

Contango — The price differential between two months when the nearer month is at a discount to the further one.

Counterparty — A party with whom one has a contract.

Derivative — A financial instrument derived from an underlying physical commodity. Includes futures, forwards, swaps and options.

Derivatives broker — Normally describes a broker acting as an intermediary on the OTC market. Any contract is between buyer and seller and the broker receives a commission.

Digital option — Option which pays a fixed sum if the conditions are met and nothing if they aren't. Also known as a binary option.

EFP — Exchange for physical. A physical deal priced on the futures market.

EFS — Exchange for a swap. A swap priced on the futures market.

European option — An option which can only be exercised at expiry. Most OTC options are European.

Exercise — The conversion of an option to the underlying futures contract or other instrument.

Expiry date — The day on which an option expires.

Fence — An option trade involving the purchase of calls and sale of puts or purchase of puts and sale of calls. Normally called a collar if traded over the counter.

Floor — A put option (normally over the counter).

Floor broker — A futures broker with a floor membership which allows it to execute orders on the floor of the exchange.

Forward curve — The price structure of a market as determined by the prices being traded and quoted into the future.

Futures broker — All futures trades must be executed through a futures broker, who receives a commission. Unlike cash brokers, futures brokers are the principal to the market: they have a contract with the exchange and with their client.

Futures contract	A standard contract, traded on an exchange, for purchase and sale of a standard quantity and quality of a commodity.
Hedge	Taking an equal and opposite position with futures or another instrument to the physical position held.
Historical volatility	The statistical measure of the volatility of a market over a given time period.
Implied volatility	The volatility of the market as determined from the option premium. Used as a measure of the market's expectation of future volatility.
In-the-money	An option which would be profitable if exercised immediately.
Intrinsic value	The amount by which an option is in-the-money.
IPE	International Petroleum Exchange. A London-based futures exchange trading crude oil, oil products and natural gas futures and oil options.
Last trading day	The last day of trading for a futures contract.
Local	Members of futures exchanges dealing solely or mainly on their own account.
Long	1. A long position will make money when the market goes up and lose money when the market goes down.
	2. 'Long options' — Someone who has bought options (but may be short of the market).
Lot	A standard contract unit on an exchange.
Margin (original)	The returnable deposit charged by the clearing house when a position is opened.
Margin (variation)	The difference in value between the price at which the contract was opened and the current market value.
Market-maker	1. A company providing over-the-counter instruments.
	2. A company on the exchange options floors quoting all options.
Nymex	New York Mercantile Exchange. New York-based exchange trading a wide range of energy futures and options.
Offer	Price where sellers are prepared to sell. Also known as ask.
Open interest	The number of unclosed contracts on the futures market.

Option	An instrument giving the buyer the right to be long (a call option) or short (a put option) of a commodity at the strike price.
Original margin	The returnable deposit charged by the clearing house when a position is opened.
Out-of-the-money	An option which would not be profitable if exercised immediately.
Over-the-counter	A contract agreed between two parties other than on an exchange. Normally used to describe off-exchange derivative trading (usually abbreviated to OTC).
Paper	Any derivative instrument used for hedging.
Physical market	Market for the physical transfer of a commodity from buyer to seller. (Also cash market.)
Position	A commitment to a market through bought and sold contracts.
Premium	The amount paid by the buyer of an option.
Put option	An option giving the buyer the right to be short at the strike price.
Settlement price	The price at which the futures market closes. It is a weighted average of the last minute or two (depending on the market) of trading and is the price at which all futures contracts are margined.
Short	1. A short position will make money when the market goes down and lose money when the market goes up. 2. 'Short options' — Someone who has sold options (but may be long of the market).
Spot month	The nearest traded futures month.
Spread	The differential in price between two different contracts, whether in the same or different markets.
Strike price	The price at which an option may be exercised.
Swap	The exchange of a fixed price for a floating price over a pre-determined period.
Swaption	An option on swap contract.
Theta	The rate of decline in an option's value with passing time.
Time decay	The decline in an option's value with passing time.

Time spread	Buying in one time period and selling the same quantity in another in anticipation of a change in the differential. Also called calendar spread.
Time value	The part of an option value reflecting the time left to expiry (often also used to include all aspects of an option value except intrinsic value).
Trigger pricing	A deal allowing the buyer or seller to choose when to fix the price of a deal on several occasions.
Variation margin	The difference in value between the price at which the contract was opened and the current market value.
Volatility (historical)	The statistical measure of the volatility of a market over a given time period.
Volatility (implied)	The volatility of the market as determined from the option premium. Used as a measure of the market's expectation of future volatility.

6 UK traded gas market

Geoff Moore, Independent Consultant

6.0 Developments since 2001

Caroline Harper

Introduction

Since Geoff Moore wrote this chapter in 2001, the energy trading markets across the world have experienced unprecedented and far reaching convulsions – the final outcome of which is not yet known. This section provides a brief commentary on events over that time.

Early days

At the beginning of 2001 observers were expecting the rapid growth of trading activity to continue, particularly via internet trading. The introduction of NETA (New Electricity Trading Arrangements) in April 2001 was expected to increase the level of electricity futures trading dramatically and bring together the gas and electricity markets as never before. Indeed the regulator was so concerned about the gaming possibilities arising from the differences in the balancing regimes of the gas and electricity markets that he proposed bringing the two together by reducing the balancing period for gas to that of electricity. The debate over whether and how to do this is still continuing[1].

In general, trading activity was booming, with US companies in particular expanding their activities to encompass the UK, competing vigorously for staff and driving trader remuneration to heady heights. Meanwhile, Dynegy bought the BG storage business and hence took control of most of the UK gas storage.

Shadows on the horizon

Despite this growth in activity, several issues were beginning to cause headaches for traders. The dramatic increase in the price of gas had led to the need for credit levels and hence financial exposures to increase commensurately, in some cases reducing the number of viable counter parties. Creditworthiness became an increasingly important issue, causing particular problems for a number of small suppliers who relied entirely on third parties to ship and supply their gas (notably Aquila withdrew from their role as provider of shipping services to small players).

Entry capacity availability at St Fergus became a major issue, as there was insufficient to meet producers' needs, particularly in summer. This led to the introduction of six-monthly auctions for entry capacity

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[1] Ofgem News Release, PR42, 28 May 2002, see Ofgem website (www.ofgem.gov.uk).

which drove prices so high that in some months entry capacity cost more than the underlying product and became an actively traded commodity. This in turn led to significant financial over-recovery for Transco, which had to be returned to shippers. It also resulted in significant volatility in transportation charges.

On certain days the shortage of capacity at St Fergus became so acute that Transco was forced to buy it back from shippers at extremely high prices. This led to an investigation by Ofgem[2] regarding shipper behaviour, although no evidence of gaming was found.

Ofgem has now introduced longer-term capacity auctions[3], as producers in particular found it difficult to make investment decisions regarding bringing gas into St Fergus, given the volatility of entry capacity prices created by a six monthly auction regime. The first auction was held in January 2003.

The bombshell

These problems paled into insignificance as 2001 drew to a close and perhaps the most significant player in the developing market – Enron – collapsed in a blaze of publicity which continues to this day. EnronOnline disappeared, creating concerns as to liquidity as well as leaving companies with significant exposures, although these were larger in the electricity market than in gas.

In many ways the gas market proved surprisingly resilient, as other players moved in to take Enron's place (initially Dynegydirect and more recently ICE). While a number of companies lost a great deal of money owed to them by Enron, there was remarkably little difficulty in replacing forward positions left exposed by Enron's demise, suggesting that liquidity was not as impacted as would be expected from the removal of the dominant market maker.

Over the next six months, details about Enron's collapse began to emerge, and the image of energy trading companies became badly tarnished. Where analysts had previously urged companies to 'be more like Enron', this was now the last company to be seen to be emulating, and the business model that so many had applauded was now viewed with deep suspicion. Companies who were primarily traders (or who had marketed themselves as such) suffered badly as their credit ratings and share prices plunged.

Dynegy recently withdrew from online trading, leaving ICE as the primary online OTC market maker, and virtually all US owned trading companies have significantly reduced trading activity in the UK. Many are expected to close their UK operations and sell assets (Aquila has

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[2] Ofgem News Release, PN91, 27 November 2001, *Ofgem's investigation into shipper conduct in the capacity market in October 2000: Conclusions* (73/01) see Ofgem website (www.ofgem.gov.uk).

[3] Ofgem News Release, PN99, 14 December 2001, see Ofgem website (www.ofgem.gov.uk).

announced that they will be pulling out of the UK energy trading business altogether) and some may even go bankrupt. These were the very companies who only a year earlier had been flooding into the UK.

UK gas market in 2002

Liquidity in the UK gas trading market continues to hold up surprisingly well, given the continuing reduction in players and the seriously reduced liquidity in US energy markets and the UK electricity market. The latter is experiencing virtually no futures trading although there is an active OTC forward market focused mainly on the short-term. The IPE has stopped listing UK electricity futures for lack of demand despite maintaining high levels of volume in both oil and gas futures.

The reason for this is far from clear. Is it because the identity of traders has changed, and the market is more dominated by gas producers with no material interest in electricity trading? Is it connected to the major role played by Centrica? Given the fact that a number of players own gas-fired power stations, why has the expected arbitrage between gas and electricity apparently not happened?

This is a critical time for trading – some observers believe the fallout from Enron will mean a return to the more traditional way of buying and selling gas. This would mean a return to longer term depletion contracts with only very large players in the game and trading a small scale activity used to balance physical flows. Some of these observers cite the consolidation in the industry structure both in terms of vertical integration and gas and electricity as a reason why trading levels will not recover. Others believe that once the genie is out of the bottle, even a scare such as Enron cannot put it back in, and that trading in both gas and electricity will start to develop and grow again once the shakeout is over.

It seems inevitable that the identity of the players will change from the halcyon days of early 2001, with large gas producers and big European players with substantial assets and customer bases being most likely to dictate the direction of the market. It will be interesting to see whether UBS (who purchased Enron's US energy trading business) will successfully resurrect EnronOnline under a new name, and whether some of the other banks such as Barclays Capital Markets will make a significant impression. These two and other banks certainly have the advantage over the more classic gas trading companies at present given their high credit ratings. The question is whether they will find that the profits justify the risks.

From the regulatory perspective, Ofgem's recent publications suggest it is still looking to reduce the balancing period for gas, but the arguments now put forward are more about security of supply than interrelations with the electricity market. With a new Director of Gas Trading Arrangements at the helm (Kyran Hanks who has worked both for Ofgem and Enron in the past) and the departure of Callum

McCarthy (the Director General) in 2003 it will be interesting to see what changes ensue.

The mood of the moment is very much one of caution compared to the heady expansionary days of early 2001. It seems likely that there will be further casualties from the Enron fallout, and the players of 2003 seem certain to be very different from those of 2001.

6.1 Origins

6.1.1 Market liberalisation

The origins of the UK traded gas market – sometimes loosely called the 'gas spot market' – are to be found in the liberalisation, or de-monopolisation of the UK gas industry. This is not surprising, as it is impossible to conceive of a healthy traded market in the days when the British Gas Corporation (BGC) had a legal or *de facto* monopoly.

Until 1986, the market for gas at the wholesale level – between the producer and the final consumer – was, effectively, all controlled by BGC (formerly The Gas Council and Area Gas Boards). Virtually all gas production was purchased by BGC – the exceptions being 'own use' by producers and some flaring – and, until government policy dictated otherwise, BGC also had a statutory monopoly of supply to end users for fuel use.

The difference between final demand and economic production was managed through the considerable flexibility built into supply contracts and by BGC storage and demand management, for example interruptible contracts. There was neither the need nor the place for separate wholesalers and traders in the UK gas industry, though a theoretical role may have existed in international trade.

The wholesale price of gas, under the long-term contracts of the day, was negotiated in an imperfect market – in economists' terms – and was heavily influenced by the UK government, which owned BGC until it was privatised in 1986. The government's dual aims of privatisation and the introduction of competition into the public sector gas and electricity markets radically altered the structure of the UK gas industry leading, among other things, to the creation of a traded gas (and power) market.

6.1.2 Introduction of competition

The relentless government campaign to introduce competition into the UK gas market employed a number of measures, the most effective of which were the 'Undertakings' extracted from British Gas in the wake of the 1988 Monopolies and Mergers Commission (MMC) investigations and the appointment in 1986 of a Regulator for gas – the Office of Gas Supply (Ofgas) – charged with the duty to 'enable' competition[4].

The process (see Table 6.1) began with the Oil and Gas (Enterprise) Act of 1982, which removed the statutory right of first

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[4] Gas Act (1986) Part 1, Section 4 (2)(d) 'to enable persons to compete effectively in the supply of gas through pipes at which, in relation to any premises, exceed 25,000 therms a year'. At the time, the adoption of the word 'enable' rather than 'promote' was seen as highly significant.

refusal held by British Gas on purchases of gas from offshore and onshore producers for national transmission and distribution, and allowed for third-party access (TPA) to BG's pipelines. It was followed by the Gas Act (1986) which privatised British Gas and removed BG's monopoly of supply to large consumers (i.e. those over 25,000 therms/year) and obliged the company to transmit gas through its pipelines for its competitors. But the failure of competition to develop at an acceptable rate led the government to take other measures following the first referral of British Gas plc, as it had become at privatisation, to the MMC in 1988. These included, importantly for the traded gas market, a series of 'Undertakings' agreed by BG, first, not to buy all the gas on offer, and, secondly, to quit market share in the end use market and to 'release' some of its own portfolio of gas supplies to the market (1991).

Table 6.1 Liberalisation of the UK gas market

1982	Oil & Gas (Enterprise) Act
1986	Gas Act allows customers consuming more than 25,000 therms/year to choose supplier Office of Gas Supply (Ofgas) established British Gas Corporation (BGC) privatised as British Gas (BG) plc
1988	Monopolies & Mergers Commission (MMC) inquiry Recommends that BG contract for no more than 90% of new gas production and publish price schedules for the industrial & commercial market (25,000 – 2 million therms)
1989	Electricity Act creates framework for privatised electricity industry
1990	British Gas restructures into three business units (Gas Business in Great Britain, Exploration & Production, and Global Gas) Electricity Pool (England & Wales) starts trading
1991	Office of Fair Trading (OFT) Review, BG undertakes to reduce market share and to release gas under long-term contract to other suppliers
1992	Consumer threshold reduced to 2,500 therms/year
1993	Monopolies & Mergers Commission (MMC) recommends unbundling of British Gas' businesses, but Government rejects advice
1994	British Gas restructures into five businesses including Transco, which will be responsible for transporting and storing gas
1995	Gas Act sets out timetable for full competition and establishes new licensing system for pipeline operators, shippers and gas suppliers British Gas obliged to give up half of market to independent suppliers
1996	Network Code issued setting out rules and procedures for third-party access to UK gas pipeline grid
1997	Monopolies & Mergers Commission (MMC) recommends lower transportation charges and separate regulation of storage charges British Gas de-merges and spins off take-or-pay contracts into Centrica
1998	All customers allowed to choose gas supplier Centrica finishes re-negotiating take-or-pay contracts
1999	Ofgas forces British Gas to unbundle storage activities from Transco Ofgas merged with Office of Electricity Regulation (Offer) to form joint regulator, Office of Gas & Electricity Markets (Ofgem)

6.1.3 Regulatory intervention

Because competition for gas end-users was being hampered by the difficulty in obtaining supplies (long lead times for new fields to be on stream and the competition for supplies by generators) British Gas was obliged by the 1992 Undertaking to sell specific quantities of gas to other suppliers. 500 million therms was released to applicants from the 1992/3 supply year (beginning 1 October) onwards at the BG weighted average cost – or WACOG – plus a very small margin.

At that time, BG's WACOG was seen as an attractive price and the applications exceeded the volumes available. By the second year of the programme (1993/94) there were 70 applicants and it became clear that some shippers were making multiple applications and that other shippers were applying for gas that they did not intend to supply to end users, but would resell to other shippers. The quantity released was reduced to 250 million therms in 1995/6 – the last year of the release gas programme – by which time availability of gas was not an issue and, in any event, BG's WACOG was 'out of the market' and unattractive.

Some see the gas release programme, which operated from 1992/93 to 1995/96, as the beginning of a traded market since some of the applicants for the gas did not intend to supply it to customers themselves. Thus a secondary market was created (for the first time) as some of the successful applicants sold the release gas on to other potential suppliers. But an equally important prior ingredient necessary for the establishment of a traded market was sufficient players able and willing to trade those gas supplies which were released or 'not purchased' by BG.

Power generators, in the form of National Power and Powergen and new Independent Power Producers (IPPs), were freed to buy gas supplies by the progressive privatisation of the electricity sector after 1989 and bought the vast majority of non-BG gas in the early 1990s. They provided another 'engine' for the embryo wholesale or traded gas market (see below), although arguably they stunted the growth of competition in the industrial and commercial market by buying most of the new supplies available.

Following the Monopolies and Mergers Commission (MMC) Enquiry of 1988 and the perceived inadequate growth in competitive supply subsequently, the Office of Fair Trading (OFT) also sought in 1991 an Undertaking from BG plc to deliberately lose market share to others[5]. This Undertaking, together with political pressure on producers to compete in the final market, slowly increased the number of Suppliers and Shippers who were potential players in the traded

[5] BG agreed with Ofgas in 1992 to limit its share of the non-tariff market (larger industrial and commercial customers) to 40 per cent by 1995, to release gas to other shippers to enable them to supply the remaining share of this market, and to undertake not to buy all the gas on offer.

market. In the meantime, Ofgas was concentrating on making the gas 'carriage' or 'shipping' regime more user friendly to potential competitors.

The government had adopted the stance that, although the BG monopoly of supply was no longer acceptable, transportation at the national and local level was a 'natural' monopoly and needed national control rather like the National Grid in electricity. However, there should be a separation of the supply and transportation function so that subsidies or preferences would not be available to the transporter's own marketing arm.

But the opportunity for a complete separation at privatisation was passed by. In the period between 1986 and the voluntary de-merger into Transco (now owned by Lattice as part of a further de-merged BG Group) and Centrica in 1997 Ofgas had to tackle the issue of separation of accounts as well as regulating transportation charges and prices in the published 'Tariff' markets of BG (less than 25,000 therms/year where published Tariffs applied).

Perhaps of greater importance for the growth of competition, however, was the role of Ofgas as umpire in the development of the negotiations of shipping terms between new entrant suppliers and BG Transportation Dept. 'Negotiated TPA', in European parlance, was the basis of the 1982 Oil & Gas (Enterprise) Act, with appeal to the Secretary of State for Energy, but the 1986 Gas Act not only obliged BG to publish principles for transportation charges but put the Director General (DG) of Ofgas in the arbiter's seat.

Before the introduction of the Network Code – a detailed set of transportation rules of universal application (see Chapter 10 for a detailed description) – contracts for transportation were bilateral but with the DG involved in some detail to make sure BG's terms were not restrictive. As time went on, and especially after the Network Code was introduced, TPA had in effect become 'Regulated' – a pattern that may well be repeated in Continental Europe where regulators are directly involved or are arbiters of the process.

Ofgas insisted that BG published a transparent charging mechanism which forced them away from the initial individual, distance related approach. Instead an Input and Output zonal system of universal application was introduced. This, combined with the obligation imposed on BG to publish Industrial and Commercial sales prices gave new entrants the visibility they needed to guarantee to undercut the established player. Downstream costs had largely become a matter of fact; all that remained was to source gas on competitive terms.

6.1.4 Access to pipelines

Like North America and the European Union, competition policy makers in Britain recognised that it would be an impenetrable barrier to entry to expect new suppliers to build their own pipelines or to negotiate unaided with incumbent pipelines. Hence the 1982 and 1986 Acts provided for access – though detailed terms, naturally enough, were not prescribed at the time.

As these terms were thrashed out and became transparent competition became truly 'enabled' and, perhaps incidentally, the prospects for a traded gas market were much enhanced. Provision is, in fact, made in the legislation for pipelines to be built in competition with the existing grid and ten other Public Gas Transporters[6] currently exist in addition to Transco though this is a fringe activity compared with Transco's throughput.

Transco is the pre-eminent Public Gas Transporter with the only nationwide pipeline system. The role of Transco is now clearly seen as an independent service provider though there has been a continual battle with the Shipper community over the services offered and the cost of provision. Ofgas has 'held the ring' during these debates which currently are focused on each proposed modification to the Network Code, of which there have been over 400.

Initially the debate was over the formulation and constituents of the Network Code. A battle won by Transco was to introduce into the Code a daily balancing requirement for Shippers although this has caused administrative difficulties for all. Prior to the Network Code there was little doubt that the transportation grid was subsidising the imbalance (accidental or deliberate) of individual Shippers by physically providing supply to customers irrespective of the Shippers inputs on the day. The economic cost of this 'service', if any, was being borne by the BG trading arm or Transco itself.

The Network Code now makes it clear that, although Transco is responsible for system wide balancing and safety, Shippers are responsible for their own energy balance on the system day-to-day. To the extent that Shippers do not balance, certain penalties apply by forcing the Shipper to buy from or sell to the system at prescribed prices (see Chapter 10). There are many other important issues embodied in the Public Gas Transporters' licence and obligations but those operational aspects which impact most directly on the traded gas market are title tracking and transfer of ownership and, in particular, how Transco facilitates trading on-system and manages the interface with Interconnectors.

[6] The main functions of Public Gas Transporters as well as Shippers and Suppliers are outlined in Chapter 4.

6.2 Growth factors

6.2.1 New entrants

Competition did not exactly burgeon in the UK gas market. It was to a large extent forced on the major participants by government policy. Excluding a few large consumers – who were frustrated by BG monopoly practices – the enthusiastic players of today were, initially, reluctant or, at least, apprehensive about competing. However, once the ground had been prepared by legislation and Ofgas' interpretation and implementation of policy, the competition bandwagon started to roll.

The growth in the number of players was an important ingredient for the traded gas market. This initial growth took on two significant forms. The end-use market became, slowly, more competitive. New entrants as Suppliers, such as the, then, independent AGAS and United Gas (a Utilicorps Company) and marketing affiliates of producers such as Shell/Esso (Quadrant), BP/Statoil (Alliance), Mobil, Amerada Hess and Conoco (Kinetica, a 50:50 Conoco/PowerGen company) were early players.

These new entrant downstream gas players were potential and actual participants in the embryonic gas trading market, and so also was a different type of company – the gas burning power generators. Power generators were encouraged to enter a small but growing secondary market for gas, because they had to match long-term contract supplies with on-the-day performances of power stations.

There was inevitably a mis-match that had to be absorbed by the flexibility in the supply contract or by buying/selling at a wholesale level. Some of the first wholesale deals in 1992/1993 were from generator to gas marketing company. Very early examples of trading were between PowerGen and Kinetica, but soon fully arm's-length arrangements took place.

These early deals were bilateral and private but several companies (e.g. PowerGen, National Power, Amerada, and Kinetica) soon developed a 'standard form' which differed in detail between companies, but were similar in substance. The 'Over-The-Counter' (OTC) market was effectively established in 1993 and 1994, using this kind of standard contract though the market was still opaque and illiquid.

Soon other participants emerged like merchant banks, attracted by the financial aspects of gas trading, and Regional Electricity Companies (RECs) ready to attack the gas end-use market because they were in the same kind of business. Producers in their own capacity (rather than as marketing affiliates) soon also discovered the advantages of an immediate market for all sorts of package size, after years of having to prove reserves and supplies of considerable longevity before they could be sold to BG.This meant that the total supply available for sale was increased at a stroke.

Also the Trader, per se, appeared in late 1994 and 1995. Liquidity was aided by the activities of Accord Energy Ltd., a joint venture between British Gas plc and NGC Corp. (Natural Gas Clearinghouse Corporation, now Dynegy) of Houston, Texas. Enron, the US power utility, pipeline operator and energy trader, was soon active as well (1995).

The introduction of US methods, and aggressive market making, helped liquidity and encouraged new entrants to enter the traded (or wholesale) market. The number of players and volumes traded were also influenced by the relative collapse of prices from levels pertaining in the long-term contracts of the day. Prices under these contracts were of the order of 23–24 pence/therm – escalated by oil products, other energy and inflation measures such as the wholesale price index (WPI) – in early 1994, while traded market prices, for monthly gas, fell during 1994/5 to around 10 pence/therm in the summer of 1995.

New entrants to the traded market could therefore easily undercut those established players relying on long-term supplies, which, in the UK did not have price re-openers that were common in Continental European contracts. The larger industrial customer was the main beneficiary of this price competition as new suppliers raced to obtain market share. These customers were, however, not very significant players directly in the traded market which is probably explained by their reluctance to get involved in the complications of shipping gas for their own use.

There were perhaps 15 to 20 regular participants in the Traded market in 1994, mainly Marketers, RECs and Generators. By 1996 this had become more like 50 to 60 with Traders, Financials and Producers joining the other participants. Currently Marketers, Producers and Traders are the backbone of the market but new participants from Continental Europe have become very influential since the opening of the UK/Continent Interconnector in October 1998.

6.2.2 Need for flexibility

Although release gas and the mis-match of supplies and requirements in the power generation sector can be regarded as the ‘kick-starts’ to a secondary market at the wholesale level in the gas supply chain, these forces could never have sustained a healthy Traded Market on their own. The Release Gas programme ended in 1995/96 and the first wave of the power station ‘dash for gas’ became less important as the new generating sets were finished and debugged.

But the generators’ mis-match of supplies and requirements was a specific example of a more general problem. As the competitive market grew, the uncertainty over a market share and gas requirements for individual shipper/suppliers also grew. There was little doubt that in 1993 and 1994 the sum of individual market share aspirations exceeded the total market size. This, combined with the growth in the number of players, created the need for a more flexible, short-term market in order to re-trade supply deficits and surpluses.

It helped that there was an aggregate surplus of gas and capacity in the UK, but this was not in itself the primary cause. It was also the case that costs of entry to a new player in the bilateral trading market were low. Barriers to entry increased marginally with the Network Code daily balancing regime, but were still low to any credit-worthy player. The access to lower cost gas than in historic portfolios obviously also eased entry.

The single most important reason for the growth of the market was the need for more flexibility in a changing market that could not be provided by the traditional long-term take-or-pay contracts. This need was rapidly strengthened by the fact that prices fell dramatically and put virtually all long-term contracts out-of-the-money. Hence, players needed to blend into their portfolio some cheaper short-term gas.

New entrants with predominantly short-term gas were at a great advantage. The traded market also enabled shippers to source gas seasonally which, although the price became seasonal and volatile, often proved cheaper overall than booking storage or buying 'swing' in long-term contracts. The introduction of daily balancing as part of the Network Code increased the need for flexibility and a mechanism to supply daily gas.

Another development aided the growth of the market and this was the introduction of trading at the so called National Balancing Point (NBP) after March 1996 which, facilitated by Transco, became a 'user friendly' way of trading (see section 6.2.3 below and Chapter 10).

6.2.3 The Network Code

It is difficult to overestimate the importance of the Network Code for trading in the UK gas market. Daily balancing has already been mentioned; this created a market in very short-term gas, within day, day ahead and over the next few days/weekend. It also gave rise to the Flexibility Mechanism and its successor, the On-the-day Commodity Market (OCM). Perhaps more important in the long run for its influence on volumes traded was the introduction of the National Balancing Point. This geographical fiction, because it is not a point at all, was invented for the balancing mechanism of the Network Code but it rapidly evolved as a trading 'point' as well.

In reality it meant that gas could be traded on-system with many advantages to buyer and seller compared to the Beach Terminal trading points. Once Transco had agreed to transfer title (a term used loosely as, strictly, Transco retains title until the gas is re-delivered) the trade was complete without the claims validation of ownership problems which was dogging beach trades. NBP trading simply required Transco to match trades from the two counterparties and transfer the 'ownership' of gas on the pipeline system. Such gas could be regarded as completely reliable as it was already on the system and it was already Entry Paid. In a very real sense, the NBP, despite its lack of physical identity, is a trading Hub. The NBP also became the delivery point for the IPE contracts, though Beach Terminals were considered at one time.

The Network Code also introduced an additional trading activity in the form of the Flexibility Mechanism (sometimes called the Flexibility 'Market' though this term is somewhat misleading as it was not a true 'market' – there being only one buyer/seller – Transco – in the auction system). The Flexibility Mechanism has now been replaced since October 1999 by the On-the-day Commodity Market or 'OCM', which is described below and in more detail in Chapter 10.

A further boost to trading opportunities was the introduction in January 1997 of a natural gas futures contract on the International Petroleum Exchange or IPE (see Chapter 8 and below), and the opening in October 1998 of the UK/Continent Gas Interconnector pipeline. The Interconnector immediately led to arbitrage trading between the very different UK and Continental price regimes and soon led to a formal trading 'Hub' in Zeebrugge in Belgium.

6.2.4 Beach terminal trading

The natural (and perhaps only) place to trade gas in the formative days of the market was at Beach Terminals. These terminals, and sub-terminals within them, were the points where title historically passed from producers to British Gas, and they are the entry points to the transmission grid where Transco now takes title until re-delivery to the Shipper at the point of consumption. They were also the points where offshore Allocation Agreements split production between the various contracts for supply and, if necessary, the individual contract or field participants.

Each of the six Terminals had its own distinct – and very different – Entry Charges to the transmission system. Bacton was a popular trading point as it had the lowest Entry Charge of all and, like St Fergus, a large throughput. Bacton became the pricing point for trading with other Terminals calculated at a differential, which was based largely but not entirely on transportation cost differentials. This was a bit like Basis differentials from Henry Hub in the USA although the analogy should not be pushed too far as Bacton did not have the status of the delivery point of the main futures contract (as with Henry).

The resident Allocation Agreements at terminals were an imperfect mechanism for the Traded Market, especially after daily balancing was introduced. The ownership in production, and therefore the passage of title to a Trader, was usually computed many days in arrears and it was not possible to know whether deliveries had been made on-the-day. Apart from allocation delays themselves any offshore problem could lead to a *force majeure* claim and/or possible default on delivery to trading parties who may not have been able to cover themselves because of delays in data if for no other reason.

The Claims Validation Agency, an independent body, was set up to provide, hopefully undisputed, resolution to ownership question but they were hampered by delays and other inadequacies in the data available. In late 1998 an important agreement was reached – The Claims Validation Information Agreement – which removed many of the difficulties but by then the whole emphasis of trading had moved away from Beach Terminals to the National Balancing Point (see 6.2.3 above).

6.2.5 Standard contracts

Very early in the history of UK gas trading, parties sought to develop a simpler form of contract than the traditional, extremely complicated and lengthy long-term supply contracts. This was inevitable to an extent, as short-term gas is inherently simpler to provide for especially compared with field-wide depletion contracts[7] with their draconian provisions on Sellers' obligations to supply.

But the necessary emphasis on simplicity and speed of transaction was also a driver. Contracts rapidly took the form of a covering agreement that could provide for many individual transactions. Though they were fairly similar between different companies, they were only 'Standard' as between the agreed counterparties; they were not standard on an industry wide basis.

This gap was filled by the 1997 NBP agreement (described in and appended to Chapter 9). Since then a Beach standard agreement has also been developed but does not have the same following.

6.2.6 Price reporting

Both liquidity and transparency improved as time went on but particularly in 1995. Price reporting by *PH Energy Analysis Ltd.* (also popularly called *Heren*) and others began to gain market acceptance, particularly when the weekday publication *British Spot Gas Markets* (now *European Spot Gas Markets*) was established[8]. *Petroleum Argus* also established a daily report (*European Natural Gas*) and *Platts*, well known for their oil industry reports, also joined in. Much later the

[7] See Chapter 11 for a full discussion of the issues and complications of long-term supply and depletion contracts.

[8] For further information about gas price reporting see the *Heren* (www.heren.com), *Argus* (www.petroleumargus.com), *Platts* (www.platts.com) websites. FT Energy (www.ftenergy.com) has now merged with Platts.

Financial Times introduced a European equivalent to their US publication, *Gas Daily*.

It is of interest why transparency of prices emerged so effectively – and there is no single answer. One explanation is that, given that enterprising reporters were going to publish prices anyway, the serious long-term traders wanted quotations to be accurate. These players also saw that the future of a healthy market, and in particular the number of new participants, depended on confidence in the published numbers. Furthermore, derivative trading instruments, such as swaps and options, could not emerge without some independent price measures to be used in settlement.

Others, perhaps, wished to move the market in a particular direction – to their advantage – by reporting but were soon defeated by the 'law of large numbers' as many began to report trades. Those who expected to benefit by opacity either came around to the view that an efficient market was in their interest, or, in the event, had no choice in the matter.

Buyers of longer-term gas – and other gas outside of the Traded Market – also wished to be able to index gas to the new market prices; they also supported the reporting of prices and the development of indices of the short-term market. The desire for escalation indices led some of the reporters to publish specific indices such as the Heren Index in ESGM with a clearly defined basis of calculation and averaging of reported deals.

The growing number of Brokers in the market also provided transparency of a kind, at least as far as the participants in direct touch with them.

In February 1997, transparency was further enhanced by the screen based IPE market, where market participants could see the prices on the Exchange in real time. Other periodicals and the IPE itself release the end of day Settlement Prices (closing prices on the day) to the public domain. The IPE also publishes an NBP Gas Price Index[9] for escalation purposes (see Chapter 8). The OCM – operated by EnMO – is also screen based and real time (for participants) and was available from October 1999. OCM figures are also made available to the public domain daily through price reporters and the EnMO website (www.enmo.co.uk).

[9] Available from the IPE website (www.ipe.uk.com).

6.3 Current structure

A description of gas trading in the UK has to encompass at least three distinct market sectors – the bilateral or OTC market, the IPE exchange traded market and the OCM. The OTC market can be further sub-divided into the NBP, Beach Terminals and the Interconnector. Each is rooted in the physical needs of the gas supply system, but all have the potential to make use – to a greater or lesser extent – of sophisticated derivative financial trading instruments such as swaps and options.

As a rather crude differentiation of these markets Table 6.2 sets out the main scope of each market in terms of the duration of supplies which are predominantly traded and quoted on each (as at August 2002).

Table 6.2 Structure of the UK gas market

Supply duration	**OTC**	**IPE**	**OCM**
Within day	Yes	No	Yes
Days	Day ahead, weekend	Next 7 days	Day ahead, Next 7 days, weekend
Balance of month	Yes	Yes	No
Months	Next 6	Next 16	No
Quarters	Next 12	Next 6	No
Seasons	Use quarters	Winter & summer	No
Years	Next two years	Use quarters or seasons	No

Of course, the situation is dynamic and subject to change.

6.3.1 OTC market

The main form of traded market contract in the formative days of the OTC market was a monthly quantity, sometimes with ‘Swing’, which was an ability to take an optional quantity above the minimum specified. Contracts without Swing were called ‘Flat’, i.e. with equal daily quantities over the month. Later the market was to broaden out (especially in 1996 and 1997), particularly after the balancing requirements of the transmission system moved to daily balancing from monthly.

Figures obtained by Ofgas for their Review of Gas Spot Markets (April 1997), show that the vast majority of gas traded in the first quarter of 1995 was in monthly parcels, whereas, by the first quarter of 1996, daily trades and within-month quantities were much more significant. The figures collected for 1997 show a significant increase in within-day and quarterly trades (see Table 6.3 below). These were the last figures published on a comparable basis but they are indicative of the maturity that the market had reached by then, a level which it still retains or has enhanced in terms of more sophisticated traded products.

The OTC Market trades anything between within-day and multi-year gas. The price reporting agencies currently will typically report prices for Within day, Day ahead, Weekend, Balance of month, Front month and a further 5 Months, several Quarters and Annual gas.

Table 6.3 Share of OTC trades by duration, per cent

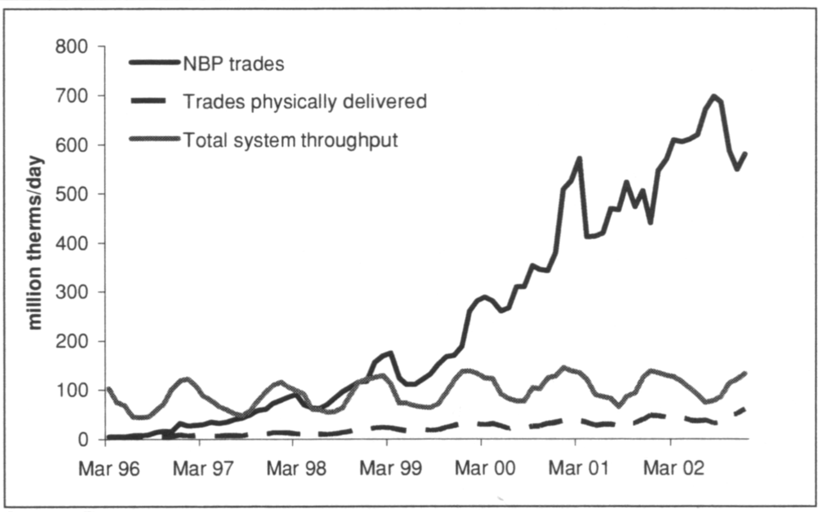
	1Q95	1Q96	1Q97
Within day	0	2	14
Day	0	39	26
Within month	7	19	19
Month	86	31	16
Quarter	7	7	21
Year	0	2	4
Total	100	100	100

Source: Ofgas, Review of Gas Spot Markets, April 1997

Thus, an OTC forward curve of prices can be discerned just as with exchange traded gas such as on the IPE exchange in London or NYMEX in New York (see section 6.4.4 below).

No hard figures for total OTC traded volumes along the forward curve are available. When traded many deals are 'P&C' – private and confidential – though some deals are reported by specialist price reporters. Hence, though the market became semi-transparent as far as volumes and prices were concerned, the prices probably had more validity than volumes. Volumes were less transparent because an unknown proportion of deals is reported (perhaps less than half).

Current, or 'In-the-month' aggregate trades at the National



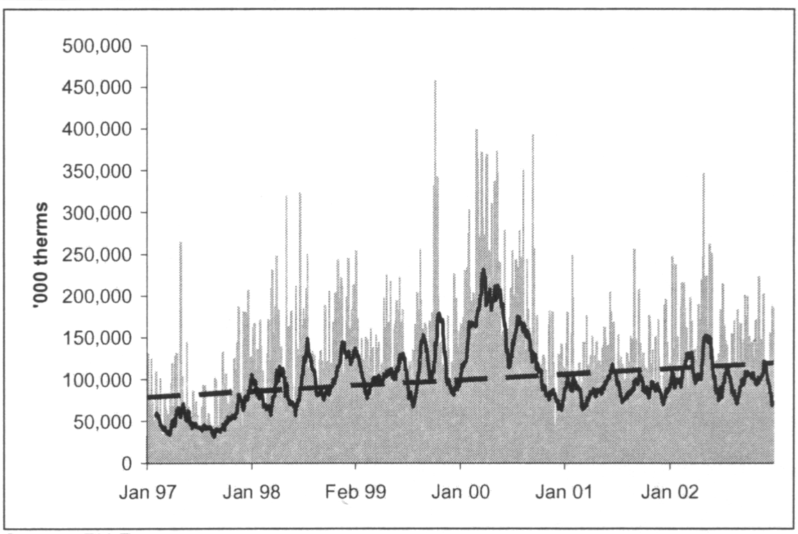
Source: Transco

Figure 6.1 Current NBP trades in the UK gas market

Balancing Point (NBP) became available from Transco in March 1996 (see Fig. 6.1). These figures measure NBP/OTC trades and the relatively small number of IPE trades which go to physical delivery in the month. However, the figures miss deals netted out by the counterparties before notifying Transco and also, of course, the unpublished number of Beach trades in the month. As described elsewhere, the OTC traded market has largely switched from Beach to NBP, but also NBP trades active beyond the reported months are missed by the published data. In other words, the In-the-month trades do not catch trades in the more distant parts of the forward curve, nor the number of times the current month may have been traded in the past.

The NBP figures show a steeply rising trend, in large part due to the amount of re-trading that takes place prior to the gas reaching an end-user. This re-trading, or 'churning factor', has reached a multiple of 17–18 at times and averaged over 11 in 2001. Using an assumption that Beach trades are only 10 per cent of active NBP trades it is apparent that OTC trading has seen about 125–130 billion therms change hands in the year 2001 compared to a system throughput of just over 39 billion therms/year and the trend is steeply upward. Of this throughput, 27 per cent or 10.5 billion therms have reached final consumption via the traded market according to Transco, who would be the only entity to know.

PH Energy in European (formerly British) Spot Gas Markets publishes the number of trades reported to it along the whole forward curve and the volumes which have been traded – including the future volumes to be delivered. This has represented an erratic but generally



Source: PH Energy

Figure 6.2 Reported OTC trades in UK gas market rising trend as demonstrated by a straight line fit and 21 day moving average trendline – roughly the number of trading days in the month (see Fig. 6.2). This series is of doubtful value as a measure of the total market size because of the unknown number of trades not reported. At the very least, it is probably indicative of the trend.

During 2000 an average of 150 million therms/day were reported and conventional wisdom would suggest that a multiple of two to three times that volume was actually traded. Some insiders would put this much higher at perhaps 700–800 million therms/day. In 2001, the volume of reported NBP OTC trade fell sharply to an average of around 90 million therms/day as high gas prices and credit concerns reduced the number of companies able to trade, but volumes picked up again in 2002 to an average of over 100 million therms/day in the first eight months of the year despite the problems caused by the collapse of Enron.

A rapidly expanding sector of the OTC Market has been trading through and around the Interconnector since October 1998. In its first year of operation short-term trading is thought to have been of the order of 2 billion therms (the equivalent of more than 5 bcm) and probably exceeded the volume supplied under long-term export contracts in that year which in some cases were on build-up quantities. In 2000 the traded volumes are not known but may well have been of the order of more than 10 per cent of total UK trades.

6.3.2 IPE gas futures contract

The IPE natural gas futures contract was introduced in January 1997 (February 1997 was the first contract). This contract is a formal exchange-traded futures contract and initially provided for a strip of twelve individual monthly contracts. Chapter 8 is devoted to the IPE gas futures contract and describes its workings in more detail.

The market is electronic and screen based allowing anonymous trading by the participants. Transactions are cleared by the London Clearing House Ltd. (LCH), which removes counterparty risk. The contract can, if necessary, go to delivery at the NBP though the vast majority of trades are settled financially. Less than 10 per cent of lots traded are thought to go to delivery. The IPE thus provided a classic futures based hedging medium as well as adding to liquidity and, substantially, to price transparency.

The contract was greeted with some enthusiasm by the market participants and by Ofgas. It was traded in a rather subdued manner for its first year or so of operation, with a limited number of participants, but, as Figure 8.3 in Chapter 8 shows, picked up considerably in 1999 and 2000. One reason for this growth was the gradual expansion of contracts to trade.

A Balance of the Month (BOM) contract was added in August 1997 allowing trading of the remainder of the current month, whereas the previous contracts were for whole months only. The futures strip was extended to 15 months in April 1998, and daily contracts for the week ahead (the next seven days) were introduced in June of that year. In October 1999, the forward curve was further extended by the addition of seven 'quarter months' (monthly contracts at quarterly intervals). It currently trades seven quarters followed by two 'seasons' – six monthly summer and winter periods – allowing participants to take positions more than three years ahead (see Chapter 8).

For the participants, the IPE market had advantages compared with the OTC market. It increased liquidity by enabling on- and off-screen arbitrage, as well as hedging forward physical gas and/or exchange between physical and financial positions. Ultimately the IPE encouraged more derivatives by providing an unambiguous settlement pricing structure.

Though OTC price reporting provided a reasonably accurate pricing series that could be used for settlement or the indexing of longer-term contracts to 'spot', the screen-based exchange prices seemed to be preferred by many parties. Anonymity had a great appeal to some of the larger (market moving!) players and the lack of counterparty risk had a wide appeal. By mid-1999 more than 40 companies were reported to be trading, which was a significant proportion of the traded market participants. An increase in players from Continental Europe has been another feature, especially in 2000.

6.3.3 On-the-day Commodity Market (OCM)

The OCM was only one part of the Ofgas initiated 'Revised' or 'New' Gas Trading Arrangements (NGTA). The other main set of proposals related to the auctioning of Transco's pipeline capacity on a shorter and shorter time basis. Both parts of the NGTA are in a state of development and neither has reached its final form yet.

A timetable for these future modifications of the regime is to be found in the Ofgem document *The New Gas Trading Arrangements: Further Developments of the Regime – A Decision Document* (28 February 2000)[10]. However, this programme has slipped considerably since. The OCM was designed to be a market based medium to aid Shippers and Transco to fulfil their respective balancing requirements (Shippers to balance their energy inputs and outputs on the day and Transco to balance the system as a whole to maintain security of supply).

Additionally the OCM provides price information to 'cash-out' imbalances and give the right incentives to Shippers to bring forward/or take back gas. It was introduced to overcome the perceived shortcomings of the Flexibility Mechanism (FM), which was the earlier

[10] A copy of this is available from the Ofgem website (www.ofgem.gov.uk).

method for Transco to balance the system and to 'penalise' individual shipper imbalances.

Ofgem described the objectives of the new balancing arrangements as:

> (1) Introducing an On-the-day Commodity Market (OCM) that provides a screen based, anonymous, fully-cleared trading platform allowing Shippers to fine tune their within-day gas positions and BG Transco to balance the system;
>
> (2) Reducing Shippers' balancing tolerances by 25% to increase incentive on Shippers to balance their own portfolios; and
>
> (3) Providing BG Transco with commercial incentives to reduce balancing costs by rewarding balancing actions taken close to the average price of gas trades on the OCM and penalising BG Transco for actions taken away from the market price.

Ofgem outlined its views on further development to the gas-balancing regime in its July 2000 review and decision document[11], the September 2000 consultation document[12] and additional proposals published for consultation in February 2001[13]. A key element of these changes was the removal of balancing tolerances, originally scheduled for 1 April 2000, and their replacement with a linepack service from Transco.

The rationale for such a change is that it would improve cost targeting by providing greater incentives for Shippers to balance their own portfolios where possible. Those Shippers that lack the flexibility to deal with within-day changes to their portfolios would purchase the flexibility they needed through the linepack services which would allow Shippers to carry over any imbalances of gas from one day to the next.

The hope and desire was that the OCM would produce market based prices on a within-day basis (also extended to day-ahead gas) which would be more reflective of market conditions than the FM, which was not regarded as a true market (hence the word 'mechanism' rather than market). Experience has shown that OCM prices closely track, indeed heavily influence, the OTC prices for prompt gas.

In many ways the influence of the OCM belies its comparatively small size despite rising volumes of trade – in 2001 1.7 billion therms

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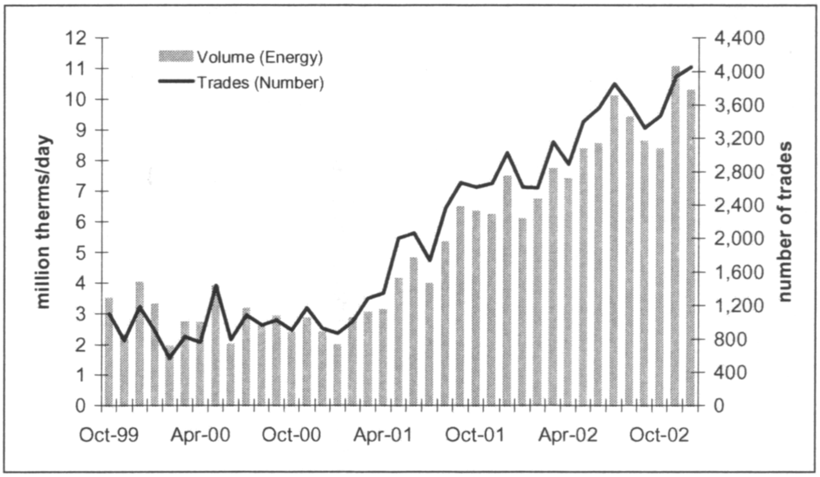
[11] The New Gas Trading Arrangements, A review of the arrangements and further development of the regime, July 2000, available from the Ofgem website (www.ofgem.gov).

[12] Storage and The Gas Regulations 2000 Exemption Regime: A consultation document, 20 September 2000; available from the Ofgem website (www.ofgem.gov).

[13] The New Gas Trading Arrangements: further reform of the gas balancing regime – a consultation document, February 2001, available from the Ofgem website (www.ofgem.gov).



Source: EnMo

Figure 6.3 Number of OCM trades and volumes traded

was traded compared with within-month volumes of 120 billion at the NBP – and the number of transactions at around 3000 per month is only 10 per cent of the NBP. Figure 6.3 shows volume experience in the OCM and the number of trades. The relatively low figures for volumes in the first year of operation did give some support for a pessimistic view on liquidity but this has improved markedly over the past eighteen months. The IPE market looked sluggish at a similar stage in its history. OCM volumes in 2002 have risen to over 8 million therms/day and are now equivalent to around 5 per cent of current reported OTC NBP trades but not all of that business is on a within-day or day-ahead basis. OCM might be about 20–30 per cent of that particular business.

In one sense, the OCM is inherently less liquid than the NBP OTC Market measured each month by Transco. In the market for balancing gas the Shipper wants physical gas so we would not expect the re-trading ratio of 10–11(multiple) which is typically seen in the current OTC market each month. Furthermore, for the same reason one might expect a more distinct seasonal pattern of volumes in the OCM than in other sectors of the market. In fact as Figure 6.3 shows the pattern of trades is not noticeably seasonal.

The Flexibility Mechanism (FM) produced very erratic System Marginal and System Average Prices (SMP and SAP), the prime examples occurring in December 1997 (see Chapter 10). Furthermore, it did not provide for Inter Shipper balancing because Transco was the only counterparty for those bidding gas on the FM screens. FM often produced many System buys and sells on the same day, thereby suggesting a structural instability.

Also, the FM was revenue neutral to Transco, who recovered all the costs from the Shippers and, some would say, transferred to Shippers the consequences of any ill-conceived or ill-managed maintenance activities. Transco were simply price takers under FM and were indifferent as they could pass it on to the Shippers. FM bids were location specific and large price premiums were paid for short notice supply adjustments. The FM, maybe, suited Transco but did not give the Shippers much flexibility to bid from anywhere on the system.

The OCM clearly overcomes some of these drawbacks, in that gas is traded between Shippers as well as between Shipper and Transco. Nearly 70 per cent of OCM trades were between Shippers in the first year of operation. The prices have been less erratic and have been derived from real trades on every day that the market has been open. (A fallback SAP is based on a 7 day (unweighted) moving average, but has never been needed so far.) Once the day-ahead trading was started up, Shippers could also begin to see the extent of their exposure to SAP a few hours in advance.

To fully understand how the OCM works, one must recognise that it is, in fact, three markets rather than one and, in some Shippers' opinions, this gives rise to some of the OCM's initial liquidity problems. The three subdivisions are named 'Title', 'Physical' and 'Locational'.

Title trades

Title trades give rise to change of ownership, but do not give rise to changes in the volume of gas on the system. Thus they help Shippers with individual imbalances but do not affect the total system balance and appear, for that reason, to be of less interest to Transco, who do not improve their system balance unless some physical adjustment is made as a consequence. This category is active most days.

Physical trades

Physical trades require physical upward or downward adjustments to supply somewhere on the system; i.e. not location specific but at the NBP. This category has more appeal to Transco as it immediately affects the system balance. Often this is the largest category on a day reflecting Transco participation.

Locational trades

Locational trades are, as may be deduced, location specific at sub-terminal level at the beach and, although these trades might appeal to Transco if their system balance could be improved in a particular region (location), this category is comparatively little used.

Over the first year of operation, slightly less volume was traded on average than under the old FM. This is generally regarded as a sign that Shippers are handling their own balances better and less system balancing by Transco is needed. A more flexible capacity regime has also had its effect.

Of course, different parties had different expectations of the OCM. Ofgem are publicly satisfied and regard the NGTA as a model for electricity reforms (the New Electricity Trading Arrangements or NETA). Callum McCarthy, Director General of Gas and Electricity Supply, described the NGTA as ‘a wholesale market in gas which is flexible, deep and liquid’ in a press release[14] as early as November 1999. This view was not then shared by the major players on the market, certainly not after a mere month of operation. Even now, most would consider it is early days and there were concerns that the fragmentation of the OCM into three different markets and the, arguably, conservative approach to the OCM by Transco did not help liquidity. Although OCM trades were initially equally split between Physical and Title trades, the balance shifted almost exclusively to Title trades from 2001 onwards.

Still the vast majority of within-day and day-ahead transactions are in the OTC (telephone) market despite the convenience and visibility of the screen based OCM. Some think that overall liquidity would improve if the markets were combined into a single entity, where gas could be bought and sold at NBP or specific locations much like the OTC market: this would embrace both Title, Physical and, perhaps Locational trades.

Generally speaking, Shippers are pleased to have an alternative market to the OTC and the IPE (which is not, in any case, very useful for very short-term balancing and is mainly a financial market – very few trades go through to delivery).

As to participants there are just under 50 Shippers signed up to the OCM, many of whom have more than one ‘session’ or distinct trading point. By mid-2002 there were around 90 odd sessions in operation compared with only 50 in early 2001. This represents a significant proportion of the players on the OTC market. This level of interest is encouraging as is the growth in trading volumes over the past eighteen months. Current players include Transco, of course, and Shippers who are producers and final customers as well as marketing companies, who are the mainstay of the business. In June 2002, Transco provided around 10 per cent of the volume.

Another concern about liquidity is that Shippers, who are directly interested in the level of SAP and SMP, might want to avoid pushing it in the wrong direction and prefer, therefore, to trade OTC rather than OCM. In fact, arbitrage has led to very small differentials between the two markets.

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[14] Ofgem News Release, PN43, 3 November 1999, see Ofgem website (www.ofgem.gov.uk).

6.3.4 Options, swaps and other derivatives

OTC put and call options for physical gas, mainly the latter, were first traded in 1994. Their use expanded in 1995 as price transparency improved. Financial swaps became evident in 1996 as price data improved, but the market in derivatives did not really take off until after the IPE was established in early 1997. By 1998, the market in options and swaps could be regarded as reasonably liquid, although options trading still remains a purely OTC activity as far as the UK traded gas market is concerned. At least half a dozen companies could, by this time, be expected to give a prompt/informed quote for such products. The Interconnector was another impetus to more sophisticated gas trading products.

Chapter 5 is devoted to derivatives of the physical gas traded markets, and describes the instruments in detail.

6.4 Recent trends

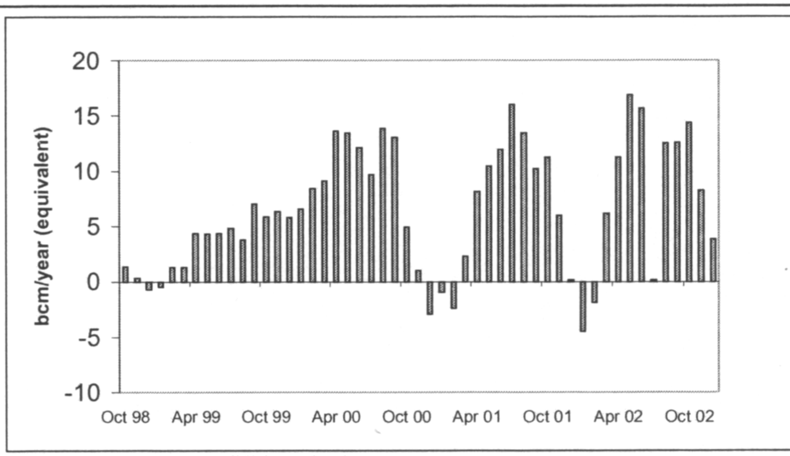
6.4.1 Interconnector arbitrage trading

The UK-Continent Gas Interconnector was envisaged and built as a one way, fully-booked, easterly flowing pipeline, at least until the UK ran short of gas. Long-term supply contracts were expected to be the main business of the pipeline and this was reflected in the 100 per cent ship or pay transportation charges.

However, some of the long-term contracts signed in the year before gas flowed also included elements that anticipated, and certainly helped, the development of the short-term market. The Conoco/Gasunie contract included a 'claw back' or interruptible arrangement, whereby the Seller could retain supplies in the UK on a short-term basis. A Centrica contract provided for re-delivery to the Buyer at the NBP rather than the Continent.

This sort of arrangement enabled and encouraged arbitrage. Additionally it was the case that only half the capacity was, in the event, committed to long-term contracts and a much lesser amount was committed in year one. Worries about reliability gave some Interconnector shippers an incentive to look for 'back-up' supplies on the Continent and, all together, these factors produced a helpful background for the growth of trading.

The most important factor was, however, the disparity between UK and Continental prices. The conjunction of low oil-related Continental gas prices and seasonal gas prices in Britain soon captured the interest of potential traders from both ends of the pipeline. The pipeline turned to 'reverse flow' (i.e. to Britain from the Continent) in December 1998,



Source: Interconnector (UK) Limited

Figure 6.4 UK-Continent Interconnector net pipeline gas flows only two months after the Interconnector was opened and to the surprise of those few well enough informed to know it happened (see Fig. 6.4).

The eastward flow to be overcome was nearer a 2–3 bcm/year equivalent rather than the 10–11 bcm/year of announced or rumoured signed up contracts. Reverse flow the second winter had rather more forward flow to overcome and rather less incentive to do so as the differential between Continental and UK winter prices had narrowed considerably with a reduction in UK winter prices and with stronger oil prices. Quarter One (Jan-Mar 1999) at the NBP was at 17 pence/therm when the Interconnector opened and at 11 pence/therm by end December.

This may not be all due to the reverse flow potential, but it is recognised that during the first year of the Interconnector it considerably reduced the seasonal differential in UK prices. Since then, it flowed east until November 2000, when high UK prices once more proved irresistible. Forward flow was resumed briefly on 15 January 2001 only to reverse again a few days later illustrating the fine balance of physical flow that winter. Notifications of changes in direction and pipeline flow data are available from Interconnector (UK) Limited's website (www.iuk-isis.com). Pipeline flows were originally published only on a monthly basis, but are now (since 2 March 2001) available daily.

Arbitrage between the UK and the Continent now plays an important role in the European gas market with both physical and financial trades being made on a regular basis. But in July 2002 arbitrage trading was disrupted by a leakage of gas liquids into the Interconnector from the UK gas grid causing the Interconnector to be shut down so that the "out of specification" gas could be pumped back into the UK.

6.4.2 European markets

It is not surprising that arbitrage has been a feature of Interconnector trading since inception as there were large price differentials and a liquid trading market with a standard contract already in operation at the UK end. A standard trading agreement to operate at Zeebrugge, much in the way of the tried and tested NBP contract in Britain, was announced in early November 1999. This contract is not compulsory at the Hub but the Hub Services Agreement (HSA 99)[15] for the Zeebrugge Hub is necessary if gas is physically to leave the Hub.

The Zeebrugge Hub, about 200 metres from the Interconnector flange, was the first 'true' Hub in Continental Europe. The Hub services are quite limited in scope compared with the North American model – which would be expected to offer Balancing, Parking, Loaning,

[15] A new Hub Services Agreement (HSA 2001) applied from 1 December 2001.

Imbalance Trading and often Storage Services as well as basic Wheeling (pipeline to pipeline) and Title Transfer (see Chapter 2).

Zeebrugge, like the NBP before it, only provides Title Transfer and not the other services that traders would value[16]. But this should not detract from the enterprise of Distrigas[17] in setting up the Hub and becoming the operator. As time goes on, the range of services offered is expected to increase. Though the official Hub was new as of November 1999, trading at the Interconnector/Zeebrugge flanges was already well established in its first year of operation, mainly by those who had an equity position in the Interconnector.

Trading in the Interconnector, or more accurately at its flanges, in its first year was 4–5 bcm – including the forward deals – equivalent to around one quarter of the annual pipe capacity. Figures released (soon after the first year of operation) by Centrica, one of the largest Interconnector traders, highlighted the importance of Monthly and Quarterly deals in their own portfolio and that 16 plus players were then in the market. By 2001 the number of players had probably increased to more than 25. In 2002 more than 40 companies had signed up to be Huberator customers.

On a short-term basis, players have been able to get their gas transported at a considerable discount to the fully amortised ship-or-pay costs of the original equity holders. Ways of getting 'access' to the Interconnector without any capacity rights are physical or financial swaps (e.g. the innovative deal done by Centrica and Dynegy where the contract can be settled financially – i.e. no physical gas involved – based on indexed prices at the NBP and at Zeebrugge). Essentially this model can be a fixed-to-floating or floating-to-floating (location) price swap.

Also, several parties have obtained transmission onwards from Zeebrugge, courtesy of Distrigas, though discounts in this activity are not so obvious – perhaps as equal treatment is more of an issue with a monopoly transporter.

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[16] For more information on Zeebrugge hub services see the Huberator website (www.huberator.com).

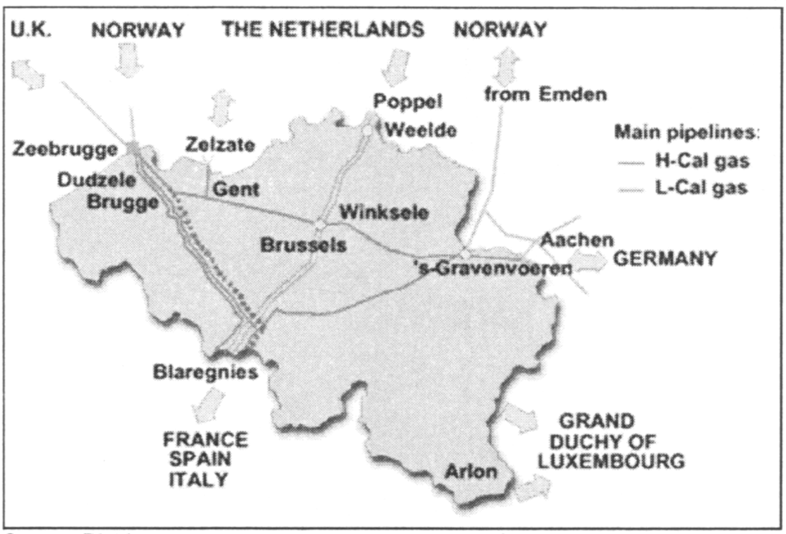
[17] Distrigas was split into two companies, Fluxys and Distrigas, in December 2001. Fluxys is now responsible for operating the Zeebrugge Hub and for gas transportation in Belgium.

The onward transmission to Holland and Germany has been somewhat hampered by the quality constraints imposed on the system by supplies destined for public distribution in Germany. The transporter has therefore imposed similar limits upon the variation of calorific value in the system supplying Zelzate and Eynatten, near Aachen (see Fig. 6.5).

This has not prevented, however, trading at these two border points which are now becoming pricing points (or Hubs) along with Bunde/Oude Statenzijl (Dutch-German border) near Emden where physical Swaps have been arranged and traded prices quoted extensively. Belgian border prices still tend to be priced in relation to the NBP in Britain as this is the major influence on Zeebrugge prices but as the traded market grows in Europe all manner of other prices will be taken into account.

Harmonisation of quality at Bacton and Zeebrugge is not complete though work continues. The hydrocarbon dewpoint is a particular issue where Transco cannot guarantee to meet the requirements at the Zeebrugge end. Improvement in the situation has accompanied the arrival of SEAL pipeline which increases blending flexibility in the grid but also has a direct connection to the Interconnector.

Prior to construction of the Interconnector odorisation was an issue which eventually required the whole Transco grid to be de-odorised to accord with Continental practice. Continental influence in the Interconnector is now higher than it was at inception, partly because arbitrage has proved attractive to the incumbents as well as the new entrants. If end use competition breaks out on any scale attitudes may



Source: Distrigas

Figure 6.5 Main pipeline links with Belgium change again but, by then, so much will be irreversible thanks to the success of the Interconnector, its associated infrastructure, and its newly spawned Hub.

The European Federation of Energy Traders (EFET)[18] is working away to facilitate energy trading by concentrating on gas and electricity initially and providing a forum for like-minded, and more generally, newcomers to the European energy trading scene. They are intending to identify, and lobby to remove, barriers to free trade in the wholesale market, to promote public relations and, to the extent required, standardisation and transparency. A standard power contract has been developed by the group. EFET says it is not looking for a head on clash with the incumbent Continental companies in the end use market. In fact, such companies are welcome to EFET provided they are themselves trading but they seem to be a little wary so far. They currently comprise 46 trading companies from 14 European countries.

6.4.3 New products and participants

Enron began trading in 1995, a little after Accord Energy in 1994. Both these companies brought a North American expertise to the UK market. Though not the only companies with such experience, they were market makers in physical gas and the more sophisticated products. Both leveraged on booked storage and/or a large portfolio of gas supplies to offer enhanced service products to the market. In 1999, 'virtual' storage services received some publicity, particularly from Enbank (Enron), though other companies could do the same thing. This was the provision of a 'storage' service (injection or withdrawal at will) from a portfolio of supplies without physical storage necessarily taking place.

By 2000, Enron offered direct trading from an internet website, EnronOnline[19] where bid and offer prices for a number of products, including gas at a number of locations, were shown online for instantaneous trades. Other companies followed, increasing the transparency and liquidity of the market both in Britain and Continental Europe. Dynegy also opened a web based trading site, Dynegydirect[20] and a number of large oil companies and financial trading houses have collaborated to launch a very extensive worldwide OTC trading platform, Intercontinental Exchange (ICE)[21]. But the development of the online market received a serious setback towards the end of 2001 with the collapse of Enron, which not only damaged liquidity but also forced many companies to retrench their trading activity and restructure their plans. Dynegy closed down its web trading site, Dynegydirect, in June

[18] For more information see the EFET website (www.efet.org).

[19] EnronOnline ceased trading in November 2001.

[20] Dynegydirect was suspended in June 2002.

[21] www.intercontinentalexchange.com

2002 leaving IntercontinentalExchange as the main online trading platform in the OTC market.

The main changes in the type of participant in the traded market as it has become more mature have been brought about by increased interest from 'Financials' and Pan-European companies. Merchant Banks for example are attracted by the potential market for Risk Management Products and Continental players are anticipating a spread of short-term trading across Europe in both Gas and Electricity[22]. Some of the latter companies are utility based US giants such as TXU, Aquila, Southern Energy, Duke and others. European international energy companies, such as E.ON Energie and RWE Energy Trading, as well as the incumbent pipeline and utility companies have also swelled the ranks of actual and potential traders.

In the UK there are 62 Shippers, a similar number of Industrial Suppliers and 28 registered Residential Suppliers – with considerable overlap of companies. With the addition of a few Traders who do not generally supply end users and Continental companies trading via or around the Interconnector there are perhaps 70–80 'sometime' players and maybe a dozen to twenty trading all day every day.

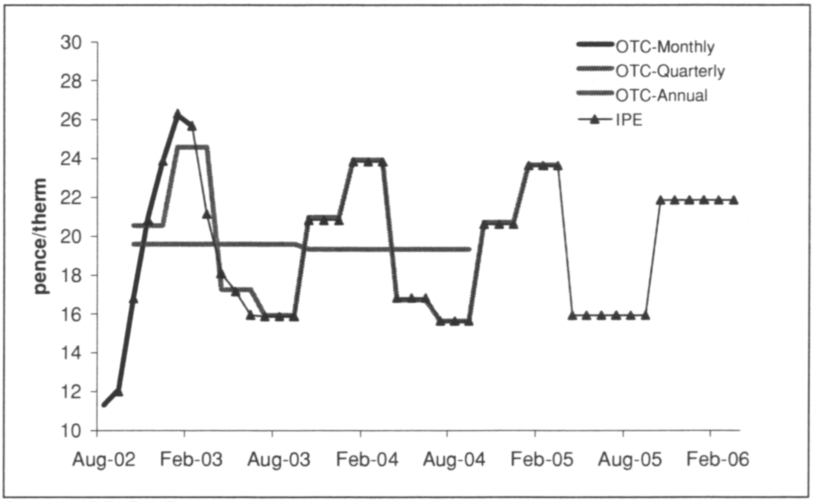
6.4.4 Price behaviour

It will be clear from the above that there is a multiplicity of prices for a number of products. Monitoring and examining them all is a task beyond all but the serious participants, who are as interested in spreads as much as absolute prices. On a daily basis a 'snapshot' of prices is comparatively easy to handle and present using OTC price reports and the IPE (the OCM only trades gas for delivery within the day and the day ahead). In this way a market forward price curve can be constructed, but to be used properly it has to be time-stamped. Figure 6.6, for example, shows the market view of the forward curve on 15 August 2002. The IPE and OTC prices are very similar, which must be the case in an efficient market.

It is interesting to note the strong seasonal pattern displayed by the forward curve which reflects market expectations about the future behaviour of gas prices. As the forward curve shows, the UK gas market is expected to be in backwardation (downward sloping with nearby prices higher than those for future delivery) during the peak winter demand period.

Backwardation in commodity markets indicates tight prompt supplies, usually associated with low operating stocks, as some participants are prepared to pay a premium for immediate access to the commodity. There is no upper limit to the size of the backwardation. Lower prices for future delivery indicate that the market does not expect

[22] Many US companies have either scaled back their trading activities or even withdrawn from the European market following the demise of Enron, but the market continues to attract new entrants as the structure changes.



Source: IPE, PH Energy

Figure 6.6 UK gas market forward curve, 15 August 2002

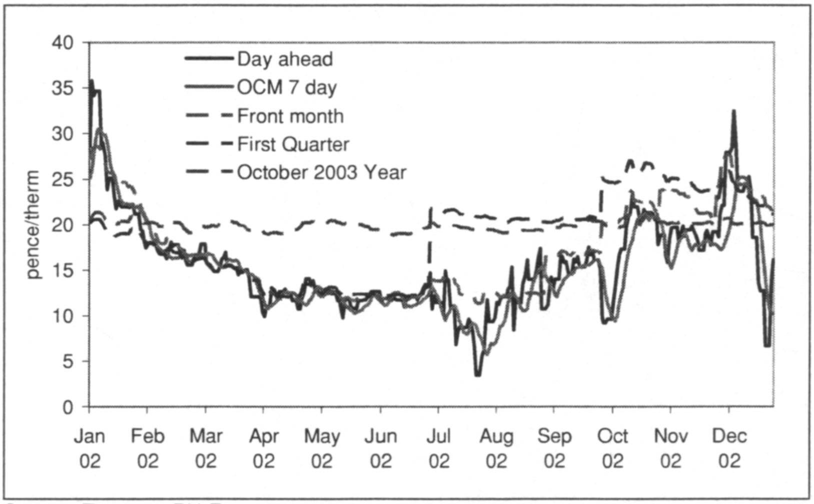
present prices to be sustained since there is time for additional supplies to be made available.

If the forward curve is upward sloping, with prompt prices below those for future delivery, this is known as a contango. In commodity markets a contango provides a financial incentive to hold stocks since prompt supplies can be purchased at a discount and sold for future supply, thus providing a return on storage. The marginal cost of storage therefore sets an upper limit to the size of the contango.

Overall price trends are less easy to present without resorting to 3D maps and/or complex charts. Figure 6.7, for example, tracks example products (Day ahead, Front month, the nearest Quarter one (usually used as the winter price indicator, rather than Quarter two) and the nearest gas year over the year 2001. Longer-term prices continued on a slow upward trend during 2001 supported by rising oil prices but this was overlaid by the restoration of a clear seasonal pattern for shorter-term prices after the turmoil of the preceding year.

A clearer picture of movements over the history of the traded market is illustrated by the Front month price series in Figure 6.8 below. This shows the Front month price at the end of the previous calendar month (prices are for delivery at Bacton up to February 1997 and the NBP subsequently). Monthly packages of supply have the advantage of being traded with decent liquidity over the whole active life of the traded market.

The short-term (monthly) price started at the beginning of 1994 at near parity with long-term contract prices. As traded gas took off it was clear, and a lot clearer than under the old regime, that there was a surplus of supply. Some had over-contracted supply and were putting it



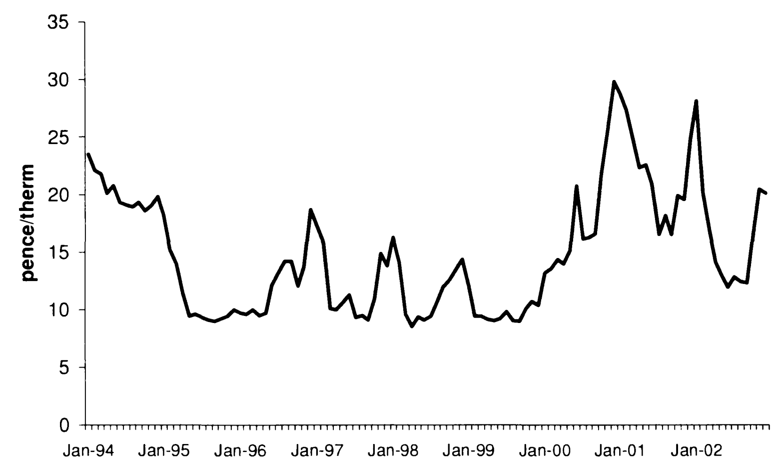
Source: Transco, PH Energy

Figure 6.7 OTC forward gas market prices, 2002

back on the secondary market. The price slid downwards over 1994 and fell even more rapidly in 1995 – some would say 'collapsed' – to less than half the year's starting levels. Most Suppliers were long on gas and only the newest entrants and traders were able to capitalise on a short position. End user prices began to be dominated by the new short-term market.

Interestingly prices remained at around the 10 pence/therm level throughout the 1995/6 winter reflecting a total lack of seasonality through that and the previous winter. A distinct seasonal pattern did, however, emerge in the next winter after the introduction of the Network Code and its stricter balancing requirements. One good reason for this development was that even with supply and demand in balance over the year as a whole there had always been a surplus of production capacity in summer. It was simply that this seasonal surplus had been masked by the long-term contract structure where the surplus capacity was dedicated to the long-term buyer whether he used it or not.

Traders and other Shippers who anticipated the development of seasonal differentials were able to maintain margins in an increasingly competitive market. Seasonal differentials eroded somewhat in 1997/98 as players made greater, or more efficient, use of storage. In 1998/99 the seasonal pattern was all but crushed mainly because of the opening of the UK/Continent Interconnector pipeline. Continental prices were still dominated by long-term contracts which were not nearly so seasonal in price and were escalated mainly by oil products (with long lags). Oil prices were low at that time and high British winter prices were arbitraged to more moderate levels.



Source: PH Energy

Figure 6.8 OTC front month prices (end of month), 1994-2002

Since then, of course, oil prices have boomed taking Continental gas prices with them and this, in part, caused the very strong revival in UK gas prices over the year 2000 which was sustained in 2001 lifting the monthly gas price at times back to or even beyond the levels where it started in 1994. As a result, the incumbent Continental gas companies must be relieved that the traded market has not had the threatened effect of totally undermining the Continental price structure. Short-term trading may yet have that effect as it becomes more widespread, especially if the companies representing the main supply sources to Europe join in and long-term contracts switch to gas price indices instead of oil.

6.5 Future developments

In very general terms, the most likely developments in the traded gas market are that there will be more of it and it will expand its scope geographically and in terms of products traded. To add a little more substance to this proposition it is possible to speculate upon some of the forces behind this dynamism.

At the final market end of the gas chain it is obvious that gas and electricity are converging. Suppliers now market both fuels in the UK and local authorities have done so for years in Continental Europe. The large scale multi-utility concept is being imported from the USA which goes beyond mere fuels. The Btu supplier/trader will soon be commonplace, and with new technology residential as well as industrial fuel switching should be possible. Hence a supplier should be able to offer heat and power, or Btus, at the cheapest price by optimising across fuels. Internet access and remote control of domestic appliances and metering should aid this process.

Multi-energy exchanges already exist and cross-energy trading is an obvious next step. This would allow one commodity to be converted or traded against the other on the Exchange by a simple conversion.

The infrastructure of the gas market should soon be enhanced through minimal investment by the development of trading Hubs – which are as much commercial manifestations as physical. The scope for Hubs of the US model is much greater in Europe as a whole than in the UK alone. There is, for example, more onshore storage in most Continental countries because of the history of long-term high load-factor imports. Storage enhances considerably the scope and value of gas Hubs. Also gas from diverse, and sometimes remote, sources meets at certain key points in Europe where Hubs should develop.

With a certain amount of investment, such as the linkage of Heimdal in the Norwegian Offshore to the Frigg lines to the UK at St Fergus, a physical and commercial 'ring main' will soon be available to link Hubs in the UK, Norway, Holland, Belgium and Germany promoting arbitrage and, thus, more trading.

Internet trading is already with us and – despite the setbacks caused by the demise of Enron – will ultimately recover and no doubt expand considerably as confidence is restored and more secure credit and clearing mechanisms are established.

The total 'commoditisation' of gas is underway in North America and Europe and it is likely to be followed by a similar and parallel process for production and pipeline capacity, storage and other services.

7 Prospects for competition in Continental Europe

Simon Blakey, CERA

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7.0 The European gas industry in 2003

Three significant developments must be reported in regard to the evolution of a short-term trading market in gas as the heating year for 2003 begins.

First, in the past two years the political drive to change the structure of the industry has remained unabated – in the face of continuing industry opposition. The European Commission has pushed the 'Madrid Process' well beyond its advertised brief of 'coordinating best practice among regulators', and turned it into the vehicle whereby it has effectively pursued its own agenda of imposing further structural change on an often reluctant, but ultimately acquiescent, industry.

Second, over-the-counter (OTC) trading has emerged at a key location on the Dutch-German border – Bunde (on the German side) and Oude Statenzijl (on the Dutch side). Although trading is not yet either deep or liquid, the levels of activity in this OTC market had grown sufficiently by mid-2002 for the reputable trade press to feel confident of reporting monthly price assessments, based on their journalists' regular telephone contact with participants in the market.

Third, the structural changes in the industry and the need to adapt to a trading environment are changing the identity of the companies who make up the industry itself.

All these developments support a basic judgement that the trading market is here to stay, and will grow significantly from its current beginnings.

From Madrid to Barcelona

The European Commission created a forum[1], in the Madrid Process, which began by 'monitoring' the implementation of the 1998 Gas Directive. As the process moved on through its series of five occasional meetings from 1999 through 2001, the agenda was gradually shifted – by use of position papers and outside reports – to a point where the Commission could lay before the Council of Ministers of the EU a wholly new set of proposals for the future of the gas industry.

These new proposals moved gas transmission companies beyond the 1998 requirement that they should separate their accounts and management processes to the obligation to 'structurally unbundle' their transportation and supply businesses. This meant that – although the same holding company could in principle own both the pipes and the gas in the pipes – the operating companies for each part of the business would in future have to be different entities.

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[1] Copies of the Madrid Process working papers, presentation and conclusions can be found on the Commission's website (europa.eu.int/comm/energy/en/gas_single_market/madrid.html).

Moreover, the Commission let it be known through the Madrid Process that it did not consider the 'NTPA' (negotiated third party access) solution – allowed equally alongside 'RTPA' (regulated third party access) by the 1998 Directive – to be satisfactory in terms of achieving a liberalized gas market in a Single European energy market. Finally, the Commission brought pressure to bear on those countries that had outlined a slow schedule for widening eligibility for competitive gas purchasing to all customers, to accelerate the schedule. These elements were brought together in a proposal for the Heads of Government of the EU to approve at a meeting in March 2002 in Barcelona.

The Heads of Government duly obliged, and, while political allowance was made for France until presidential and parliamentary elections were out of the way in mid-2002, the Commission's ideas for the future of the gas industry were given the seal of approval by the Council of Ministers. A new Directive[2], incorporating these changes from the 1998 'compromise', was prepared for implementation in 2003[3].

Bunde spot market

If Germany is the key heartland of the European gas industry (see below, section 7.5.1), then the implantation of a trading-based business for Europe requires that there should be a German hub for the trading.

The Zeebrugge spot market in Belgium, and the Distrigaz operated hub for title transfer and other services, was the first spot market to be established in continental Europe. However, because of its direct connection via the Interconnector with the much more liquid and longer established British National Balancing Point (NBP) market, Zeebrugge's prices and activity are closely linked to the British market.

In north-west Germany, the availability of gas supply from different sources – Dutch, Norwegian, and domestic German gas production – and the accessibility of different regional pipeline systems – Ruhrgas, BEB, Thyssengas, EWE, Wingas and the Dutch Gasunie system – provide the conditions for the development of a trading hub that is independent of the British market. There are storage facilities in the region at Krummhörn, Nuttermoor, and Etzel, and there is ready access to swing supply from Dutch and German gas fields, and from the large Rehden storage facilities via the Wingas system.

The Bunde spot market grew slowly from the first short-term trades in 1999. By summer 2002, traded volumes were reported to have reached about 3 TWh in some months (about 300 million cubic metres),

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[2] Papers relating to the new Directive can be found on the Commission's website (europa.eu.int/comm/energy/en/internal-market/int-market.html).

[3] EU Energy Ministers agreed on 25 November 2002 to revise the Gas and Electricity Directives with the aim of opening up to competition all industrial and commercial markets from 1 July 2004 and all household markets from 1 July 2007.

which can be considered to be equal to about one percent of the hinterland market that can be served by Bunde. These are small volumes still, and represent very little liquidity by comparison with the UK market. Nevertheless, they are closely comparable with the early British spot market of the mid-1990s. It can be predicted with confidence that the market will grow to the point where it provides a price reference point for customers and suppliers alike in a gas-to-gas competitive world.

Transformation of the corporate landscape

In response to the political drive for continuing change in gas industry behaviour and practice, some profound changes are now taking place in the corporate landscape.

In the Netherlands and Italy, the former monopoly gas companies Gasunie and SNAM first had their monopolies taken away and now have been broken up. SNAM has been replaced by a pure pipeline operating company, Rete Gas Italia, while the supply and marketing of gas is undertaken by ENI, in competition with other (smaller) companies. Pipeline transport activities in the Netherlands are now performed by GasTransportServices, which (in the first instance) is to be wholly owned by the government, and the marketing of gas is in future to be the independent business of the former private sector partners in Gasunie, Shell and ExxonMobil.

In France and Belgium, the separation of transport from supply and marketing is not yet formalized, but will undoubtedly follow when the new Directive is implemented in 2003 and beyond.

And in Germany, perhaps the most radical changes of all are about to happen. This is associated with, and a consequence of, the acquisition of Ruhrgas by E.ON[4].

E.ON is Germany's biggest energy conglomerate. It already combines the oil interests of Veba, and the electric power interests of Preussenelektra and Bayernwerk. Its gas interests, before 2002, were held mainly through Preussenelektra's ownership of the Thuga group and Contigas, as well as various direct holdings in, for example, EWE, Schleswag and Gelsenwasser. It also had an essentially passive holding of less than 10 percent in Ruhrgas, the largest (by far) regional and inter-regional gas pipeline company in Germany. Ruhrgas is Europe's largest importer of gas. It also has a crucial position in the coordination of gas dispatching throughout the continent, because pipelines such as the MEGAL and TENP cross its territory, before delivering Russian gas to France and Dutch gas to Italy. What happens

[4] E.ON's proposed acquisition of Ruhrgas was initially rejected by the Federal Cartel Office and Monopolies Commission. Although this ruling was overturned by the Economic Minister, the deal was subsequently blocked by a court injunction from nine rival companies. Legal objections were dropped in January 2003 after E.ON made concessions to the rival companies.

to Ruhrgas, therefore, and to the pricing of access to Ruhrgas's pipes, matters a great deal to everyone in the German gas industry, and to importers, exporters and gas customers in the wider European gas industry as well.

E.ON and BP came to an arrangement in late 2001 for the sale of BP's 25 per cent share in Ruhrgas, which began the process by which E.ON could take operational control of Ruhrgas.

The scale of the resulting entity would be huge, and its market position in gas and electricity clearly would be dominant in Germany. Unsurprisingly therefore, the Federal Cartel Office and the Monopolies Commission in Germany, along with many smaller and competing or potentially competing companies, viewed the takeover unfavourably.

However, the German government has taken the view that the national interest would in fact be served by such a merger of giants. In the first instance, that is because E.ON, as owner of Ruhrgas, will be better placed than Ruhrgas alone (or with its old shareholding structure) to invest in developing gas in Russia, should the day come when that is open to foreigners. And in the second place, government approval of the merger can be made conditional on a number of structural changes – notably the unbundling of Ruhrgas' pipes from its gas supply business – that will bring Germany's gas industry structurally into line with its EU partners, along the lines laid out by the European Commission during the Madrid Process.

That is a great prize – for the German and European authorities alike – that will set the seal on the process of corporate transformation that is taking place all over the continental gas industry.

All these complex moves are variously reported, in the trade press and the general press, as advances and retreats in, as it were, a great dance involving 'progressives' and 'reactionaries' in the industry. Yet it is clear that the shape that is emerging in the industry in 2003 is one in which the physical and corporate infrastructure will be well suited to a trading basis with which European gas will operate in the next decade.

7.1 Introduction

The driving force behind the move to a competitive gas market on a wider scale in Europe is the Directive on Common Rules for the Transmission of Natural Gas, more frequently known simply as the 'Gas Directive'. Formally, this Directive came into force on 10 August 1998, after its adoption by the Council of Ministers and the European Parliament. This means that within two years (that is, by August 2000) each of the member countries of the European Union (EU) ought in principle either to have introduced new legislation or to have adapted their existing national legislation into 'conformity' with the terms of the Gas Directive.

'Conformity' is one of those delightful words that appear from time to time in the language and legal formulae of the European Union that are capable of having a wide range of meanings thrust upon them. The width of meaning is such that the urgent national interest of any individual member state does not have to be completely overridden by the content of a Directive that has been agreed at the EU level.

However, in the case of the Gas Directive, and of its (slightly) elder sister the Electricity Directive, the 'conforming' of national legislation in most EU countries looks as if it will indeed have a profound effect on the way that gas is supplied and traded. The transformation of electricity from a utility service to a commodity product is already well under way, and the same is almost bound to happen to gas.

Other European countries (Switzerland, Norway, the Czech Republic, Hungary and others), who are not members of the EU, but whose gas industries are physically connected with the European Union gas networks, will also have to adapt the terms on which their industries operate to something like the framework of EU rules.

What this means is that practically the whole of the gas market in Europe – all 430 billion cubic metres per year of it – will be the arena in which gas is traded as a commodity within a few years. This potential market will be four to five times larger than the British market that has seen such a rapid development of spot trading in gas in the last five years. It is a market whose equivalent in energy terms would be about 6.7 million barrels a day of oil, and will represent a very significant new business opportunity for those companies with the skills, position and determination to take advantage of it.

This chapter examines what is happening across the continent of Europe to open up these markets and this opportunity. It looks first at the nature of the key terms and conditions of the Directive, then at the consequences for market liberalisation that are arising as a result of customer pressures, and at the direct effect of the operation of the UK-Continent Interconnector. Finally, it provides a 'tour d'horizon' of the structural changes that are taking place in the gas industries of the major gas-consuming countries of the European Union, and, more briefly, at the progress of competitive gas markets in the rest of Europe.

7.2 The EU Gas Directive and beyond

The main provisions of the Gas Directive are fairly well known by now. They are designed to provide the basis for a competitive gas business in each member state of the EU, and in candidate member countries (such as Poland, Hungary and the Czech Republic) as well. More than this, it is the declared intention of the European Commission 'not to create 15 or more liberalized national markets, but to create a Single Market for gas'.[5] And so in addition to understanding the main provisions, it is important also to know what processes are now being put in place to further their implementation.

There are six key provisions, as follows:

- The abolition of the exclusive right of any one company within a European country to import or export natural gas
- The right of any company or legal person to build and operate new gas facilities (storage or pipelines, for example)
- The gradual opening of existing infrastructure to use by certain 'eligible customers' — third-party access
- The separation of the accounts of integrated gas pipeline companies so that the costs and profits associated with the business of buying and selling natural gas are separately identifiable from those that arise from the business of operating pipelines – the 'unbundling' of accounts
- The publication by owners of pipelines of 'the main commercial conditions' under which third parties will be able to use existing infrastructure – to all intents and purposes this will mean the publication of a tariff for transporting third-party gas
- The creation of efficient dispute settlement mechanisms – that is, either a regulatory authority or a competition court that will supervise and judge on questions of abuse by any company of a dominant position in the gas market.

In one way or another, all these provisions are being taken account of by European Union member and candidate member governments as they adapt their legislation and the structure of their national gas industries to the Directive. Three factors have been identified that allow for some exceptions to these rules to be introduced, should a government wish to do so. They are: that public service obligations may exist which would be harmed, or made impossible to implement, if access were granted to third parties; that take-or-pay obligations to gas

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[5] Klaus Geil, DG XVII European Commission *'Implementation of the EU Gas Directive – progress, scale and impact'*, Brussels May 1999.

suppliers may make it impossible for a transmission company to honour its obligations while providing third-party access; and that there may be 'emergent' or new gas markets, where heavy investment is at an early stage of depreciation, where third-party access would be inappropriate.

It is striking that the steps that are now being put in place to implement the key provisions, and the qualifications with which the exceptions are being hedged around, all point in the direction of a faster liberalisation of the European gas markets than was anticipated at the time in 1998 when the Gas Directive itself was adopted by the EU.

First, there is a formal process of dialogue between the European Commission and member states. The Commission is using this process of dialogue to draw to the attention of member states what elements of a liberalised gas market have and have not been implemented by existing or proposed national legislation. As a practical tool, the Commission uses a sort of cross-reference list, known as the 'transposition grid' — to encourage member states to come up to the mark of what the Commission, in its wisdom, considers will be required for the Single Market in natural gas to become a reality.

Second, the EU Gas Regulatory Forum is providing regulators with a means of exchanging 'best practice' approaches to implementing and monitoring the spread of competitive gas markets. In the realm of electricity, meetings among regulators have become systematic and much-valued by the regulators under the auspices of what is known as the 'Florence Process' — named after the location of the first meetings. A first meeting of regulators for gas took place in Madrid late in 1999. Two more sessions took place in May and October 2000, and a fourth session in July 2001[6]. The 'Madrid Process' will see the coordination of regulatory "best practice" in gas follow the path set by the electricity regulators. This is not a trivial development. In a world where incumbent owners and operators of gas transmission systems have more — much more — knowledge of the costs and conditions of operating their assets than their regulators do, the exchange of knowledge among regulators about broad principles and about the finer points of the tricks of the trade will be an important driver for change.

Third, public service obligations are being strictly and narrowly defined by the Commission. Remember that one of the grounds for national governments to allow exceptions to the provision of third-party access (see section 7.1 above) is that public service obligations may be protected from any harm that third-party access may imply. In practice, the concern is that pipeline capacity may be so fully taken up by eligible industrial customers buying cheap gas direct from a supplier that the transmission company is unable to supply remotely-located householders or other small customers. In a complex network of supply, this sort of event is difficult to prove or disprove either way. The

[6] See the European Commission website for the Internal Market for Gas (europa.eu.int/comm/energy/en/gas/gas_single_market/index_en.html).

allocation of the costs of providing the capacity is, in the last resort, a matter of some fairly arbitrary accounting decisions — although there are some general economic principles and some sophisticated technical models available to look at the question. The burden of proof that capacity is not available, or that public service obligations would be threatened by a particular transaction for a third party's access to the grid, is firmly and squarely placed on the company and government that may wish to ask for a derogation from providing third-party access on these grounds. Given the network complexities, proof will always be hard to find. A legal case has already been tested with regard to electricity in Germany on this question (*Enron versus Elektromark*, January 1999) — and the courts found decisively (indeed, in the tone of the judgement, almost derisively!) against the incumbent's claim that its other customers' supply security would be threatened by providing Enron with access to its transmission grid because of bottlenecks at particular substations on the network. Similar conditions are likely to arise in gas. Indeed, discussions with the relevant political authorities suggest to the author that even the French government — who were the most insistent on allowing the 'public service obligation exception' — will not be inclined to use it, the burden of proof being too hard.

Finally, and most noticeably, after years of pushing for the right to adopt negotiated as well as regulated third-party access terms, most European countries are in practice going to move to a regulated system, with all the panoply of Network Code type rules in which gas trading can take place. Even in Germany, where negotiated third-party access (NTPA) became an article of faith for most of the gas industry during the process of discussion of the Directive, and of the corresponding new German Energy Law, voices are now raised in some companies to suggest that a regulated system may be better for customers, more easily implementable, and better for the industry itself (see section 7.5.1 below).

7.3 Third-party access: customer pressure

The changes in the legislative environment that are being driven by the implementation of the Directive will rapidly become only a secondary feature of the story. The most striking recent feature — and one that is likely to grow very much stronger in the first years of the new millennium — is the pressure from customers for new ways of buying their energy.

This is taking a number of forms. For convenience, we may group them into four categories: heavy industry, multi-site aggregators, regional distributors, and power companies. There are in practice overlaps between and among these four categories, but it provides a useful framework for understanding what is going on, and for what is likely to happen.

7.3.1 Heavy industry

Many industrial companies across Europe have surprised themselves and their shareholders by the cost reductions they have been able to achieve by changing the way in which they purchase electricity following electricity liberalisation. They are now hopeful of achieving similar cost reductions in their gas purchases.

In Germany, especially, where the average price of industrial power in 1997 was, according to a major survey by the industrial federation VIK, about 15 pfennigs per kWh, many buyers now have prices below 7 pfennigs per kWh. Nothing has changed in the fuel cost or capital cost composition of the generation of electricity — it is simply the ability to purchase competitively that has brought about this revolution.

Where customers have particularly 'good' load factors, or a location of demand that is helpful for the optimization of a utility's transmission system, they are able to negotiate prices as low as 5 or even 4.5 pfennigs per kWh. Companies that have more than one major industrial site (as most large industries do) are introducing purchasing techniques that aggregate their purchasing power — instead of relying on the local plant manager and his or her relationship with the local utility supplier. Furthermore, they then 'shop around' for supplies from various generators/distributors, to supply energy to all their sites throughout Europe. They can often use the threat of taking away the custom of their biggest plants from its local utility as leverage to get a good deal for the price of power to their smaller or more remote plants.

Since the abolition of the 'demarcation' rules in Germany, this customer pressure has opened wide the power market. A similar process is now beginning in gas. These customers are usually keen to see the development of transparent spot markets in gas, so that there is some clear benchmark against which they can judge their purchasing opportunities — rather than the detective work involved in finding out what they might or might not be able to get from a transmission company whose prices remain at best opaque, at worst unknown.

Many industrial customers of gas have now developed a cadre of specialist energy purchasers whose skills and expectations have been honed in already competitive markets. The French purchasing manager of a French tyre company manufacturing in the UK has for some time now become accustomed to putting out a portfolio of bids for competitive gas and electricity supply — in Britain. If he moves back to France, he will expect soon to be able to take the same approach.

An American conglomerate that has transformed its internal energy purchasing processes to centralise buying in North America, and to use the Internet to place its short- and long-term orders, will expect its managers in Europe to adopt the same approach. A Swedish paper manufacturer, skilled in hedging its cost exposure to energy in the volatile Nordic Power Pool, will not listen kindly to a monopoly utility telling its plant managers in Germany, France or Italy that security of supply and absence of price risk are a necessary benefit that the customer gets from his monopoly supply of natural gas.

Furthermore, there is a small but important group of companies — like Cargill or Louis Dreyfus — whose business model for decades has involved both heavy manufacturing or processing plants (grain depots, corn mills, oil refineries) and massive commodity trading activities. These companies have a direct interest in seeing a wider use of the combination of assets and skills that they possess — and to take advantage of the synergies between the two. It is clearly in their interest to see the growth on continental Europe of a gas trading business, with spot, forward and derivative markets and all the tools of the trading trade.

This revolution in heavy industrial customer expectations in continental Europe sounds the death-knell for the traditional pattern of one utility/one customer, where geography was the only basis for the relationship. The revolution is creating the key constituency that will support third-party access to pipelines — and acceptable commercial terms for that access.

7.3.2 Multi-site aggregators

Not yet very visible in continental Europe — but certainly just over the horizon — are the 'multi-site aggregators'. These are companies who, by virtue of their annual consumption on individual sites falling just below the threshold that would make them eligible for third-party access, will perceive themselves to be at a competitive disadvantage with their bigger brethren. They will not sit silently by if they see a significant opportunity to reduce costs being missed. And so they will begin to lobby for the right to 'aggregate' their multiple sites, to be considered as a single purchase — and thus above the eligibility threshold. As a result, these lines — which are difficult to draw — are even harder to maintain. From medium-sized industrial customers to large commercial chains of restaurants and hotels, a large number of potentially eligible customers from below the threshold of eligibility will bring pressure to bear in countries that choose to establish such thresholds, as the Directive allows.

7.3.3 Frustrated regional distributors

In Austria, Belgium, Germany, the Netherlands and Italy regional and municipal or local distribution companies are an important part of the gas supply chain. They typically own and operate some medium-pressure pipelines, and have extensive low-pressure distribution networks. They provide the metering and billing services and the direct interface with retail customers. Many of them provide multi-utility services — including water, electricity, waste management as well as gas supply, and sometimes also cable television and local Internet access as well.

These companies bear various relationships to the large transmission companies: as part owners, part subsidiaries in the complex cross-ownership structures in Austria and Germany; as majority-owned subsidiaries (in the case of Italgas affiliates, where SNAM has a majority, in Italy); or as 'independent' municipal companies whose technical service agreements tie them almost entirely to the operational management of the transmission companies' main shareholder (in the case of Belgian municipalities and their relationship with Distrigas' parent Tractebel).

Many of these companies are very small, very local, and have more the character of local political fiefdoms rather than independent commercial enterprises. They represent a conservative element in the gas industry, and, in Germany for example, have provided a bulwark against change for many years. However, some of these companies are quite large enterprises, with a strong commercial orientation. Companies like HGW of Hamburg, EWE of Oldenburg, AEM of Milan, or ENECO in the Netherlands show these characteristics. They are ideally placed to leverage their customer-base, billing systems and scale of operation into growth and more profitable activity by taking advantage of new fuel purchasing opportunities that will open up with third-party pipeline access.

Like the industrial customers referred to above, they will bring strong pressure to bear for the terms of access to the natural gas transmission grids in their respective countries to be set at levels that are commercially attractive for them to expand the scope of their direct supply. The most aggressive and innovative of them, such as Essent (formerly Entrade) in the Netherlands, are developing active gas trading operations as a new business, built from their customer relations in the 'downstream' and their electricity generating assets in the 'upstream'.

7.3.4 Power companies

Electricity generating companies form the fourth category of potentially powerful lobbyists that will wish to take maximum advantage of third-party access to gas transmission lines. Many incumbent, private sector European generators – notably in Germany and Spain — expect generous terms for gas transmission access and a quid pro quo for what they have had to concede in terms of access to electricity networks.

Among new entrants to the electric power business, many are North American companies, whose gas buying habits have been developed in a competitive gas transmission environment. Finally, both incumbents and new entrants have, in the late 1990s, begun to explore the money-making opportunities of running 'merchant' or 'semi-merchant' plants — where not all the output of the power plant is pre-sold under a power purchasing agreement, or dispatched in an integrated grid operation. For these 'merchant' or 'semi-merchant' plants to operate economically and effectively, it is desirable that there should be a well-functioning market for gas that does not depend on the sole discretion of a dominant gas transmission company.

The development of wide-ranging pressures from such diverse customers — heavy industry, multi-site aggregators, regional distributors, and power companies — is proving to be the critical factor in breaking down the resistance of the major transmission companies in continental Europe to the spread of competitive markets for gas. These pressures may themselves have been triggered or unleashed by the political and legal processes that were associated with the development of the Directive. But it is the customers' increasingly vociferous insistence that will ensure that competition will become a widespread reality, and that the exceptions will be very rare indeed.

7.4 The UK-Continent Interconnector

The concrete reality of trade through the Interconnector that links the British grid at Bacton to the Belgian grid at Zeebrugge has brought spot trading, British-style, to the front door of the continental gas market at Zeebrugge.

In its first year of operating experience from October 1998 through to September 1999, the Interconnector caused relatively modest changes to the gas business environment on the continent. Most of the gas that flowed from Britain to customers in Belgium, France, Germany, or the Netherlands was under long-term contract to the major transmission companies, and as such was absorbed by them in their portfolio of long-term contracts.

Moreover, during the first winter, spring and summer of operation, the price of gas under long-term import contracts from Russia, Norway, Algeria and the Netherlands was depressed because of its time-lagged indexation to oil prices, which declined sharply through 1998 and into early 1999. Accordingly, there happened to be relatively little difference between the spot price of gas in the UK market — set by short-term competition among different UK North Sea gas suppliers — and the price of gas under long-term contracts such as the Norwegian Troll Gas Sales Agreements (TGSAs).

Indeed, the very first trade at 6 am on the first October morning of the Interconnector's operation was not a UK export at all, but a sale of gas (by exchange) by MEGAS from Mobil's continental European production to a customer in Britain. In December 1998, the pipeline's capability to operate in 'reverse flow' — flowing gas from Zeebrugge into Bacton — was tested in earnest, and for one week the compressors at Bacton were reversed, in order to import gas from the continent to Britain. Subsequently the expected pattern of export from the UK to the continent has been the norm.

But those early experiences illustrate an important feature of the trade through the Interconnector that reflects real structural differences in the markets. Put simply, at times of peak demand, Britain is short of gas, and the continent is long. At off-peak times, the UK Continental Shelf surplus and a competitive market make themselves felt — offering extra gas to an already well-supplied continent. The net flow of gas through the Interconnector has now settled, therefore, into a pattern of UK exports in spring, summer and autumn, and UK imports in winter.

In the spring and summer of 2000 — the second year of operation — aggressive buying by major Continental gas transmission companies, and some supply shortages in the UK North Sea, pulled up the off-peak price of spot gas in Britain towards the oil-related Continental border price. Most traders and observers of these events concluded that a sort of 'managed' arbitrage had emerged as the market still lacked the necessary characteristics of a mature, well-functioning market.

In the coming years, if the right tools are in place, then the structural differences between the UK and the Continent will provide the foundation for the growth of a permanent arbitrage between the two markets.

The right tools will include an appropriate trading contract, wider trading relationships, and a more widespread analytical understanding of the dynamics of the market.

- **A trading contract.** Practical problems with incompatible gas quality standards between Bacton and Zeebrugge hindered the development of an active market in the early months of Interconnector operation. The Zeebrugge standard contract and 'hub services agreement' that have been established by Distrigas are an important first step in developing an appropriate trading contract. But, continuing problems may be expected with liquidity in the Zeebrugge spot market as long as the quality issue creates technical barriers to a more active trade, and as long as the standard contract maintains its initial very tight hourly balancing requirement for traders using the system.
- **Wider trading relationships.** Trading at Zeebrugge involves some of the UK companies that have been active in the over-the-counter market at Bacton and at the British National Balancing Point (NBP), and some Norwegian operators who have downstream gas marketing or gas-based manufacturing interests in the UK and in north-west Europe. Non-traditional gas companies in the continental markets, such as Essent in the Netherlands and Wingas in Germany have also taken positions in the new market, but trade involving the major transmission companies or large industrial users of gas has only started to build up in 2001. The involvement of these companies in Zeebrugge trade will be necessary before the market will really take off. The widening of trading relationships around the spot contract, involving these companies, is likely to be a major theme of the next few years in the European gas business.
- **Better analytical understanding.** There is not yet much evidence that the analytical tools to support gas trading activity have been developed or are in use by companies whose traders make up the present community of trading. The analysis of market fundamentals in the European gas business lags far behind its North American counterpart, and even further behind the world oil industry. Short-term statistical

information on the state of supply and demand in the market is closely-held by the operators of dispatching rooms, and estimates of the future direction of demand, availability of supply and movement in storage levels are simply unavailable to the vast majority of those who are currently active in the market. For the time being, the best available analytical tool for most traders is the forward curve on the spot price itself. At Zeebrugge this involves a very thin forward market; and, in any event, forward curves are not necessarily very good indicators of the actual movement of spot prices through time — especially when unsupported by any knowledge or understanding of the immediate and prospective supply and demand fundamentals.

In summary, the tools are by no means yet fully developed, but the outline of what is needed in the new continental marketplace is already clear.

7.5 The new European marketplace

The new marketplace that is opening up in continental Europe will emerge according to how each of the major national European governments chooses to implement the EU Gas Directive in their respective national markets. In each case, the likely result will emerge from a combination of market pressures from new entrants, the domestic political context, and the corporate response of the major incumbent transmission companies. This section summarizes the way in which these forces interact in each of the major continental European markets.

7.5.1 Germany

Germany is the key heartland of the European gas industry, and it is developments there that will determine the pace and the extent of transition to the new marketplace. In principle, every customer in Germany is already free to purchase gas from any supplier, and to contract on an individual basis for the transport of that gas through any of the private or municipally-owned transmission and distribution pipelines that criss-cross the country.

This freedom has existed since the long-standing practice of 'demarcation' agreements between adjacent pipeline companies was declared illegal in the 1998 Energy Law and the subsequent reform of the Cartel Law. However, in practice it remains very difficult for any individual customer to arrive at satisfactory negotiated terms for payment of a transport fee, since guidelines only began to emerge in 2000 as to what constitutes an acceptable transport tariff.

For the owner of the pipeline any such transaction will involve the loss of a customer, and, probably, an increase in the unit cost of serving all other customers. In the absence of competitive pipeline routes, it will always be in the interest of the pipeline owner therefore to set the transport fee that he is prepared to offer at a level that will make it uneconomic for the customer to do the direct purchasing deal that he hoped for.

Given this background, the German Federal Government indicated to the gas industry that it would be prepared to legislate further (beyond the Energy Law and the Cartel Law reform) in order to bring German legislation into line with the spirit of the European Directive — unless the industry itself, in collective discussions with representatives of the main customer interests, could come to a satisfactory set of guidelines for transport tariffs.

This triggered the process known as the 'Verbandevereinbarung' — or 'VV-Gas', to distinguish it from its electricity counterpart, the 'VV-Electricity'. This process was, by August 2000, supposed to put in place a set of tariffs and tariff principles that will enable all customers in

Germany to have access on a non-discriminatory basis to gas transmission and distribution networks. The process is extremely complex. It involves, on the customers' side, the VIK and the BDI (the main German industrial federations), and on the gas industry's side, the BGW (Bundesverband der deutschen Gas- und Wasserwirtschaft) as the official representative of the industry.

It is far from clear what primary interest the BGW represents: the high pressure transmission companies, with their large take-or-pay contractual obligations for imported and German-produced gas, or the seven hundred or more municipal and smaller regional distribution companies, who may themselves have something to gain — as commercial entities — from more competitive gas purchasing conditions at the wholesale level. Nor is it obvious that the regional and municipal companies, who are often tied in a complex web of cross-shareholdings with their supra-regional suppliers, and face local political constraints as well, actually operate or are incentivized as commercial entities.

What does seem clear is that, in the proposals that were initially put forward by the industry under the VV-Gas were designed to make sure that the industry retained most of the profit from the locational advantages of swapping gas that is input to the German 'national' gas system from the various input points — with customers gaining no advantage from any particular locational or geographical position.

This feature of the proposals caused the Competition Directorate of the European Commission (DG Comp, formerly DG-IV), in an unrelated judgement concerned with the Exxon-Mobil merger proposals, to state clearly its view that the proposals would do little or nothing to create a competitive gas industry in Germany. The challenge is thus thrown down to the Federal German government to make good on its threat to 'legislate again', if the combined effects of the Energy Law, the Cartel Law reform and the VV-Gas are deemed insufficient to promote genuine access to the gas grid in Germany.

On the other hand, the large number of pipeline companies in Germany, the pressures from customers (described in section 7.3 above), and the deep desire of the gas industry to avoid a regulator, may lead to an outbreak of sharp competition in gas – as already seen in electricity.

7.5.2 Netherlands

Opinion is divided as to whether the new Gas Law[7] puts the Netherlands in the forefront of liberalisation of its gas industry, or

[7] Although the Netherlands is, and has been for forty years, a major producer and exporter of natural gas, the new Gas Law is in fact the first specifically gas-related legislation ever proposed in the country. The former 'legal regime' consisted of a unique mixture of Napoleonic-era legislation (the Mining Law of 1810), parliamentary understandings expressed in Memoranda such as the De

whether the Netherlands is in reality a 'laggard' rather than a leader, and simply creating a 'spin' to give the impression of the rapid promotion of competition.

Such a division of opinion is consistent with an elegant, and remarkably apposite, description of the foundations of Dutch gas policy that was penned by the Swedish environmental and energy expert Mans Lonnroth, in his mid-1980s book *The Troll Dance*.

> 'There are two souls in every Dutchman; the trader and the conservationist. The trader created the great Dutch trading empire of the seventeenth century, with its associated flourishing of culture. The conservationist built the dykes to keep the sea out of his homeland. Dutch gas policy has always owed a share to each tradition: with one eye on the outside world and the rich export markets to be had by trading there, and the other on the essential need to conserve, and to preserve the heritage for future generations.'

This description aptly covered the character of the Dutch gas policy, built on the foundations of the De Pous Memorandum in the early 1960s, which at the same time has promoted the export of gas and the integration of the Dutch gas supplies into the economic fabric of its European Union customers in Belgium, France, Germany and Italy and promoted the development of minor gas deposits (the 'small fields policy') in order to keep in the ground for as long as possible the great strategic reserve of low-cost Groningen gas.

It just as neatly captures the challenges, even contradictions, at the heart of the current Dutch government policy in implementing the Gas Directive. On the one hand, in the long tradition of liberal economic policy, the Government wishes to implement in letter and spirit a European Union Directive that will create an opportunity for more competition, and for the lowering of industrial costs throughout the Dutch economy. On the other hand, it wishes to preserve the security and industrial benefits that the 'small fields policy', and the strategic management of Groningen as a swing field — for Europe as well as for the Netherlands — has brought.

The particular corporate and contractual relationships between Gasunie (monopoly transmission company and exporter) and NAM, the owner of the Groningen concession, that have brought about this delicate balance are not consistent with the functional 'unbundling' of transmission and gas supply services that are ultimately implied by the reforms introduced by the new legislation. Political debate will rage for

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Pous Memorandum, and various private law agreements between state entities and private companies. A good recent account is given by Malcolm Peebles in *Gas to Europe: The Strategies of Four Major Suppliers*, R.Mabro and I. Wybrew-Bond (eds.) OUP, 1999, pp. 95 to 100 and 105 to 108.

some time in the Netherlands as the authorities struggle with these inconsistencies.

In the meantime, a wholly new constituency of gas and power trading and wholesaling companies (including home-grown companies such as Essent or Eneco, and foreign 'new entrants' such as the American company Reliant's UNA purchase) have entered the business. Most of these new entrants in fact are building their businesses on the foundations of consolidating regional and local gas and power distribution companies. This new constituency has no vested interest in the existing fabric of the 'Dutch gas house', as it is sometimes called, and is likely to press vigorously for reduction in the rates of transmission tariff from the first set published by Gasunie in 1998.

The combined weight of these new companies and of the energy-intensive customers will accelerate liberalisation in the Netherlands, opening up an important 40 bcm market and perhaps spilling over into an adaptation of the Dutch export strategy.

7.5.3 Italy

In Italy the government faces a particular dilemma in implementing the Gas Directive. For many years now, the national gas transmission company, SNAM, has been the most consistently profitable part of the ENI group, with an assured cash flow that significantly enhances the value of its parent company. The government has a direct financial interest in maximizing the value of ENI — in part to obtain the best price possible for share sales to the private sector, and in part to enable ENI to use its own paper in the acquisition of foreign assets, as it seeks a more diversified, international future. Yet there is also a widespread recognition among the 'political class' that competition in the gas business will create wider economic benefits to Italian industry as a result of cost reductions.

The resolution of this dilemma is simply in timing. The Italian authorities have a clear intention that the business of gas supply shall be conducted separately from the business of transmitting gas through pipes — and that the former business will involve several competing suppliers operating under a network code, and that the latter will be a regulated monopoly. The precise timetable will probably be hostage to the financial and strategic objectives for ENI that are referred to above, but the end point in Italy is already clear. There is not, as in France, the same widespread political support for the existing monopoly structure as the only guarantor of high quality 'servizzio publicco'.

Moreover, the practical implementation of a regulated, not negotiated, third-party access regime will benefit from experience gained in the last four years in the regulation of electricity. 'L'Autorita per l'energia elettrica e il gas' (AEEG) has already established an effective body of regulatory practice, with detailed oversight and understanding of the cost structure of the electricity transmission business. It is likely to move rapidly to adapt its experience and practices to the regulation of an independent gas transmission business after the division of SNAM into two parts is implemented.

The opening of the large Italian market is highly significant in terms of opening continental European industry to competition. It is a large market — 70 bcm nationally, and one that is still growing strongly, especially in sales to the power generation sector. It is also a very well-developed one in the northern third of the country, in which over 45 bcm of the final consumption is concentrated. Here there are direct pipeline connections via the TENP to the transmission hub on the Dutch-German-Belgian border near Aachen (Eynatten/Bocholtz), and via the TAG to Baumgarten on the Slovak-Austrian border. SNAM has capacity rights in these lines, and takes title to its long-term take-or-pay gas at these hubs.

Some form of revision or assignment of these long-term contracts will almost certainly be a consequence of the separation of pipeline ownership from gas supply, and the availability of formerly 'Italian' gas in northern Europe or at Baumgarten may be an important feature of the future growth of spot or spot-related trade in continental Europe.

7.5.4 France

In France the political process that was involved in preparing a white paper on the implementation of the EU Directive shows clearly the importance to a wide segment of French opinion of the defence of 'service public' as a distinctive and important part of the mixed economy. The gas industry remains an important constituent of that 'service public'.

There will be three main consequences. First, the number of customers who will have the right under French law to purchase gas from competing suppliers will be restricted in the first instance strictly to the minimum requirements laid down for eligible customers in the Directive itself. Secondly, the unbundling of gas transmission and gas supply businesses will be limited to a separation of accounting and reporting functions within Gaz de France rather than the creation of separate corporate entities. And thirdly, the active participation of the EDF-GDF trade unions in the policy-making process will continue to act as a brake on the liberalisation process.

Yet the process of change is not as slow as is often perceived outside France. There are two elements that cannot be overlooked: customer pressure and the appointment of an independent regulator with a strongly European perspective. The problem of the 'sub-eligibility threshold' and the 'multi-site aggregator' (discussed in section 7.3 above) will be particularly acute in France. Customers whose volumes of consumption fall short of the eligibility threshold will insist on parity of treatment with the eligible customers.

The regulator in France will be independent of the Government, and is likely to take seriously the European dimension of his role — in response to the Europe-wide focus of many French industrial and commercial consumers of gas. Between them, the customers and the regulator will be an important countervailing force to the public service orthodoxy.

Gaz de France, recognising this, raced ahead of the formal legislative requirements and published — on its own initiative — a set of third-party transmission tariffs two months ahead of the 'August 2000' deadline for implementation of the Gas Directive.

7.5.5 Belgium/Luxembourg

The Belgian gas transmission system is now the intersection of the gas-to-gas competitive market in Britain and the oil-linked market in continental Europe. The rules that are established for the Belgian market by the national authorities are therefore important for the future market conditions in Europe as a whole.

At present, Distrigas, the Belgian national transmission company, offers a 'Hub Operator' service and has established a standard contract for short-term trading at Zeebrugge. The company is well placed both geographically and corporately to become continental Europe's first 'pure transporter'. It is effectively a subsidiary of the Tractebel conglomerate, which has a strong trading culture, and in 1998 reshaped its accounting structure in order to open up the option of becoming a pure transporter, rather than merchant pipeline.

But several hurdles still need to be overcome before the conditions are quite right for trading to take off at the Zeebrugge hub. Transportation terms across Belgium must still be negotiated individually by customers or suppliers, so the process of creating a market is inevitably fairly slow. And the terms for access to the domestic Belgian market are not yet established in a way that enables Belgian industrial or commercial customers, or the larger Belgian municipalities, to have genuine choice of supplier.

Diversity of gas supply into Luxembourg is provided by independent connections from Germany as well as Belgium, so that the municipal and industrial customers in the Grand Duchy are ideally placed to take advantage of third-party access, although formal rules were not in place by August 2000 and the Gas Directive was not signed into law until April 2001.

7.5.6 Other European Union gas markets

The five markets discussed above represent almost 80 percent of the whole continental gas market, and are well integrated with each other in terms of pipeline connections. The Austrian and very small (and non-EU) Swiss markets are also closely integrated with the above markets, but most of the other European Union markets are either entirely, or to some significant degree, physically independent of the integrated market. In order of importance these other markets are: Spain, Denmark, Finland, Ireland, Sweden, Portugal, and Greece. With the exception of Spain, plans for competitive gas supply are developing more slowly in these markets than in the rest of the EU.

Together they account for an annual volume of sales of about 30 bcm — the energy equivalent of only about 460,000 barrels per day of oil. The pace and extent of implementation of the Directive in these national markets will therefore be of less consequence for the development of a Europe-wide competitive market, although trading opportunities with particular customers or customer groups, and financial hedging against gas spot prices at the main European hubs may become a more widespread practice.

7.6 Conclusion: 'Not gas, but ideology'

When the Interconnector pipeline was first proposed, an acute Dutch observer of the European gas business remarked: 'It is not gas that the British will export, but ideology'. The ideology of market dealings as an economically efficient and fair way of running the network of gas supply was, in the early 1990s, completely alien to the corporate structure and to the gas buying and selling practices of most of the European industry.

The terms and provisions of the first European Commission drafts on third-party access to pipelines were widely believed to be unworkable, inconsistent with fair treatment for different classes of gas consumers, and inimical to the long-term security of gas supply in Europe. These were powerful objections, and have in fact delayed the advent of third-party access by about ten years, compared with the original 'Single Market' timetable.

But the operation of the Interconnector, and the consumer benefits (in terms of lower prices, and in most cases, better service) that have flowed from liberalisation of electricity in the continent and of gas in Britain, have brought about a sea-change in attitudes. From the perspective of the year 2001, it is not a question of 'whether' the European gas market will become a trading business, responsive to short-term market pressures and spot price signals, but simply of how quickly this will come about.

8 IPE natural gas futures

Stephen Barraclough and Jason Pegley, IPE

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8.1 The IPE

The International Petroleum Exchange (IPE) is Europe's leading energy futures and options exchange. Incorporated in November 1980 in response to increasing fluctuations in world oil prices, the Exchange provides a forum in which users can minimise exposure to changes in energy prices in the underlying physical markets.

Futures and options are the financial tools most frequently used to hedge, or manage, this volatility and price exposure. Futures are standardised legally-binding agreements to buy or sell a specified commodity at some fixed future date at a price and terms agreed today (see Chapter 5). They are traded on a recognised futures exchange which, together with some form of integral clearing mechanism, acts as counter-party to all transactions. This guarantees the performance of the contract.

IPE gas oil futures were launched early in 1981 followed by Brent crude futures in 1988. IPE Brent crude futures are a key part of the Brent blend market complex that is used as a benchmark for more than two-thirds of the world's internationally-traded crude oil. Further developments have included the launch of options contracts for both the Brent and gas oil contracts, and in January 1997, the launch of the natural gas futures contract.

In May 2001 IPE merged with IntercontinentalExchange[1] (ICE), a new online energy exchange based in Atlanta, USA. ICE uses an internet-based electronic trading system and is one of the fastest growing electronic commodity marketplaces in the world, with over 6,000 regular users from over 700 of the world's largest trading counterparties. ICE offers more than 600 different contracts in oil, gas, electricity and metals.

The Brent and gas oil contracts are currently traded predominantly by open outcry, with some electronic trading at the very beginning of the day before the trading floor opens. The natural gas and electricity futures contracts are traded electronically on the ICE's electronic trading platform.

IPE natural gas futures are available in several contract forms – day, balance of the month, month, quarter and season – and are used for four distinct purposes:

- for 'hedging', that is the management of the price risk inherent in the commodity;
- for use as a benchmark in discovering value, price setting or price indexation within supply or purchase contracts;
- for trading purposes as an investment opportunity; and

[1] www.theice.com

- for the physical delivery of natural gas into the UK gas network.

The IPE and its Members operate within a regulatory structure in accordance with the UK Financial Services and Markets Act. This provides a secure regime and environment for the trading of futures and options. The Financial Services Authority (FSA) regulates the Exchange. The IPE is a Recognised Investment Exchange (RIE) under the umbrella of the FSA, with the Exchange defining and implementing regulation appropriate for all IPE energy contracts. The IPE is required to operate an independent Compliance Department, which monitors and investigates users to ensure that trading takes place according to the specified rules and procedures.

All current IPE contracts are cleared through the London Clearing House (LCH) which guarantees their financial performance. Founded in 1888, the LCH now clears over 130 different futures and options contracts and over 900 UK equities. By clearing six exchanges – the London International Financial Futures and Options Exchange (LIFFE), incorporating the London Commodity Exchange; the London Metal Exchange (LME); London Stock Exchange; the European Energy Derivatives Exchange (Endex), IntercontinentalExchange and the IPE – each with different trading characteristics and diverse risk portfolios, the LCH spreads the risks which it counters.

The LCH eliminates the risk that a counterparty to a trade may default by acting as an intermediary in all transactions – 'the buyer to every seller and the seller to every buyer' – for which it holds a returnable deposit known as a margin. There are two forms of margin, initial margin and variation margin.

The initial margin is a deposit calculated to cover the closure of any position by LCH between the time the position is opened and the close of trading on the day the position is opened. Variation margin is then calculated every day that the relevant position remains open. Variation margin accounts for the daily difference in price relative to the price of the contract at the previous close.

If the price rises, funds flow to the position holder. Conversely, if the price of the position falls at settlement, then funds equivalent to this fall in value (price at close yesterday minus price at close today, multiplied by the number of contracts held) is drawn on the contract holder. In this way the daily value of all positions held is updated or "marked to market". The use of margins is a key difference between futures (which are cleared) and OTC forwards (which are not usually cleared and/or re-valued at the end of each trading period).

8.2 The UK gas market

The UK is the largest gas consumer and producer in Europe and currently has the most highly-developed gas commodity trading market in the region, having started the liberalisation process much earlier than other European countries (see Chapters 4 and 6).

The gas market in the UK is now fully competitive following the initial privatisation of British Gas in 1986 and a progressive liberalisation programme over the next fifteen years. There are now over 60 companies producing natural gas on the UK Continental Shelf (UKCS) and about the same number involved in the shipping, trading and marketing of natural gas in the UK. This has created the conditions for a competitive and liquid commodity market in natural gas, and with existing communities of traders comfortable with trading oil products and finance houses familiar with trading, the UK has had a relatively straightforward passage into trading of energy as a commodity.

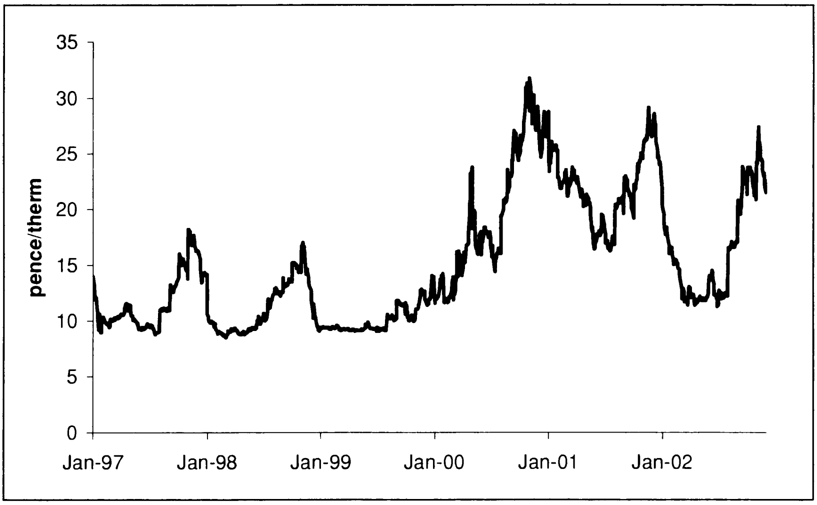
Gas consumption is also highly variable both within the day and seasonally, reflecting the pattern of domestic use, and is subject to unpredictable shifts because of the weather. With only relatively limited storage available to the gas supply system, natural gas prices can be very volatile, creating the environment for a liquid and transparent gas commodity market and effective derivative trading instruments, such as futures contracts.

8.2.1 Demand and prices

Natural gas is used primarily in the UK for:

- **Industrial processes** – as a feedstock, process fuel or heat source;
- **Space heating** – in homes, offices, factories and public buildings;
- **Electricity generation** – most new power stations are gas fired as a result of market liberalisation which initially brought low gas prices.

For many industrial users consumption varies little from day to day or season to season. But this is not the case for all market segments. Space heating demand in particular shows large fluctuations as a function of external temperatures. Consumption is higher during the winter and lower during the summer. The average domestic consumer shows a ‘swing’ (ratio of peak to average demand) of around 300 per cent. Consumption for power generation shows a less marked swing but nevertheless demand rises during the winter months, with the electricity generated used for space heating and lighting.



Source: IPE

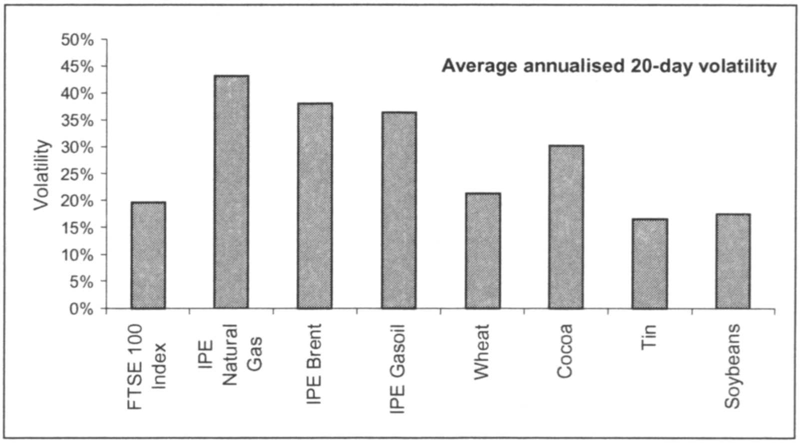
Figure 8.1 IPE natural gas futures prices, front month

With only limited storage available, the seasonality of demand in the UK natural gas market was translated into the behaviour of natural gas prices, both spot and futures. In recent years, spot gas prices have shown a strong seasonal pattern (see Fig. 8.1 above) and this was reflected in the shape of the forward price curve for the IPE natural gas futures contract. But this pattern has changed since the Interconnector pipeline opened up a physical link with Continental European markets in October 1998, exposing UK gas prices to the influence of oil prices which are widely used in long-term supply contracts on the Continent.

8.2.2 Role of storage

Despite a strongly seasonal demand profile, the UK actually has a smaller total storage capacity than some other European countries. Total UK storage capacity represents just under 4 per cent of average annual consumption, compared with more than 20 per cent in Austria, France, Germany and Italy. This relatively small storage capacity is due to a number of factors:

- the lack of aquifers and other suitable rock formations, and shortage of on-shore depleted gas fields with the necessary geological characteristics;
- the short distance from shallow offshore fields which made it relatively more economic to install additional facilities to enable higher gas production and delivery in winter; and
- the use of interruptible sales contracts, so that demand could be curtailed in unusually extreme situations.



Source: IPE

Figure 8.2 Relative volatility of IPE natural gas prices, 2001

The majority of the physical gas storage capacity is now managed as an independent[2] commercial storage service for the UK gas industry (see also Chapter 4). Together, the offshore Rough facility and the onshore Hornsea salt cavities, account for almost nine-tenths of total UK gas storage capacity. LNG storage facilities at the Isle of Grain, Partington, Glenmavis, Avonmouth and Dynevor Arms are also used to balance the operations of the National Transmission System (NTS).

Rough facility is very large, reasonably, flexible and can store up to 30 TWh. Rough has a high deliverability rate of 455 GWh/day – enough to supply the UK market for 13 days. It can be used to cut the cost of peak supplies and provides an alternative to new beach swing capacity or other supply sources. The Hornsea salt cavities provide a total of 3.5 TWh of storage with a deliverability rate of 195 GWh/day. Hornsea storage can be used for fine-tuning load balances or to take advantage of short-term price movements.

Some companies also offer 'virtual' storage services, utilising the flexibility inherent in their supply and demand contracts or gas field operations to mimic the effect of storage, as was traditionally done by British Gas in earlier years.

For various reasons, including shifting balances between supply and demand throughout the year, natural gas prices in the UK show high volatility, compared with other traded commodities (see Fig. 8.2). But this may also be partly because the gas trading market is still immature.

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[2] Dynegy purchased the Rough and Hornsea facilities from British Gas in 1999. Hornsea was sold to Scottish & Southern in September 2002. Rough was sold to Centrica in November 2002 (subject to regulatory consent).

8.2.3 Market structure

The progressive liberalisation of the UK natural gas market over the past fifteen years from single monopoly supplier to a fully competitive commodity market has been accompanied by widespread changes in market structure. This includes a discernable shift from long-term to shorter-term contracts. As the end-user market was opened up to competition during the 1990s, suppliers and customers took advantage of the flexibility of selling and buying short-term gas. Often, this was necessary in order to stay in balance within the day.

A bilateral (over-the-counter, or 'OTC') telephone market for gas for between a day-ahead and up to three years ahead grew from the early part of 1994 laying the foundations for the subsequent introduction of IPE natural gas futures. Many publications, including *Petroleum Argus* and *European Spot Gas Markets (ESGM*, formerly *BSGM),* report details of volumes and prices traded in the over-the-counter OTC (bilateral) market as well as IPE volumes and IPE settlement prices. OTC trades are reported for various time horizons from gas 'on the day' through to transactions for up to three or four years ahead. But it must be borne in mind that, quite naturally, not all deals done find their way into published reports. Increasingly OTC volume is transacted on electronic trading platforms. It is open to question how much of this volume and price information reaches the wider world.

There are differences between futures prices and reported OTC prices. Futures prices are transparent and widely accessible by a large and dispersed audience. All trades done contribute to published prices. But it is an impossible task to record and report all OTC deals, so prices reported may never be conclusively validated. Nevertheless, an underlying physical spot market is generally an essential prerequisite for any futures contract in any commodity. A futures contract cannot exist in isolation and must be "derived" from an underlying spot market, which is why such contracts are known as "derivatives".

The size of the underlying spot market necessary for the launch of a successful futures contract need be no larger than 10 per cent of total physical demand, assuming that the spot market in question is expected to grow. The gathering momentum for transparent transportation regimes in Continental European natural gas markets, the need for participants to manage their price risk, and the opening of the Interconnector between the UK and Belgium, all suggest further potential growth in the UK and Continental short-term traded gas markets.

8.2.4 Need for a futures contract

Among the other factors necessary to sustain a liquid futures contract are:

- a good number of counterparties;
- a variety of users (producers, consumers, investors);
- a stable economic, political and regulatory environment; and
- a supportive trading community.

A diversity of users is critical since healthy markets require a combination of risk averse and risk receptive players as well as a mixture of buyers, sellers and traders.

In summary, those who use the contract will have differing risk perspectives and profiles. Hedging is the primary activity for those who have an interest in the physical commodity, such as producers, shippers and consumers. At one end of the supply chain, producers are concerned about falling prices; while, at the other end, consumers are concerned about rising prices. Both types of company use futures with the goal of not losing money on physical market transactions, and are typically *risk averse.*

Using futures as an investment tool often, but not always, entails having no interest in owning the physical commodity. Such users are *risk-seekers* and take a futures position in the anticipation of making a profit. Investors rarely allow a contract to expire into physical gas, almost always closing out before trading ceases.

A stable economic, political and regulatory environment is also required since users are likely to want to use an Exchange in a stable country with strong regulatory controls. Such a regime ensures fair access and treatment for all participants and clearly defined trading rules. The Financial Services Authority (FSA), which takes its mandate from HM Treasury, regulates the IPE.

Industry support is also necessary since an Exchange will typically not impose a futures contract on a market. In order to be a success, there needs to be a core of participants who want the contract to succeed. Typically, the industry will assist the Exchange in the design of the contract.

Between 1992 and 1996 a structural revolution took place in the UK gas industry. Several factors combined to make the sale and purchase of gas at shorter and shorter notice a workable proposition:

- a surplus of physical supply over and above contracted requirements, which producers or intermediaries were willing to make available to the market;
- the emergence in 1994 of a bilateral, telephone-based spot market, although illiquid and opaque at first;
- agreement on pipeline access and charges applicable for gas transportation;

- a requirement to match the daily demand of end-users to daily system deliveries encouraged a new, wider market eager to work around the perceived inflexibility of existing contracts;
- growing competition between an increasing number of market participants;
- the renegotiation of uneconomic long-term contracts; and
- a mismatch between the supply of gas and the requirements of electricity generators and new entrant gas marketers.

Given these favourable conditions the IPE saw an opportunity for:

- an exchange-traded natural gas futures contract;
- real time prices, accessible immediately;
- the elimination of counterparty risk;
- the purchase or sale of gas with total anonymity.

The IPE therefore launched a futures contract which has evolved to allow the buying and selling of the right to natural gas for delivery periods between a day ahead and over three years ahead.

8.3 The IPE natural gas contract

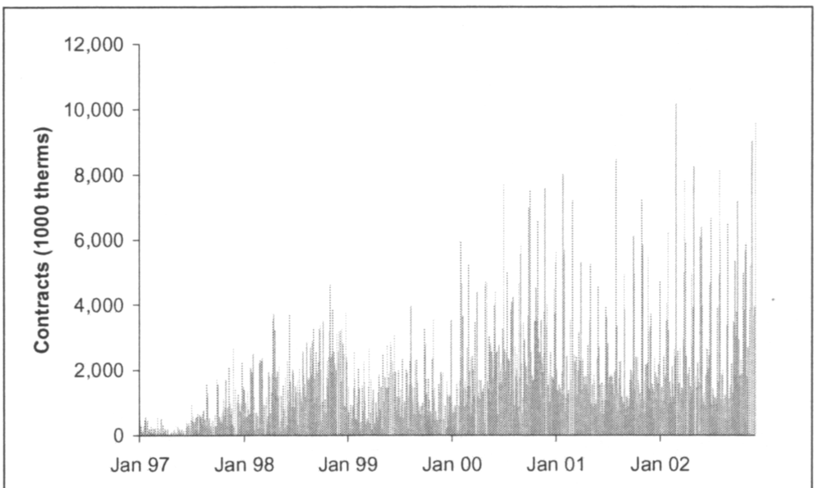
8.3.1 History

Following consultation with the gas and power industry, the IPE concluded that conditions were right to research the launch of natural gas futures in 1995. Gas and electricity were then amongst the fastest growing forms of energy market. Oil markets remain larger, but are increasingly mature and – although the gas oil and Brent crude contracts are highly successful – their growth potential is limited since oil-based contracts are in the mature stage of the lifecycle.

The growth in consumption of natural gas has come primarily at the expense of coal, and to a lesser extent, fuel oil. Gas has a number of environmental benefits, particularly lower levels of emissions, plus favourable power generation economics, especially since the advent of combined-cycle gas turbines (CCGT).

The IPE established a Natural Gas Working Group of gas industry participants during 1996 and, after almost a year of consultation, the natural gas futures contract was launched on 31 January 1997. Initially for monthly delivery up to 15 months ahead, the contract was subsequently extended, first to include balance of the month and day-ahead contracts, and latterly to quarter and season contracts (see 8.3.2 below). Delivery, if incurred, is taken or made at the UK National Balancing Point (NBP).

In the first year of trading, February 1997 to January 1998, natural gas futures traded over 80,000 lots rising to over 300,000 lots (nearly 1,300 per day) in 1998. This rose to over 500,000 lots (2,000 per day)



Source: IPE

Figure 8.3 IPE natural gas futures volumes, 1997–2002 in 2000 (see Fig. 8.3). 2001 saw the onset and consolidation of significant competition in screen-based trading alternatives, with Enron and Spectron prominent, and as a consequence volumes fell back to just below 500,000. During 2002 volumes were boosted by the drive to use cleared markets to remove counterparty and credit risk issues, and migration to the ICE trading platform. Volumes achieved a record 583,800 lots.

Initial thinking focused on a number of beach delivered contracts at import terminals such as Bacton, St Fergus, and Theddlethorpe. However, due to the continuing difficulties in finalising claims to gas at the beach brought about by the introduction of the Network Code in 1996, and the requirement for daily balancing by shippers, spot trading shifted from the beach to the NBP. NBP trading was also encouraged by the straightforward transfer of rights possible at the NBP on firm gas guaranteed present within the Transco network. The typical chronology of launching a futures contract is to wait until a liquid spot market has developed. In the case of the natural gas futures contract, the launch took place soon after the creation of the Network Code and the development of the NBP spot market.

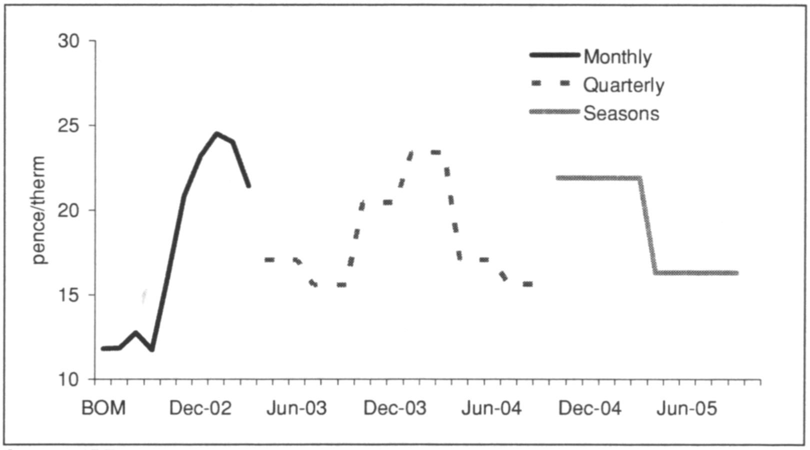
The new contract was to be screen traded as opposed to the traditional pit and 'open-outcry' method. This decision was taken for the following reasons:

- the UK natural gas spot market was not considered large enough for brokers to support the large floor trading teams necessary;
- floor space for an additional trading pit was limited; and
- the IPE already had a state-of-the-art screen trading system in ETS.

Screen trading can be more cost-effective than open outcry since large floor trading teams are not required. The anonymity of the final buyer is, if anything, even greater on a screen but remains a feature of both trading methods. It may be more difficult to gauge market sentiment from a screen, since the immediate human interaction which generates sentiment about the market is not so obvious. Many claim that such interaction is essential for a truly liquid market. Others refute this claim as defensive and protectionist.

8.3.2 Contract specifications

IPE natural gas futures are deliverable unless positions are closed out before expiry. Physical delivery takes place within the UK at the National Balancing Point (NBP) – a notional point at which the grid operator, Transco, effects a daily balance between the input and withdrawal of gas on the UK National Transmission System (NTS). Prices are quoted in UK Sterling, in units of pence per therm. There are



Source: IPE

Figure 8.4 IPE forward price curves, 7 June 2002

no position limits and no limits on daily price movements. The minimum price movement – 'tick size' – is 0.01 pence/therm.

The lot size is 1,000 therms of natural gas per calendar day for the duration of the contract. For example, one June natural gas futures contract is equivalent to 1,000 (therms) $\times$ 30 (days) or 30,000 therms. The minimum contract size is 5 lots (5,000 therms) per calendar day. Contracts are available in a number of different forms for different time horizons from one day ahead to over three years ahead for season contracts (see Fig. 8.4 above):

Day contracts are listed from the day ahead (D-1) to seven days ahead (D-7).

Balance of the month (BOM) contract is a strip of individual day contracts. The exact number of day contracts is determined by the number of days outstanding in the current calendar month. The BOM contract reduces in size on a daily basis generating a daily delivery obligation.

Month contracts are strips made up of individual and consecutive calendar days. A monthly contract is 28, 29, 30 or 31 individual day contracts, depending on the number of days in the calendar month. Month contracts are listed 9, 10 or 11 consecutive months into the future.

Quarter contracts are strips of three individual and consecutive month contracts. Quarter contracts are for standard calendar quarters, i.e. Jan-Feb-Mar, Apr-May-Jun, Jul-Aug-Sep, or Oct-Nov-Dec.

Season contracts are strips of six individual and consecutive month contracts. Season contracts are either for Apr-Sep or Oct-Mar.

The absolute size of the contract therefore depends on duration. So, a month contract for September would be 30,000 therms as there are 30 days in September; a quarter contract for Q1 (Jan-Feb-Mar) would usually be 90,000 therms, except in a leap year when it would be 91,000 therms. If contracts are not closed out before expiry, delivery must be made in equal measure on each day of the number of lots remaining open at expiry.

Trading ceases for the front month (first month listed) at close of trading two business days before the first delivery day for that month. The balance of the month (BOM) contract is listed once the front month expires. Trading hours are currently from 8:30 to 17:00 UK time, although it is likely that earlier opening will be introduced during 2002. Daily contracts are traded only from 8:30 to 16:00 UK time to enable the London Clearing House to finalise delivery arrangements for next day delivery. All trades are conducted electronically via the ICE platform, but contracts can also be registered using the exchange of futures for physicals (EFP) mechanism (see Chapter 5 and section 8.5 below).

8.3.3 The trading platform

The IPE natural gas futures contract was the first European energy futures contract to be launched exclusively using an electronic trading system. From its launch in January 1997 until October 2002, it was traded on the IPE's Energy Trading System (ETS). In October 2002 the contract migrated on to the web-based ICE trading platform, known as 'WebICE'. WebICE[3] is a fully-functional browser-based front-end to Intercontinental's electronic trading platform using a minimum of 128 bit encryption to ensure secure communication.

Users trade the contract either by viewing the ICE platform or a similar data feed and then by telephoning a broker, or by trading directly using the ICE platform to execute trades. All trading is anonymous, with the London Clearing House (LCH) being the counterparty to every purchase and to every sale. The LCH guarantees payment (should the buyer default) and undertakes delivery (if the contract should go to delivery, and the seller default). In this way the risk of dealing with another party ('counterparty risk') is eliminated.

The contract is open to all-comers able to satisfy Membership of the Exchange and able to open a clearing agreement with a Member to clear all trading undertaken.

The contract is subject to surveillance during trading hours by IPE Market Supervisors, who monitor trading activity in real time. In

[3] www.theice.com

addition, a history of all trading activity, either by company or by individual terminal, can be played back by designated staff of the Exchange for audit purposes. Only authorised users may self-execute. Authorised users must trade only in their own identity.

Although there are no 'position limits' to restrict trading, the ICE platform does prompt the user should any action taken be significantly 'out of market', that is not closely related to current pricing or activity. The ICE platform offers 'equality of access' for all users.

8.3.4 Trading natural gas futures

In order to trade natural gas futures it is necessary to sign a clearing agreement with an IPE Member. Members may also offer brokerage services for the contract. A list of IPE Members is available on the IPE website (www.ipe.uk.com). Any IPE trade has to be cleared by a full Member of the Exchange and the London Clearing House. Brokers earn revenue by levying a commission each time a client trades. These commission rates are negotiable and are not set by the IPE.

There are currently three methods of using the IPE natural gas futures contract:

- obtain a real-time IPE price feed from an independent 'quote vendor' or use the IPE "Energy Live" data feed. When prices are shown at which clients wish to trade they call the broker, who will execute the instruction via the ICE platform;
- take an ICE platform on a 'view-only' basis. The ICE platform provides additional information not available from quote vendors, including depth of market. This facility enables users to see the bids and offers staked up behind the best bid (highest price to buy) and best offer (lowest price to sell). Clients will again call the broker to execute a trade;
- take an ICE platform on an 'execution' basis. In order to do this users need to become a Member of the Exchange. Choosing to execute brings with it the responsibility of execution risk, previously assumed by the broker.

All open futures contracts are 'marked-to-market' on a daily basis. This gives rise to nominal daily profit or loss cash flows, although in practice the broker may agree other arrangements with the client. These cash flows represent the difference between the traded price and the closing price of each contract on each day. In effect, all open positions are re-valued on a daily basis until the position is either closed out or expires into physical delivery. This differs from over-the-counter (OTC) contracts, where profits or losses may not be realised until the expiry of the contract – although many OTC contracts are also marked-to-market for the same reasons as futures. Margin payments ensure that the clearer (in this case the London Clearing House) can protect all users against default by any buyer or seller, thus eliminating counterparty risk.

The actual margin required is determined by the number of positions open at any one time, and by the degree of volatility forecast in the market. Margin levels (or the "scanning range") are assessed quarterly by the London Clearing House and reviewed with the IPE. Collateral can be held, and arrangements for the payment and receipt of margin can be made by the broker according to individual requirements.

There are three categories of margin payments: initial margin, variation margin, and delivery margin.

> Initial margin is, in effect, a 'good faith' deposit, normally 10–15 per cent of the value of the contract.
>
> For example, an 'open' position made up of a purchase of 10 August futures represents 10 lots x 1,000 therms = 10,000 therms x 31 days = + 310,000 therms. The initial margin will be the open position multiplied by the margin. If, for example, this 'scanning range' was set at 2 pence/therm, then the initial margin would be 310,000 therms x 2p/therm, or £6,200.
>
> Variation margin is levied on a daily basis and is designed to cover the movement in price of a contract in a single day. This is commonly referred to as 'marking-to-market'.
>
> For example, consider 10 lots purchased for August delivery at a price of 17.65 pence/therm. The August month settlement price at the close falls to 17.52 pence/therm. The variation margin would be –0.13p (17.52p – 17.65p) multiplied by (31 days x 1,000 therms × 10 lots) equivalent to a debit of £403.
>
> On the following day the position remains open, August firms and settles at 17.58 pence/therm. In this case, the calculation would be (17.58p – 17.52p) multiplied by (31 days x 1,000 therms × 10 lots) or a credit of £186.
>
> Delivery margin (or spot month margin) is levied on contracts that are into delivery. It is designed to ensure that participants who hold open contracts at expiry and therefore expect to take or make delivery have allocated adequate funds for the purpose. It is also intended to force less-well capitalised speculators out of the market, thus reducing short-term speculative pressures. In the case of the IPE natural gas monthly futures contract, spot margins are levied at close of business two business days before the delivery day.

8.4 Using natural gas futures

Natural gas futures contracts can be used for a wide variety of purposes from price discovery to risk management (see Chapter 5).

Traditional long-term natural gas supply contracts often require protracted negotiations on price and escalation, mostly linked to a basket of oil products and inflation measures such as the PPI (see Chapters 11 and 12). IPE prices can be used as part of a pricing formula such that negotiations are only concerned with the differential, rather than an absolute price. In this way supply contracts can be negotiated more rapidly and both parties will achieve a market-related price.

Those who use natural gas futures as a risk management tool include:

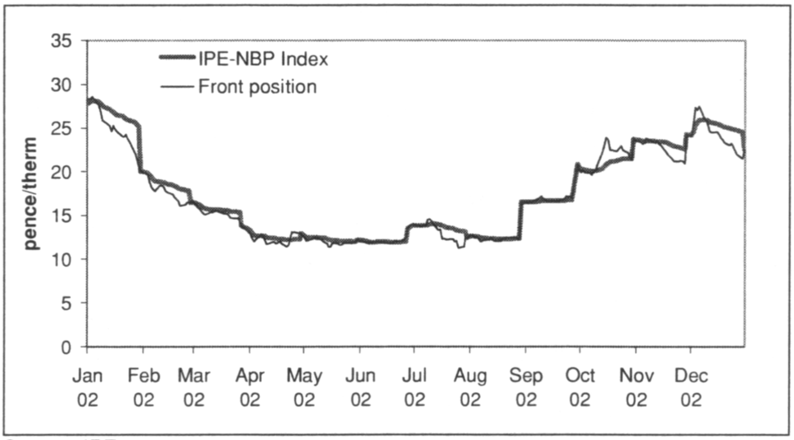
- North Sea gas producers;
- power generators;
- large industrial consumers; and
- natural gas traders.

By using futures in conjunction with market-related physical supply pricing, gas market participants should be able to secure significant savings relative to traditional contracts without sacrificing security of supply. These might include importers, exporters, shippers, city municipalities, and large industrial companies.

8.4.1 The IPE-NBP Natural Gas Index

The IPE calculates a daily NBP Natural Gas Index. This is done in order to facilitate and encourage the pricing of term supply contracts on a floating, rather than fixed, price regime. The Index is an unweighted average of the front month settlement prices. It is published daily by *ESGM (European Spot Gas Markets)* and *Petroleum Argus*, as well as being carried on all Quote Vendor screens. The Index can also be accessed via the IPE website (www.ipe.uk.com) and is available free of charge by e-mail.

The Index is an unweighted rolling average of the front month settlement prices calculated at the end of each trading day. The Index is calculated from the first day of trading for the front month (at which point the Index is just the settlement price for that day) and accumulated for each trading day until the end of trading for the front month. The final Index is calculated at the close of trading on the date that the front month contract expires. This is always two business days before the first delivery day of the expiring contract. The process then



Source: IPE

Figure 8.5 IPE-NBP Natural Gas Index, 2002

starts again on the first day of trading for the new front month contract (see Fig. 8.5).

Consider a term supply contract between a producer and shipper, or between a shipper and end-consumer. Both could agree at the outset of the contract to use the final IPE Index as the benchmark price for physical deliveries in the coming month. So, for example, they would use the IPE Index upon expiry of the December futures contract as the pricing indicator for all physical gas deliveries to be made under the term contract in the calendar month of December.

It may be that the parties agree a differential to the Index. For example, the supplier may want a premium to the Index for guaranteeing security of supply. The differential that is agreed could be absolute (a fixed price element in pence/therm above the Index) or on a percentage basis (a proportional price element, say 2 per cent above the index). It can be seen that both parties to the term contract are achieving a 'fair' market related price.

This floating price approach enables much faster negotiation, and greater flexibility for both parties to hedge their exposure independently of each other. A further benefit is the time savings that accrue by avoiding a tender process; often the case with a fixed price contract. By using the IPE Index in a term contract pricing formula players can be confident that the price paid or received is always 'at the market'.

This can be illustrated by the examples that follow.

8.4.2 Gas producer

Imagine a gas supplier with 2 bcm of gas to sell each year. The supplier might sell 1.75 bcm via a number of long-term contracts to three shippers or purchasers, and market the remaining 0.25 bcm on a spot basis. This could be to power generators, other producers, shippers, consumers and Interconnector customers.

Imagine 0.25 bcm is sold spot in the ten months between August and May. This is equivalent to 90,000 lots, or 9,000 lots per month, or say, on average, 300 lots per day.

The producer can hedge the spot sale using IPE natural gas futures and can also fix the price for long-term contract sales either by using the published IPE-NBP Natural Gas Index, or by developing a custom index using IPE settlement prices in the month prior to delivery for deliveries taking place in the delivery month.

On 7 September a producer is concerned about a possible (but unseasonal) fall in natural gas prices in three months' time. The price on the spot physical market is currently 20 pence/therm. If the producer was able to lock in a sale price of around 17 pence/therm this would represent an acceptable margin on equity gas production of 1,550,000 therms in December. In order to hedge this exposure the producer sells 50 December futures (1000 therms/day). These are available on 7 September at 18.5 pence/therm.

By the end of October the producer is looking to close with buyers for the physical December production. The best offer received is 14 pence/therm, which is finally accepted. Simultaneously, the broker is instructed to buy back the 50 contracts to close out the futures position opened on 7 September. The price of December futures on the screen is now only 14.5 pence/therm.

By constructing a hedge, the profits from the futures trade should offset the losses made on the physical market and ensure an effective selling price above 17 pence/therm. The realised, or effective selling price will equal the agreed price of 14 pence/therm for the physical gas, plus any profit made on the futures transactions.

In this example, the profit on futures is:

$$18.5 - 14.5 = 4.0 \text{ pence/therm.}$$

And, since, the physical gas sale realised 14p pence/therm, the effective sales price is:

$$14.0 + 4.0 = 18.0 \text{ pence/therm.}$$

8.4.3 City municipality in Europe

Stel is a city-state in Northern Europe. It buys all its requirements from a long-standing partner, TPC. Citizens use 3 bcm per year for heating, cooking, and in district heating schemes.

Stel buys 2.5 bcm on long-term contract, including 1.0 bcm through the UK-Belgium Interconnector.

Stel City Council sets the price in these contracts using IPE settlement prices during the month prior to physical delivery for sales during the following month. Stel then buys the balance of 0.5 bcm in the bilateral telephone/OTC market at prevailing prices.

Stel is now growing in confidence in using derivatives and has considerable expertise in using futures and OTC instruments. Management are now considering granting the authority and setting trading limits for the trading team to operate a 'book'. This activity will be strictly defined and controlled, but should enable Stel traders to take advantage of opportunities in the market, perhaps unrelated to immediate physical gas needs. Using expertise Stel forecasts a profit on these activities. Profits are to be shared between all citizens in the form of lower energy prices.

8.4.4 Power generator

New power generators are in an ideal position to sign shorter-term supply contracts, although most still require long-term demand contracts to satisfy financiers. Imagine a large new generator buying 5 bcm each year. The generator either uses the gas to generate electricity, or if the incentives are right, will interrupt that generation to sell gas into the short-term or spot market. At present 70 per cent of the generator's gas requirements are purchased long-term through four separate contracts. The generator uses the IPE Index and an OTC index to price long-term gas purchases, buying the balance on the OTC market at prevailing prices. The generator can therefore use the IPE to hedge exposure to rising market prices.

8.4.5 Large industrial consumer

Large-scale process and industrial users, such as glass, fertiliser, steel, and ceramics also have an ideal opportunity to use futures. This is particularly true if output is sold ahead at a known price. For example, PRS is an ammonia plant using 0.5 bcm of natural gas each year. This represents 180 million therms per year, or the equivalent of the gas demand of 300,000 average sized domestic homes.

PRS buys 80 per cent of supplies on three long-term contracts, including two via the UK-Continent Interconnector. One contract is at a fixed price, one indexed to a basket of crude oil prices, and one indexed to a combination of IPE and OTC prices. The gas buyer at PRS is also able to draw on gas in storage, and to put gas into store on demand.

PRS routinely uses futures to hedge exposure to rising gas prices. Contracts sourced from the UK include a 'self-interrupt' clause, which enables PRS to leave gas in the UK market when the price is attractive and the physical gas can be sold spot. PRS is currently evaluating the possibility of interrupting or reducing production during the winter to take advantage of attractive prices in the spot gas market.

Imagine it is January and PRS has agreed fertiliser sales in three months' time based upon an estimated cost of gas of 23 pence/therm.

The January physical spot price is 20 pence/therm. PRS also buys April natural gas futures, currently trading at 22 pence/therm.

Towards the end of March, physical gas in the spot market reaches 27 pence/therm. PRS then sells April natural gas futures bought for 22 pence/therm for 26.5 pence/therm.

By using a hedge, the profits arising from the futures trade will largely offset the loss made on the physical position and ensure an effective buying price below 23 pence/therm. The effective selling price will therefore equal the market price of 27 pence/therm for the physical gas, plus any profit on the futures transaction.

Since the profit on April futures is:

$$26.5 - 22.0 = 4.5 \text{ pence/therm}$$

The price of physical gas purchased in the spot market is now 27 pence/therm. Thus the effective purchase price is equivalent to:

$$27.0 - 4.5 = 22.5 \text{ pence/therm.}$$

8.4.6 Gas trader

X-trade is a new company formed by two entrepreneurs. They have recruited a team of traders and risk managers. X-trade provides risk management services to the gas and power industries. It takes positions both on OTC and IPE but always closes these out before delivery takes place because it has no ability to handle physical gas. X-trade do feel they have the skills to manage price risk, and offer investment services both for clients and for their own account.

In October, the Head of Trading takes the view that rising production in the North Sea is likely to lead to a fall in natural gas prices. Xtrade therefore take a speculative position in the futures market, selling 5 December natural gas futures, equal to 31 days x 5 lots x 1,000 therms = 155,000 therms of gas, at 19 pence/therm.

By mid-November, the gas price has indeed fallen so that December futures are trading at 17 pence/therm. Xtrade then buy back 5 December futures at 17 pence/therm, thereby closing out the position.

The profit on Xtrade's speculative futures trade is:

$$19.0 - 17.0 = 2.0 \text{ pence/therm,}$$

which, multiplied by 155,000 therms amounts to £3,100. Of course, if prices had risen because of, say, unexpectedly cold weather, X-trade might have been facing a loss rather than a profit.

8.5 Delivering natural gas

8.5.1 Delivery mechanisms

Futures are most often used as a paper tool by hedgers and investors. In this way a position is always closed out prior to expiry, and the futures contract not used to make or take delivery of physical gas. The vast majority of futures contracts do not go to delivery since physical players may prefer the flexibility of physical contracts available from the OTC market. It is a feature of the IPE contract that positions can expire into physical delivery at the National Balancing Point (NBP). This is ultimately effected by the input of trade nominations by both counterparties to the trade into the Transco AT-Link system (see Chapter 10). Anonymity is maintained right through to delivery since LCH will be maintained as the counterparty. Once Transco matches opposing nominations to buy and sell, delivery is effected. At present, about 5 per cent of IPE natural gas futures result in physical delivery.

An additional feature of the IPE natural gas futures contract is the facility Exchange of Futures for Physical (EFP)[4] with a willing counterparty. In an EFP two parties agree (independently of the IPE) to either swap cash and futures positions, or to establish opposite positions with each other in both the cash and futures markets. Thus futures are being used not only as a financial instrument for hedging price risk but also as a vehicle for delivery. EFPs can be used to close out a futures position, to transfer futures positions, or create equal and opposite futures positions with the counterparty. An EFP can be done up to half an hour after closing and outside IPE trading hours but must be registered when the Exchange opens.

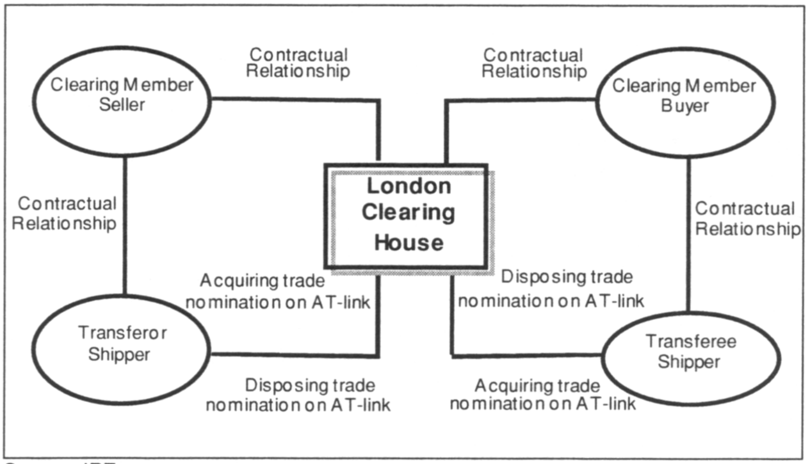
Given that the two counterparties involved are altering their futures positions 'off-exchange' there is a stringent requirement that a genuine physical transaction must lie behind an EFP. The IPE undertakes random checks and those parties that cannot substantiate a genuine physical transaction may be liable to severe penalties. Once an EFP is registered only the number of futures lots is shown to other market players and not the price of the physical transaction, which remains confidential to the two parties involved.

Example: EFP

Consider an example of an EFP which results in the mutual closing out of two companies' futures positions.

Company X has a futures position of 50 lots short December while Company Y has a futures position of 50 lots long December. X has

[4] The IPE natural gas futures contract also provides a facility for the Exchange of Futures for Swaps (EFS).



Source: IPE

Figure 8.6 What happens on delivery?

1,550,000 therms (which corresponds to 50 lots) of gas available for immediate delivery at the NBP which Company Y would like to take. X and Y agree an independent price for the physical transaction. This physical transaction also removes the need for X and Y to maintain their respective futures positions. The two parties therefore agree to execute an EFP and instruct their respective IPE brokers to register the deal. Company X now goes long 50 lots December futures (from Y) whereas Y goes short 50 lots December futures (from X). In this way both X and Y have closed out their respective futures positions.

8.5.2 What happens on delivery?

If the contract expires into delivery further margining takes place. Delivery, or spot month, margin is collected to insure against non-performance during the delivery phase of a futures contract. Once a monthly contract expires a counterparty will hold a position in both the declining Balance of Month (BOM) contract and in the daily contract for next day delivery. Clients will continue to incur variation margin on the BOM contract and will lodge delivery margin with the broker for the next day delivery of the daily contract.

The delivery margin to be collected from the buyer is calculated from the number of lots for delivery multiplied by the contract size and the Exchange Delivery Settlement Price (EDSP).

The EDSP represents the price of gas applicable on the delivery day. It is assessed two days prior to the delivery day by canvassing a range of market participants. The EDSP may be different for each delivery day and the final invoice will detail the volume relating to each day multiplied by the EDSP for that day. By the end of the delivery month the LCH will be holding 28, 30 or 31 days of buyers' security depending on the month in question. This progressive accumulation of funds is required since the buyer is receiving gas for which he has yet to pay. These funds are held until payment of the final invoice, which takes place according to industry practice 19 days after the delivery month.

Thus the EDSP for a given daily delivery may be different from the actual price traded. The client will have received or paid the effective difference between the EDSP and traded price by means of variation margin. Thus the price traded is the price effectively paid.

The delivery margin collected from the seller is held as security against a failure to deliver. This is calculated as the number of lots for delivery multiplied by the contract size multiplied by the Seller Default Price (SDP).

SDP is calculated with reference to the System Marginal Price (SMP) buy price (see Chapter 10). If the seller fails to deliver, the LCH will have to buy physical gas at this price to meet the contract obligations to the buyer. It is first called on the business day prior to delivery and is held until confirmation of delivery performance on the day following delivery (see Fig. 8.6).

8.6 Future developments

The IPE's future intentions can be split into three main areas:

- consolidation and growth of the existing UK contract, building on the liquidity which has been apparent since the contract migrated to the ICE platform in October 2002,
- exploiting the synergies available from listing both OTC and futures contracts on a single platform – providing a 'one-stop shop' for the energy industry's risk management and trading needs, and
- considering opportunities for European based contracts.

Appendix 8.1

IPE Natural Gas futures contract

BACKGROUND

The IPE Natural Gas futures contract enables trading, risk management, hedging, pricing and physical delivery in a growing energy market.

The contract is deliverable unless positions are closed out prior to expiry. Physical delivery takes place within the UK at the National Balancing Point (NBP). This notional point is where National Grid Transco effects a balance every day between the input and withdrawal of gas on the UK National Transmission System (NTS).

FEATURES OF THE CONTRACT

Position limits

There is no restriction in the size of positions held.

Price transparency

Real-time prices are available on the ICE platform, IPE Energy Live and from major data vendors.

Variable parcel size

Trading takes place in multiples of 5 lots, 1 lot equals 1,000 therms per day. Because the contract is denominated in daily units a monthly contract for June has a value of 5 lots x 30 (days) x 1000 therms = 150,000 therms.

(1 therm = 100,000 Btu (British thermal units), 29.3071 kilowatt hours or 25,200 kilocalories)

Realisable profits

The daily mark-to-market process enables profit or loss to be realised ahead of expiry.

Increased flexibility

Enables users to separate contract pricing from existing long-term physical supply arrangements.

Contract security

The London Clearing House acts as the central counterparty for all trades. LCH guarantees the financial performance of every contract registered with it up to and including delivery, exercise and/or settlement.

Delivery mechanism
IPE Natural Gas futures also offer users the opportunity to make or take delivery of natural gas. Delivery is effected at the NBP by the transfer of rights from the Seller to LCH and from LCH to the Buyer. If a user goes to delivery on a monthly contract and then wishes to trade again then gas can be traded on the prevailing Balance of Month (BOM) contract.

Natural Gas Index
The IPE-NBP Natural Gas Index is calculated at the end of each trading day. It is an un-weighted rolling average of the front month settlement price calculated at the end of each trading day. The final Index is calculated at close of trading on the date that the front month contract expires (close of trading on the day that is two business days prior to the first delivery day). The final Index therefore represents the unweighted average of all settlement prices of the expiring contract month ('front month'). IPE distribute free of charge by e-mail the evolving index as it is calculated day by day on the current front month by email. The final index for the expired front month is published to the IPE website.

CONTRACT SPECIFICATION

Date of launch
31 January 1997

Trading hours
Open 08:30 – 17:00, Daily contracts 08:30 – 16:00.

Trading mechanism
ICE platform or by the Exchange of Futures for Physicals (EFPs) or by the Exchange of Futures for Swaps (EFSs).

Contract size
Minimum of 5 lots of 1,000 therms per lot of natural gas per day.

Unit of trading
1 lot equals 1,000 therms of natural gas per day.
(1 therm = 29.3 kilowatt hours)

Quotation
The contract price is in Sterling, pence per therm.

Minimum price fluctuation
0.01 pence per therm.

Maximum daily price fluctuation
There are no limits.

Contract description
Season contracts are strips of six individual and consecutive contract months. Season contracts are always an (April–September) strip or (October – March) strip.

Quarter contracts are strips of three individual and consecutive contract months. Quarter contracts always comprise a strip of (Jan–Feb–Mar) or (Apr–May–Jun) or (Jul–Aug–Sep) or (Oct–Nov–Dec).

Month contracts are strips of individual and consecutive calendar days. A Month contract comprises 28, 29, 30 or 31 individual day contracts, determined by the number of calendar days in the month in question. Month contracts are listed 9, 10 or 11 consecutive months into the future, depending on the cycle of the contract structure at that time.
If not closed out at expiry contracts obligate delivery or taking delivery of the number of lots remaining open upon expiry on each day in that contract period.

Balance of the Month (BOM) contracts comprise a strip of individual Day contracts. The precise number is determined by the number of days still outstanding in the current month. The BOM contract reduces in size each day, generating a Day contract representing the delivery obligation of that day.

Day contracts are listed from day ahead to seven days ahead.

Initial margin
Initial margin is a deposit held by LCH to cover the costs incurred in closing out a position in default. It is returned with interest upon the closing of the position, or at expiry.

Daily variation margin
All open contracts are 'marked-to-market' each day. Variation margin is calculated on the number of lots for each open contract. This process uses the difference in settlement prices from day to day.

DELIVERY MECHANISM

Expiry
The first month contract ceases trading at close of business on the last but one business day of each month.

The BOM contract ceases trading at close of business on the last but one business day prior to the last but one calendar day of each month.

The Day contract ceases trading at 16:00 on the business day prior to the delivery day.

Delivery
Acquiring and Disposing Trade Nominations (buyer from LCH, seller to LCH) are input by buyer and seller to BG Transco AT Link system before 18:30 on the business day prior to delivery. Delivery takes place in kilowatt-hours (at 29.3071 kilowatt hours per therm).

Transferor or transferee arrangement
Should buyer or seller not be entitled to submit Trade Nominations or to have access to AT Link then either may appoint a 'transferor' or 'transferee' to do so on his or her behalf. By 16:45 on the last business day prior to delivery seller and buyer submit NBP Delivery Confirmation documents to LCH which specify the transferor or transferee, and the number of lots going to delivery. Both transferor and transferee in parallel submit NBP Transferor or Transferee documentation to LCH, which confirms ability to submit Trade Nominations to AT Link. By 18:00 LCH sends seller, buyer, transferor and transferee an NBP Conversion and Confirmation Report. This specifies the number of lots in kilowatt-hours to be quoted when submitting Trade Nominations. All parties must enter and finalise Trade Nominations by 18:30.

LCH issues account documentation to buyers and sellers no later than 18:00 hours on the day which is 17 business days immediately following the last day of the month in which delivery began.

The buyer pays the daily Exchange Delivery Settlement Price (EDSP) for each delivery. The EDSP represents the value of gas on the delivery day and is the settlement price recorded on the second business day immediately prior to the first delivery day. The EDSP for each daily delivery will differ from the price of the original trade by the amount of variation margin debited and credited since the initial trade was done.

Price
Excludes any charges payable to Transco. Exclusive of VAT or other duty that may become payable on the sale or transfer of rights in respect of natural gas.

Buyer's obligations
Nominate a transferee to take a transfer of rights to natural gas; notify LCH of the details of the transferee; ensure acceptance by the transferee of rights to natural gas from LCH; be responsible for the

timely performance of the obligations of the transferee on buyer's behalf; make payment in Sterling to LCH.

Seller's obligations
Nominate a transferor to make a transfer of rights to natural gas; notify LCH of the details of the transferor; ensure the transfer of rights to natural gas to LCH; be responsible for the timely performance of the obligations performed by the transferor on seller's behalf.

Exchange of Futures for Physical (EFP)
EFPs can be used to liquidate futures positions where both parties hold equal and opposite physical and futures positions; EFPs can also be used to initiate futures positions where both parties hold physical positions only.

EFPs may take place at any time up to 30 minutes after the close of trading and must be registered in accordance with IPE procedures.

Law
The contract is governed by English law.

CLEARING AND REGULATION

Clearing
LCH guarantees all contracts. All IPE Members are either members of LCH or have a clearing agreement with a Floor Member who is a member of LCH.

Regulation
The IPE operates in accordance with the requirements of the Financial Services and Markets Act 2001. This requires the observance of the highest standards of business conduct and contract security. In accordance with the Act all IPE Members are either directly authorised by the Financial Services Authority or are members of the Securities and Futures Authority, the self-regulating organisation for the conduct of investment business in commodity, financial and other futures and options.

IPE is a Recognised Investment Exchange.
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9 UK gas trading contracts

Eldon Pethybridge, British Gas

9.1 Introduction

9.1.1 Types of contract

In the UK gas spot market, sellers and buyers trade gas under two types of primary contract: the beach contract and the NBP contract.

In a beach contract, the seller contracts to sell gas to the buyer at a gas terminal at which gas is brought ashore from its point of production.

In an NBP contract, the seller and buyer, in effect, trade rights in gas within the Transco pipeline system. Each undertakes to make trade nominations to Transco of the quantity of gas to be traded and the period for performance. The trade nominations must correspond and be made in compliance with the conditions stipulated by Transco in its Network Code for such nominations to be made. Transco then takes account of the trade nomination quantity in determining, for each day in the period for performance, the respective daily imbalances of the seller and buyer with Transco. The letters NBP stand for National Balancing Point, a notional point within the pipeline system that is part of Transco's gas transportation charging methodology.

There also exists in the UK gas spot market a range of secondary contracts, derived from beach and NBP contracts. Secondary contracts include locational and time swaps, options, and contracts for differences. The International Petroleum Exchange's screen-based natural gas futures contract was launched as an NBP contract.

The opening, in October 1998, of the UK Interconnector gas pipeline between Bacton and Zeebrugge, connected the UK to the Belgian, and thus the European, gas grid and led to the trading of gas at Zeebrugge. The contractual features of Zeebrugge trading, and its linkages with UK gas spot market contracts, are discussed briefly at the end of this chapter.

9.1.2 Contract format

Typically, participants in the UK spot market agree and commit to writing, in respect of trades that they may transact, beach and NBP contract terms and conditions that will apply as standard. The objective of doing so is to simplify the trading process. Generally, terms and conditions are agreed separately for beach and NBP contracts but some participants have produced combined documents. Where participants operate under separate terms and conditions, they will normally enter into umbrella netting agreements, so as to incorporate payment netting and cross-default provisions across trades.

The various terms and conditions produced by participants, for beach or NBP trades, have much in common. In part, this is because they stem from, and are intended to operate in, the same or similar circumstances. Another reason is that most participants trade as both sellers and buyers, and therefore are content to agree terms and conditions that strive to achieve a balance between the interests of seller and buyer. In addition, it is in the interests of seller-buyer participants seeking to manage exposure to potential liabilities, to fix upon seller and buyer obligations that are complementary.

In mid-1997 a number of participants negotiated a set of NBP terms and conditions to govern short-term NBP trading, in relation to quantities of gas that would be non-variable ('flat') within the period for performance of the trade. By this time, NBP trading had become considerably more popular than beach trading and it was hoped that these terms and conditions, known as NBP 1997, would come into common use in the market. The NBP 1997 terms and conditions appear as Appendix 9.1.

Trades, whether beach or NBP, are generally entered into on the telephone, the parties' intention being that they will be contractually bound without more paperwork. To this end, telephone lines on which trading takes place are usually taped to provide a record of deals struck. Some contracts include for this, by way of a clause in which each party consents to the monitoring and recording of communications between their employees, waives the right to any further notice of such monitoring and recording, and agrees to notify their employees that monitoring and recording of communications is occurring.

It is normal practice for the specific terms and conditions of each trade to be confirmed in writing in a trade confirmation, however named, of perhaps one or two pages. The trade confirmation, which incorporates the agreed standard terms and conditions by reference, is usually prepared, signed and sent by facsimile transmission from one party to the other, for approval, signature and return transmission by the other party.

Some parties contract on the basis that all beach and/or NBP trades between them will constitute one contract or master agreement. Such an approach facilitates the incorporation of payment netting and cross-default provisions across trades.

In some sets of agreed standard terms and conditions, the parties seek to establish:

- which party is to prepare and send the trade confirmation, and the time-frame for doing so;
- the position if the trade confirmation is not sent, or not returned;
- whether the taped record of the communication in which the trade was agreed takes precedence over the trade confirmation, in the event of any inconsistency.

For an example of such rules, see Clause 2 of NBP 1997. Such rules, whilst purporting to be declaratory, are of course always open to evidence that, in the circumstances that prevailed at the time, the parties in fact reached some other agreement or reached no agreement at all.

9.2 Beach contracts: performance

9.2.1 Background

Historically, a producer of gas from the United Kingdom Continental Shelf normally contracted for its sale at the point at which the producer's pipeline joined with the pipeline system of the onshore transporter. The onshore transporter — primarily the British Gas Corporation prior to 1986 — was also the buyer of the gas. At the junction of the offshore and onshore pipelines it would take delivery of, and title to, all gas that it had contracted to buy. To protect the integrity of its pipeline system, the onshore transporter required gas delivered into its pipeline system to meet its requirements with regard to quality and pressure.

The introduction and establishment of competition in gas supply led eventually to the separation within British Gas plc — the privatised successor to the British Gas Corporation — of gas trading and gas transportation, and ultimately the demerger of the company. The major onshore transporter — now Transco, part of the Lattice Group — is allowed to buy and sell gas only for pipeline balancing and other operational purposes. Nevertheless, as the onshore transporter and recipient of almost all gas traded at the beach in the UK gas spot market, the terms upon which it takes delivery of gas into, and allows for offtake of gas from, its pipeline system, have an important bearing on the content of beach contracts.

Transco's terms are set out in its Network Code, prepared pursuant to its public gas transporter licence. Persons wishing to arrange with Transco for the transportation of gas must hold a gas shipper licence (with one exception — see section 9.3.1) and contract with Transco to be bound by the terms of the Network Code. These stipulate, amongst other things:

- the means by which the quantity of gas delivered into the pipeline system is to be determined;
- that Transco takes title to, and risk in respect of, all gas delivered into its pipeline system, the points of delivery at the gas terminals being known as system entry points;
- that gas delivered into the pipeline system must meet Transco's requirements as to quality and pressure;
- that the principal unit of time in respect of which a gas shipper must account to Transco for quantities of gas entered into and offtaken from the pipeline system is the gas flow day, namely the period that begins at 0600 hours on a day and ends at 0600 hours on the following day; and

- that the principal accounting period is a calendar month.

Transco has access to measuring equipment whereby the aggregate quantities of gas flowing at a system entry point can be determined. However the data that this equipment produces has to be reconciled with the claims made by gas shippers in respect of quantities of gas entered into the pipeline at a system entry point on a gas flow day. This task is undertaken by a claims validation agent acting on behalf of all gas shippers, in accordance with agreed rules that allow inconsistencies in the claims of gas shippers to be resolved. The claims validation agent makes returns to Transco on a monthly basis, stating in kilowatt hours the quantity of gas entered into the pipeline system by each shipper at each entry point. This issue is discussed further in section 9.2.4.

A simple specimen set of terms and conditions for beach contracts is set out as Appendix 9.2.

9.2.2 Sale and purchase obligations

A beach contract is founded upon a simple exchange of obligations. It is usual to stipulate that, for the duration of the period during which the trade is to be performed, the seller shall sell and the buyer shall purchase gas in accordance with agreed standard terms and conditions and the trade confirmation incorporating them.

The agreed standard terms and conditions then develop this exchange, so as to address issues relating to the transfer of rights in gas from seller to buyer.

9.2.3 Delivery

It is customary for beach contracts to refer to the process whereby such rights are transferred as one of delivery of gas. This language reflects the physical realities at a gas terminal in overall terms, as the gas piped ashore by producers flows — is delivered — into the Transco pipeline system. However, as a description of the interaction between a seller and a buyer that have contracted for the sale and purchase of a quantity of gas at a gas terminal, it arguably implies a degree of personal activity and involvement that does not exist. As Mr Justice Colman put it in *National Power PLC v United Gas Company Limited and another* (3 July 1998, unreported), 'the transfer of a particular quantity of gas from a seller to a buyer within this regime involves rather special considerations'.

In particular, the flow of gas through a gas terminal and into the Transco pipeline system is a continuous one in which many sellers and buyers have interests. In the words of Mr Justice Colman, 'when gas is bought and sold, what passes by "delivery" is a contractual right as against the seller to an undivided share in the gas flow as measured over a limited period of time, usually one day...'. If only in the interests of clarity, there is a case for including an acknowledgement of this in the parties' agreed standard terms and conditions.

Beach contracts define a delivery point, at which the buyer's contractual rights in the gas flow will arise. The location of a gas terminal, for example Bacton, is specified, and the delivery point will perhaps be described as the flange, weld or other agreed mark connecting any sub-terminal facilities with the Transco pipeline system at that gas terminal. Alternatively, the delivery point may, in the language of Transco's Network Code, be referenced as the system entry point or aggregate system entry point at that gas terminal. This conceptualisation of the delivery point coincides both with that in older long-term gas sales contracts, some of which are the source of spot market gas, and with that contained in Transco's Network Code.

Gas spot trading is concentrated at gas terminal, and not sub-terminal, level. For example, seller and buyer contracting for delivery at Bacton, will most likely specify Bacton as the delivery point, rather than, say, the Phillips sub-terminal. Clearly, for terminal-level trades at gas terminals comprising two or more sub-terminals, the delivery point has to be defined so as to include all sub-terminals through which gas flows into the Transco pipeline system.

Transco's Network Code commits a gas shipper who claims, against Transco, rights in respect of gas entered into Transco's pipeline system, to a warranty:

- that it will have title at the point of delivery to all gas delivered or tendered for delivery to the pipeline system by it at any system entry point, and
- that such gas will be free from any lien, charge, encumbrance or adverse claim.

In a beach contract, the buyer protects its position against Transco by taking a warranty in like terms from the seller.

Transco also provides, in its Network Code, that title and risk in gas delivered to the system at a system entry point shall pass to Transco at the relevant point of delivery identified by Transco at each individual system entry point. Echoing this, beach contracts generally assert that title and risk in gas pass at the delivery point. This assertion is not without difficulty. As already noted, 'delivery' is a contractual right of the buyer, as against the seller, to an undivided share in the gas flow. Therefore within the meaning of the Sale of Goods Act 1979, the goods contracted to be sold are, at the moment of 'delivery', unascertained. By section 16 of that Act, no property in goods is transferred to the buyer unless and until the goods are ascertained: see *In re Wait* [1927] 1 Ch 606 and *In re Goldcorp Exchange Ltd* [1995] 1 AC 74. Likewise by section 20, risk passes with property unless otherwise agreed.

However there is authority to support the view that Transco, as the recipient of the aggregate gas flow, can and does take property and also risk at the system entry point: see *Karlshamns Olje Fabriker v Eastport Navigation Corpn. (The Elafi)* [1982] 1 All E.R. 208; [1981] 2 Lloyd's Rep. 679. On this basis, an assertion in beach contracts that title and risk shall pass at the delivery point is perhaps justifiable, provided that the meaning and intent is clear. In the Network Code, it is stipulated that the warranty of title given to Transco shall be treated as satisfied where the user of the system has arranged for delivery, or tender of delivery, of gas to the system by a person or persons who has or jointly have title (at the point of delivery) to such gas and such person or persons jointly pass title to Transco. There is a case for including similar language in a beach contract.

9.2.4 Quantity

Beach contracts stipulate for the trading of quantities of gas measured in energy units, for example kilowatt hours (the measure used by Transco), therms or megajoules.

By and large, participants in the gas spot market trade quantities of gas that are fixed and constant for each gas flow day of the trade performance period ('flat gas'). Whether the seller has fulfilled its quantitative obligations is for determination at the end of each such day. The requirements of Transco with regard to within-day flow rates, and the capabilities of Transco in this respect, are left to be dealt with at an operational level and, subject to what is said in section 9.2.5, generally form no part of the commercial bargain struck between seller and buyer.

A small number of trades give the buyer rights to nominate and vary the quantity of gas to be sold by the seller. Nominations for a Sunday to Sunday week may have to be notified to the seller by perhaps the previous Thursday or Friday. Thereafter, the buyer may, by further notice to the seller, vary the nomination in force by giving, say;

- not less than 24 hours notice before the gas flow day, for a variation of more than 50 per cent;
- not less than 12 hours notice before the gas flow day, for a variation of less than 50 per cent but more than 25 per cent; and
- not less than 6 hours notice before the gas flow day, for a variation of 25 per cent or less.

Notice periods differ, depending upon the capabilities of the seller and the value attached to such rights by the buyer.

In some instances, nomination rights are vested in the seller. Such instances arise principally where the seller is a producer disposing of gas produced in association with crude oil.

Where buyer nomination rights exist, they are almost always accompanied by a take-or-pay provision that obliges the buyer to nominate and take delivery of a minimum quantity of gas during the trade performance period or, alternatively, to pay at the end of the trade performance period for a quantity representing the difference between the stated minimum quantity and the quantity actually taken, if less.

Beach contracts often allow the seller a small tolerance in respect of the quantity of gas delivered. For example, the agreed standard terms and conditions may say that the daily quantity contracted shall be treated as having been delivered even if the actual quantity delivered varies from that contracted by up to plus or minus two per cent on a gas flow day, or plus or minus one per cent over the month as a whole.

It is normally stated in beach contracts that measurement of the quantity of gas delivered shall be in accordance with the standards, methods and practices of Transco at the delivery point. There are two aspects to the process of measurement.

First, a determination is made, by reference to metering and other equipment, of the volume of gas flowing through a system entry point, generally in cubic metres, and of the calorific values of that flow. This allows a calculation to be made of the aggregate quantity of gas, in energy units, that flows through the system entry point on a gas flow day.

Second, sellers of gas receive information from those who have sold gas to them, after the gas flow day, as to the quantity of gas that was delivered. In the case of gas sold by a producer, this information is derived from the allocation and related agreements that govern the entitlement of a producer to gas produced from the offshore field or fields in which he has interests. In turn, this information, in the possession of a subsequent seller, becomes the basis for deciding what quantities have been delivered to its buyers. Some beach contracts, in acknowledgement of the role of allocation agreements, include words to the effect that gas shall be measured in accordance with the relevant allocation agreements.

These two aspects to the process of measurement are reconciled through a claims validation agent. When Transco's Network Code came into effect in March 1996, gas shippers set up a company, Claims Validation Services Limited, to employ claims validation agents having responsibility for reconciling claims to gas at the various system entry points. The agents are told by Transco the aggregate quantity of gas, in energy units, that has flowed through a system entry point on a gas flow day. Producers, sellers and buyers also provide to the agents information about the quantities they have traded at that system entry point on that day. If the aggregate quantities that persons claim to have delivered into Transco's pipeline system differ from the quantity notified by Transco, the claims are adjusted in accordance with rules set out in the various agreements that relate to the work carried out by the agents. The adjusted claim figures are notified to Transco within fifteen business days of the end of each month, to allow Transco to determine the gas transportation and other charges due from gas shippers.

The claims validation rules stipulate that trades with a person who is not a 'principal', that is, not a party to the claims validation agreements, must be left out of account. Accordingly, beach contracts tend to contain cross-warranties that, in respect of any transaction, the parties will be principals to the claims validation arrangements at the delivery point for the duration of the trade performance period.

The claims validation rules are not proof against error and therefore beach contracts have tended to stop short of saying that the quantity of gas delivered shall be that determined by the claims validation arrangements. However, in practice, the figures determined through these arrangements are usually regarded as best evidence of the quantity delivered.

9.2.5 Quality and pressure

The quality and pressure of gas delivered must, for reasons connected with the safety and integrity of Transco's pipeline system, comply with the requirements specified by Transco in this regard. Beach contracts invariably provide as much.

The attainment and detailed management of Transco's requirements is an operational matter between Transco and the operators of the sub-terminal or other producer facilities immediately upstream of a system entry point. Beach contracts do not elaborate on these matters, except in one respect, namely that it is usual to provide that the seller shall use reasonable endeavours to ensure that gas is delivered at uniform hourly rates. This mirrors a corresponding obligation in Transco's Network Code upon a gas shipper who enters gas into the pipeline system.

9.2.6 Seller's failure to perform

A seller may fail to deliver the quantity of gas contracted for on a gas flow day.

In the case of under-delivery, the earliest beach contracts adopted the remedy provided by historic long-term contracts, namely a shortfall provision. Broadly speaking, a shortfall provision compensates a buyer through the recovery of a stipulated percentage of the contract price multiplied by the amount of the under-delivery on the gas flow day. The recovery may be achieved through a discount — typically between 20 and 30 per cent — on the price to be paid for gas delivered in the month or months following that in which the under-delivery has occurred; or by some other means of set-off against amounts otherwise due for gas delivered.

Shortfall provisions had the advantage of offering a simple pre-determined measure of compensation for under-delivery, in circumstances where an assessment of actual loss could be problematic and could involve the buyer in a degree of disclosure, for the purpose of adducing evidence of loss, that could be commercially prejudicial. However this necessarily meant that, in the event, the shortfall provision might not accurately reflect the buyer's actual losses.

This became more significant with the advent of Transco's Network Code. A buyer that is delivering gas into Transco's pipeline system and suffers an under-delivery may, as a result, be left in a situation in which attributable quantities of gas offtaken from the pipeline system at the end of the gas flow day substantially exceed quantities of gas it is treated as having delivered into the system. This excess attracts imbalance charges which were derived, when the Network Code came into force, from the highest price paid by Transco for gas on the gas flow day from the flexibility mechanism — now the On-the-day Commodity Market (OCM) — (the 'System Marginal Buy Price' or 'SMBP'). At times of high demand for gas, the System Marginal Buy Price may be many times greater than the contract price.

Accordingly, newer beach contracts have sought to replace shortfall provisions by a compensation clause associated with market prices or, specifically, the prices generated by the On-the-day Commodity Market. Two formulations are commonly found.

First, compensation may be fixed at the System Marginal Buy Price for the day of the breach, less the contract price, the difference being multiplied by the under-delivery quantity. However, this measure is resisted by some spot market participants on the grounds that the aggregate imbalance of a buyer who suffers an under-delivery may not be such as to cause it to incur imbalance charges calculated wholly or partly at the System Marginal Buy Price. In such circumstances, the buyer will be compensated beyond its actual losses and the amount of the over-recovery could be substantial.

Secondly, compensation may be fixed at the average of prices for both the purchases and acquisitions of gas in the On-the-day Commodity Market (the 'System Average Price' or 'SAP') for the day of the breach, less the contract price, the difference being multiplied by the under-delivery quantity. This is subject to the buyer having the right to claim actual losses incurred, if greater, but capped at the product of the System Marginal Buy Price less the contract price, multiplied by the under-delivery quantity. This second formulation addresses the criticism of the first, in that it prevents a buyer recovering at the System Marginal Buy Price if its actual losses are less. Its disadvantage is that, in order to prove loss greater than the System Average Price, the buyer must show evidence of all quantities of gas delivered into or offtaken from Transco's pipeline system on the gas flow day, something which it may be reluctant to do for reasons of commercial confidentiality.

A buyer that suffers an under-delivery may also face scheduling charges from Transco, if the difference between actual quantities delivered and those nominated to Transco on the day prior to the gas flow day exceeds the tolerance allowed. Scheduling charges are relatively modest but a beach contract may also provide for these to be recouped.

A seller may also fail to perform by over-delivering gas. This can arise against the buyer's wishes because the claims validation rules provide that, where a seller and a buyer report to the agent differing figures in respect of the quantity traded between them, and these differences cannot be otherwise reconciled, the figure reported by the seller prevails. In consequence, if the buyer is delivering gas into the Transco pipeline system at the contractual delivery point, the over-delivery quantity may become part of the aggregate quantity of gas that the buyer is treated as having delivered.

Beach contracts that deal with this issue will perhaps provide for the seller to indemnify the buyer in respect of all costs and charges thereby incurred. The buyer may have suffered system entry capacity overrun charges from Transco, if its available capacity at the system entry point, whether bought from Transco or transferred from another gas shipper, is less than the aggregate of its deliveries into the system. In addition it may face scheduling charges from Transco. A beach contract may rule that the buyer shall be entitled to take the over-delivery quantity free of charge or at the System Marginal Sell Price (SMSP), which is defined by the Network Code as the lowest price received by Transco for gas it sells on the gas flow day from the On-the-day Commodity Market.

A seller may fail to perform by delivering gas that is not in accordance with Transco's specification for gas entering its pipeline system. Transco's Network Code obliges a gas shipper that delivers off-spec gas to indemnify Transco in respect of the costs of clearing and cleaning its pipeline system downstream of the system entry point as may be necessary, provided that the indemnity shall be limited to an applicable liability price multiplied by the off-spec quantity.

Beach contracts oblige a seller to indemnify the buyer in such circumstances, on similar terms.

Transco reserves the right to refuse to accept off-spec gas into its pipeline system. In beach contracts, buyers reserve similar rights.

In practice, Transco, when it is aware that off-spec gas is tendered for delivery into its pipeline system, may nevertheless willingly accept delivery. If so, a buyer under a beach contract is normally also bound to take delivery of such gas.

Beach contracts generally stipulate that a seller, once it is aware of, or anticipates, a failure to perform, should give notice to the buyer of all relevant circumstances. Amongst other things, prompt notice allows a buyer to mitigate its position.

In *National Power PLC v United Gas Company Limited and another* (3 July 1998, unreported) the seller had contracted to sell gas measured volumetrically, in cubic feet. In the course of the performance period, the seller purchased quantities of gas measured in energy units and purported to convert these purchases into volumetrically measured quantities, in order to satisfy its sales obligations. Not knowing the calorific values of the purchased quantities, the seller made these conversions on the basis of estimates of the calorific values. The buyer claimed that the seller was in breach of contract for having failed to deliver goods of the contractual description. Mr Justice Colman found for the buyer.

The circumstances of this case are perhaps unlikely to be repeated in today's UK gas spot market, where trading is almost exclusively in energy units. However, in addition to the detailed contractual analysis that the judgment contains, the case remains interesting in a number of respects.

First, Mr Justice Colman went on to hold that, notwithstanding the seller's breach, the buyer had accepted the gas under section 35 of the Sale of Goods Act 1979. The buyer had entered into a range of onward sales contracts, both at the beach and for consumption of the gas at the premises of end-users. The judge concluded that under these contracts, the gas had been 'delivered', within the meaning of the Sale of Goods Act 1979, when equivalent quantities were offtaken from Transco's pipeline system at supply points. This delivery was an act inconsistent with the continuing ownership of the seller.

Second, the buyer had been suspicious of the performance information given by the seller pursuant to the contract and had requested of the seller various other data, some of which the seller had refused to divulge. The buyer eventually purported to terminate the contract by reason of this refusal, on the grounds that it constituted a material breach of the seller's obligations. The judge held that the refusal did not amount to a material breach, within the meaning of the contract, because it related to the non-performance of contractual obligations which had already occurred and was confined to the quantification of the consequences. It was a breach of an essentially ancillary term and of relatively small commercial consequence. Therefore the termination notice was ineffective.

Thirdly, the buyer argued that the failure of the seller to deliver goods of the contractual description triggered the operation of the shortfall provision in the contract. Having reviewed the construction of the shortfall provision, the judge, at a later hearing, accepted this argument.

9.2.7 Buyer's failure to perform

The physical and operational characteristics of gas spot trading, and the determining nature of the claims validation rules on matters of quantity, restrict the opportunities open to a buyer to wrongfully refuse or otherwise fail to take delivery of gas. As a result, it is uncommon in beach contracts to find provisions that specifically address such circumstances. Rather, it is customary for the parties to agree a minimum quantity of gas that will be taken by the buyer during the performance period and enforce this by a take-or-pay provision. Such an arrangement is customary even where the daily quantity of gas that the buyer has contracted to purchase is not subject to rights of nomination and variation, and therefore cannot be varied by the buyer from day to day.

In a take-or-pay provision, the parties agree, at the time of contracting, the minimum quantity to be taken. They also agree circumstances in which this minimum quantity may be reduced during the performance period. Normally these circumstances will be restricted to *force majeure* events affecting either party, and under-deliveries by the seller. At the end of the performance period, a reckoning takes place. If the reduced minimum quantity is greater than the quantity of gas actually taken by the buyer, the buyer pays to the seller an amount equal to the difference between the two quantities, multiplied by the contract price.

In long-term contracts, it was common to find take-or-pay provisions accompanied by a make-up clause, under which a buyer that had paid for gas in a contract year that it had not taken, could take that gas without further payment, in one or more subsequent contract years after having taken the reduced minimum quantity applicable in the subsequent year. However make-up provisions are not often found in spot trades.

Sellers' concerns regarding the failure of a buyer to perform, tend to centre upon the buyer's obligation to pay. This issue is considered in section 9.4.3.

9.2.8 *Force majeure*

Both sellers and buyers have cause to include *force majeure* clauses in beach contracts. In NBP contracts, as explained in section 9.3.5, the considerations facing the parties are somewhat different.

With regard to beach contracts, the operational risks associated with the production and delivery of gas have traditionally made it attractive to a seller, especially a producer-seller, to have in a sales contract a *force majeure* provision relieving it from liability in circumstances where it is unable to perform contractual obligations for reasons beyond its control. However in a contract for delivery of gas at a gas terminal, at which various parties are trading gas, a gas production failure offshore is unlikely to be enough to relieve a seller from its obligation to deliver gas to its buyer. If gas can be bought at that terminal to satisfy the buyer's requirements, wholly or partly, a seller that fails to do so may have difficulty convincing the buyer that it ought to be relieved from non-performance on grounds of *force majeure*.

A buyer, for its part, faces the risk that Transco may be unable to take gas into its pipeline system because of, for example, an operational constraint on pipeline capacity, and that as a result the buyer is prevented from taking delivery of gas from its seller.

Accordingly it will be attractive also to the buyer for there to be a *force majeure* provision in a beach contract.

Usually, beach contracts reference *force majeure* to the standards of a reasonable and prudent operator. A reasonable and prudent operator is defined along the lines of someone seeking in good faith to perform their contractual obligations and, in so doing and in the general conduct of the undertaking, exercising that degree of skill, diligence, prudence and foresight that would reasonably be expected from a skilled and experienced person engaged in the same type of undertaking under the same or similar circumstances. *Force majeure* is then defined as any event or circumstance not within the reasonable control of a party, or a person, acting and having acted as a reasonable and prudent operator.

The distinction between applying the standard of a reasonable and prudent operator to persons generally, or restricting it to parties to the beach contract, is important. A provision that restricts the application of the reasonable and prudent operator standard to the contractual parties, makes *force majeure* relief available even if the person responsible for the *force majeure* event or circumstance, not being a party to the contract, has been negligent or otherwise culpable.

Force majeure provisions in beach contracts are to the effect that a party shall be relieved of liability to the extent that owing to an event or circumstance of *force majeure* it is unable to perform any of its obligations in relation to a trade. Typically, this general statement is extended by the citation of specific incidents or circumstances that the parties agree either will or will not amount to *force majeure*. For example, it may be stipulated that any failure by any customer of the buyer to take gas shall not amount to *force majeure*.

Beach contracts invariably provide that a party intending to seek relief on grounds of *force majeure* shall, as soon as reasonably practicable, notify the other party of the *force majeure* event or circumstance, give an estimate of the period of time that its inability to perform its obligation is likely to persist, and take such steps as are reasonably practicable to re-establish the conditions that will allow it to resume performance as soon as reasonably possible. A beach contract may also provide that, if a *force majeure* event or circumstance continues beyond a stated period, either party may terminate the trade upon notice to the other.

It is more common for sellers to claim *force majeure* than buyers. In practice a seller affected by a *force majeure* event or circumstance may have sufficient gas to deliver some but not all of the quantities that it has contracted to sell. To deal with this situation, beach contracts often include a clause to the effect that such gas as is available to the seller shall be allocated on a pro-rata basis between itself and all its buyers, proportionate to the quantities to which it and its buyers would otherwise have been entitled.

It is conceivable that an event of *force majeure* could disrupt the performance of a trade for a considerable period of time. Accordingly, a beach contract may state that, if a *force majeure* event continues beyond a specified number of days, either party may thereafter terminate the trade upon notice.

9.3 NBP contracts: performance

9.3.1 Background

The taking by Transco of title to all gas delivered into its pipeline system meant that the concepts of gas trading that underpin beach contracts could only with difficulty be extended to allow, say, trading of gas at pipeline junctions within Transco's pipeline system. Further, the terms upon which Transco transported gas through its pipeline system did not permit any trading of gas within the pipeline system on any other conceptual basis, prior to 1996. NBP contracts only became possible upon the implementation of Transco's Network Code on 1 March 1996.

NBP trading began slowly but soon became immensely popular with spot market participants. The reason for its popularity is that an NBP trade, in performance, is nothing more than the making by Transco of corresponding adjustments to the respective daily imbalances of the seller and buyer with Transco, in line with the quantity agreed to be traded. Therefore the quantities that are the subject of the trade are fixed. There is no place in an NBP trade for tolerances, and the quantity traded is not subject to change as a result of the operation of the claims validation rules, which have no application. For the same reason — as explained in section 9.3.5 — there is little scope for the quantity traded to be vulnerable to claims for *force majeure* relief by either party. Nor, in such a trade, can there be any query about gas quality.

NBP trading, being dependent upon the provisions of Transco's Network Code, is only open to those who have contracted with Transco to be bound by the Network Code. Transco, in compliance with the licensing framework set out in the Gas Act 1986 as amended by the Gas Act 1995, stipulates that as a condition of acceding to the Network Code and becoming a user of Transco's pipeline system, a person must hold a gas shipper licence. An exception has been made in the case of the London Clearing House Limited, which clears the International Petroleum Exchange's natural gas futures contract.

9.3.2 Section C6 of the Network Code

An NBP trade, to be effective, must comply with the terms set out by Transco in Section C6 of its Network Code. These are as follows:

- the quantities subject to the corresponding trade nominations of the two users must be equal;
- a trade nomination must specify the gas flow day, the identity of the user, whether it is a disposing or an acquiring trade nomination, the identity of the user making the

corresponding trade nomination, and the trade nomination quantity;

- a trade nomination may not be made earlier than 30 days before the gas flow day, or between the scheduling start time and the nomination finalisation time (currently 1600 hours and 1700 hours on the day prior to the gas flow day), or later than 0400 hours on the gas flow day;
- a trade nomination will be ineffective and will be rejected by Transco if the corresponding trade nomination is not submitted:

  where the first trade nomination was submitted before the gas flow day, by 0700 hours on the gas flow day,

  otherwise, within 60 minutes before or after the first trade nomination was made;
- a trade nomination may be withdrawn by the user who submitted it at any time before the gas flow day but may not be amended or withdrawn within the gas flow day (but without prejudice to any subsequent trade nomination).

For the purposes of the Network Code, a trade nomination is 'made' by a user where the user has submitted a trade nomination which has not been rejected by Transco in accordance with Section C6. Transco reserves the right to reject a trade nomination if the terms set out above are not met or if either user is in breach of Transco's requirements as to creditworthiness.

For the avoidance of doubt, Section C6 makes it plain that a user may make a trade nomination for a gas flow day irrespective of whether the user delivers gas into, or offtakes gas from, Transco's pipeline system on that gas flow day.

9.3.3 Trade nominations: contractual provisions

NBP contracts place upon the parties contractual obligations that, if performed, will ensure that the terms of Section C6 of the Network Code will be satisfied. In particular, for each gas flow day, within the trade performance period, upon which gas is to be the subject of an NBP trade:

- each party undertakes to make a trade nomination to Transco, being in the case of the seller a disposing trade nomination and in the case of the buyer, an acquiring trade nomination, identifying the other party as the person making the corresponding trade nomination;
- each party undertakes to make its trade nomination for the contracted quantity;

- each party undertakes to make its trade nomination before 0400 hours on the gas flow day or such earlier time as may have been agreed; and
- each party undertakes that, where Transco has accepted the corresponding trade nominations, it shall neither withdraw nor amend its trade nomination without the consent of the other.

The submission of trade nominations to Transco is made through Transco's computer system, UK Link. NBP contracts commonly provide that if UK Link is for some reason unavailable, the parties shall make their submissions by such other means as Transco may provide in the circumstances.

NBP trades, like beach trades, are predominantly for flat gas, and the parties, where possible, tend to make their net trade nomination submissions to Transco en bloc, well in advance of the performance dates to which the trade nominations relate.

Transco stipulates that trade nominations must define the quantity that is the subject of the trade nominations in kilowatt hours. Many spot trades are negotiated in different energy units and therefore parties to such trades agree a means of conversion, the number of decimal places to which conversion is to be taken, and the principles by reference to which numbers will be rounded up or down. If the quantities respectively expressed in trade nominations that are intended to correspond, are not exactly the same, Transco will reject the trade nominations.

Where an NBP trade has been agreed prior to the gas flow day or days that constitute the trade performance period, the parties will seek to ensure that, for each gas flow day, their corresponding trade nominations are submitted and accepted by Transco not later than the time on the previous day by which input and offtake quantities have to be notified to Transco.

In part this is simply good administration. However, spot market participants also wish to provide comfort against the possibility that a counterparty may delay submitting its trade nomination, with a view to leaving open the opportunity to breach the trade and use gas underlying an NBP trade to take advantage of price volatility on the gas flow day. For example, when demand for gas outstrips supply, a seller may be able to secure a price for gas on the gas flow day that is many times greater than the price it has contracted to take in trades previously entered into. The financial return in such circumstances may also be greater than the damages that the seller may be liable to pay a counterparty for breach.

If the parties contract to have their corresponding trade nominations submitted and accepted by Transco on the day prior to the gas flow day, failure by one party to do so crystallises the breach sufficiently early to give the other a reasonable period to mitigate its exposure. An alternative or additional solution is to seek to provide for liquidated damages at a level that deters a party from acting in this way. However, such a formulation is likely to lead to compensation at Transco's System Marginal Price and, as noted in section 9.2.6, many spot market participants have been loath to agree this.

In the NBP 1997 terms and conditions, which are widely used, the approach taken is to oblige the parties to use reasonable endeavours to make their respective trade nominations by, in the case of the seller, 1300 hours on the day before the gas flow day and, in the case of the buyer, by 1600 hours on the day before the gas flow day.

9.3.4 Failure to perform

In NBP trading, a party fails to perform if it fails to submit a trade nomination that accords with its contractual obligations, with the result that its or its counterparty's trade nomination is rejected by Transco. NBP terms and conditions, like the under-delivery provisions in the newer beach contracts, usually include a clause that compensates the counterparty by reference to prices generated by the On-the-day Commodity Market.

The thinking of gas spot market participants regarding levels of compensation for breach of an NBP contract is reflected in the NBP 1997 terms and conditions, which require the parties to elect, at the time of contracting, for Option A or Option B.

In the case of breach by the seller for any day, Option A obliges the seller to pay to the buyer the sum, where positive, of (SMBP–CP) × DQ, where CP is the contract price and DQ is the quantity of gas that was the subject of the trade on that day. Option B obliges the seller to pay to the buyer the sum, where positive, of (SAP–CP) × DQ, unless the buyer can show, and chooses to show, that the actual loss suffered was greater, in which case the seller is obliged to pay to the buyer the sum that represents the buyer's actual loss, capped at the sum calculated in accordance with Option A.

In the case of breach by the buyer for any day, Option A obliges the buyer to pay to the seller the sum, where positive, of (CP–SMSP) × DQ. Option B obliges the buyer to pay to the seller the sum, where positive, of (CP–SAP) × DQ, unless the seller can show, and chooses to show, that the actual loss suffered in respect of that day was greater, in which circumstances the buyer must pay to the seller the sum that represents the seller's actual loss, capped at the sum calculated in accordance with Option A.

The respective merits of these different approaches were discussed in section 9.2.6. In NBP trading, Option A now tends to be more commonly selected than Option B.

9.3.5 *Force majeure*

In an NBP trade, the operational risks associated with gas production, delivery and transportation that face both seller and buyer under a beach contract have no direct relevance to the capability of either party to perform its contractual commitments. As already noted, a user may make a trade nomination for a gas flow day irrespective of whether it delivers gas into, or offtakes gas from, Transco's pipeline system. Of course, the aggregate daily imbalance of a party to an NBP trade may be vulnerable to such operational risks, with the result that the NBP trade leaves the party exposed to daily imbalance charges. However the view of most spot market participants has been that these risks ought not to give grounds for a party to be relieved from obligations to make a trade nomination.

As a result, the *force majeure* provisions found in NBP contracts have a relatively small ambit. Whilst the NBP 1997 terms and conditions, for example, make relief available if a party is by reason of *force majeure* rendered unable wholly or in part to carry out its obligations, these obligations, being restricted to the submission by the parties of trade nominations to Transco as contracted, appear to be limited to circumstances in which Transco is unable or otherwise fails to process or act upon trade nominations. Such circumstances are likely to arise only in the event of a major operational emergency affecting Transco's pipeline system.

The perception that *force majeure* relief has a very limited scope in NBP trading has been an important factor in its development.

9.4 Price, billing and payment

9.4.1 Price

A seller that performs its obligations is entitled to payment from the buyer of the agreed price. Beach and NBP contracts always include provisions to this effect.

The agreed price — typically referred to as the contract price — is quantified by reference to the energy unit traded. The energy unit predominantly traded is the therm, and prices are generally in pence and fractions of pence to not less than two decimal places.

In many trades, the contract price is fixed for the duration of the performance period. However it is not uncommon to find price indexation, whereby the price payable by the buyer is determined by reference to prices derived from trading of the International Petroleum Exchange's natural gas futures contract, or from price assessments published by one of the daily reporters, for example *European (formerly British) Spot Gas Markets*, *Petroleum Argus* or *Platts*. In a trade in respect of which the duration of the performance period is relatively long, the parties will normally make provision for an alternative index, should the index specified in the contract cease to be published prior to the expiry of the performance period.

9.4.2 Billing

In accordance with practice in older long-term gas sales contracts, beach and NBP contracts almost always provide for billing in arrears on a monthly basis. The seller commits to sending to the buyer a monthly statement, with an invoice, on or before the tenth day following each month in the period for performance of the trade. The buyer commits to paying the invoice on the twentieth day of the month or on the tenth day after receipt, whichever is the later.

The contents of the monthly statement are usually prescribed by the contract. The intention is that the seller should set out sufficient information, for each day of the month to which the statement relates, to enable the buyer to understand how the invoiced amount has been reckoned.

In beach contracts, specific provision is often made for a monthly statement to be adjusted, by means of a subsequent monthly statement or otherwise. As noted in section 9.2.4, the claims validation agents have until fifteen business days after the end of a month to notify claims figures to Transco. In practice, the calculation of such figures is not complete by the date upon which the seller must invoice the buyer, namely the tenth day following the month end. This leaves open the possibility that the invoiced quantities may differ from those eventually validated by the agents.

Some contracts also provide that, after the end of the period for performance of the trade, the seller must provide a reconciliation statement to the buyer, together with any further invoice thereby made necessary. In the case of a contract pursuant to which the buyer has rights to nominate and vary the quantity of gas to be sold, the reconciliation statement will perhaps deal with the computation of the amount payable by the buyer, as a result of its having taken less than the minimum quantity stipulated by the contract. It may also deal with any differences between the quantities invoiced on the basis of the final monthly statement, and those later validated by the claims validation agents.

9.4.3 Taxes, duties, etc

The buyer will be required to pay Value Added Tax (VAT) associated with the quantities sold. As for other taxes, royalties, duties and other impositions, it is normal to leave these with the party that would otherwise be required by law to pay them (see Chapter 15).

Spot market trades, being mainly short-term and for comparatively modest quantities of gas, tend to be silent regarding any new tax that may be introduced.

9.4.4 Payment and failure to pay

It is usually provided that payment shall be made in sterling by direct bank transfer or equivalent instantaneous transfer of funds, to an account notified for this purpose by the payee. The introduction by the European Union of the euro, as a pan-EU currency, has not, to date, impacted upon contractual provisions for payment within Great Britain.

The parties may also provide for the situation where the due date of payment under the contract is not a day upon which the banks are open for business. In such circumstances, payment may become due on the previous or next banking day, or the banking day, whether before or after, that is nearest to the due date.

Typically, there will be many trades in place between any two spot market participants. It is normal for them to arrange for all payments due between them to be set off against each other, so that one netted amount is paid on the due date.

Contracts will normally state that, in the event that any amount invoiced is disputed, any amount that is not disputed should nevertheless be paid on or before the due date for payment.

If payment is not made on or before the due date, provision is invariably made for interest to be payable by the defaulting party until such time as payment is eventually made. Further, it is common, if the failure to pay all or part of any amount due continues, for the other party to have the right to suspend or terminate the trade, if it is ongoing.

9.5 Information and confidentiality

9.5.1 Exchange of information

It is generally the case that each party agrees to provide to the other such information as is available to it as may reasonably be required by the other, in order to perform its obligations and enforce its rights in relation to a spot trade.

The provision of such information is subject to any restrictions on disclosure of information by which a party may otherwise be bound. In practice, these may be substantial, because spot market participants tend to make their trades subject to wide ranging confidentiality clauses.

9.5.2 Confidentiality

Confidentiality clauses start from the position that a party shall not disclose the terms and conditions of a trade or any information provided in relation to the trade, without the prior consent in writing of the other party. However, such clauses usually go on to list a series of exceptions in respect of which consent will not be required. These exceptions can be grouped under a number of headings:

- disclosure in compliance with legal/regulatory requirements, that is, where disclosure may be compelled by any applicable laws, by judicial process, by any regulatory agency having jurisdiction, or by the rules of any recognised investment exchange.
- disclosure to a party's agents, that is, directors, employees, affiliated companies, and persons professionally engaged by the party. Disclosure of confidential information to a party's agents is normally conditional upon the party requiring them to treat the information disclosed as confidential.
- disclosure to a party's financiers, that is, the party's banks or other financial institutions engaged in the financing of the party's business activities. As in the case of a party's agents, disclosure of confidential information to financiers is normally conditional upon the financiers being required to treat it as confidential.
- disclosure in connection with performance of the trade, that is, to Transco and claims validation agents, in so far as necessary. Both are subject to stringent confidentiality obligations in respect of information so disclosed. At the time of entering into a trade, the parties may also agree that

details be disclosed to the publishers of spot market price assessments.

- disclosure to an intending assignee, who must in turn be required to treat the disclosed information as confidential.

9.6 Assignment

In spot gas trading, as is often the case when parties contract, the right to assign the benefits of the trade is subject to obtaining the prior written consent of the other party. However it is generally provided that consent may not be unreasonably withheld.

As it is common for producers to trade their assets with others, assignments and novations are required in relation to long-term contracts in which producers sell gas from a gas field identified in the contract. This is not the case with spot trades, which are not ostensibly asset-based. In practice, assignment provisions in beach and NBP contracts tend to be called into play when a party is involved in corporate restructuring.

9.7 Termination

9.7.1 Background

It was noted in sections 9.2.8 and 9.4.4 that parties to a trade reserve the right to terminate the trade in the event of extended *force majeure* or non-payment. Beyond this, it is usual for parties to provide for termination wherever the basis for further mutual performance of a trade has been undermined or is in doubt.

9.7.2 Financial failure

Parties to a trade invariably agree that, where legal processes or proceedings associated with financial failure are invoked by or in respect of one of them, either the trade shall terminate automatically or the other party shall have the right to terminate the trade with immediate effect, by giving notice.

The right to terminate is often extended so as to operate:

- in the event of a party failing to provide or maintain any security — for example a guarantee — agreed to be put in place as a condition of the trade;
- in the event of a material adverse change in the financial standing of a party that, in the reasonable opinion of the other, affects its ability to perform its obligations in respect of the trade.

In such circumstances, a period of perhaps 48 or 72 hours may be stipulated, following service of the notice to terminate, for the party under scrutiny to provide assurances to the other's satisfaction.

9.7.3 Material breach

Typically, the parties will also allow notice of termination to be given where one of them is materially in breach of any of its obligations in respect of a trade. Given that the terms of trades usually contain a range of subsidiary obligations, breach of which may not affect or threaten performance of the primary obligations to deliver and pay for gas, or, as the case may be, to make (and make payments in respect of) corresponding trade nominations, the right to terminate for material breach could be far-reaching, although the decision on this point in *National Power PLC v United Gas Company Limited and another* (3 July 1998, unreported) — see section 9.2.6 — suggests that the courts will take a cautious view. In order to contain this right within reasonable bounds, it is normal to prescribe that before it may be exercised, in the case of a breach capable of remedy, prior notice must be given specifying the material breach and requiring it to be remedied.

Thereafter the right to terminate is only exercisable if the party upon whom notice has been served has failed, within perhaps ten days (or other specified period) of having received such notice, to take substantial steps to remedy it.

9.7.4 Effect of termination

Out of caution, the contract may state that termination shall not affect rights accrued prior to termination, or any terms that continue in force after termination. Further, it may provide mechanisms for the calculation and making of payments from one party to the other following termination. In order to manage credit exposure, parties may put in place cross-default provisions, to the effect that the termination of a trade will bring about the termination of all gas and other trades between the parties.

9.8 Miscellaneous

9.8.1 Liabilities

Parties almost always include a clause or clauses limiting their respective liabilities, in contract, tort or otherwise, for consequential or indirect losses, except where expressly stated in the contract. To the extent that such clauses are couched in general terms, there is doubt about their effectiveness, and parties, where able to do so, will particularise the losses that they wish to exclude.

9.8.2 Notices

The degree of ongoing communication necessary to the performance of both beach and NBP contracts makes it important to indicate clearly how and where parties to a trade are to make contact with each other. The timing of notices may also be critical and it is customary to include provisions governing when a notice will be treated as having been received.

9.8.3 Waiver, variation and entirety

Parties also attempt to safeguard the integrity of their bargain by employing provisions commonly found in commercial contracts:

- restricting the waiver of any breach to the breach to which it is specifically related;
- stipulating that any variation of a trade, to be valid, must be in writing and signed by an authorised representative of each party; and
- excluding and superseding any representations made by either party prior to the trade being entered into.

9.8.4 Applicable law and dispute resolution

UK gas spot trades are made subject by the parties to English law, and the parties generally submit to the exclusive jurisdiction of the English courts. The absence from both beach and NBP contracts of issues having a high degree of technicality has meant that there is little demand for the appointment of experts to resolve disputes. Although in some areas of commerce, arbitration is a popular means of obtaining an adjudication on a dispute, it has had few enthusiasts amongst participants in gas spot trading.

9.9 Zeebrugge and other European trades

Contract terms and conditions for gas trading at Zeebrugge were pioneered by participants in the UK gas spot market, in response to the construction and opening, in October 1998, of the UK Interconnector gas pipeline from Bacton. These terms and conditions have much in common with those employed in UK beach trading. In particular, they provide for the seller to deliver, and give title in, gas to the buyer at a specified delivery point.

As in the case of UK beach trading, contract terms and conditions for gas trading at Zeebrugge reflect the requirements of the relevant pipeline operators. Accordingly the terms upon which Distrigas[1] S.A., as owner and operator of the Belgian gas pipeline system, takes delivery of, conveys, and allows the offtake of gas from that system, have had an important influence on specific issues. Of especial note are:

- Distrigas requires information to be given on an hourly basis as to quantities of gas delivered;
- the specification that gas must meet in order that Distrigas will accept it into its pipeline system differs slightly from Transco's specification; and
- Distrigas itself validates claims to quantities of gas between trading participants.

At first, Zeebrugge trades fixed as the delivery point the junction of the UK Interconnector and the Distrigas pipeline system. However, early in 1999, major participants in gas trading at Zeebrugge opened discussions with Distrigas to try to establish terms and conditions of trading and operating procedures that would be standard for Zeebrugge gas trading, with a view to promoting transparency and market liquidity.

The result was the publication late in 1999 of Zeebrugge Natural Gas Trading Terms and Conditions (ZBT 99) and a Hub Services Agreement (HSA 99). Both of these documents have recently been revised and are now known – in their revised forms – as ZBT 2001 and HSA 2001 respectively[2]. They identify, as the delivery point for gas trades, the Zeebrugge Hub, being a point marked as such within the Interconnector Zeebrugge Terminal Distrigas, part of the Distrigas pipeline system immediately downstream of the UK Interconnector. For trading purposes, Distrigas provides gas transit services to and from the Zeebrugge Hub.

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[1] Fluxys is now the Belgian system operator (www.fluxys.net).

[2] Copies of ZBT 99, ZBT 2001 and HSA 2001 can be downloaded from the Huberator website (www.huberator.com).

Under ZBT 2001 each party to a trade at the Zeebrugge Hub, for the purpose of delivering gas, has two primary obligations:

- it must make a trade nomination of a daily and hourly quantity to the Hub Operator, a Distrigas subsidiary called Huberator S.A., the quantities to be nominated being those agreed for the trade by the parties; and
- it must, in the case of the seller, make the matched quantity available for offtake by the buyer at the Zeebrugge Hub, and in the case of the buyer, offtake that quantity.

Breach of either of these obligations by a party entitles the other to damages that are determined by reference to a formula. The formula takes the difference between, on the one hand, the contract price and, on the other hand, a published market price, relevant to the time of default, that is adjusted in favour of the non-defaulting party.

ZBT 2001 includes a *force majeure* provision in respect of events or circumstances beyond the control of a party acting as a reasonable and prudent operator. Events which, provided they satisfy this definition, are stated to amount to *force majeure*, include forces of nature and accidents to any transportation facilities or other transporter plant or equipment necessary for the implementation of the trade. The party not claiming *force majeure* has the right to terminate a trade in the face of the *force majeure* event continuing for a period equivalent to 25 per cent of the supply period or a period of 60 days or more.

ZBT 2001 stipulates that trades shall be governed by and construed in accordance with Belgian Law. Disputes are to be settled by arbitration under the Rules of Arbitration of the International Chamber of Commerce in Paris.

Gas trading also takes place at other European gas pipeline junctions. The European Federation of Energy Traders - EFET - has recently published a draft EFET Gas Master Agreement[3], with the intention that this Agreement becomes a template that participants can adapt for use at any trading point.

[3] Copies of the draft EFET Gas Master Agreement can be obtained from the EFET website (www.efet.org).

9.10 Conclusion

By comparison with contractual forms in use in unrelated areas of commodity trading, beach and NBP contracts were relatively simple in conception. This reflected, to a considerable degree, the wish of the first traders to avoid complexity and uncertainty.

However the UK gas spot market and the terms of Transco's Network Code, continue to evolve. The quantities of gas traded have grown enormously, and the opening of the UK Interconnector pipeline between Bacton and Zeebrugge and the development of gas trading elsewhere in Europe have prompted further growth and introduced additional participants. More recently, the collapse of Enron, a major participant in the market, has caused others to look long and hard at the terms and conditions under which they trade. All these factors are beginning to lead to revisions which will bring about more exacting and sophisticated forms of contract.

Appendix 9.1 NBP 1997 terms

SHORT-TERM FLAT NBP TRADING TERMS AND CONDITIONS

1 *Definitions and Interpretation*

1.1 The following words or phrases, where they appear in these terms and conditions or in a Confirmation, shall have the meanings respectively ascribed to them.

"Accurate Trade Nomination" shall mean in respect of a Day and a quantity of Gas, a Trade Nomination made by a Party which complies with the Code Credit Limits and Clause 4.1.3 before 0400 hours on the Day (being in the case of the Seller a Disposing Trade Nomination and in the case of the Buyer an Acquiring Trade Nomination) for the Daily Quantity identifying the other Party as the person making the corresponding Trade Nomination;

"Acquiring Trade Nomination" shall have the meaning specified in the Network Code;

"Affiliate" shall mean any holding company or subsidiary company of a Party or any company which is a subsidiary company of the holding company of a Party and the expressions "holding company" and "subsidiary" shall have the meanings respectively ascribed to them by section 736 Companies Act 1985;

"Argus Gas Price" shall mean the bid price where the non-defaulting Party is the Buyer or the offer price where the non-defaulting Party is the Seller as published on a Day for the remainder of the Supply Period by Petroleum Argus Ltd in Petroleum Argus European Natural Gas;

"Banking Day" shall mean a day (other than a Saturday or a Sunday) on which the clearing banks in London are open for business;

"Buyer" shall mean the Party required to make Acquiring Trade Nominations pursuant to the Transaction;

"Code Contingency" shall have the meaning specified in the Network Code;

"Code Credit Limit" shall have the meaning specified in the Network Code;

"Confirmation" shall mean a document that incorporates these terms and conditions by reference and confirms the details of the Transaction. The Confirmation shall be substantially in the form of the Schedule hereto;

"Contingency Procedures" shall have the meaning specified in the Network Code;

"Contract Price" shall mean the sum agreed as such for the transaction, exclusive of VAT and other applicable taxes;

"Daily Imbalance" shall have the meaning specified in the Network Code;

"Daily Quantity" shall mean the daily quantity of Gas agreed between the Parties as such for the Transaction;

"Day" shall mean the period beginning at 0600 hours on a day and ending at 0600 hours on the following day;

"Disposing Trade Nomination" shall have the meaning specified in the Network Code;

"Early Termination Payment" shall be an amount payable on termination in accordance with Clauses 10.4, 10.5 and 10.6;

"Force Majeure" shall mean any event or circumstance beyond the reasonable control of a Party which totally prevents a Trade Nomination from being submitted by such Party to Transco or from being received and taken into account by Transco in determining such Party's Daily Imbalance;

"Gas" shall have the meaning specified in the Network Code;

"Gas Flow Day" shall have the meaning specified in the Network Code;

"Heren Gas Price" shall mean the bid price where the non-defaulting Party is the Buyer or the offer price, where the non-defaulting Party is the Seller as published on a Day for the remainder of the Supply Period by PH Energy Analysis Ltd, in British Spot Gas Markets;

"IPE" shall mean the International Petroleum Exchange;

"IPE Gas Price" shall mean the IPE settlement price as published by the IPE on that Day for the remainder of the Supply Period;

"LIBOR" shall mean, in respect of a month, the one month London Interbank Offered Rate (expressed as a percentage per annum) in sterling as notified by National Westminster Bank plc at which a deposit of a principal sum equal to the relevant sum in question under these terms and conditions as would have been offered by such bank to prime banks in the London Interbank Marker at such banks' request at or about 1100 hours on the first Banking Day in such Month for a period commencing on such Banking Day and ending on the first Banking Day in the next succeeding Month;

"Month" shall mean a period beginning at 0600 hours on the first day of a calendar month and ending at 0600 hours on the first day of the following calendar month;

"Monthly Statement" shall have the meaning specified in Clause 6.1;

"NBP Trade" shall mean, in respect of a quantity of Gas, where:

(a) in respect of any Day two Users make corresponding Trade Nominations in respect of that quantity of Gas subject to and in accordance with Section C6 of the Network Code, and

(b) neither Trade Nomination is amended or withdrawn thereafter), the deduction by Transco of that quantity of Gas in determining for that Day the Daily Imbalance of the User making the Disposing Trade Nomination and the addition by Transco of that quantity of Gas in determining for the same Day the Daily Imbalance of the User making the Acquiring Trade Nomination;

"Network Code" shall mean the document, as modified from time to time, setting out transportation arrangements established by Transco pursuant to its public gas transporter's licence;

"Party" shall mean one or other of the parties to the Transaction;

"Pricing Indices" shall mean the Heren Gas Price and the Argus Gas Price and the IPE Gas Price;

"Seller" shall mean the Party required to make Disposing Trade Nominations pursuant to the Transaction;

"Supply Period" shall mean the period during which, pursuant to the Transaction, the Parties shall make NBP Trades, such period commencing and terminating on the Days agreed for the Transaction;

"System Average Price" shall have the meaning specified in the Network Code;

"System Marginal Buy Price" and **"System Marginal Sell Price"** shall have the respective meanings specified in the Network Code;

"Therm" shall mean one hundred and five million five hundred and six thousand joules (105,506,000 J);

"Trade Nomination" shall have the meaning specified in the Network Code;

"Transaction" shall mean an oral or written agreement to undertake one or more NBP Trades such agreement to include, inter alia, these terms and conditions, details of the Supply Period, the Daily. Quantity, and the Contract Price;

"Transco" shall mean BG plc or any successor to the BG plc public gas transporter licence;

"UK Link" shall have the meaning specified in the Network Code;

"User" shall have the meaning specified in the Network Code;

"Week" shall mean a period of seven (7) days beginning at 0600 hours on any Sunday and ending at 0600 hours on the following Sunday;

1.2 Any reference in these terms and conditions to a Transaction includes any permitted assignment, novation, supplement or amendment thereto;

1.3 Any reference to a Clause or Clauses is a reference to a clause or clauses in these terms and conditions;

1.4 Words in the singular may be interpreted as including the plural, and vice versa;

1.5 Any reference in these terms and conditions to a statute or statutory instrument or order is a reference to that statute, statutory instrument or order as from time to lime amended, re-enacted or supplemented;

1.6 In the event of conflict between the terms of a Confirmation and these terms and conditions, the terms of the Confirmation shall prevail;

1.7 Any reference in the Transaction to a quantity of Gas shall mean a quantity expressed in Therms. Any reference in the Transaction or the Confirmation to time shall be to the time in London.

2 Confirmation Procedure

2.1 The Seller shall, within three (3) Banking Days of a Transaction being entered into, send by facsimile transmission to the Buyer a signed Confirmation recording the details of the Transaction;

2.2 If the Buyer is satisfied that the Confirmation accurately reflects the terms of the Transaction the Buyer shall sign and return the Confirmation by facsimile transmission to the Seller within three (3) Banking Days of receipt of the Confirmation;

2.3 If the Buyer is not so satisfied, the Buyer shall inform the Seller of any inaccuracies. The Seller shall, if it agrees that the Confirmation is inaccurate, issue a new Confirmation and the provisions of Clause 2.1 shall apply;

2.4 If the Buyer does not return the Confirmation, duly signed, in accordance with Clause 2.2, or notify the seller of any inaccuracy in accordance with Clause 2.3, the Buyer shall be deemed to accept the Confirmation;

2.5 If the Buyer has not received a Confirmation from the Seller within three (3) Banking Days of a Transaction being entered into, the Buyer shall send the Seller a Confirmation, and Clauses 2.2, 2.3 and 2.4 shall apply mutatis mutandis in relation to such Confirmation by replacing in such clauses all references to "Buyer" with "Seller" and "Seller" with "Buyer";

2.6 Subject to Clause 2.4, on signature by both Parties, the Confirmation shall, save in the event of manifest error, prevail over any oral or written agreement in respect of the Transaction;

2.7 The Parties hereby consent to the recording of telephone conversations in respect of the Transaction;

2.8 Failure or persistent failure by the Seller or the Buyer to send a Confirmation shall not be a material breach of the Transaction.

3 Representations and Warranties

Each Party represents and warrants to the other that it has obtained and will maintain at all times during the Supply Period all licences, authorisations, permits, consents and other approvals necessary to enable it to fulfil its obligations under the Transaction and that it is and will remain a party to the Network Code.

4 NBP Trades

4.1 Trade Nominations

4.1.1 Each Party shall in respect of a Day within the Supply Period for which the Daily Quantity is greater than zero make an Accurate Trade Nomination;

4.1.2 If, on any such Day, UK Link is affected by a Code Contingency and which affects a Party, such Party shall submit its Trade Nomination by the means and in the manner provided for in the Contingency Procedures;

4.1.3 Trade Nominations shall be made in kilowatt hours, for which purpose the conversion from Therms shall be calculated in accordance with the following formula:

K = 29.3071 x T

rounded to the nearest kilowatt hour, an exact half being rounded upwards; where "K" is the quantity expressed in kilowatt hours and "T" is the quantity expressed in Therms;

4.1.4 Where in respect of a Day the Trade Nominations submitted by the Parties pursuant to the Transaction are considered not to be effective and are rejected by Transco in accordance with section C6 of the Network Code:

(a) a breach by the Buyer shall be deemed to have occurred if the last Accurate Trade Nomination notified to Transco in respect of the Transaction was made by the Seller; and

(b) a breach by the Seller shall be deemed to have occurred if the last Accurate Trade Nomination notified to Transco in respect of the Transaction was made by the Buyer;

4.1.5 Where Transco has accepted an Accurate Trade Nomination, neither Party shall, unless otherwise agreed by the Parties, amend or withdraw such Accurate Trade Nomination;

4.1.6 The Parties shall use their reasonable endeavours to make Accurate Trade Nominations by, in the case of the Seller, 1300 hours on the Day before the Gas Flow Day and, in the case of the Buyer, by 1600 hours on the Day before the Gas Flow Day.

4.2 NBP Trade: breach by the Seller

Save and except in respect of an event of *Force Majeure*, if for any Day the Seller is in breach of Clauses 4.1.1, 4.1.2 or 4.1.5, the Seller shall pay to the Buyer either:

A. the sum, where positive, of (SMBP–CP) x DQ, where "SMBP" is the System Marginal Buy Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity; or

B. the sum, where positive, of (SAP–CP) x DQ, where "SAP" is the System Average Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity, unless the Buyer can show that the actual loss suffered in respect of that Day was greater, in which circumstances the Seller shall pay to the Buyer such sum as represents the Buyer's actual loss, such payment to be no greater than the amount calculated in accordance with 4.2A.

The Parties shall specify for the Transaction the basis of compensation payable in the event of a breach.

Payment in accordance with the provisions of this Clause 4.2 shall be in full and final satisfaction of the right of the Buyer and the sole remedy available to the Buyer in respect of a breach by the Seller of Clause 4.1 howsoever caused and even where caused by the negligence or breach of duty of the Seller except for any other remedies expressly provided in the Transaction.

4.3 NBP Trade: breach by the Buyer

Save and except in respect of an event of Force Majeure, if for any Day the Buyer is in breach of Clauses 4.1.1, 4.1.2 or 4.1.5, the Buyer shall pay to the Seller, either:

A. the sum, where positive, of (CP–SMSP) x DQ where "SMSP" is the System Marginal Sell Price for that Day, "CP" is the Contract Price and "DQ" is the Daily Quantity; or

B. the sum, where positive, of (CP–SAP) x DQ where "SAP" is the System Average Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity, unless the Seller can show that the actual loss suffered in respect of that Day was greater, in which circumstances the Buyer shall pay to the Seller such sum as represents the Seller's actual loss, such payment to be no greater than the amount calculated in accordance with 4.3A.

The Parties shall specify for the Transaction the basis of compensation payable in the event of a breach. Payment in accordance with the provisions of this Clause 4.3 shall be in full and final satisfaction of the rights of the Seller and the sole remedy available to the Seller in respect of a breach by the Buyer of Clause 4.1 howsoever caused and even where caused by the negligence or breach of duty of the Buyer except for any other remedies expressly provided in the Transaction.

4.4 Payment of Compensation

Any amount due under either:

(a) Clauses 4.2A or 4.3A; or

(b) Clauses 4.2B or 4.3B where the amount for the purpose of this Clause 4.4 shall be on the basis of SAP, unless the Seller under Clause 4.2B or the Buyer under clause 4.3B has agreed in writing to a greater level of actual loss;

may, at the election of the non-breaching Party, be set-off against amounts due or becoming due under Clause 6.

5 The Contract Price

In respect of a Transaction:

5.1 the Buyer shall pay the Seller in arrears for each NBP Trade a sum calculated by multiplying the Contract Price by the Daily Quantity;

5.2 the Buyer shall pay any VAT in relation to each NBP Trade on receipt of appropriate tax invoices from the Seller and shall ensure that all royalties, taxes, duties and other sums legally payable by the Buyer arising as a result of each NBP Trade are paid;

5.3 the Seller shall ensure that all royalties, taxes, duties and other sums legally payable by the Seller arising as a result of each NBP Trade are paid.

6 Billing and Payment

6.1 On or before the tenth (10th) day of the Month following each Month which is wholly or partly in the Supply Period the Seller shall send to the Buyer a statement ("Monthly Statement") which shall show for the preceding Month:

6.1.1 the quantity of Gas in respect of which NBP Trades have been effected on each Day in that Month;

6.1.2 the quantity of Gas in respect of which the Contract Price is payable and the resultant sum owing to the Seller;

6.1.3 the Contract Price;
6.1.4 any amount owing from one Party to the other or already paid or set-off under Clause 4A or 6.7;
6.1.5 the net amount payable from one Party to the other after taking into account all the matters set out above, and
6.1.6 VAT and any other applicable taxes;
6.2 On the twentieth (20th) day of the Month in which the Monthly Statement is received by the Buyer or the tenth (10th) day after receipt, whichever is the later ("the due date"), the Buyer or the Seller, as the case may be, shall pay to the other Party the net amount payable in accordance with the Monthly Statement.
6.3 Payment shall be made by the due date in sterling by direct bank transfer or equivalent transfer of immediately available funds to the Party to whom it is due and to the credit of the account specified by that Party;
6.4 If the due date for payment is not a Banking Day then payment shall be made on the previous Banking Day.
6.5 If a Party disputes any sum shown in the monthly statement as being payable by that Party, it shall make payment of any undisputed amount on or before the due date for payment and shall give notice of the amount in dispute and the reasons therefor to the other Party. The Parties shall seek to settle the disputed amount as soon as possible.
6.6 If a Party fails to pay to the other Party by the due date for payment any amount due:
6.6.1 interest shall be payable on that amount at a rate equal to the base lending rate for sterling of National Westminster Bank plc applicable from time to time plus three (3) percent compounded annually from the date when the payment is due until and including the date the payment is made;
6.6.2 the Party to whom the amount is due may terminate the Transaction in accordance with Clause 10.2;
6.6.3 the Party to whom the amount is due may, upon notice to the Party who has failed to pay, suspend the Transaction until such time as payment is received;
6.7 A Party shall be entitled to set off against any undisputed amounts which it is due to pay to the other Party in respect of any or all Transactions with such Party, any undisputed amounts that it is due to receive from such Party.

7 Force Majeure

7.1 If a Party is by reason of *Force Majeure* rendered unable wholly or in part to carry out its obligations in accordance with Clause 4, then upon notice in writing of such *Force Majeure* from the Party affected to the other Party as soon as reasonably practicable after the occurrence of the event or circumstances relied on, the Party affected shall be relieved of liability to the extent that it is in breach by reason of *Force Majeure* and for the period during which such *Force Majeure* persists, provided that:

7.1.1 the Party seeking relief under this Clause 7 shall advise the other party as soon as practicable of the event or circumstance constituting *Force Majeure* together with its estimate of the likely effect of such *Force Majeure* on its ability to perform its obligations hereunder and of the likely period of such *Force Majeure*; and

7.1.2 the Party affected shall use all reasonable endeavours to terminate or overcome the event or circumstance constituting *Force Majeure*;

7.2 Either Party may terminate a Transaction by giving three (3) Banking Days notice to the other if *Force Majeure* in respect of that Transaction continues for seven (7) Days or more.

8 Information and Confidentiality

The terms and conditions of the Transaction and all information provided thereunder shall be treated as confidential and shall not be disclosed without the prior written consent of the other Party, save that consent shall not be required for disclosure:

8.1 to directors, employees or Affiliates of either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

8.2 to persons professionally engaged by either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

8.3 to any government department or agency having jurisdiction over that Party;

8.4 to any bank or other financial institution in relation to the financing of either Party's business activities, provided that the bank or other financial institution, as the case may be, is required by that Party to treat the information disclosed as confidential;

8.5 to the extent required by any applicable laws, judicial process or the rules and regulations of any recognised stock exchange;

8.6 to any intending assignee of the rights and interests of either Party under the Transaction provided that such intending assignee in turn is required by that Party to treat the information disclosed as confidential;

8.7 to Transco for the performance of the Transaction;

8.8 to the extent that such information is in or lawfully comes into the public domain other than by breach of this Clause 8; or to price reporting agencies in respect of Contract Price; Supply Period and Daily Quantity only.

9 Assignment

9.1 Subject to Clause 9.2, neither Party shall assign to any person any of its rights or obligations in respect of a Transaction without the written consent of the other Party, which consent shall not be unreasonably withheld. For these purposes it shall be unreasonable to withhold consent in the case of an assignee that is demonstrably capable of fulfilling the obligations of the assignor in respect of a Transaction;

9.2 A Party may assign its rights, and obligations in respect of a Transaction to an Affiliate on notice to, but without the consent of the other Party provided that the assignor shall not be relieved of any obligations that such Affiliate fails to perform.

10 Term and Termination

10.1 The non-defaulting Party may terminate the Transaction forthwith by giving notice to the other Party:

10.1.1 in the event of the other Party becoming insolvent, ceasing to trade or having a receiver, liquidator, administrator or administrative receiver appointed over some or all of its assets or if proceedings are commenced for its dissolution or winding up (other than a voluntary winding up for the purposes of solvent amalgamation or reconstruction); or

10.1.2 in the event of the other Party being in breach of Clause 3; or

10.1.3 in the event of the other Party failing to provide or maintain security for performance of its financial obligations as agreed at the date of the Transaction; or

10.1.4 in the event of a material adverse change in the financial standing of the other Party when compared to such Party's financial standing as at the date of the Transaction which change affects its ability to perform its financial obligations in respect of the Transaction, and such Party fails to provide reasonable security for the performance of its financial obligations in respect of the Transaction within three (3) Banking Days of the other Party's request therefore.

10.2 The non-defaulting Party may terminate the Transaction by giving five (5) Banking Days' notice to the other Party in the event that other Party:

10.2.1 is materially in breach of any of its obligations under the Transaction;

10.2.2 fails to pay the amount specified in the Monthly Statement in accordance with Clause 6; provided that the Party in breach has failed to remedy the breach before expiry of the notice period. In the case of the breach being remedied, the notice is deemed not to have been given.

For the purpose of this Clause 10.2 a persistent failure by one Party to make Trade Nominations in respect of a Transaction shall be deemed to constitute a material breach.

10.3 The termination of the Transaction, however occurring, shall not affect any rights or obligations that may have accrued to either Party prior to termination.

10.4 Following termination in accordance with Clauses 10.1.1, 10.1.2 or 10.2, one Party shall pay to the other the Early Termination Payment within five (5) Banking Days of notification of the amount of the Early Termination Payment in accordance with Clauses 10.5, 10.6 and 10.7.

10.5 The Early Termination Payment shall be the amount (if any) calculated by the non-defaulting party as follows:

(MV–RV)–I where the non-defaulting party is the Buyer,

or

(RV–MV)–I where the non-defaulting party is the Seller,

where:

(a) subject to Clause 10.6, **"MV"** is the market value of the Transaction calculated as follows:

sum of **(D x DQ) x GRP**

where:

"D" is the number of Days from the date of termination to the end of the Supply Period on which the Parties had agreed in accordance with the Transaction to enter into NBP Trades;

"DQ" is the Daily Quantity for each D;

"GRP" is the Gas Reference Price, which is the average of the Pricing Indices published on the date of termination for each D.

(b) **"RV"** is the remaining contract value calculated as follows:

(D x DQ) x CP

where:

"D" is the number of Days from the date of termination to the end of the Supply Period on which the Parties had agreed in accordance with the Transaction to enter into NBP Trades;

"DQ" is the Daily Quantity for each D;

"CP" is the Contract Price;

(c) "I" is the amount by which the sum of MV–RV or RV–MV as applicable is discounted to reflect the present day value as at the termination date. The rate of interest for the purpose of this calculation shall be equal to LIBOR as quoted at the date of termination or the first Banking Day after the date of termination from the due date for payment of each future invoice and the deemed due date for payment of future invoices shall be the 20th of each month.

10.6 Where none or only one of the Pricing Indices is available to calculate the Early Termination Payment, then the Early Termination Payment shall be calculated by taking the average of three reasoned equations, such reasons to be reasonable, from three experts, appointed by the non-defaulting Party.

11 Liabilities

Except as otherwise expressly provided herein, neither Party shall be liable to the other, whether in contract, tort or otherwise at law, for any loss of use, profits, contracts, production, revenue or for business interruption or for any consequential or indirect loss or damage of whatsoever nature and howsoever arising and even where caused by the negligence or breach of duty of either Party.

12 Waiver

No waiver by either Party of any breach by the other in respect of a Transaction shall operate or be construed as a waiver of any other breach.

13 Variation

No variation to the provisions of a Transaction shall be valid unless it is in writing and signed by an authorised representative of each Party.

14 Entirety

On signature of the Confirmation by both Parties or deemed acceptance of the Confirmation in accordance with Clause 2.4, the Confirmation shall be the entire agreement between the Parties in relation to the Transaction and supersede and extinguish any representations previously given or made other than those included in these terms and conditions and the Confirmation.

15 Severability

If any of the provisions of the Transaction are found by a court or authority of competent jurisdiction to be void or unenforceable, such provision shall be deemed to be deleted from the Transaction and the remaining provisions shall continue in full force and effect. The Parties shall in such event seek to agree upon a valid and enforceable provision to replace the provision found to be void or unenforceable.

16 Notices

Any notice or other communication to be given or made in respect of the Transaction by one Party to the other shall be given or made in writing to the other at that Party's registered office or such other address or contact number as that Party shall notify to the other from time to time and shall be deemed to have been received:

16.1 if delivered by hand, on the Banking Day delivered or on the first Banking Day following the date of delivery if delivered on a day other than a Banking Day;

16.2 if sent by first class post, on the second Banking Day after the day of posting or, if sent from outside the United Kingdom, on the fifth Banking Day following the day of posting;

16.3 in the case of a facsimile transmission, on the day of transmission if that day is a Banking Day or on the first Banking Day after transmission if that day is not a Banking Day and provided that a valid transmission report confirming good receipt is generated.

Where a notice is sent by facsimile, the Party giving the notice shall (but without prejudice to Clause 16.3), if so requested by the other Party, resend the notice as soon as reasonably practicable by facsimile.

17 Applicable Law

The Transaction shall be governed by and construed in accordance with English Law and the Parties shall submit to the exclusive jurisdiction of the English Courts.

Appendix 9.2 Short-term beach trading terms and conditions

1. **Definitions and Interpretation**

1.1 The following words or phrases, where they appear in these terms and conditions or in a Confirmation, shall have the meanings respectively ascribed to them:

"Affiliate" shall mean any holding company or subsidiary company of a Party or any company which is a subsidiary company of the holding company of a Party and the expressions "holding company" and "subsidiary" shall have the meanings respectively ascribed to them by section 736 Companies Act 1985 as amended

"Business Day" shall mean the period between 0900 hours and 1700 hours on a day (other than a Saturday or a Sunday) on which the clearing banks in London are open for business

"Buyer" shall mean the Party required to take delivery of and pay for (or if not taken, pay for) Gas pursuant to a Transaction

"Confirmation" shall mean a document signed by the Parties that incorporates these terms and conditions and confirms the details of a Transaction and is in substantially the form of the Schedule hereto

"Contract Price" shall mean the sum agreed as such for a Transaction between the Parties

"Daily Quantity" shall mean the quantity of Gas agreed as such for a Transaction between the Parties

"Day" shall mean the period of hours beginning at 0600 hours on any day and ending at 0600 hours on the following day

"Defaulting Party" shall have the meanings specified in Clauses 12.1 and 12.2

"Delivery Point" shall have the meaning specified in Clause 4.2

"Force Majeure" shall mean any event or circumstance not within the reasonable control of a person acting and having acted as a Reasonable and Prudent Operator but shall be subject to the exclusions specified in Clause 9.2

"Gas" shall have the meaning specified in the Network Code

"Gross Minimum Bill Quantity" shall mean, in respect of the Supply Period, the Gross Minimum Bill Quantity agreed as such for a Transaction between the Parties

"Month" shall mean a period beginning at 0600 hours on the first day of the calendar month and ending at 0600 hours on the first day of the following calendar month

"Monthly Statement" shall have the meaning specified in Clause 8.1

"Net Minimum Bill Quantity" shall mean, in respect of the Supply Period, the Gross Minimum Bill Quantity less:

1.1.1 the aggregate of the quantities of Gas to be delivered on any Day during the Supply Period in pursuance of Clause 3 which the Seller did not for any reason (including without limitation Force Majeure but excluding the Buyer's failure to accept delivery of Gas tendered for delivery by the Seller in accordance with the terms of a Transaction) deliver on the Day in question; and

1.1.2 the aggregate of the quantities of Gas to be delivered on any Day of which the Buyer refused or failed to accept delivery for reasons for which it was relieved from liability under Clause 9 or entitled so to do under Clause 5.2 (save to the extent that any such quantities are included in Sub-Sub-Clause 1.1.1)

"Network Code" shall mean the document, as modified from time to time, setting out the transportation arrangements established by Transco pursuant to its public gas transporter's licence

"Non-Defaulting Party" shall mean, where one Party is a Defaulting Party, the other Party

"Off-Spec Gas" shall have the meaning specified in Clause 5.2

"Party" shall mean one or other of the Parties to a Transaction

"Quantity" in relation to a quantity of Gas shall mean quantity expressed in Therms

"Reasonable and Prudent Operator" shall mean a person seeking in good faith to perform its contractual obligations and in so doing and in the general conduct of its undertaking exercising that degree of skill diligence prudence and foresight that would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking under the same or similar circumstances; and any reference to the standard of a Reasonable and Prudent Operator shall be a reference to such a degree of skill diligence prudence and foresight

"Reconciliation Statement" shall have the meaning specified in Clause 8.3

"Seller" shall mean the Party required to deliver Gas pursuant to a Transaction

"Shortfall Gas" shall have the meaning specified in Clause 6.1

"Supply Period" shall mean the period agreed as such for a Transaction between the Parties, save that if a Transaction is terminated in accordance with Clauses 8.7.2, 9.4 or 12, the Supply Period shall end on the date on which such termination becomes effective

"System Marginal Buy Price" shall have the meaning specified in the Network Code

"Terminal" shall mean the terminal agreed as such for a Transaction between the Parties

"Termination Payment" shall have the meaning given in Clause 12.4

"Therm" shall mean one hundred and five million five hundred and six thousand joules (105,506,000 J) as specified in ISO 1000: 1981

"Transaction" shall mean a transaction for the sale and delivery of Gas governed by these terms and conditions

"Transco" shall mean BG plc or any successor as public gas transporter licensee

"Transco Pipe-line System" shall mean the System as defined in the Network Code

"Transco Entry Requirements" shall have the meaning specified in Clause 5.1

"Week" shall mean a period of seven (7) days beginning at 0600 hours on any Sunday and ending at 0600 hours on the following Sunday.

1.2 Any reference in these terms and conditions to the delivery of Gas by the Seller to the Buyer is a reference to the passing to the Buyer of a contractual right as against the Seller to an undivided share in a flow of Gas.

1.3 Any reference in these terms and conditions to a Transaction includes any permitted assignment, novation, supplement or amendment thereto.

1.4 Any reference to a Clause or Clauses is a reference to a Clause or Clauses in these terms and conditions and references to Sub-Clauses and Sub-Sub-Clauses shall be construed accordingly.

1.5 In the event of conflict between the terms of a Confirmation and these terms and conditions, the terms of the Confirmation shall prevail except where expressly provided to the contrary.

2. **Sale and Delivery**

For the duration of the Supply Period the Seller shall sell and deliver Gas to the Buyer and the Buyer shall take delivery of and pay for (or if not taken shall pay for) Gas in accordance with these terms and conditions and those of the Transaction.

3. **Quantity**

3.1 The quantity of Gas that the Seller shall sell and deliver to the Buyer:

3.1.1 shall be measured in accordance with the standards methods and practices of Transco at the Delivery Point for entry into the Transco Pipe-line System;

3.1.2 shall be on each Day the Daily Quantity.

4 **Title, Delivery, and Risk**

4.1 The Seller warrants:

4.1.1 that it will have title to all Gas delivered to the Buyer (and this warranty shall be treated as satisfied where the Seller has arranged for delivery of Gas to the Transco Pipe-line System by a person or persons who has or jointly have title at the Delivery Point to such Gas and such person passes or persons jointly pass title to such gas to Transco);

4.1.2 that such Gas shall be free from all liens, charges, encumbrances and adverse claims of any kind.

4.2 The Seller shall deliver Gas to the Buyer at the Delivery Point, which shall be the flange, weld, or other agreed mark connecting any sub-terminals and other terminal facilities at the Terminal with the Transco Pipe-line System.

4.3 The Seller shall use reasonable endeavours to ensure that Gas is delivered at uniform hourly rates.

4.4 Title and risk in Gas delivered shall pass at the Delivery Point.

4.5 Each Party warrants to the other:

4.5.1 that during the Supply Period for a Transaction it shall be a principal in relation to claims validation arrangements at the Terminal; and

4.5.2 that it has obtained or will procure and maintain at all times during the Supply Period for a Transaction all necessary licences, authorisations, permits, consents and other approvals necessary to enable it to fulfil its obligations in respect of such Transaction.

5 **Quality and Pressure**

5.1 The Seller shall ensure that Gas delivered at the Delivery Point shall conform to the quality and pressure requirements of Transco at the Delivery Point for entry into the Transco Pipe-line System (referred to in these terms and conditions as the "Transco Entry Requirements").

5.2 In the event that any of the Gas that has been delivered or tendered for delivery does not conform with the Transco Entry Requirements ("Off-Spec Gas"):

5.2.1 the Seller, as soon as reasonably practicable after becoming aware of such non conformity, shall notify the Buyer accordingly, and of the cause and probable duration, and shall take such steps as are reasonably practicable to bring all Gas tendered thereafter for delivery into conformity with the Transco Entry Requirements;

5.2.2 if Off-Spec Gas has been tendered for delivery but not delivered, the Buyer, being aware that the Gas so tendered is Off-Spec Gas, may

5.2.2.1 refuse to accept all or part of such Off-Spec Gas until the non-conformity has been remedied (but shall not so refuse if Transco is willing to accept delivery of the same);

5.2.2.2 take delivery of all or part of the Off-Spec Gas but thereafter shall have no rights or remedies in that respect against the Seller by reason of the Gas being Off-Spec Gas and shall pay for it as if it conformed with the Transco Entry Requirements;

5.2.3 if the Buyer takes delivery of Off-Spec Gas not being aware that the Gas is Off-Spec Gas, the Seller shall indemnify the Buyer from and against all loss, damage and expense for which the Buyer is or becomes liable in clearing or cleaning any installation downstream of the Delivery Point as may be necessary following and as a result of the Buyer having so taken delivery of Off-Spec Gas, provided always that the Seller's liability shall be limited to the indemnity given hereunder and shall not, in respect of any one failure, exceed an amount equal to ten (10) percent of the Contract Price multiplied by the quantity of Off-Spec Gas so delivered. Subject to this the Buyer shall pay for the Off-Spec Gas so delivered as if it conformed with the Transco Entry Requirements.

6 **Under-deliveries**

6.1 If on any Day the quantity of Gas that the Seller shall deliver to the Buyer shall fall short of the Daily Quantity, then the shortfall, except to the extent that it has been caused:

6.1.1 by Force Majeure for which the Seller is relieved from liability under Clause 9, or

6.1.2 by the Buyer refusing or failing to accept delivery other than for reasons for which it is entitled so to do under Clause 5.2

shall be classified as Shortfall Gas and the Seller shall pay to the Buyer the sum, if positive, calculated in accordance with the following formula:

(SMBP – CP) x SG

where "SMBP" is the System Marginal Buy Price for the Day, "CP" is the Contract Price, and "SG" is the Shortfall Gas.

6.2 The provisions of Clause 8 shall apply in respect of any sum due pursuant to Clause 6.1, except that if the Supply Period has expired and any such sum has not been included in a Monthly Statement or in the Reconciliation Statement, the Buyer shall invoice the Seller who shall pay such sum on the tenth (10th) day after receipt.

6.3 The Seller shall as soon as reasonably practicable provide to the Buyer such information as is available as may reasonably be required by the Buyer in relation to any incidence of Shortfall Gas.

6.4 The provisions of this Clause shall be in full satisfaction of the rights of the Buyer in respect of Shortfall Gas and the sole remedy available to it.

7 **The Contract Price**

7.1 The Buyer shall pay the Seller the Contract Price for all quantities of Gas delivered.

7.2 If at the expiry of the Supply Period the Buyer has taken delivery of quantities of Gas that in aggregate are less than the Net Minimum Bill Quantity for the Supply Period, the difference shall be paid for by the Buyer at the Contract Price and such payment shall be the Seller's sole remedy in that respect.

7.3 The Buyer shall pay any VAT on the purchase of Gas on receipt of appropriate tax invoices from the Seller and shall pay or cause to be paid all royalties, taxes, duties, and other such sums legally payable by a purchaser of Gas arising after the Delivery Point.

7.4 The Seller shall pay or cause to be paid all royalties, taxes, duties, and other such sums legally payable arising at or before the Delivery Point but shall have no liability for any charges relating to the transportation from the Delivery Point of Gas delivered to the Buyer.

8 Billing and Payment

8.1 On or before the tenth (10th) day of the Month following each Month in the Supply Period the Seller shall send to the Buyer an invoice, together with a Monthly Statement which shall show for the preceding Month:

8.1.1 the quantity of Gas delivered on each Day in that Month and the resultant sum owing to the Seller

8.1.2 any sum owing from one Party to the other under any other Clause, including any adjustments in respect of any previous Monthly Statement

8.1.3 for the purpose of ascertaining the Net Minimum Bill Quantity for the Supply Period, any deductions from the Gross Minimum Bill Quantity that are to be made for any Day in that Month and the reasons for the deductions

8.1.4 the net sum payable from one Party to the other after taking into account all the matters set out in this Sub-Clause.

8.2 On the twentieth (20th) day of the Month in which the Monthly Statement is received by the Buyer or the tenth (10th) day after receipt, whichever is the later, the Buyer or the Seller, as the case may be, shall pay to the other the net sum payable in accordance with the Monthly Statement.

8.3 On or before the twentieth (20th) Business Day of the Month following the end of the Supply Period the Seller shall send to the Buyer an invoice, together with a Reconciliation Statement which shall show for the Supply Period:

8.3.1 the quantity of Natural Gas delivered during the Supply Period and the aggregate of the Daily Quantities for the Supply Period

8.3.2 the sums paid and any sum outstanding under the Monthly Statements relating to the Supply Period

8.3.3 the Net Minimum Bill Quantity, the deductions made from the Gross Minimum Bill Quantity in calculating it, the difference between the Net Minimum Bill Quantity and the quantity of Gas delivered during the Supply Period and any sum due from the Buyer in that respect

8.3.4 any sum owing from one Party to the other under any other Clause, including any adjustments in respect of any Monthly Statement

8.3.5 the net sum payable from one Party to the other after taking into account all the matters set out in this Sub-Clause and deducting any sum outstanding under any Monthly Statement relating to the Supply Period.

8.4 On the tenth (10th) day after receipt of the Reconciliation Statement, the Buyer or the Seller, as the case may be, shall pay to the other the net sum payable in accordance with the Reconciliation Statement.

8.5 Any payment under these terms and conditions shall be made in sterling by direct bank transfer or equivalent instantaneous transfer of funds to the Party to whom it is due at the bank and to the credit of the account specified by that Party.

8.6 If the due date for payment, under Clause 8.2 or 8.4 as the case may be, is not a Business Day then the due date for payment shall be the previous Business Day.

8.7 If either Party fails to pay the other any sum due

8.7.1 interest shall be payable on that sum at a rate equal to the base lending rate for sterling of Barclays Bank plc applicable from time to time plus three (3) percent compounded annually from the date when the payment is due until it is made, and

8.7.2 the Party to whom the sum is due may, having given not less than ten (10) days notice to the other, either suspend delivery or receipt of Gas, as the case may be, in relation to the Transaction for such period as that sum remains due, or terminate the Transaction, or both, without prejudice to any other remedies available.

8.8 When any sum is in dispute, any undisputed portion shall be paid promptly and after settlement of any dispute, any sum agreed or adjudged to be due, together with any interest payable thereon under Clause 8.7.1 or otherwise, shall be included in the next Monthly Statement or the Reconciliation Statement, as the case may be, if any. If such sum has not been included in a Monthly Statement or in the Reconciliation Statement, the Party to whom it is due shall invoice the other who shall pay such sum on the tenth (10th) day after receipt of such invoice.

9 Force Majeure

9.1 A Party shall, except as otherwise specified in this Clause, be relieved of liability to the extent that owing to an event or circumstance of Force Majeure it is unable to perform any of its obligations in relation to a Transaction.

9.2 Force Majeure shall not include:

9.2.1 any failure by any person to supply Gas to the Seller, other than failure caused by an event or circumstance beyond the control of such person judged by the standard of a Reasonable and Prudent Operator

9.2.2 the Buyer taking delivery of Off-Spec Gas not being aware that it is Off-Spec Gas

9.2.3 any failure by any customer of the Buyer to take Gas

9.2.4 Transco requiring, for reasons other than Force Majeure, to interrupt the transportation of the Buyer's Gas.

9.3 A Party intending to seek relief on grounds of Force Majeure shall, as soon as reasonably practicable after the occurrence of the event or circumstance on which it intends to rely,

9.3.1 notify the other Party of the occurrence of the event or circumstance and give an estimate of the period of time that its inability to perform any of its obligations is likely to persist;

9.3.2 take such steps as are reasonably practicable to re-establish the conditions that will allow it to resume performance within a reasonable time of the obligations that it is unable to perform; and

9.3.3 resume performance of those obligations as soon as reasonably possible.

9.4 Either Party may terminate a Transaction by giving ten (10) days notice to the other if a Force Majeure event or circumstance continues for thirty (30) days or more.

9.5 If as a result of Force Majeure the quantity of Gas available to the Seller at the Delivery Point on any Day is less than the aggregate of the quantity nominated by the Buyer and the quantities of Gas that the Seller has contracted to deliver at or after the Delivery Point to other persons, the Seller shall use reasonable endeavours to deliver to the Buyer a quantity of Gas that is in the same proportion to the quantity nominated by the Buyer, as the quantities it delivers respectively to those other persons are in to the quantities of Gas that the Seller has contracted to deliver to them.

10 **Information and Confidentiality**

10.1 Subject to any restrictions on disclosure of information by which a Party may be bound, each Party shall provide to the other such information as is available as may reasonably be required by that other Party to perform its obligations and enforce its rights in relation to a Transaction.

10.2 The terms and conditions of a Transaction and all information provided thereunder shall be treated as confidential and shall not be disclosed without the prior written consent of the other Party, save that consent shall not be required for disclosure

10.2.1 to directors, employees or Affiliates of either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

10.2.2 to persons professionally engaged by either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

10.2.3 to any government department or agency having jurisdiction over that Party;

10.2.4 to any bank or other financial institution in relation to the financing of either Party's business activities, provided that the bank or other financial institution, as the case may be, is required by that Party to treat the information disclosed as confidential;

10.2.5 to the extent required by any applicable laws, judicial process or the rules and regulations of any recognised stock exchange;

10.2.6 to any intending assignee of the rights and interests of either Party under any Transaction provided that such intending assignee in turn is required by that Party to treat the information disclosed as confidential;

10.2.7 to Transco, to the extent necessary for the performance of a Transaction;

10.2.8 to the extent necessary to comply with the claims validation arrangements at the Terminal;

10.2.9 to Gas price reporting agencies, in respect of the Contract Price, the Supply Period, and the Daily Quantity only; and

10.2.10 to the extent that such information is or lawfully comes into the public domain.

11 Assignment

Neither Party shall assign to any person any of its rights or obligations under any Transaction without the written consent of the other, which shall not be unreasonably withheld.

12 **Termination**

12.1 A Transaction shall terminate automatically and without notice in the event that a Party (the "Defaulting Party"):

12.1.1 is dissolved (other than for the purposes of amalgamation or reconstruction);

12.1.2 makes a general assignment or arrangement with or for the benefit of its creditors or becomes subject to an administration order; or

12.1.3 has a resolution passed for its liquidation or receivership (other than for the purposes of amalgamation or reconstruction).

12.2 Either Party may terminate a Transaction by giving notice to the other, in the event of the other (the "Defaulting Party"):

12.2.1 undergoing a material adverse change in its financial standing which affects its ability to perform its financial obligations in respect of a Transaction, and failing to provide reasonable security for the performance of such obligations within three (3) Business Days of being requested so to do;

12.2.2 being materially in breach of any of its obligations under any Transaction, provided that notice terminating a Transaction shall not be given, in the case of a breach capable of remedy, unless prior notice has been given specifying the breach and requiring it to be remedied, and the Party in breach has failed to take substantial steps to remedy the breach within ten (10) days thereafter.

12.3 The termination of a Transaction, however occurring, shall not affect any rights or obligations that may have accrued to either Party prior to termination and shall not affect the terms of the Transaction that expressly or impliedly continue in force after termination.

12.4 On or as soon as reasonably practicable after the date of termination of a Transaction under Clause 8.7.2, 12.1 or 12.2, the Non-Defaulting Party shall in good faith calculate a termination payment (the "Termination Payment"), being the amount that it reasonably determines to be its total losses and costs (or gains, in which case expressed as a negative number) in connection with the termination of the Transaction, including loss of bargain; and shall promptly notify the Defaulting Party of the Termination Payment and the detail of its calculation.

13 **Miscellaneous**

13.1 Except as expressly provided in these terms and conditions or those of a Transaction:

13.1.1 neither party shall be liable to the other, whether in contract, negligence or otherwise, save in respect of death or personal injury resulting from the negligence of that Party; and

13.1.2 neither Party shall be liable to the other, whether in contract, negligence or otherwise, for consequential or indirect loss or damage (which, without prejudice to the generality of the foregoing, shall include loss of profits or revenue).

13.2 No waiver by either Party of any breach by the other of these terms and conditions or those of a Transaction shall operate or be construed as a waiver of any other breach.

13.3 These terms and conditions and those of the Transaction are the entire agreement between the Parties in relation to the Transaction to which they relate and supersede and extinguish any representations previously given or made other than those included in these terms and conditions and those of the Transaction, and those, if any, made fraudulently. No variation shall be effective unless made in writing and signed on behalf of the Parties by persons authorised to do so.

13.4 Any notice or other communication to be given or made under these terms and conditions by one Party to the other shall be given or made in writing to the other at the address specified by the Party and shall be deemed to have been received

13.4.1 on the Business Day delivered, if delivered by hand;

13.4.2 on the second Business Day after the day of posting, if sent by post; and

13.4.3 on the Business Day received in legible form if sent by facsimile transmission.

13.5 Each Party consents to the monitoring or recording, at any time or from time to time, by the other Party of any and all communications between officers or employees of the Parties, waiving any further notice of such monitoring and recording, and agrees to notify its officers and employees of such monitoring and recording.

13.6 These terms and conditions and those of any Transaction shall be governed by and construed in accordance with English Law and the Parties shall submit to the exclusive jurisdiction of the English Courts.

10 OCM and the Network Code

Mike Madden and Nick F. White, MJMCSL

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10.1 Introduction

This chapter describes the role and function of the On-the-day Commodity Market (OCM) within the framework of the Network Code, and the impact that the OCM and its predecessor, the flexibility mechanism, have had on the development of gas trading within the UK and European gas markets. Before launching into a full discussion of the OCM and its various characteristics, it is first of all helpful to examine the Network Code as a whole. The OCM is but one aspect, albeit a very important one, of the operation of the Code and in order to understand the purpose of the OCM it is first necessary to have some understanding of the Network Code itself.

The main areas covered in this chapter are as follows:

- Operating under the Network Code;
- Imbalance and scheduling charges;
- A discussion of the OCM;
- The future of within-day trading.

10.2 Operating under the Network Code

10.2.1 Introduction to the Network Code

The Network Code[1], introduced on 1 March 1996, was the fruit of much consultation between Transco and the shippers involved in the newly-competitive gas market. The Code is a contractual document consisting of some 500 pages of closely-typed legal text which cover the commercial and operational aspects of transmitting gas from its arrival at the beach terminal to the time when it reaches the end-user. (NB: An end-user is the name given to what used to be known as the customer.)

The main parties to the Code are Transco (the pipeline operator) and the shippers that use the pipeline system to transport gas purchased at a beach terminal from that terminal to their customers, although more recently additional players have signed onto the Network Code in order to enable them to participate in the trading of both gas and capacity. The Network Code makes clear the rights and responsibilities of all parties. Within the Code are 24 sections, covering areas such as the function of the national balancing point (NBP), operational balancing, scheduling, and OCM bidding to name but a few. March 1996 was referred to as the 'soft landing' date, with a six-month transition period before the Code took full effect on 1 September 1996 (the 'hard landing').

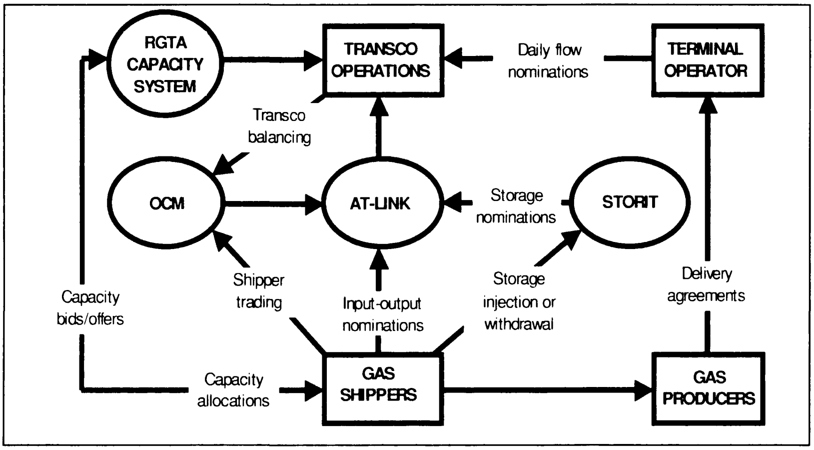
The Network Code has been modified many times since its introduction, with over 600 modification proposals considered. However, over the last four years there has been a concerted reform process known as RGTA (Reform of Gas Trading Arrangements). The initial results of this process (NGTA, or the New Gas Trading Arrangements) came into operation on 1 October 1999.

Daily balancing

Perhaps one of the key aspects of the Network Code and one of its most hotly-debated principles is the requirement placed upon all shippers to balance daily deliveries with daily demands. Daily balancing of the amount of gas put into the system by shippers and gas removed from the system by the shippers' customers is a key point of the Network Code, and one of the most important changes it brought into being.

Before the introduction of the Code this balancing had been carried out on a monthly basis. Monthly balancing was a more simple process for shippers, for whom this change to daily balancing has meant a rise in their overheads. This is due to the fact that a far closer watch has to

[1] Copies of the Network Code can be obtained from the Transco website (www.transco.uk.com). Transco is now a member of the Lattice Group.



Source: MJMCSL

Figure 10.1 Information flows and IT systems

be kept on nominations and offtakes, with many shippers setting up operations rooms manned 24 hours a day. (This rise in overheads may, however, be cancelled out by greater efficiency in nominations leading to a reduction in balancing costs.)

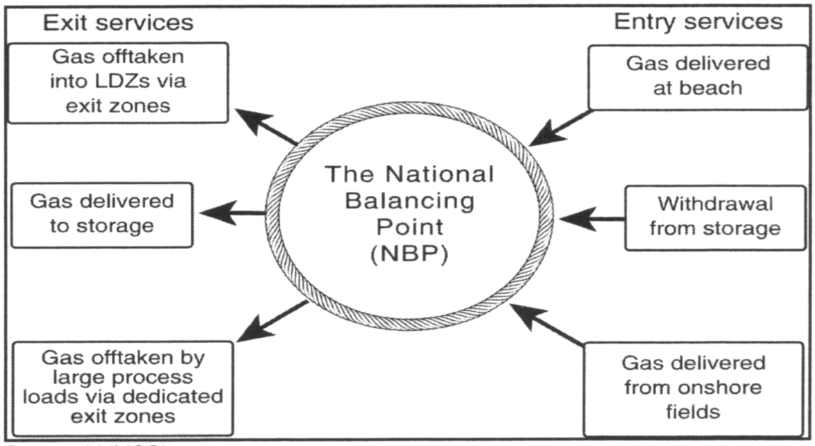
Information flows

Central to the operation of the Network Code is the UK-Link computer system, operated by Transco but used by all parties involved in the process of transporting gas. The UK-Link system is the means by which information is passed between Transco and the shippers. Within the UK-Link system is the sub-division known as AT-Link, which is the means through which all the balancing arrangements under the Network Code are monitored and carried out (see Fig. 10.1).

Following the introduction of NGTA in October 1999 several additional IT systems have been developed to augment or replace functions of AT-Link. Transco's RGTA Capacity System enables shippers to enter bids and offers and register trades for system entry capacity. The EnMO Altrade system provides the On-the-day Commodity Market where Transco and the shippers can trade gas both for system balancing and other functions. There is also a separate STORIT system handling shippers' storage nominations. All three of these systems are in some way connected to AT-Link.

10.2.2 The National Balancing Point

A key aspect of the Network Code was the introduction of the concept of the 'National Balancing Point' (NBP). The NBP, which was the source of much debate, is a notional point in the national transmission system (NTS) through which all gas is deemed to flow and about which



Source: MJMCSL

Figure 10.2 The National Balancing Point (NBP)

all gas is required to balance (see Fig. 10.2). It is not a physical point that can be marked on a map of Great Britain, or located on a map of Transco's pipeline system. It is instead a notional point, dreamed up by the originators of the Network Code. The simplification of the Transco pipeline network into entry points (feeding gas into the NBP) and exit points (receiving gas from the NBP) greatly eased the complexity of introducing competition into the gas market in Great Britain.

Knowledge of how much gas a shipper intends to flow through the system is crucial to Transco since it has the responsibility for maintaining the correct pressure in the national transmission system at all times, this being essential for the safety and security of the system. Because the transmission system is so complex (with over 5,900 km of pipeline, six main entry points and many exit points of different types), the system as a whole is balanced around the NBP, as well as it being the focal point for calculating each shipper's balance between deliveries and offtakes.

In order to deliver gas to, and remove gas from the NBP, two types of Transco services need to be acquired, namely:

- entry services, and
- exit services.

Entry services

An entry service is the service provided by Transco that enables gas to be delivered from its source to the NBP. Typically, entry services allow for gas to be delivered into the NBP from an offshore field via the offshore pipeline infrastructure, from a storage facility, or directly into the national transmission system from an onshore gas field. The basic principle is that of a 'ticket to ride' – in order to flow gas into the NBP the shipper must acquire sufficient entry capacity to permit the flow.

Exit services

Similarly, in order to remove gas from the NBP, capacity needs to be booked at one or more exit points. Typical exit points would include power stations, storage facilities, or exit points which feed Local Distribution Zones (LDZs).

10.2.3 Entry capacity

The entry capacity regime is currently undergoing a radical transformation through the RGTA process. Under the original formulation of the Network Code, shippers could book entry and exit capacity in flat twelve-month tranches. Capacity was deemed to be infinite and was sold at an administered price based on the long-term marginal costs of system expansion.

This capacity regime, and in particular the 'infinite capacity' rule, was severely criticised following major constraints at the St Fergus entry terminal in the summer and autumn of 1997[2]. As a response the industry devised a new entry capacity regime which was implemented in October 1999. The key to this regime was the linking of capacity sold by Transco to the physical capability of the system. The physical capability of the entry points to Transco's system varies with demand and system configuration. Therefore Transco was required to sell in advance monthly tranches of capacity profiled to reflect expected levels of available capacity. This regime itself suffered strong criticism due to claims that auction prices were inflated by artificial capacity constraints. In the summer of 2001, industry concerns over the level of capacity available for October 2001 to March 2002 led to a last-minute change to the regime so that capacity was released for sale at each terminal up to the maximum physical capability of that terminal.

During the course of 2002 the entry capacity regime has been further developed with the introduction of long-term capacity allocation rights. Under this new regime shippers can buy capacity up to 15 years ahead. There will be a series of auctions offering capacity on a quarterly, monthly and daily basis.

The first auctions for quarterly system entry capacity (QSEC) were held in January 2003. Transco is required to offer 80% of its System Operator (SO) baseline entry capacity (a level of capacity agreed by Transco and Ofgem as part of Transco's price control process setting a minimum volume of capacity that Transco must offer for sale at each system entry point) as QSEC for years 3 to 15. There is intended to be

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[2] Ofgem's investigation into the capacity problems at St Fergus and Bacton was published in December 1999 and is available from the Ofgem website (www.ofgem.gov.uk).

a further QSEC auction each year from 2003, probably to be held in July or August. Under its incentive schemes, Transco is encouraged to make additional capacity available above the levels set out in its price control, if the auction results indicate demand for this capacity. The intention of the long-term capacity regime is that it will not only provide shippers with greater certainty regarding future capacity entitlements and costs, but will also provide Transco with much better long-term investment signals to improve its planning and investment process.

Under the new regime monthly system entry capacity (MSEC) will be sold for years 1 and 2. QSEC holdings will also cascade down into MSEC holdings two years ahead. Transco is required to retain 20% of its SO baseline capacity to be sold short-term as MSEC or daily system entry capacity (DSEC). MSEC may be purchased in advance in auctions which will probably be held every six months, or as rolling monthly system entry capacity (RMSEC) when any remaining unsold MSEC is offered to the market just before the delivery month. DSEC is offered in auctions at the day-ahead stage.

Transco can also sell daily interruptible system entry capacity (DISEC) at the day-ahead stage. Day-ahead or on the day Transco may choose to sell additional DISEC or DSEC, or to interrupt DISEC and, if necessary, buy-back DSEC, in order to conform shippers' aggregate capacity holdings at each entry point to the physical capability of that entry point on the day. Under the new regime Transco will be selling a very large volume of capacity in advance, which may exceed Transco's ability to provide capacity at certain locations and times. Therefore Transco is also permitted to issue tenders to buy-back capacity in advance, through contestable forward or options contracts, or through bilateral buy-back deals. Shippers may also trade capacity holdings with each other, and the RGTA capacity system provides an electronic bulletin board to assist shipper capacity trading.

10.2.4 Exit capacity

Currently NTS and LDZ exit capacity procedures continue under the pre-RGTA regime. Although there have been discussions surrounding the harmonisation of exit and entry capacity regimes, major reforms to exit capacity have not yet occurred. Transco automatically assigns exit capacity to shippers on the basis of the maximum registered offtake rate of their customers in the particular LDZ or NTS exit point. Exit capacity is sold in flat twelve-month tranches at an administered price. No exit capacity is required for interruptible customers.

Future exit capacity developments are likely to treat all customers as firm initially but then permit 'interruptible' customers to strike contracts with Transco for interruption. This is intended to bring greater cost-reflectivity and competition in the exit capacity regime, as interruptible contracts can be priced against alternatives such as LNG storage and pipeline investment.

10.3 Imbalance and scheduling charges

In order for Transco to be able to balance supplies and demand effectively on any given gas day, it is important to provide accurate and timely information. Consequently three types of penalty charges exist to encourage shippers in their accuracy:

- **daily balancing charges** involve the sale or purchase of gas by the shipper to return its balance to zero on any given day (known as the cash-out);
- **scheduling charges** are made by Transco when the difference between the shipper's nomination quantity and the actual quantity falls outside of an agreed imbalance tolerance;
- **Incentivised Nominations Scheme (INS) charges** are levied by Transco as a penalty for differences between shipper flow nominations put onto the system before and during the day, and end-of-day allocations.

The following section describes these charges in more detail.

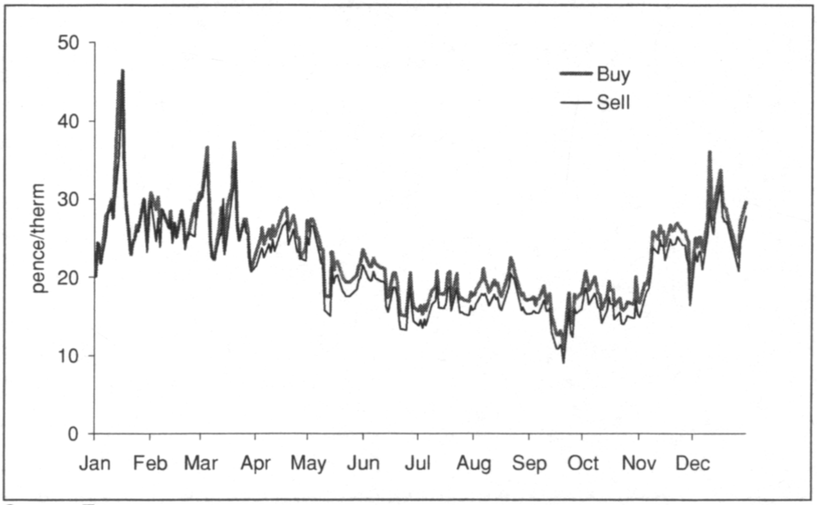
10.3.1 Charges associated with shipper imbalance

During the first five years of operations under the Network Code, shippers were granted an imbalance tolerance band which protected them from exposure to punitive balancing charges within the tolerance. However, these tolerances were removed from April 2001. Shippers are now cashed out for any imbalances at a marginal price. This system is designed to give shippers an incentive to balance their system inputs and off-takes.

If Transco has to buy in gas to make up a shortfall, the offending shipper(s) will be charged for that additional gas at SMP (Buy), and a shipper who over-delivers will have to sell their gas at SMP (Sell).

- SMP (Buy) is calculated as the greater of the highest priced Transco action on the OCM on that day or the System Average Price (SAP) – the volume-weighted average price of all the trades on the OCM that day – plus 0.84 pence/therm.
- SMP (Sell) is calculated as the lesser of the lowest priced Transco action on the OCM on that day or SAP minus 0.95 pence/therm.

Figure 10.3 below, which shows SMP buy and sell prices during 2001, illustrates that the prices charged for imbalances may occasionally prove extreme!



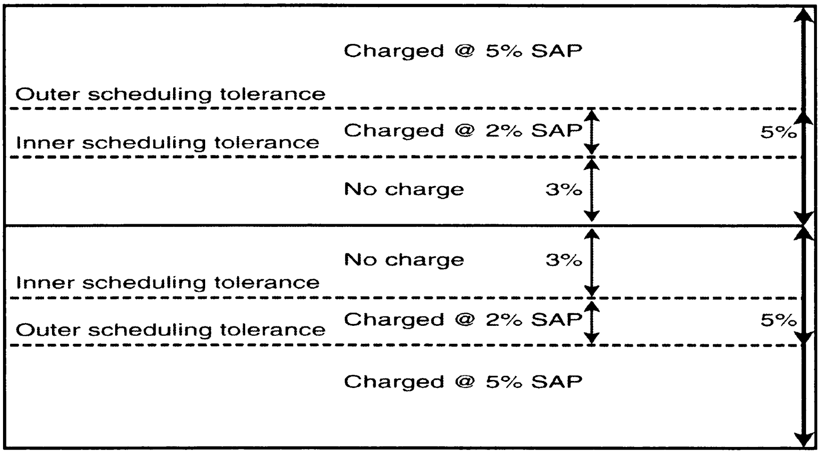
Source: Transco

Figure 10.3 System marginal buy and sell prices, 2001

Prior to the gas flow day, each shipper is required to inform Transco of how much gas it will put into the system and how much gas its customers will offtake. This process of nomination is made electronically through AT-Link and related systems. Until the actual gas flow day there is no requirement that nominated gas flow and offtakes for an individual shipper should actually match, and renominations can take place as necessary to bring this match about. On the day, however, the actual gas flow into the system and offtakes from it must match the final nominations or penalties called scheduling charges are incurred. The implementation of the INS scheme in October 2002 has introduced additional incentives on shippers to enter accurate nominations before and within-day.

10.3.2 Scheduling charges

The purpose of scheduling charges is to provide an incentive for shippers to actually deliver what they have nominated, and to offtake what they have forecast. The original purpose of scheduling charges was to ensure the honesty of the shippers in their input and output nominations. Initially the level of scheduling charges was set to provide a ‘rap across the knuckles’ to shippers. However, the reality has been that on days when considerable amounts of money can be made either in the OCM or on the OTC gas market, the impact of scheduling charges is minimal.



Source: MJMCSL

Figure 10.4 Scheduling charges on input nominations

Charges associated with input scheduling

Input scheduling charges are charged on gas deliveries at entry points into the system, such as a terminal. The structure of these charges is shown in Figure 10.4 above.

If gas delivered by a shipper falls within a ± 3 per cent tolerance band of the nominated quantity, the shipper will not receive any scheduling charge. At between 3 and 5 per cent above or below the nominated quantity a charge at 2 per cent of SAP will be made, and outside of the 5 per cent band over or under deliveries will receive an input scheduling charge of 5 per cent SAP. Although the charges are not high, shippers who are trying to maintain profitability will obviously wish to avoid them if at all possible, and therefore have an incentive to be accurate in their nominations.

Charges associated with output scheduling

Output scheduling charges are incurred by end-users who do not offtake the quantity of gas they requested a shipper to supply. The varying types of end-user are allocated different scheduling tolerance bands:

- A daily metered (DM) supply point has a scheduling band of ± 25 per cent of the output nominated quantity;
- A VLDMC (such as a power station) has a scheduling band of ± 3 per cent of the output nominated quantity;
- A firm supply point has a scheduling band of ± 20 per cent of the output nominated quantity;

- An interruptible supply point has a scheduling band of ± 25 per cent of the output nominated quantity.

In order to explain the operation of output scheduling charges the simple example of a power station has been chosen. The scheduling tolerance band for most gas-fired power stations, as VLDMCs (very large daily-metered customers), is 3 per cent. If the scheduling difference, that is the difference between the final nomination and the actual quantity offtaken, falls outside of the 3 per cent scheduling tolerance band a charge will be levied on the shipper. However, if the scheduling difference falls within the 3 per cent band, no charge will be made.

Within the tolerance band for all four types of site described above there is no scheduling charge. Outside of the tolerance band the charge is 1 per cent of SAP. These charges are made by Transco to the shipper who could, if it wished, pass them on to the end-user. Therefore, in theory at least, these charges act as an incentive to keep the system in balance by penalising those customers who do not offtake the quantity of gas they had forecast they would consume. It is in the customer's interests, therefore, to forecast its gas needs accurately, thus enabling the shipper to make nominations more accurately and assisting in the process of balancing the system.

10.3.3 Incentivised Nominations Scheme

The Incentivised Nominations Scheme (INS) was introduced in October 2002. The rationale for INS is to give shippers an incentive to nominate accurately before and within-day as well as for the end-of-day (EOD). Under the INS scheme, shipper nominations at 0200 (on D-1), 1200, 1800 and 2200 are compared with EOD allocations. If Transco has taken a balancing action on that day, INS charges will levied at one quarter of the relevant SMP-SAP differential for each INS period.

10.3.4 Changes to the imbalance and scheduling regime

Over the last two years there have been a number of concerns raised by both Ofgem and Transco regarding system balancing. In particular, Transco has identified significant variations between input flows nominated by shippers on AT-Link and actual flows within-day – which are provided to Transco by terminal operators hourly in the form of Daily Flow Notifications (DFNs).

These variations may suggest that some shippers are profiling input flows (under the Network Code shippers are required to input gas to the NTS at a constant rate). The increased uncertainty for Transco is claimed to have had a negative effect on its balancing performance, particularly on days when Transco has taken balancing actions on both sides of the market. Ofgem has also indicated its concern over possible interactions between the gas and electricity markets, where gas-fired power stations could change operating patterns to meet electricity price peaks and cause balancing problems on the gas network.

In order to mitigate these problems Ofgem published a consultation document in February 2001 suggesting a shift to a shorter balancing period, initially of six hours, possibly moving to one hour or even one half-hour (which would bring gas into line with the electricity market) in the future. Other proposals included removing balancing tolerances (which was implemented in April 2001) and the sale of linepack services by Transco.

There was strong industry opposition to the proposal for shorter balancing periods, and no such change has so far been implemented. In its place, the INS scheme has been developed in an attempt to improve the accuracy of information provided to Transco and the efficiency of Transco's balancing actions. There is, however, an expectation that if INS does not work in practice, Ofgem may begin to push for shorter balancing periods again.

10.4 On-the-day Commodity Market

10.4.1 Overview

If the system of balancing gas delivery nominations and offtakes resulted in a perfect match on each gas day, there would be no need for Transco to take any action to balance the gas transmission system. However, regardless of the various penalties against shippers that cause a system imbalance, nominations may still be inaccurate and action often does need to be taken to maintain the correct balance within the pipeline system.

If too much gas is delivered into the system (the system is long on gas), pressure may rise and the security of the system be put at risk. If there is too little gas (the system is short), pressure may drop. In extreme situations supplies may fail altogether.

It may be obvious to Transco before the gas day that nominations into the national transmission system and out from the NBP are not in balance, and they will request shippers to renominate. If the process of renomination fails to bring the system into balance, Transco will make use of the On-the-day Commodity Market (OCM)[3] to bring this about.

The OCM began operation in October 1999. The OCM replaced the flexibility mechanism that was part of the original Network Code. The OCM allows Transco to trade with shippers in order to balance the system. It also provides a within-day electronically-traded exchange for shipper-to-shipper trades. The intention of combining these functions was to increase liquidity in the market from which Transco could source its balancing gas, and thus reduce balancing costs.

10.4.2 Design of the OCM

Although an OCM was originally proposed by some parties in 1995, Transco and others had argued that such a system would put at risk Transco's operational balancing of the system. This led to the development of the flexibility mechanism – a tool which allowed shippers to enter bids and offers that Transco could select to help balance the system. However, the flexibility mechanism remained separate from the over-the-counter (OTC) market and its low level of liquidity, as well as the fact that whenever Transco entered the market it was a distressed buyer or seller, occasionally led to extreme prices.

On 16/17 December 1998 the weaknesses inherent in the flexibility mechanism were painfully exposed when Transco bought a small

[3] The new gas trading arrangements (NGTA) and the OCM are described in a series of Ofgem decision documents published in September 1999 which are available from the Ofgem website (www.ofgem.gov.uk).

amount of gas on the flexibility mechanism at nearly £5/therm[4]. Total costs to the industry of balancing on these two days were estimated at £12m. Therefore the RGTA process called for the replacement of the flexibility mechanism with an On-the-day Commodity Market, together with incentives on Transco to reduce the costs of its balancing actions. The key features of the OCM included:

- the combination of Transco-shipper and shipper-shipper trade functionality. This was intended to provide a liquid pool from which Transco could source balancing gas;
- an independent market operator (IMO). The appointment of an IMO would allow Transco to trade in the market on equal terms with other players;
- the creation of a secure, electronically-traded, cleared within-day market, with real-time price discovery. Screen trading was intended to remove some of the risk of OTC trading and allow the market to respond efficiently to Transco pricing signals.

The appointment contract for the OCM was awarded to EnMO, a joint venture between Altra, a North American energy trading systems provider, and NGC, the England and Wales electricity grid operator. The OCM was based on Altra's existing North American energy trading platform, Altrade, with adjustments for the UK market. Parties wishing to trade on the OCM are required to pay market fees and transaction costs. Access is via dedicated communication links or modem.

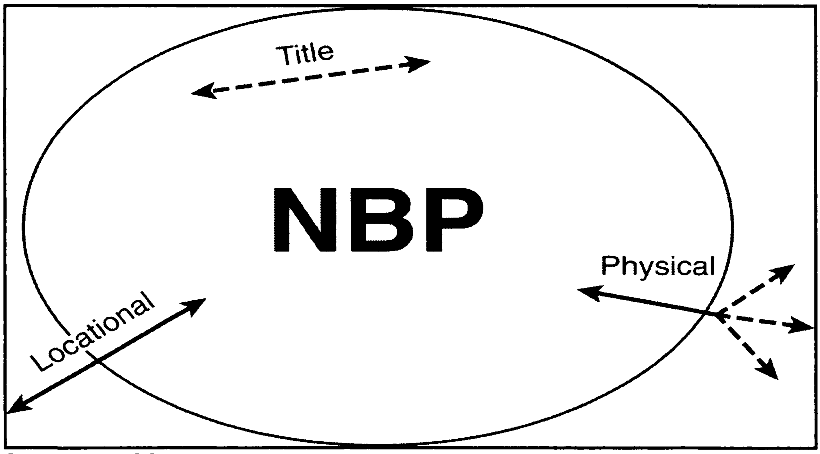
10.4.3 Operation of the OCM

The OCM was designed to fulfil multiple functions, including Transco's roles as system operator and residual balancing operator, as well as shippers' individual trading and balancing roles. Therefore the OCM offers three distinct types of trade (see also Fig. 10.5 below):

Locational trades allow Transco to buy or sell gas at specific points on the national transmission system (NTS). Locational trades can be used by Transco to resolve constraints at particular locations on the NTS. The gas is traded at the NBP (i.e. it is already entry-paid) but the source or destination of the gas is specified.

Physical trades allow Transco or other parties to purchase physical gas. Although the trade occurs at the NBP, the physical contract requires that there will be a physical flow to or from the NBP resulting from the trade. Physical trades may be used by Transco to alter the net

[4] Ofgas' investigation into the Gas Interruptions Regime for Winter 1998/99 was published in March 1999 and is available from the Ofgem website (www.ofgem.gov.uk).



Source: MJMCSL

Figure 10.5 Trades on the OCM

balance of the system by requiring shippers to adjust their flows of gas into or out from the NBP.

Title trades do not require a physical flow of gas. Rather a title trade enables the transfer of ownership of gas that is already at the NBP. As such, the title market is the primary location for shipper-shipper OCM trades. Transco may also use title trades. Although the trade itself may have no impact on the net balance of the system, Transco may use the title trade to send a signal to the market that the system is short. As both physical and locational markets tend to trade at a premium to the title market, there may be advantages to Transco using the title market, despite the lack of a direct physical flow resulting from it. After three years of trading on the OCM, it is now rare for a physical or locational trade to occur, and Transco almost always uses the title market unless there is a pressing operational need for a locational or physical trade.

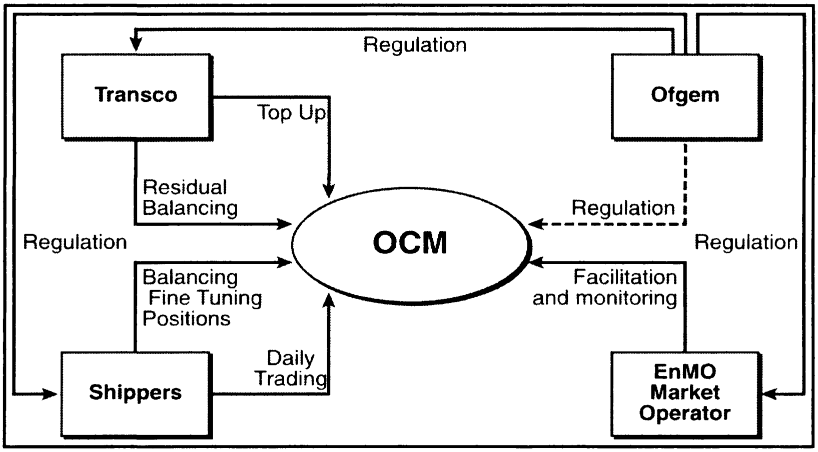
10.4.4 Relationships in the OCM

The various relationships of the different parties to the OCM are summarised in Figure 10.6.

Shippers may use the OCM both for balancing and speculative trading. Transco uses the OCM in its role as residual system balancer. It also purchases top-up gas from the OCM. Ofgem and EnMO respectively provide regulation and facilitation of the market.

10.4.5 The impact of the OCM

The OCM has provided a secure and reliable system both for Transco's system balancing and shipper-shipper trading. However, concerns remain over the level of liquidity on the OCM, which remains below that



Source: Ofgem

Figure 10.6 Relationships in the OCM

of the OTC market. Although system balancing costs have reduced since the introduction of the OCM there is still concern that low liquidity may lead to extreme prices, particularly out of ordinary trading hours. In May 2001 EnMO unveiled its new trading platform, EnEx, which offers gas trading up to seven days forward, as well on-the-day, and will eventually permit gas and electricity trading on a single platform[5].

10.4.6 Commercial opportunities in the OCM

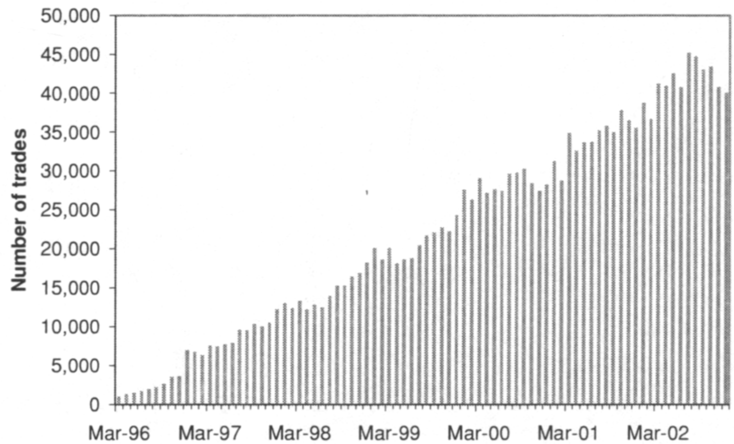
The OCM and its predecessor, the flexibility mechanism, have had a variety of impacts on the competitive gas market in the UK. In particular, the introduction of within-day system balancing have influenced the following areas:

- development of 24-hour operations;
- development of gas trading;
- joint ventures with end-users.

Development of 24-hour operations

The introduction of the Network Code and daily balancing did much to encourage the shipping community to develop 24-hour operations, since the incentives (or penalties) under the daily balancing regime were sufficiently high to be a cause of concern. These incentives, combined with the opportunities provided to the shipping community by Transco to make (or to lose) money through the flexibility mechanism, meant that a fresh impetus was provided to shippers to develop 24-hour operations. When the Network Code was first introduced, many

[5] For further information see the EnMO website (www.enmo.co.uk).



Source: Transco

Figure 10.7 Growth of OTC NBP trades, 1996-2002

players sought to extend their existing working hours from an 0800 to 1800 hour day to an 0600 until 2400 hour day. However, many players soon found that such an arrangement was unsatisfactory and developed fully-fledged 24-hour rotating-shift control room operations.

Development of gas trading

With the development of 24-hour operations and the introduction of the flexibility mechanism, many players began to see the advantages of trading gas day-ahead, on the day, and after the day. (NB: Initially after the day trading was not explicitly allowed under the Network Code despite the fact that it was taking place.) Consequently the development of gas trading in the UK gas market was given a significant impetus by the introduction of the Network Code, daily balancing and, in particular, the flexibility mechanism. Many shippers sought to underwrite the investment required for developing 24-hour operations by increasing their activity in the gas trading market.

By 2001 gas trading activities on the OCM, the IPE natural gas futures market and the OTC spot market had grown dramatically (see Fig. 10.7). For example, the volume of NBP trades notified to Transco for August 2001 was 443 TWh, over six times the total system throughput for that month. Although gas trading volumes dipped in December 2001, following the collapse of major gas trader Enron, volumes and liquidity appeared to have recovered by January 2002 with 496TWh of trades notified to Transco. By August 2002 volumes had reached a record 634TWh. Gas trading has become a key part of shipper activity. The development of NETA also raises the possibility of increased convergence between gas and electricity trading markets.

Joint ventures with end-users

Another area where the flexibility mechanism and the OCM have seen the development of new business ventures has been in the creation of joint ventures between shippers and end-users, particularly the large power generators. On a day when the Transco pipeline system has insufficient gas, certain power stations may have the flexibility to switch off gas and onto oil or coal. Although such activity does incur additional fuel and maintenance costs for the power generator, at certain levels of gas price it is nevertheless profitable for the power generator or other process user to take such action. Therefore a number of joint ventures/arrangements have been made between Network Code shippers and large end-users, where there is a degree of profit-sharing for any accepted bids on the OCM.

Yet another area where this type of joint venture has flourished is where a process user such as a power station can take more gas on a day when Transco has too much gas in the system and is seeking to sell it away from the NBP. A typical example would be a power station that would normally choose to burn coal as the cheaper fuel but is able to switch to gas when gas prices in the OCM or spot market are sufficiently cheap.

A further development in the short-term gas market has been the development of market-related interruptible prices. Traditionally interruptible prices have been set with a flat discount against the firm price for a similar product. Such an arrangement clearly did not provide any real incentive for the end-user to switch off on a particularly cold day when interruption was required. In fact, such a tariff structure provided a strong disincentive for the end-user to behave in a market-related fashion. Consequently, since the development of the flexibility mechanism and high within-day gas prices, many end-users have sought interruptible contracts with market-related pricing mechanisms within them, so that there is a sharing of any profits made by the shippers.

In many respects the interruptible market in the UK is still waking up to the opportunities that liberalisation and the introduction of the Network Code has brought. For example, in addition to the potential for market-based interruptible tariffs, many players are beginning to see large process users such as power stations as an alternative to gas storage. Although historically interruptibles were seen as a peak shaving tool, they are now being seen as a commercial tool to be used in conjunction with, or instead of, storage.

10.5 Future of within-day trading

The reform of gas trading arrangements (RGTA) and the introduction of the OCM have seen many significant changes to the operation of the gas trading market. The development of a variety of markets and financial instruments as well as the high liquidity of the OTC market show that the UK gas market is moving towards maturity. However, there are a number of issues that are likely to continue to affect gas trading operations under the Network Code.

10.5.1 Development of the balancing regime

Ofgem has proposed further developments of the balancing regime. In particular, Ofgem has suggested a move from daily to hourly or even half-hourly balancing[6]. Ofgem's initial proposals in February 2001 met with strong opposition from most sectors of the industry. However, in February 2002 Ofgem published revised proposals suggesting, among other things, a temporary shift to six-hour balancing periods. If implemented, this would result in very significant changes to the gas trading market. Such changes may be driven by interactions with the electricity trading market. Other likely developments include the sale of a linepack service, enabling shippers to buy and trade rights to utilise the inherent flexibility of the gas transportation system, and revision of Transco's balancing incentive.

10.5.2 Information uncertainty

Following the implementation of NGTA significant problems have emerged concerning the quality of within-day information flows. Transco relies on two major sources of information for its operational analysis of flows into the system. These are AT-Link nominations by shippers and DFNs (Daily Flow Notifications) provided by the terminal operators. During the summer of 2000 in particular, Transco alleges that there were large discrepancies between DFNs and AT-Link nominations. This may suggest that some shippers or producers have been profiling gas flows for commercial advantage. There are a number of possible outcomes of this issue, including investigations into whether parties breached their obligations under their shippers' licences, additional information requirements, shorter balancing periods and shifts to balancing offshore. The development of the INS scheme has been the first major change to the regime in an attempt to improve information provided to Transco, although evidence from the first few months of operations under INS suggests that some problems remain.

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[6] Ofgem's proposals are described in *The New Gas Trading Arrangements: Reform of the gas balancing regime – revised proposals*, published in February 2002 and available from the Ofgem website (www.ofgem.gov.uk).

10.6 Conclusion

The Network Code has been a qualified success, enabling the UK gas market to operate effectively and facilitating the spread of competition to all customers, as well as encouraging the development of gas trading markets. However, the continuing RGTA process suggests that many more changes are likely in the development of the Network Code and the UK gas trading market.

11 Take-or-pay contracts

Michael Brothwood, Denton Wilde Sapte

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11.1 Introduction

The commitments made by individual sellers and buyers in gas purchase contracts are determined by their appreciation of the commercial realities of the market in which their contracts are to be performed. It follows that as the markets and participants change the commitments made by contracting parties will change. Nevertheless, despite significant changes in the structure of the gas market, some sellers and buyers continue to use take-or-pay clauses in longer term contracts because it suits their commercial interests.

This Chapter includes a full description of the various possible components of take-or-pay arrangements and indicates how they have been adapted to take account of the needs of buyers and sellers in liberalised gas markets. It discusses the reasons for the decline in the use of take-or-pay contracts that has accompanied the changes in market structures, legal issues relating to the enforcement of take-or-pay clauses, the treatment of take-or-pay contracts under the EU Gas Directive and a number of issues under EU competition law.

Chapter 12 is concerned with the changes in gas pricing and gas pricing arrangements resulting from the changes in market structures.

11.2 Changing market structures

Major changes in the structures of the gas markets in North America and Great Britain[1] have occurred over the last 15 years and these are now spreading to Continental Western Europe and Ireland[2]. These changes were brought about by legislation, interventions of competition authorities or industry regulators, and consumer pressures and have led to a substantial decline in the use of take-or-pay contracts and fundamental changes in gas pricing and gas pricing arrangements.

In the early years of the natural gas industry the structures in each of these markets were characterised by national or regional monopolies (legal or de facto) of transportation, distribution or supply or a combination of two or more of them. The monopolies effectively prevented gas-to-gas competition by preventing access to customers or

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[1] Great Britain comprises England & Wales and Scotland. The United Kingdom (UK) comprises England & Wales, Scotland and Northern Ireland. Until 1996 when the gas Interconnector between Scotland and Northern Ireland was opened there were two physically separated gas markets in the UK – the market in Great Britain and the market in Northern Ireland. For the purposes of this chapter they are treated as if they had remained physically separated markets.

[2] These changes are driven in large part by the EU Gas Directive (Directive 98/30EC of the European Parliament and of the Council of 22nd June 1998 concerning common rules for the internal market in natural gas. (O.J. L 204/1, 21.7.98)). The Directive (also referred to as the IMG Directive) entered into force on 10 August 1998. It was required to be implemented by the Member States by 10 August 2000. Member States were required to open up their national gas markets to competition in three stages - 20% by August 2000, 28% by August 2003 and 33% by August 2008. These were minimum requirements. The Directive requires that further steps towards liberalisation be considered in 2006 in the light of experience gained from the staged approach. Member States could if they so wished accelerate the expansion of their competitive markets. Many Member States did so. The Directive also required the Member States to introduce measures to enable suppliers of gas to the competitive sector to obtain access to transmission and distribution pipelines in order to supply eligible customers (i.e. those gas purchasers who are entitled to purchase gas in the competitive sector of the gas market). Member States were permitted a choice of access regime. They could choose for their gas transmission and distribution systems a negotiated third-party access regime (nTPA) involving direct negotiations between system owners and applicants for transportation; a regulated third-party access regime (rTPA) with published tariffs, or a combination of the two (e.g. rTPA for transmission pipelines and nTPA for distribution pipelines). Most Member States opted for regulated TPA and when they did so, also appointed energy regulatory bodies for the gas (and electricity) industries the responsibilities of which include approval of transportation tariffs.

to pipelines. Contractual arrangements for the supply of natural gas and LNG into these markets reflected the fact that the supplies of gas came from specific fields specifically developed to supply a particular market. They took one of two forms. These were the depletion contract or the supply contract[3]. In both cases the contracts were long-term (15 – 25 years) take-or-pay contracts. The gas prices were linked to movements in the prices of fuels competing with gas, such as fuel oil and gas oil and sometimes, in the gas market in Great Britain in particular, with inflation indices (Producer Price Index (PPI) and Retail Price Index (RPI)).

In both the North American gas market and the gas market in Great Britain, the reduction or removal of the existing monopolies and the introduction of gas-to-gas competition has resulted in the emergence of price indexed gas markets. By price indexed we mean here that the price of gas under contract is linked directly to the current market price of new gas sales in the traded market for short-term gas or 'Spot Market' possibly at parity but also at a small discount or premium depending on circumstances. In the North American market where the first market liberalisation measures were introduced in the late 1970s and early/mid 1980s,[4] a very substantial level of gas-to-gas competition had been achieved by the beginning of the 1990s. In Great Britain the first tentative steps towards the introduction of competition were taken

[3] Under a depletion contract the seller agrees to sell the economically recoverable reserves (or a proportion of the economically recoverable reserves) of an agreed field or fields. The Daily Contract Quantity ('DCQ') is set as a fraction of those reserves. Such reserves are inevitably an uncertain quantity. Depletion contracts were widely used in the earlier stages of development of the UK and Norwegian sectors of the North Sea. The daily quantities to be delivered are nominated by the buyer based on the DCQ applicable at the relevant time. Under a supply contract the seller agrees to sell a specific quantity of gas to be delivered in accordance with the nominations of the buyer. Supply contracts have always been used for sales of Russian gas, Algerian gas (LNG and, more recently, pipeline gas), and Dutch Gas. They have been used for some years for all supplies of Norwegian gas and are now almost exclusively used for supplies into the UK market. The causes of the change to supply contracts include the disappearance of monopoly buyers and the development of larger gas fields (e.g. the Troll field).

[4] The main measures were the Natural Gas Prices Act of 1978 which ended the Federal Government control on well-head prices for gas – thereby removing a major obstacle to gas-to-gas competition and Order 380 of 1984 of the Federal Energy Regulatory Commission (FERC) which effectively released the local distribution companies from their existing take-or-pay obligations under contracts with the pipeline companies. The pipeline companies were faced with serious financial difficulties under their long-term take-or-pay contracts with the producers. These difficulties were normally resolved by renegotiation of the contracts. Very few of the disputes came before the courts.

in 1982 by the third-party access provisions of the Oil and Gas (Enterprise) Act 1982[5]. This was followed by measures contained in the Gas Act 1986, which established the regulatory regime applicable to British Gas plc, the successor to the state owned British Gas Corporation[6]. These measures, together with subsequent major interventions by Ofgas (the Gas Regulator, now the Office of Gas and Electricity Markets, Ofgem), the Office of Fair Trading and the Monopolies and Mergers Commission (the national authorities responsible for the application of the general competition law), and the Government brought about a substantial degree of gas-to-gas competition by 1995.

The introduction of gas-to-gas competition in the North American gas market led to a rapid change in pipeline/customer practices (in particular a move to short-term contracts) although, as mentioned in footnote 4, the producer/pipeline long-term contracts were left in place. In the gas market in Great Britain the comparatively slow pace of development of competition in the end user market led initially to only minor changes in contracting practices and pricing arrangements. It was the emergence of a short-term traded market and price-indexed gas markets that brought about significant changes in these practices and arrangements in both of these gas markets. These changes reflected the concern of the buyer to minimise its greatly increased price risk in a competitive and sometimes volatile gas market. One means of reducing this risk was to enter into shorter-term contracts. In both these markets the majority of new supplies are now bought under daily, monthly or quarterly contracts but medium term (3-10 years) supply contracts are also in evidence. The medium term contracts normally contain take-or-pay obligations. Short-term contracts (less than three years) also normally contain a take-or-pay obligation (but generally have a prescribed remedy such as a 'keep-whole' provision or (in Britain) a charge based on the Network Code cash-out provisions without a make-up right)[7]. However there are still some new supplies of pipeline gas into these markets (mainly supplies to power generators) that are bought under long-term take-or-pay contracts. An additional and very important means of reducing marketing risk has been to link the prices of new medium- and short-term gas contracts to movements

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[5] Section 17 The Oil and Gas (Enterprise) Act 1982.

[6] The main measures included the introduction of competition in the supply to major gas users (consuming in excess of 25,000 therms per year), the appointment of a Gas Industry Regulator and overall control of transmission charges by the Gas Industry Regulator.

[7] For an explanation of make-up see section 11.4.2.

of published gas price indices[8] and even long-term supplies to generators normally give the buyers some flexibility to avail themselves of short-term or 'spot' gas.

It was thought possible that the implementation of the Gas Directive would bring about in time a level of gas-to-gas competition sufficient to create traded indexed gas markets across the EU. However, despite the encouragement given to this view by the opening of gas trading at Zeebrugge in 1998 following the opening of the UK-Continent Interconnector in October of that year there has been little development of gas-to-gas competition in most of the natural gas markets of the Continental West European countries (including Ireland), and even less development of cross border gas-to-gas competition[9]. As a result, developments similar to those in the North American gas markets and in the gas market in Great Britain are yet to occur. The majority of new gas supplies in the Continental West European markets are still bought on long term take-or-pay contracts.

The reason for this lie mainly in the fact that the Gas Directive was only intended as a first step towards liberalisation of gas markets in the European Union. This is apparent from: the staged approach to market opening (culminating in a minimum requirement of 33% of market opening by August 2008); the absence of an agreed methodology for calculating transportation charges; the right given to Member States to choose a negotiated TPA regime or a regulated TPA regime; and the absence of a requirement to separate transmission and distribution from production and supply.

The emergence of gas-to-gas competition, within the restricted context of the Directive, has been retarded in some of the Member States. France finally enacted the implementing legislation required by the Directive at the end of 2002. However, despite the absence of the legislation, third-party access to gas pipelines has been granted to industrial users, though not usually at very favourable tariffs. In Germany, despite the 100% opening of the gas (and electricity) markets, the progress towards gas-to-gas competition has been very slow. This is largely attributable to the Government's choice, quite legitimate, of a negotiated TPA regime. However the legislation implementing the regime was drafted in general terms with the result

[8] This point is developed further in Chapter 12, section 12.3 (Price indexed gas markets).

[9] Following the opening of the UK-Continent Interconnector, which links Bacton with Zeebrugge, sales of gas were made by British sellers to Continental buyers on a long-term basis. Sales were also made in both directions on a spot/short-term basis. It is understood that some of the British export contracts provided for interruption by the Seller or re-delivery at the NBP in Britain at the option of the Buyer to facilitate trading. Subsequently, significant gas trading has developed at Zeebrugge.

that important operational issues, in particular the methodology for calculating transportation charges, were not dealt with. The Government left such issues to be dealt with by self regulation through an agreement between gas industry participants (the Verbandevereinbarung für Gas). The latest agreement was reached on 3 May 2002, and relates to the period October 2002 – October 2003. The provisions of the agreement and amendments to it have been subject to challenge by the German cartel authorities and the competition authority of the European Commission. Progress on access for new players has been very slow, as the rules for self-regulation were developed by the existing players.

The slow development of the gas liberalisation process resulted in pressures from many Member States and industry participants including the European Federation of Energy Traders (EFET) a body comprising electricity and gas traders which was created in 1998. EFET has produced a standard form of spot trading contract for gas, but this is not widely used.

In the spring of 2000 dissatisfaction with the pace of liberalisation in a number of industries, particularly the gas and electricity[10] industries, led to political steps being taken by the European Council to accelerate the liberalisation of the two industries. These are described in Chapter 12 Sections 6.2 and 6.3.

[10] Liberalisation of the electricity industry in the EU is the subject of the Electricity Directive (Directive 96/92/EC) of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity (O.J. L27/20 of 30.1.97). The Directive (also referred to as the IME Directive) entered into force on 18 February 1997. It required the Member States (other than Belgium, Greece and Ireland) to implement the Directive not later than 18 February 1999. The transitional arrangements under which Belgium, Ireland and Greece were permitted to delay implementation of the Directive have expired and each of these states has passed legislation implementing the Directive. The structure of the Electricity Directive was substantially followed in the Gas Directive. The Directive provided for competition in new generating facilities and for a gradual opening up to competition of national electricity markets. The minimum thresholds for opening up national electricity markets to competition were 40 GWh by February 1999, 20 GWh by February 2000 and 9 GWh by February 2003. In some of the Member States, particularly those which have opened up their national electricity markets to competition at a faster rate than that required by the Directive, there have been significant reductions in electricity prices.

11.3 Take-or-pay clauses

11.3.1 Rationale

Take-or-pay clauses are an important protection for the gas seller particularly under long-term contracts. The clause ensures that the seller will receive a minimum income stream throughout the life of the contract (or at least for the pay back period of any financing) even if the buyer does not take delivery of the specified minimum quantity of gas. The income stream is important for the seller as in order to raise project finance for the underlying gas project it will need to satisfy its bankers (or corporate treasury) that it will have an income stream which is sufficient to meet capital repayments and interest costs over at least the pay back period of the financing.

It should be noted that the take-or-pay clause provides the seller with much greater financial protection than would be available if it were to rely solely on a minimum purchase obligation of the buyer. Failure by the buyer to meet a minimum purchase obligation would only give the seller a right to damages. The measure of damages might be difficult to establish as the seller would have to prove the resulting damages, if necessary, by litigation. The damages would normally be based upon the difference between the contract price of the gas and the market price of gas at the time of default. In addition the seller would normally have an obligation to mitigate its loss arising from the buyer's failure to take a minimum quantity.

Under a take-or-pay clause with fixed (or in some cases escalated) prices the buyer takes the price risk and also, in the case of depletion contracts, the risk of changing volumes. If the economic conditions in the buyer's market change radically during the life of the contract the buyer may not be able to sell at a profit the minimum quantity of gas contracted to be taken or, if not taken, paid for. If this occurs the buyer may run into severe financial difficulties. The buyer's price risk is diminished if it has an assured market share (e.g. because of a national or regional monopoly of supply) in the whole of its market or in a specific and important market sector (e.g. the household market) and also has protection in its contract terms against competition from competing oil products such as fuel oil and gas oil. However, where at the time of entering into a take-or-pay commitment the buyer is either already facing gas-to-gas competition, or believes that gas-to-gas competition may emerge during the life of the contract, the buyer is unlikely to be willing to accept a take-or-pay commitment unless appropriate safeguards against the effects of gas-to-gas competition are included.

It should be noted that in the early field linked depletion contracts the seller, in return for the acceptance by the buyer of a take-or-pay obligation, frequently dedicated to the buyer for the purposes of performing its supply obligations under the contract the whole of the recoverable reserves of the project field. This dedication was normally accompanied by a specific agreement by the seller not to sell the gas produced from the field to any person other than the buyer. It is to be noted that such an undertaking may give rise to difficulties under EU competition law. This point is developed later (see section 11.6.2).

11.3.2 Essential elements

The take-or-pay provisions of a gas contract typically comprise the following three elements:

the take-or-pay obligation
rules relating to recovery of *make-up*
rules relating to carry forward

Sometimes a fourth element, rules relating to *valley gas*, is included.

Section 11.3.3 below contains an illustrative text of a take-or-pay clause. The terminology used, particularly the terms make-up, carry forward and valley gas may appear somewhat opaque. The following brief comments may assist in understanding them.

Take-or-pay obligation

The take-or-pay obligation ensures that the seller receives the cash flow attributable to the agreed minimum quantity in each of the successive agreed take-or-pay periods (e.g. year, six months, or three months) throughout the contract even though the buyer has taken delivery of less than the minimum quantity.[11]

Make-up

Make-up is a right which entitles the buyer to apply sums paid for gas not taken as a credit against payment liabilities in respect of gas delivered in subsequent take-or-pay periods, usually when it takes delivery of more than the minimum quantity.

Carry forward

Carry forward is a mechanism that entitles the buyer to share in the cash flow benefit to the seller that arises if, in the take-or-pay period, the buyer takes a quantity that exceeds the minimum quantity (after allowing for any part of the excess that has been used under the make-

[11] As a result of the operation of the price adjustment mechanism the gas price will fluctuate throughout the contract period. The price may also change as a result of the operation of the price re-opener clause. Future cash flow projections cannot, therefore, be totally certain.

up right) (the 'excess quantity'). Such quantity can be used by the buyer to reduce the minimum quantity in subsequent take-or-pay periods. If so used it is known as 'carry forward gas'.

Valley gas

In place of the carry forward gas mechanism the buyer is in some contracts entitled to pay for the excess quantity at an agreed discount. Gas so paid for is known as 'valley gas'.

The discount shares between the parties the financial benefit which the seller would otherwise receive as a result of early payment for the gas taken in excess of the minimum quantity. In depletion contracts the discount represents an acceleration of gas production and thus of cash flow. In supply contracts this acceleration may give rise to additional as well as accelerated sales depending on the terms of the contract.

As mentioned, in some contracts the buyer is given an option to choose between using the excess quantity either as carry forward gas or as valley gas. The valley gas provision in the illustrative take-or-pay clause in section 11.3.3 below contains such a choice.

11.3.3 Illustrative text

The following Articles illustrate some of the principles, but clearly the actual contractual agreement will depend on the strength and skills of the negotiating parties. The balance of the clauses will be reflected in the price negotiation.

Article 1.1: Annual Take-or-pay

(1) In respect of each Contract Year the Buyer will either take and pay for or, if not taken, pay for a minimum quantity of natural gas (the 'Minimum Quantity') and such quantity shall be the Adjusted ACQ for that Contract Year calculated as provided in Article 1.1(2) below

(2) If in any Contract Year the Buyer takes and pays for less than the Minimum Quantity for that Contract Year the Buyer shall pay for the shortfall (expressed in megajoules) at a price equal to the Prevailing Contract Price.

Such shortfall shall be converted into megajoules using the weighted average of the gross calorific values of the natural gas delivered under the agreement in the relevant Contract Year and if no natural gas has been delivered under this agreement in such Contract Year then the gross calorific value shall be deemed to be the weighted average of the gross calorific values of the natural gas delivered hereunder in the last Contract Year in which natural gas was delivered.

(3) Any quantity (expressed in megajoules) not delivered but paid for in respect of a Contract Year together with the quantities so paid for in respect of any previous Contract Year or Contract Years and not already recovered pursuant to the provisions of Article 1.3 shall be known as 'Make-Up Aggregate'

Article 1.2: The Adjusted ACQ and the Establishment of the Minimum Quantity

(1) For each Contract Year there shall be calculated

An amount of Natural Gas (herein called the 'Adjusted Annual Contract Quantity' or 'Adjusted ACQ') which shall be

(a) The Annual Contract Quantity (or 'ACQ') applicable for the relevant Contract Year

Less

(b) The sum of the following

(i) the aggregate of the daily amounts of Natural Gas properly nominated by the Buyer for delivery during the relevant Contract Year which the Seller did not for any reason deliver on the day in question (including without limitation failure to deliver as a result of Force Majeure) but excluding any quantities which the Buyer did not accept for any reason

(ii) the aggregate of the daily amounts of Natural Gas properly nominated by the Buyer for delivery during the relevant Contract Year which the Buyer did not accept for reasons for which it was excused from liability for reasons of Force Majeure or on the grounds that the Natural Gas did not comply with the Specifications of this Agreement relating to Quality or Pressure

(iii) the Carry Forward Aggregate (or any part thereof) [in respect of which the Buyer shall have given notice in accordance with Article 1.4(2)]

Article 1.3: Recovery of Make-Up Aggregate

(1) Whenever any Make-Up Aggregate exists then the Buyer shall receive as hereinafter provided a credit in respect of any Natural Gas taken by the Buyer in excess of the Minimum Quantity in the relevant Contract Year up to the balance of the then outstanding Make-Up Aggregate. [Such credit shall not exceed an amount in megajoules equivalent to [ ] per cent of the ACQ for such Contract Year.]

Such credit shall be eligible for payment in respect of any part of the Make-Up Aggregate which is attributable (applying the principle specified in Article 1.3(2) below) to Make-Up Aggregate which arose in a prior Contract Year at one hundred (100) per cent of the Prevailing

Contract Price for the Contract Year in which such Make-Up Aggregate is recovered

[Interest provision may be included]

(2) The quantities to be used in reducing the Make-Up Aggregate shall be established by applying the first in first out principle to the quantities constituting the Make-Up Aggregate

(3) The credit which the Buyer will receive in any Contract Year shall be taken into account in the Annual Reconciliation Statement in respect of such Contract Year and to the extent that the sum due from the Buyer to the Seller is less than the amount of such credit the Seller shall refund the balance to the Buyer

(4) Any such credit or refund to the Buyer shall be deemed to be a recovery of Make-Up Aggregate by the Buyer to the extent of the number of Megajoules corresponding to such credit or refund and the outstanding balance (if any) of the Make-Up Aggregate shall be reduced commensurately

Article 1.4: Carry Forward Aggregate

(1) If and to the extent that in any Contract Year the aggregate of the amounts of Natural Gas taken by the Buyer under this Agreement (excluding any amount of Natural Gas in respect of which the Buyer will receive a credit pursuant to Article 1.3(1)) exceeds the Minimum Quantity for such Contract Year then the Buyer may by notice in writing to the Seller given not later than the last day of March in the Contract Year preceding the Contract Year in which such excess occurs elect that the provisions of this Article 1.4(1) shall apply to such amount instead of the provisions of Article 1.5(2). If the Buyer so elects such amount shall be classified as Carry Forward in respect of such Contract Year and such Carry Forward together with Carry Forward so classified in respect of any previous Contract Year or Contract Years shall (except for any Carry Forward previously used pursuant to Article 1.2(b)(iii) in reduction of the Adjusted ACQ applicable to any previous Contract Year) be known as the Carry Forward Aggregate in force at any time or from time to time

(2) The Buyer may by notice in writing to the Seller given not later than the fifth day of October in any Contract Year require that all or any part of the Carry Forward Aggregate be used (under Article 1.2(i)(b)(iii)) to reduce the Adjusted ACQ which would otherwise apply in respect of the previous Contract Year [Provided that such use in respect of such previous Contract Year shall not exceed a quantity of Natural Gas

equal to [ ] per cent of the ACQ applicable in such previous Contract Year]

Article 1.5: Valley Gas

(1) If and to the extent that in any Contract Year the aggregate of the amounts of Natural Gas taken by the Buyer under this Agreement (excluding any amount of Natural Gas in respect of which the Buyer will receive a credit pursuant to Article 1.3(1)) exceeds the Adjusted ACQ for such Contract Year then except where the Buyer shall in respect of such Contract Year have given a notice pursuant to Article 1.4(2) (Carry Forward) the Buyer shall receive a credit in respect of all Natural Gas so taken by the Buyer in excess of the Adjusted ACQ (which amount of Natural Gas is herein called 'Valley Gas') and such credit shall be at the difference between the Prevailing Contract Price and the Valley Gas Price (being a price equal to [ ] per cent of the Prevailing Contract Price) together with interest thereon calculated in accordance with Article [ ] from the day in the relevant Contract Year following that on which the Buyer made payment for the relevant quantity of Valley Gas until payment of such credit

(2) The credit which the Buyer will receive in any Contract Year shall be taken into account in the Annual Reconciliation Statement in respect of such Contract Year and to the extent that the sum due to the Seller is less than the amount of such credit the Seller shall refund the balance to the Buyer in accordance with Article [ ]

11.3.4 Commentary

As noted above, actual contracts will depend on the terms negotiated by the parties concerned. This section does not recommend the form of the terms used for illustration here; it merely presents a selection of clauses commonly discussed.

Establishment of the Minimum Quantity

Establishment of the Minimum Quantity (*Article 1.1*) is achieved by:

- calculating the sum of the Daily Contract Quantities (DCQs) for the take-or-pay period. Where, as in the illustrative text, the take-or-pay period is one year, the sum of the DCQs is the Annual Contract Quantity (ACQ).
- deducting from the sum of the DCQs for the take-or-pay period (in the text the ACQ) the following:
  - quantities of gas not delivered by the seller in the take-or-pay period for any reason
  - quantities of gas not taken by the buyer in the take-or-pay period by reason of force majeure

- quantities of carry forward.

Some contracts provide for additional deductions (e.g. a deduction equal to a specified percentage of the ACQ, and a deduction to adjust for unusually warm winter weather).

The quantity remaining after all the adjustments have been made is, in the case of annual take-or-pay, known as the adjusted ACQ. That quantity is the minimum quantity for the year.

As the buyer must pay for the gas not taken, it is necessary to convert the volumes of gas not taken but paid for into energy by multiplying the volumes not taken by the calorific value (CV). The text contains in *Article 1.1(2)* a provision dealing with this conversion.

After conversion into energy units (e.g. megajoules, kWh, therms, MM (million) Btu's) the quantities not taken but paid for are known as Make-Up.

Make-Up Aggregate and Recovery of Make-Up Aggregate

Make-up aggregate is defined in *Article 1.1(3)*. The payments representing the outstanding balance of the make-up aggregate at the end of a take-or-pay period are automatically used (see Article 1.3) as a credit towards the purchase price of that part of the gas taken by the buyer in a subsequent take-or-pay period that exceeds the minimum quantity.

The make-up provisions sometimes impose on the buyer a quantitative and/or time limit in relation to the use of the make-up aggregate. (See *Article 1.3(1)*).

A specific issue arises in respect of the price to be applied to that part of the make-up aggregate that is credited. The text provides (*Article 1.3(2)*) that the make-up aggregate is to be used on a first in first out basis. The prevailing contract price at the time at which the relevant make-up has arisen (i.e. the year in which that gas was paid for but not taken) is likely to be different from the prevailing contract price at the time at which the make-up is recovered. The illustrative text provides (*Article 1.3(1)*) that the prevailing contract price in the Contract Year in which the make-up quantity is recovered shall apply. However there is no standard practice. In negotiating this point the views of the parties as to the likely movements of gas prices between the two dates will be important.

Carry Forward

(For text see *Article 1.4*)

The concept of carry forward and its relationship to make-up has already been explained in section 11.3.2. It should be noted that as carry forward gas is used in the establishment of the volume of the minimum quantity no conversion of such gas into energy is required.

Valley Gas

(For text see *Article 1.5*)

The concept of valley gas and its relationship to carry forward gas has already been explained in section 11.3.2. Where the valley gas clause permits the buyer to choose between using the excess gas either as carry forward gas or valley gas, the decision by a buyer to choose valley gas rather than carry forward gas will depend on a number of factors including its view on future movements of the contract price and the possibility, or otherwise, of having to make substantial payments in the future for gas not taken.

11.4 Enforcement of take-or-pay obligation

The introduction of gas-to-gas competition in Great Britain raised legal issues about the enforceability of the take-or-pay obligations in existing contracts[12] in the changed market circumstances.

The legal point was whether under English law the obligation to pay for gas not taken might be unenforceable because the payment should be regarded as damages payable for breach of an obligation to take the minimum quantity. If that could be established then it could be argued that the payment obligation should not be enforced by the courts because it was a penalty. A court will find that damages should be treated as a penalty if the sum to be paid to the seller (e.g. the full price of the gas not taken) constitutes a payment of damages that are far in excess of the actual loss suffered by the seller as a result of the failure to take. Under English law penalties are not enforceable.

It is clear that the English law relating to penalties applies only to payments to be made by a buyer as a result of a breach of a contractual obligation (e.g. an obligation to take delivery). It does not apply to payments to be made under a contingent promise to pay money (e.g. to pay a sum if a specified event occurs or does not occur (e.g. taking less than the minimum quantity)). It follows that the law relating to penalties would not apply to payments to be made by the buyer under a separate obligation to pay money to the seller if it takes less than the agreed minimum quantity.

This point is well illustrated in an English Court of Appeal case of 1992 - Coneco Limited v Foxboro Great Britain Limited. The case involved a take-or-pay obligation to a supplier of engineering services. The principles of the case are applicable to take-or-pay in the context of gas contracts. The case was not reported but the transcript of the judgments is available through UK Lexis on-line services. Each of the three Judges in the case reached the same conclusion – namely that under the take-or-pay clause as drafted the obligation of the buyer of the services to pay for the shortfall from the minimum payment did not arise from a breach of an obligation to take services having a minimum value but from a separate and contingent obligation to make good the shortfall in payment for services. As a result the obligation to pay should not be treated as a penalty and the obligation could be enforced.

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[12] The same issue arose in the context of US take-or-pay cases involving the gas producers and the pipeline companies (see footnote 3). Some disputes were litigated in the US courts but the validity of the take-or-pay obligation was generally upheld. There was little incentive to litigate the validity of the take-or-pay obligation in the courts in Great Britain because of the strength of the legal argument in favour of its validity.

In the context of gas take-or-pay clauses incorporating make-up and carry forward provisions a separate argument may also be made. This is that the compensatory effect for the buyer of these provisions is evidence that the payments for gas not taken are not intended as damages for failure to take the minimum quantity but form part of a pre-payment arrangement under a separate obligation to pay for gas not taken by which the seller is compensated for the costs which it would otherwise incur from the reduced cash flow resulting from the breach of that obligation.

The legal position in connection with penalties may not be the same under the laws of other EU Member States (e.g. Germany and Greece). If it is not then the possibility of challenging the take-or-pay clause on the grounds that the payment obligation is a penalty may be available. The point may become relevant in the context of an application for a derogation under Article 25 of the EU Gas Directive where the criterion – 'the efforts made to find a solution to the problem.' (Article 25.3(f)) is to be applied. In this connection reference should be made to section 11.5.1 below.

11.5 Provisions of EU Gas Directive

The relevant provisions of the EU Gas Directive relating to take-or-pay contracts are contained in Articles 17 and 25. The Directive (Article 17.1) permits pipeline undertakings to refuse access to their systems on the basis of 'serious economic and financial difficulties with take-or-pay contracts having regard to the criteria and procedures set out in Article 25'[13].

11.5.1 Article 17

The effect of Article 17.1 is to permit a gas transportation company to defer the onset of competition in respect of those of its customers who are supplied by it under a long-term take-or-pay contract if the granting of access to its system to a third party for the purposes of supply to those customers would cause the company 'serious economic and financial difficulties with take-or-pay contracts ... ...'. If the granting of access would not cause such difficulties then access cannot be refused except on the other grounds specified in Article 17.1.

It should be noted that the Directive does not contain any provisions which have the effect of making illegal or unenforceable take-or-pay obligations under contracts entered into by gas pipeline companies (or any other company) prior to 10 August 1998 (the date upon which the Gas Directive came into force) or prohibiting or making unenforceable take-or-pay obligations in gas purchase contracts entered into after that date.

Article 25 lays down the procedures and criteria to be applied in connection with an application from a gas transporter for a temporary derogation from the requirement to grant access to its system on the basis of the grounds of serious economic and financial difficulties with take-or-pay contracts. The procedures and criteria, which are quite complex, are explained below.

11.5.2 The Article 25 procedure

Under Article 25 a pipeline undertaking may apply for a temporary derogation from the relevant pipeline access requirement of the

[13] Article 17.1 also permits transportation companies to refuse access to their systems on the basis of lack of capacity, or where the access to the system would prevent them from carrying out public service obligations. The expression public service obligations is not defined in the Directive but Article 3.2 states that public service obligations may relate to security, including security of supply, regularity, quality and price of supplies, and to environment protection.

Directive (i.e. Article 15 (negotiated access) or 16 (regulated access))[14] depending on the choice of access regime made by the Member State concerned). Member States may permit undertakings to refuse access either before or after the undertaking has applied for a temporary derogation. Duly substantiated reasons for refusal must be given. Where an undertaking has refused access the application shall be presented without delay. Applications must be made on a case by case basis (Article 25.1).

An application may be made if the undertaking 'encounters, or considers it would encounter, serious economic and financial difficulties because of its take-or-pay commitments accepted in one or more gas purchase contracts'. Article 25.3 clarifies the term 'serious difficulties' with the following statement: 'Serious difficulties shall in any case be deemed not to exist when the sales of natural gas do not fall below the minimum offtake guarantees contained in a gas purchase take-or-pay contract or insofar as the relevant gas purchase take-or-pay contract can be adapted or the natural gas undertaking is able to find alternative outlets'.

Applications may be made in respect of contracts entered into before or after the coming into force of the Directive. Article 25.3 states that in respect of a contract entered into before 10 August 1998 a decision on a request for a derogation 'should not lead to a situation in which it is impossible to find economically viable or alternative outlets'. The statement would appear to enhance the possibility of obtaining derogations in respect of such contracts.

The granting of a derogation involves a two stage procedure. Applications for derogations must be made to the Member State or its designated competent authority in which the pipeline to which access has been or will be refused is situated. If the Member State concerned takes a decision to grant a derogation then that decision must be referred to the European Commission. Article 25.3 contains a non-exclusive list of nine criteria to be applied by the Member State in considering applications for derogations and also by the Commission in considering a decision of a Member State to grant a derogation.

The first stage - application to Member State/Designated Competent Authority

The conditions which an undertaking must satisfy when making an application for a derogation have already been explained. However, two further points should be noted.

The possibility for an undertaking to apply for a derogation before serious economic and financial difficulties have arisen is important. It is

[14] Article 14.1 of the Gas Directive permits Member States to adopt a negotiated access procedure or a regulated access procedure, or both of them. The differences between the two types of procedures are explained in Chapter 12, section 12.6.2.

particularly important if the Member State permits (as it is entitled to do under Article 25.1) applicants to refuse access before they have applied for a derogation. However, as mentioned, applicants who do so refuse access must submit an application without delay.

If alternative solutions are not reasonably available and taking into account the criteria contained in Article 25.3, the Member State or its designated competent authority may decide to grant a derogation.

The second stage - The Commission

Article 25.2 imposes on the Member State concerned or, if appropriate, its designated competent authority, the obligation to notify the Commission without delay of its decision to grant a derogation. The Commission may within four weeks of receipt of the notification request the Member State or its designated competent authority to amend or withdraw the decision to grant a derogation. If the Member State or its designated authority does not comply with the request within a period of four weeks then the Commission is authorised to make a decision in accordance with procedure 1 of Article 2 of Decision 87/373 EEC[15].

11.5.3 The nine criteria of Article 25.3

The nine criteria are set out below. They are set out in the order in which they might be considered by an applicant for a derogation and not the order in which they are listed in Article 25.3.

A possible order of priority of the criteria to be applied by an applicant for a derogation is as follows:

(1) The dates of signature and terms of the contract in question, including the extent to which they allow for market changes (Article 25.3(e)).

(2) The seriousness of the economic and financial difficulties encountered by natural gas undertakings and transmission undertakings or eligible customers (Article 25.3(a)).

(3) The need to fulfil public service obligations and to ensure security of supply (Article 25.3(b)).

(4) The position of the natural gas undertaking in the gas market and the actual state of competition in this market (Article 25.3(c)).

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[15] Decision 87/373 EEC was repealed in July 1999 by Council Decision 1999/468 EC of 28 June 1999 laying down the procedures for the exercise of powers conferred on the Commission. The Commission must now make its decision in accordance with the advisory procedure set out in Article 3 of Decision 1999/468 EC.

(5) The level of connection of the system with other systems and the degree of interoperability of these systems (Article 25.3(h)).

(6) The extent to which, when accepting the take-or-pay commitments in question, the undertaking could reasonably have foreseen, having regard to the provisions of this Directive, that serious difficulties were likely to arise (Article 25.3(g)).

(7) The efforts made to find a solution to the problem (Article 25.3(f)).

(8) The objective to achieve a competitive gas market (Article 25.3(a)).

(9) The effects the granting of a derogation would have on the correct application of the Directive as regards the smooth functioning of the internal natural gas market (Article 25.3(i)).

Comments

It is quite clear from Article 25.3(e) (see above) that an application for a derogation in respect of a contract entered into before the Directive entered into force will be treated more sympathetically than an application in respect of a contract entered into after the Directive came into force. Also it seems likely the degree of sympathy will be greater for contracts entered into some time before the Directive came into force – i.e. a contract entered into in 1991 when the process of negotiation of the Directive was first starting would receive more sympathetic treatment than a contract entered into in 1997 when the process was nearly completed.

In view of Article 25.3(f) it is difficult to envisage that an application for a derogation in respect of a contract entered into after 10 August 1998 will succeed unless it contains pricing provisions which reflect market changes (particularly the effect of gas-to-gas competition).

We are not aware of any cases where the Article 25 procedure has been invoked by a gas transportation company. In the case of Continental West European transportation companies this may be because the relevant take-or-pay contracts contain price reopener clauses which protect them from the effects of gas-to-gas competition

It is likely to remain important for major gas wholesaling companies that also carry on a transportation function and are responsible for ensuring security and continuity of supply to include in their gas purchase portfolio an element of long-term take-or-pay gas. As mentioned, the Directive does not prohibit such contracts. Such contracts would co-exist with the wholesaler's medium- and short-term contracts and also its spot contracts. For a contract to be used in a gas market where gas prices are not indexed the inclusion in the price re-opener clause of a provision that the introduction of gas-to-gas competition is an event which would trigger the operation of the clause should not in any way inhibit, at least from a contractual point of view, the parties from entering into a long-term take-or-pay contract. However, the inclusion of such a provision would diminish the security of cash flow hitherto enjoyed by the producers, a situation that many producers will assert is very damaging to their interests and to the development of new gas fields. In a contract for use in a gas market where gas prices are indexed the price adjustment clause should reflect movements in gas prices.

11.6 Impact of EU competition law

11.6.1 Basic provisions

The provisions of the EC Treaty relating to anti-competitive agreements are contained in Article 81 (ex Article 85) of the EC Treaty (as amended)[16].

Article 81(1) prohibits agreements between (inter alia) undertakings that may affect trade between Member States and that have as their object or effect the prevention, restriction or distortion of competition within the common market. Article 81(2) provides that such

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[16] The Articles, Titles and Sections of the Treaty establishing the European Community ("ECT Treaty" or "Treaty of Rome") and also those of the Treaty on European Union ("Maastricht Treaty") as amended by the Treaty of Amsterdam were re-numbered by the Treaty of Amsterdam. Under this re-numbering Article 85 of the EC Treaty was re-numbered as Article 81.

Article 81 (ex Article 85) EC Treaty

"1. The following shall be prohibited as incompatible with the common market; all agreements between undertakings, decisions by associations of undertakings and concerted practices which may affect trade between Member States and which have as their object or effect the prevention, restriction or distortion of competition within the common market, and in particular those which:

(a) directly or indirectly fix purchase or selling prices or any other trading conditions;

(b) limit or control production, markets technical development, or investment;

(c) share markets or sources of supply;

(d) apply dissimilar conditions to equivalent transactions with other trading parties, thereby placing them at a competitive disadvantage;

(e) make the conclusion of contracts subject to acceptance by the other parties of supplementary obligations which, by their nature or according to commercial usage, have no connection with the subject of such contracts.

2. Any agreements or decisions prohibited pursuant to this Article shall be automatically void.

3. The provisions of section 1 may, however, be declared inapplicable in the case of:

- any agreement or category of agreements between undertakings;
- any decision or category of decisions by associations of undertakings;
- any concerted practice or category of concerted practices;

which contributes to improving the production or distribution of goods or to promoting technical or economic progress, while allowing consumers a fair share of the resulting benefit, and which does not:

(a) impose on the undertakings concerned restrictions which are not indispensable to the attainment of these objectives;

(b) afford such undertakings the possibility of eliminating competition in respect of a substantial part of the products in question."

agreements shall be automatically void. However Article 81(3) contains provisions that permit the European Commission to grant exemptions from the application of the prohibition in certain circumstances. Also, under Regulation 17/62[17] a procedure was established whereby a party to an agreement may apply to the European Commission for a negative clearance (i.e. a statement by the European Commission competition authorities) that the proposed agreement did not infringe the prohibition of Article 81(1) and/or an exemption that although the arrangements fell within the prohibition of Article 81(1) the arrangement should be exempted from the prohibition under the terms of Article 81(3).

Provisions in an agreement which contravene Article 81(1) will be void (unless the provisions of Article 81(3) are declared inapplicable) and therefore unenforceable. In addition penalties may be imposed on the parties by the European Commission.

11.6.2 Legal issues relating to gas supply contracts

These are the legality under EU competition law of:

- the long-term exclusive gas supply contract;
- the exclusive supply obligations arising from the dedication provisions contained in depletion contracts; and
- the joint gas selling arrangements of the producers.

Each of these issues is examined and discussed below.

EU law and long-term exclusive energy supply contracts

It is generally accepted that long-term exclusive supply contracts may restrict or distort competition because for a long period they restrict the freedom of the seller to sell to third parties and the buyer to buy from third parties. If in addition the long-term contract includes a take-or-pay obligation then the contract places an additional constraint on the buyer from seeking supplies from third parties.

Although there are no cases in which the Commission or the European Court of Justice (ECJ) have considered the application of Article 81 to long-term gas take-or-pay contracts, the Commission has considered the application of its provisions to long-term exclusive power purchase contracts. The case (the Pego Case) involved contractual arrangements between a power generating consortium (which included National Power plc, Electricité de France and Electricidade de Portugal (EDP)). The generating consortium (the 'Generator'), agreed to purchase from EDP (the state owned electricity generating transmission and distribution company), a coal fired

[17] Council Regulation No 17/62 (OJ L13, 21.2.62, p204).

generating project that EDP was constructing in Portugal. The Generator agreed to complete the construction of the generating capacity. There was to be a Power Purchase Agreement (PPA) under which the Generator agreed to provide the whole of the capacity and energy of the power station to EDP for a period of 28 years.

The parties applied to the Commission for a negative clearance/exemption. In the Commission's notice[18] the Commission required, as a condition of granting the exemption that the exclusive supply arrangements should be reduced from 28 years to 15 years. For the remaining thirteen year period the Generator was to negotiate a 'first option' to supply electricity to third parties in the competitive electricity market if there was surplus capacity which was not required for supply to the captive market. The rationale for reduction in the 28 year supply commitment was that 15 years was the period for pay back of the financing arrangements for the construction of the generating plant which had been entered into by the consortium.

This decision may be relevant to the duration of the take-or-pay commitments of the buyer under long-term gas supply contracts. As mentioned in section 11.3.1 the take-or-pay commitment is frequently for the whole of the contract period (15 – 25 years). In the case of many contracts this is a considerably longer period than the pay back period for the financing. The continuation of the take-or-pay obligation after that period has expired constrains the freedom of the buyer to purchase gas from third-party sources, a factor which is of considerable significance when price indexed gas markets are developing or expected to develop.

It will be interesting to see whether the Commission challenges under Article 81 the validity in long-term gas contracts of take-or-pay commitments for the whole of the contract life. Such commitments if they only affect trading within the UK or any part of it might also be challenged in the UK under the provisions of the Competition Act 1998[19]. A corresponding commitment affecting trade within another

[18] Notice pursuant to Article 19(3) of Council Regulation 17 concerning a request for a negative clearance or exemption pursuant to Article 85(3) of the EEC Treaty. Case No/V34.598 - Electricidade de Portugal/Pego project.

[19] The Competition Act 1998 introduced into UK law prohibitions against agreements and arrangements which restrict trade within the UK or any part of it. These are based on the prohibition of Article 81 (ex Article 85) of the EC Treaty. Also a prohibition against abuse of dominant position in the UK or any part of it is introduced. This is based on the provisions of Article 82(ex86) of the EC Treaty. The Act came into full effect on 1 March 2000. Schedule 13 of the Act contains transitional provisions which exempt certain types of gas contracts from the prohibition against restrictive agreements. The provisions apply to gas purchase contracts for delivery in Great Britain entered into before 1 March 2000 for the purchase of gas produced from the North Sea. The transitional provisions expire in March 2005.

Member State might also be challenged under the national competition laws of that Member State.

EU law and dedication provisions in depletion contracts

Dedication provisions are only found in depletion contracts. They involve the dedication by the seller to the buyer of the whole of the economically recoverable reserves of the field. Dedication is normally accompanied by an agreement by the seller not to sell or use any of the gas produced from the field except for purposes of supplying gas under the contract. The rationale for these obligations is that they are necessary for the buyer for the purposes of ensuring its security of supply (until recently the buyer was in many cases a national monopoly supplier) and that the dedication is offered by the seller in return for the acceptance by the buyer of the take-or-pay obligation.

The main competition law concern in connection with dedication provisions is, as in the Pego case, the commitment by the seller to supply energy on an exclusive basis for a long period (from 15 to 25 years).

Dedication provisions are regarded as anti-competitive as the seller is prevented for the whole of the economic life of the field from supplying gas produced from the field to third parties. This is likely to be anti-competitive as other potential buyers cannot buy gas from that field at any stage in its life. It is particularly undesirable in markets where there is gas-to-gas competition.

However the argument can be made that as the dedication is accepted in return for the acceptance by the buyer of a take-or-pay obligation the dedication provisions should be permitted to continue for the duration of the financing payback period (i.e. the principles in the Pego case should be followed). It should however be noted that the payback period for upstream gas facilities are likely to be shorter than the 15 year period accepted by the Commission in the Pego case.

It would seem unlikely that long-term depletion contracts entered into after the coming into effect of the EU Gas Directive in August 1998 that contain a dedication clause for the life of the field would be approved by the Commission. However the Commission might be attracted by a convincing security of supply argument by the buyer particularly in circumstances of scarcity of supply. A dedication provision the duration of which was linked to the project financing payback period might be acceptable to the Commission.

EU law and joint gas selling arrangements

Among the list of examples of agreements which may affect trade between Member States and therefore may fall within the prohibition on anti-competitive agreements contained in Article 81 EC Treaty a specific mention is made of agreements which 'directly or indirectly fix purchase or selling prices or any other trading condition'. One of the main purposes of the prohibition is to prohibit international selling cartels. However it may have a significant impact on the joint marketing of gas by producing licence holders[20].

The importance of EU law in this area is well illustrated by the statements of the European Commission[21] in connection with the joint selling of gas from the Britannia Gas Condensate Field (a UK continental shelf field).

In this case the Britannia field joint venturers, who were the UK subsidiaries of a number of major international oil companies, applied for a negative clearance/exemption in respect of an oral agreement to appoint one of their members to be responsible for the conduct of negotiations with potential buyers of the Britannia field gas. The negotiator was to negotiate for sale of part or all of the gas from the field on behalf of all member companies. The member companies had the right to take part in the negotiations and some did so. The negotiator had no power to bind the other joint venturers and each member could decline to accept the sales arrangements concluded by the negotiator. The participants were free to sell their gas supply in competition with any arrangements made as a result of the negotiations by the appointed negotiator, but none of them did so.

In reaching its decision the Commission decided that the relevant market was the future supply of natural gas by producers to the 'wholesale' level ('forward gas'). Competition in the upstream market was considered by the Commission to consist in competition in placing potential production with buyers (i.e. bringing a field to production and selling its gas for supply in a future period). The Commission decided that there could be no potential contractual competitor to Britannia within the time frame as there was then no means of transporting such gas to the UK and no certain prospects of being able to do so. For the sale of Britannia gas on Continental markets the lack of physical infrastructure and the uncertainty about the future existence of such infrastructure made forward sale of Britannia gas routed through the UK mainland impracticable. In reaching this view the Commission took into account that during the period in which the agreement was in effect (February 1992 to December 1994) there was no pipeline connection

[20] As Exploration and Production licences are frequently granted to consortia of companies and the costs of development and operation are shared between them it is not surprising that common contract terms (in some cases including prices) have been agreed between the consortia members and their buyers. This practice was particularly prevalent during the period during which depletion contracts and national monopoly buyers were common. In those markets where gas-to-gas competition has been introduced and where medium/short-term supply contracts are now in use the joint selling of gas has substantially disappeared.

[21] Notice pursuant to Article 19(3) of Council Regulation No 17 Case No IV/E-3/35.3.54 – The Britannia Gas Condensate Field (96/C291/05).

between the UK gas market and the Continental gas market. At that time no firm decision had been made to construct the UK-Continent Gas Interconnector[22]. The Commission considered the relevance of the already constructed Interconnector between the UK and the Republic of Ireland. This pipeline was relatively small and intended to safeguard security of supply if Irish domestic production of gas was interrupted. The Commission considered that the Interconnector had no significant impact on trade between Member States.

In the circumstances the Commission considered that the agreement was not liable to have an appreciable effect on trade between Member States and subsequently granted a negative clearance.

In its analysis the Commission emphasised that the effects of the agreement on trade must be considered in the time frame of the agreement (i.e. February 1992 – December 1994) and with regard to the information available at the time of the agreement's implementation. This reservation is extremely important. The UK-Continent Interconnector has since come into operation. It seems highly unlikely that a negative clearance would now be given in the case of similar joint negotiating arrangements particularly involving price[23].

[22] See footnote 8 above.

[23] The comments of the Commission in its decision to close its examination on the Corrib gas field in Ireland (European Commission Press Release, IP/01/578, April 20 2001) support this view. Also the recent actions of the Commission in relation to the Norwegian joint negotiating consortium for the sale of gas produced from the Norwegian sector of the North Sea (the "GFU") and the sales contracts entered into under the terms negotiated by the GFU indicate the rigorous approach now being adopted by the Commission to joint selling (European Commission Press Release – Commission Objects to GFU Joint Gas Sales in Norway IP/01/830 May 2001).

12 Gas pricing arrangements

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12.1 Introduction

Prior to the emergence of price indexed gas markets (see Chapter 11), the purpose of the price adjustment clause in the North American and British gas markets was to enable the seller to benefit (i.e. to obtain full market value or, in the case of USA, secure the most that the regulators would allow)[1] from increases in prices of competing alternative fuels and to enable the buyer's selling prices to remain competitive if prices of alternative competitive fuels fall[2]. The clause was also used, particularly in British contracts, to provide a measure of protection for both parties against the effects of inflation/deflation or possibly devaluation.

The purpose was achieved by providing an automatic 'escalation' mechanism for adjusting the price of gas supplied so that the contract price remained competitive with the competing alternative fuels. Sometimes this automatic mechanism was combined with a 'Price Re-opener' (see below). The automatic mechanism used linked the contract price in each period to the movements of published indices of the competing fuels. These have traditionally been alternative oil fuels (i.e. fuel oil and gas oil) but more recently, particularly in gas supply contracts to power generators, electricity and coal have been included. Price adjustment clauses were invariably included in long-term gas supply contracts and in medium term contracts (3 years or more). Shorter term contracts (particularly those of 1 to 3 years duration) usually include price adjustment clauses. In contracts for one year or less the need for protection against movements in prices of competing fuels diminishes.

The distinction between the initial purpose of the price adjustment clause and the purpose of the clause in the price indexed gas markets of North America and Britain is reflected in section 12.2 and section 12.3 below. Section 12.2 contains illustrative texts (British form and Continental Western European form) of price adjustment clauses linked to fuel oil and gas oil price movements. Section 12.2.4 contains a commentary on the texts. Section 12.3 contains, in section 12.3.2, an illustrative text of a gas price linked adjustment mechanism in a contract for use in price indexed gas markets.

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[1] In US contracts the common practice was to enable the seller to obtain the maximum price authorised by the relevant regulator (i.e. FERC or the State Regulator).

[2] In the case of the Continental Western European gas markets these were initially, and currently remain, the prime purpose of the price adjustment clause. This situation will change as gas to gas competition emerges and when price indexed gas markets emerge.

12.2 Price adjustment clauses

12.2.1 Key provisions

The illustrative texts set out below (British form and Continental Western European form) are shortened versions of a price adjustment clause for a gas market that is not price indexed. They set out the price adjustment formula and the provisions dealing with the calculation of new values of the indicators in the formula.

It is particularly important in drafting price adjustment clauses to ensure that the chosen indices are reliable and published regularly. The full text of such a clause would also contain provisions relating to the following matters:

- change in the base period/weighting/classification of the inflation index;
- unavailability or change in the basis of, or error in, an indicator;
- an expert to be appointed to establish a replacement indicator or relevant figure;
- a provisional contract price and provisional prevailing contract price.

The texts of these provisions are not included in the shortened version of the clause as their precise contents depend very much on the laws and procedures of the market into which the gas is sold. However the commentary on the text (section 12.2.4) contains comments on the main issues connected with the drafting of such provisions.

12.2.2 British form

The multiplicative formula is normally used in gas contracts in Britain.

1. Price Adjustment

1.1 In the month of October in each Contract Year (herein referred to as the 'Review Month') the Initial Price (P_o) shall be revised for the purpose of determining the Prevailing Contract Price for the next Contract Year.

1.2 The Prevailing Contract Price (P) shall be obtained by applying to the Initial Contract Price (P_o) the following formula:

$$P = P_o \left((a) \frac{GO}{GO_o} + (b) \frac{FO}{FO_o} + (c) \frac{C}{C_o} + (d) \frac{E}{E_o} + (e) \frac{I}{I_o} + (f) \frac{PPI}{PPI_o} \right)$$

P_0 is the Initial Contract Price of [ ] [pence] per hundred [megajoules] (or other appropriate unit of energy)

GO is the arithmetic average of the prices of quarterly prices of Gas Oil in [Great Britain] expressed in [Pounds Sterling] per tonne (each such quarterly price being herein called the 'Gas Oil Price') for the four (4) consecutive quarters ending three (3) months prior to the beginning of the Review Month as published by the [Department of Energy] in the monthly publication *Energy Trends* under the heading 'Prices of fuels used by Industry in Great Britain' and the sub-heading 'Gas Oil' for the size category of consumer entitled 'Large'

GO_0 is the arithmetic average of the prices of Gas Oil for large consumers for the four (4) quarters covering the period July [ ] to June [ ] (inclusive) which is agreed to be [ ]

FO is the arithmetic average of the quarterly prices of Heavy Fuel Oil in [Great Britain] expressed in [Pounds Sterling] per tonne (each such quarterly price being herein called the 'Fuel Oil Price') for the four (4) consecutive quarters ending three (3) months prior to the beginning of the Review Month as published by the [Department of Energy] in the monthly publication *Energy Trends* under the heading 'Prices of fuels used by Industry in Great Britain' and the sub-heading 'Heavy Fuel Oil' for the size category of consumer entitled 'Large'

FO_0 is the arithmetic average of the Fuel Oil Prices for large consumers for the four (4) quarters covering the period July [ ] to June [ ] (inclusive) and which is agreed to be [ ]

PPI is the arithmetic average of the monthly values of the index 'Index numbers of producer prices - Output home sales: - Output of manufactured products' (which index is herein called the 'Producer Price Index') for the twelve (12) months ending three (3) months prior to the beginning of the Review Month as published in the Central Statistical Office *Monthly Digest of Statistics*

PPI_0 is the arithmetic average of the monthly values of the Producer Price Index for the 12 months covering the period July [ ] to June [ ] inclusive.

NOTE: Appropriate indices should be added for coal (C), retail electricity (E) and (I) (supply of electricity to industrial users).

The letters (a), (b), (c), (d), (e) and (f) represent the fraction adding up to one or less representing the weighting of the importance of each of the components.

12.2.3 Continental Western European form

The typical Continental Western European Price Adjustment Clause differs from the corresponding British clause in two main respects. Price adjustments are made more frequently than one year (half yearly/quarterly) and the formula is generally 'additive' rather than the multiplicative British form. This form includes additional ingredients to convert different energies from their published unit - gallons, tonnes etc. - into a common (thermal) unit and frequently these are adjusted to reflect different efficiencies in use and different pass-through factors (i.e. relative weightings and, with sometimes, less than 100 per cent pass-through to the gas price).

A typical formula might be as follows:

$$P_n = P_o + 0.0036\ (GO_n - GO_o) + 0.0017\ (HFO_n - HFO_o)$$

[Other indices to be added as appropriate.]

Where:
P_n is the applicable price to the buyer
P_o is the initial price to the buyer

The decimal fractions represent a combination of conversion and pass through factors plus any adjustment for efficiencies. Conversion factors reflect the fact that the price of the relevant oil product is expressed by reference to weight or volume and must be converted into an appropriate energy unit such as a kWh using an agreed conversion factor. Additionally, a currency conversion mechanism may be necessary.

For Gas Oil prices Continental Western European (German) contracts generally use official German Government statistics published monthly in *Preise und Preisindizes für gewerbliche Produkte (Erzeugerpreise)* published by the Statistisches Bundesamt Wiesbaden for various districts in Germany. Even in contracts outside Germany these are used in the absence of reliable local equivalents. The German statistics correlate quite well with Rotterdam or North West Europe Indices used in earlier contracts. The gas oil index 'CARGOES, CIF, NWE, BASIS ARA, GASOIL 0.2' as published in *Platts European Marketscan* by the McGraw-Hill Companies Inc. was frequently used.

For Continental Western European (German) contracts prices for heavy fuel oil of a maximum sulphur content of one (1) per cent published in the official German Government statistics published in Wiesbaden are normally used but 'CARGOES, CIF, NWE, BASIS ARA, IPCT' as published in *Platts European Marketscan* by the McGraw-Hill Companies Inc is also frequently used for these purposes.

12.2.4 Commentary

Base periods

The choice of the period to be used for the purposes of computing the base value of each of the chosen indices for competing fuels/inflation will have a significant impact on the price level in each subsequent year. For example, the choice as a base period of a period in which the prices of competing fuels are considered to be historically low would be particularly damaging to the buyer unless factored into the price.

The choice as to the frequency (e.g. yearly/6 monthly/quarterly) of price reviews may have significant, but uncertain, implications for future prices under the contract. The uncertainty derives from the fact that the contract price of the gas is always established by reference to the uncertain movements of the chosen indices. In particular, if in the period between the signature of the contract and start of deliveries there are significant changes, up or down, in the values of the chosen indices, these will impact on the contract price of deliveries even in the first year of deliveries.

Frequency of price review

There is no standard practice as to the frequency of price reviews. Annual price reviews are common in British contracts but as mentioned half yearly and quarterly reviews are used more often in the Continental Western European contracts. The length of intervals between price reviews can have considerable economic consequences in times of rapidly rising and also rapidly falling prices. Frequent price reviews are beneficial to the seller in times of increasing prices. In times of falling prices frequent reviews are favourable to the buyer.

Choice of pricing elements

As mentioned the formula would normally contain indices representing competing fuels and may include inflation. For many years the only competing fuels were fuel oil and gas oil. However in the gas market in Great Britain the developing competition with electricity led in the 1990s to the inclusion of first coal and then electricity in the formula for gas sales to power generators.[3]

[3] It should be noted that gas tolling agreements (sometimes called energy conversion agreements) in which an owner of gas enters into an agreement with an electricity generator under which the generator will, for a fee, make available generating facilities for the purpose of converting the gas into electricity do not involve a sale of the gas. The generator provides a service and does not own the gas or the electricity produced from it.

Evaluation of share in formula

The evaluation of the percentage share of a competing fuel in the formula is, logically, made on the basis of the market share of the competing fuel at the time the contract is entered into. Contracts sometimes include a provision to deal with variation of the percentage share during the contract life to cover the position if the market share of the particular fuel should change substantially from that at the time at which the contract was entered into.

Changes in the base, weightings or classification of indices

During the life of a contract it is quite likely that such changes will occur to one or more of the chosen indices. Such changes are particularly likely to occur to inflation indices as these include components that change in importance as time goes on, leading to a need for reweighting. Inflation indices are also politically sensitive and will be rebased to avoid the numbers appearing 'too large'. It is important that the contract contains a clear procedure for dealing with disputes over the variations required following such a change. Typically the contracts provide for a period during which the parties attempt to agree a solution and, if no agreement is reached, recourse to an expert whose determination is to be binding.

Rebasing error or non-publication of indices

It is normal to include provisions to deal with these possibilities. Here again a clear dispute resolution procedure is required.

Provisional contract price arrangements

It is important to ensure that where it is not possible at the price review date to calculate the revised price there is always an agreed price for gas supplied under the contract. This need is met by providing that the contract price in the period immediately preceding the price review in which the difficulty of calculating the adjusted price occurred shall apply until such time as the revised price is agreed. A financial adjustment procedure is included to deal with overpayments/underpayments in the period between the price review date and the agreement on the revised price.

Bottom Stops (or Floors) and Top Stops (or Caps)

Experiences in operating price adjustment clauses in times of major price uncertainty led to a practice of including in price adjustment clauses provisions that impose minimum and maximum price limits on the price that may be charged. This can be dealt with by including specific Floors and Caps but more sophisticated techniques like using separate and differently constituted indices as upper limits – Top Stops – or lower limits – Bottom Stops – are frequently used.

12.3 Price indexed gas markets

12.3.1 OTC and exchange markets

The 'de-regulation' or de-monopolisation of the gas industries and advent of gas to gas competition in the gas markets in the US and Great Britain brought about the buying and selling of large quantities of gas under 'spot' and short-term contracts. As the spot and short-term market prices are potentially and actually volatile there was an immediate need for the market participants (producers, wholesalers, traders, marketers and customers) to use appropriate instruments to manage their price risk in the new environment.

The final buyers and marketers were the main impetus for this development as they were concerned to buy gas at the same price as their competitors (especially new entrants). They were also eager to have the right to buy their future gas requirements at a known relationship to the market. On the other hand both buyers and the producers also benefit from buying or selling forward at a known price when the market is sufficiently developed to have a forward curve of future prices but with the ability to hedge those prices if necessary.

Such developments required a liquid and price transparent market. In the over-the-counter (OTC) market such price transparency was obtained in Great Britain, and the USA before it, initially from price reporting agencies/publications that produced published prices and price indices[4]. Later in both countries a formal exchange[5] was set up dealing in a gas contract for future delivery i.e. the New York Mercantile Exchange (Nymex) in the USA and, in the UK, the International Petroleum Exchange (IPE). These Exchanges show prices over the day and end of day settlement prices on electronic screens. By means of the reported OTC prices or Exchange based prices both parties may protect themselves from the consequences of price movements

[4] The figures quoted on an OTC index represent assessments of prices made by independent third parties from information about bid and offer prices for supplies of gas under individually negotiated bilateral supply contracts for the delivery of gas on a specific day at a specific delivery point. Information about such prices is obtained by enquiries of the various market participants. Such information is usually supplied on a confidential basis. Deals done under such contracts are known as 'over the counter' deals. The implication is that they are bespoke deals but in practice they tend to be done on standard forms with only the quantity, location and price as the variables.

[5] The figures quoted in an Exchange Index are market information about actual settlement prices for pipeline deliveries on a specific day at a specific delivery point sold and purchased under the terms of a standard form of contract traded on a regulated energy exchange.

between the date upon which the contract is entered into and the delivery date by entering into hedging arrangements and/or by indexing to current prices.

The prices and contract terms of OTC deals in the US market are typically based upon 30 day supply contracts for pipeline delivery at specified delivery points such as state borders or city gates. The published prices are for delivery within the month. Additionally, however, new gas and modifications to current longer term or monthly contracts are made on a daily basis at daily prices. Several publications report prices. Prices are reported, for example, daily in *Gas Daily* (a Financial Times publication) and *Daily PriceLine*, weekly in *Natural Gas Week* (both the Oil Daily Co.), *Gas Markets Week* (also a Financial Times publication) and *Natural Gas Intelligence* (Intelligence Press Inc.) and monthly in *Inside Ferc's Gas Market Report* (McGraw-Hill).

There are four gas futures hubs in North America, three of which are wholly or partly run by Nymex. Nymex trades natural gas futures and options contracts based on delivery at the Henry Hub (Louisiana), Alberta (Canada), and the Permian Basin (Texas). The other hub is run by the Kansas City Board of Trade (KCBT) which trades natural gas futures and options contracts based on delivery at the Permian–Waha Hub, West Texas. The major part of US trading takes place at Henry Hub.

The reported prices for Nymex futures are normally quoted for 24 individual months ahead but it is possible to trade for up to 36 months ahead. Option contracts are available for 12 consecutive months plus 15, 18, 21, 24, 27, 30, 33 and 36 months on a June–December cycle.

The prices and contract terms of OTC deals in the gas markets in Great Britain are based upon several different points of supply being either at the National Balancing Point (NBP) – a notional point on the UK national transmission system – or beach terminals such as St Fergus or Bacton terminal and at sub terminals within the major terminal. Also, in late 1998 and 1999 an OTC market in gas for delivery at Zeebrugge (the Continental landing point of the UK/Continental Gas Interconnector) emerged. This was followed in November 1999 by the launch of the Zeebrugge Gas Trading Contract (revised Spring 2002). This contract is for physical deliveries. It contains a voluntary set of conditions for trading and companies may still use their own bilateral contracts or amend the special conditions. Also, in the Spring of 2002, gas trading got underway at the Bunde-Oude hub on the Dutch-German border.

Information about these sales and also sales of pipeline capacity at terminals are published each weekday in publications such as *European Spot Gas Markets (ESGM)* – formerly *British Spot Gas Markets (BSGM)* – (PH Energy Analysis Ltd), the Petroleum Argus *European Natural Gas*, Platts *European Natural Gas Report* and *Gas Daily* (formerly a Financial Times publication). The gas supply prices published are typically for Day Ahead, Balance of the Month (BoM), the

Prompt Month and the next 5 months individually, and several quarters and years ahead. Weekend and Within-Day prices are also available and some publications make up purpose built indices specifically for price indexing, an example being the Heren Index in *ESGM* and the IPE Natural Gas Index.

The IPE is the only UK exchange on which natural gas futures contracts are traded. Delivery is only at the NBP. The standard delivery period for a 'lot' on the IPE is a month but one week ahead daily prices are also traded and quarter prices are constructed from the monthly figures. An initial 12 whole months curve was soon extended to balance of month and 15 further months (with 7 daily contracts). Then as of October 1999 an additional 7 quarter months were added. Despite this wide selection of published or screen prices only a limited number of examples are used in practice.

12.3.2 Use of published indices

In the North American market the custom is to link term contracts (anything more than a month or two) to an index, i.e. the appropriate reported price at the time of delivery (published for many locations) plus or minus a few cents. Term contracts generally command a small premium over the daily or monthly index price. The price for the gas is the published price on the day or month of delivery plus the premium or, possibly, minus the discount, agreed at the time of the deal.

Alternatively (in the US) buyers are invited to fix upon a Nymex Henry Hub price as shown on the official screen and agree with the counterparty the appropriate basis differential for the delivery point in question (being the appropriate location differential from Henry Hub).

In the UK the vast majority of short-term contracts are made on a fixed price basis. This is because they generally provide for delivery within a limited period of time e.g. Day Ahead, BoM, the next few months or quarters. Fixed prices are, of course, influenced by the published value of reported deals, present and future but they do not specifically enter into the process of negotiation.

In both the US and UK it is possible to hedge a fixed price deal by taking the classic equal-but-opposite position on a futures exchange (Nymex or IPE). Options to buy or sell (call or put options) are arrangements to reduce or hedge risk, both requiring a price transparent market to allow proper pricing of options. Caps and Floors are also used – these being a particular form of an option.

In the early days of the traded market in Great Britain, i.e. before the IPE natural gas futures contract was launched in January 1997, parties wishing to index prices used prices published in, say *BSGM* or a blend of *BSGM* and *Petroleum Argus* prices – these being the pioneer price reporters. Generally monthly prices were used for indexing. After January 1997 the IPE settlement prices for Prompt Month Contracts started to be used for pricing of medium term contracts.

The use of the IPE prices on a Prompt Month basis in medium term bilateral OTC contracts is illustrated by the following typical wording:

> 'Contract Price' shall mean in respect of any Month of the Supply Period (a 'Relevant Month') the average of the official settlement prices published by the IPE in respect of its NBP natural gas contract for each IPE trading day during the Price Reference Period subject to Clause [X] below.
>
> 'Month' relates to the gas flow day, i.e. the period from 0600 hours on the first day of the calendar month until 0600 hours on the first day of the next following calendar month.
>
> 'Price Reference Period' in respect of a Relevant Month is the period starting on the last IPE trading day in the calendar month immediately preceding the calendar month immediately preceding the Relevant Month and ending on the penultimate IPE trading day of the calendar month immediately preceding the Relevant Month.

Clause [X] deals with unavailability of IPE settlement prices.

It provides that if:

(a) official IPE settlement prices have been unavailable for a period of eight (8) consecutive IPE trading days during a price Reference Period; or

(b) an error is contained in one or more official IPE settlement prices during a Price Reference Period; or

(c) the basis upon which official IPE settlement prices are calculated or compiled has changed so as to materially affect their validity for the purposes of ascertaining a realistic market price for gas at the NBP over any Relevant Month; or

(d) the IPE NBP natural gas contract has been discontinued;

either party shall have the right to give notice to the other, whereupon the parties shall meet and seek in good faith to agree a means whereby the effect of such occurrence can be removed by adjustment to or replacement of the official IPE settlement price as the basis for the Contract Price over the Price Reference Period or Periods affected by the occurrence. If agreement is not reached within 30 days the matter is referred to an expert.

The procedures for appointment of the expert and the procedures to be followed by the expert and powers of the expert are contained in the contract.

12.3.3 Changing forms of contract

The growth of short-term trading has led to standardisation of contracts in the OTC market. In both Great Britain and the USA individual firms developed their own 'standard' forms which in time became increasingly similar. There was also a movement to develop an industry wide model. In the US market a model form of contract has been prepared by the Gas Industry Standards Board. This is primarily intended for use by gas traders. In the British market a Standard Short-Term Flat NBP Trading Terms and Conditions (NBP 1997) was developed in 1997 and used for trading based on the NBP. This contract is explained and commented on in Chapter 9. It is used for nearly all OTC trading involving the national transmission system in the British market. A standard form is, of course, a pre-requisite for Exchange traded gas.

The emergence of standardised gas contracts generally involves the introduction of framework contracts which contain the standard contract terms such as warranties, events of default, liquidated damages, *force majeure* and credit provisions. As and when deliveries are required to be made under the contract a confirmation of the transaction is signed by the parties. This sets out specific commercial terms for the individual deliveries such as price, quantity, term, delivery points and any other special conditions. The standard contract terms are incorporated into the confirmation by reference. Where there is no framework contract the contract may in some cases be contained on a single sheet of paper. On the front are the details of the specific commercial terms and on the reverse the standard contract terms are set out.

12.4 Price re-opener clauses

12.4.1 Purpose

Price re-opener clauses are frequently used in long-term/medium-term contracts and are commonly found in the Continental Western European Gas purchase contracts. They are usually linked with the principle of 'Netback' pricing used in establishing prices for the major long/medium term contracts for the supply of gas to Continental Western Europe. Netback pricing is intended to secure that the price at which a gas wholesaler buys gas is at a level at which the wholesaler is able to sell the gas to the end consumer at a price that competes with competing fuels. This is achieved by 'netting back' (i.e. subtracting from) the price to the end consumer all transportation and other costs incurring in transporting the gas from the delivery point to the wholesaler's market.

Their purpose is to provide a mechanism for revising the price provisions where, as a result of changed economic circumstances affecting the buyer's gas market, the then prevailing price provisions of the contract do not reflect the changed market circumstances. An obvious result of changed circumstances would be that the price adjustment clause currently in use no longer fulfilled its purposes (see section 12.1 for description of purposes of the price adjustment clause).

12.4.2 Clauses

There is no standard form for a price re-opener clause as a number of important points are subject to negotiation on a case by case basis. A description is therefore provided of the main elements that are found in a traditional Continental Western European price re-opener clause. They are as follows:

- Right to request a price review:

  There is a 'trigger provision' under which either party is entitled to request a review of the price provisions (subject to restrictions on frequency – see below) if it believes that economic circumstances prevailing in the buyer's market area have changed significantly* as compared with the economic circumstances prevailing, in the case of the first request, at the time at which this contract was entered into and, in the case of any subsequent request, at the time when the last price adjustment was agreed under this clause. The request must be made in writing and contain full reasons for the request. The changes in economic circumstances must be beyond the control of the buyer and the seller.

**In some contracts there is no indication as to the magnitude of the change in economic circumstances that is required to trigger the clause. However in such circumstances the arbitrators would probably apply a significant effect test when determining whether the change in economic circumstances was sufficient to warrant an adjustment.*

An obligation on the parties to meet within a specified period [2] months from the date of the request to enter into discussions as to whether an adjustment of the price provisions is warranted and if so the terms of the alterations to be made.

- Factors to be taken into account in determining whether variation should be made and the extent of the variation:

  - any special delivery or other features relating to the contract;
  - price levels at the point of import of comparable long-term supplies of gas to Western Europe under current contracts having regard to all circumstances of such supply;
  - buyer's protection provision.

  It is agreed by the parties that at all times the price provisions of the agreement shall make it possible for the buyer to market the gas supplied under the terms of this agreement on reasonable economic terms in competition with other forms of energy* assuming sound marketing practices and efficient management on the part of the buyer.

  **In new contracts it would be prudent to include a reference to natural gas.*

- Description of any factors that are not to be taken into account in determining whether a variation is warranted:

  This clause frequently contains a provision allocating risk between the parties in the event of tax changes affecting natural gas or competing fuels. This is often a difficult issue as the interests of the seller and buyer are frequently totally opposed. The solution adopted will reflect the respective negotiating strengths of the parties.

- Request for arbitration in the event of failure to reach agreement:

If no agreement is reached within [6] months from the date of notification of the request for a price review a right for either party to submit the matter to arbitration in accordance with the provisions of Article [ ]; [Arbitration].

Other matters.

These include:

- agreement that as long as no agreement and no arbitration award is effective the prices and the terms applicable on the date of the request shall continue to apply;

- agreement restricting frequency of review of price provisions. The right to make requests has traditionally been limited to one every three years. It is not uncommon to allow one (sometimes two) requests for adjustment in addition to those at three year intervals. In a time of major changes in gas prices intervals of less than three years are likely to become the norm.

12.4.3 Commentary

Trigger provision

As will be seen the scope of the trigger provision is extremely wide. This reflects the concern of the parties to ensure that unexpected events, both foreseeable and unforeseeable, will trigger the price re-opener provided that they satisfy the terms of the clause particularly that the changes in economic circumstances must relate to the market of the buyer. It is usual to specify that the imposition of, or changes in, energy taxes are considered to be changes in economic circumstances.

Buyer's protection provision

This provision is important. It establishes that no change to the price provisions may be made under the re-opener clause if as a result of the change the buyer would be obliged to operate its business on an uneconomic basis.

Failure of parties to reach agreement – resolution of disagreement

If the parties fail to reach agreement as to the revised price terms to be included the parties must make provision for the appointment of a third party or parties to determine the revised price terms. In Continental

Western European contracts the parties normally choose to appoint arbitrators. The arbitration clause should contain all provisions relating to the arbitration (e.g. number of arbitrators – 3 is frequent in Continental Western European Contracts), the venue of the arbitration and the language of the proceedings.

12.5 LNG pricing arrangements

The pricing arrangements for the purchase of LNG have many of the characteristics of pricing arrangements for the purchase of pipeline gas. LNG contracts typically include take-or-pay clauses and also arrangements for make-up and carry forward.

However the LNG variants of these clauses reflect the fact that periodical deliveries are made under such contracts in contrast to the continuous deliveries made under pipeline contracts. The periodic deliveries are made to the buyer either to the tanker owned or chartered by the buyer at the export port (in the case of an f.o.b. contract) or to the buyer's reception terminal at the import point (in the case of a c.i.f. contract).

As deliveries are made at intervals the take-or-pay period is normally at least a year and maybe longer (e.g. two to three years). The take-or-pay quantity is calculated on the basis of the delivery of a minimum number of cargoes of a specified size within the take-or-pay period. If the number of cargoes taken by the buyer is less than the minimum then the buyer pays for the quantity not delivered (established by reference to cargo size). However make-up applies and the payment for that quantity may be taken as a credit against the price of cargoes taken in subsequent take-or-pay periods in excess of the minimum number of cargoes.

LNG projects have a very substantial infrastructure cost content and there is rarely an opportunity to substitute buyers. As a result LNG contracts, except for small marginal cargoes, are always long term even in circumstances where the LNG is to be sold into a market where there is a developed traded gas market. The price mechanisms include price adjustment clauses containing provisions for adjustment to reflect movements of competing fuels – particularly fuel oil and gas oil and sometimes price re-opener clauses. As in the case of pipeline gas the price adjustment provisions have been adapted to the changing competitive scene in import markets where there is a price indexed gas market with the result that contracts for the sale of LNG into the North American market are now normally priced against published indices of gas prices in the relevant market[6]. Sales of LNG for supply to power generators, contain, as in the case of pipeline gas contracts, price

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[6] As LNG has not been imported into the UK for some years there has been no corresponding experience in that country. In Continental European countries which import LNG (including France, Italy and Greece) buyers of LNG will, as is the case with the Continental European buyers of pipeline gas, wish to ensure that their major LNG contracts contain price mechanisms which provide protection against the consequences of the introduction of gas to gas competition.

indexation arrangements that are related to electricity prices and sometimes coal.

Recently, spot trading of LNG cargoes has become more common, partly because of the emergence of an LNG surplus, as a result of economic downturn in traditional markets, and partly because of the opportunities offered by gas shortages experienced in the US market a couple of years ago. Having broken out of the very restrictive long term contracts, players are likely to continue to look for opportunities to trade marginal volumes of LNG. This may in turn lead to the development of a wider traded market for LNG cargoes. But opinion remains divided about how soon this will happen. LNG only accounts for about 7 per cent of world gas trade movements.

12.6 Future developments

12.6.1 North America and UK

The introduction of gas to gas competition creates the pressures that bring about fundamental change in gas pricing arrangements. This occurred in the North American gas markets in the 1980s and in the gas market in Great Britain in the early 1990s and has led to the widespread use of spot/short-term contracts based on indexed gas prices that have been described. These markets are now mature competitive gas markets and no substantial developments affecting gas pricing arrangements in them are foreseen in the near future. However in due time the trends towards 'convergence' with electricity and towards multi-utilities may well lead to energy pricing (Btus or kWhs) rather than pricing of distinct fuels. A re-emergence of bundled energy plus services may also result from end user preferences.

12.6.2 European Union – the internal energy market

The political decisions taken by the European Council[7] referred to in Chapter 11.1 at its meeting in the Spring of 2000 were followed by a request to the Commission to develop proposals for the acceleration of the creation of the Internal Energy Market (i.e. electricity and gas). In response to this request the Commission published its proposals in March 2001[8].

The proposal comprised two measures. These were a proposal for a Directive amending the Electricity and Gas Directives and, in connection with the electricity sector only, a proposal for a Regulation on conditions for access to the network for cross border exchanges of electricity.

The proposed amendments to the Electricity and Gas Directives were similar. They were aimed at accelerating the pace and scope of liberalisation of national markets. In the case of gas they required (inter alia)

- an acceleration of market opening from (33% by 1/1/2008 under the Directive) to full opening of the non household (i.e. industrial/commercial) market by 1/1/2004 and of the full opening of the non-household market by 1/1/2005;

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[7] The European Council is a political body comprising the Heads of State or Governments of the Member States and the President of the European Commission. It is charged by Article 4 of the Treaty on European Union (Maastricht) "with providing the European Union with the necessary impetus for its development" and with "defining the general political guidelines thereof".

[8] For the latest information please refer to the EU Energy and Transport website: Thematic Site for Energy (europa.eu.int/comm/energy/index_en.html).

- the removal of the nTPA option (i.e. only rTPA permitted);
- the appointment of independent national gas regulators to administer (inter alia) rTPA;
- full legal and administrative unbundling of marketing and transportation activities.

The Commission proposals of March 2001 did not contain a proposal for a Regulation on Conditions for access to the network for cross border exchanges of gas. However the Commission has stated that it will proceed with a similar regulation for gas when the electricity regulation has been agreed. The proposed electricity regulation contains, in connection with cross border tariffs, a requirement that such tariffs should be cost based to take into account actual use of system. It provides for the establishment of a compensation scheme for the system users that host cross border transfers. This system is to be administered by the Commission. In connection with the proposed cross border congestion management scheme an important and continuing regulatory role is envisaged for the Commission.

The proposals for amending the Electricity and Gas Directives were welcomed by the European Council at its meeting in March 2001. Although many Member States welcomed the amending proposals France objected strongly to the acceleration of market opening particularly in relation to the opening of the (household) market. Germany also objected to the proposals but mainly on a narrow issue relating to the establishment of an independent gas regulator. The European Council requested the Commission to report again on the proposal at the European Council meeting to be held in March 2002. In the intervening period there was considerable discussion between the Commission and the German and French Governments in connection with their respective objections to the proposals. These resulted in a compromise position that is reflected in the Presidency Conclusions of the March 2002 meeting of the European Council.

The Presidency Conclusions in the field of energy include the following:

- The European Council urged:
    - The Council of Ministers and the European Parliament to adopt as early as possible in 2002 the pending proposals for the final stage of the market opening of electricity and gas including:
    - freedom of choice of supplier by all European non householder consumers as of 2004 for gas and electricity. This must amount to at least 60% of the total market;

  - separation of transmission and distribution from production and supply;
  - in the light of experience and at a date before the spring European Council in 2003 a decision on further measures taking into account the definition of public service obligations, security of supply and in particular the protection of remote areas, and of the most vulnerable groups of the population;
  - non discriminatory access for consumers and producers to the network, based on transparent and published tariffs;
  - establishment in every Member State of a regulatory function with the appropriate regulatory framework with a view to ensuring in particular effective control of the tariff setting conditions.

- The Council of Ministers was urged to reach as soon as possible in 2002 an agreement for a tariff setting system for cross border transactions in electricity including congestion management, based on the principles of non-discrimination, transparency and simplicity.
- The European Council invited the Commission and the Council of Ministers to analyse at the Spring European Council Meeting in 2006 the global performances of the European Internal Energy Market, in particular the degree of transposition of the regulatory framework, and its effects on consumer protection, infrastructure investments, effective integration of markets and interconnections, competition and environment.

It is now the duty of the Council of Ministers, the European Parliament and the Commission to respond to the urgings of the European Council. The first task of the Commission will be to prepare a revised proposal for the Directive amending the Electricity and Gas Directives reflecting the decisions of the European Council and to circulate the proposal for consideration by the Council of Ministers and the European Parliament[9]. The normal procedures for the adoption of a Directive by the European Parliament and the Council of Ministers will then follow. At the same time the Commission will proceed with negotiation of the proposed Regulation on Conditions for Access to the Network for cross border exchanges in Electricity in the Internal Electricity Market. This

[9] EU Energy Ministers agreed on 25 November 2002 to revise the Gas and Electricity Directives with the aim of opening up to competition all industrial and commercial markets from 1 July 2004 and all household markets from 1 July 2007.

regulation is a vital element in the acceleration of electricity liberalisation.

If the completion dates for the amending Directive and Access Regulation set by the European Council (end 2002) are met then the way should be open for a substantial development of competition in the non-household (i.e. industrial and commercial) market for electricity in 2004. The development of substantial gas to gas competition in the non-household market for gas in 2004 will be dependent upon the progress made towards the adoption of a Regulation for Conditions of Access to the Network for cross-border exchanges in Natural Gas in the Internal Gas Market. The possibility of a mandatory extension of competition to the household markets for gas (and also electricity) in the near future seems remote.

12.6.3 Enlargement of the EU internal energy market

The measures leading to the acceleration of competition in gas (and electricity) markets scheduled to apply as of January 2004 will have been adopted sometime before the accession candidate[10] countries accede to the EU. At the time of accession, the candidate countries will have to incorporate these measures and all other relevant EU gas (and electricity) legal measures into their national laws, subject to any transitional terms that may be negotiated by individual Member States. At that time, and subject to any reservations, the stage would be set for their participation in the enlarged EU internal gas market with its gas to gas competition and traded indexed gas markets.

It should be noted that Bulgaria, Romania and Turkey are not included in the list of accession candidate countries. The economies of Bulgaria and Romania are not yet sufficiently adapted to enable accession to take place. There are currently a number of obstacles to the admission of Turkey to the EU that seem likely to take some time to resolve.

[10] The accession candidate countries are: the Baltic states (Estonia, Latvia and Lithuania), Poland, Hungary, the Czech Republic, Slovakia, Slovenia, Malta and Cyprus. The EU summit meeting in December 2002 agreed to the accession of these countries by May 2004, subject to certain conditions. It also agreed to continue talks with Turkey and to begin talks with Bulgaria and Romania for possible accession in 2007.

13 Running a gas trading business

Neil O'Hara, Arthur Andersen

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13.1 Introduction

The last ten years have been a period of upheaval for the UK gas industry. An ideological push for liberalisation introduced competition in the gas market and encouraged the convergence of gas and electricity commodity markets. These changes are now being extended throughout Continental Europe as a result of the European Gas and Electricity Directives (see Chapters 4, 7 and 12). The upheaval introduced new uncertainties, concerning price volatility, location, timing and price structures. This forced gas market participants to think in new ways about the risks that threatened to erode the value of their companies.

In order to manage and capture the value of these new risks many companies have created an Energy Trading and Marketing (ETM) function. The precise role of the ETM function will depend on the current skill sets of the company, the size of its exposures and its overall strategic vision. As ETM groups develop, other more intangible benefits such as better information on market developments and on the fundamentals of supply and demand, also emerge.

The tools and methodologies that are being used by the ETM function in the gas industry have evolved with the market. Prior to liberalisation, companies were using complex long-term contracts to support dedicated physical supply arrangements. After liberalisation, reliable price indices, standardisation of contracts and the introduction of financially-settled deals encouraged the growth of transparency and liquidity. Increased trading encouraged new complex risk management tools and, with the introduction of options, companies were not only able to manage and monetise their physical gas flows and contractual flexibility, but also to take specific risks.

The possibility of taking on incremental risk from the market created new challenges for the ETM function, for example:

- is the objective of the group to balance the asset portfolio or to extract extra value over the expected return of a balanced position?
- how should ETM interact with other business units? This includes issues such as culture, behaviour and remuneration.

Once the company has an understanding of the value that can be extracted from certain areas of the gas value chain with an ETM group, senior management may need to rethink the role of the ETM. In particular, a major issue is whether the ETM should continue to develop within the company or, because of market complexity, whether trading and risk management should be outsourced to a service provider.

13.2 Energy trading and marketing

13.2.1 Evolution

Before the liberalisation of the UK gas market, the whole value chain was managed by one company — British Gas — ensuring that all risks were the responsibility of a single company. But bundling risk across the entire business made it difficult to identify who was responsible for a specific risk within the company. In addition, the end-user was forced to pay for the cost of bundled risk management. With no clear quantification or accountability it was difficult to measure the performance of the risk management process.

The advent of liberalisation fragmented the industry value chain and allowed new participants with a variety of strategies to enter the market. These strategies varied from specialising in discrete parts of the value chain, to participating in, and managing, activities spanning the whole chain.

Competition

The regulator (formerly Ofgas, now Ofgem) played a leading role in the creation of competition in the UK gas market. This included the release of production to new market participants and the publication of tariffs. Not surprisingly this gave new entrants an opportunity to compete and attract end-users as customers, and eroded British Gas's market share.

The resulting shift in market share for both the new entrant and the existing supplier caused mismatches in their supply and demand portfolios. This change in the balance of portfolios was one of the key reasons that led to the creation of Energy Trading and Marketing (ETM) groups and the development of risk management techniques.

As well as re-distributing market share, the arrival of competition also heralded an attack on margins and profitability. In order to be able to sustain margins and returns, new and innovative methods to extract value and preserve existing margins were invented.

Gas for power

As new power generation projects moved away from more traditional sources of fuel supply such as coal to gas, there were several knock-on effects which helped to increase the possibilities for gas trading. These included the provision of specific demand shapes by the feedstock supplier, the sale of excess supply by the generator, and the management of the 'take-or-pay' element of the contract.

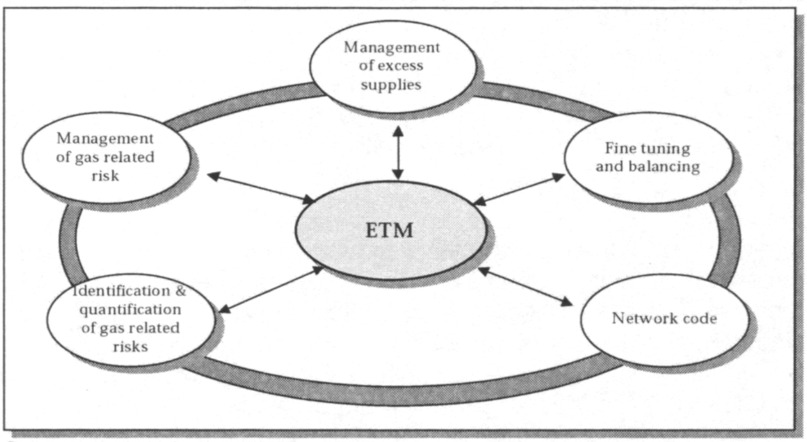
This fine-tuning or portfolio management shifted the role of the ETM group towards adding value for the business. By providing such services, the ETM function linked physical reality to the risk management demands of the new core energy business that had emerged.

13.2.2 Key drivers

Management of excess supplies

One of the first objectives of some ETM groups was to market their company's excess supplies of upstream production. This was because many new uncontracted fields were able to come on stream as a result of gas liberalisation. Historically, producers had not engaged in new gas field developments unless the monopoly supplier, British Gas, had contracted for the volumes. Producers could now, however, develop uncontracted fields to satisfy the increasing demands for gas-fired generation and to allow participation in the competitive market.

In 1997, British Gas demerged into BG plc (consisting of Transco, the pipeline network and certain upstream assets) and Centrica plc (consisting of all existing domestic, industrial and commercial customers, the supply portfolio including take-or-pay contracts and certain upstream assets). As deregulation progressed, Centrica managed the resulting price and quantity risk through the process of contract renegotiation. Part of this process not only focused on the financial issues of contract restructuring, but also on the handing back of volumes to producers that Centrica did not require, given its obligations under the new legislation and expectations of the future effects of competition. As a result, producers had to manage these additional volumes through marketing or trading activities.



Source: Arthur Andersen

Figure 13.1 Key drivers for energy trading and marketing

Fine tuning and balancing

New market structures emerged that placed potentially severe financial penalties on companies out of balance. Further, with new entrants in the downstream market, customer demands created supply profiles that could not be replicated by upstream assets. Such market developments exposed the need for a team that could match the imbalance between the supply and demand inherent in a company's portfolio.

Matching or 'fine tuning' portfolios allowed firms to market more sophisticated products with more complex demand profiles to end-users based on the understanding that the traders could manage the residual risk. This type of risk management was probably one of the biggest steps forward in the evolution of the ETM group. Management could see a clear advantage from developing this expertise within the company.

Network Code

Another major step in the evolution of the role of the ETM group was the creation of the daily balancing regime and the flexibility market introduced by Transco (see Chapter 10). These new markets required shippers to manage their supply and demand mismatch on a daily rather than on a monthly basis. Furthermore there were large penalties levied on out-of-balance positions. Depending on corporate risk appetite, the existence of such a penalty was perceived as either a threat or opportunity and encouraged the development of many new trading and hedging instruments.

The introduction of the Network Code by Transco for use by the gas shipping community required companies to commit time and resources to managing this operational framework. Energy companies in the gas value chain were forced to make a decision about whether to invest extensive resources in order to participate in the shipping market, or to outsource this role to another firm through marketing deals. If an ETM group decided to become a shipper it had to ensure that it followed all the developments related to its role. This added to market complexity and the associated legal and regulatory management skills became another way in which trading functions could differentiate themselves and succeed in the marketplace.

Identification and quantification of gas related risks

Companies also became aware that price and quantity risk were not the only threats to and opportunities for gas trading participants. As the balancing market evolved it allowed the value inherent in a diverse and flexible portfolio to be identified and realised using risk variables such as location, volatility and price structure.

ETM groups began to view the timing of gas flows as 'risk buckets' and came to understand that each bucket should be valued and traded differently. The development of such valuation and trading strategies was only possible once new benchmarks, price indices and routes to market became available.

Risk management

Having identified and quantified the risks, the next step for an ETM group was to manage the risk. In the past, one person usually performed all these roles. However, as the market became more complex and trading volumes rose, it became necessary to segregate responsibilities so that the different processes being carried out were supported by appropriate control mechanisms and managed by people with appropriate skills.

This segregation of roles also reflected the different cycles of activity for tasks within the ETM function. For example, some require minute-by-minute attention while other, more analytical, roles manage tasks over a longer period of time and do not have to meet deadlines imposed by the market. Such segregation became even more important when the balancing market created greater volatility and risks for the ETM group.

13.2.3 Business models

Upstream marketing affiliate

One of the primary reasons for developing gas trading activities was to manage the uncommitted supply that producers had available as new fields came on stream. Producers had the option of selling or delivering gas at the beach and using external marketing companies as their route to market. For some this was an appropriate strategy, as they did not wish to become exposed to the complexities of the Network Code and balancing charges. Other producers, however, felt that due to the size of their exposures and the potential opportunities within the value chain, they needed to develop the skills to participate further downstream.

The development of an ETM function also provided other more intangible benefits such as information on market developments and the fundamentals of supply and demand.

Downstream procurement

In many senses, the role of a downstream procurement function is the opposite of an upstream marketing affiliate. In this case, particularly with new entrants to the supply market, a portfolio had to be built and managed from scratch. The main aim of the new downstream procurement groups was to replicate the extensive upstream portfolio of the monopoly supplier. This was achieved with a combination of contracts, physical and financial instruments, and trading skills that balanced the firm's supply and demand mismatch. In this way the ETM function was seen as complementary to the core supply business.

The downstream procurement role became particularly important when the Regional Electricity Companies (RECs) started offering dual fuel products to the end-user. Because these firms did not have large upstream gas assets on their balance sheet, their primary contact with the gas market was through their purchase of long-term gas for use in their power stations. Such traditional purchases were managed directly between the station and the supplier and did not require further risk management by the RECs beyond the nomination process.

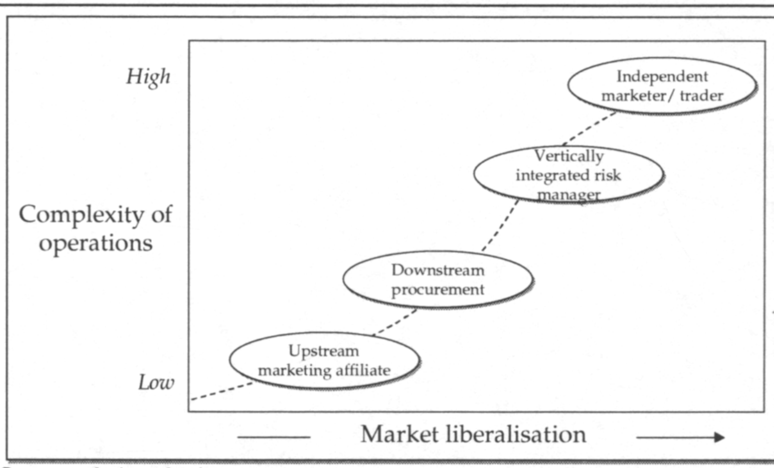
Vertically integrated risk manager

A number of market participants had both upstream and downstream portfolios that were potentially self-hedging.

But the simple matching of supply and demand quantities was not always a reliable hedge, particularly when new entrants entered the domestic market. The vertically integrated risk manager also had to take account of the timing of the flows of demand and supply and not just the total flow over a period.

Independent marketer/trader

Independent marketers and traders are the main providers of liquidity, transparency and risk management products. These firms have no assets from which to obtain committed supply, or a downstream customer portfolio to provide demand. Their positions are created by seeking risk and by making commitments which, at the time of transaction, they may not be able to fulfil. As well as holding risk from unhedged positions, this type of ETM group is willing to provide other market participants with hedging instruments that further increase its own risk profile.



Source: Arthur Andersen

Figure 13.2 Types of business model

Such ETM groups believe that their view of supply and demand, their operating systems and trading skills are capable of providing a profitable solution to the mismatch that they are willing to run on their book. They believe that they can manage this risk by innovative methods without relying on an extensive upstream and downstream portfolio.

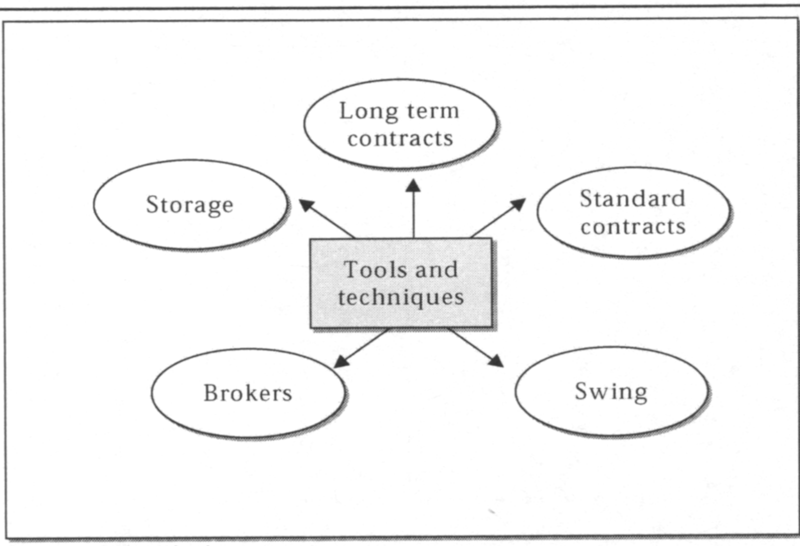
13.2.4 Trading environment

Long-term contracts

Long-term contracts were initially the instruments most commonly used by participants. These complex contracts were constructed to support dedicated physical supply arrangements. Long-term contracts, however, could not support a market where rapid transaction turnover is necessary and did not facilitate the growth of a traded market.

Standard contracts

The introduction of standard contracts settled against a beach price index or the National Balancing Point (NBP) was the most important factor enabling rapid growth in turnover of the number of transactions (see Chapters 5, 6, 8, 9 and 10). These standard terms simplified trading by referring to a master document with only a simple confirmation necessary to cover the essential elements of the new deal such as term, price and location (see Chapter 9). Standard contracts accelerated the development of bilateral trading as companies now had the ability to repeat transactions many times without recourse to



Source: Arthur Andersen

Figure 13.3 The trading environment

lawyers or complex terms and conditions.

Swing valuation

The valuation of swing has always been a topic of great debate, but it became a key issue during gas market liberalisation. Swing value was analysed both in relation to storage and financial option theory. It was swing's unique within-day flexibility and the ability to trade it on the flexibility market that led participants to revisit – at great length – the ways of valuing this product. The pricing of swing or the comparison to storage value often used the forward curve as a predictor of a nomination pattern. However, such simple analysis did not take into account more sophisticated option trading techniques that examined its potential value as a trading, as well as a hedging, product.

Brokers

Brokers play a major role in the gas market for several reasons. In the early days of trading, when no futures prices were available, brokers provided transparency to a market that would otherwise have to wait until the end-of-day reports to discover the latest price traded or the area of greatest liquidity. These price reports were compiled by publishers and faxed out so as to be ready for the next day together with any accompanying news stories that might provide useful information to the traded market.

Since brokers continually gather prices from different players and act as an intermediary in the marketplace, they also provide an easy route to the market for companies that do not have the requisite resources to spend many hours a day phoning all possible counterparties. Broker support also allows the trader to concentrate on elements of the firm's position that hold the greatest risk.

Storage

Storage became more important as a trading tool and portfolio management instrument as competing suppliers offered more complex demand profiles to their clients. This was particularly important when domestic competition began as suppliers had to reflect the non-daily metered demand placed upon them. Such demand could, at times, only be met by the use of an instrument such as storage.

The management of storage became a distinct role on its own as large investments were made in the instrument. Storage was then used to trade and to extract value from the forward curve as well as more traditional portfolio hedging. This change in use of an asset or contract, from a hedging instrument into a more effective optimising instrument, has become a familiar theme as traders map instruments to services. The storage market has recently evolved to a stage where traders can replicate and sell a service such as storage on a virtual basis as they are confident they can access the necessary flexibility.

13.2.5 Recent developments

Flexibility and liquidity

As gas trading developed, new products became available that provided greater flexibility and liquidity. This flexibility was reflected in the use of options. Liquidity also increased from the overall growth in the range and number of financial instruments being traded.

Options provide traders with a way to replicate the flexibility of assets and contracts that are found in traditional supply portfolios. Further, for the cost of a small premium paid in advance, purchased options allow a leveraged position to be taken that can help capture the value of market price fluctuations without taking the full risk of a physical position (see Chapter 5). This type of flexibility trading encourages new participants to the market and illustrates how many different types of trading can take place at points on the value chain. Market participants can utilise differentiated skill sets or portfolios to monetise their particular unique competitive advantage.

Another development that supported the continuing growth in liquidity was the emergence of financially-settled trades. This allowed smaller participants or traders without a physical portfolio to take market price risk without incurring the complexities of physical delivery, balancing and nominations. Larger positions can be built, developed, taken, or maintained in the knowledge that they could be closed out with other financial trades as liquidity continued to grow.

Risk appetite

Traders now have access to many different instruments and hedging tools with different characteristics and payoffs. For many participants, what may have started as a simple volume management exercise has developed into a complicated trading and risk management function with many traders involved in the taking of incremental risk. So what operational boundaries have been developed to manage these groups? Energy firms have had to consider carefully the role of the ETM group and have developed risk monitoring and measurement methodologies.

One of the key considerations is the objective of the group. Is the group's objective to balance the portfolio or to extract value over and above the normal return expected from a balanced position? This requires the establishment of risk limits and guidelines for the extent of matched and unmatched positions. These boundaries reflect the role of the ETM group and will, in turn, be reflected in the group's performance measures. There will not be many highly bonus-incentivised traders in a firm running a flat position!

Business unit interaction

If the ETM group is part of a larger organisation then it will be essential to establish how it interacts with other business groups. Issues that require careful consideration and management include culture, behaviour and remuneration. The ETM group will typically develop a distinct culture that may differ in 'look and feel' to the rest of the organisation. Where trading is not seen as a strategic focus in itself, but as complementary to the rest of the organisation, it will be difficult to maintain this distinctness of culture and behaviour and perhaps therefore its effectiveness. In addition, the ETM group may require remunerating in a different way from the rest of the organisation and so the Human Resources Department will need to understand the changes that are taking place within the market and organisation.

Over a period of time, it may also become necessary to restructure and re-engineer the firm, particularly those areas owning risk, in a way that reflects an environment of increased risk and volatility. Creators of risk should understand whether they are meant to manage the risk or transfer it. If the risk is passed on to another part of the business then that business unit must know it is now responsible, and understand how to quantify and manage the risk. Although this is a simple principle it is unfortunately often overlooked. Firms need to move away from an inward looking business unit mentality to a broader process driven risk management structure.

13.2.6 Future strategies

The key strategic question facing many companies is whether to continue trying to make profits from gas trading or whether to outsource the activity.

Some organisations have progressed through the full cycle of the evolution of the ETM function described above. They have a business framework and an understanding of the value that can be extracted from certain areas of the gas value chain by the ETM group. In addition they may have an understanding of how to leverage the firm's inherent core business skill sets, knowledge and assets to amplify the value of trading. At this stage the ETM group often faces key challenges from top management such as:

- resolving the impact of profit and loss swings;
- determining the case for using mark-to-market* accounting;
- understanding why the firm has become involved in what may be perceived as a non-core business.

The original function of the ETM group was to manage risk. This has often subsequently developed in such a way that it forms a business unit in its own right, performing far-reaching risk management tasks that were never considered at the outset. In some cases, the ETM group

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* Accounts can be drawn up using either historical cost or current market value. Current market prices or mark-to-market accounting are widely used to value open trading positions (see Chapter 14).

drives marketing, sales and production activities. Furthermore, the ETM group may even drive investment/divestment decisions through its data gathering effort and its understanding of pricing and value signals.

Senior management are therefore often forced to rethink the role of the ETM group. The group may have completed the task of seeing the firm through the complex process of deregulation and mitigated the risk that emerged. At the next stage, it may become appropriate to outsource the role of trading to a service provider, as the gas market is becoming more complex, with similarities to the financial markets. However, it is also possible that, equipped with the best infrastructure, processes, controls and procedures, the ETM group may become a significant business unit. It may have the ability to extract above-normal profits from a specific part of the gas value chain by working the company's networks of assets more efficiently than if this role was outsourced. Many firms have started to make such choices, and will have to continue making them during the market liberalisation process.

13.3 Internal control framework

A well-designed infrastructure and internal control framework is critical in any trading environment, and this is particularly true for gas. The gas trading business is characterised by some of the highest volatilities in any traded market and operates around the clock. In such a testing environment anything less than a robust framework is taking a gamble with the future. Trading organisations supported by a weak infrastructure and poorly designed controls can quickly suffer significant losses and can even lead to bankruptcy. The infrastructure required is similar in nature to that required for other traded markets but must be customised to take into account the special nature of the energy markets. The following principles must be considered when designing gas-trading infrastructure:

- only transactions authorised by management and consistent with the firm's goals and objectives may be executed;
- limits should be determined that set the size of value exposed to market volatility;
- all transactions are accurately recorded in the company's records; and
- management receives clear, relevant and correct information on a timely basis to be able to assess the entire trading position.

Clearly the extent to which these principles are implemented needs to be considered in the light of:

- the size of the trading business;
- the nature of trading activity – e.g. plain vanilla or complex instruments;
- the objectives of the trading organisation – hedging and risk management or proprietary trading;
- the management's risk tolerance and risk appetite; and
- the volume of transactions.

Consideration of these factors will determine how sophisticated and complex the framework needs to be, as well as the balance between manual and automated tasks, and the role of information systems in supporting the operations.

13.3.1 Organisation structure

The organisation structure of a gas trading company determines the 'tone at the top' and also provides the mechanism for management oversight of the trading operations. Typical organisations split the functions between:

- **Front office:** encompassing commercial staff including traders, originators and marketers and supporting analysts. These staff are authorised to execute transactions, within predetermined limits, that either create or mitigate risk and generate profits for the company. Due to the 24-hour nature of the gas trading business, physical product schedulers are typically authorised to execute product-balancing transactions as well as trade short-term transactions and must also be included in the front office.

- **Middle office:** encompassing risk control staff who are responsible for independently reporting on and validating risk positions and ensuring that transactions are within trading limits. The function typically reports to the Trading Control Officer (TCO). Risk control staff are not authorised to execute trades but rather analyse the impact of existing transactions.

- **Back office:** encompassing accounting and support staff who record transactions and collect or pay funds due under the trading transactions. For a gas trading organisation, pipeline statement reconciliation, which is a critical process, also forms part of the back office.

In addition, there are a number of other critical functions that cannot be classified into front, middle or back office. These include credit assessment and monitoring, and legal support.

Segregating functions between the front, middle and back offices is important as it eliminates well-known risks such as traders valuing and reporting on their own trades or unilaterally moving cash, as well as concentrating functional expertise in each group. In fact, this principle can and should be taken further in determining the sub-divisions within front, middle or back offices. For instance, the front office should be split between traders, who are best suited to gathering market intelligence using their contacts, and analysts, who are capable of analysing risks embedded in complex contracts, e.g. long-term take-or-pay contracts, and developing ways of optimising and extracting maximum value.

For a trading operation to operate in an effective and well-controlled manner there is a need for appropriate senior management oversight. A well-recognised method for providing such oversight is the establishment of a 'Risk Management Committee' (RMC) consisting of senior management from different aspects of the business including trading and commercial, risk control and finance. The RMC should meet on a regular basis to discuss the activities of the trading function and review the risk position. The head of the risk control function, the TCO, should either be a member of, or report to, the Risk Management Committee. In addition, the TCO should also have 'dotted line' reporting to the Audit Committee of the company (or equivalent). This provides the TCO with a route for reporting on activities of the organisation outside the normal organisation structure, without compromising his or her position. It is an extremely effective process for avoiding undue pressure or influence from within the TCO's normal reporting lines.

13.3.2 Clear policies

Before trading, the organisation must be clear about the purpose of these activities — does the trading function provide a hedging and risk management service to other parts of the business or is it responsible for generating profits as a stand alone business unit? The organisation also must consider which markets traders are allowed to transact in, what products are allowed to be traded, and how much risk is permitted. The policies must set out the answers to these questions in addition to defining the overall control framework, reporting lines and guidance on the key processes in place.

13.3.3 Processes and systems

In any trading organisation, a number of critical processes need to be carefully designed to ensure the company works in an efficient and effective manner. These processes include:

- credit assessment and monitoring;
- contract establishment;
- timely and accurate deal capture;
- product scheduling to ensure physical balance;
- timely independent confirmation of deals executed;
- mark-to-market valuation;
- trade settlement and accounting; and
- information systems.

Credit assessment and monitoring

Given the high-volume, low-margin nature of the gas trading industry, a gas trading company must ensure the credit-worthiness of a counterparty prior to entering into any trades. This applies not only to sales to counterparties, but also to purchases, especially where the supplier has committed to a fixed price. Clearly once the transaction has been executed, companies must continue to monitor credit risk, not only at a particular moment, but also the potential risk that could exist, given certain events in the market, for example, if prices were to change by a large amount. In extreme circumstances, counterparties may fail to deliver under the contract, either because they cannot afford to do so or because they have gone bust.

Contract establishment

Since most trading transactions are executed orally, it is critical that documentary evidence exists to support the transaction. The confirmation process provides some evidence but will not include all the necessary clauses to protect both parties. In the UK, standardised contracts such as NBP 1997 for physical and forward trading and the International Swaps and Derivatives Association (ISDA) Master Agreement for financial over-the-counter trading have been developed (see Chapter 9). These, however, should be in place before trading begins and their validity checked by company lawyers. Variations from the standard contracts need to be reviewed by appropriately qualified legal personnel.

Timely and accurate deal capture

It is impossible to establish an overall trading position if the initial capture of existing and ongoing deals is inaccurate, incomplete or untimely. Issues arise in the gas trading business due to the high volume of transactions, or more frequently, due to transactions that existing deal management systems cannot fully capture. This may be a result of using simple spreadsheets or due to complex contracts that cannot be entered into even well-developed trading systems. These problems exist even in financial markets, but are more common in the gas-trading sector due to its relative immaturity.

Product scheduling to ensure physical balance

Penalties for being out-of-balance in open-access gas transmission and transportation systems can be substantial. The impact of weather on usage, operational failures of producing assets, limitations in storage capacity and deliverability and constraints in the transmission system can all produce large swings in delivery requirements. A robust process for ensuring that the company is balanced is the key to ensuring that any profits generated do not bleed away through penalties. Given the historical development of gas networks in Europe (stand-alone systems run independently by state-owned companies), networks often develop their own rules, procedures and supporting information systems for nomination, balancing tolerances, and reconciliation as they open up. It will be necessary to have personnel who are familiar with these pipeline specific procedures and can not only balance, but also exploit differences in the rules to the maximum benefit of the gas trading company.

Timely independent confirmation of deals executed

An independent confirmation process provides a mechanism for trading companies to maintain documentary evidence of transactions executed orally over the phone. Typically one or both counterparties will prepare a standard confirmation which is faxed to the other for signature and return. Problems can arise in gas trading if participants are not aware of the importance of this process, or because of poor information systems that do not automatically prepare and fax confirmation, or due to the complexity of transactions. Often confirmations are not even sent back and, in the US, companies have even resorted to a general disclaimer that if confirmations are not disagreed within a certain time period, they are deemed as accepted. Whether this would ever be legally enforceable is debatable, but it certainly highlights the scale of the problem facing the gas industry.

Mark-to-market valuation

Trading operations need to be evaluated based on the original goals and objectives of the operation. One of the key measures in assessing the performance of the operations is marking the entire portfolio to market. Common problems in gas trading arise from companies only marking the financial trading or derivatives portfolio to market and excluding physical deals, contracts and assets. Other problems arise where there is difficulty in obtaining reliable forward price curves and in incorrectly analysing risk characteristics of the portfolio, including embedded optionality, such as swing. Finally, problems can arise from the incorrect valuation of options due to a poor understanding of volatility. The volatility of the gas market makes it preferable to calculate a mark-to-market value on a daily basis (see Chapter 14). Traders ideally need to mark-to-market using a continuous feed of real-time prices.

Given the volatility of the gas market and the speed with which different factors impact prices, mark-to-market techniques alone are not sufficient for assessing risk in the portfolio. These should be combined with processes such as sensitivity analysis, stress testing and shock analysis (or other measurement tools) on a regular basis to be able to assess fully the impact of possible changes in the market.

Trade settlement and accounting

The records necessary to account for, and control, trading transactions need to be maintained independently of the trading function. They need to contain information necessary to verify statements received from brokers, pipelines etc., to support entries into the general ledger; designate transactions as hedging or non-hedging; and to generate the necessary reports. Frequently problems arise because accounting departments look at results on an accruals basis, i.e. recognise profits and losses as physical product is delivered, whereas trading groups consider their profits on a mark-to-market basis. There is currently a strong move in the US to align financial reporting with the way traders assess themselves, i.e. towards mark-to-market. It is likely that this trend will be repeated in Europe, particularly given the preponderance of US trading firms who are active in Europe (see Chapter 14).

Information systems

Information systems in the gas trading business can be classified broadly into three areas:

- physical logistics, product scheduling and balancing;
- risk analysis and risk management; and
- settlement and back office accounting.

Most gas trading companies start recording deals on simple spreadsheets and, as the business grows, progress to more robust systems, including basic relational databases such as Microsoft Access, to commercially-available packages or to custom designed solutions costing millions of pounds. Again the need for systems should be considered in the light of factors such as the volume and complexity of transactions, the size of operations, and the need for integration.

In the UK gas industry physical logistics systems have traditionally been custom developed by individual trading operations. These have been designed to interface with the UK pipeline network bulletin boards, such as Transco's AT-Link (see Chapter 10). It is likely that as the European gas industry liberalisation progresses and more pipeline operators provide open-access services, third-party providers of logistics software will enter the market to fill the need created.

Risk management systems are critical to quantifying and assessing the financial risks inherent in a trading business. Risk management systems vary greatly, ranging from systems that are based on advanced spreadsheets to extremely sophisticated software, running in real-time, able to model extremely complex deals, capable of providing different types of forward curve building tools and performing risk analysis. As with any system, the more sophisticated the system, the more support is needed to maintain it.

In the gas industry currently, settlement systems are perhaps the least customised systems. Most companies rely on limited functionality built into their logistics and risk management systems or, alternatively, rely on their existing general ledger and accounting systems to handle invoicing, receivables and payables ledgers.

With the different systems that are used in a gas trading function, avoiding duplicate entry of the same data is important to ensure maximum efficiency and data integrity. Software providers are rapidly working towards integration of systems. In some cases this takes the form of direct interfaces between different systems, but more commonly in sophisticated operations, this is being achieved by using appropriate 'middleware'. With the European gas industry changing rapidly, and software providers continuously developing new products, it is likely that they will lag behind developments in the marketplace.

13.4 Role of the gas trading function

13.4.1 Areas of responsibility

With the continued liberalisation of the UK and European gas markets, market reform and change has created and made transparent gas market risks, in many cases passing the risk from the incumbent monopolies to the new market players. In the UK the reform of the Network Code, coupled with the emergence of spot, physical and financial markets has encouraged gas companies to manage the risks inherent in their corporate portfolio more proactively.

The need to unbundle vertically-integrated activities and the emphasis on arm's-length structures in much of the regulatory reform has led to the emergence of a distinct gas trading function. Previously gas companies did not differentiate between the various types of risks and typically passed them through to customers. But now the trading function has to be accountable and its performance measured in order to assess its capability and success.

The role of the gas trading function encompasses the management of risks associated with a company's gas assets, including contracts, customers, and upstream and downstream assets. Risk management must be in line with the company's overall strategic direction and its appetite for risk. This role is reflected in a range of responsibilities assumed by the gas trading function, usually divided between the front, middle and back office (see Table 13.1)

Table 13.1 Front, middle and back office responsibilities

Gas trading area	Responsibility
Front office	to analyse and manage the market opportunities and risks associated with spot and forward energy sales and purchases; to develop, initiate and transact business with various counterparties in accordance with the company's stated strategies, objectives and policies.
Middle office	to validate the overall portfolio by assessing the accuracy and completeness of the transactions and the forward curves; to maintain the overall control environment; to assess compliance with company policies and trading and authorisation limits; within the organisation, the Middle Office must be independent of the Front Office to ensure proper control.
Back office	to manage trade settlements, general ledger maintenance and cash management; within the organisation, the Back Office must be independent from the Front and Middle Offices to control the cash management function.

In order to carry out these roles, the gas trading function will undertake a number of generic activities in each of these areas. These activities vary by size of the gas trading function and complexity of deals being undertaken. This in turn is a function of the risk appetite of the company and the maturity of the gas market within which it is trading, for example in less liberalised markets, marketing and OTC trading may be more significant roles than in a liquid market where derivatives trading may have greater focus.

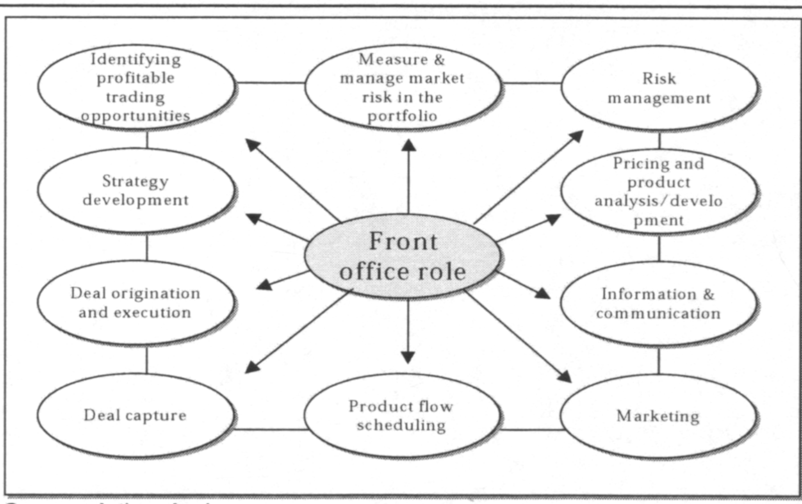
13.4.2 Front office

Identifying profitable trading opportunities

The front office will be responsible for identifying profitable trading opportunities in the gas market in line with the company's risk appetite as expressed by trading limits and its trading strategy. It will do this using its own portfolio assets or by taking outright positions in the marketplace, depending on the group's perception of the under- or over-valuation of risk.

Measure and manage market risks in the portfolio

The front office will be responsible for understanding the risk exposures of its gas portfolio and designing suitable long- and short-term strategies to manage and mitigate these risks. Depending on the role of the gas trading function within the company's overall strategy, the front office may be responsible for minimising exposure to market risk, or in other situations may be responsible for exposing the company to market risk where the company believes it can profit from such a position.



Source: Arthur Andersen

Figure 13.4 Front office activities

Strategy development

The front office will be responsible for developing the company's overall gas trading strategy. This strategy will be formulated by senior traders and management of the function and will be based on long- and short-term views on market patterns and fundamentals. A trading strategy may for instance take into account such market issues as the moratorium on gas-fired power stations, the start of the new On-the-day Commodity Market (OCM), the shutdown of a key beach terminal, the impact of a sudden weather front, or constraints on the UK–Continent Interconnector pipeline.

Deal origination and execution

The front office is responsible for sourcing trading deals either through ongoing key account management and marketing, or through deals done direct with the marketplace. The front office is also responsible for executing those deals by agreeing price and terms with the buyer in accordance with the company's policies and procedures. In particular, these controls emphasise the segregation of duties within the gas trading area so that incompatible duties cannot be combined, e.g. executing and confirmation of trades.

Deal capture

The initial recording of all trade details is also the responsibility of the front office traders using a deal ticket. Taped phone lines also provide a record of deal details for control purposes. These details are then processed through the front office systems and provide an audit trail of transaction process.

Pricing, product analysis and development

The pricing of deals, whether routine or for large one-off deals, is also carried out by the front office. In some cases, the front office team will also analyse current gas risk products in the marketplace and will look to develop further products in line with customers' demands. Such innovative activity drives product evolution and the standardisation of contracts in liberalising gas markets.

Marketing

The front office will be responsible for managing key accounts and building long-term relationships with current and prospective customers. The front office marketing team will also be responsible for liaising with traders and other commercial developers in order to meet customers' needs and develop innovative ways to service their risk management needs. The scale of this marketing activity will depend on the extent of the company's activities, for example a large upstream gas producer may need a significant marketing team to find a downstream market for its product.

Product flow scheduling

The front office will be responsible for the day-to-day operations of the company's gas flows, including managing balancing and nominations processes in line with the Network Code. In particular, they will be responsible for ensuring the company does not incur any imbalance charges on a day-to-day basis. Typically, the operations team will also have authority to execute short-term deals in order to maintain appropriate balancing and product scheduling responsibilities.

Risk management

The front office retains overall responsibility for understanding the different risks to which the company is exposed. These risks include not only gas price and quantity risks but may also include basis, operational, credit and forecasting risks. The team will be responsible for disaggregating the gas portfolio into its constituent risks and managing these books in an appropriate fashion given the company's overall strategy and risk appetite.

Information and communication

Finally the front office will be responsible for aggregating, analysing and communicating market signals across its trading portfolio. Acting as a central clearing house for information from the market, the gas trading function can provide valuable information that will drive trading strategy, and can also be passed on to related company groups such as asset developers.

13.4.3 Middle office

Deal confirmation

The middle office is responsible for confirming all deals executed by the front office in order to ensure the integrity of deal information and adherence to trading and credit limits.

Ensure deal capture

The middle office will ensure a complete record of all deals using tools such as pre-numbered deal tickets.

Portfolio and forward curve validation

The middle office is responsible on a daily basis for validating price curves, net trading positions and market exposure against broker quotes. Such validation is achieved through a careful understanding of the company's portfolio, the gas risk management products being traded and through continuous communication with the front office to keep track of specific market or portfolio shifts, e.g. outages, regulatory announcements, bad weather, etc.

Monitoring of portfolio compliance

The middle office is responsible for monitoring compliance with the company's assigned limits for trading, credit and portfolio exposures. It will also be responsible for reporting any exceptions to these policies to an appropriate risk oversight function within the company.

Portfolio stress testing and statistical analysis

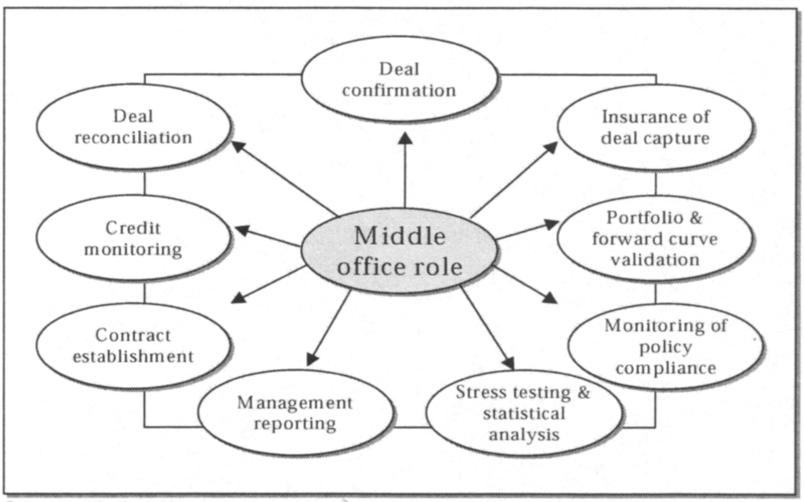
The middle office will monitor the exposure of the company's gas trading portfolio using such techniques as scenario analysis and stress to test the portfolio against shifts in key variables, e.g. a sudden movement in gas prices or a supply outage.

Management reporting

The middle office is responsible for determining management's information requirements regarding gas trading performance and will ensure the delivery of any such position reports on a periodic basis (within day, daily, monthly, etc).

Contract establishment

The middle office will manage the administration involved in the establishment of master contracts and other contractual terms. It will



Source: Arthur Andersen

Figure 13.5 Middle office activities

maintain copies of all contracts and a list of authorised counterparties and update them on a regular basis. In doing so, the team will liaise with marketing personnel in the front office as well as corporate legal advisors where relevant.

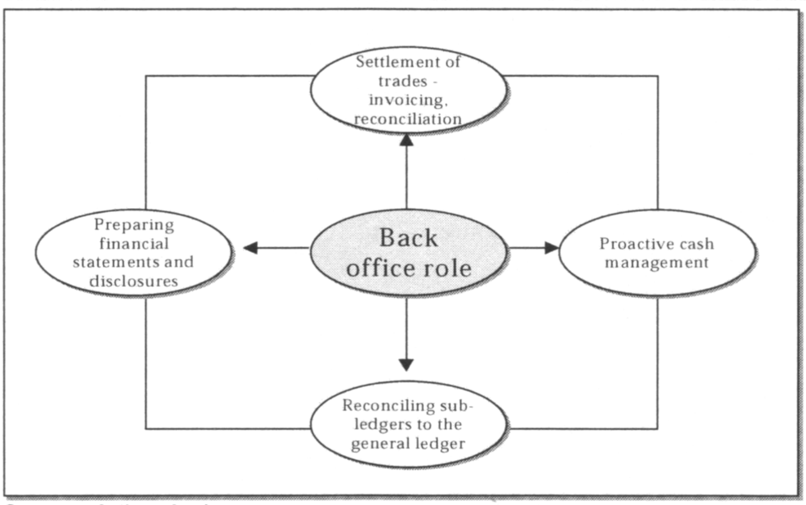
Credit monitoring

The middle office is responsible for monitoring and reporting on compliance with the company's credit policies and procedures. In particular, this will include ensuring that no deal has been executed without having established counterparty limits in place. The middle office will continuously review current credit line exposures by absolute amount, by concentration of exposures and by stress testing credit exposures. The middle office team will be responsible for preparing and commenting on credit exposure reports.

13.4.4 Back office

Settlement of trades

The back office is responsible for automatically generating invoices or remittances on a month-end basis from the gas trading function's information systems. The back office team then undertakes to reconcile invoices to deals recorded by the front office. Where relevant the back office team is responsible for investigating variances between nominated and actual volumes on a timely basis. The team will also manage the filing and maintenance of all settlement and trade details for a suitable time period in line with legal and corporate requirements.



Source: Arthur Andersen

Figure 13.6 Back office activities

Proactive cash management

The back office will establish processes and procedures to manage its cash balance actively. In particular, and where possible, the back office will attempt to accelerate the receipt of debtor amounts and to use fully the credit period extended by creditors.

Reconciling sub-ledgers to the general ledger

As part of the monthly process of closing the books, the back office will undertake to reconcile all sub-ledgers to the general ledger, explaining all movements and variances where applicable.

Preparing financial statements and disclosures

The back office will be responsible for the preparation of financial statements and disclosures that reflect the conduct of the trading group's operations over the period. These accounts may either be prepared using the mark-to-market method of valuation, or using the more traditional accruals concept. In the case of mark-to-market accounting procedures, the back office will also be responsible for ensuring appropriate financial reserves are taken against the gas portfolio. The preparation of these accounts will also take into account the appropriate treatment for intercompany trading activity and will indicate the appropriate classification of financial instruments for tax purposes, for example hedging or non-hedging transactions.

13.5 Future developments

Looking ahead, the gas (and electricity) industry is becoming increasingly commoditised. Already over 500 regulatory reforms have been made within the UK gas industry in attempting to establish an efficient and effective marketplace for all participants. As the gas industry moves towards greater transparency and increases its connections with continental Europe, the role of the gas trading function is seen as central not only to business survival but to business success.

Moving from the simple management of risk as a 'bolt-on' to traditional activities of gas market participants, the trading function has assumed a pivotal role in many organisations in managing risk on a centralised and enterprise-wide basis. The application of gas trading skills to the management of the total corporation in terms of total asset and liability risk is inevitable in an age of free trade and greater liquidity and transparency. In this environment the value-adding role of the gas trading function will become ever more important in identifying, creating and sustaining shareholder value in the new millennium.

14 Accounting

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14.9 Disclosure requirements

14.9.1 United States

14.9.2 United Kingdom

14.10 Gas market issues

14.10.1 Imbalance accounting

14.10.2 Take-or-pay contracts

14.11 Conclusions

14.1 Introduction

An enterprise may enter into gas trading activities for a number of reasons. Gas companies engaged in the exploration and production of gas may wish to secure prices to be obtained from future production. A supplier may wish to secure prices to be paid in the future for gas purchases or for proceeds received from the supply of gas to its customers. 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 supplier, the motive for the transaction is normally precautionary with gas 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 gas 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 gas price related derivative instruments. This chapter considers accounting guidance available in the form of accounting standards and industry best practice. The accounting treatment applicable to all the major gas trading products or instruments – forwards, futures, swaps, options and physical hedges – will also be considered in turn, illustrated by detailed examples.

14.2 Accounting guidance

The development of gas 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. Little authoritative accounting guidance has been developed in the United Kingdom. Accounting practice for the industry has therefore drawn primarily upon guidance from the United States.

The primary source of authoritative guidance in the US is drawn from Financial Accounting Standard 133 *Accounting for Derivative Instruments and Hedging Activities* (FAS 133), issued by the Financial Accounting Standards Board (FASB) in 1998, and FAS 138 *Accounting for Certain Derivative Instruments and 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, guidance on disclosure requirements is given by Financial Reporting Standard 13 *Derivatives and Other Financial Instruments: Disclosures* (FRS 13). This, however, does not deal with the recognition or measurement of financial instruments. Brief reference is also made to oil and gas trading activities in the Oil Industry Committee's Statement of Recommended Practice (SORP), *Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities.* In addition, guidance may be drawn from the Statement of Recommended Accounting Practice on *Off-Balance Sheet Instruments and Other Commitments and Contingent Liabilities.* Although issued for the banking industry, useful reference can be made to this 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 accounting guidance in the UK, it is possible for two enterprises in similar circumstances to account for a transaction involving a gas related commodity or instrument differently, giving rise to different 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.

14.3 General principles

In order to apply the principles of hedge accounting, under both UK and US GAAP, two criteria should apply:

- the transaction must be designated as a hedge of an existing asset, liability or firm commitment, or a specific anticipated transaction; and
- 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 gains or losses are recognised and included in the profit and loss account on the realisation of the underlying hedged item or transaction.

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.

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.

Under US GAAP (FAS 133) the accounting treatment for items designated as hedges is rather more detailed and is discussed in more depth later in this chapter. For example, in the case of 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.

Where any of the two criteria mentioned above do not apply then the instrument concerned, subject to being able to derive a market value (e.g. due to liquidity concerns), 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.

Mark to market accounting is not mandatory under UK GAAP in these circumstances. In fact, since the mark to market approach involves using market values rather than the historical cost principles on which UK GAAP is based, this would require the application of the 'true and fair' override. Nevertheless, mark to market accounting is generally regarded as best practice for trading companies – even though there is no formal guidance on measurement issues (see section 14.2 above).

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 market value changes of the instrument. Typically, on execution of the future, 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 accounts	£x	
Cr	Creditors – commissions payable		£x

On settlement of the commission (possibly 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 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 gas 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 gas 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 hedge 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 gas (for November delivery) hedges physical gas 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); and
- 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. For illustrative purposes quantities have been designated in therms (1 therm is 100,000 Btu) in line with gas trading practice in the UK. Assume that on 1 January, an enterprise enters into 25 IPE natural gas monthly futures contracts for the sale of 25,000 therms per day for March delivery (total 775,000 therms) at a price of 20 pence per therm. The enterprise has entered into the contract to hedge March production. Its broker requires an initial margin of £15,000 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	£15,000	
Cr	Cash		£15,000

(to reflect payment of the initial margin).

On 31 January, the price of a monthly futures contract for March delivery is 21 pence per therm and the broker imposes a margin requirement as follows:

Case 1: 100 per cent cash requirement for the change in the price per therm

Case 2: 20 per cent cash requirement for the change in the price per therm

In the first case, the additional margin payable to the broker is a further £7,750 (1p x 775,000 therms). The following accounting entry will be made at 31 January:

Dr	Debtors – margin account	£7,750	
Cr	Cash		£7,750

(to reflect the payment of the variation margin),

Dr	Other assets – deferred loss on futures contracts	£7,750	
Cr	Debtors – margin account		£7,750

(to reflect the reclassification of the constituent parts of the margin account).

Both the margin account (£15,000) and the deferred loss on futures contracts (£7,750) 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	£7,750	
Cr	Cash		£7,750

(to reflect the payment of the variation margin),

Dr	Profit and loss account – losses on futures contracts	£7,750	
Cr	Debtors – margin account		£7,750

(to reflect the marking to market of the futures contracts).

At this date, for the speculative contract the balance sheet would include only the initial margin within debtors.

In the second case, the additional margin payable to the broker is £1,550 (20 per cent x 1p x 775,000 therms). The following accounting entries will be made at 31 January if the transaction was undertaken as a hedge:

Dr	Debtors – margin account	£1,550	
Cr	Cash		£1,550

(to reflect the payment of the variation margin),

Dr	Other assets – deferred loss on futures contracts	£7,750	
Cr	Debtors – margin account		£7,750

(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, during 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	£1,550	
Cr	Cash		£1,550

(to reflect the payment of variation margin),

Dr	Profit and loss account – losses on futures contracts	£7,750	
Cr	Debtors – margin account		£7,750

(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 three months and whenever financial statements or earnings are reported by an enterprise.

The high-effectiveness requirement has been interpreted in practice by the Securities and 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, defines 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 in the 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 a gas 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 gas 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 gas 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 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, a gas producer uses a futures contract as a fair value hedge for a holding of gas inventory. 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 gas in different locations may execute a single futures contract as a hedge. However, where the underlying items are dissimilar – such as stocks of gas in markets that are not linked in any way – 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 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 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, reduction in enterprise risk – not required under FAS 133 – 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, a gas producer will normally have a clear idea of the expected quality of gas to be sold from one of its fields. It will normally have a firm idea of production or delivery 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 course 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 pro-rated 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 therms of gas in its next fiscal quarter might designate the sales of the first 100,000 therms in each month as the hedged transactions. It could not, however, simply designate any sales of 300,000 therms 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 therms of 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 is 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, there should be 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. Some exchanges, however, impose daily limits on permitted price movements to attempt to ensure an orderly market. Unanticipated events, such as an exceptionally cold spell or a supply interruption, 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 designation of 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 these as hedges – thereby reducing the extent of the back office responsibilities. However, the impact of this approach on reported results will need to be considered.

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 but traded 'over the counter' or on the OTC markets (see Chapters 5, 6, 9 and 10).

Forward contracts may also simply be a gas supply agreement between a gas producer and an independent power producer to cover the purchaser's requirements for a period of time, say for the next twelve months. In another situation, a non-operator with a small stake in a producing gas field may have an agreement to sell its share of gas production at a contracted, or fixed, price.

These examples illustrate forward priced contracts where physical delivery at some point in the future is without price risk as prices have been agreed in advance between the gas producer and its counter-party that ultimately takes delivery of the gas. However, they do not come within the scope of gas trading transactions being considered here. Forwards, in a trading context and as considered here, refer to paper deals on the OTC market where physical delivery is not normally expected to result.

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 a requirement under FAS 133); and
- 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.

There are arguments for recording forward sales and purchases that are undertaken as part of an enterprise's gas trading activities as part of turnover and cost of sales respectively. However, where gas trading is not the principal activity of the enterprise (for example, a gas producer or power generator), the most appropriate basis is to account for such transactions on a net basis. 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 level of revenues or gross margin. Typically, a transaction is undertaken with a financial intermediary and reversed at the time that physical delivery takes place to another counter-party. At the time of reversal, net settlement is made with the intermediary.

Accounting for forward transactions is best illustrated by way of example. Assume that in January, an upstream entity's gas production from one of its gas fields scheduled for three months hence (in April) remains uncontracted and unpriced. Its gas production is currently at 50,000 therms per day. Accordingly, it faces price exposure on 1.5 million therms (being 50,000 therms x 30 days) to be produced in April. To hedge this production, it sells 1,500,000 therms of gas forward at 20 pence per therm. During April, it closes out the forward contract by purchasing 1,500,000 therms forward (April delivery) for 22 pence per therm. Its previously uncontracted production in April is then subsequently sold, at spot prices, also for 22 pence per therm. The accounting entries during the period would be:

Dr	Debtors	£300,000	
Cr	Forward sales		£300,000

(to record the forward sale in January),

Dr	Forward purchases	£330,000	
Cr	Creditors		£330,000

(to record the closing out of the original forward contract in April),

Dr	Debtors	£330,000	
Cr	Profit and loss account – turnover		£330,000

(to record the sale of the April gas production on the spot market),

Dr	Profit and loss account – turnover	£30,000	
Dr	Forward sales	£300,000	
Cr	Forward purchases		£330,000

(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 to be recorded gross, the enterprise's turnover would be shown as £630,000, not withstanding April's actual gas production being 1,500,000 therms. This would give an 'average' price per therm of 42 pence. By recording forward purchases and sales net, turnover for the period shown is £330,000 (from the spot sale) with a net loss on forward trading of £30,000. As the transaction was undertaken as a hedge, this loss would be offset against turnover to result in net disclosed turnover of £300,000. Hence, the 'average' price per therm realised is 20 pence.

If the enterprise entered into the forward transactions for speculative purposes, the £30,000 loss on the trading transactions would not be offset against turnover but shown as other operating income/expense, below 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 represent 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.

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, a gas 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 supplier who faces price volatility in his cost of sales, in the form of gas 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; and
- participation hedges.

The accounting treatment for these instruments is considered by way of example.

14.6.1 Average price instruments

A gas producer enters into a price swap of 25,000 therms per day of gas with a financial intermediary at 20 pence per therm for a twelve month period. The producer is expected to produce at least this quantity of gas per month. In practice it sells its production on the spot market. At the end of each calendar month settlement takes place with the bank. This settlement will be defined by reference to a published source (such as *Heren*, IPE prices, or prices quoted in the *Financial Times*). If the average price of gas exceeds 20 pence per therm, a payment will be made by the producer to the bank. If the average price of gas is below 20 pence per therm, a top-up payment will be made by the bank to the producer.

If the average price of UK gas at the National Balancing Point (NBP) for the month of April is 22 pence per therm, the accounting entries required will be as follows:

Dr	Cash	£165,000	
Cr	Turnover – gas sales		£165,000

(to reflect the sale of its production on the spot market, the producer having received £165,000, i.e. 25,000 therms per day over a period of 30 days at an average price of 22 pence per therm)

Dr	Turnover – gas sales	£15,000	
Cr	Cash		£15,000

(to reflect a payment of £15,000 by the producer to the bank, i.e. 25,000 therms per day over 30 days at 2 pence per therm, the difference between the swap contract price of 20 pence per therm and the 22 pence per therm actual average for the month of April).

The net effect of these two entries will be to include £150,000 in the producer's profit and loss account as turnover. In essence, the enterprise has fully hedged its production.

If the average price of gas for April is 19 pence per therm the following accounting entries would be made:

Dr	Cash	£142,500	
Cr	Turnover – gas sales		£142,500

(to reflect the sale of gas production on the spot market)

Dr	Cash	£7,500	
Cr	Turnover – gas sales		£7,500

(to reflect the payment by the bank to the producer)

The net result of these entries would also be to include £150,000 in turnover.

In the above example, no initial payment was made by either party. If an initial payment of £12,000 was made by the gas 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, one-twelfth of this would be amortised:

Dr	Turnover – gas 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 gas. 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 the 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 risk, 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 gas 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 which sets the maximum price (ceiling) to be received by the gas 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, a gas producer (monthly production – 25,000 therms per day) and bank may set a floor of 18 pence per therm and a ceiling price of 22 pence per therm. The per therm difference in price will be settled between the two parties if the average price is outside the range set. If the average price is 16 pence per therm, a payment of £15,000 (18 p/th – 16 p/th x 25,000 therms/day x 30 days) is made to the producer. The following adjustment is made to turnover, assuming the transaction is a hedge:

Dr	Cash	£15,000	
Cr	Turnover – gas sales		£15,000

If the average price rises to 25 pence per therm the producer pays £22,500 (25 p/th – 22 p/th x 25,000 therms/day x 30 days) to the bank with the following adjustment to turnover:

Dr	Turnover – gas sales	£22,500	
Cr	Cash		£22,500

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 gas is in the range 18 pence to 22 pence per therm, 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 pence per therm difference in gas price.

For example, a gas producer enters into a swap as a hedge with a bank on the following terms:

- 25,000 therms per day are swapped for a year;
- monthly settlement is made based on a floor of 20 pence per therm;
- if the average price falls below 20 pence per therm, the producer receives a cash payment amounting to the difference between the average price and 20 pence for each therm produced;

- if the average price exceeds 20 pence per therm, the producer pays 20% of the per therm difference in price for the volume hedged for each therm produced; and
- there is no initial premium or payment.

In the example, if the average price of gas is 18 pence per therm in April, a payment of £15,000 (20 p/th – 18 p/th x 25,000 therms/day x 30 days) will be made by the bank to the producer resulting in the following accounting entry being made:

Dr	Cash	£15,000	
Cr	Turnover – gas sales		£15,000

If the average price is 25 pence per therm, the producer pays the bank £7,500 (25 p/th – 20 p/th x 20% x 25,000 therms/day x 30 days) with the following accounting entry being made:

Dr	Turnover – gas sales	£7,500	
Cr	Cash		£7,500

If a gas 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. However, if the enterprise was an independent power producer acquiring gas for its power plant 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 a gas producer may hedge twelve 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 25,000 therms per day for gas sales at 22 per therm, receiving or paying 100 per cent of the per therm difference. Settlement is at the end of the twelve month period. Its financial year end is 31 March, when it has produced 2,250,000 therms receiving average proceeds of

20 pence per therm. Its forecast production for the next nine months is 6,875,000 therms.

Although settlement will not be made until 31 December, the enterprise will have received revenues of £450,000 (2,250,000 therms x 20 p/th).

Dr	Cash	£450,000	
Cr	Turnover – gas sales		£450,000

It will make an adjustment to turnover at 31 March to reflect the unrealised gain of £45,000 (22 p/th – 20 p/th x 2,250,000 therms) on the swap contract at this date:

Dr	Debtors – unrealised gain on swap	£45,000	
Cr	Turnover – gas sales		£45,000

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 2,250,000 therms but the forecast for the full year is now increased to 11,406,250 therms (or 31,250 therms/day), it would be appropriate to regard the enterprise as hedging 80 per cent of its production. Consequently, the adjustment at 31 March would be reduced to £36,000.
- If production for the period is 2,250,000 therms but forecast for the full year is reduced to 5,475,000 therms (or 15,000 therms/day), the adjustment to turnover at 31 March remains at £45,000. (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.

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 accounting 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 gas 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 two 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 rate 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 gas 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 gas at prevailing market prices in the UK in three months' time. By taking advantage of currently low prices in another geographic market, say Belgium, the enterprise's Belgian affiliate may acquire an equivalent quantity of gas on the spot market on behalf of the enterprise. In three months' time when prices have recovered, the enterprise acquires the gas it is contracted to purchase in the UK and sells the gas previously acquired in Belgium.

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 Belgium at similar prices to those paid in the UK, the net cost to the enterprise is the lower cost of the gas originally acquired in Belgium.

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 under US GAAP.

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.

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 depicted in the balance sheet, it is necessary for the enterprise's accounting policies to be disclosed fully. Where gas 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 resulted in the issue of FAS 133 *Accounting for Derivative Instruments and Hedging Activities*, issued in 1998. 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.

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 twelve months.

  iii) The maximum length of time over which the enterprise is hedging its exposure to the variability in future cash flows for forecast 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 they are 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 items.

For cash-flow hedging transactions, FAS 133 requires 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 Gas market issues

Unlike in the oil markets, particular issues arise in respect of the physical trading of gas especially in a deregulated environment. These include imbalance issues and take-or-pay contracts. These are considered below.

14.10.1 Imbalance accounting

Since gas supply companies cannot determine exactly what their customers will purchase at any one point in time, there could be a mismatch between the gas volumes that companies may have estimated as sales and the amount that the network operator has made this company input into the pipeline (the network operator will also charge the suppliers transportation and capacity costs based on this volume).

In the UK, for example, Transco (the network operator) estimates the amount of gas that each shipper is required to input (on a daily basis) into the system in order to satisfy the consumption requirements of their customers. This is referred to as the 'deemed' demand. This volume is also used to calculate the transportation charges that Transco is able to levy. Transco uses a complex algorithm, which is defined in the Network Code (see Chapter 10) to determine each shipper's 'deemed' demand. Each shipper's booked sales (actual sales based upon customer meter readings) may be different to the 'deemed' figure. This difference is commonly referred to as the 'imbalance'.

The imbalance arises as a result of the large number of estimates involved in both deemed demand and booked sales (since it is necessary to estimate consumption during the period for a proportion of a company's customers at the end of any accounting period). This should only represent a timing difference to be settled by the reconciliation process. Site by site reconciliations are performed for the larger industrial and commercial meter points (over 73,200 kWh per annum in the UK). Transco raises credits or additional charges to the industrial and commercial shippers with the corresponding charges or credits to domestic shippers settled under the reconciliation by difference process (RbD). RbD started in the UK on 1 February 1998 and all balances prior to this date were settled during 1999.

At the end of each period, each shipper then creates either an imbalance debtor or creditor depending on whether its booked sales figures were higher or lower than the deemed figures. The shipper should assess the robustness of its estimating processes in order to raise a provision against the imbalance debtor if it felt that this, or part of this, is unlikely to be recovered.

14.10.2 Take-or-pay contracts

The historical development of gas markets in the UK and elsewhere was characterised by long-term supply contracts between shippers and producers, often up to 25 years, and often for the entire production of the field. These contracts in the 1970s, 1980s and early 1990s were commonly regarded as necessary to persuade producers to develop the gas supplies in the UK Continental Shelf. They were also driven by the fact that the UK had a monopoly supplier of gas whose primary objective was to obtain security of continuous gas supplies. Contract prices in these long-term contracts are determined by reference to indices which varied from contract to contract; typically they included some of the following: RPI, crude oil prices, gas oil prices, heavy fuel oil prices and the US dollar exchange rate (see Chapters 11 and 12). All these long-term contracts also contained provisions under which the purchaser pays annually for a minimum contracted volume of gas, whether this is actually taken or not, hence the term 'take-or-pay' contracts.

These contracts presented two fundamental problems to the purchaser as gas markets were opened up to competition in the 1990s. First, they committed the purchaser to paying for gas that it might not be able to use as its share of the market varied. This reduced the purchaser's flexibility and could lead to it having an over supply of gas. Secondly, due to the nature of the pricing mechanism built into the contracts, they could quite easily be much more expensive than the new spot market prices for gas.

The financial effects of oversupply are that the purchaser has to expend a greater cash flow than would otherwise be necessary. However, the gas paid for but not used can be used in the future. This should be accounted for as a prepayment within the balance sheet. The prepayment created must be valued at the lower of cost and net realisable value, therefore there may be a write off to put through the profit and loss account if the contracted prices are higher than the market price.

In the UK, the take-or-pay contracts were seen as a threat to the survival of several firms, as these contract prices were significantly higher than market and they did not provide the flexibility required to compete in a fast deregulating market. Therefore some companies were in favour of renegotiating these contracts and the late 1990s were characterised by the announcement of multi-million pound renegotiation deals. Generally, the renegotiations involved the payment by the purchaser to the producer to either terminate the supply contract (re-assign it back to the producer) or to secure a lower price for the contracted volume of gas. The accounting treatment for these payments in the purchaser's books depended on the nature of the renegotiation. For deals where supply was terminated the payments were usually expensed through the profit and loss account often treated as exceptional operating costs. In cases where a more favourable purchase price was obtained for the same volume, the payment was treated as a prepayment in the balance sheet and then released to the profit and loss over the remaining life of the contract. Some renegotiations involved both a reduction in price as well as in volumes. In these cases the payment had to be allocated to each aspect of the deal and then the part in payment of terminating supply volumes expensed and the remainder matched to the benefit derived from the lower purchase prices. By corollary, from the perspective of the seller of the gas, payments received upon the renegotiation of gas supply contracts (in consideration for the reduction in price of gas supplied) should be accounted for as deferred income. This deferred income is then amortised and recognised in the income statement over the period of the supply contract.

There has been considerable recent debate about the application of FAS 133 to UK long-term gas contracts. Generally, these contracts meet the definition of a derivative under FAS 133 as they have:

a) an underlying variable from which the contract derives its value, namely the gas price;

b) a notional amount, defined in million cubic feet per day (mcfd) or therms;

c) no significant payments made on entering the contract; and

d) can be settled net since gas is an interchangeable unit for which there are quoted market prices in a market that can absorb contract quantities.

Under FAS 133 derivatives must be valued fairly, with movements in those values recorded in the profit and loss account, unless the derivatives qualify for the "normal purchase normal sale" exemption. Generally, UK long-term gas contracts meet several of the criteria for the "normal purchase normal sale" exemption. These contracts are typically for the physical delivery of gas for volumes that are expected to be used or sold over a reasonable period of time in the normal course of business and are rarely settled net.

However, the contracts generally fail to obtain this exemption as they:

a) contain optionality clauses such as take-or-pay provisions; and

b) the contract prices are indexed to a basket of commodities, (for example, fuel oil, gasoil, kerosene, electricity and the producer price index) which are not "clearly and closely" related to the underlying price of gas.

Nevertheless, since long-term gas contracts are not standardised contracts, each should be considered individually on its own merits when determining whether they need to be marked to market under FAS 133.

14.11 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 gas trading activities is dependent on a clear understanding of the enterprise's strategy and transactions. US GAAP is prescriptive in its approach in relation to measurement issues and rules about hedge accounting. However, in the UK there is limited accounting guidance on measurement issues.

In order to comply with US GAAP'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 gas trading activities. As a result, a proper understanding of the financial statements of a company engaged in gas trading is dependent on clear and appropriate disclosures of the accounting policies and the nature of the transactions it undertakes.

15 Taxation of gas trading

Phil Greatrex, CW Energy

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15.1 Background

The gas trading markets are now well established in a number of jurisdictions, notably the USA, the UK and the Far East. The markets are not however quite so well established as the oil trading markets and gas trading is not yet done on an international basis. The major traders do however operate globally.

Most developed tax jurisdictions attempt, ultimately, to tax the profits generated in their location but it can be almost impossible, with global trading activities, to assess where particular profits are being generated. With traders in touch with each other and with the market moving constantly, the fact that a particular contract is made in, say, Europe which generates a profit, does not necessarily mean that the profit has been earned for the corporation in the European location. The contract could have been taken out to hedge a loss-making position elsewhere in the worldwide 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 cross-border nature of many trading activities, it has become increasingly difficult to isolate profit or loss by location. Consequently 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 assess accurately the profits made in their location.

An international trading group will generally be concerned to ensure that double taxation does not arise and that the worldwide 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. In these circumstances agreeing a commission, or cost mark up, basis of taxation in other locations can be attractive. Alternatively, locating the activities in a country which offers special incentives to gas traders can defer or reduce overall tax costs.

This section sets out the main principles for the taxation of gas trading activities in three of the main gas trading centres of the world, i.e. the UK, the USA and Singapore.

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 and gas related activities so far as direct tax is concerned. The taxation affairs of most, but not all, gas trading groups are handled by the OTO. The OTO have built up considerable expertise in the area of inter company transfer pricing and the UK gas market over the last few years and have learnt a great deal about the way such international 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 worldwide profits.

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.

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 companies (CFCs) 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.

Supplies of goods situated in the UK or of services treated as supplied in the UK will be within the scope of UK VAT regardless of the residence of the supplier.

15.2.3 Residence

Since 1988 UK incorporated companies have been automatically resident in the UK for corporation tax purposes. (However see comment below on effect of double taxation treaties.)

A non-UK incorporated company may also be UK tax resident if its 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 for the application of the treaty, which of the two locations the company will be deemed to be resident in. Certain treaties, however, permit the company to be treated as resident in both locations.

Furthermore, if under a double taxation treaty, a company, which is incorporated in the UK, is treated as resident outside the UK, by virtue (usually) of being effectively managed outside the UK, it will also be treated as not resident under UK domestic law.

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 of 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 negotiate. It is possible to obtain a post-transaction ruling after the end of the accounting period, which 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 that 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 usually 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 at 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, in any event, 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 that are related. (See the definition of a permanent establishment contained in the OECD model tax treaty at 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 made by the branch under gas trading contracts (particularly traded or over-the-counter options or price swaps) will be UK supplies. For contracts treated as supplies of goods, different rules apply based generally on their location at the point of delivery or appropriation.

UK subsidiary

UK resident subsidiaries are chargeable to UK corporation tax on their worldwide 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 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 (April 1, 2002) 30 per cent, although this rate may be reduced to the small companies rate (currently, 19 per cent) where the profits charged to tax are small (currently less than £1.5 million) or 0 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 worldwide 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 the previous year's chargeable profits and gains.

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 gas trading, cannot be utilised to reduce tax on ring fence profits. From 17 April 2002 these profits, after adding back financing costs, are also subject to an additional 10 per cent charge.

The standard rate of VAT is 17½ 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 excisable 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. There are also a number of limited treaties dealing mainly with shipping and air transport. The list of countries with which the UK has a full treaty is as follows:

Antigua	India	Philippines
Argentina	Indonesia	Poland
Australia	Ireland	Portugal
Austria	Isle of Man	Romania
Azerbaijan	Israel	Russian Federation
Bangladesh	Italy	St.Christopher & Nevis
Barbados	Ivory Coast	Sierra Leone
Belgium	Jamaica	Singapore
Belize	Japan	Slovak Republic
Bolivia	Jersey	Slovenia
Botswana	Kazakhstan	Solomon Islands
Brunei	Kenya	
Bulgaria	Kiribati	

Burma (Myanmar)	Korea	South Africa
Canada	Kuwait	Spain
China (People's Republic)	Latvia	Sri Lanka
	Lesotho	Sudan
Croatia	Luxembourg	Swaziland
Cyprus	Macedonia	Sweden
Czech Republic	Malawi	Switzerland
Denmark	Malaysia	Tajikistan
Egypt	Malta	Thailand
Estonia	Mauritius	Trinidad
Falkland Islands	Mexico	Tunisia
Fiji	Moldova	Turkey
Finland	Mongolia	Turkmenistan
France	Montserrat	Tuvalu
Gambia	Morocco	Uganda
Germany	Namibia	Ukraine
Ghana	Netherlands	USA
Greece	New Zealand	Uzbekistan
Grenada	Nigeria	Venezuela
Guernsey	Norway	Vietnam
Guyana	Oman	Yugoslavia
Hungary	Pakistan	Zambia
Iceland	Papua New Guinea	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 gas 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 15.2.5 above) is payable in four instalments; being in months 7 and 10 of the year in question, and in months 1 and 4 of the following year. 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 required to self assess the position of the non resident in the same way as the non-resident company would be if it were UK resident.

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 following month. 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 gas traders

Some international trading organisations have set up offices in the UK 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. However, in many such cases people based in the UK 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 15.2.4 above).

However, such arrangements are becoming increasingly hard to operate. Firstly, the individuals based in the UK 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. It could be that the trader has, in any event, 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 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 usually be agreed in advance with the Inland Revenue and the basis of taxation agreed may well include an element of 'cost plus' (see 15.2.4 above) as well as a commission.

Where there is substantial speculative trading controlled by the UK traders outside of the global network, the Inland Revenue may seek to isolate any profit from such activity and to tax it separately.

For VAT the location, in the case of a sale, of the product outside the UK generally means the transaction is outside the scope of UK VAT altogether for the supplier or seller. However, a buyer who brings goods to the UK from abroad or who is designated as the consignee when the goods are shipped by the seller, is liable to pay or account for VAT (as input tax in the case of goods from outside the European Union, or acquisition VAT for goods from other EU Member States).

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. Equity gas that is sold to Centrica plc (the successor to the British Gas Corporation) under field specific contracts entered into before 1975, when PRT was introduced, is however exempt from PRT.

Where gas is sold under a long-term contract that provides for payments to be made at a certain minimum level each year regardless of whether gas is delivered (take-or-pay provisions), special rules apply. For PRT the receipt is only brought into charge when the gas is subsequently delivered in a later period. If it transpires that the gas is never delivered the receipt is brought into charge on the date when the obligation to deliver any further gas lapses. The treatment for corporation tax would be the same, although this is under basic principles, rather than under any specific provision of the law.

Gas trading profits are not subject to PRT, although the price obtained by a trader on selling any equity produced gas will be brought into the PRT net. A number of upstream companies sell their equity production to a gas trading affiliate that will then market a combined gas stream. The inter-affiliate sale will have to be priced for tax purposes on an agreed arm's-length price taking account of all the circumstances of the sale, e.g. spot, long term, swing factors, etc. This agreed price will be the gas trader's base price against which his taxable profits will be computed. Any profits made against this base price will be outside the PRT and ring fence corporation tax net.

15.3 United States

David Zimmerman & John S. Levin, Miller and Chevalier

15.3.1 Introduction

The US has long been a trading centre within the global market for oil and gas trading activities with significant amounts of trading taking place in New York, Houston and Chicago.

15.3.2 Scope of tax

US corporations

US corporations are taxed on their worldwide income. A corporation is treated as a US corporation if incorporated under the laws of any one of the States, regardless of where managed or controlled. US subsidiaries of a foreign corporation are taxed on their worldwide 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 undistributed 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, rents, 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 is taxed at regular US corporate rates (at 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 source 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 the US source income of a foreign corporation that is engaged in a trade or business in the US is treated as effectively connected with the conduct of 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 gas 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 the 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 and the office regularly carries on activities of the type that produce such income. A US office is a material factor in the realisation of the income from the sale of personal property 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 sales 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 (USRPI) are treated as effectively connected with a US trade or business. Included in the definition of a USRPI are interests in real property located in the United States (including an interest in a gas 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 trade or business for foreign income taxes paid or accrued on their foreign source effectively connected income.

15.3.3 Residence

For US corporate income tax purposes, a company's country of incorporation rather than residency is used to determine income tax liability.

15.3.4 Taxation of income and gains

The regular US corporate tax rate is progressive for the first $100,000 of income, ranging from 15 per cent to 34 per cent. The 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 $10,000,000. Income above $10,000,000 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 equalize 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 business to the extent such earnings are not reinvested in the US business. 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 are currently taxed at the same rate as other income. 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 be carried back two years and carried forward twenty years in computing income subject to US tax. Net operating losses arising in tax years ending in 2001 and 2002 may be carried back five years.

15.3.5 Tax administration

US corporations are required to file an annual income tax return.

Foreign corporations engaged in US trade or business, or that have a permanent establishment in the US, at any time during the tax year must file an annual tax return. This rule applies even if the foreign corporation has no net income that is effectively connected with its US business.

Foreign corporations not engaged in US trade or 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 by 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 Tax treaty network

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
- Latvia
- Lithuania
- Luxembourg
- Mexico
- Moldova
- Morocco
- Netherlands
- New Zealand
- Norway
- Pakistan
- Philippines
- Poland
- Portugal
- Romania
- Russian Federation
- Slovakia
- 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 Bermuda and the Netherlands Antilles that apply to limited items.

15.3.7 Special considerations for gas 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 trade or business as long as the foreign corporation does not have a US office through which the commodities 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 trade or business even if the foreign corporation has a US office through which the trades are effected. This exception, however, does not apply to foreign corporations that are dealers in commodities.

In order for a foreign corporation to qualify for these exceptions, 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 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 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 any 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.

Gas 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 possible, however, to obtain advance rulings in the US which could cover how profits from a global trading activity will be allocated to the various taxing jurisdictions for US tax purposes.

15.4 Singapore

Alain Ahkong, Pioneer Associates Ltd.

The Asia-Pacific region is one of the world's fastest growing markets for natural gas today. Containing over half of the world's population and formerly largely dependent on coal for power — especially in China and India — the region's demand for natural gas has increased steadily. Greater weight is now given by these countries to the environmental concerns linked to the burning of coal and major investments in infrastructure are being made by countries such as Malaysia, Indonesia and Thailand to transport gas for distribution and local use.

Singapore, situated at the tip of the Malaysian Peninsula, has contributed to the growth of the region's gas markets. Its ideal location provides for close proximity to both the major gas producers and gas markets in the region. The major regional gas producers include Malaysia, Indonesia, China, Brunei and Vietnam, and the major regional gas markets include Japan, South Korea, Taiwan and Hong Kong. This close proximity benefits gas traders who use Singapore as an international gas trading centre. Of even greater benefit to gas traders is the Singapore Government's commitment to make Singapore an international oil and gas trading centre which is seen in its introduction of the Approved Oil Trader (AOT) tax incentive scheme in 1989.

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.

Singapore's success as a regional gas-trading centre is reflected by the growth in the number of oil and gas traders in Singapore. There are currently more than 100 oil and gas traders in Singapore and the list continues to grow. These traders include oil majors and refiners and gas traders. In view of the Singapore Government's actions to promote the oil and gas industry in Singapore an increasing number of companies are expected to expand their oil and gas trading operations into Singapore. As such, the income tax laws and the taxation of oil and gas 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:

(a) income accruing in or derived from Singapore, and

(b) income received in Singapore from outside Singapore (i.e. foreign source income received in/remitted to Singapore).

There is no capital gains tax in Singapore.

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 the purchase of any movable property which is brought into Singapore.

A non-resident company carrying on business in Singapore through a branch is taxable on income accruing in 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 operation.

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 was 25.5 per cent. With effect from the Year of Assessment 2002, the rate is reduced by 1 percentage point to 24.5 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.

In addition, a 5 per cent tax rebate is granted on the computed tax.

For Year of Assessment 2003, the exemption threshold will be retained but the corporate tax rate will be reduced from 24.5 per cent to

22 per cent. The 5 per cent tax rebate will, however, be withdrawn in view of the reduction in tax rate.

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 substantial 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 Structure of business entities

Representative offices of non-Singapore companies

Foreign companies that have been granted procedural approval from International Enterprise Singapore (formerly known as the Singapore Trade Development Board) to set up representative offices in Singapore are not permitted to undertake any business transactions in Singapore, including to conclude contracts, or open or negotiate any 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 in Singapore are strictly confined to promotional and liaison work for its head office. Thus, it is not normally subject to Singapore income 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 dividend to its shareholder 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.

In the Government's 2002 Budget Statement, the Finance Minister announced that a one-tier corporate taxation system will replace the existing full imputation system with effect from January 1, 2003. Under the one-tier corporate tax system, corporate profits are taxed at the corporate level only. Dividends declared from such profits are tax exempt to the shareholders.

Singapore service company

A foreign company may incorporate a Singapore subsidiary that would provide 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 Singapore tax treaties

Singapore has concluded double tax treaties with the following countries:

Australia	India	Papua New Guinea
Bangladesh	Indonesia	Philippines
Belgium	Israel	Poland
Bulgaria	Italy	Portugal
Burma (Myanmar)	Japan	Sri Lanka
Canada	Korea, South	South Africa
China (PRC)	Latvia	Sweden
Czech Republic	Luxembourg	Switzerland
Cyprus	Malaysia	Taiwan (ROC)

Denmark	Mauritius	Turkey
Egypt*	Mexico	Thailand
Finland	Netherlands	United Arab Emirates
France	New Zealand	United Kingdom
Germany	Norway	Vietnam
Hungary	Pakistan	

** awaiting ratification*

Singapore has also concluded an agreement on mutual tax exemption with:

- USA — on income derived from the 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 the 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 tax 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 and gas traders

In order to encourage the further growth of the Singapore oil and gas trading industry and to encourage international oil and gas 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 International Enterprise Singapore, 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 concessionary rate of tax of 10 per cent on qualifying income from qualifying trading activities in approved 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 out of all other profits and 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 based on their trading headquarter functions and activities, world-wide networks and track record performance. 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 includes:

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 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; or
- a overseas branch 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:

1. Physical trading, which means 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 company from and sold to:

   - 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; 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.

2. Petroleum futures trading, which means 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 company 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.

Exchanges currently specified in the Regulations are as follows:

(a) International Petroleum Exchange (IPE);

(b) New York Mercantile Exchange (Nymex); and

(c) Singapore International Monetary Exchange* (Simex).

3. Over-the-counter (OTC) hedging, which means 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.

<u>Approved products</u>
Qualifying petroleum products for 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 base stock or its derivatives, naphtha, paraffin wax and sulphur.

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*merged with the Stock Exchange of Singapore (SES) in December 1999 to form the Singapore Exchange (SGX).

15.5 UK taxation of trading instruments

15.5.1 Introduction

Gas traders can use a number of different types of 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.

Petroleum Revenue Tax (PRT)

PRT is not chargeable on the profits derived from financial or trading instruments and can be disregarded in the taxation of gas trading activities. Its impact has, however, to be borne in mind by traders seeking to hedge group exposures.

Corporation tax

The corporation tax legislation does not adequately cover the use of most trading instruments, 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 gas 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 gas trading companies, where this is their only activity, this is fairly easy to establish, but for companies who have a gas trading arm 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 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, a gas company may hedge against the sale of its equity production to 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.)

While the treatment of an instrument taken out in connection with a specified volume of gas should fall within the revenue category, this may not, however, be the case where the volume of gas covered by the 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.

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. These ring fence profits, after adding back financing costs, are also subject to an additional 10 per cent charge from 17 April 2002.

It is important, therefore, that costs incurred in connection with upstream activities achieve a ring fence tax deduction. Gains and losses on trading 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.

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.

The above describes the general PRT and corporation tax treatments of trading instruments. Where the position is potentially different for specific instruments the treatment is described below.

15.5.2 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 will not apply to gas, although can potentially apply to crude oil or refined products; 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.

15.5.3 Futures

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 generally a contract for the supply of goods. This is on the basis that the contract can technically go to delivery, notwithstanding that the vast majority of such contracts do not. The supply will take place where the goods are located. In most cases this is taken to be in the country in which the exchange on which they are traded is situated.

Gas futures contracts on the IPE are essentially exempt from VAT and the rules for determining the value of the supply can be complicated. Such contracts cannot technically go to delivery and are thus treated as supplies of financial services with the same treatment as financial futures.

15.5.4 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 gas 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 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.

In VAT terms options, whether traded, or over the counter, are supplies of services. Contracts for gas will be essentially taxable at the standard rate of 17½ 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 17½ 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, including the IPE gas futures contract, on the other hand are normally exempt from VAT with a consequent possible restriction on the amount of input VAT to be recovered.

15.5.5 Swaps

Gas trading swaps, i.e. exchanges of gas streams, with or without a price differential, would normally be treated as part of the trading activity of the company. For an upstream company swapping its own physical 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.

The treatment of a swap for VAT purposes is as an exempt financial service. This is because the essence of a swap contract is the hedging of a price variation in the underlying product and the contracts are based on only *deemed* purchases and sales. 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 Union.

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.

16 Gas in power generation

Rowland Sheard, Energy Links Consultancy

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16.1 Introduction

This Chapter looks at the technology and economics of gas-fired power generation and puts them into the context of electricity markets. Gas is now generally the fuel of choice for most new power plants following the development of the combined cycle gas turbine (CCGT), which has transformed the economics of electricity generation. And gas' share of the power generation market is growing rapidly in many countries helped by the liberalisation of electricity markets. Market opening encourages the building of new gas-fired CCGT plants by new entrants, especially Independent Power Producers (IPPs).

16.2 Power generation technologies

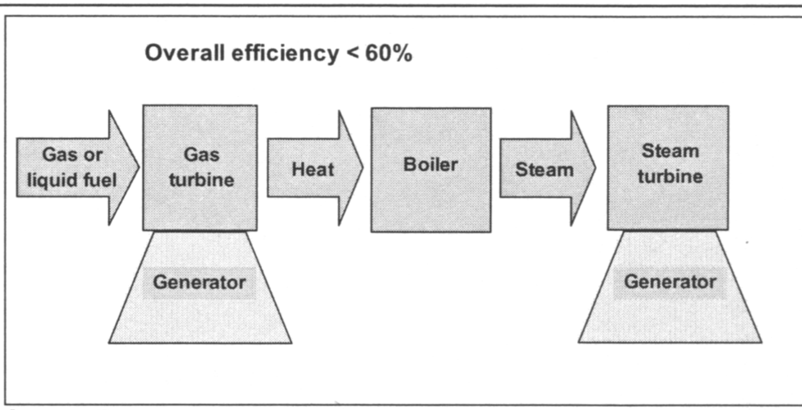
All bulk electricity is produced in fundamentally the same way. Mechanical energy is used in an electric generator to move coils of wire in a magnetic field. This induces current in the wires. It is the way in which mechanical energy is produced that differentiates the various modes of electricity generation.

Methods of generating electricity

At the simplest level, windmills directly drive an electricity generator. Similarly, in hydroelectric stations water flows through a turbine. The turbine has blades that drive a shaft and this operates the electricity generator. It is interesting to note that in the pumped storage schemes operated in the UK by First Hydro at Dinorwig and Ffestiniog (totalling just over 2,000 MW) the turbine is reversed at times of lower power demand and uses electricity at low cost to refill the water dams. The combination is, in effect, storing electricity.

Figures 16.1 to 16.3 below illustrate the mainstream methods of power generation. Virtually all conventional fossil fuel and nuclear stations generate steam, which is then used to drive a steam turbine.

The other technology used is the gas turbine. This is a turbine driven by hot gases produced by burning fuel. Despite its name the fuel can be solid, liquid or gaseous. The important issue is that when the gases reach the turbine blades they should be clean, i.e. not containing solids or products that could corrode the blades. Currently the most common fuels used in gas turbines are natural gas and gas oil (sometimes known as distillate). Heavy fuel oil has also been used, but fuel pre-treatment is needed, as is regular cleaning of the turbine blades.



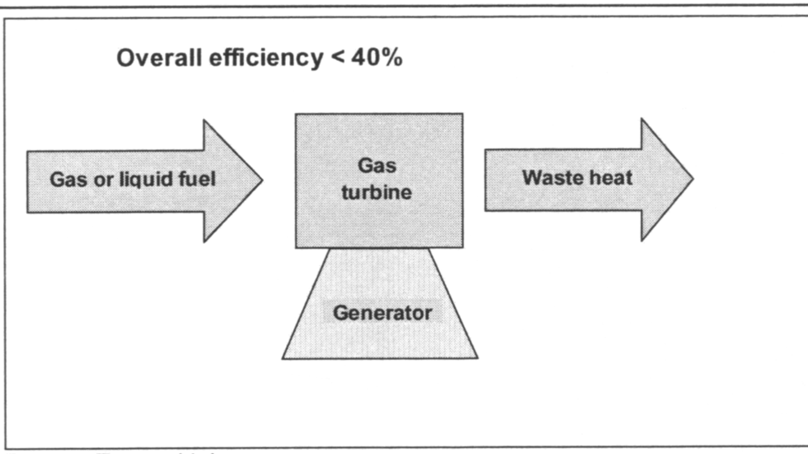
Source: Energy Links

Figure 16.1 Conventional power station

Since coal is the world's most abundant fossil fuel resource, perhaps the most potentially interesting electricity generation technology is coal-fired gas turbines; this involves gasifying the coal and passing the gas on for normal use in a gas turbine. The gasification process includes stages to remove the worst pollutants; but it is not economic at gas prices up to perhaps $4-5/million Btu using current technology. The other clean coal technologies involve fitting flue-gas desulphurisation to conventional boilers or fluidised bed combustion where sulphur can be removed within the fluidised bed. A UK government review[1] of energy sources for power generation has suggested that the main use for this technology will be in countries like China and India where cheap natural gas is not an option. Indeed the Cabinet Office Performance and Innovation Unit 2002 Energy Review[2] suggests that the UK government sees clean coal technologies as depending on carbon sequestration – for example carbon dioxide could be disposed of in sub-sea strata.

Open cycle gas turbine

In the UK, the process of using the turbine on its own is sometimes called an open cycle gas turbine (OCGT) or simple cycle gas turbine operation. This process does not have the heat recovery boiler associated with the combined cycle gas turbine (CCGT - see below). OCGT plants are generally used to provide electricity at peak demand



Source: Energy Links

Figure 16.2 Open cycle gas turbine

[1] *Review of Energy Sources for Power Generation*, Cmd 4071, October 1998; a copy of this report can be found on the Department of Trade and Industry website (www.dti.gov.uk).

[2] *The Energy Review*, February 2002; a copy of this report can be found on the Cabinet Office Performance and Innovation Unit website (www.piu.gov.uk).

periods and use gas oil as the fuel. It is usually not commercially sensible to use natural gas in OCGT plant, because they may only be used for a few hours a year at times of peak demand. Gas purchase is associated with high fixed transportation costs, irrespective of the number of hours of use. Currently the total OCGT capacity in England and Wales is about 1000 MW, with plant ranging in size between 34 and 140 MW capacity.

There have been proposals for building up to about 1000 MW of additional OCGTs as 'embedded' generation. These are OCGTs sized up to about 50 MW which would be situated (embedded) in the local electrical distribution system, thus avoiding charges from the National Grid. In contrast to existing OCGTs they would run mid-way in the merit order, that is, through much of the day rather than just at peak. The generating costs are around 2.3 p/kWh at 50 per cent load factor, although with high oil prices this could rise to around 4 p/kWh. This compares with prices of about 2 p/kWh and 3.5 p/kWh respectively for gas powered base load generation (assuming the same range of oil prices). This is comparable to figures for CCGTs (see below). However, the UK government is:

- seeking to constrain such developments as the thermal efficiency is no more than 40 per cent compared with new CCGTs with efficiency of around 60 per cent.
- concerned that a key driver for such schemes is the avoidance of grid charges, which could lead to increasing grid charges for remaining customers.
- seeking to concentrate embedded generation on renewable technologies such as wind power and combined heat and power (CHP).

A measure of engineering progress in the field of turbines is that over the last 30 years or so the thermal efficiency of open cycle gas turbines has risen from below 20 per cent to 40 per cent (on a net calorific value (CV) or lower heating value (LHV) basis).

Combined cycle gas turbine

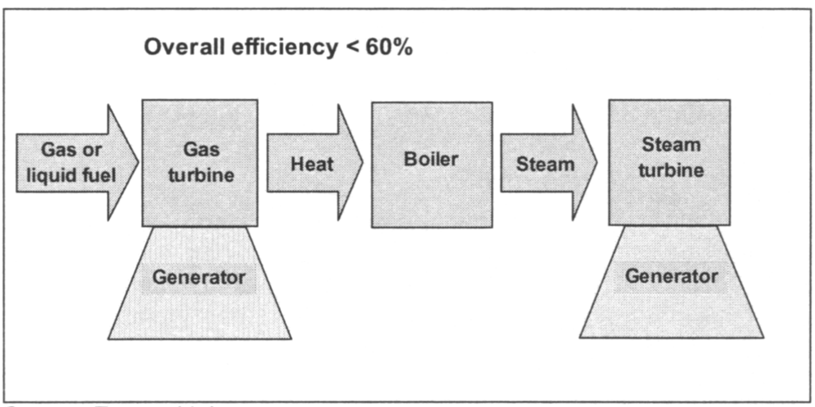
The development that has changed the whole world power generation market is the introduction of combined cycle gas turbine (CCGT) technology. This takes the heat coming out of a conventional gas turbine and puts it into a steam boiler. The steam generated is put through a steam turbine and this generates additional electricity. In broad terms this combination produces 50 per cent more electricity than the same turbine operating as an OCGT. It has revolutionised the economics of electricity generation from gas. Compared with other technologies for mainstream power generation, a CCGT can be built in about half the time needed for a coal fired plant and produces only half the amount of CO_2 per kWh generated. This is particularly valuable in the light of the Kyoto Protocol targets which the UK government signed up to in December 1997.

A 650 MW plant uses around 1 million therms of natural gas per day or about 1 bcm per year.

Combined heat and power

The other key electricity generation markets are combined heat and power (CHP) and cogeneration. The two processes are similar except that CHP is usually associated with projects where low-grade heat is produced in conjunction with power generation, whereas in cogeneration the production of heat and power are both important. In CHP schemes, the heat is used for general domestic and commercial heat loads — in this case, the actual thermal efficiency is not impressive for much of the year when space heating is not needed. Cogeneration typically takes place at an industrial site where heat and power can be well matched for much of the time within industrial processes with resulting high thermal and economic efficiencies.

It should be noted that to maximise electricity generated from a given amount of heat, the steam is condensed to produce the maximum amount of mechanical energy. In cogeneration or CHP projects the steam is not fully condensed so that the resulting higher temperature can be used in industrial or chemical processes. In this case the electricity generated is less but the overall energy efficiency is usually higher.



Source: Energy Links

Figure 16.3 Combined cycle gas turbine

16.3 Economics of gas-fired power generation

In the UK there has been continuing argument about the economics of gas-fired turbines when compared with coal-fired plant. Politically motivated clouds have tended to obscure the true position, although the UK government probably accepts the figures in Table 16.1, which are derived, unless otherwise stated, from the DTI review of energy sources for power generation mentioned above.

Table 16.1 Costs of power generation

New CCGT generation	2.0 – 2.4 p/kWh (base load)
New coal generation (with FGD*)	2.6 – 3.25 p/kWh (base load)
Existing coal generation#	1.3 p/kWh
Retrofit FGD	0.3 – 0.5 p/kWh
Existing CCGTs#	1.74 p/kWh

Source: Energy Links Consultancy

Assumes a gas price of 20 p/therm, and a coal price of 100p/GJ (conservative estimate)

* FGD – flue gas desulphurisation essential to meet current pollution targets.

assuming no contribution to capital costs

Several conclusions can be drawn from the figures in Table 16.1:

- new coal-fired generation plant is uncompetitive in the UK, even with gas prices as high as 20 p/therm;
- new gas-fired generation cannot compete with existing coal plant unless the coal-fired plant has to be fitted with FGD;
- existing gas-fired CCGTs are very competitive with existing coal-fired plant if gas costs 16 p/therm and coal at a very low 100 p/GJ (it is estimated that UK coal prices are 120 p/GJ for break even at the pit). But with gas at 20 p/therm, coal is more economic to run than gas.

For completeness, it must be recognised that there are other technologies for electricity generation, often referred to as renewables. Some of the key technologies are listed in Table 16.2 below. Other technologies are also being developed, such as wave power and fuel cells, but these are not yet commercially viable.

Table 16.2 Other power generation technologies

Technology	Process	Comment
Photo-voltaic	Electricity from natural light	Currently expensive for normal use but companies such as BP Amoco are investing, which suggests it may have a long-term future. ETSU[3] do not however see any potential in the UK (ETSU - R- 103)
Landfill	Power generation from steam generated by natural or accelerated waste decomposition	Very limited market - needs subsidies
Waste	Power generation from steam generated from burning waste.	Given restrictions on landfill this could become a small but economic process
Energy Crops	Power generation from steam generated from burning crops which are grown for that purpose	These are CO_2 neutral i.e. the crop absorbs as much CO_2 in its production as it produces in combustion
Wind power	Power from onshore or offshore wind turbines	Currently the most economic non-fossil fuel technology

The cost of electricity generated using renewable technologies has been put into context in Table 16.3 below, which is taken from *The Energy Review*[4], a UK Cabinet Office Policy Innovation Unit report (February 2002).

Table 16.3 Costs of power generation from renewables

Technology	Cost* p/kWh	Economic potential TWh/yr	Technical potential TWh/yr	Practicable potential TWh/yr
Building integrated photovoltaics (BIPV)	7	0.5**	266	37
Offshore wind	2.5-3.0	100	~3500	100
Onshore wind	<3.5	58***	317	8****
Biomass (energy crops)##	4	33	"large"	"large"
Wave	4	33	600+	50
Tidal stream#	7	1.8	36	1.8
Small hydro	7	1.8	40	3
Waste technologies: municipal solid waste	7	6.5	13.5	6.5
Landfill	2.5	7	7	7

[3] Energy Technology Support Unit (ETSU), part of AEA Technology, Environment.
[4] A copy of the PIU report is available from the Cabinet Office website (www.cabinet-office.gov.uk).

* ETSU for the DTI, derive 'resource cost' curves for all technologies, that increase with cost, in most cases up to a maximum level at which external (practicable potential) constraints cut in. The costs quoted are those at which this maximum level of deployment would be achieved. The exception is BIPV, where only the potential at less than 7p/kWh is included – significantly larger potential would be available at higher cost.

** BIPV practicable potential is limited by assumptions about penetration rate into new buildings, economic potential to even lower penetration of those new buildings with potential for offset building costs.

*** Assumes minimal constraints due to planning, network and build rate.

**** Assumes constrained build rate and no network reinforcement – hence the somewhat counter-intuitive result that economic potential is higher than practicable potential.

Tidal stream devices exclude large barrages, ruled out by the DTI on capital cost and environmental grounds. Practicable potential/resource is not provided in the study for this technology type.

Assessment restricted to energy crops for the purposes of this analysis for reasons discussed below, additional contributions are assessed in the DTI work – from forest and agricultural wastes and residues, and from other biodegradable wastes.

With current wholesale power prices at less than 2p/kWh the UK government target of 10 per cent of electricity supplied generated from renewables will be difficult to achieve.

16.4 Gas contracts

Gas for use in power generation is regarded by gas sellers as a major new market for gas and, more importantly, an opportunity to achieve high prices. This is particularly the case in countries where the gas and power industries have not been fully liberalised. For, where the buyer of gas for power generation is faced by only one seller of gas, the gas price can be set at breakeven against coal. Table 16.4 below takes data from Table 16.1 to derive a breakeven price for gas.

Table 16.4 Breakeven price for gas-fired power generation

New CCGT generation	2.0 – 2.4 p/kWh (base load)
New coal generation (with FGD)	2.6 – 3.25 p/kWh (base load)
Difference	about 0.6 – 0.8 p/kWh

The difference between the costs of new CCGT and new coal generating capacity means that a generator might be willing to pay about 10 p/therm extra for gas, at 60 per cent efficiency. This gives a total gas price around 30 p/therm or about $4.80/million Btu. The economics vary from country to country and plant to plant, but in most cases a gas breakeven price can be derived of around $4–5/million Btu. This position holds broadly true in most markets that are exposed to world coal prices (currently at very best 110 p/GJ) — except in special circumstances such as projects where there is a mine-mouth power plant.

Some optimistic gas sellers, or those in a monopoly position, take this to mean that power generators should pay $4–5/million Btu for their gas. This is somewhat naive. What the figure means is that gas will still be the best buy as compared with coal even if the price rises to $4–5/million Btu. The actual price paid will be subject to a negotiation which will take account of such factors as the structure of the gas market, the presence of multiple gas suppliers and the need or desire of one or both parties to conclude a long-term deal. Other low priced alternative fuels such as petroleum coke (often virtually a refinery waste product) and Orimulsion (a bitumen based product potentially available in vast quantities from Venezuela) combined with improved gasification technology may in time set lower breakeven prices for gas.

Traditionally power generators have concluded long-term gas deals to secure the finance for power plant projects, or even simply to secure fuel supplies at a time when it was thought that oil and gas were about to run out. This also suited the gas supplier, who might be making a large investment in infrastructure to get the gas to market. The monopolistic power generator was also protected from the market risk of paying too much for gas. An injudicious purchasing decision caused suffering to the customer not the generator!

But with greater market liberalisation the world is changing. Generators are now vulnerable to competition, and now worry about profit and risk rather than long-term supplies, so that the nature of gas contracting is changing. These changes may result in different market structures. For example: the UK, which was until recently dominated by traditional long-term indexed contracts; continental Europe, which has a tradition of long-term contracts based on netback values; and, finally, rapidly growing new markets such as South America and the Pacific Rim.

16.4.1 UK market

In essence, the conventional long-term gas contract in the UK gave the buyer long-term certainty of gas supplies at a known gas price indexed, for example, to oil and producer price inflation (PPI). A typical price formula is given below:

$$\text{Gas Price} = \text{Base Gas Price} \times \left(0.5 \times \frac{\text{Current Oil Price}}{\text{Base Oil Price}} + 0.5 \times \frac{\text{Current PPI Value}}{\text{Base PPI Value}}\right)$$

In this example, the gas price moves half in line with inflation and half in line with oil prices. This is a very simplified version of a gas price index, which might include several types of oil — heavy fuel oil, gas oil or crude oil — which might also have dollar-denominated prices.

Gas contracts for CCGTs in the early 1990s all tended to have this structure. The largest weight in the price index was often given to inflation — which was thought to be a good proxy for electricity indexation — while the balance tended to be a mix of oil products (to meet the aspirations of the seller, usually an oil company) and coal (the main competitor as power station fuel). But as time moved on, and, more importantly, the market was opened up to competition, it became clear that gas was no longer a simple adjunct to oil but had a market-related value of its own. As might have been forecast, but was not, the value of gas in a free market was largely determined by supply and demand and oil prices almost became a second order issue. Those purchasers of gas who were slow to realise this were badly affected by the new gas-on-gas competition. Price escalators were therefore transformed.

In this situation, gas buyers — who were in effect wholesalers selling gas on to final customers — were generally forced to buy gas on a relatively short-term basis, usually indexed to the price of gas at the time of supply. In other words the price of gas became wholly related to the spot gas price. This meant that if all gas wholesalers were to buy on a similar basis, a significant part of market risk would be removed. Thus the traditional long-term wholesale gas market ceased to exist.

However the market for gas in power generation has developed in different ways, depending on the type of industry participant: major generators such as the Scottish power companies, Innogy (formerly the

UK division of National Power and now the subsidiary of RWE, the German energy company) and PowerGen (now the subsidiary of EON, the German energy company); existing IPPs (independent power producers); and new IPPs and Cogen plants (i.e relatively small projects producing both heat and power).

The majors

The majors are big players in the UK gas market; for example both Innogy and PowerGen have around 3,000 MW of CCGTs already; each company therefore has a gas demand of around 1500 million therms per year. On top of this Innogy has a dual fuel, 1200 MW coal/gas station at Didcot capable of taking an additional 2 million therms a day when the gas price drops to competitive single figures.

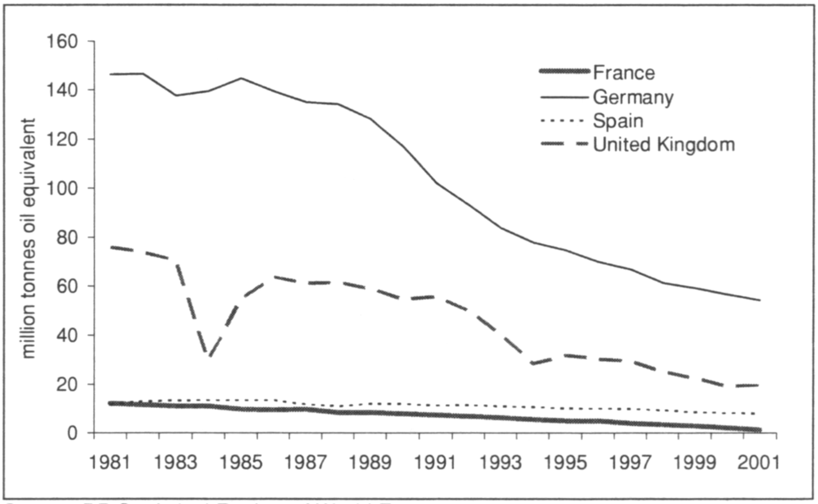
These companies have a number of existing CCGTs with associated long-term gas purchase contracts that, in most cases, do not cover the life of the plant. Some have contracts to buy gas from fields that are already off 'plateau', that is the gas field is in decline. The result of this is that not only are the majors likely to buy cheap gas on the spot market in the summer if they have fulfilled their contractual take-or-pay obligations, but also some may be buying day to day to make up shortfalls on their total gas portfolio.

In terms of new plant, the majors are not constrained to buy gas under long-term contracts for new power station projects. They can see that gas buyers may be in the ascendant for a number of years into the future and they can fund their projects from their balance sheets without seeking project finance – which usually requires parallel agreements for long-term gas input and power output.

Existing IPPs

Independent power producers (IPPs) in the UK mostly have conventional long-term gas purchase contracts of up to 15 years at relatively high prices. Many have British Gas long-term interruptible (LTI) contracts. These contracts are conventional in terms of their indexation but they are unique in two ways: first, they are interruptible, and secondly, their effective take-or-pay level is only about 55 per cent, making them very easy to manage. This also means that they are free to buy significant volumes of gas from the spot market outside the winter months if the prices are more favourable.

Many IPPs with relatively high priced contracts have renegotiated their gas purchase contracts and/or taken a write off in their accounts in anticipation of a fall in gas prices. Insofar as there are negotiations, it must be recognised that they generally consist of reducing the price in exchange for an up-front lump sum payment. The lump sum is based on the parties' respective views of what the price reduction is worth and may take account of different tax treatment in the two companies' accounts. With IPP renegotiations it is unlikely that there will also be a



Source: BP Statistical Review of World Energy

Figure 16.4 Coal production in Europe

reduction in the contracted gas quantity. It is interesting to see the effect on such renegotiated contracts of the recent gas price hike. Some of the contracts are now once again 'in the money'. However, this does not mean that the CCGTs are profitable since electricity market prices fell sharply in 2002. For example, Roosecote with a British Gas contract has been put into receivership by its owner Mission (January 2003)

Because of the uncertainty facing the new market, the first generation of IPPs had power purchase contracts with electricity customers that covered most of the offtake of the plant and were indexed to the gas price. Thus the only apparent risk for these projects was technical — would the plant be available when called? This was the way in which the first 'dash for gas' was launched. The customers were able to sign on power purchase agreements because they were Regional Electricity Companies (RECs), who had locked in franchise customers.

Since their customers originally had no choice of supplier, the REC could sign up power purchase deals with no risk that they might be uncompetitive. In other words it was the unsuspecting customer who took the price risk. Things changed in April 1999 when the market was opened up for customers below 100 kW, i.e. including domestic customers. As a result, the franchise market, in theory, no longer existed.

New IPPs

Once the franchise market ended, the prospect of power purchase agreements (PPAs) with gas price pass-through suitable for project financing receded. Counterparties would need a certain future market, and the new competitive world did not allow for this. Thus in the UK the next generation of IPPs were 'merchant plants', that is power stations selling power into the market generally on short term contracts. These power stations were able to operate in this way because the gas market was mature enough to provide secure sources of short term gas. In contrast, in markets without full-blown competition IPPs can still be structured with PPAs to support financing. However, these are not all as robust as the contracts would suggest. For example, International Power projects in Pakistan have needed renegotiation and the Enron project in Dabhol in India collapsed soon after construction was completed. Furthermore the low electricity prices in the UK have introduced 'risk-free' IPPs to risk as the holders of the PPA have faced bankruptcy — the best example being TXU — exposing both gas and coal fired plant owners to the threat of receivership.

16.4.2 Continental Europe

Gas-fired power generation in continental Europe is in the process of possibly rapid and undoubtedly uncertain transition. Coal is one of the key issues.

Figure 16.4 above shows why this is so. The politics of coal have a significant influence on the switch to gas. France is committed to running its coal industry down; Germany and Spain remain in the forefront of the fight to retain subsidies to miners. In addition in Germany, in particular, there is a large brown coal industry in the east generating both power and employment.

Table 16.5 below summarises the relative position of gas in certain key countries.

Table 16.5 Market share of gas in power generation, 2000

TWh	Total	Nuclear	Thermal total	*Share of gas in:* Thermal	Total
France	541	415	50	30.0%	2.8%
Germany	572	170	361	16.6%	10.5%
Italy	277	0	219	48.3%	38.2%
Spain	225	62	124	18.1%	10.0%

Source: European Commission

The different market shares for gas in power generation reflect the different historical development of the energy industry in each country.

France has famously committed itself to nuclear power with resulting low marginal cost of electricity, low national CO_2 emission levels and long run uncertainty of decommissioning cost. In parallel it has tried to protect its ever-declining coal industry. It is not likely, in the face of the EU Directive calling for competition in the electricity market, that France can retain its nuclear stance in the light of real market economics. Electricité de France (EdF) is already examining CCGTs and must recognise that it must build them for any incremental power demand if it is to keep out competition.

However if it attempts to do this the European Commission must surely act as this would be anti-competitive; whatever the outcome it is certainly true that those companies most interested in building positions in the new electricity markets either through acquisition or new CCGT builds, have, until very recently, steered clear of France.

16.4.3 Other markets

All round the world where power markets are growing rapidly, gas is generally the fuel of choice. It offers the lowest total cost of production and minimum pollution in a post-Kyoto world. The growth of gas in such circumstances is nothing to do with liberalisation and free markets. There will however remain some countries where other fuels will be used, particularly indigenous coal, where employment and hard currency considerations will be paramount. It is perhaps in these countries where emissions trading will have the greatest effect as new technologies are introduced to offset pollution in developed countries. Finally there is the lure of hydro generation, which attracts governments and environmentalists who see the low marginal cost of power while ignoring the fact that capital repayment periods are needed way in excess of those demanded by competing technologies.

16.5 UK electricity market

It is not possible to assess the position of gas in power generation without looking at how electricity is traded. This section looks at the UK. Electricity used to be traded through a wholesale market called the Electricity Pool of England and Wales[5]. But from 27 March 2001 this was replaced by the New Electricity Trading Arrangements (NETA)[6]. The new electricity Balancing and Settlement Code (BSC) is managed by Elexon Ltd[7]. An electricity futures contract was launched by the IPE on 19 March 2001[8] but it did not attract much interest and has been suspended.

16.5.1 UK Electricity Pool

Under the previous Pool regime, generators offered electricity for sale in that Pool to meet demand. The Pool managed a process whereby competitive bidding between generators set the price for electricity for each half hour each day and decided which generators will run to meet that demand.

Generators submitted 'day ahead' bids into the Pool by 10 am each day for the quantity of electricity that they were willing to generate for every half-hour period of the following day and the price. These bids contained for each generating unit the level of output on offer and a number of price parameters, plus any operating constraints, for example the minimum generating levels and the rate at which a generating unit could increase or decrease output.

The National Grid Company (NGC) as Grid Operator was responsible for the scheduling and despatch of generation on the day to meet actual demand. NGC produced a forecast of demand (plus reserve) taking into account weather and demand usage patterns for each half hour of the following day and then scheduled the generators' bids to meet this demand. A computer system, Generator Ordering and Loading (GOAL), aimed to produce the lowest cost generation schedule for the day as a whole, taking into account all plant limitations and generator bids. This was called the Unconstrained Schedule.

Constraints on the transmission system, availability re-declarations by generators and differences between actual and forecast demand

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[5] Information about the operation of the former UK Electricity Pool can still be found on the Electricity Pool website (www.elecpool.com).

[6] Background documents and a full description of the New Electricity Trading Arrangements (NETA) can be found on the Office of Gas and Electricity Markets (Ofgem) website (www.ofgem.gov.uk).

[7] Detailed information about the operation of the new Balancing and Settlement Code can be found on the Elexon website (www.elexon.co.uk).

[8] For details of the IPE electricity futures contract see the IPE's website (www.ipe.uk.com)

mean that the actual despatch of plant might not match that anticipated at the day-ahead stage. Generally, the price of the most expensive generating unit required to meet forecast demand in each half hour set the price for energy known as the System Marginal Price (SMP). To this was added a Capacity Payment which provided an incentive to generators to maintain an adequate margin of capacity over the expected level of demand. This payment could be high when the margin narrowed, but zero if there was a large excess of generation available.

Generators sold power into the Pool at Pool Purchase Price (PPP) (SMP plus Capacity Payment) while suppliers bought from the Pool at the Pool Selling Price (PSP) — PPP plus Uplift. Suppliers paid for the amount of electricity they were deemed to draw off at each Grid Supply Point (where electricity entered the distribution system from the National Grid) increased by a factor designed to take account of average losses on the transmission network. Transmission losses arise when electricity is transported because energy is lost due to resistance in the transmission wires and other transmission equipment.

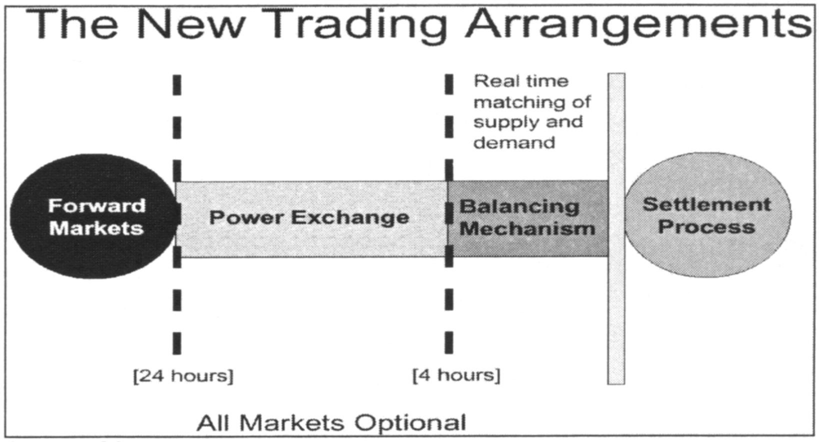
Uplift paid for a number of additional costs incurred on the day and included: Unscheduled Availability Payments (payments to generating units that were available but not required to run); additional generation costs resulting from differences between forecast and actual demand, and between generators' forecast availability and actual availability.

Settlement payments were calculated for each half hour (Settlement Period), and settlement of amounts due usually took place 28 days after the trading day. One of the underlying principles of the Pool was that it must balance financially every day.

16.5.2 New Electricity Trading Arrangements (NETA)

The Pool trading arrangements were seen by many to have a number of fundamental flaws:

- calculation of Pool prices was complex;
- capacity payments did not respond to short-term changes and are a poor long-term signal;
- bids were not reflective of costs;
- changes in Pool prices did not match cost changes;
- generators and suppliers were not faced with the full cost consequences of their actions;
- the uniform price paid to all attracted criticism from those who call for 'what you bid is what you get';
- little involvement by buyers.



Source: Ofgem

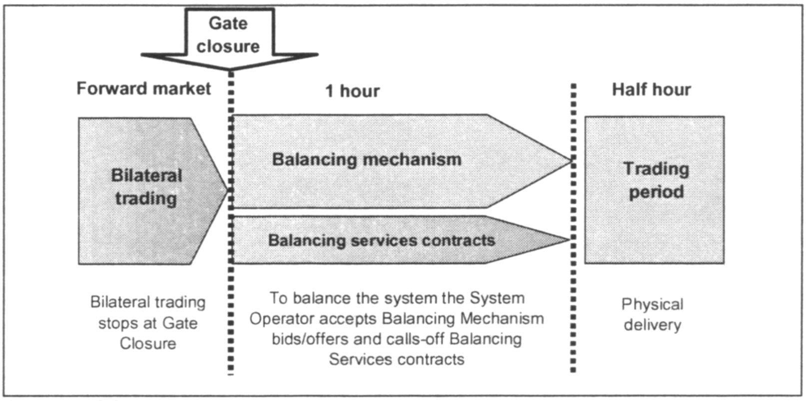
Figure 16.5 New electricity trading arrangements (NETA)

As a result, after extensive consultation between Ofgem, the Department of Trade and Industry, the UK electricity industry, and electricity consumers, the New Electricity Trading Arrangements (NETA) were introduced, going live on 27 March 2001 and replacing the former Electricity Pool as the wholesale market for electricity in the UK.

The New Electricity Trading Arrangements are summarised in Fig. 16.5 (produced by Ofgem). This shows a forward market – operating for delivery periods from within-the-day to several years ahead – and then a power exchange which operates up to 4 hours before delivery in the manner of any normal market. The forward market is currently provided by a mixture of bilateral OTC electricity trading and the new IPE electricity futures contract. Then there is real time balancing of supply and demand with NGC as the sole counterparty as in the gas flexibility market. This function is carried out by Elexon Ltd. The structure of the new electricity market is shown in more detail in Fig. 16.6 below (also based on Ofgem/DTI material).

The aim of the regulator is to ensure that the new electricity market is compatible with — if not parallel to — the gas market. The key differences are that the majority of electricity trades will be bilateral in the form of power purchase agreements between users or power suppliers such as RECs, OTC trades, or trades on electronic power exchanges. Large industry participants advise the System Operator of their balance for each half hour and bid to increase or decrease their demand for the balancing mechanism. These positions can be altered up to Gate Closure 1 hour[9] before the start of the half hour. The balancing mechanism then buys or sells electricity to match supply and demand in that half hour. During the half hour period, participants

[9] Gate closure was reduced from 3½ hours to 1 hour on 2 July 2002.



Source: Ofgem

Figure 16.6 Structure of new electricity market

deliver or receive energy based on their contractual obligations. Settlement takes place after the half hour period when payments for bilateral contracts are exchanged between counter-parties. Any energy imbalances — i.e. contract volume less metered output — are cashed out at imbalance prices.

The only part of NETA actually put in place by Ofgem is the right to buy or sell power bilaterally and the detail of the balancing mechanism with its associated information flows. All other parts, including any derivative trading instruments, were left for the market to develop.

A number of rival power exchanges were promised to provide this development, but they have had very limited success:

- IPE: this futures contract has started but had poor liquidity, resulting in its suspension
- EnMO: never started
- iVentures: never started
- APX: no futures contracts but active spot contracts
- UKPX: active spot contracts and very limited futures trading

The market is simply too small for so many participants and the problems will continue until closures or amalgamations take place, as has happened in Germany. This is in marked contrast to the UK gas market where Ofgem imposed a single electronic market for the OCM.

The bottom line for participants in the physical electricity market is that if they do not balance they must pay the prices set in the balancing market. This has little effect on the large players with flexible plant or contracts, but smaller participants are experiencing great difficulty. In essence, NETA rewards reliable generation, or rather penalises unreliable generation. While this may seem fair to economists, it hits

CHP, wind power and other initiatives which the government both supports and needs to meet the extremely ambitious targets it set itself in the international environmental arena.

Furthermore, prices have fallen generally and – even if this is more to do with market diversity and excess capacity than NETA – NETA is blamed. Low prices equally affect the government's targets; they both hinder energy conservation and adversely affect the economics of green power. Worse still, two clean running CCGTs in the UK have been mothballed in 2001/2, one being replaced by a de-mothballed coal plant, as a result of marginal coal generation costs being lower than gas. More fixes will be needed to sort out the conflict between economic good and environmental good.

What is clear is that as new mechanisms developed by the regulator and the government will evolve through market forces. That evolution will bring solutions perhaps not even foreseen by regulators. This may encompass bringing the gas and power markets closer together (see Chapter 17).

16.6 Other power markets

There are many different market mechanisms emerging throughout the world. Every aspect is changing rapidly as liberalisation evolves throughout Europe. New participants and markets not even mentioned below could suddenly become major forces. For example, the US-based Intercontinental Exchange[10] (ICE), which already owns the IPE, has the technology and know-how to make a very powerful trading platform. It is backed by such companies as BP, Shell, TotalFinaElf, Deutsche Bank, Goldman Sachs, Morgan Stanley, Société Générale, Duke, and El Paso.

It is clear that the demise of Enron may have set back progress in many European markets but this will be only temporary. The momentum both from the market and the EU is now unstoppable. The Enron effect will be financial caution, particularly in the area of credit lines, and continuing market innovations building on the very real contribution which Enron made to both the gas and power markets.

16.6.1 Nordpool

Nordpool is the Scandinavian electricity pool. This is composed of:

- **Eltermin**, a financial market for hedging and risk management;
- **Elspot**, which trades 24 one hour periods, power is intended for physical delivery, prices set from bids taking account of limited capacity and by 14:30 Day ahead prices are set; and
- **Elbas**, the next stage after Elspot, with the same hourly periods as Elspot, which closes 2 hours before delivery units of 1 MW into specific areas.

Trading is anonymous with Nordpool as counterparty.

16.6.2 Argentina

Argentina has a pool with prices set six-monthly on the basis of calculated marginal generation prices based on generators' submissions including fuel price. There are also capacity payments made for availability at peak times. Bilateral contracts are possible but the demand side of the industry has no role in the pool. As with the present UK Electricity Pool, despatch is on the basis of bids and bears no relationship to the bilateral contract position of the generator.

[10] www.intercontinentalexchange.com or www.theice.com

16.6.3 California

California launched its Power Exchange in April 1998. This, like the UK Pool, has a market-clearing price in a day-ahead market on an hourly basis. There is then a separate hour-ahead market closing 2 hours before delivery for balancing purposes, with a similar market clearing price mechanism based on the intersection of the aggregate supply/demand curves. Although the Californian Power Exchange has often been held up as a model example of how an exchange could work, serious problems have emerged in the wider Californian electricity market as a result of soaring US gas prices, leaving consumers facing blackouts or brownouts, and power utility companies facing bankruptcy.

It is interesting that those seeing the Californian model of a power exchange as one to be admired did not see that other features of the liberalised market were fatally flawed. These included, the inability of electricity sellers to pass through price increases because of price capping, the inability to buy power forward and the inability of generators to get permission to build new plant to meet market needs. The lessons to be learned from California are therefore not primarily about trading but about regulatory structures.

16.6.4 France

In France legislation is slow to emerge due to trades union resistance, but change is slowly happening and the French government brought forward the 34 per cent threshold from 2003 to the end of 2000. In parallel, a power exchange – Powernext – has opened which is also supporting competition. The table below lists active members in early 2002.

Aare-Tessin Ltd	Aquila Energy Ltd
Cargill International S.A	CNR
EdF Trading Ltd	EGL
Electrabel S.A	Endesa Trading
E.On Sales and Trading	Gaselys UK Ltd
Iberdrola Generacion	Norsk Hydro Produksjon AS
Verbund	TotalFinaElf
Union Fenosa	

Source: European Electricity Markets

France has promoted competition by the auctioning of 6000 MW of capacity from EdF's plant portfolio. France however remains determined to resist supplier choice for its domestic customers because of "public service obligations".

16.6.5 Belgium

Belgium is a very small market with little liquidity and a dominant player, Electrabel. Two developments have taken place that, at least, provide the start of a real market. Electrabel has started publishing "Price Choice", the price at which it will either buy or sell power, with a maximum volume of 100MW. Belgium has also created a Belgian Hub to facilitate trading by obviating the need to specify entry and exit points for each transaction.

Fundamentally the Belgian electricity market is likely to remain closely linked to the Dutch market, where there is more liquidity.

16.6.6 Germany

Germany gives the appearance of supporting competition, but there remain barriers to open access that are holding back new players who seek to sell power, acquire companies or build new gas-fired plant.

Despite disagreements on access rules, trading is developing. The two major trading houses – the European Energy Exchange (EEX) in Frankfurt am Main and the Leipzig Power Exchange (LPX) – have amalgamated as EEX based in Leipzig and started to offer an OTC clearing service backed by companies such CSFB, UBS Warburg and RWE.

16.6.7 Spain

Although Spain gives the appearance of an open market, the gas and electricity markets are both dominated by the existing home-based players. However, the rapid growth in Spanish electricity demand is driving a Spanish 'dash for gas' in their power market with some 31,000 MW planned, with half targeting operation by 2005. There are also signs that more companies are entering the market from outside Spain.

16.6.8 Ireland

Electricity Supply Board (ESB), the state owned generator, has auctioned 600MW of virtual capacity to facilitate competition. However, there is no traded market and the market structure and size makes such a development difficult despite the fact that there is an independent regulator. In the longer term, a traded market might develop in conjunction with the Northern Ireland electricity market, which is connected both to the Irish Republic and to Scotland through the Moyle Interconnector.

16.6.9 Poland

Poland has opened up a traded market through the Polish Power Exchange (PPX) but at the time of writing liquidity was minimal and ill designed rules effectively prevent further progress.

16.6.10 Netherlands

Trading is very active, dominated by flows between the Netherlands and Germany, with a well developed market, Amsterdam Power Exchange (APX).

17 Convergence of gas and electricity markets

Rowland Sheard, Energy Links Consultancy

17.1 Introduction

Much is being said in the US, UK and Continental Europe about the 'convergence' of the gas and electricity markets without there necessarily being any definition of the term convergence. This is a common phenomenon when new ideas arise in a changing environment. Insofar as it can be defined, convergence can be said to mean different things according to which part of the market is being discussed.

In the power generation/wholesale gas market it generally refers to the fact that gas is such a significant fuel in the electricity market, and so easy to trade both physically and commercially that, in theory at least, gas can be switched from one market to the other rapidly. Thus it is said that prices will converge to a point that the two markets are inextricably linked. At the other end of the supply chain, convergence is coming to describe the fact that the two industries are at customer level becoming one — the energy company. This new breed of company simply sells the customer the form of energy he or she wants at the lowest possible price compatible with the service that the customer requires.

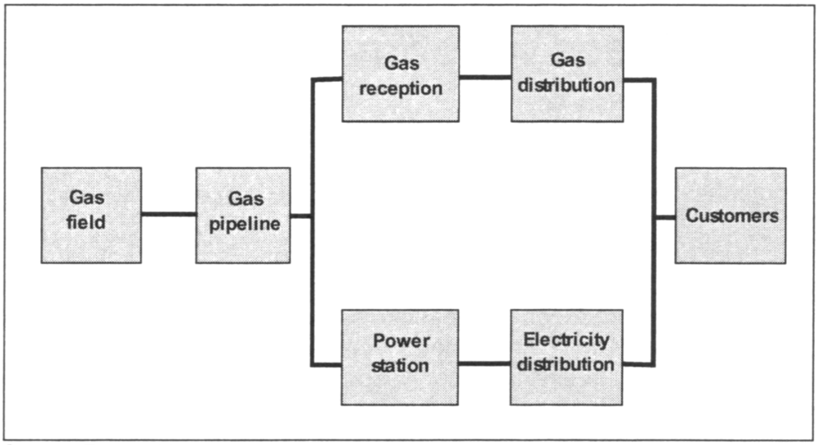
17.2 Forces for convergence

The move towards opening up monopoly markets to competition is happening in many countries. The full effects cannot always be forecast and can vary from country to country according to the particular market conditions. One unforeseen outcome in the UK and US, which may be repeated elsewhere, is the move towards convergence of the gas and electricity markets. This convergence is not only at the trading level, as gas becomes a key fuel for power generation, but also at the retail level as unbundling produces companies whose only role is to sell gas or electricity; these companies need volume sales to succeed and the natural outcome is energy supply companies that sell both gas and electricity. This trend has developed further with energy companies selling other liberalised services such as telecoms.

Historically, the gas and electricity industries have been the two major suppliers of energy to the final customer and both originally used coal as their feedstock: the power industry generating electricity from coal in conventional thermal power stations, and the gas industry making town gas from coal. In theory, it could have been said that at that time there was convergence of the two markets as both used coal as a feedstock, but without actively traded markets for the two fuels this would not have been obvious.

The traditional relationship between the gas and electricity industries has been as competitors. That competition became bitter as a result of the invention of the electric light bulb by Joseph Swan and Thomas Edison. This ended the nearly 100 year monopoly in lighting held by gas. Even in countries where both were owned by the state, the two energy sources were often driven by the need to win market. Indeed, one of the common complaints from customers was that two state industries were 'wasting' money on advertising their respective virtues rather than co-operating, which some felt was more appropriate for companies with a common owner. Overall, however, the result was good for customers. Competition between gas and electricity meant that both industries strove to improve the technology of the product and, to a lesser extent, to reduce prices. Equipment was improved; thermal efficiency was maximised; and attempts were made to minimise costs.

Overall, however, the main drawback arising from the structure of the gas and electricity industries was not just that they were state owned, but that they were usually local monopolies. In both industries this monopoly position arose from the view (rightly or wrongly) that competing pipes or grid lines were not in the public interest. In countries like the UK it is reasonable to accept that there is now a natural monopoly, certainly in local distribution of gas and electricity and, in many cases, in transmission too. It has only recently become apparent that there is no need for the distributor of gas or power to also sell that



Source: Energy Links

Figure 17.1 Supply chain convergence

gas or electricity to the final customer — supply and distribution can be unbundled.

The result of the monopoly structure in most countries was that both industries were driven to provide the customer's needs — as defined by the supplier not the customer. The industries tended to 'gold-plate' their engineering infrastructure to maintain, what would, in a free market, be regarded as excessive security. Commercial structures were equally unbalanced.

Today there is apparently a new concept of fuel convergence, or even the introduction of the Btu[1] market, arising from the fact that both markets are potentially driven by a single price — the gas price. However, this in no way explains what is happening nor does it actually explain the full effects of competition that are producing 'convergence'.

Three areas of convergence are relevant: supply chain convergence; trading convergence; and retail convergence.

17.2.1 Supply chain convergence

It is tempting to see the technical convergence within the supply chain as something new (see Fig. 17.1). This is, however, an illusion. With only a few changes of wording the supply chain could be applied to oil or coal or electricity.

One interesting aspect of technical convergence is that clean coal technology is having a direct impact on gas technology: coal will be gasified and fed into a combined cycle gas turbine (CCGT) in

[1] The Btu, sometimes BThU, is the British thermal unit, the unit of heat formerly used in the UK and currently used in the US and internationally in many gas and power projects (see Chapter 2 for definitions and conversion factors).

competition with direct use of gas in the same basic CCGT design (see Chapter 16).

17.2.2 Trading convergence

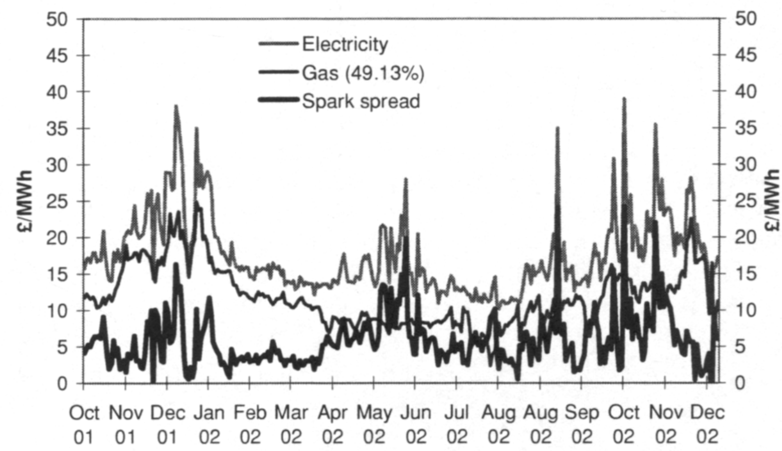
In an open market, where gas and electricity are freely traded and gas is the predominant fuel for power generation, the price of wholesale gas in effect can set the price of wholesale electricity. The relationship is however not that simple. Even where a particular fuel is not predominant it may set prices. Equally, if prices move relative to each other the price setter may change. For example in the UK, in 1999, nuclear and gas-fired CCGTs ran at base load and coal plant and to a lesser extent oil-fired plant provided the peak. Thus the price setter was coal (or oil) and full convergence of gas and electricity had not happened. But the higher gas prices seen from mid-2000 produced a significant change in market dynamics, with coal taking the place of gas in base load running and gas becoming more of a price setter.

This relationship is complicated by the environmental constraints on coal fired plant not fitted with FGD (flue gas desulphurisation) which limit annual running. These higher gas prices have coincided with low power prices as generation competition has increased due to fragmentation of power station ownership. The result has been mothballing of gas fired CCGTs and for the time being no more new CCGT projects. Similar conditions exist in continental Europe where the development of gas fired power – good for environmental reasons – is constrained by high gas prices and a very competitive wholesale electricity market.

Insofar as 'full convergence' can be defined, it might be said to be when the market price of gas for generating power defines the marginal price of electricity in the market. Equally there can be a degree of convergence when the gas price drives up the price of electricity, particularly in times of peak demand in both markets. The key issue here is that the electricity generator is free to sell gas in the gas market rather than generate.

If the result of this is that the price of electricity goes up to reflect the opportunity cost of gas, there is no problem; insofar as the economists are satisfied — although end users may be less satisfied. However, if the two markets do not operate in synchrony, for example, one market sets prices on-the-day, and the other market sets prices day-ahead, then there may be a risk that the gas industry could cause brown outs in electricity. While this might be an acceptable consequence of markets from an economist's perspective, it would not be acceptable to an end user or politician.

However, except in the case of massive price movements, the complexity of actually running CCGTs is such that quick switching of gas from power to the gas market is not worth while. In any case in the UK NETA provisions would penalise stations turning off as the



Source: Petroleum Argus

Figure 17.2 UK OTC market, day-ahead spark spread

purchasers of the output would have to replace the power from the balancing market. Unfortunately the UK regulator Ofgem is exploiting these worries to try to bring in tighter balancing periods in the gas market despite near universal rejection by the industry.

If these unpleasant consequences of commercial convergence are to be avoided it is essential that the market is supported by the one element which is relatively new — financial instruments. With these convergence only hurts those who can stand the pain. They serve to convert unmanageable risk to an appropriate level. At their simplest they enable a generator to lock in margins by forward purchases and sales which can then be closed financially.

It can be concluded that commercial convergence needs all or most of the elements of a free market to make it work safely and satisfactorily for all parties. However, the real bottom line for commercial convergence is that it is not a new concept at all. The reality of commercial convergence is running plant and fuels as profitably as possible.

17.2.3 Spark spreads

One apparently key development which suggests that convergence is actually happening is a product called the 'spark spread'. Whether it is a product or a hedging strategy is open to debate. In essence the spark spread is the difference between the cost of the fuel used to produce the electricity and the selling price of that electricity (see Fig. 17.2). It allows power generators to lock in a profit through the simultaneous purchase of a natural gas contract and the sale of an electricity contract. Clearly following the spark spread also enables the power generation market to be monitored through the forward curves.

However the spark spread is not one number and need not even be for gas. What is needed is the heat rate for the particular plant being considered (the heat rate is the amount of heat needed to generate one unit of electricity; it is directly related to the thermal efficiency of the plant). The heat rate varies from power plant to power plant even between different CCGTs. To carry out a true hedge the amount of gas bought must be the actual amount needed in a particular plant.

Attempts have been made in the UK to have a spark spread product actually priced on the difference and to achieve that a standard spark spread volume has been agreed of 60MWh of electricity and 100,000 therms of gas using a thermal efficiency of 49.13%. It would seem likely that this standard product will be the basis of market assessment through a forward spark spread curve although it is unlikely to be traded as a standard product when accurate hedges can be constructed which relate to real plant.

17.2.4 Retail convergence

The other situation which can legitimately be called convergence is the process that follows unbundling of the full supply chain in which the operations so often seen as indivisible — the transmission, distribution and supply of electricity or gas — are broken up. In most instances, transmission and distribution — wires and pipes — are a natural monopoly, which therefore merits strong regulation. In contrast, supply — in the sense of marketing — can and should be competitive. In this way, the various suppliers use the same infrastructure to deliver the product, differentiating themselves on the basis of service or efficiency or, indeed, price.

Once supply is separated it becomes clear that marketing is a business with relatively low investment requirements characterised by high volumes and low margins. Commercial advantage is gained from IT developments combined with well-managed call centres, and a very sophisticated risk management strategy to preserve the wafer-thin margins.

A comparison between an electricity supply company and a gas supply company quickly reveals a massive overlap in functions and it becomes natural to combine them into a multi-energy company. The next stage sees a series of energy companies combining to obtain geographic economies of scale.

It is tempting to suggest that there is a competition cycle of development where an electricity monopoly and a gas monopoly are broken up; followed by the creation of a number of supply companies for each fuel which gradually amalgamate and form two energy companies — completing the cycle from two monopolies to two competitors. But perhaps that is too pessimistic.

The effects of these processes can be seen in the structure of the UK market.

17.3 United Kingdom

17.3.1 Electricity privatisation

Before privatisation

The electricity industry in England and Wales was in two parts: the Central Electricity Generating Board (CEGB) and 12 regional Electricity Boards. The CEGB would build 'state of the art' power plant, the design of which would change as it was being built; as a result very few designs were repeated. They also regarded themselves as providing work for UK contractors. In fuel terms CEGB only built plant using fuels with demonstrable reserves many times in excess of plant life; thus the key fuels were nuclear and coal. Here they both supported the UK-based nuclear contractors and the UK coal industry! All these costs were passed through to the customers by the bulk supply tariff to the Electricity Boards. The resulting supply system was incredibly robust — even to the extent of withstanding the year long coal miners' strike in 1984.

The first step in commercialising the electricity industry in England and Wales was privatisation in 1991. The CEGB became four companies: National Power and PowerGen, which took over the fossil fuel stations; National Grid, at that time wholly owned by the Regional Electricity Companies (RECs), which took over the high voltage transmission system; and Nuclear Electric which remained in the public sector as the nuclear generator. Later the newer stations were sold off as British Energy and the oldest stations remained in the state sector as Magnox plc, now a part of BNFL.

The Electricity Boards became RECs with a local distribution monopoly combined with an initial supply monopoly. This supply franchise was initially removed above 1MW[2], later being reduced to 100kW. From 1998 it was intended that all domestic customers would be free to choose their electricity supplier. However, this latter aim was thwarted by the RECs' inability to get their computer systems working in time, having only had eight years' notice of the project. The programme was completed by early 1999.

The structure in Scotland is different in that two fully integrated companies were kept at privatisation: Scottish Power and Hydro-Electric. Since then Scottish Power has bought Manweb, an English REC and Scottish Hydro-Electric has merged with Southern Electric. These mergers and take-overs reflect the considerable attractiveness

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[2] 1MW is equivalent in simple heat terms to about 100,000 to 200,000 therms per year; taking account of the thermal efficiency of application of gas this increases to a range of about 125,000 to 500,000 therms per year.

of the REC. Table 17.1 below summarises the position in December 2002.

Table 17.1 Change in ownership of RECs

REC	Current Ownership
SWEB	Mirant & PP&L Resources, known as WPD (USA); supply (not wires) business sold to LE Group (originally London Electricity, now owned by Electricité de France)
Eastern	1. Taken over by Hanson then 2. Demerged into Energy Group then 3. After battle with Pacificorp and Nomura taken over by TXU (USA) 4. Supply retained by TXU, distribution sold to LE Group 5. Supply sold to Powergen after TXU Europe went bankrupt.
Manweb	Scottish Power
Norweb	1. United Utilities distribution, supply sold to TXU 2. Supply bought by Powergen from TXU Europe
Seeboard	AEP (USA), sold to EdF
SWALEC	1. Bought by Hyder; 2. Supply business sold to British Energy who then sold it to Scottish & Southern; 3. Distribution sold to WPD
Midlands	1. Proposed merger with PowerGen vetoed by MMC 2. Taken over by General Public Utilities and CINergy Corp 3. Supply (not distribution business) sold to Innogy 4. Distribution sold to Aquila but now up for sale as Aquila is withdrawing from the UK market
Northern Electric	1. Mid-American Utilities (USA), 2. Supply sold to Innogy in a package including transfer of Yorkshire distribution to MidAmerican
East Midlands	1. Taken over by Dominion Resources (USA) 2. Bought by PowerGen
London	1. Bought by Entergy (USA) 2. Sold to Electricité de France
Southern	1. Proposed merger with National Power vetoed by MMC 2. Merged with Scottish Hydro-Electric to form Scottish & Southern
Yorkshire	1. American Electric Power & Public Service Company of Colorado 2. Sold to Innogy 3. Yorkshire distribution transferred to MidAmerican as part of deal for Innogy to take over Northern distribution

This is similar to the complex pattern of power station ownership which leaves power generation largely controlled by non-UK companies, for example, German (Innogy/RWE, PowerGen/E.ON,) and American (Edison Mission & AES) – although the remaining American companies seem likely to withdraw from the UK.

After privatisation

The impact of privatisation of the generators was immediate and demonstrated the inefficiencies of the former monopolies. Projects on the stocks for new coal fired stations were cancelled and replaced with gas-fired CCGT projects. In addition, manpower was cut dramatically; for example, National Power cut its workforce by about two-thirds, before increasing it again as it built up overseas generating assets.

In parallel with the break up and privatisation of the state generation monopolies, the regulator — The Office of Electricity Regulation (Offer) — and the Department of Trade and Industry (DTI) encouraged the development of Independent Power Producers (IPPs). These were ostensibly independent private companies which built a series of gas fired combined cycle gas turbines (CCGTs) — see Chapter 16 for a more detailed description.

The contract structure for the IPPs was unusual for the UK, but normal at the time for projects seeking non-recourse project financing. The electricity from the station was bought for 12-15 years by a REC which guaranteed to pay an electricity price based on the price of gas in the gas supply contract at the time. In the UK such arrangements were in the form of 'contracts for differences' (CFDs) as, at the time of building such plant, all electricity had to be sold into the Electricity Pool (see below).

In order to protect both parties from uncertainty a financial instrument was created, the CFD, which in the case of IPPs set a price for electricity — the strike price — by means of a formula related to the gas price indexation arrangements (see Chapter 16). If the IPP generates and receives a lower price than the strike price then the instrument provides for compensation from the counter-party (usually the REC); equally the counter-party must be compensated if the IPP receives more than the strike price.

Using CFDs meant that the project companies only carried technical and generating plant availability risk. The REC was able to pass the purchase cost of electricity through to its franchise customers, provided that the regulator agreed. Thus, as with many monopoly situations, the actual risk was borne by the franchise customers. The same REC which bought the power also tended to have a significant shareholding in the IPP so that the REC could take unregulated profits from the IPP project.

In parallel to this assistance for gas fired IPPs, there was strong protection for the coal industry. At the time of privatisation the government of the day recognised that to sell National Power and PowerGen and ensure some stability there was a need to sort out the relationship between the generators and the then British Coal Corporation (BCC). The result was a coal deal to 31 March 1993 associated with which were CFDs — a proxy for power purchase deals — with the RECs, which locked in prices and margins for BCC, the generators and the RECs. These were passed through for the franchise customers to pay. At that time the delivered cost of imported coal would have been significantly cheaper than BCC coal; in addition the quality of imported coal was higher, particularly in relation to sulphur content, a source of acid rain. When the deal was done it would not have been possible for the generators to fully replace BCC with imports due to port limitations.

During the period of the BCC deal the generators invested in port facilities to strengthen their negotiating position with BCC for the negotiation of contracts beyond March 1993. This impending negotiation produced the October 1992 coal crisis with BCC announcing the closure of 31 out of its 50 deep mines. After considerable public and political pressure, a House of Commons Select Committee Report and a UK government White Paper, closures were curtailed and the government played a key behind-the-scenes role in a new coal deal which covered the period to 31 March 1998. This date also marked the target date for full competition in all areas of the electricity market.

The new deal had lower volumes of BCC coal and significantly lower prices and these were still backed up with CFDs to guarantee the margin chain. The whole process was surrounded by a pit closure programme that was inherent in the volumes which the generators could accept. The coal contracts and pit closures also provided a second and final opportunity for the coal industry to optimise its cost structure and maximise its chances for the future.

It is indicative of the problems associated with the indigenous coal industry that this long notice period did not create stability. The result was the gas moratorium — and the UK coal industry continued to struggle in a free market, recently requiring more support to compete against world coal prices.

At the same time that the electricity market was being opened to competition, the gas market was being liberalised in a much more free market manner. The first direct impact this new competitive gas market had on the electricity market was to make existing IPPs uncompetitive as spot gas prices slumped to around half the price paid in the IPPs' gas supply contracts. But due to the structure of the Electricity Pool, which kept prices above new entrant levels (see below), and the existence of CFDs to protect the IPPs, there have been few problems to date. However, a number of companies have sought to renegotiate their gas contracts down to levels nearer current prices or have written off their value in their corporate accounts. But, with higher gas prices from mid-2000, some gas contracts for power projects are now 'in-the-money' relative to the gas spot market.

The Electricity Pool

One of the better features of the CEGB structure was the way in which power stations were 'dispatched'. In this system power stations were run taking account of their thermal efficiency and fuel costs. This was duplicated in the private sector by a pool bidding system. This is described in more detail in Chapter 16. In essence, each station each day bids in a price to run its plant the next day. All plant is then paid the same price for running, with that price, the System Marginal Price — being set by the price bid by the marginal plant.

This was expected to provide the lowest prices with power being generated by the most efficient stations. This view came from the economists who saw that if there was generation overcapacity in the market, which there was, then bids would be made on the basis of marginal running costs; that is, essentially fuel costs plus a small addition for other unavoidable costs such as increased maintenance.

But the reality was different. Nuclear stations which had minimal flexibility to change or cut output, bid in zero prices. Similarly some of the IPPs also bid zero on the basis that the price they were paid by the Pool was irrelevant as they had CFDs. Thus nuclear and IPPs ran at base load and other plant set the Pool price, which meant that during much of the year coal-fired thermal stations set the price. The Pool mechanism was sufficiently well understood by the majors that a zero marginal price was only been set for a handful of half hour trading periods since the Pool started. As happens in most markets, once the majors saw that overcapacity was developing through the building of gas fired CCGTs, they shut down existing plant to remove such commercially dangerous overcapacity.

This is where the regulatory problems arose. The plant chosen for closure was either coal fired — in which case it was demonstrably older and less efficient than other plant on the system — or a relatively new oil fired plant — which was uneconomic at the time. These apparently logical decisions had the unfortunate side effect, from a regulatory perspective, of tightening the supply/demand balance and holding up market prices. In a market with many competitors this behaviour is regarded as normal operation of the market. However in the UK electricity market where all the plant which set prices was controlled by only two companies, National Power and PowerGen, the regulator saw the plant shutdowns as examples of market domination.

The first attempt to fight this was to insist on full justification of closures and a suggestion that plant should be sold. This did not work, and PowerGen and National Power were forced to sell a total of 6,000 MW of generating capacity. Unfortunately for the regulator, all the plant was sold to one company, Eastern Group (now TXU), on terms which rewarded TXU if prices were kept up. The net effect then was to replace two dominant players with three dominant players owning the price-setting plant. It is indicative of their market power that before plant was sold to TXU, National Power and PowerGen were told by the regulator that Pool prices had to be reduced. The fact that the target set by Offer was met was hardly an indication of a competitive market.

In June 1999 the regulator sought further divestment of plant by PowerGen and National Power; 4000 MW at Ferrybridge and Fiddler's Ferry by PowerGen as part of the package to allow them to take over East Midlands Electricity, and a similar amount by National Power (Drax). These sales have resulted in a significant change in the structure of the UK power generation market (see Table 17.2). This has changed further as PowerGen is seeking more plant sales to finance excursions into the US market and TXU is selling most, if not all, of its assets to focus on sales and distribution in the UK and to finance investments in mainland Europe.

Table 17.2 Shares of UK electricity generating capacity

per cent	Winter 1998-99	Winter 1999-00	Winter 2000-01
Innogy	25.2	18.7	12.3
PowerGen	24.0	16.1	14.9
British Energy	11.5	11.3	13.8
Eastern Group	10.5	10.3	8.8
Edison Mission Energy	3.3	9.2	5.9
AES	0.6	7.3	6.9
BNFL/Magnox	5.1	5.2	5.2
Interconnectors	5.0	4.9	4.7
Others	14.9	17.1	27.5
Total	100.0	100.0	100.0
Total (MW)	*63.999*	*65.330*	*67.695*

Source: NGC Seven Year Statement

Divestment and sales generally will, however, only work as a means of opening up the market and making it more competitive if the plant is sold so cheaply that the new owner has an incentive to compete on the basis of lower running costs. Furthermore it must be sold to diverse buyers to limit potential market power. This aim conflicts with the interests of power generation shareholders who seek both a suitably high price for their plant and, in the longer term, high prices in the electricity market for their remaining power generation assets. In addition owners of coal-fired plant have been manoeuvred to differing extents into contracts to buy large volumes of UK coal primarily from UK Coal (formerly RJB Mining) rather than buying 'world' coal at lower prices. This was another factor militating against real competition in electricity generation.

Another example of potential regulatory problems that plant sales can create has been demonstrated by the sale of the PowerGen stations. Both stations were bought by the US company Mission Energy, which already owned both Dinorwig and Ffestiniog (two pumped storage stations totalling just over 2,000 MW) plus one third of Derwent Power (236 MW CCGT) and 80 per cent of Roosecote (229 MW CCGT). As such Mission already controlled some 26 per cent of the peaking market, which could potentially rise to 50 per cent if they did not fit flue-gas desulphurisation (FGD) to the two PowerGen plants. On price setting the combined plant portfolio set prices for 17.5 per cent of the time during 1998/9.

Finally, in the more technical — but commercially crucial — ancillary services market Mission already has 23 per cent of such NGC expenditure with Ferrybridge and Fiddler's Ferry accounting for some 4.5 per cent. The combination would give Mission a market share twice that of its nearest competitor. Once again, as with the sale of plant to Eastern, the result does not always bring the required outcome.

The other issue which affects prices is the fact that as demand rises towards supply in a normal market, prices also rise. Prices rise to the point at which it is possible for new players to justify their investment in new capacity. As with most commodity markets this new investment is often followed by a drop in market price which discourages other new entrants. This cycle has not yet appeared in the UK – and prices have fallen from their previously excessive levels to levels where plant is being mothballed, put on the market or closed. For example PowerGen mothballed a CCGT unit at Killingholme and some older coal units bought from TXU, AES Fifoots has been put into receivership, Mission has put the gas fired Roosecote into receivership, International Power has mothballed part of its Deeside CCGT, and British Energy with its fleet of nuclear stations is struggling to survive.

These low prices are not sustainable. It will be interesting to see how the regulator will view the position as prices rise to allow new entrants to build plant needed by the market. For this volatility is a manifestation of a real, free, market.

17.3.2 Gas privatisation

In contrast to electricity, the gas industry started with a great advantage when it came to privatisation — it was a single company, British Gas plc — and the privatisation was carried out by a government perhaps nervous of interfering with utility monopolies. This was after all the structure commonplace throughout the world. It was what people knew and apparently provided protection of all kinds ranging from supply security to minimising public anxiety over safety issues.

However, like monopolies everywhere, British Gas overplayed its hand. It tried to stifle the very limited competition allowed for suppliers of gas to large users and maintained that an integrated business was essential. However, at the time the UK had a prime minister who refused to listen to 'experts', however eminent, when they were defending the status quo. This support at the highest level gave the

Gas Regulator added confidence to tackle British Gas head on and force through change. This change was later reinforced by legislation.

The initial result was a real opening up of the market to competition for industrial and commercial business driven by the availability of gas to third-party suppliers from British Gas — known as 'release gas' — priced at the weighted average cost of gas (WACOG) in British Gas' portfolio (see Chapter 6). This in effect guaranteed a margin to all suppliers since they did not have the monopoly overheads. The result was that around 50 companies entered the market. This was both unconventional and perhaps a rather artificial form of 'competition' but it worked. Soon the initial group of mainly entrepreneurial companies were followed by the big players, both down stream affiliates of the gas producers and the RECs who saw a natural new market for their skills.

The success of competition in the industrial and commercial gas market led to Ofgas introducing competition in domestic gas. In April 1996 the first trial area of 500,000 customers opened up and this was gradually extended until on 23 May 1998 the final part of the UK was opened up to gas competition.

17.3.3 Convergence at retail level

In the UK, the gas industry encountered what is virtually unique in the world, total separation of gas distribution from selling gas. Centrica plc, the demerged marketing arm of British Gas plc, sells over half the UK's gas without owning a single piece of pipe in the ground (although they sought to rectify this on a small scale through new ventures). Throughout the rest of the world, in contrast, the normal model when the whole gas industry is not under one ownership is to have a single gas transporter, or occasionally significantly more, such as in the US. The transporter delivers gas to the 'city gate' or local distribution company (LDC) which distributes gas in the local town, both with monopoly selling and distribution rights.

The result, in the UK, was that others saw an opportunity to enter the market when competition came to gas selling. One of the first groups to enter the market were the electricity distribution companies, the RECs. They saw that, in contrast to earlier times, the only requirement to enable a company to sell gas was a good selling and billing operation. They had both, so they entered the newly liberalised gas market.

The first part to be opened up was the industrial and commercial market where they found things harder than expected due to the excess of companies seeking a position. Not only were RECs starting to sell but downstream affiliates of gas producers saw an opportunity to take value from other parts of the chain. While in the industrial and commercial market most RECs sell both gas and electricity, dual fuel packages are apparently not at the heart of marketing strategy.

In the domestic gas and electricity markets, by contrast, dual fuel packages have become the norm. This has been particularly emphasised by British Gas which is the only major independent seller of domestic electricity in the UK energy market. An additional discount is offered to those taking both fuels from one supplier which reflects cost savings and, perhaps, the thought on the suppliers part that such customers are less likely to switch to another supplier.

At the level of retail appliances, the other key change which started even before the opening up of the electricity market is the virtual ending of single energy showrooms. For example, British Gas started to run Energy Centres selling both gas and electricity appliances, but they have since abandoned this approach due to the high level of competition in the sector in the UK.

The unanswered question is the effect on inter-fuel competition of such moves. Until now the gas and electricity industries fought each other with improved technology funded from sales; but this will no longer be practical due to much reduced margins. Equally will energy companies deem such effort desirable as they no longer have a commercial interest in whether the customer buys gas or electricity? The position is the same for appliance manufacturers who generally make both gas and electric appliances.

17.4 Continental Europe

Competition is growing slowly in Continental Europe as the effect of the EU Directives slowly trickles across the gas and electricity markets.

In terms of convergence at the retail level, it is becoming clear that the energy company selling both gas and electricity will be the norm. This is partly due to the fact that in countries such as Germany, the Stadtwerke already sell both.

In terms of convergence at the wholesale level, there is little evidence of any real arbitrage between the gas and power markets. This, however, is as much to do with the small market share of gas in the power market as with relative market prices. Furthermore, given the rise in gas prices and the collapse of electricity prices in markets as they open up to competition, it seems unlikely that there will be quite the 'dash for gas' in Continental Europe as was seen in the UK in the 1990s.

Perhaps the most interesting difference between the UK and the continental route to competition is that part of the UK process was the destruction of the large players as the RECs were taken over, broken into supply and distribution and then merged and the power generators forced to sell off plant. In contrast national champions seem to be the order of the day in most other EU members.

For example, the German government recently tried to overrule the Kartelamt (Cartel Office) to allow E.ON – a major power player – to take over Ruhrgas, the largest gas company in Germany. Subsequent court actions by other potential players in the German market to stop the takeover of Ruhrgas were unresolved at the start of 2003. The French government is equally reluctant to break up Gaz de France or Electricité de France.