The Network Code

Commercial and operational implications for the UK gas industry

MIKE MADDEN

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FINANCIAL TIMES
Energy Publishing

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Published and distributed by
Financial Times Energy Publishing

A division of Pearson Professional Limited
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ISBN 1 85334 725 6

Typeset by C&J Palmer, Wedmore, Somerset BS28 4AH.

Printed and bound in Great Britain by Copyspeed Printing plc, 878 High Road, North Finchley, London N12 8QA.

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EXECUTIVE SUMMARY

The introduction of the Network Code on 1 March 1996 was probably one of the biggest and most significant changes that the gas industry in Great Britain has experienced since the change from town gas to natural gas in the late 1960s and early 1970s. The Network Code consists of some 500 pages of closely spaced legal contract drafting covering all commercial and operational issues of the transport of gas from the beach to the customer's burner tip. Writing a Management Report on the impact of the Network Code on the British gas industry at this volatile time has been like trying to write the history of the world in 50,000 words. Even during the process of writing this report many aspects of the Network Code were changed and proposals were made for its modification. There were well over 100 proposed modifications to the code, some of which have been implemented.

DEVELOPMENT OF THE COMPETITIVE GAS MARKET IN GREAT BRITAIN

Chapter 1 sets the scene before the introduction of the Network Code, explaining the history of third party access in Great Britain from the formation of the Gas Council through to the privatisation of British Gas (BG) and its subsequent battles through the Monopolies and Mergers Commission (MMC) and the Office of Fair Trading (OFT) with the government and the regulator of the day. The development of the new regulatory regime by the regulator, Ofgas, is also covered in some detail. The regulatory framework which came into operation at the date of privatisation in 1986 with an RPI–2 price cap on gas sales for British Gas, subsequently developed into a tougher regulatory regime both in terms of the development of RPI–5, which occurred five years later, and the continuing pressure from the regulator over the development of the competitive market.

In response to the regulatory, political, and market pressures for the development of a fully competitive gas industry in Great Britain, which will include 19m domestic consumers, TransCo (the BG business unit in charge of operating and maintaining the pipeline and storage facilities) developed a new contractual regime which has now become known as the Network Code. The chapter also covers the development of this contractual regime from initial discussions with shippers through to the final production of the Network Code, as well as the UK-Link computer system which will manage this new competitive regime and all of the data and information associated with it.

In the mid-1990s there is a variety of operators taking part in the gas industry in Great Britain, so the difference between producers, shippers, producer-affiliates, regional electricity companies, independents, gas traders, suppliers, and the Claims Validation Agency is explained.

THE KEY POINTS IN THE NETWORK CODE

Chapter 2 explains some of the fundamental principles associated with the operation of the Network Code and describes the general structure of the gas supply system in Great Britain. This includes a description of the national transmission system (NTS), the local distribution zones (LDZ), and the entry and exit facilities, together with storage facilities. Having explained the basic structure of the gas industry in Great Britain this chapter goes on to describe the main areas of interest in the Network Code.

These areas include the national balancing point (NBP), which is a notional point on the gas supply system through which all gas nominally flows and about which every shipper on the system has to balance its portfolio. Failure to balance inputs and outputs on the day within certain tolerances will result in the transgressing shipper being required to pay certain charges. Those charges associated with shipper's imbalances will depend upon the individual shipper's shipper imbalance tolerance (SIT), and the value of the system average price (SAP) and SMP (Buy) and SMP (Sell), where SMP stands for system marginal price. In order to ascertain the degree of imbalance it is necessary for TransCo to measure the quantity of gas delivered at the entry point for each individual shipper and the quantity of gas offtaken by that shipper's customers from the system.

The deliveries of gas are calculated as a result of work undertaken by the Claims Validation Agency (CVA) which tracks title from the beach to the final owner of that gas after any gas trades. The gas offtaken by the shipper's customers is calculated in two ways: gas quantities offtaken by daily metered sites (DM) are obtained from the daily metered readings, whereas the offtakes from non-daily metered sites (NDM) are obtained using a demand algorithm. This demand algorithm is a simple formula which relates to the daily consumption of an individual site based on its demand, and the temperature characteristics of the gas supply system on that day.

In the event that the gas supply system is out of balance on the day, TransCo's first action would be to identify any forecasting error and inform those shippers of their new demand forecasts for the NDM demand sector. If, having asked shippers to rebalance their portfolios, TransCo is still unable to balance the system, it is then able to go to the flexibility mechanism and either purchase gas if the NBP is short or sell gas to the various operators if the NBP is long. In this process TransCo is meant to be a guardian of the industry's daily balance, so that any costs that TransCo incurs on the day are effectively passed on to those shippers which created that imbalance by their actions. Similarly any gains that TransCo may make on the day will also be passed on to those shippers or other members of the gas community which are prepared to turn their gas deliveries or offtakes up or down on the day to enable TransCo to balance the system.

Another charge that encourages shippers to deliver the amount of gas that they have nominated, and to offtake at large supply points the amount they have told TransCo they would offtake, is the scheduling charge. Scheduling charges are incurred when a shipper's nomination is outside a tolerance band of either inputs or offtakes. Although scheduling charges are not high – in the order of 1–2% SAP – in a highly competitive gas industry they are not popular.

In order to deliver gas into the gas transportation system it is necessary for each shipper to book entry capacity to get gas into the NBP. Entry capacity has to be booked in 12-month tranches, and any additional capacity booked will run for a further 12-month period from the day that capacity is available. Similarly, if a shipper wishes to offtake gas from the NBP exit capacity has to be booked. Exit capacity is also booked in 12-month tranches, although an increase in capacity will increase the total capacity booked for a further period of 12 months. Where a shipper has customers in the local distribution zone (LDZ) it is also necessary for the shipper to book capacity for those sites which require it. These would include DM sites, where the shipper would be required to give a supply offtake quantity (SOQ). The SOQ relates to the maximum quantity of gas that is expected to be offtaken on any day. For NDM sites the demand algorithm sets a theoretical SOQ and the quantity of capacity booked on those sites is automatically booked at the exit zone as well.

GAS TRANSPORTATION CHARGING

Chapter 3 describes how gas transportation charging has developed since 1990 from its initial cost-based approach with the charges effectively being calculated on a distance-related basis, through to the charging methodology that we have today. The charges developed over a period of time, initially with the inclusion of distance capping and backhaul. Distance capping is the term applied to the process of discounting long distance transportation charges, since on most occasions as a result of the integrated nature of the NTS the gas will probably travel from another closer beach terminal to the end user. Backhaul is a word borrowed from North America, which refers to gas notionally flowing against the actual flow, hence the term backhaul. As the market grew, there was a genuine desire by all parties to move to a more cost-reflective and flexible means of charging, so an entry/exit charging methodology based on long run marginal costs (LRMCs) began to develop. The increase in the size of the market-place, together with the move towards daily balancing, encouraged the introduction of entry/exit charging, which it was decided should be based on the LRMC model. The objective of the LRMC model, which has been used by TransCo for the calculation of NTS charges since 1 October 1994, is to derive more cost-reflective prices based on forward looking data. Ultimately the aim was to send the right economic signals to the gas transportation market-place, although with any fully integrated network, such as TransCo's pipeline network, the full use of LRMCs would create a highly complex matrix of charges.

Chapter 3 also describes how these LRMC charges are calculated and how they have been implemented. Areas covered include the charging of capacity on the NTS at entry and exit points, and NTS commodity charges. It then goes on to explain how LDZ charging based on average accounting costs is undertaken, and this is illustrated by the various tables and formulas provided by TransCo. The calculation of commodity charges on the NTS is straightforward, with a postalised charge of 0.0333p/kWh, whereas the commodity charges for LDZ usage are based on a logarithmic function. Other charges made by TransCo in relation to dataloggers, meter-readings, and special meter reads are also explained.

No discussion on the development of gas transportation charging would be complete without a look into the future, and so this chapter briefly describes the proposed three-node charging model which is under discussion within the industry. It is somewhat ironic that the three-node methodology in many ways is a move back towards distance-related charging, on the basis that it is meant to be more cost-reflective and as such send purer economic and operational signals to the industry as a whole. Whether such a move will be prudent and effective remains to be seen.

THE IMPACT OF THE NETWORK CODE ON PRODUCERS UPSTREAM

Until the introduction of the Network Code many producers had not been involved to any great extent in the development of gas-to-gas competition in Great Britain, or in discussions concerning the Network Code. Obviously some had been engaged in selling gas to shippers, or had developed their own gas marketing organisation, but the consultation process of the Network Code had been largely driven by TransCo and the shipping community. Therefore when the code was finally introduced some producers received a bigger shock than the shippers, which had become accustomed to TransCo's operation and thinking behind the code. It is fair to say that during the consultation process on the code many more producers without downstream interests did show an interest in its development, recognising the need to influence the final outcome.

The Network Code will most definitely have an impact on offshore economics. The most obvious is the cost of gas charged by producers, since gas coming into the NTS at different beach terminals will incur different entry charges from TransCo, and these will vary considerably. Consequently there can be an economic case for laying a slightly longer offshore line to a cheap terminal rather than a shorter line to a more expensive terminal, although this state of affairs rarely happens. Nevertheless gas available in the southern basin is likely to command a slightly higher price on the basis that the entry charge at Bacton is considerably lower. A second area where producers have been affected has been in terms of capital investment. During the early days of gas-to-gas competition it was noticeable that new gas that was coming onstream tended to be purchased with a low swing, which obviously enabled producers to maximise profit and minimise capital expenditure.

$$\text{Load factor is defined as:} \quad \frac{\text{Average daily demand} \times 100}{\text{Peak daily demand}}$$

$$\text{Swing is defined as:} \quad \frac{\text{Peak availability} \times 100}{\text{Daily contract quantity}}$$

In the UK load factor usually refers to gas demand and swing refers to gas supply.

While there has been, and will continue to be, an argument regarding the necessity for offshore investment in pipelines and compressors to provide swing, compared with onshore investment in pipelines and storage, nevertheless the swing offered by producers during the 1990–96 period has slowly decreased to the point where flat gas is quite commonplace. However, with the introduction of the Network Code this is beginning to change, and storage is being purchased by shippers as a means of providing swing. It may be that some producers will see the opportunity to add value to their gas and possibly enhance their long-term price prospects by offering swing to potential gas purchasers.

The code has also had an impact on gas contracts, since shippers now require much more information both before the day, within-day, and after the day. In fact the provision of information to the Claims Validation Agency (CVA) has been one of the main difficulties encountered by the introduction of the code. The producers have in many cases chosen not to provide base statements to the CVA on the basis that the provision of such information is not in the original gas contracts. The main reason given has been concerns about liability. This lack of provision of information combined with the somewhat antagonistic view taken by some players in relation to the provision of base statements has caused some difficulties which, at the time of writing this report, are still unresolved. Another area of gas contracts that is beginning to change is the technical specification relating to quality. In the early days of gas transportation when a shipper purchased gas from a field partially owned by British Gas Trading, or gas was delivered via a commingled pipeline, the relevant gas specification in the BG purchase or allocation agreements would be referenced. However, with the introduction of full gas-to-gas competition and the separation of TransCo and British Gas Trading, such an arrangement was no longer acceptable. Therefore, TransCo is in the process of establishing appropriate and acceptable gas quality specifications at each of the beach entry points. As a result of the development of the flexibility market many shippers are also seeking improvements in notice periods and ramp rates so that they are in a position to respond to TransCo's renomination requests.

THE IMPACT OF THE NETWORK CODE ON SHIPPERS

While many shippers were commercially astute and highly involved in the discussions associated with the Network Code, the impact on the shippers should not be underestimated. The main point to note is that the whole industry is moving from a monthly balancing regime to a daily one. This means that whereas before the code's introduction nominations could be made weekly and shippers could go home at 5pm on a Friday, the gas industry is moving in all aspects towards a 24-hour a day, 365-day a year industry. This was a huge change from the old monthly balancing contracts, so that most shippers are having to consider or are in the process of setting up 24-hour manned control rooms. Obviously such a move does increase their overheads and has become a barrier to entry.

The effect of daily balancing charges as a result of the flexibility mechanism should also not be underestimated. Certainly during the early months of the code's operation, under a relatively relaxed transitional balancing regime, high levels of system marginal price (SMP) were experienced, which did send shock waves throughout the industry. While some changes have been made to smooth out the impact of high SMP on the industry, the high cost of being out of balance on exceptionally cold days has caused many shippers to consider whether their annual supply/demand matching is suitable. In many cases this has resulted in shippers purchasing storage or seasonal supplies of gas.

Since it is now necessary for shippers to purchase entry and exit capacity the industry is also seeing the development of a capacity trading market. While this is still in its early stages it is expected that over a period of time the capacity trading market will become progressively more liquid with an increased number and size of trades.

Another area that is also developing is the operation of a day-ahead spot market. At present the operation of this is primarily via telephone trades between the various commercial members of the shippers' gas teams. However, the International Petroleum Exchange (IPE) has been working on a screen based trading system and, although it has experienced difficulties because of the problems associated with closing out deliveries via the CVA, it is expected that in early 1997 the IPE will deliver a gas trading screen for NBP trades. This will increase the level of activity in the day-ahead spot market and at some stage will probably be followed by a within-day spot market if the industry is prepared to let it develop.

The high prices experienced by shippers in the flexibility mechanism in March and May 1996 have encouraged many shippers to examine their peak gas requirements carefully. This has led to some purchasing gas, while others have purchased storage.

GAS STORAGE

The provision of storage was technically available before the introduction of the Network Code although, partially as a result of the inflexibility of the service offered in the early years of competition but mainly because it was not necessary, few operators purchased or operated storage from TransCo. The various types of storage facility that British Gas Storage has at its disposal include the Rough field – an old gas field; salt cavity storage – large underground cavities that have been leached out to create storage facilities; and liquefied natural gas (LNG) – where gas is stored in its liquid form. BG Storage offers a variety of storage services to the gas industry in Great Britain, including firm storage services, where gas can be delivered into a facility and can be withdrawn from a facility with few restrictions; and constrained storage services, which are LNG facilities that need to be able to deliver gas into the NTS on some peak days during the year. TransCo has a commitment from any organisation that books storage in constrained LNG facilities to enable it to remove some of the shipper's gas from storage on days of exceptionally high gas demand. The benefit to the shipper is a reduction in transport charges.

BG Storage also provides interruptible storage services from the Rough facility. Any gas that has been injected into Rough may be withdrawn on an interruptible basis only. Interruption is triggered when TransCo forecasts that there will be insufficient deliverability or operational constraints that would limit its ability to deliver gas from Rough into the NTS. This right of interruption can only be taken on days when gas demand is above 85% of peak.

In order for a shipper to identify whether or not it requires storage it is necessary to assess the supply/demand characteristics of its particular gas purchase and demand portfolios respectively. Historically BG had done this analysis by constructing load duration curves (LDCs). During the early years of gas-to-gas competition, because of the relatively relaxed contractual regime in place, this was not a necessity. Therefore, few shippers had any expertise in drawing up these load duration curves. There are a variety of ways in which LDCs can be constructed, depending on the complexity of the shipper's supply and demand portfolio. BG Storage currently has a program known as the Locutus Load Curve program, which is a simple spreadsheet model originally written to enable shippers to become more familiar with the whole concept of LDCs. While the current Locutus program is probably too simplistic to model all aspects of the way in which a shipper's demand portfolio would function under the Network Code, it does nevertheless provide a good starting point. BG Storage has said that it is planning to release an updated version of Locutus in early 1997, which would take account of the impact of the introduction of the code.

Following the introduction of the Network Code and the expectation that the price of SMP (buys) and SMP (sells) from the flexibility mechanism will be costly to shippers which have large imbalances (particularly during the winter months), the whole market for storage and swing appears to be growing. Whereas before its introduction, storage was primarily a load balancing tool which enabled BG to balance supply and demand on a seasonal basis, in the commercial environment of gas-to-gas competition storage it will be, and is already becoming, a commercial tool. For example, storage will become a tool to assist in gas trading. This will be particularly true with the growth of the spot gas market as well as increased activity in the flexibility mechanism. Storage will also be useful when used in conjunction with gas purchase contracts, for example in mitigating potential take-or-pay problems at the end of the contract year. Although it cannot make take-or-pay problems go away it will provide additional flexibility. Finally, with the potential for less secure supplies of gas coming from the former Soviet Union, other east European countries, and possibly even further afield, the combination of an insecure gas supply with a large storage facility could prove exceptionally useful.

SUPPLY POINT ADMINISTRATION

The transfer of supply points from British Gas Trading to other shippers, and from one shipper to another, has been an area that has dogged BG's and shippers' lives since the introduction of gas-to-gas competition. In order to facilitate its introduction into the domestic market, as well as to improve its performance in managing the existing competitive market of some 300,000 supply points, BG has introduced a new sites and meters database. The aim of this is to ensure that every customer in the country is on this database, with the appropriate meters and address information. TransCo has gone further to develop a computer system which comes under the heading of supply point administration (SPA), which enables shippers to receive quotations, and introduce and remove supply points electronically. The object of this process was to provide an almost automatic method which would enable large numbers of supply points to be transferred from one shipper to another and be introduced into the correct gas transportation contract without too much manual intervention or too great a delay. The means of doing this was via batch file communication.

TransCo and the shipping community have had a considerable number of problems associated with SPA. These problems have included supply points not appearing on any shipper's portfolio, or a supply point occurring on more than one shipper's portfolio. In order to solve these problems TransCo, in conjunction with the shippers, established a number of initiatives, the first of which was known as supply point reconciliation, which was to ensure that the right supply points with the right information appeared on the right portfolios. The second initiative was known as Project Phoenix which sought to resolve a variety of problems affecting shippers, including supply point problems.

THE IMPACT OF THE NETWORK CODE ON END USERS

The impact of the Network Code, particularly with the move from monthly to daily balancing, and the introduction of the hard landing on 1 September 1996, is still being felt. 'Hard landing' was the term used by the industry to describe the introduction of full daily balancing. Before this date a transitional regime was in place, which bridged the gap between monthly and daily balancing. Nevertheless there are changes in the way in which organisations purchase gas at the beach, transport gas through TransCo's system, and even in the way in which some of the large consumers think about gas and make purchasing decisions.

The introduction of gas-to-gas competition was felt most keenly in the early days by the power generation community which was also experiencing the liberalisation of markets with the introduction of independent power stations. The introduction of gas-to-gas competition increased the choice of gas suppliers for large power generation projects which, therefore, reduced the price of potential supplies. However, with the introduction of daily balancing the power generators are expected to perform this operation within tight tolerances.

The industrial and commercial gas market has seen increasing gas-to-gas competition since 1990 and has received the benefit of decreasing prices. Many purchasers of energy in this market have become considerably more commercially astute in their purchase of gas and many now have a thorough understanding of the operation of the gas market and the impact of spot prices and so on. In fact the reduction in gas prices to this sector of the British business community has caused problems with some of their European counterparts who are now complaining that energy costs in Great Britain are too low! The expertise of some of these large industrial and commercial customers in minimising their gas costs has increased considerably, with some end users improving their demand forecasting to minimise balancing charges and scheduling penalties on their respective shippers. Consequently those end users which are able to perform in this way receive cheaper priced gas.

The domestic market was just beginning to feel the impact of gas-to-gas competition as this report was being finalised, with some 18% of the domestic market in the south-west of the country being transferred to non-BG gas marketing companies.

Bearing in mind the inertia expected in the domestic market, 18% is probably a good figure at such an early stage, although some commentators are disappointed.

In conclusion, the introduction of gas-to-gas competition within Great Britain, while not being a seamless transfer from a monopoly market to a truly competitive market, has nevertheless gone without major incident: gas supplies have continued to flow, there have been no major supply failures, and prices have continued to fall.

THE FUTURE

In many respects the future of the gas industry in Great Britain should be an exciting one, with 95% of the domestic market still to receive the benefits of gas-to-gas competition, which it will do in the next two to three years, and the prospect of construction of the Interconnector allowing for either gas export or gas import.

New markets are forecast to develop within Great Britain. In particular, it is expected that a spot gas market will develop for both day-ahead and within-day gas if the IPE screen based trading system can be successfully implemented. The development of the spot market in Great Britain will be crucial by the time the Interconnector is commissioned in 1998, because the opportunity will arise for pan-European gas trading. Ideally it would be good for the country if that gas trading hub could be operated at Bacton or the NBP. Similarly it seems highly likely that a capacity trading market will develop.

Although the Network Code was introduced on 1 March 1996 and has had a hard landing on 1 September 1996, many improvements and enhancements will continue to be made over subsequent years as the British gas market develops.

CHAPTER 1: THE DEVELOPMENT OF THE COMPETITIVE GAS MARKET IN GREAT BRITAIN SINCE 1990

INTRODUCTION

This chapter provides background information on the British gas industry and examines how the competitive market has developed since 1990, written with the interests of overseas readers and any new entrants to the British gas sales market particularly in mind. It also includes a brief summary of the new contractual regime, and how it works, together with a description of the main operators, including TransCo, producers, shippers, and Ofgas. The development of the Network Code and how the Network Code UK-Link computer system works is also described.

HISTORY OF THIRD PARTY ACCESS IN GREAT BRITAIN

Pre-1986

By the end of the 1930s there were approximately 11m gas consumers in Great Britain. These consumers were supplied with town gas that was made from coal. Most of the town gas companies were privately owned or municipal undertakings. In 1949 these various organisations were nationalised by the postwar government and collected together into what became known as the 12 area gas boards. A central body known as the Gas Council acted as a link between the area gas boards and the government. The Gas Council provided assistance to the area boards in carrying out research and borrowing money.

In the 1950s and 1960s the gas market began to decline, with rising costs and the image of gas being a dirty and unsafe fuel. However, this all changed with the discovery of natural gas in the UK sector of the North Sea during the mid-1960s. It was estimated that the reserves of gas found were of a size sufficient to supply the British gas market, and consequently gas reception terminals were constructed on the east coast, along with a national high-pressure gas transmission system. However, the gas supply infrastructure put in place by the area boards had been designed and built for town gas, not natural gas, so with the introduction of natural gas the existing town gas burning equipment had to be converted. This process of conversion started in 1967 and took approximately 10 years, during which time the gas supply network was also progressively converted to natural gas.

Establishing the British Gas Corporation (BGC)

In the 1972 Gas Act the Gas Council was renamed the British Gas Corporation (BGC) and took control of the 12 area gas boards. BGC was responsible for buying gas on behalf of the area boards, although these regional organisations remained fairly autonomous. The introduction of natural gas with its clean high speed image, combined with the oil crisis of the late 1970s, meant that the market share of gas grew considerably over the following years. This led to increased activity offshore, with more exploration and production companies making discoveries, and also increased activity onshore which led to the construction of the national transmission system (NTS).

By the time the Conservative government had come to power in the 1980s the problems associated with the gas industry had been largely forgotten. Therefore, when in 1985 the government announced its intention to privatise BGC and to sell shares in the business to the public, it was no great surprise.

The privatisation of BGC

Before 1986 the British Gas Corporation was a nationalised utility buying, transporting, and selling gas on a monopoly basis to all gas consumers in England, Wales, and Scotland. The Gas Act of 1986 allowed the business of BGC to be transferred to British Gas (BG), and in November 1986 shares in BG plc were offered for sale. One of the great debates that took place at this time was whether BGC should be sold as a whole or whether it should be divided up into smaller sections. In the event the chairman, Sir Denis Rooke, won the argument and BGC moved intact into the private sector as BG plc.

November 1987 – the first MMC inquiry

In November 1987, as a result of complaints from large industrial customers, the director general of the Office of Fair Trading (OFT) referred BG to the Monopolies and Mergers Commission (MMC). The MMC discovered that many gas consumers in the industrial market had no immediate or realistic alternative to gas, nor were they able to purchase gas from an alternative supplier. The MMC also found that there was discrimination in the pricing and supply of gas to large industrial customers in the contract market, because for certain customers there were no alternative energy supplies available. The MMC also identified the fact that BG was able to price gas supplies selectively to individual consumers, which meant that any potential competition could always be undercut by BG, and was therefore against the public interest.

In order to remedy this state of affairs, in 1988 the MMC recommended that BG should undertake the following measures:

- publish a schedule of firm and interruptible gas prices for the industrial and commercial market using more than 25,000 therms a year;
- not discriminate in its pricing or supply of gas;
- not refuse to supply gas via an interruptible contract for reasons related to the use made of that gas, or availability of an alternative fuel;

- publish information on the common carriage terms available;
- not contract for more than 90% of any new gas field. This became known as the 90/10 rule.

The MMC concluded its report by stating that if competition failed to develop over the next five years, consideration should be given to the structure of the gas industry in the UK and how it might be changed to facilitate competition.

February 1990 – the first non-BG supplier

In early 1990 Quadrant, a joint venture between Shell and Esso, signed a gas transportation agreement with BG and became the first independent gas supplier in the UK gas market.

October 1990 – three more new entrants

In October 1990 three more new gas suppliers entered the UK market. These were AGAS, Mobil, and BP. Some of these used gas from their upstream affiliates, whereas others purchased gas via swap arrangements.

October 1991 – completion of the OFT review

In October 1991 the OFT published its findings on the effectiveness of the remedies required of BG as a result of the 1988 MMC report. BG had largely complied with the MMC's requirements, and had even gone beyond them in some cases. It had purchased considerably less gas than the 90/10 rule required, and had also made gas available under its own gas purchase agreements via 'gas swaps', to enable its competitors to gain entry to the market earlier than new field development times would allow. Ironically, these actions occurred at the same time as the electricity market was developing via the introduction of combined cycle gas turbines (CCGT). Consequently a large proportion of the gas available for the embryonic gas market was being swallowed by large power generation projects. The OFT found that the actions recommended by the MMC and taken by BG had not been effective in introducing self-sustaining competition in Great Britain, and consequently made the following recommendations:

- BG should release some gas from its own purchase contracts for use by competitors;
- there should be divestment of BG's transportation and storage business (T&S), and T&S should deal even handedly with all gas marketing companies;
- the tariff monopoly should eventually be abolished;
- BG's industrial market share should be limited to 40%.

Formal agreement with the OFT in March 1992

Following the publication of these OFT findings, BG had a series of negotiations with the OFT, which culminated in an agreement in principle in December 1991, and a formal list of undertakings which were given in March 1992. In summary BG undertook:

- to facilitate competition so that at least 60% of gas to contract customers was supplied by non-BG suppliers by 1995;
- to use best endeavours to secure development of competition in the contract gas market;
- to establish a separate T&S unit by 1 January 1994;
- to publish separate accounts for T&S, and BG Trading, from 1 December 1993;
- to produce a consultation document on gas transportation pricing, and publish a transparent pricing regime for use by 1 October 1992;
- that BG Trading would be treated as a shipper by 1 January 1993;
- that BG Trading and all other shippers would be treated on the same basis;
- to produce a discussion document on storage services by 1 January 1993;
- to ensure that gas transportation, system reinforcement and extension, and site connection would be undertaken on a non-discriminatory basis between BG and other shippers by 1 January 1993.

Second MMC referral July/August 1992

At this point in the history of the gas supply business in Great Britain the facts and their interpretation become slightly murky. The view of Ofgas was that a radical structural change was required by BG in order for competition to develop effectively in Great Britain, whereas BG's view was that the cumulative regulatory changes which had occurred since privatisation were making it increasingly difficult for it to manage its business effectively. The combination of the revised tariff formula at RPI–5 and the rapid loss of market share should also be taken into consideration. Therefore, BG and the secretary of state asked the MMC (under the Fair Trading Act) to undertake a thorough investigation of the supply and transport of gas in Great Britain. Ofgas also sent references to the MMC (under the Gas Act) on transport, storage, and public gas supplier issues.

August 1992 – reduction of tariff threshold from 25,000 to 2,500 therms a year

The reduction of the tariff threshold at this time was a highly significant step taken by the energy secretary, Tim Eggar. What is interesting is that at a stroke the minister increased the number of potential customers in the competitive arena from 30,000 to 300,000. While this may have seemed like a good idea at the time, the relatively short period of notice combined with a computer system that had not been designed for such a large number of customers caused a turbulent period for both BG and shippers. While it clearly contributed to the opening up of the competitive market, the subsequent problems caused by an almost immediate tenfold increase in the size of the competitive market were considerable. The rapid increase in the size of the competitive market, combined with the system and process problems that BG was having, could not have come at a worse time, since BG's poor performance in billing, meter-reading, and transportation quotations only gave ammunition to its competitors.

August 1993 – the second MMC report

Following a year-long analysis of the gas industry, the MMC published its report. It consisted of four volumes, totalling nearly 1,200 pages. The main recommendations were:

- the divestment of BG Trading;
- T&S to operate as a separate unit, regulated on RPI–X basis;
- the modification of the tariff formula to reflect the new market conditions in which BG found itself;
- that there should be a further reduction of the tariff threshold;
- that there should be a delay on the introduction of domestic competition until the 21st century.

While the 1993 MMC report was far-reaching, it did stop short of recommending opening up the domestic market immediately. It did, however, recognise the need for a readjustment of the RPI–X formula.

December 1993 – government decision on MMC report

Although the 1993 MMC report made many wide-ranging recommendations, nevertheless it was up to the president of the Board of Trade, Michael Heseltine, to decide whether or not to accept any of the recommendations made by the MMC. Following a four-month delay the government announced its acceptance of many of the MMC recommendations, with some surprising changes:

- domestic competition was to be introduced as soon as possible, along the lines of the following timetable
  — April 1996 – first pilot for approximately 5% of the market,
  — April 1997 – second pilot,
  — April 1998 – full competition;

- BG to separate trading and transportation (into separate business units, rather than totally separate divested companies).

March 1994 – restructuring of British Gas

Following on from the 1993 MMC inquiry and Mr Heseltine's announcement, BG formally announced it was restructuring into five business units:

- Business Gas – to serve the existing contract market;
- Public Gas Supply – to serve the existing tariff market;
- TransCo – to operate and maintain the pipeline and storage facilities;
- Retail – to run the showroom operations;
- Service – to run the service operations.

October 1994 – Ofgas cap on transportation and storage charges

In October 1994 Ofgas announced its first price cap for transportation and storage charges. At RPI–5, it was seen as a tough regime for TransCo to operate under.

1994–95 – the process of developing the Network Code

The Network Code, as defined by TransCo, is a set of business rules within a legal framework that defines the rights and responsibilities of TransCo and the shippers, and forms the basis of all contracts between them.

The development of the Network Code began in 1994 with the publication of four 'high level principle' papers on Services (Capacity Broking and Trading); Pricing; Supply Point Administration; and Energy Balancing. Throughout 1994 and 1995 TransCo was in discussion with shippers and Ofgas to translate the broad principles of the Network Code proposed by TransCo in these 'high level principle' papers into detailed business rules governing the terms of access to the transportation system. The development of the Network Code has progressed in the following manner.

Translation of high level principles into detailed business rules

The high level principles have been negotiated and refined in a series of public meetings over a two-year period to produce a set of agreed detailed business rules. It was these detailed business rules which formed the basis of the work to produce the main Network Code document.

The production of the legal draft

Based on the work done in producing the detailed business rules, the legal team then produced a series of versions on the various sections of the code. It was these sections which were combined together to form the main Network Code legal document.

This, of course, is a gross simplification of the process, which involved a tremendous amount of hard work for a large number of individuals from TransCo, gas shippers and other major players in the gas industry.

November 1995 – Gas Act receives royal assent

During this time the UK government also needed to put in place appropriate legislation to handle the opening up of the domestic market to competition. Its intention to do so was originally stated in the Queen's Speech in November 1994, although it took until November 1995 for it to become law. The introduction of the Network Code was twice delayed, from 1 October 1995 to 1 December 1995 and then to 1 March 1996. The reason given for these delays was that the DTI had not drafted shipper licences in sufficient time for their introduction.

1 February 1996 – the Network Code goes live

Finally, after two false starts, the Network Code went live on 1 March 1996. Once implemented it has not been without its difficulties or incidents, but all things considered TransCo can rightly regard the implementation of the code as a success.

DEVELOPMENT OF OFGAS AND THE REGULATORY REGIME

Establishing the regulatory framework

The privatisation of BGC in 1986 to form BG plc included the establishment of a complicated regulatory structure. This involved setting up the Office of Gas Supply (Ofgas) and the Gas Consumers Council (GCC).

The Ofgas ethos

The first director general of gas supply, Sir James McKinnon, often stated that he wanted Ofgas to be light-handed in its approach to regulation. However, often in the same breath almost, Ofgas would also declare itself as a 'surrogate to competition'. It is against this background that the regulatory environment in Great Britain developed.

The concept of being a surrogate to competition grew up because Ofgas felt that until full competition developed it would have to apply regulatory pressure on BG that would make it behave as if in a competitive market. The theory behind this was that once true competition was established regulation could be much more light-handed. This has been true in the competitive gas sales market where, as competition has developed, the need for BG Trading to publish pricing schedules has been removed. However, since TransCo is likely to continue to be a monopoly transporter of gas in Great Britain for the foreseeable future, it is likely to continue to be on the receiving end of light-handed regulation (and have the bruises to prove it!).

In the Ofgas consultation document, 'Price Control Review, British Gas Transportation and Storage', published in June 1995, Ofgas stated that it has certain specific objectives in regulating TransCo.

Unbundling to promote competition By forcing TransCo to unbundle all of its services, those areas where competitors can offer alternatives can be identified and competition encouraged. A good example would be meter reading.

Control of prices Control of TransCo's prices will continue to be a main focus of the Ofgas approach. The argument behind this is that in the absence of a competitor Ofgas must force TransCo to keep its costs down by actually making it reduce its prices by a certain percentage less than inflation by being a surrogate for competition. (It is not entirely clear whether what really happens is that TransCo behaves like a monopoly being regulated by a regulator at RPI–5, rather than a player in a competitive market.)

Incentive to efficiency This objective put forward by Ofgas means that TransCo should still have an incentive to make money.

Maintain standards of service Ofgas is concerned that it it imposes a tough price cap on TransCo the company will reduce costs by cutting standards. Therefore, the aim of making TransCo meet certain levels of service is to avoid this.

Information Ofgas often feels in a weak position in dealing with TransCo, in that TransCo has all the information and Ofgas has few alternative sources. Therefore, Ofgas continues to ask TransCo for more information as well as making international comparisons.

Transparency of process In order to give confidence to all users of the system Ofgas will make the process of price control as transparent as possible. One of the reasons for this is that other system users have often felt in the dark about how certain price control decisions were made.

BG's obligations under the 1986 Gas Act

The 1986 Gas Act gave BG, as a public gas supplier, a number of obligations, the most relevant of which are summarised below.

- BG was required under Section 10 of the 1986 Gas Act to supply gas to any customers using 25,000 therms a year or less, who were within 25 yards of a relevant gas main.

- Initially BG's consent was required for the supply of gas by competitors to any end user using less than 25,000 therms a year, although this was subsequently reduced to 2,500 therms a year.

- As a public gas supplier, BG had to operate under the terms of its original authorisation, which was granted for a period of 25 years.

The quotations from Volume 2 of the 1993 MMC inquiry shown in Figure 1.1 aptly describe the principal duties of the secretary of state and the director of Ofgas.

Figure 1.1 Summary of the duties of the secretary of state and Ofgas

Principal duties

1.7 Section 4 of the Gas Act, as amended by section 38 of the Competition and Service (Utilities) Act 1992 (the 1992 Act) and article 2 of The Gas (Modification of Therm Limits) Order 1992 (the 1992 Order) imposes on the Secretary of State and the Director a duty to exercise their functions in a way best calculated to secure:

(a) that authorised gas suppliers satisfy, 'so far as it is economical to do so, all reasonable demands for gas in Great Britain';

(b) that such suppliers are 'able to finance the provision of gas supply services'; and

(c) in relation to the conveyance and storage of gas, 'secure effective competition' between gas suppliers.

1.8 Subject to the requirements set out in paragraph 1.7(a) and (b), the Secretary of State and the Director must exercise their function in the manner best calculated to:

(a) protect the interests of gas consumers 'in respect of the prices charged and the other terms of supply, the continuity of supply, and the quality of gas services provided';

(b) 'promote efficiency and economy' on the part of the authorized gas suppliers and the 'efficient use' of the gas supplied;

(c) protect the public from dangers arising from the transmission, distribution or use of gas; and

(d) enable effective competition in the supply of gas at rates which, in relation to any premises, exceed a threshold of 2,500 therms a year (the new threshold, which was reduced by the 1992 Order from 25,000 therms a year came into effect in August 1992).

1.9 In protecting the interests of gas consumers in respect of the quality of gas supply service, particular account must be taken of the interests of those who are disabled or of pensionable age.

Source : MMC inquiry 1993, volume 2

Development of RPI–X

One of the main strands of the regulatory regime has been the control of tariffs for those end users using less than 25,000 therms a year.

Tariff formula for 1988–1992

The original price control formula used by Ofgas was known as RPI–x+y, where x=2 and y=costs. Basically this formula allowed BG to pass through any changes in its gas costs, while the non-gas component was limited to the Retail Price Index less two percentage points. It was seen by many as a relatively relaxed formula. Certainly BG was highly profitable during this time, and the share price performed well. A summary of how the first tariff formula was constructed is shown in Figure 1.2.

Figure 1.2: Summary of RPI-2

The tariff formula is set out below, using the subscript to represent the relevant year, as:

$$M_t = \left[1 + \frac{RPI - 2}{100} \right] P_{t-1} + Y_t - K_t$$

where

M_t = maximum average price per therm in relevant year t

RPI_t = the percentage change in the RPI between that published for October in year t and that published for the immediately preceding October

$$P_{t-1} = \left[1 + \frac{RPI_{t-1} - 2}{100} \right] P_{t-2}$$

but, in relation to the first year, P_{t-1} shall have a value equal to the average price per therm in the financial year commencing on 1 April 1986 less the allowable gas cost per therm in that year all calculated as if the financial year commencing on 1 April 1986 were a relevant year;

Y_t = gas cost per therm in the relevant year t

K_t = the correction per therm, positive or negative, in year t:

$$K_t = \frac{T_{t-1} - (Q_{t-1} M_{t-1})}{Q_t} \left(1 + \frac{I_t}{100}\right)$$

T_{t-1} = tariff revenue in relevant year t–1

Q_{t-1} = tariff quantity in relevant year t–1

Q_t = tariff quantity in relevant year t

M_{t-1} = maximum average price per therm in relevant year t–1

I_t = the percentage interest rate in year t which is equal to, where Kt has a positive value, the average specified rate plus three, or where Kt has a negative value, the average specified rate

Source: MMC, 1993

The RPI–2 price formula allowed for a 100% pass through of gas purchase costs for the period 1987–1992, with the inflation based index providing an annual ceiling above which the cost of gas to tariff users could not go. In theory such an arrangement gave BG a strong incentive to increase its overall profits, while at the same time improving efficiency and reducing costs. However, one of the big weaknesses in this arrangement was that the gas cost component of tariff gas prices was not capped, which gave BG little or no incentive to keep its gas costs down. Whether as a result of a weak regulatory pricing formula or good internal cost management by BG, BG's profits continued to rise during this period, causing much unwanted attention from the media.

The first transportation charges made by BG during this period were based on a rate of return of 4.5%, the argument being that BG transportation was a low risk business and as such a low rate of return was applicable.

Tariff formula for 1992–97

As a result of the shortcomings of the RPI–2 formula, negotiations for the second tariff formula concluded in April 1991 with BG and Ofgas agreeing a basic formula of RPI–5. A brief summary of this formula is shown in Figure 1.3.

Figure 1.3: Summary of RPI–5

$$M_t = \left[1 + \frac{RPI_t - 5}{100}\right] P_{t-1} + \left[\frac{F_t - Z_t}{100}\right] 18.388 + E_t - K_t$$

$$P_{t-1} = P_{t-2}\left[\frac{1 + RPI_{t-1} - 5}{100}\right]$$

where

M_t = maximum average price per therm in relevant year t

RPI_t = the percentage change in the RPI between that published for October in year t and that published for the immediately preceding October

The formula for K_t remained unchanged.

P_{t-1} and P_{t-2} now relate to the period April–December 1991, and the following new terms were introduced:

F_t = Gas Cost Index (GCI) in respect of year t

Z_t = 100 (1.01^N–1) in which N is the number of years between 1991 and the year t

E_t = all usable energy efficiency cost per therm in year t

18.388 = pence per therm amount representing gas costs across the entire market in the base year

Source: MMC, 1993

After much public posturing BG did agree the pricing formula of RPI – 5 with Ofgas, which was to take effect from April 1992, the objective being that the non-gas components of gas prices could only increase by inflation less 5%. This was seen by BG as a formidable goal to meet. However, what made the formula tougher than the previous one was the fact that the original gas cost factor from the previous formula was replaced by a new gas cost factor. This was to be indexed each year against a basket of prices in an attempt to emulate contract price escalation. Nevertheless, this factor, known as the Gas Cost Index (GCI), was also subject to the following reduction:

- a cumulative annual reduction factor of 1%;
- an energy efficiency factor. The aim of this was to pass through any costs incurred in implementing energy saving schemes approved by Ofgas.

Impact of the 1993 MMC inquiry on regulation

The combination of RPI–5; the OFT recommendations; increased loss of market share; regulatory uncertainty; and the reduction of the tariff threshold from 25,000 therms a year to 2,500 therms a year sent BG and Ofgas to the MMC. As a result of the 1993 MMC report several measures were introduced, including:

- separate RPI–X pricing formulae for control of charges for BG's pipeline system (for purposes of clarity and brevity, BG's pipeline system will be referred to as TransCo);
- full internal separation of TransCo and BG Trading;
- the establishment of a common set of contractual obligations for all users of the system between TransCo and shippers.

In June 1994, Ofgas moved the debate forward by publishing a consultation document entitled 'Proposed Price Controls on Gas Transportation and Storage', and in August 1994 the director general of Ofgas decided that price control for transportation charges should take the form described in Figure 1.4.

Figure 1.4: Summary of transportation price control

$$M_t = \left[1 + \frac{RPI_t - X}{100}\right] P_{(t-1)} - K$$

where

M_t	=	the price per therm transported in year t
P_{t-1}	=	the corresponding price in the previous formula year
RPI	=	the movement in the Retail Price Index between these two years (October 1994–March 1997)
X	=	the efficiency factor
K_t	=	the correction factor

Notes

1 The director general for gas supply set the first year's gas prices at 14.6p/therm.

2 X was set at 5.

3 Rates of return on new investment and on book asset values were in line with the MMC recommendation.

Source: Ofgas, August 1994

The 1997 pricing review

Throughout 1995 and 1996 the debate surrounding the regulation of TransCo's charges was taking place in earnest. Ofgas had recommended a tough new pricing regime for both TransCo and British Gas Trading. Finally, in autumn 1996 TransCo decided to initiate another MMC inquiry.

THE NETWORK CODE CONTRACTUAL REGIME

Under the Network Code regime the code is a legal document which governs the terms and conditions between the public gas transporter (PGT), otherwise known as TransCo, and the shippers. The Network Code is a generic term used by the industry to cover a suite of interacting agreements.

The principal document

This is the main document to which all participants in the Network Code have to become signatories. It consists of several hundred pages of closely drafted legal text, and incorporates all of the current gas industry requirements. The 24 sections include, for example, system use and capacity; nominations; operational balancing and flexibility bidding; entry requirements.

The transition document

In implementing the Network Code it was recognised by the industry that there needed to be a transition from the processes surrounding the monthly balancing regime to those associated with a daily balancing regime. Therefore the Network Code transition document outlines those aspects of the Network Code which are seen as interim, to allow for the bedding in of the code. The transition document will initially overrule some of the terms in the code, although as certain key dates or criteria are reached the terms in the principal agreement will take precedence.

Modification rules

Even before the ink was dry on the signatures to the Network Code there were calls for modifications in certain areas. Also, in the light of commercial experience, certain parts of the code have needed to be changed quickly. Consequently a formal change mechanism has been built into the code, which enables all relevant parties (TransCo, shippers, and Ofgas) to make suggested changes and have them reviewed by a panel made up of representatives from the industry.

THE UK-LINK COMPUTER SYSTEM

At the heart of the commercial and contractual principles which make up the Network Code is the UK-Link computer system. UK-Link is a collection of computer systems developed by TransCo to monitor and support the commercial and operational framework of the code. These systems are operated by TransCo but are used by all parties involved in the gas transportation process. While each shipper may have its own system as well, each of these systems is to a large extent dependent on TransCo's system for many of the fundamental processes. This section gives a brief overview of the computer systems that TransCo has put in place to facilitate the operation of the Network Code. Because of the complexity and size of the new

TransCo computer system, the finer details of the system have deliberately been omitted.

UK-Link is the title given to the overall systems project, which includes five individual projects:

- Information Exchange;
- AT-Link;
- the sites and meters database;
- supply point administration;
- Invoicing 95.

This has led to a measure of confusion, with TransCo and the shippers using the term UK-Link to describe any computer system work being undertaken by TransCo.

Information Exchange

While not technically a computer project, Information Exchange (IX), is the means by which TransCo and all shippers communicate with each other.

AT-Link

AT-Link is the name given to the part of the system that supports energy balancing, nominations, allocations, and capacity trading. It is actually based on a US system, and has been further enhanced to work in the UK. AT-Link is made up of seven modules.

Services and capacity booking TransCo defines a shipper service as an agreement between TransCo and a 'business associate' (e.g. a shipper) for the reservation of a particular gas transportation service. This could be the booking of entry capacity 'entry services', or exit capacity 'exit services', or even the use of storage facilities which are currently owned and operated by TransCo. The shipper services available are entry; exit; Rough storage (space only or firm); salt storage (space only or firm), and LNG (unconstrained and constrained).

Capacity trading This is the service provided by TransCo where one shipper is able to buy capacity from another. This module of the AT-Link is designed to facilitate this process. Those shippers with spare capacity are able to post an offer on the system which other shippers are able to see. If a potential buyer sees a posted bid that it wants to accept, then a deal can be struck. Once a deal has been agreed the contractual right to use that capacity will be transferred to the buying shipper, although the original owner of the capacity is still responsible for making the capacity payments to TransCo. The two parties in the capacity trade obviously make their own invoicing arrangements. The development of this secondary market will be crucial to the long-term development of the competitive gas market in Great Britain.

Gas flow nominations This area of the system covers the need for both TransCo and shippers to know how much gas is going to be delivered at the sub-terminals. Therefore, once a shipper has booked capacity in the system it must then inform TransCo how much gas it intends to flow and at what sub-terminal. The system is primarily designed to enable shippers to make their requests for gas flow and for TransCo to approve them. The nomination process also includes nominations away from the national balancing point (NBP) to exit services such as individual supply points or particular exit zones. The nomination process is summarised in Table 1.1.

Table 1.1: D–1 nomination times

Nomination type	Time on previous day
Daily metered sites (DM) output nomination time	1200 hours
Non-daily metered sites (NDM) output nomination time	1400 hours
Storage nomination time	1430 hours
Storage manager nomination time	1500 hours
Input nomination time	1500 hours
Scheduling start time	1500 hours
Nomination finalisation time	1700 hours
Re-nomination start time	1800 hours

Note: D refers to the actual gas day in question and D–1 refers to nominations made on the day before the relevant gas day

The flexibility mechanism The concept behind the flexibility mechanism is that it provides a market based method for TransCo to balance the system. AT-Link does this by allowing shippers to create bids on the system either to buy gas from or to sell gas to TransCo. Consequently when TransCo feels the need to take action it examines the bids on the list and chooses the one which will impose least cost on the system (subject to operational constraints). The four types of bids that AT-Link facilitates are:

- input system buy – TransCo is short of gas and therefore offers to buy more gas at input point;
- input system sell – TransCo is long, and therefore requires the amount of gas flowing into the system to be reduced;
- output system sell – TransCo is long, and therefore needs to accept offers from shippers which will take more gas out of the system, possibly by interruption of gas supplies to some customers;
- output system buy – TransCo is short and therefore requires the amount of gas flowing out from the system to be reduced.

Measurements The purpose of the measurement module is to obtain the relevant metering information on gas flows, which is located outside the AT-Link environment, and provide the data in a compatible form for use by other AT-Link processes. The data serve two main functions:

- daily meter information is provided from sub-terminals, storage injections, storage withdrawals, national offtakes, large supply points, aggregated supply points, onshore fields, to assist the process of energy balancing;
- the meter details provided to AT-Link are used by other AT-Link processes.

Allocation and balancing The allocation process within AT-Link is the process whereby the total outputs across the 13 local distribution zones (LDZs) are allocated to individual shippers. The balancing process within AT-Link looks at the differences between deliveries and demands on the gas supply system and calculates any under- or over-deliveries. The charges incurred by the shippers will depend upon the size and make-up of their individual portfolios.

Invoicing. While the majority of charges incurred by shippers will be invoiced via Invoicing 95 (see below) the balancing, storage, and NTS capacity charges are invoiced via this section of AT-Link.

The sites and meters database

The sites and meters database (SAMD), is a huge database which will contain details of every meter and supply point connected to the TransCo system. The data held in the database are then used by AT-Link elsewhere.

Supply point administration

Supply point administration (SPA) is the part of the system that handles the process of introducing and removing supply points. SPA sits between the shippers and SAMD and manages the movement of supply points according to the relevant rules within the Network Code. The SPA module within UK-Link refers to SAMD to validate requests for supply point introductions from shippers. SPA is meant to be a largely automated system that is driven by the shipper. Initially there was talk of this part of UK-Link being a real-time system with on-line access. However, TransCo finally developed an automatic system which receives and sends batch files.

Invoicing 95

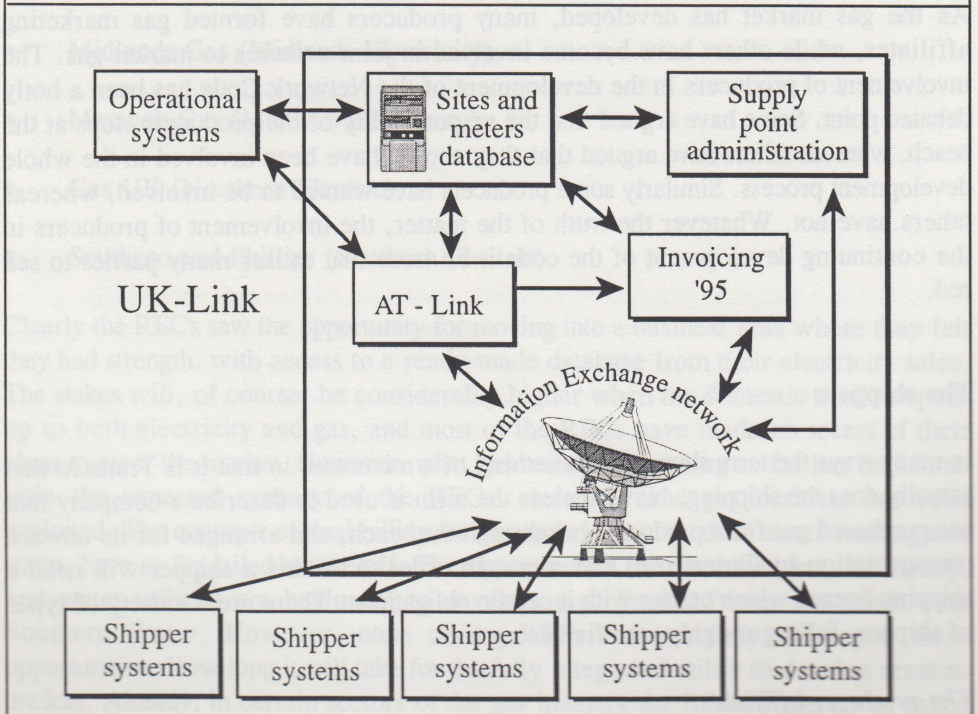
Invoicing 95 produces all invoices generated by TransCo, except the balancing invoices produced by AT-Link. Table 1.2 describes the main invoices produced by TransCo and the system from which they originate.

These systems are all connected together by the IX system to produce the UK-Link computer system shown in Figure 1.5.

Table 1.2: TransCo invoices

Invoice type	System	Comments
NTS capacity	AT-Link	Includes entry, exit and LDZ capacity for daily metered consumers
Balancing	AT-Link	
Storage	AT-Link	
Commodity	Invoicing 95	Includes LDZ commodity, customer commodity, LDZ, ratchet and customer capacity
LDZ capacity	Invoicing 95	Includes LDZ capacity, fixed customer charges, datalogger charges, datalogger rebates, datalogger check recalls, meter reading, and customer capacity
Adjustment invoices	Invoicing 95	For LDZ capacity and commodity
Reconciliation	Invoicing 95	Reconciles TransCo's estimates against actual meter readings
Ad-hoc	Invoicing 95	For unique billing situations
Interest	Invoicing 95	

Figure 1.5: The UK-Link computer system



Source: BG

THE MAIN INDUSTRY PARTICIPANTS

Historically the gas industry in Great Britain was made up of three major parties – the exploration and production companies, British Gas and the customers. With the introduction of competition and the development of the Network Code this has all changed. This section describes the various types of operator in the new gas industry and their roles.

The gas transporter (TransCo)

No list of participants would be complete without the inclusion of TransCo. TransCo is the monopoly provider of gas transportation and storage, and as such is responsible for moving gas from the beach (entry points) to the end users (customers).

The producers

Producers is the generic term given by the industry to the exploration and production companies which actually find the gas offshore, drill the wells, and deliver the gas along undersea pipelines to the beach. Typical producers are Mobil North Sea, BP and Amoco.

As the gas market has developed, many producers have formed gas marketing affiliates, while others have become involved in joint ventures to market gas. The involvement of producers in the development of the Network Code has been a hotly debated point. Some have argued that the responsibility of the producers stops at the beach, whereas others have argued that they should have been involved in the whole development process. Similarly some producers have wanted to be involved, whereas others have not. Whatever the truth of the matter, the involvement of producers in the continuing development of the code is an issue that causes many parties to see red.

The shippers

In many ways the term shipper is something of a misnomer in that it is TransCo that actually does the shipping. Nevertheless the term is used to describe a company that has purchased gas from producers or others at the beach, and arranged for its onward transportation by TransCo to end users. In order to do this a shipper will need a shipping licence which carries with it certain obligations. There are a variety of types of shipper, falling roughly into five categories.

The producer affiliates

The producer affiliates are those shippers that have grown out from producers. Typical examples are Amerada Hess Gas Ltd (Amerada Hess), Mobil Gas Marketing (UK) Ltd (Mobil North Sea), and Total Gas Marketing (Total Oil Marine).

In many ways the producer affiliates are the 'big boys on the block'. They do at least have access to a sympathetic gas seller, even though their upstream partners may drive a hard bargain. The gas marketing companies usually form part of a cohesive long-term gas sales strategy, and consequently although the dips in prices seen in 1996 might encourage belts to be tightened no one has yet left the business. Also the partners of these shippers usually have deep pockets and so can ride out the current difficulties.

The regional electricity companies

The regional electricity companies (RECs), otherwise known as the utilities, were quick to realise the added value of entering the gas sales market, both in the industrial and commercial market, and the domestic market. The term REC, borrowed from the privatisation of the electricity industry, is used to describe all those regional electricity companies that have entered the gas marketing business. Some have entered as fully fledged shippers, such as Eastern Natural Gas which purchased the Johnston field and has gone on to make its mark in the industry, while other RECs have formed joint ventures with other shippers. RECs that are involved in the gas marketing business include:

- Sweb Gas (South Western Electricity);
- Eastern Natural Gas (Eastern Electricity);
- Midlands Gas (Midlands Electricity);
- Manweb Gas (Manweb Electricity);
- Gas UK (Northern Electric);
- Southern and Phillips (Southern Electric).

Clearly the RECs saw the opportunity for moving into a business area where they felt they had strength, with access to a ready-made database from their electricity sales. The stakes will, of course, be considerably higher when the domestic market opens up to both electricity and gas, and most of the RECs have made no secret of their plans to enter the market. However, what has been disappointing so far has been how little the expected synergy of the RECs' electricity and gas business has been exploited. The concepts of dual billing for gas and electricity, dual meter reading and so on, have so far failed to take off. The opportunities for combined gas, electricity, and water utilities are beginning to develop, e.g. ScottishPower has taken over Southern Water. However, none of the RECs has yet fully developed these opportunities. How long it will take for the fully integrated utility to develop remains unclear. Already, in certain sectors of the gas industry the RECs prefer to be called 'the utilities'.

The generators

With the advent of gas-fired electricity generation, and the increase in the number of power stations fired by gas, a large amount of gas transported by TransCo is done on behalf of the electricity generators. Currently the main users of gas for producing electricity are National Power and PowerGen. However, a large number of other power stations are supplied with gas by other shippers. In many ways the generators are in a unique position. While they are some of the largest consumers in terms of the volume moved by TransCo, because their gas offtakes at the power stations are telemetered they have access to more timely and accurate information than most. This access to metering information enables these large shippers to balance more accurately, which in turn means that the Network Code demands tougher tolerances in terms of daily balancing. This has caused the generators to cry 'foul', although despite some tough talking by all parties the generators are still expected to balance their offtakes to tighter tolerances than other smaller daily metered sites (DM).

The independents

The term independents is the name given by the industry to those shippers which have no obvious upstream links with a producer, or downstream link with REC or large power generator. Some are, in fact, independent companies owned by entrepreneurs which entered the gas market when it first opened up and have managed to carve out a niche market for themselves. Some are owned by larger companies that saw an opportunity to make money in the developing competitive gas market. Unfortunately, as the gas market has got tougher and more complex many have either been taken over by larger operators or moved into gas sales only, allowing the larger companies to ship on their behalf. Typical examples of independents are Bell Gas, Volunteer, and Gas Light and Coke.

With the introduction of the code and daily balancing some of the remaining independents will have to be highly competent at what they do to minimise their potential financial exposure to balancing charges.

The suppliers

A supplier is a company which contracts with a shipper to buy gas, effectively at the entrance to the customer's meter. A gas supplier requires a supplier licence, but does not deal directly with TransCo in any way. Typical examples of this type of arrangement would be those companies that signed deals with United Gas during the early development of competition. United Gas purchases gas in bulk, ships it with TransCo, and receives meter readings which it passes on to its clients. Examples of companies operating under this type of arrangement include Eastern Electricity (in its early years), Caledonian Gas and Butler Fuels.

As competition began to develop some suppliers decided that they were large enough to cut out the middle man and ship for themselves. However, with the introduction of the Network Code and the increasing complexity of daily balancing, it seems highly likely that the middle man will regain a role.

The gas traders

With the Network Code and the increasing level of competition has come the development of a gas trading market. Although still in its infancy the day-ahead spot market is beginning to have a recognised price index in the Heren Index, but with the market still increasing in liquidity many treat the index with a measure of caution. Nevertheless there is definitely a developing telephone trading gas market. Some companies are beginning to employ gas traders of their own, often bringing them from North America where gas trading is more developed, or using independent trading houses.

A day-ahead screen-based gas trading system is planned by the International Petroleum Exchange (IPE) for early 1997 which, if all goes well, will help the spot market to develop.

The Claims Validation Agency

The Claims Validation Agency (CVA) is the organisation which is responsible on behalf of the shippers for calculating how much gas is delivered to each shipper, the idea being that the CVA employs independent agents (currently Coopers & Lybrand and the IPE) to track title of gas from the beach to TransCo. The processes employed by the two CVA agents have encountered various difficulties which are continuing to be addressed. Nevertheless there has been an improvement in the speed and accuracy of data provided by the CVA. One of the problems it encountered was the concern felt by some producers over potential liability claims for the provision of incorrect information. This has not been helped by the feeling of some producers that they had been excluded from the debate, although others did not want to get involved. Whatever the rights or wrongs of the situation, the producers are now becoming more involved, although it remains to be seen whether the current solution will the the final one.

CONCLUSION

The development of the British competitive gas market has been nothing if not turbulent. Nevertheless, to move from a fully integrated monopoly in 1990 to a fully competitive gas market by 1998 (the date when full domestic competition is due to take place) will be quite an achievement if all goes well. This will have been achieved by all parties, despite the obvious tensions, working together to reach a more or less common goal. There is no doubt that some things could have been done better, and certainly the unseemly rhetoric flowing in both directions between TransCo and its regulator, Ofgas, has probably hindered the process rather than helped it. Nevertheless what some of our fellow members of the European Union initially dubbed the 'British experiment' and then the 'British disaster' is now being seen as a success and a possible model for Europe.

CHAPTER 2: THE KEY POINTS OF THE NETWORK CODE

INTRODUCTION

This chapter describes the key areas covered by the Network Code. To understand the commercial implications that the introduction of the code will have for the gas industry within Britain, it is necessary briefly to describe the physical configuration of the gas supply system, as well as the commercial structure of the code. The chapter then goes on to discuss in more detail the core areas of the Network Code which include daily balancing, the flexibility mechanism, scheduling penalties and capacity booking.

THE GAS SUPPLY SYSTEM

The pipeline system which is currently owned by BG plc and run by wholly owned subsidiary, TransCo, is referred to here as the gas supply system. TransCo transports gas on behalf of its clients, usually known as shippers, between the terminals and storage facilities via high pressure pipelines to local distribution zones (LDZs). Once gas reaches the LDZs it is then distributed through lower pressure pipelines, known as the local distribution networks, to customers.

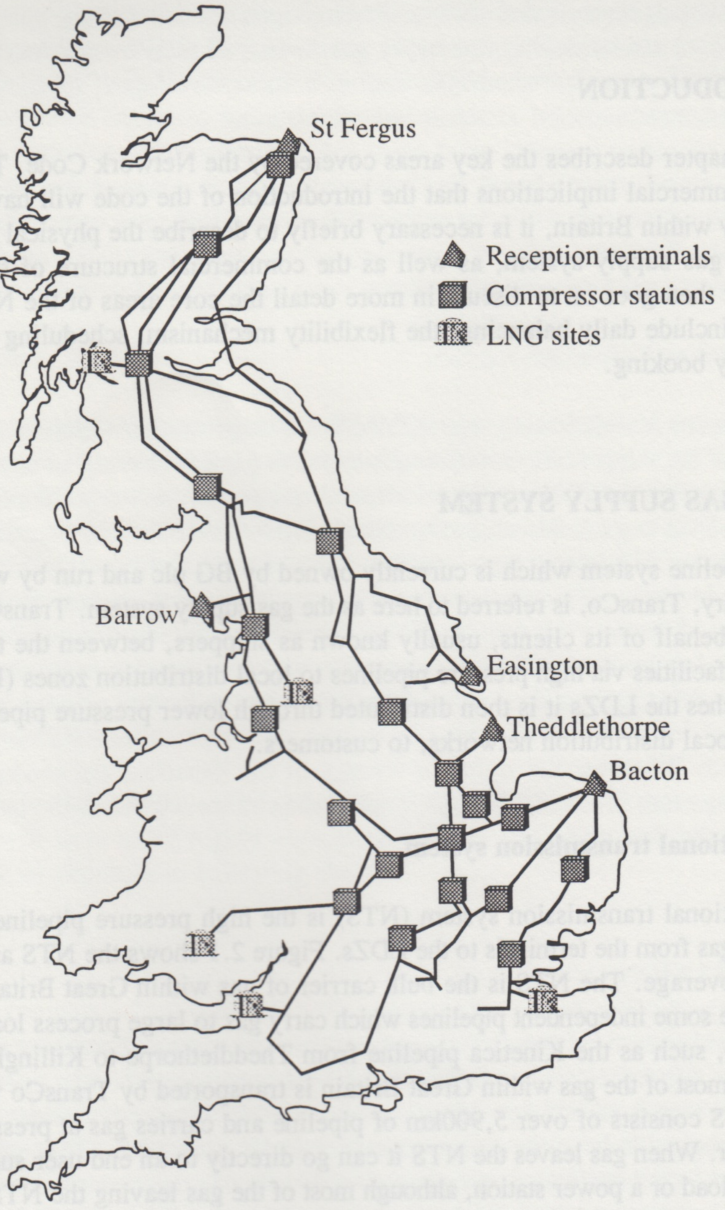
The national transmission system

The national transmission system (NTS) is the high pressure pipeline system that carries gas from the terminals to the LDZs. Figure 2.1 shows the NTS and the extent of its coverage. The NTS is the bulk carrier of gas within Great Britain. Although there are some independent pipelines which carry gas to large process loads or power stations, such as the Kinetica pipeline from Theddlethorpe to Killingholme power station, most of the gas within Great Britain is transported by TransCo via the NTS. The NTS consists of over 5,900km of pipeline and carries gas at pressures as high as 75 bar. When gas leaves the NTS it can go directly to an end user such as a large process load or a power station, although most of the gas leaving the NTS goes to the LDZs for onward distribution into the industrial, commercial, and domestic markets.

Local distribution zones

Local distribution zone (LDZ) is the name given to the group of geographical zones that make up the whole country, and by and large they are analogous with the old British Gas regions. Figure 2.2 shows the geographical make-up of these zones. Each LDZ is a distinct supply area within the overall TransCo gas supply network.

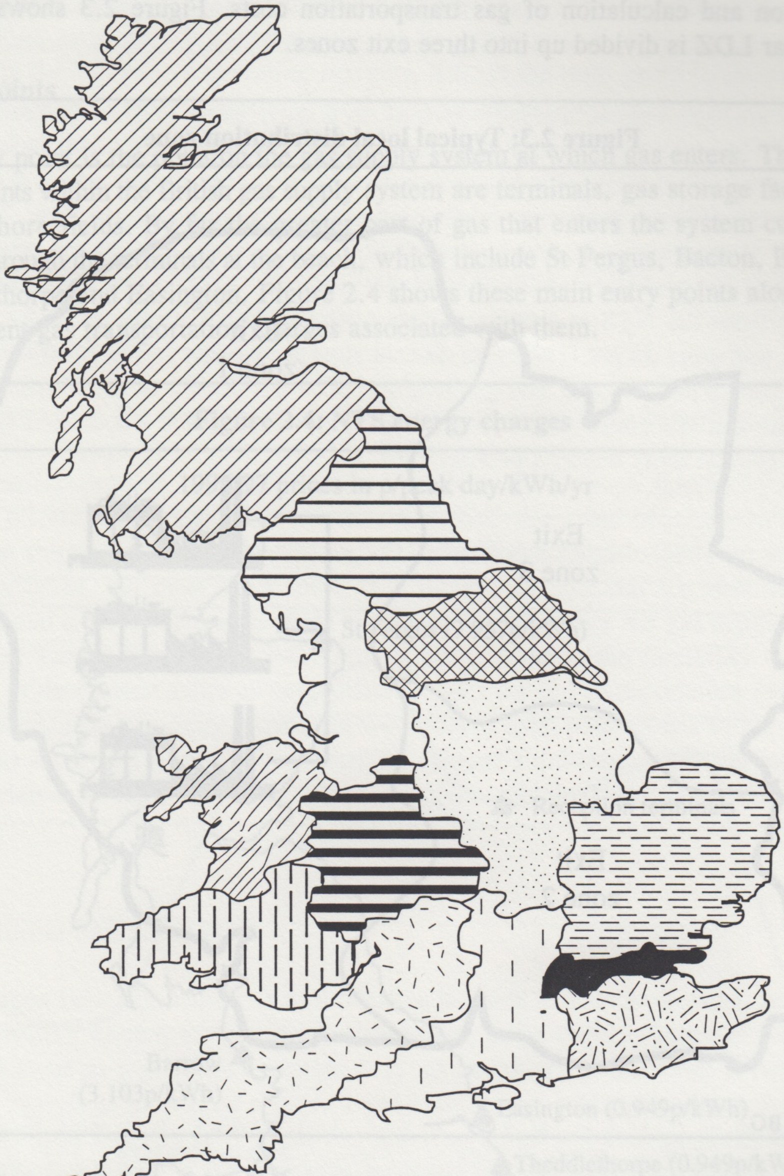
Figure 2.1: National transmission system



Source: BG

TransCo's division of the country into 13 geographical areas called LDZs is partly historical, in that they are largely analogous to the old BG regions, but is primarily for operational and balancing reasons. In order to balance the gas supply system on a given day, TransCo needs to be able to calculate and allocate the quantities of gas transported on behalf of each shipper. To measure the total amount of gas being transported through the gas supply system on any day to shippers and end users has been one of the main difficulties that TransCo has had to contend with, the challenge being how to calculate the actual demand of a particular shipper. This has been further complicated by the opening up of the domestic market since, with over 19m customers ultimately entering the competitive market, the prospect of measuring their

Figure 2.2: Local distribution zones



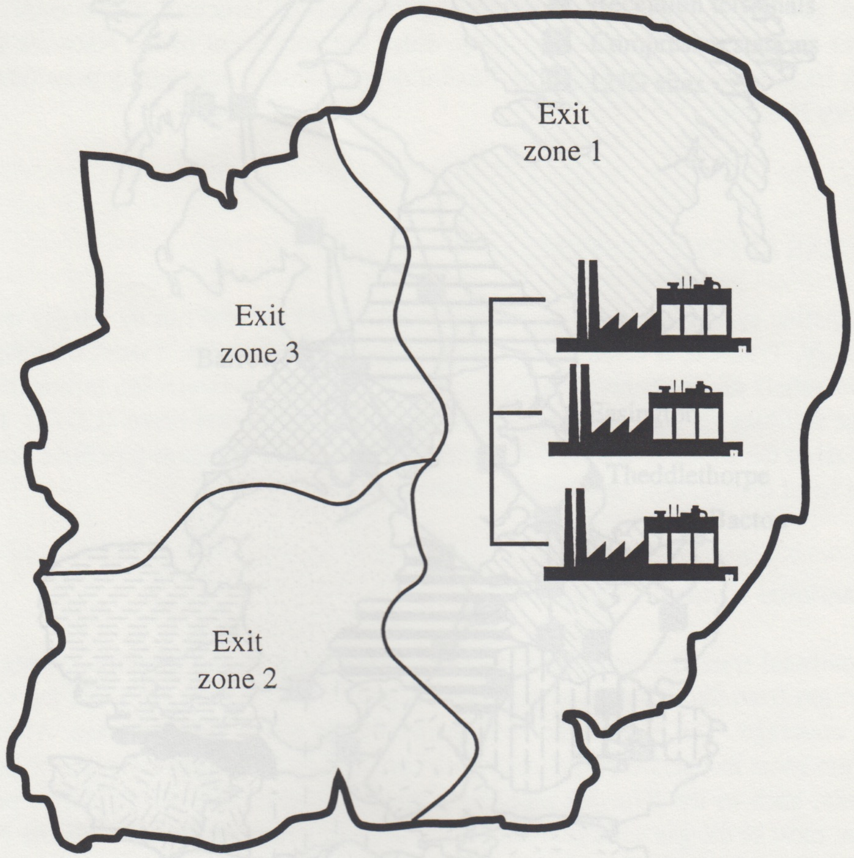
Source: BG

consumption daily even with the measurement technology currently available was operationally and commercially unfeasible. Therefore, by dividing the country into LDZs the task of measuring the quantity of gas consumed in a particular LDZ was made easier and is described in more detail later in the report. TransCo and the shippers agreed that an attempt to datalog 19m end users would be uneconomic and operationally unwieldy. Therefore, with the use of a demand algorithm, the gas consumption for certain categories of end users was estimated on the day, and the gas divided between the shippers in that particular LDZ.

Exit zones

An exit zone is a uniquely defined area within an LDZ, and is primarily used in the allocation and calculation of gas transportation costs. Figure 2.3 shows how a particular LDZ is divided up into three exit zones.

Figure 2.3: Typical local distribution zone



Source: BG

Most LDZs are integrated gas supply networks, with end users being supplied from a variety of regional offtakes on most days of the year to ensure security of supply. Nevertheless, on a day of high demand it has been possible for TransCo to identify the particular offtake(s) that feed specific areas of the LDZs. Exit zones were then created by grouping together the supply points that were supplied from particular offtake(s). The concept of exit zones was first used when entry/exit charging was introduced. One of the main reasons for creating exit zones was to create a reasonably simple yet cost-reflective method of charging for gas transportation. It should be noted that the economic purists within the industry would have preferred every individual regional offtake to be designated as an exit zone and have a charge for transporting to it, in order to obtain true cost-reflectivity. However, sometimes the quest for true cost-reflectivity has to be sacrificed for pragmatic operational viability, which is why the current TransCo charging structure has 33 exit zones.

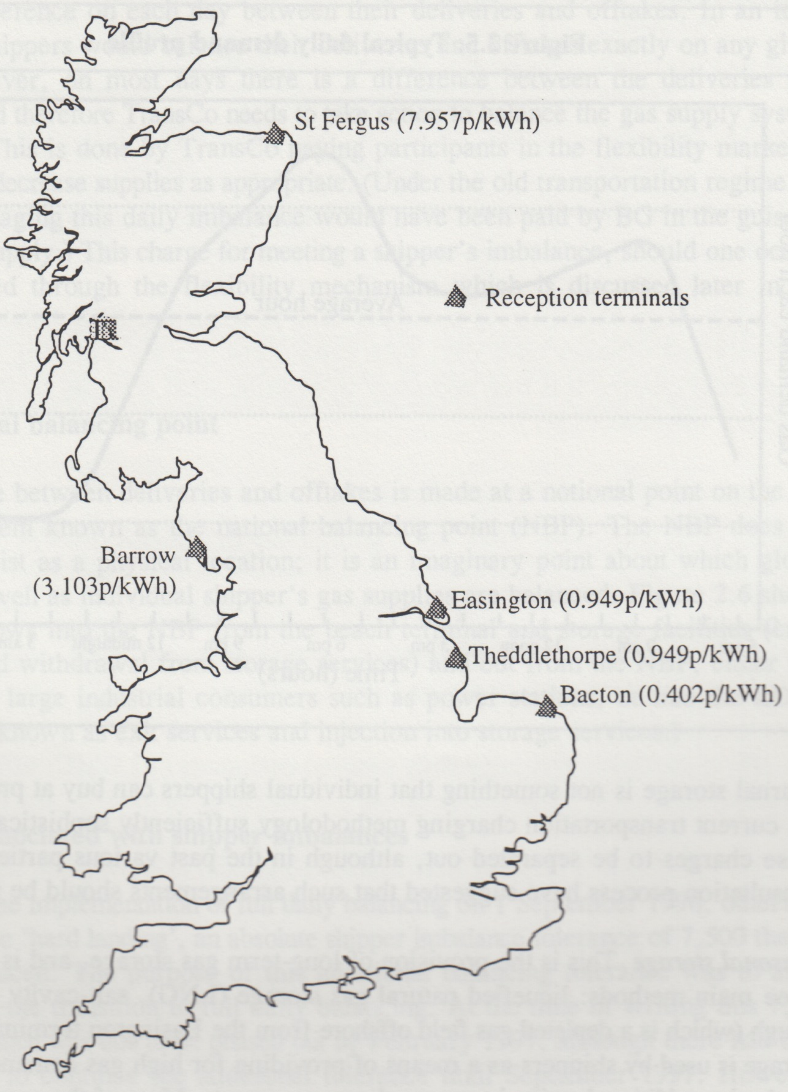
There is no reason why the charging mechanism should not become more complex as the level of understanding increases and the appropriate technology becomes available.

Entry points

An entry point is the point on the gas supply system at which gas enters. The main entry points within the British gas supply system are terminals, gas storage facilities, and onshore fields. By far the greater part of gas that enters the system currently comes through the terminals at the beach, which include St Fergus, Bacton, Barrow, Theddlethorpe and Easington. Figure 2.4 shows these main entry points along with the current gas transportation charges associated with them.

Figure 2.4: NTS energy charges

1996/97 prices in p/peak day/kWh/yr



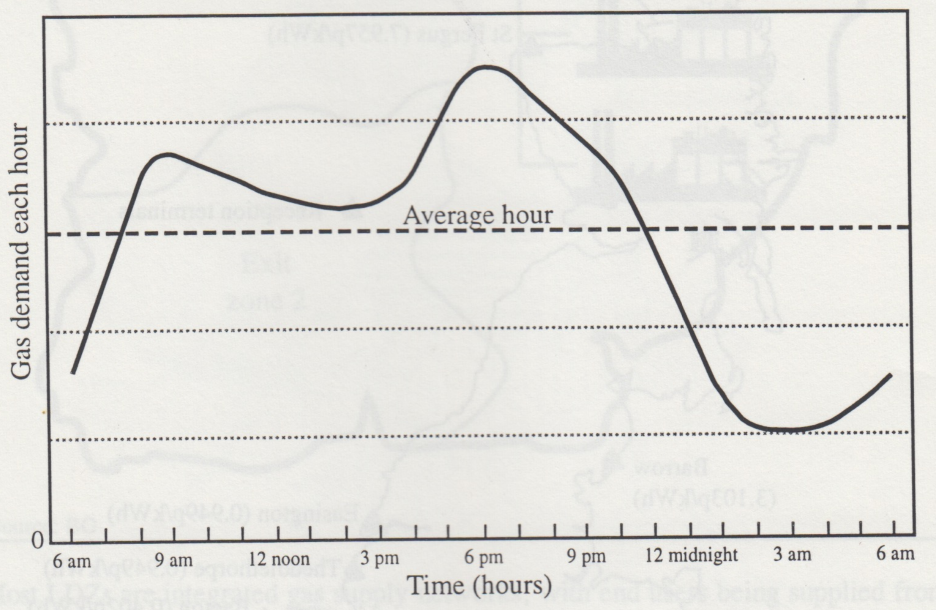
Source: BG

Gas storage facilities

The term gas storage usually covers two particular areas in the context of the British gas industry. These are diurnal storage and seasonal storage. Therefore, for the benefit of clarity it is worth defining what is meant by each of these terms.

Diurnal storage This is storage required on a daily basis to meet fluctuations in demand. The gas supply system has been designed and operated historically on the basis of steady flow rates. This has meant that BG was able to take gas at a constant rate from the offshore producers, minimising rapid fluctuations in gas flow. This had the effect of maximising depletion rates offshore, and minimising capital expenditure in terms of the provision of swing, etc. Similarly the LDZs were also designed to take gas from the NTS at a constant rate over the day. Unfortunately for the gas industry, end users do not. Therefore diurnal storage, usually in the form of pipeline storage known as line pack and gas holders, allows TransCo to use diurnal storage to smooth out the short-term variations between supply and demand. Figure 2.5 shows a typical daily demand profile.

Figure 2.5: Typical daily demand profile



Diurnal storage is not something that individual shippers can buy at present, nor is the current transportation charging methodology sufficiently sophisticated to allow these charges to be separated out, although in the past various parties within the consultation process have suggested that such arrangements should be put in place.

Seasonal storage This is the provision of long-term gas storage, and is provided by three main methods: liquefied natural gas storage (LNG), salt-cavity storage, and Rough (which is a depleted gas field offshore from the Easington terminal). Seasonal storage is used by shippers as a means of providing for high gas demands instead of purchasing additional swing in gas purchase agreements. Most of the seasonal storage facilities are at the extremities of the gas supply system, and are used to maintain security of gas supply on days of high gas demand. This is done by delivering gas into the system at points of high demand and low pressure, such as south London from the Isle of Grain. The alternative would be to provide additional pipeline capacity all year round, which would not be economic. A third use for seasonal storage is for TransCo's operating margins. This is the term given to the provision of gas storage to meet operational problems in the gas supply system. (Storage is discussed in detail in Chapter 6.)

MAIN AREAS OF INTEREST IN THE NETWORK CODE

General description

The backbone of the Network Code is the provision for daily balancing. This is a substantial change from the monthly balancing provisions in the original gas transportation contracts. An energy balance is calculated for each shipper by working out the difference on each day between their deliveries and offtakes. In an ideal world the shippers would balance their deliveries and offtakes exactly on any given day. However, on most days there is a difference between the deliveries and offtakes, and therefore TransCo needs to take action to balance the gas supply system each day. This is done by TransCo paying participants in the flexibility market to increase or decrease supplies as appropriate. (Under the old transportation regime the cost of managing this daily imbalance would have been paid by BG in the guise of public gas supply.) This charge for meeting a shipper's imbalance, should one occur, is calculated through the flexibility mechanism which is discussed later in the chapter.

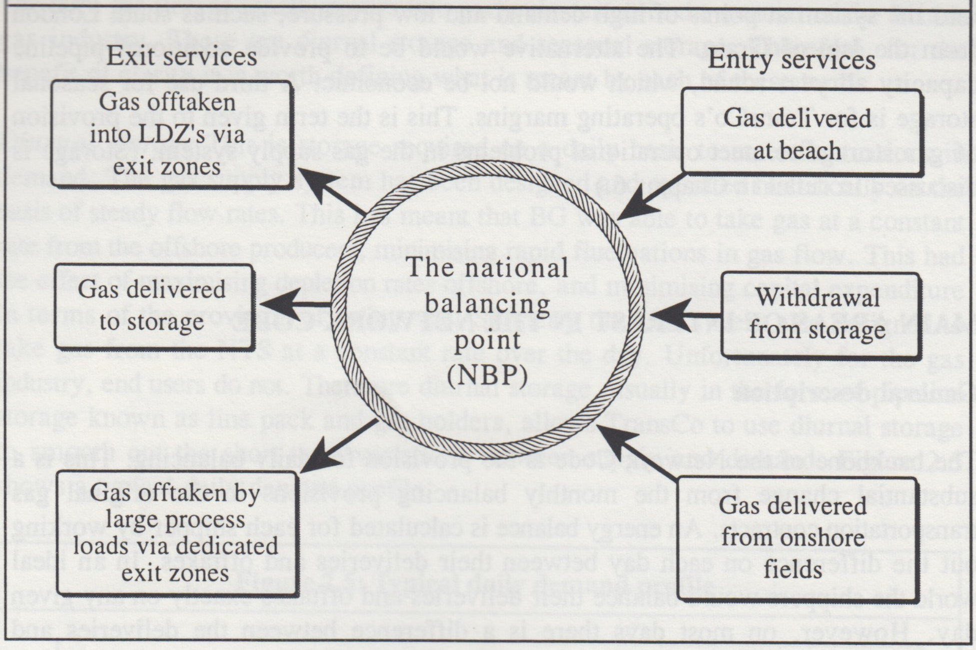
The national balancing point

The balance between deliveries and offtakes is made at a notional point on the gas supply system known as the national balancing point (NBP). The NBP does not actually exist as a physical location; it is an imaginary point about which global supplies as well as individual shipper's gas supplies are balanced. Figure 2.6 shows how gas flows into the NBP from the beach terminal and storage facilities (entry services and withdrawal from storage services) and out from the NBP, either into storage, to large industrial consumers such as power stations, or into the LDZs. (These are known as exit services and injection into storage services.)

Charges associated with shipper imbalances

Following the implementation of full daily balancing on 1 September 1996, otherwise known as the 'hard landing', an absolute shipper imbalance tolerance of 7,500 therms was introduced. The purpose of this additional balancing tolerance was to assist shippers in the transition to full daily balancing. At the time of writing this 7,500 therm tolerance was due to be phased out by February 1997, although there had been a proposal to continue the additional tolerance until September 1997. However,

Figure 2.6: The national balancing point



in order to simplify the explanation of charges associated with shipper imbalances, it has been assumed that full daily balancing has been implemented as stated in the final version of the Network Code and that any transitional arrangements have stopped.

Under full daily balancing, if a shipper fails to achieve a daily balance between deliveries and offtakes on a day, then certain charges are incurred. In order to discuss these charges it is first necessary to describe what is meant by the shipper's imbalance tolerances (SIT).

The shipper imbalance tolerance This is the name given to the tolerance band within which a shipper's imbalance charges are limited to the system average price of gas (SAP). The shipper's imbalance tolerance is calculated by the sum of the following tolerances:

- 3% of the user's daily metered (DM) offtakes on the day (under the transitional arrangements the figure for DM offtakes is 8%);
- 3% of the user's very large daily metered customers (VLDMC) offtakes on the day;
- 3% of the user's offtakes from connected system exit points on the day;
- 2% of the user's deliveries on the day;
- plus the magnitude of the user's non-daily metered (NDM) forecast deviation (if any) for the gas flow day.

Calculation of SAP, SMP (Buy) and SMP (Sell) SAP is defined as the system average price on the day, and SMP as the system marginal price. The Network Code was drafted so that if a shipper was within its particular SIT it would be cashed out at SAP, and for any under- or over-deliveries the shipper would be cashed out at SMP (Buy) and SMP (Sell) respectively, where the values of SMP were the last relevant bids to be accepted. However, prior to the introduction of the hard landing on 1 September 1996, when full daily balancing was introduced, a minor modification was made to the way in which SMP (Buy) and SMP (Sell) were calculated during the first two months of the hard landing and this is described in Table 2.1.

Table 2.1: Method of calculating SAP, SMP (Buy) and SMP (Sell) during the first two months of the hard landing

Bidding activity	SMP (Buy)	SMP (Sell)	SAP
No accepted bids	Rolling 7-day SAP	Rolling 7-day SAP	Rolling 7-day SAP
Only system buys	Top 50% priced volumes	Calculated SAP	Calculated SAP on the day
Only system sells	Calculated SAP	Bottom 50% priced volumes	Calculated SAP on the day
Systems buys and sells	Top 50% priced volumes	Bottom 50% priced volumes	Calculated SAP on the day
Month end cashed out on basis of 30-day SAP			

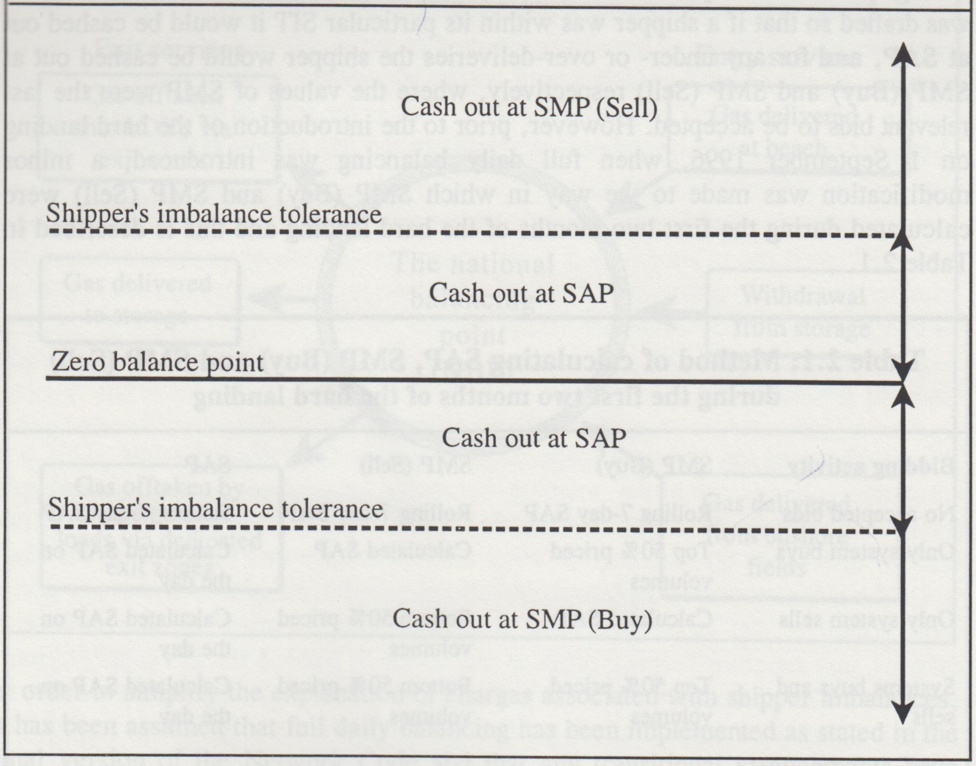
The objective of this change was to smooth out the impact of 'peaky' SMP price changes. Following this two-month settling in period for the hard landing, the calculation of SMP (Buy) and SMP (Sell) reverted to those shown in Table 2.2.

Table 2.2: Present method of calculating SAP, SMP (Buy) and SMP (Sell)

Bidding activity	SMP (Buy)	SMP (Sell)	SAP
No accepted bids	Rolling 7-day SAP	Rolling 7-day SAP	Rolling 7-day SAP
Only system buys	Last accepted bid	Calculated SAP	Calculated SAP
Only system sells	Calculated SAP	Last accepted bid	Calculated SAP on the day
Systems buys and sells	Last accepted bids	Last accepted bids	Calculated SAP on the day

The effects of the shipper's imbalance tolerance and the charges of SAP, SMP (Buy) and SMP (Sell) which are incurred for being within and without the band respectively are shown in Figure 2.7.

Figure 2.7: Shipper balancing charges



Measurement

One of the main challenges facing TransCo was to ascertain the balance between the deliveries and offtakes for each individual shipper. In theory the shipper's deliveries are calculated relatively easily because the gas is metered as it enters the gas transportation system and is allocated to individual shippers at the beach. In practice this proved to be somewhat more complicated, as a result of the complexity of title tracking with the Claims Validation Agency (CVA). Offtakes relating to a particular shipper are also more difficult to calculate since some of the shipper's customers will not be daily metered. In fact, with the increasing introduction of domestic competition the majority of shippers' customers will be non-daily metered sites. Therefore, the quantity of gas transported on a particular day by an individual shipper is calculated using the following processes.

Gas deliveries These are easily obtained from the meter readings and allocation arrangements at the beach, with individual shipper's deliveries being calculated by the CVA.

NTS offtakes These are obtained from daily meter readings either via datalogger readings or on-line telemetry.

Offtakes for daily metered sites (DM) These are also obtained from the daily meter readings via datalogger readings.

The offtakes from non daily metered sites (NDMs) These are obtained using a demand algorithm.

Once the above information is available an imbalance may be calculated for each individual shipper.

During the Network Code discussion period some shippers suggested that the ability of shippers to balance inputs and outputs on the day should be left to the market-place, and that companies should be able to buy or sell spot gas within-day to meet their imbalances. TransCo argued, however, that with the present metering technology such arrangements were not realistic without the introduction of real-time meter reading. Consequently, since TransCo has a responsibility to balance the gas supply system on any given day, a suitable mechanism needed to be found that maintained the security of the gas supply system and charged those companies which had created the imbalance while rewarding those which helped balance the system.

Otherwise if too little gas is delivered and the pressure in the gas transportation system drops, then ultimately supplies may be lost. Similarly, if too much gas is delivered into the gas supply system then pressures may rise and again the security of the system may be endangered. So while it was the shippers' responsibility to balance their deliveries and offtakes on any day it was also recognised that shippers had insufficient information to enable them to achieve a balance within-day. Therefore the code gives TransCo the responsibility and means for balancing the gas supply system globally on any given day. This means that TransCo may require additional gas to be delivered or other suppliers to reduce their deliveries of gas to maintain a balance on the day. TransCo's first defence in order to balance the gas supply system on the day is to inform shippers of any anticipated imbalances as a result of changes in TransCo's forecast of the domestic market. This gives shippers the opportunity to rebalance their own gas portfolios by either increasing or decreasing supplies and demand as appropriate. This process of shippers changing their gas input and output nominations is known as the renomination process.

However, it may be that, even following renomination by a number of shippers, TransCo still observes a global imbalance that cannot be accommodated within the operational flexibility that it has at its disposal. In such a situation TransCo may call upon the flexibility mechanism to provide the additional flexibility it requires to balance the system. If insufficient gas is available within the required timescale, TransCo may use operating margins gas, which is storage gas specifically set aside to meet operational shortfalls of this type. In a realistic commercial world no shipper is going to deliver additional gas for the 'good of the nation'. Consequently TransCo will incur costs on behalf of the shipping community in seeking to balance the gas transportation system on a day. These costs will then be passed on to the shippers which created the imbalance. The process by which TransCo balances offtakes and deliveries globally across the gas supply network is known as the flexibility mechanism.

The flexibility mechanism

The flexibility mechanism is a pseudo market-based method which enables TransCo to balance the gas supply system on any given day. Often referred to as a flexibility market, this is really a mechanism and not a true free market, because TransCo is the main party which contracts with other players in order to ensure a balance on the day. The flexibility mechanism does not allow shippers to contract with each other on a given day in order to maintain a balance. There is a provision within the code which does allow shippers some flexibility in trading within-day, although it is not sufficiently useful to constitute a free market in within-day flexibility.

The system can be either long or short. If the system is long (with too much gas), TransCo needs either shippers or producers which are delivering gas to reduce their deliveries at the beach in order to reduce the gas in the network. Alternatively, another means of reducing quantities of gas at the NBP would be for consumers to take more gas from the NBP. While it may not be usual at present for consumers to take more gas, it is certainly a possibility in the future. Similarly if the NBP is short (with insufficient gas in the system to meet forecast demands), TransCo needs to buy additional gas at the beach by asking shippers or producers to deliver additional gas over and above their already nominated deliveries. Alternatively, TransCo can ask shippers and/or their consumers to cut back their offtakes of gas from the NBP. This can be done by customers being interrupted and receiving a financial benefit for the interruption.

There are four types of flexibility bid that may be made.

Input system sell This occurs when TransCo is long and wishes to sell gas from the NBP to a shipper or producer at the beach. It is a flow of gas in an opposite direction to the normal flow, with gas flowing from the NBP back to the terminal. However, operators may only make input system sell bids if they have a delivery of gas that they are able to reduce at the terminal.

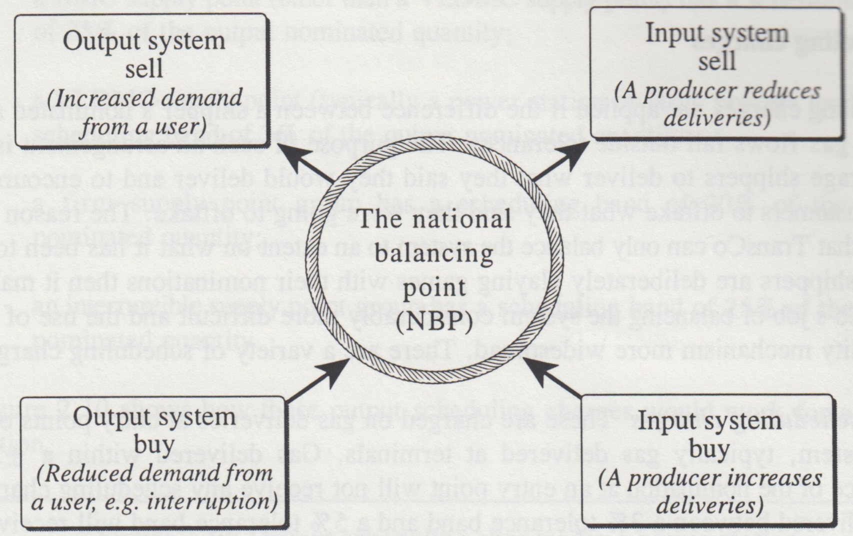
Output system sell This occurs when the NBP is long and a system user offers to offtake more gas from the NBP or to inject additional gas into storage. This could happen when a large user such as a power station was using an alternative fuel such as oil but offered to switch to gas should its bid price be accepted.

Input system buy This occurs when the NBP is short of gas. The shipper or producer will then deliver more gas from the terminal than previously nominated. Similarly an additional withdrawal from storage may occur although this is dependent on the price of gas on the day.

Output system buy This occurs when the system is short and TransCo buys gas at the NBP, effectively from end users or customers. It is an opposite flow back from the customer to the NBP, and would normally occur when a user is interrupted. A typical example of this would be a power station or process user, which was able to switch easily to an alternative fuel providing the price was right.

These various types of bid are shown in Figure 2.8.

Figure 2.8: The flexibility bidding mechanism



Bidding into the flexibility mechanism

While the flexibility mechanism supplies TransCo with a means of balancing the gas supply system on the day, nevertheless the mechanism also provides shippers, producers, and large end users of gas with the opportunity to maximise profits. In order to bid into the flexibility market an operator may enter a bid on to the TransCo computer system up to one month before the day of the bid. These bids will include the following information:

- whether it is a buy or sell;
- the quantity of gas;
- the calorific value of input gas;
- how quickly the bid could be activated;
- the price of the bid in kilowatt hours.

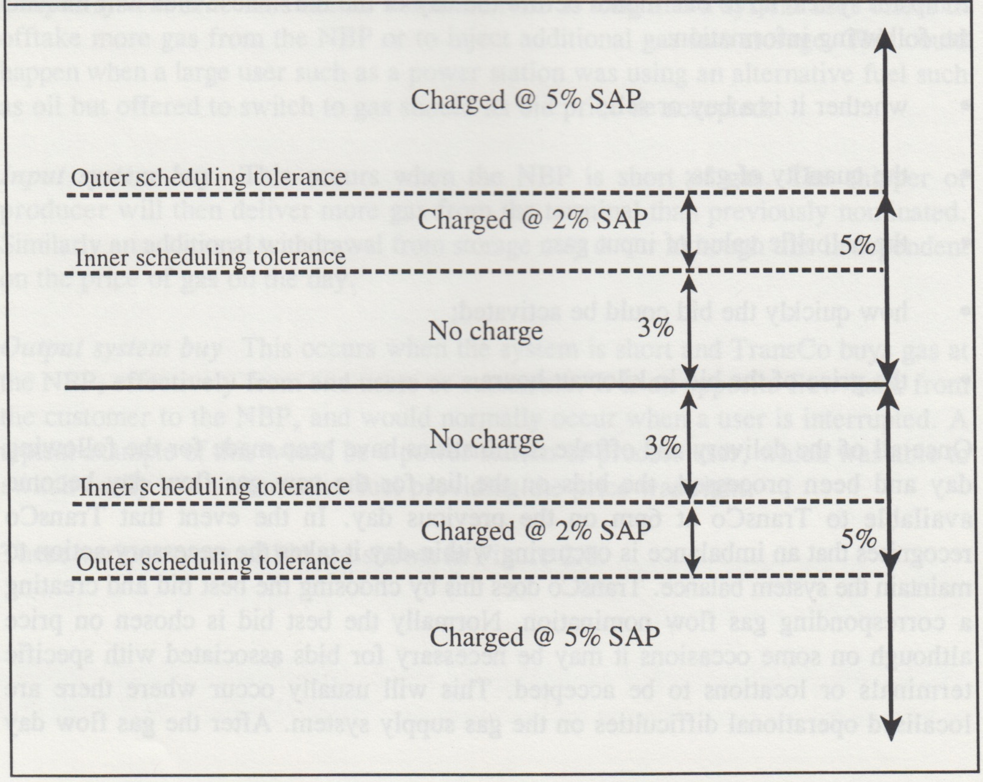
Once all of the delivery and offtake nominations have been made for the following day and been processed, the bids on the list for the new gas flow day become available to TransCo at 6pm on the previous day. In the event that TransCo recognises that an imbalance is occurring within-day it takes the necessary action to maintain the system balance. TransCo does this by choosing the best bid and creating a corresponding gas flow nomination. Normally the best bid is chosen on price although on some occasions it may be necessary for bids associated with specific terminals or locations to be accepted. This will usually occur where there are localised operational difficulties on the gas supply system. After the gas flow day those shippers whose bids had been accepted will receive either an invoice or a credit note as appropriate.

Scheduling charges

Scheduling charges are applied if the difference between a shipper's nominated and actual gas flows fall outside tolerances. The purpose of such an arrangement is to encourage shippers to deliver what they said they would deliver and to encourage their customers to offtake what they said they were going to offtake. The reason for this is that TransCo can only balance the system to an extent on what it has been told, and if shippers are deliberately playing games with their nominations then it makes TransCo's job of balancing the system considerably more difficult and the use of the flexibility mechanism more widespread. There are a variety of scheduling charges.

Input scheduling charges These are charged on gas deliveries at entry points onto the system, typically gas delivered at terminals. Gas delivered within a ±3% tolerance of the nomination at an entry point will not receive any scheduling charge. Gas delivered between a 3% tolerance band and a 5% tolerance band will receive a penalty of 2% of the system average price of gas (SAP), whereas deliveries outside a ±5% tolerance band will receive penalties at 5% of SAP. While the actual scheduling charges are not very high (if SAP were 10p/therm then 2% of SAP would be 0.2p/therm) nevertheless they are high enough to discourage too much arbitrage at the beach in relation to nominations and deliveries. Figure 2.9 shows how scheduling charges on deliveries at the beach or other inputs to the NBP would work.

Figure 2.9: Scheduling charges on input nomination

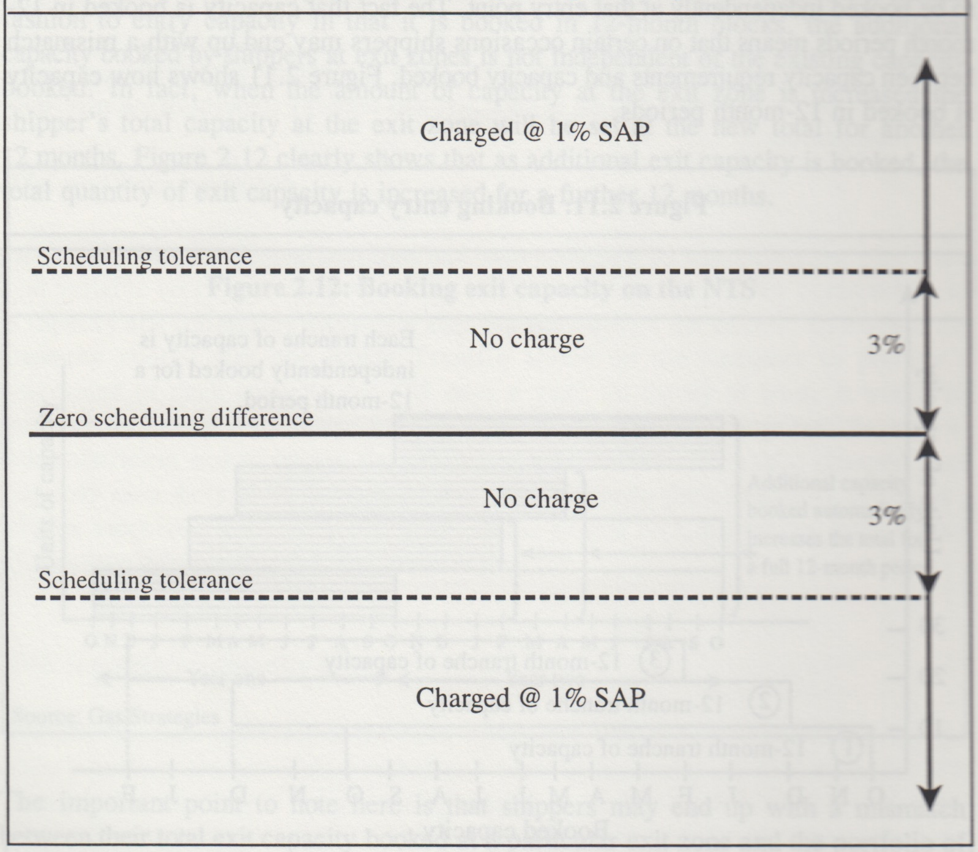


Output scheduling charges These occur at four main groups of sites which fall into the following scheduling bands:

- a DMC supply point (other than a VLDMC supply point) has a scheduling band of 25% of the output nominated quantity;
- a VLDMC supply point (typically a power station or large process load) has a scheduling band of 3% of the output nominated quantity;
- a firm supply point group has a scheduling band of 20% of the output nominated quantity;
- an interruptible supply point group has a scheduling band of 25% of the output nominated quantity.

Figure 2.10 shows how these output scheduling charges would work for a power station.

Figure 2.10: Output scheduling charges for a power station



For all four categories of site the charge is 1% of SAP. Again, while such a charge is not high it is certainly something new for large process users to take account of in their gas purchasing economics. However, some large process gas users are refusing to accept any pass through of these charges from their gas suppliers. While this may minimise costs in the short term it would be better for shippers and consumers alike to improve gas demand forecasting.

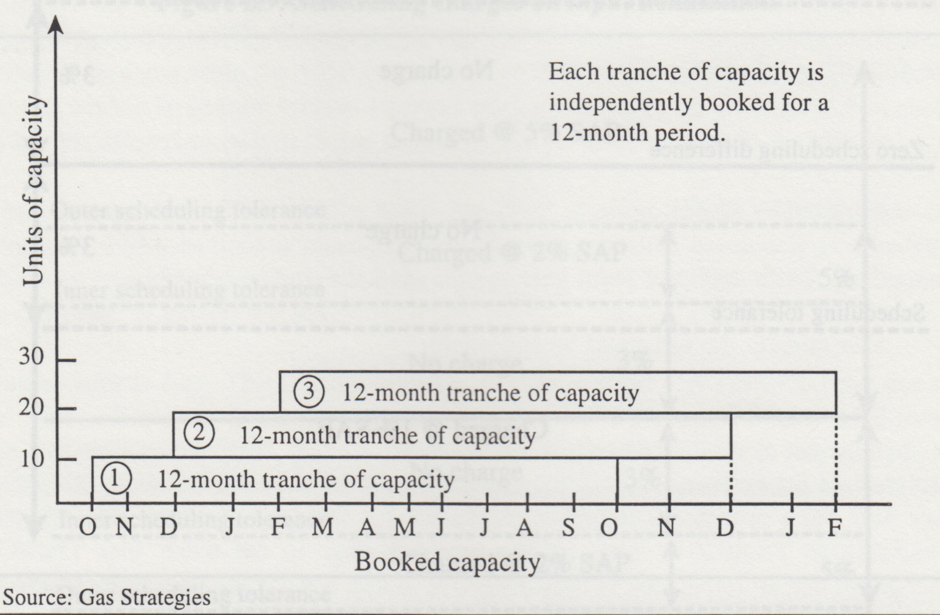
CAPACITY BOOKING ON THE NTS

There are two types of capacity that can be booked in relation to the gas supply system. These are pipeline capacity and storage capacity. Pipeline capacity is covered in this chapter, while storage capacity booking is dealt with in Chapter 6.

Booking entry capacity

In essence entry capacity is the amount of gas which a shipper or producer requires to deliver into the gas supply system at a specific input point. Typically a shipper may wish to deliver 100 units of gas at one of the five terminals, for example, at Bacton. Entry capacity is booked in 12-month blocks and if shippers require additional capacity within the year, then additional 12-month blocks of capacity need to be booked independently at that entry point. The fact that capacity is booked in 12-month periods means that on certain occasions shippers may end up with a mismatch between capacity requirements and capacity booked. Figure 2.11 shows how capacity is booked in 12-month periods.

Figure 2.11: Booking entry capacity



Source: Gas Strategies

The main point to note is that booked capacity cannot be withdrawn and also that when the 12-month period expires that capacity is no longer booked. However, if a shipper books entry capacity at a particular terminal and its gas source fails mid-year for an extended period of time, the shipper has the opportunity to dispose of that capacity at the beach by trading it to another shipper. If a shipper underestimates the requirement for capacity at the beach and over-delivers then the shipper will incur an additional charge known as capacity overrun.

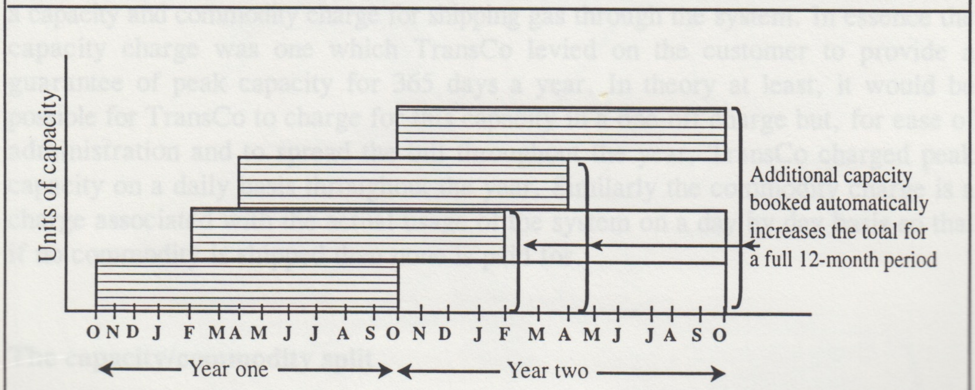
For example, if a shipper books 100 units of gas at a particular terminal and then delivers 120 units, it will be expected to pay for the additional 20 units worth of capacity that it used for the whole 12-month period at a premium rate.

In the light of the above example it is important for shippers when booking capacity to forecast their requirements accurately. The alternative is for the shipper to be involved with distress sales of capacity or distress purchases, which prove uneconomic.

Booking exit capacity

Exit capacity is booked at the exit zone and is the combination of shippers' forecasts of their exit capacity for their daily metered sites (DM) together with the capacity that TransCo has automatically assigned for their non-daily metered (NDM) consumers based on the agreed formula. While exit capacity is booked in a similar fashion to entry capacity in that it is booked in 12-month blocks, the additional capacity booked by shippers at exit zones is not independent of the existing capacity booked. In fact, when the amount of capacity at the exit zone is increased the shipper's total capacity at the exit zone will be set at the new total for another 12 months. Figure 2.12 clearly shows that as additional exit capacity is booked, the total quantity of exit capacity is increased for a further 12 months.

Figure 2.12: Booking exit capacity on the NTS



Source: Gas Strategies

The important point to note here is that shippers may end up with a mismatch between their total exit capacity booked at a particular exit zone and the portfolio of customers receiving gas through that exit zone. It is therefore possible for shippers to end up with additional capacity that is not required if they lose a customer to a competitor, or if a customer goes out of business, etc. Therefore a key feature of a shipper's ability to maintain its profitability will be its ability to monitor its booked exit capacity against actual requirements, with any surplus or shortfall being traded or purchased respectively. Similarly to entry capacity, if a shipper's portfolio of DM customers fed via a particular exit zone exceeds the booked exit capacity then the shipper will incur exit overrun charges, which are currently set at a premium to the normal rate.

Booking capacity in the LDZ

LDZ capacity is the capacity associated with specific end users and is booked on the basis of the end user's supply offtaken quantity (SOQ). (SOQ refers to the maximum capacity booked for an individual site, and means supply point offtake capacity.) Where a shipper has a daily metered site (DM) then the shipper is responsible for nominating the SOQ for that particular site, whereas for NDM customers the demand algorithm sets the theoretical SOQ for a particular site and a quantity of capacity is booked appropriately. TransCo effectively takes responsibility for the booking of LDZ capacity and exit zone capacity for NDM supply points, whereas a shipper is responsible for booking LDZ capacity and exit zone capacity through its estimate of the end user's SOQ. Therefore TransCo will only penalise shippers for the underbooking of DM SOQs. Again, as with entry and exit overruns, the premium is double the normal rate.

It does seem highly likely, with the introduction of demand algorithms and more stringent penalties for underbooking of capacity, that capacity underbooking may well have disappeared.

CHAPTER 3: GAS TRANSPORTATION CHARGING

INTRODUCTION

This chapter gives a general overview of the charging methodology for transportation, with particular reference to the current entry/exit charging system together with the long run marginal cost (LRMC) charging methodology and the LDZ charging function. A brief overview of the TransCo three-node model proposal is also given. However, before discussing these areas it is worth examining how gas transportation was originally charged for when gas-to-gas competition first started in Great Britain in 1989, and why there has been a move towards an entry/exit methodology based on LRMCs.

BACKGROUND

The first charging methodology used by TransCo (then British Gas, Gas Transportation Services) for gas transportation was put in place in 1989. These charges were related to a simple accounting cost base on a distance related basis.

The cost base approach

In simple terms the original cost base had been produced by examining the way fixed and variable costs were allocated. This analysis then resulted in the construction of a capacity and commodity charge for shipping gas through the system. In essence the capacity charge was one which TransCo levied on the customer to provide a guarantee of peak capacity for 365 days a year. In theory at least, it would be possible for TransCo to charge for this capacity in a one-off charge but, for ease of administration and to spread the bill throughout the year, TransCo charged peak capacity on a daily basis throughout the year. Similarly the commodity charge is a charge associated with the actual usage of the system on a day by day basis so that if no commodity is shipped then none is paid for.

The capacity/commodity split

Despite the fact that most of the costs associated with moving gas through the gas supply system are associated with fixed costs in the order of 90% fixed to 10% variable, when charges for gas transportation were first established it was decided that the split between capacity and commodity should be 50:50. The philosophy behind this was that TransCo was in the business of facilitating gas-to-gas competition and it was not appropriate for TransCo to pass on all customer risk to the new shippers, therefore a 50:50 split was agreed.

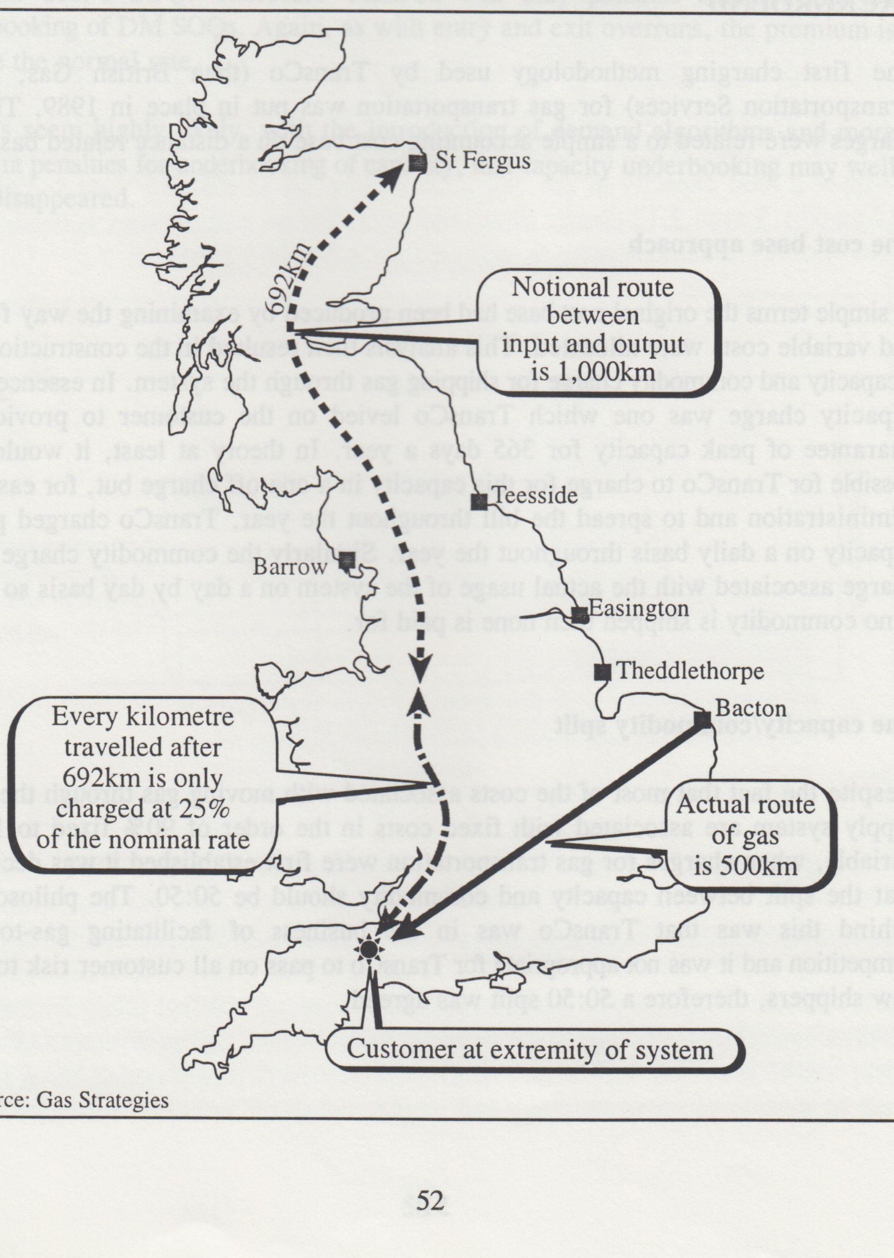
Site charges

Charges associated with the provision of metering and other site services local to the customer were covered under the term site charges. (Under the current charging methodology these charges broadly come under the customer charges category.)

Distance capping

Before the introduction of distance capping a supply point would be charged the full distance from the entry point (a beach terminal) to the supply point. In some cases this could be 1,000km or more. Clearly, because of the integrated nature of the NTS, the gas did not actually travel the full distance, but would be fed from another terminal which effectively meant that TransCo would be over-recovering its true costs. After a lively debate between TransCo, the main shippers and the regulator it

Figure 3.1: Distance capping



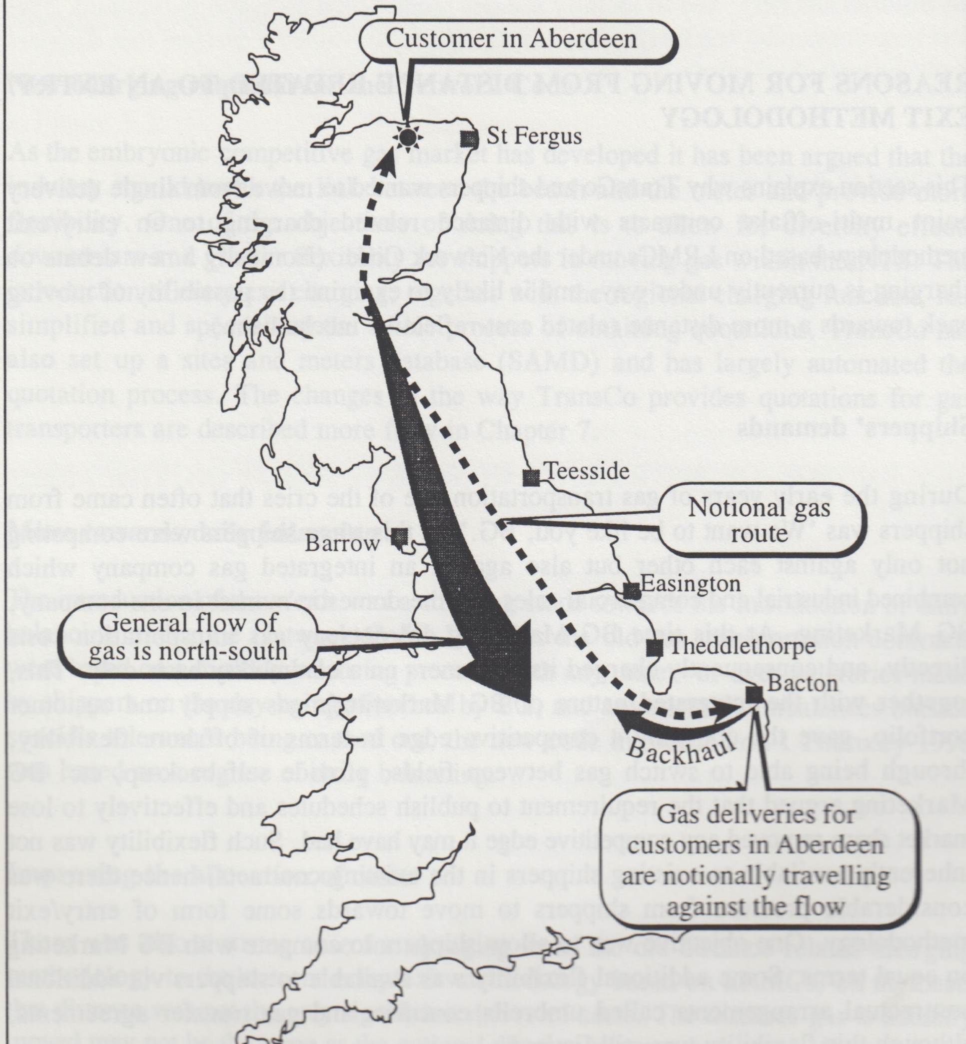
Source: Gas Strategies

was proposed that after gas had travelled an average distance through the NTS the shipper would be given a discount. Because of the dynamic nature of the NTS this average distance varied from day to day, as a result of fluctuating demands and seasonal effects, so a composite average distance was agreed, of 692km. Therefore for every kilometre in excess of 692km the charge would be 25% of the normal charge. Clearly this reduced prices to sites at the extremities of the system. The impact of reduced charges was felt particularly by those shippers with gas at St Fergus, as Figure 3.1 shows.

Backhaul

Another area where gas transportation prices were reduced was where shippers were transporting gas against the normal flow. For example, gas may be delivered at Bacton but actually be offtaken at Aberdeen, as shown in Figure 3.2.

Figure 3.2: Backhaul



Source: Gas Strategies

Such an arrangement would be known as backhaul, which is a pipeline term borrowed from North America, where a pipeline company would give discounts for deliveries against the flow. It was argued that where shippers were in fact helping to reduce reinforcement and other system costs by delivering gas against the flow a reduction in charging should result. Following another lively debate between TransCo, the shippers, and Ofgas a discount was agreed. Therefore, in order to take account of these backhaul effects, the distance travelled by the gas when delivered against the flow was divided by two.

Cost recovery through a rate of return

Initially a rate of return of 4.5% on net assets was chosen by Ofgas to establish the level of gas transportation charges. The reason why an apparently low rate of return was chosen was that transportation was seen as a low risk business (being a natural monopoly), and also TransCo had a remit to facilitate the introduction of the new competitive market. Therefore, a low rate of return in the early stages of opening up the market was deemed appropriate by the regulator, Ofgas.

REASONS FOR MOVING FROM DISTANCE RELATED TO AN ENTRY/ EXIT METHODOLOGY

This section explains why TransCo and shippers wanted to move from single delivery point multi-offtake contracts with distance related charging to an entry/exit methodology based on LRMCs under the Network Code. (Ironically a new debate on charging is currently under way, and is likely to examine the possibility of moving back towards a more distance related cost-reflective mechanism.)

Shippers' demands

During the early years of gas transportation one of the cries that often came from shippers was 'We want to be like you, BG.' At this stage shippers were competing not only against each other but also against an integrated gas company which combined industrial and commercial sales and the domestic market in one company, BG Marketing. At this time BG Marketing did not pay gas transportation costs directly, and consequently charged its customers on a commodity basis only. This, together with the integrated nature of BG Marketing's gas supply and customer portfolio, gave the company a competitive edge in terms of offshore flexibility, through being able to switch gas between fields, provide self back-up, etc. BG Marketing argued that the requirement to publish schedules and effectively to lose market share removed any competitive edge it may have had. Such flexibility was not inherently available to existing shippers in the existing contracts, hence there was considerable pressure from shippers to move towards some form of entry/exit methodology. One objective was to allow shippers to compete with BG Marketing on equal terms. Some additional flexibility was available to shippers via additional contractual arrangements called umbrella contracts and gas transfer agreements, although this flexibility was still limited.

Increase in the size of the market-place

When the competitive market was first opened up the number of supply points that could be supplied via third party gas suppliers was 30,000 sites. This was the total number of sites with annual demands greater than 732,000kWh (25,000 therms). However, during the summer of 1992 the government, through the Competition and Utilities Act, reduced the tariff threshold from 732,000kWh a year to 73,200kWh a year. This had the effect of increasing the size of the competitive market to approximately 300,000 sites.

Clearly, the existing distance related methodology, with the complexities of finding the correct offtake tier for individual sites, was not designed to cope with such large numbers of sites and, as history has shown, both TransCo and shipper systems struggled to cope with the increased number of sites. During the last quarter of 1992 the number of supply points supplied by third party shippers increased 10-fold from 5,000 to 50,000. Clearly the old single delivery multi-offtake contracts could not cope with the opening up of the domestic market. The logistics of attempting to provide quotes for 19m domestic customers caused shippers, TransCo and Ofgas to apply themselves to finding a sensible solution.

New charging required for the Network Code

As the embryonic competitive gas market has developed it has been argued that the industry should break the link between the beach and the meter and provide more flexibility. One of the objectives of doing this is to allow for diversity effects downstream and greater flexibility for shippers in moving gas within the NTS. The introduction of entry/exit charging, together with the regional charging function, has simplified and speeded up the whole process of obtaining quotations. TransCo has also set up a sites and meters database (SAMD) and has largely automated the quotation process. The changes in the way TransCo provides quotations for gas transporters are described more fully in Chapter 7.

Move towards daily balancing

The introduction of entry/exit was a stepping stone towards the introduction of daily balancing under the Network Code. Whereas the old gas transportation contracts were based on a monthly balancing process, with any under- or over-deliveries made by shippers on the day being absorbed by BG, and any monthly imbalances outside specific tolerances being cashed out, the new code introduced on 1 February 1996 was based on a regime of daily balancing.

Improving the allocation of costs

There was also a strong case for changing from the old distance related charging methodology to the current entry/exit methodology based on LRMCs, on the basis that distance was not the only significant driver of costs. The distance gas is actually moved may not be the same as the notional distance between input and offtake points.

This point is underlined by the fact that TransCo modified its charging to include the concept of distance capping and backhaul. More appropriate cost drivers would include location of input and offtake points, peak flows, load factors and delivery pressure.

Economic efficiency

The use of average accounting costs does not give the 'right' economic signals. In theory, an economically efficient allocation of resources will be achieved when the price of a good or service is set equal to the cost of producing the marginal unit of output. TransCo decided against using short run marginal costs, because of their inherent instability, and went for long run marginal costs to try to smooth out some of the lumpiness.

Simplicity

The old system required TransCo to identify and measure a notional route through the transmission tiers, and to identify the tier from which each site is supplied. This was time-consuming and inefficient. Ideally TransCo wanted a method that shippers could operate themselves, and hence entry/exit was born.

Removal of anomalies

Quite often it was a matter of historical accident whether a site was connected to the medium pressure or the low pressure distribution system, and under the old charging system two otherwise identical sites could face significantly different transport charges, hence the move to a charging structure based on load size.

DESCRIPTION OF ENTRY/EXIT CHARGING BASED ON THE LRMC MODEL

Before describing the entry/exit charging methodology, it is worth outlining briefly how the long run marginal cost model works, since it is upon that model that the entry/exit charges are based. The objective of the LRMC model, which has been used by TransCo for the calculation of NTS charges since 1 October 1994, is to derive prices based on forward looking data, and to give economically efficient signals to all users of the system. LRMCs were calculated by evaluating the additional reinforcement costs required at 'pinch points' in the system to meet a chosen increment of flow, typically 100m cu ft/d (2.834m cu metres/d) between all entry points and all system offtake points.

The use of a base plan

Before assessing the cost of increasing system flows, the analysis begins with the TransCo base plan, which outlines TransCo's forecasts of future demand over a 10-

year period. Each year base plan assumptions made by TransCo were grounded in data from a variety of sources including commercial data sources, industry journals, and returns from TransCo's base plan supply/demand questionnaire. The base plan not only sets out the expected supply/demand for the next 10-year period, but also gives an indication of the expected level of investment which is required to meet those forecasts.

The method of calculation

The theoretical calculation of LRMCs requires the calculation of the costs of meeting an increment of capacity from the base year to infinity. In TransCo's case the chosen increment was 100m cu ft/d. The annual equivalent cost was then derived by dividing the LRMC annuity value by 10 years. TransCo has argued that to divide by a larger number of years would not be practical as it was impossible to set up supply/demand assumptions for a period greater than 10 years. This process is then carried out for similar increments at all entry and exit points, and a full table of annualised reinforcement costs for all 10 years is produced. The table is then known as the full matrix and would normally contain reinforcement costs resulting from the combination of all entry and offtake points.

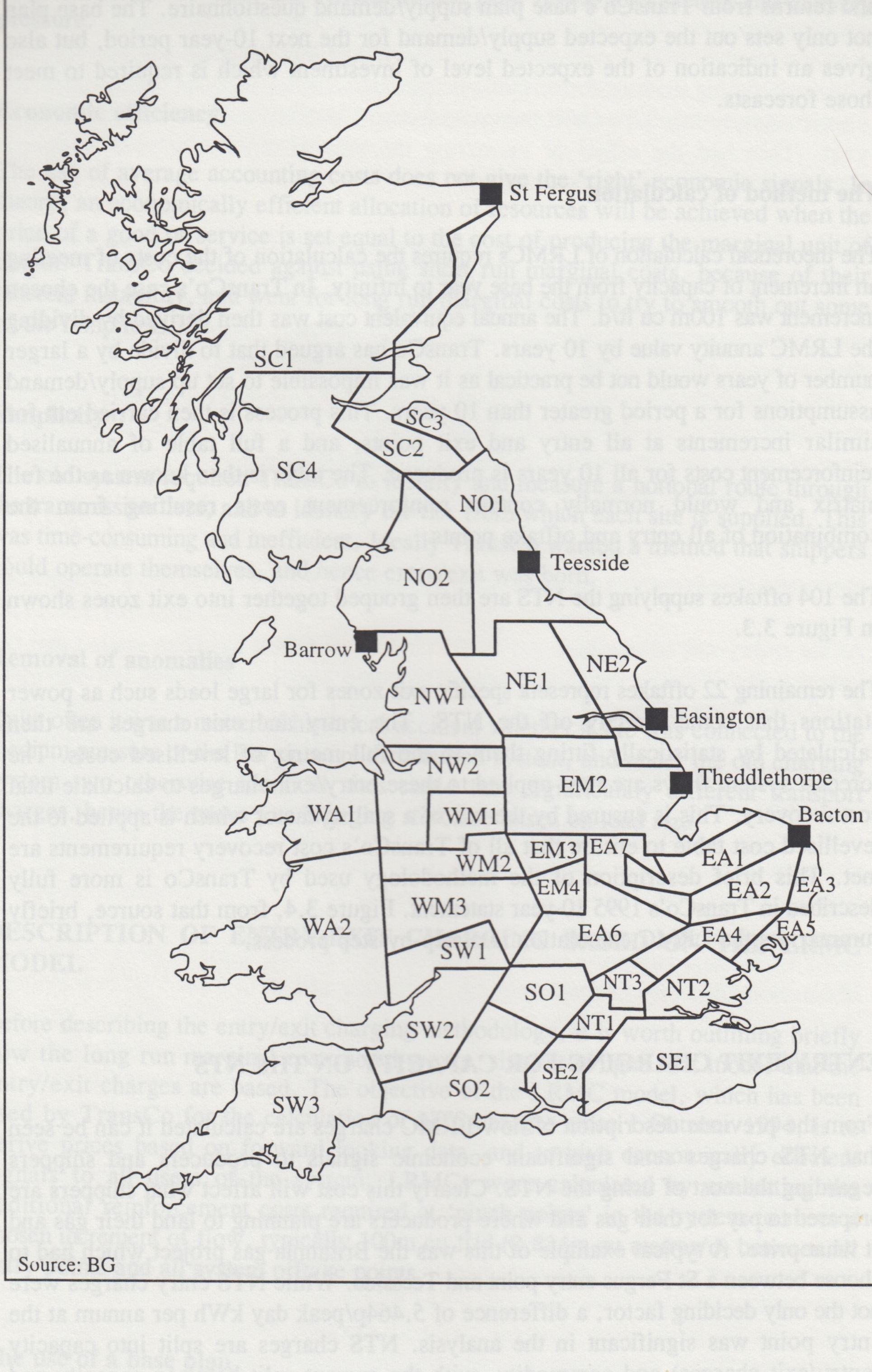
The 104 offtakes supplying the NTS are then grouped together into exit zones shown in Figure 3.3.

The remaining 22 offtakes represent specific exit zones for large loads such as power stations that come directly off the NTS. The entry and exit charges are then calculated by statistically fitting them to the full matrix of levellised costs. The forecast system flows are next applied to these entry/exit charges to calculate total cost recovery. This is ensured by the use of a scaling factor which is applied to the levellised cost table to ensure that all of TransCo's cost recovery requirements are met. This brief description of the methodology used by TransCo is more fully described in TransCo's 1995 10-year statement. Figure 3.4, from that source, briefly summarises the LRMC calculation in a step-by-step process.

ENTRY/EXIT CHARGING FOR CAPACITY ON THE NTS

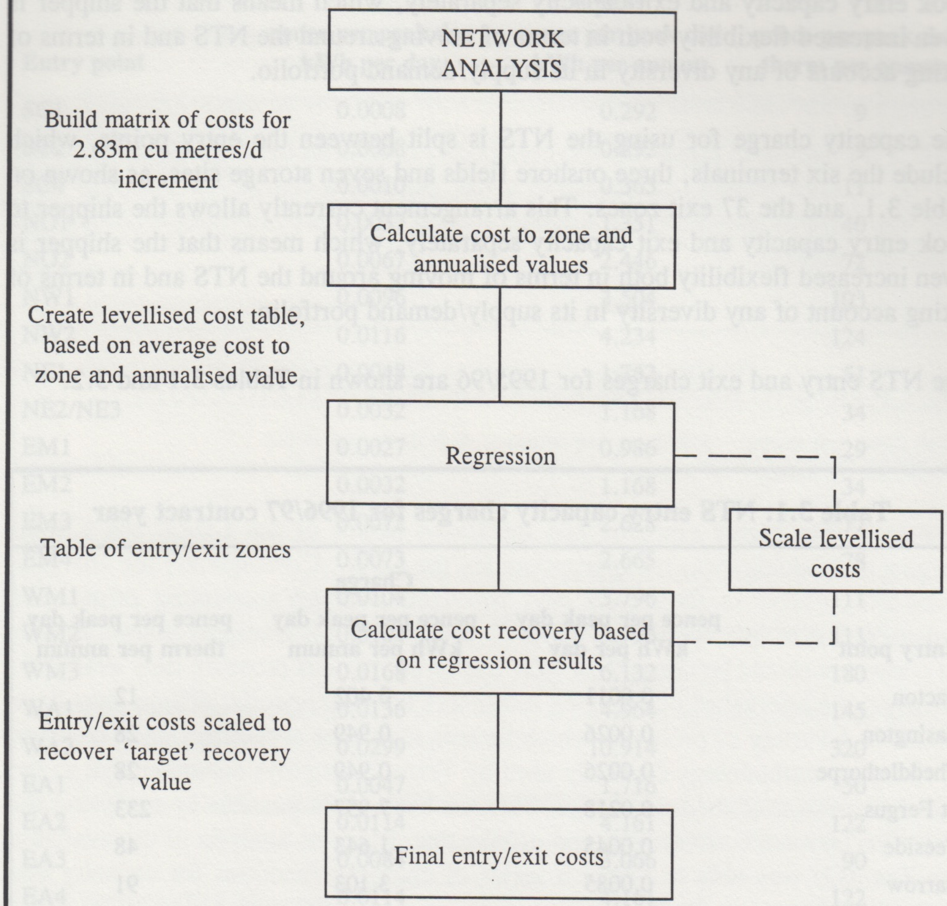
From the previous description of how LRMC charges are calculated it can be seen that NTS charges send significant economic signals to producers and shippers regarding the cost of using the NTS. Clearly this cost will affect what shippers are prepared to pay for their gas and where producers are planning to land their gas and at what price. A typical example of this was the Britannia gas project which had to choose between a St Fergus entry point and Teesside. While NTS entry charges were not the only deciding factor, a difference of 5.464p/peak day kWh per annum at the entry point was significant in the analysis. NTS charges are split into capacity (entry/exit charges) and commodity, with the current split between capacity and commodity being 50:50.

Figure 3.3: The exit zones



Source: BG

Figure 3.4: The LRMC calculation in a step-by-step process



The figure represents a flow diagram of the steps involved in the LRMC model, the data requirements at each stage, and the output produced at each stage. The process is:

- The reinforcement costs required to sustain a 2.834m cu metres/d (100m cu ft/d) increase in demand sustained over 10 years are calculated using TransCo's network analysis program, Falcon. This model simulates gas flows in the system for each combination of six input points and 126 offtakes. This exercise is carried out on a network based on TransCo's base case supply and demand projections for three individual years – 1996/97, 1998/89, 2003/04.

- Offtakes are amalgamated into 37 exit zones and the annualised present value of average reinforcement costs calculated for each input point/exit zone combination. There are also 22 large industrial loads on the NTS which are treated as specific exit zones. Estimated LRMCs are then presented as levellised costs for the full matrix of input points to exit zones.

- Regression methods are used to derive separate entry and exit charges from the full matrix of levellised costs.

- Forecast system flows are applied to the entry/exit charges to calculate total cost recovery. A scaling factor is then applied to the levellised cost table to ensure cost recovery requirements are met.

The capacity charge for using the NTS is split between the entry points, which include the six terminals, three onshore fields and seven storage sites, as shown on Table 3.1, and the 37 exit zones. This arrangement currently allows the shipper to book entry capacity and exit capacity separately, which means that the shipper is given increased flexibility both in terms of moving around the NTS and in terms of taking account of any diversity in its supply/demand portfolio.

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The NTS entry and exit charges for 1995/96 are shown in Tables 3.1 and 3.2.

Table 3.1: NTS entry capacity charges for 1996/97 contract year

	Charge		
Entry point	**pence per peak day kWh per day**	**pence per peak day kWh per annum**	**pence per peak day therm per annum**
Bacton	0.0011	0.402	12
Easington	0.0026	0.949	28
Theddlethorpe	0.0026	0.949	28
St Fergus	0.0218	7.957	233
Teeside	0.0045	1.643	48
Barrow	0.0085	3.103	91
Onshore fields			
Hatfield Moors	0.0026	0.949	28
Caythorpe	0.0024	0.876	26
Wytch Farm	0.0000	0.000	0
Burton Point	0.0074	2.701	79
Storage sites			
Rough (entry at Easington)	0.0026	0.949	28
Hornsea	0.0026	0.949	28
Glenmavis	0.0128	4.672	137
Partington	0.0065	2.373	70
Dynevor Arms	–0.0009	–0.329	–10
Isle of Grain	–0.0006	–0.219	–6
Avonmouth	-0.0011	-0.402	-12

Source: BG

Table 3.2: NTS exit charges for 1996/97 contract year			
	Charge		
Entry point	pence per peak day kWh per day	pence per peak day kWh per annum	pence per peak day therm per annum
SC1	0.0008	0.292	9
SC2	0.0008	0.292	9
SC4	0.0010	0.365	11
NO1	0.0037	1.351	40
NO2	0.0067	2.446	72
NW1	0.0096	3.504	103
NW2	0.0116	4.234	124
NE1	0.0048	1.752	51
NE2/NE3	0.0032	1.168	34
EM1	0.0027	0.986	29
EM2	0.0032	1.168	34
EM3	0.0072	2.628	77
EM4	0.0073	2.665	78
WM1	0.0104	3.796	111
WM2	0.0104	3.796	111
WM3	0.0168	6.132	180
WA1	0.0136	4.964	145
WA2	0.0299	10.914	320
EA1	0.0047	1.716	50
EA2	0.0114	4.161	122
EA3	0.0084	3.066	90
EA4	0.0114	4.161	122
NT1	0.0150	5.475	160
NT2	0.0186	6.789	199
NT3	0.0126	4.599	135
SE1	0.0211	7.702	226
SE2	0.0150	5.475	160
SO1	0.0144	5.256	154
SO2	0.0199	7.264	213
SW1	0.0182	6.643	195
SW2	0.0231	8.432	247
SW3	0.0283	10.330	303

Source: BG

NTS commodity charges

The NTS commodity charge is much simpler; it is a flat charge which is applied to all gas throughput on the NTS, as shown in Table 3.3.

Table 3.3: NTS commodity charge for 1996/97	
p/kWh	p/therm
0.0333	0.976

Source: BG

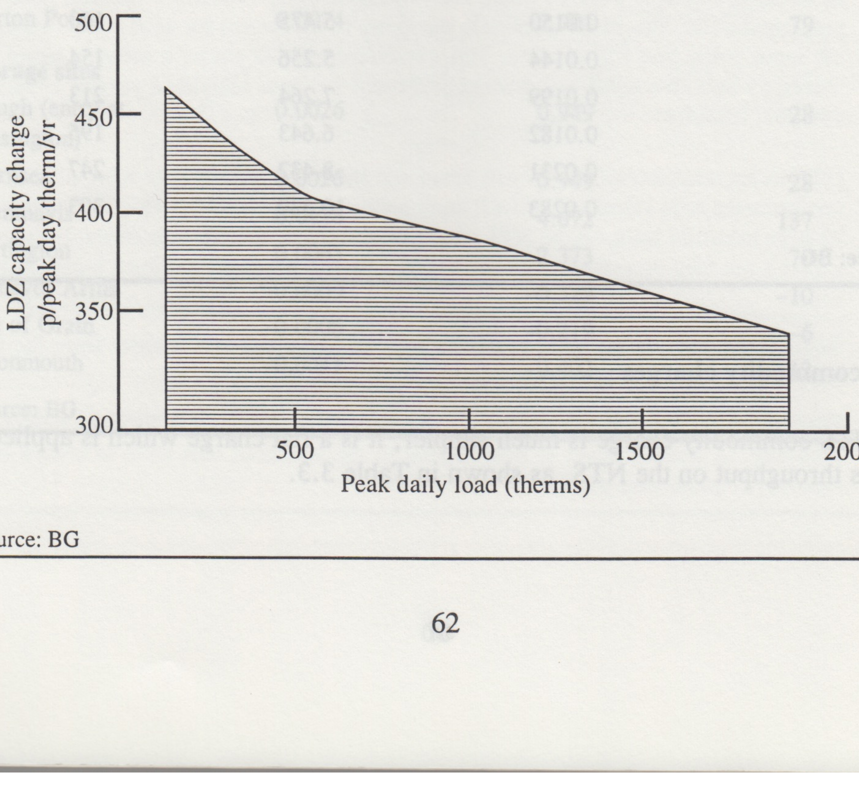
While it is possible to argue that the commodity charge on the NTS should in some way be distance related, the choice of a flat 'postalised charge' by TransCo went some way towards smoothing the distance related differences in transportation costs across the country.

LDZ CHARGING BASED ON AVERAGE ACCOUNTING COSTS

Charging methodology

Because of the highly complex and integrated nature of the LDZs, the LRMC charging methodology was not appropriate for the LDZs. Consequently the charging methodology used in the LDZs was based on average accounting costs. The fundamental principle applied by TransCo in charging for transport in the LDZs is that customers should be charged for their use of the various pressure tiers available. However, the anomalies of charging customers for their specific offtake tiers have resulted in a variety of problems which include under- or over-charging. Therefore the charging methodology currently used by TransCo employs customer size as the main determinant of the unit charge. This has been made possible by analysing the correlation between customer size and offtake tier. From its analysis of the available data TransCo was able to create a series of charging functions for capacity and commodity charges in the LDZ.

Figure 3.5: The LDZ charging function



Source: BG

The capacity and commodity charging functions each recover approximately 50% of the LDZ transport revenue.

LDZ capacity charges

From Table 3.4 it can be seen that sites in different load band sizes are charged out at different rates. This difference in charges is supposed to represent the change in use of the LDZ offtake tiers. Where a site is daily metered (DM) a value of the peak load (PL) will easily be obtainable. However, where a site is non-daily metered (NDM) an estimate of its peak load will be made using TransCo's demand algorithms.

Table 3.4: LDZ capacity charges, 1996/97

Annual load size	pence per peak day kWh per day	pence per peak day kWh per annum	pence per peak day therm per annum
Up to 73,200kWh (2,500 therms)	0.0405	14.78	433.1
73,200kWh (2,500 therms) and above	0.1047–0.0344 ×ln {ln(PL/29.298)}	38.22–12.56 ×ln {ln(PL/29.298)}	1119.6–367.9 ×ln {ln(PL)}

ln {ln(PL)} means the natural logarithm (to the base e) of the natural logarithm of the peak daily load, PL (in kilowatt hours or therms as appropriate).

Source: BG

LDZ commodity charges

The principles behind the calculation of the commodity charges in the LDZ are the same as those for the capacity charges and require no further explanation at this point.

Table 3.5: LDZ commodity charges, 1996/97

Annual load size	Charge (p/kWh)	Charge (p/therm)
Up to 73,200kWh (2,500 therms)	0.2582	7.565
73,200kWh (25,000 therms) and above, up to 9.60m kWh (327,497 therms) peak day	0.2647–0.0936 ×ln {ln(PL/29.298)}	7.755–2.742 ×ln {ln(PL)}
9,60m kWh (327,497 therms) peak day and above	0.0267	0.782

Source: BG

CUSTOMER CHARGES IN THE LDZ

Again the main principle that TransCo has sought to apply in this area is that the charges incurred by a particular customer reflect the costs related to that particular customer. Costs are incurred in the following areas:

- meters and meter reading;
- service pipes;
- emergency cover.

Consequently the larger the site the higher the actual charges, although they do become a smaller proportion of the total charge due to the higher throughput. In order to levy customer charges in a cost-reflective manner, TransCo has divided the sizes of sites into three distinct bands:

- Band 1 – up to 73,200kWh (2,500 therms) a year;
- Band 2 – 73,200kWh to 732,000kWh (2,500–25,000 therms) a year;
- Band 3 – above 732,000kWh (25,000 therms) a year.

The way in which TransCo applies the charges in these bands differs slightly and is described as follows.

Band 1: up to 73,200kWh (2,500 therms)

Table 3.6: Customer charges for sites up to 73,200kWh (2,500 therms), 1996/97

	pence per day	annual charge (£)
Fixed charge	4.1096	15.00
	pence per kWh	**pence per therm**
Commodity charge	0.1682	4.928

Source: BG

Sites in Band 1 are predominantly domestic customers and will have a typical service and meter that can be seen in most homes in the UK. There are no dataloggers fitted on these sites and the expectation is that the site will be dealt with as a non-daily metered site using the demand algorithm, with the meter being read periodically (usually annually). The customer charge is made up of a fixed charge plus a commodity charge as shown above.

Band 2: 73,200kWh to 732,000kWh (2,500–25,000) therms

Table 3.7: Customer charges for sites from 73,200kWh to 732,000kWh (2,500–25,000 therms), 1996/97

		pence per day	annual charge (£)
Fixed charge non-monthly read sites		19.3382	70.58
Fixed charge monthly read sites		53.1203	193.89
	pence per peak day kWh per day	**pence per peak day kWh per annum**	**pence per peak day therm per annum**
Capacity charge	0.0146	5.3290	156.10

Source: BG

Sites in Band 2 are predominantly small commercial users and number approximately 270,000. These sites may require monthly meter reading if their energy consumption is a high proportion of their total costs, such as a fish and chip shop. The customer charge is made up of a fixed charge, which can vary depending upon the frequency of meter reading, together with a fixed capacity charge which varies depending on the size of the site.

Band 3: above 732,000kWh (25,000 therms)

Table 3.8: Customer charges for sites above 732,000kWh (25,000 therms), 1996/97

	pence per peak day kWh per day	pence per peak day kWh per annum	pence per peak day therm per annum
Charging function	0.4447×(PL)^–0.34	162.3×(PL)^–0.34	1,508×(PL)^–0.34
Datalogger charges		**pence per day**	**annual charge (£)**
Standard charge/datalogger		103.9699	379.49
Annual check read/site		2.5701	9.38
Rebate/site, if all meters are datalogged		30.8411	112.57

1 TransCo makes an additional charge per site for an annual check. This is to ensure that the datalogger and meter are giving the same reading.

2 When all meters on a site are datalogged there is a rebate in the customer charge. This is because the site will no longer require a monthly meter reading visit for TransCo to read the non-datalogged meters.

3 The current threshold down to which the Network Code envisages datalogging is 2,196,000kWh (75,000 therms) a year. Therefore for sites whose annual consumption is above the threshold dataloggers will be charged for directly.

4 Datalogged sites taking more than 2,196,000kWh (75,000 therms) a year will not be liable for a datalogger charge, which means that TransCo is not required to provide the data. However, the shipper may request the data and pay the usual charges.

Source: BG

Band 3 primarily concerns sites that consist of industrial consumers and large commercial premises. For sites in this band the customer charge is made up of a function related to the peak daily load, together with a charge for those sites that also have dataloggers.

OTHER CHARGES

The shipper charge

When the 1995/96 transport charges were first issued a new charge was introduced known as the shipper charge. This charge proved highly controversial, first because the shipper community felt that it had not been consulted, and secondly because it increased costs. The shipper charge of 0.0113p/kWh or 0.331p/therm was meant to cover specific shipper-related costs, such as the provision of a quotation and the new computer system introduced by TransCo to manage the Network Code.

However, the new shipper charge proved so controversial among shippers that, following a series of discussions between shippers, TransCo and Ofgas, it was removed. Therefore, as a result of these discussions TransCo agreed to recover its costs through the NTS charges for 1995/96 and 1996/97, although it expected to unbundle these charges with separate prices for individual services such as nominations and confirmation from October 1997.

Meter reading charges

In the revised Gas Transportation Charges book for 1995/96 TransCo indicated that if it was expected to be liable for large financial penalties for non-performance under the Network Code that an increase in costs might result. There is also a move in the industry towards unbundling the meter reading service as well as meter installation and the laying of new connections. Consequently TransCo has offered a meter reading rebate if a shipper does not use TransCo for meter reading. The rebate is described in Table 3.9.

Table 3.9: Meter reading rebates, 1996/97

Meters read	pence per day	annual rebate (£)
Twice a year	1.29	4.71
Monthly	30.84	112.57

Source: BG

Must reads

Where a shipper chooses to provide its own meter readings, but is for some reason unable to do so, then TransCo will obtain a meter read for a charge of £40. This process is known as a 'must read'. The price of £40 is meant to cover costs associated with multiple visits, and obtaining and executing a warrant.

Domestic opening reads

With the introduction of competition in April 1996 with the pilot in south-west England, those sites that switch suppliers need to have an opening meter read. TransCo's charge for this service is £11.25.

FUTURE CHARGING METHODOLOGY – THE THREE-NODE SYSTEM

Even before the ink was dry on the final version of the Network Code, TransCo was in the process of discussing revised proposals for transportation charges with shippers. These proposals took the form of public consultation documents discussing the potential for medium and long-term changes to the way in which gas transportation charges were made in Great Britain. TransCo published three documents:

- Towards A Permanent Pricing and Services Regime
  A Nera (National Economic Research Associates) report for British Gas TransCo, November 1995 (London)

- Transportation Pricing and Services Regime – The Future
  British Gas TransCo, November 1995

- The Future of TransCo's Pricing and Services Regime – Consultation Report
  British Gas TransCo, September 1996.

The purpose of these documents and the ensuing consultation period has been to discuss a series of modifications which TransCo has been proposing to improve the use of the transportation system and to make it more cost-effective. Since much has been written on these proposed modifications, these proposals are not covered here in detail, but an outline of what has been proposed is given.

The proposed changes

In examining the possibilities for a price control review TransCo has established the following four objectives, as quoted in the Nera report:

- to promote competition and choice in the British gas markets;

- to promote the most cost-efficient use of the existing pipeline transmission system;

- to prevent wasteful and/or uneconomic investments;

- to promote transparent and cost-reflective prices.

In essence TransCo is seeking to establish a pricing mechanism that sends clearer pricing signals to the market and to recover revenues more efficiently for the use of the pipeline system.

The three-node pricing model

One of the main objectives in introducing a three-node pricing model is to improve the accuracy and cost-reflectivity of the charging. In the consultation document produced by Nera and the subsequent summary produced by TransCo, TransCo proposed to move from the existing entry/exit model of NTS charging to a more complex charging model. One of the main problems with the existing entry/exit charging model was that it does not send clear cost-reflective pricing signals to the market. Also the peculiar definition of infinite capacity being available, constrained or limited the development of a true capacity trading market. The proposal made by TransCo was to establish three nodes on the transportation system: a northern node, a Pennine node, and a southern node.

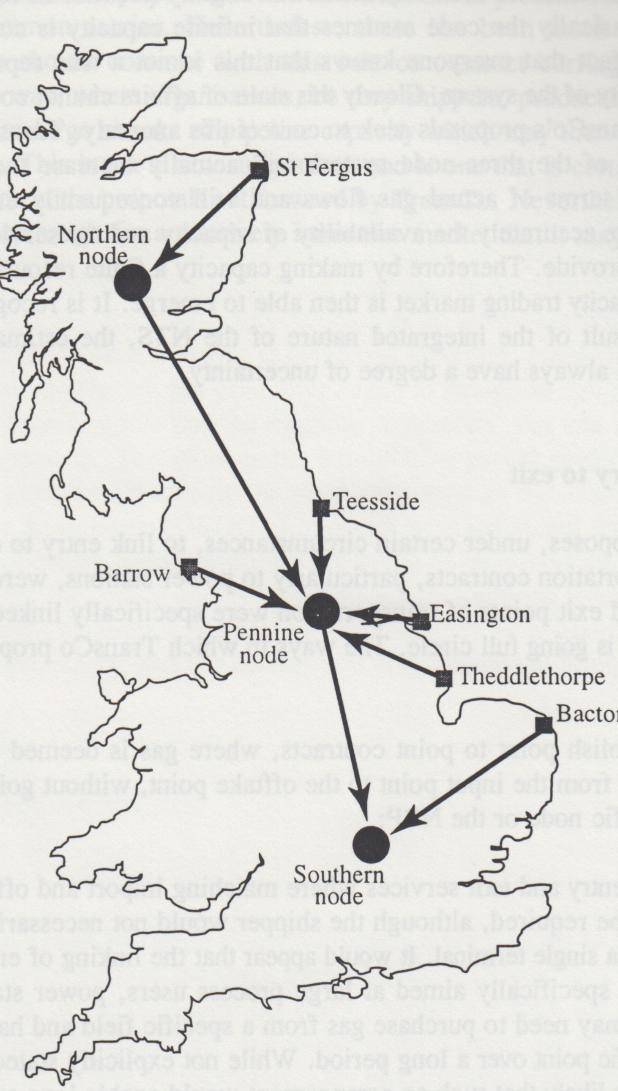
Figure 3.6 shows the proposal made by TransCo with the approximate locations of those nodes, the objective being that each entry point and exit zone would be linked with the appropriate node, and that gas would be normally delivered into those nodes for onward transportation either to existing exit zones linked to those nodes or for transportation via transfer legs to one of the other two nodes. Therefore, a shipper wishing to deliver gas from the St Fergus terminal to somewhere in south-east England would need to deliver gas into the northern node and then pay the interlink charge to the Pennine node and a further interlink charge to the southern node for onward transportation to an appropriate exit zone. While shippers would clearly be required to hold capacity in the interlink this capacity would be fully tradeable.

In TransCo's 10-year statement produced in 1995 the suggestion was originally for two pricing nodes, although in the 1996 10-year statement TransCo appeared to be proposing three. More nodes may be proposed in the future. At this stage of the consultation process it is not clear whether the three nodes will replace the individual National Balancing Point under the existing Network Code or whether three separate balancing points will be established on the transmission system. Either option is possible although obviously the creation of three balancing points could and would be an increase in complexity which would particularly affect the smaller shippers.

Forward haul flows

TransCo is also proposing in this pricing consultation process that there is a clearer unbundling of some of the services that it provides. The existing entry/exit system under the Network Code does not differentiate between forward haul gas flows and backhaul gas flows, whereas by introducing additional pricing nodes, as proposed in the consultation document, the actual flow of gas can be established. In fact, Nera in its report goes so far as to say that no backhaul transportation should be allowed at all and that only forward haul be allowed. Therefore, if shippers have customers to which they wish to transport gas against the actual flow, Nera suggests that offshore gas swaps should be arranged to facilitate this process. The argument for

Figure 3.6: National transmission system, three-node representation



Source: BG

this is that at present TransCo effectively swaps the shipper's gas with another's to facilitate the backhaul process without discussing it with them or having any recompense for providing this service. While in theory this sounds like a reasonable argument from TransCo and Nera, there is some doubt whether the gas trading markets at each of the beach terminals will be sufficiently liquid to enable such gas swaps to take place without impeding the marketing of gas. TransCo argues in its summary of the Nera document that prohibiting backhaul would in fact increase the liquidity of the gas market.

Availability of capacity

The Network Code as currently drafted is slightly peculiar in relation to booking capacity. Basically the code assumes that infinite capacity is currently available, despite the fact that everyone knows that this is not a true representation of the physical reality of the system. Clearly this state of affairs cannot continue in the long term, and TransCo's proposals seek to correct this anomaly. TransCo states that the introduction of the three-node system will actually increase the amount of data available in terms of actual gas flows and will consequently enable TransCo to calculate more accurately the availability of capacity and the service levels that it is prepared to provide. Therefore by making capacity a finite resource, as in reality it is, a true capacity trading market is then able to emerge. It is recognised, of course, that as a result of the integrated nature of the NTS, the estimation of available capacity will always have a degree of uncertainty.

Linking entry to exit

TransCo proposes, under certain circumstances, to link entry to exit. Some of the early transportation contracts, particularly to power stations, were contracts where the entry and exit points of transportation were specifically linked. It seems ironic that TransCo is going full circle. The ways in which TransCo proposes to link entry to exit are:

- to establish point to point contracts, where gas is deemed to be transported directly from the input point to the offtake point, without going through either a specific node or the NBP;
- to link entry and exit services where matching import and offtake nominations would be required, although the shipper would not necessarily have to supply it from a single terminal. It would appear that the linking of entry to exit in this way is specifically aimed at large process users, power stations and so on, which may need to purchase gas from a specific field and have it delivered to a specific point over a long period. While not explicitly stated in the proposals it seems likely that such an arrangement would enable long-term point to point transportation agreements to be negotiated with specific pricing clauses giving these long-term contracts a degree of price stability.

Pricing transportation

TransCo is also suggesting that the NTS and the regional transmission system (RTS) are merged into a single transmission system. The benefit to the shippers and to the industry as a whole would be that RTS capacity could also be traded. Another area that is also under consideration is the capacity/commodity split, as discussed earlier in this chapter.

Development of TransCo's role as a common carrier

The current arrangements in place with TransCo mean that at present TransCo fulfils the role of a common carrier. Nevertheless, there has been much debate over whether TransCo should continue with this role or contract carriage should be developed in some way, where organisations, be they shippers, producers or traders, are able to purchase large chunks of pipeline capacity which may then be traded on to other operators. This is not a new suggestion, and is one that is certainly worthy of serious discussion in the proposals put forward by TransCo. Nevertheless it would be such a dramatic change for a relatively immature market that it may well be too soon to consider it.

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CHAPTER 4: THE IMPACT OF THE NETWORK CODE ON PRODUCERS UPSTREAM

INTRODUCTION

During early discussions on the Network Code, and also during negotiation of the old (monthly) gas transportation contracts, few of the producers were involved to any great extent. There were several reasons for this. Initially the view of the producers was that they did not need to get involved in the consultation process for establishing the code. In fact many saw the consultation process as an unnecessary drain on their resources, since it involved attendance at numerous meetings. Nevertheless, as the consultation process developed, the producers began to recognise that the code was not just a document for TransCo and the shipping community, but that it would also have an impact upstream. Therefore as the consultation period gained momentum various industry groups representing the producers such as the United Kingdom Offshore Operators Association (UKOOA), together with individual representatives from a variety of producers, did show an interest in the development of the Network Code. In this chapter the code's impact on producers is examined from a variety of perspectives, including the impact of different entry charges on offshore economics, the operational implications, and the commercial and contractual implications.

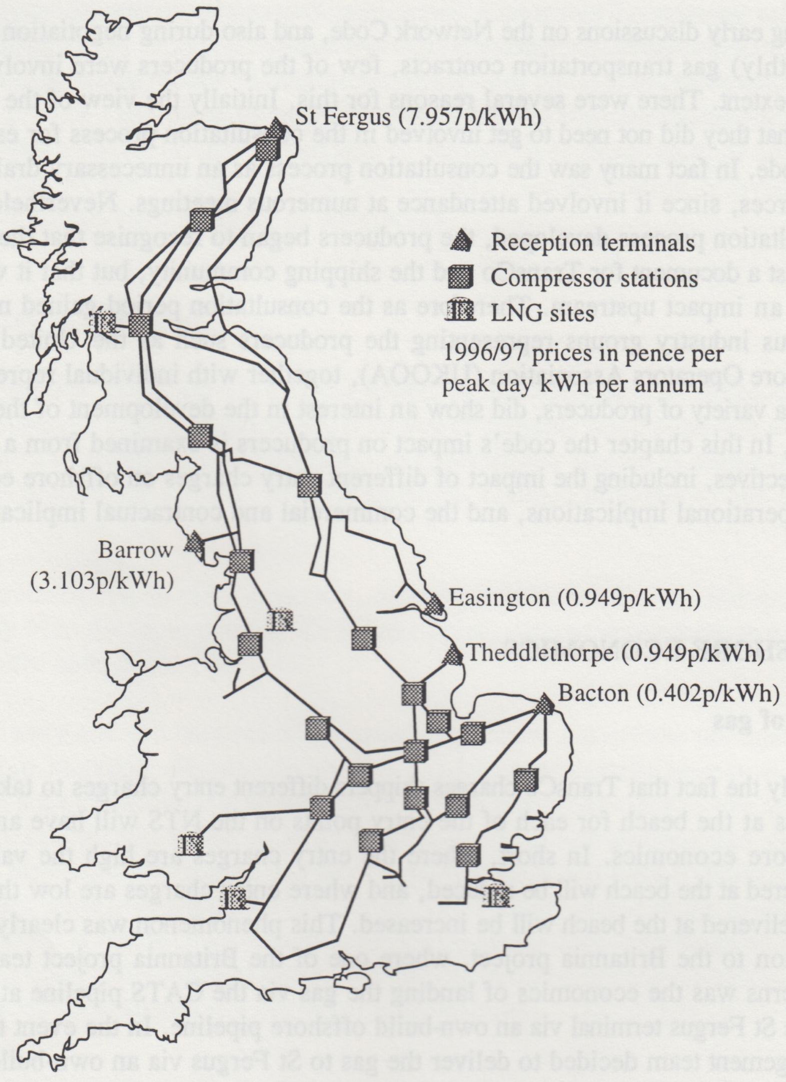
OFFSHORE ECONOMICS

Cost of gas

Clearly the fact that TransCo charges shippers different entry charges to take delivery of gas at the beach for each of the entry points on the NTS will have an effect on offshore economics. In short, where the entry charges are high the value of gas delivered at the beach will be reduced, and where entry charges are low the value of gas delivered at the beach will be increased. This phenomenon was clearly shown in relation to the Britannia project, where one of the Britannia project team's many concerns was the economics of landing the gas via the CATS pipeline at Teesside, or the St Fergus terminal via an own-build offshore pipeline. In the event the project management team decided to deliver the gas to St Fergus via an own-build offshore pipeline rather than to deliver the gas to Teesside via the CATS pipeline, although the impact of higher entry charges was only one factor of many which needed to be taken into account when the economic case was put forward for delivering the gas at St Fergus. The cost of moving gas south from St Fergus seems likely to increase further with the introduction of the three-node model, with higher internode charges for moving gas south from the Northern node to the Pennine node and from the Pennine node down to the Southern node and so on. It will be important for potential sellers of gas, particularly at St Fergus, to take this into account in relation to pricing their gas at the beach. Similarly, with this potential for large price increases in transport at St Fergus in mind, potential sellers of gas at any of the southern terminals may also want to take into account the price differential between, say, Bacton and St Fergus.

Figure 4.1 shows the national transmission system with the entry charges for each of the beach delivery terminals. From this diagram it can be seen that there is a high differential between gas delivered at Bacton and at St Fergus.

Figure 4.1: Comparison of NTS entry charges



Source: BG

Capital investment

With the introduction of gas-to-gas competition in Great Britain, the marketing strategy of many of the early shippers was to sell gas to high load factor customers, i.e. those customers that consumed gas at a reasonably consistent rate. This was hardly surprising, because TransCo's charges were partially related to load factors, and consequently the greater the usage of booked capacity the better the economics. The strategy to supply high load factor customers also affected the gas purchase strategies of many shippers, with gas being purchased with little or no swing characteristics. Therefore, during the early years of gas-to-gas competition in Great Britain the offshore producers became accustomed to selling gas at the beach with a low swing. Consequently this allowed the levels of capital expenditure required to bring gas to the beach to be reduced. However, with the introduction of the Network Code and the move to daily balancing the need for swing has increased again. Therefore those producers that are able to offer gas at a competitive price with some swing will have gained a competitive advantage. Nevertheless the provision of swing will cause producers to incur additional capital expenditure. The other point worth noting is that swing is no longer a facility provided by the producers in isolation, but rather the cost of swing provided by a producer will have to compete in the market-place with other alternatives such as interruption and storage.

Uncertainty of long-term transportation charges

The fact that the onshore transportation charges made by TransCo vary every year has given some cause for concern among those sellers and buyers of long-term gas. Whereas in the domestic, industrial, and commercial markets changes in the onshore gas transportation charges can be passed on relatively quickly to the customers, the picture for long-term gas purchasers such as power stations is not as clear. Some large power station projects take several years to break even, and any uncertainty in transportation costs will make the economic analysis more difficult. Some purchasers of gas have suggested that the producers should take the onshore transportation price risk, not an entirely popular view. Others have suggested that TransCo should offer long-term prices with an agreed escalation package. If TransCo does go ahead with the planned three-node model, together with the high internodal charge from Scotland to the south of England, then the differential transmission price between Bacton and St Fergus could become much larger. These long-term pricing problems will need to be tackled in some way by either gas sellers, gas buyers, or both. The potential move towards contract carriage may be a possible solution, although with the three-node model not expected to be introduced before October 1998 at the earliest, the uncertainty created by year-in-year pricing is unhelpful.

CONTRACTS

Most shippers of gas on the TransCo system will want to put in place back-to-back arrangements with their gas purchase contracts in relation to any commitments they may also have under the Network Code, so that gas producers are becoming increasingly interested in what the code actually says.

The Claims Validation Agency

With the introduction of the Network Code on 1 February 1996 it is now necessary for producers to take account of the effect of the code both on their old contracts and particularly on any new contracts that are under negotiation. The introduction of CVA agents has had a significant impact on the operational and economic arrangements at the beach, and consequently some producers have complained that these arrangements have been imposed upon them.

Technical specification

Under the old gas purchase agreements, which were largely between producers and BG, highly detailed gas specifications were given, usually as an attachment to the main contract, which specified the range, quality, calorific value etc. of the gas that was to be delivered. As the competitive market has developed, new gas sales contracts at the beach have often referenced the existing BG gas purchase specifications or the gas specification associated with the allocation arrangements at that particular beach delivery point. However, with the introduction of the Network Code and the increasing desire of both producers and gas purchasers for more stringent confidentiality on quality arrangements, TransCo has had to devise a means of specifying acceptable gas quality at the beach without breaching any confidentiality arrangements. Therefore, TransCo is in the process of establishing acceptable gas quality specification ranges at each of the beach entry points, which can then be used by gas purchasers and gas sellers alike as the acceptable standard permitted by TransCo to be delivered into the system.

Notice periods and ramp rates

While BG did have a measure of flexibility under its old gas purchase contracts to turn gas supplies up or down at relatively short notice, this flexibility was never designed to meet the daily balancing requirements under the Network Code. Similarly the move towards low swing gas has, if anything, reduced the level of flexibility available to gas purchasers at a time when they probably need more rather than less. Therefore it is against this background of apparently decreasing flexibility that the code was introduced.

This reduction in flexibility was acceptable during the introduction of competition to Great Britain, when shippers were effectively able to purchase flat gas and required little or no flexibility because of the monthly balancing contractual arrangements. However, with the introduction of the Network Code and the opportunity for shippers to bid into the flexibility mechanism, there is an increasing requirement from gas purchasers for more flexibility in their gas purchase contracts with producers. It seems highly likely that gas purchasers will be looking for producers to provide more flexibility in terms of the producers' ability to deliver more gas and at shorter notice, so that additional revenue might be gained from the flexibility mechanism. The potential for producers to deliver gas in excess of the maximum daily quantity (MDQ) on a particular gas purchase agreement is also being examined following the exceptionally high prices of gas in the flexibility mechanism during March, April and May 1996. In fact during these times when the flexibility mechanism was purchasing gas from shippers typically at 2–3p/kWh some producers did offer to sell additional excess gas into the mechanism via shippers in order to make money.

Provision of information

Again, with the introduction of the Network Code one of the main ways in which shippers will be able to maintain daily balances within their own acceptable tolerances is by obtaining additional and more accurate information on gas deliveries from the producers. Many gas purchasers are, therefore, seeking improved information flows from producers in relation to gas purchase agreements. This may cover the ability or inability of a particular field to deliver gas as and when requested, so that the shipper may be able to renominate as a result of this information and so on. However, the arrangements that were in place with the CVA during 1996 have to a large extent meant that information flows are less certain and slower than they were before, and therefore the whole area of the provision of timely and accurate information on gas deliveries by producers will be one of great interest to gas purchasers.

ALLOCATION OF GAS AT THE BEACH

The allocation of gas at the beach has always been a fairly complex and thorny issue, with relatively complicated allocation arrangements being put in place. However, with the introduction of the Network Code and the appointment of CVA agents at each of the beach terminals the degree of complexity and uncertainty appears to have increased. In theory the claims validation agent sits at the beach as a neutral umpire between the producers delivering the gas at the beach and the purchasers of that gas at the beach (i.e. shippers, gas traders and other parties). The objective of the CVA agent would be to analyse the deliveries of gas as received by TransCo, which is able to meter the total quantities of gas at each entry point, against the nominated deliveries by producers and the nominated deliveries by gas shippers. Where there is a mismatch between the various parties the CVA agent would highlight the discrepancy and ask the parties concerned to resolve their differences. Often these differences would just be a minor clerical error, although sometimes there could actually be a commercial conflict. During the introduction of the Network Code the CVA process was not an unbridled success, for reasons which included the poor provision of information from TransCo, the incomplete collection of all nomination information either by the CVA or the shippers, and in some cases the potential gaming by certain operators. However, with a lot of work being put in by all parties, the early problems associated with the CVA appear to be slowly unravelling. Although many operators, in particular producers, are particularly concerned about the effect of the CVA process on their contracts in respect to liabilities, it is also a concern that some suppliers are still not providing base statements.

COMMERCIAL OPPORTUNITIES RESULTING FROM THE NETWORK CODE

There are a variety of ways in which producers can gain commercial advantage through operating the Network Code, some of which are described here.

Entry into the flexibility mechanism

As previously mentioned the price of gas in the flexibility mechanism peaked much earlier than many players expected and at a much higher level. Therefore one area from which producers may gain commercial advantage as a result of the impact of the code is to make gas available for sale into the flexibility mechanism. This may be done through a joint venture with a shipper, where existing gas entry capacity owned by a shipper may be used by a producer for selling gas into the flexibility mechanism, with any profits being shared between the parties. Producers may choose to sign onto the Network Code themselves and buy some entry capacity with the expectation that in the short term this will give them access to a gas trading facility, so that on those days when gas in the flexibility mechanism was being purchased, that gas could be delivered into the flexibility mechanism. The potential income from the flexibility mechanism will depend, however, upon the availability of gas and capacity.

Anticipation of pricing changes

The transportation prices for entry are probably still more volatile than most producers would like, therefore the ability of producers to anticipate how these prices at the beach might increase or decrease could give them potential for commercial advantage in any gas sales arrangements. Clearly some producers have sought to pass on any transportation costs direct to their customers, although the ability of producers to anticipate any changes and include these in an overall price could be advantageous.

Provision of spot gas or seasonal gas

Again, as the gas market in Great Britain begins to stabilise and the gas bubble decreases, the value of peak gas will increase and those producers with an eye on the short-term gas market will be seeking to trade both on a day-ahead basis and also into the winter. A recognition of the value of seasonal gas, particularly from those producers with fields that do have high swing, will reap dividends.

Operation in a capacity trading market

Where producers have purchased capacity on the system, possibly to facilitate sales of entry paid gas, they may also take part in the developing capacity trading market. Capacity trading occurs when one operator which has spare capacity chooses to sell that capacity for a period of time to another operator. Access to this market either as a net buyer or seller of capacity could give producers profitable returns in this developing market.

Strategic alliances in order to manage risk

One of the big concerns of the upstream industry has been that the deregulation of the British gas industry would cause instability in the market-place and increase the risk associated with exploration and production offshore. To a large extent this is true. Large gas purchase contracts with 25-year take-or-pay clauses are certainly in decline, and producers selling gas into a short-term gas market may end up by picking up some of the risk. One way in which these levels of risk are being limited is with the growth of strategic alliances. Therefore over the next few years, particularly as the domestic market develops, it seems highly likely that upstream producers will be forming strategic alliances with companies which have the skills and expertise to enter the domestic market.

CHAPTER 5: THE IMPACT OF THE NETWORK CODE ON SHIPPERS

INTRODUCTION

This chapter examines the impact of the Network Code on existing and new shippers, from both a commercial and an operational point of view. Clearly, moving from a monthly to a daily balancing regime has had a considerable effect on the way that shippers operate their portfolios. While to a certain extent these changes will have been partially alleviated during the 'soft landing' period between 1 March 1996 and 1 September 1996, nevertheless, as all the provisions of the Network Code are put in place, the change in the operational methods used by shippers will be considerable. While there are a variety of areas where industry participants may gain competitive advantage, the key areas affecting the main operators are daily balancing, scheduling charges, operation in the capacity trading market, operation in a flexibility market, and operation in the day-ahead gas spot market.

MOVING FROM MONTHLY TO DAILY BALANCING

The impact on the industry as a whole of moving from monthly to daily balancing is still being felt and should not be underestimated. In order to explain the significance of this change it is worth briefly describing how the old legacy contracts worked in relation to monthly balancing.

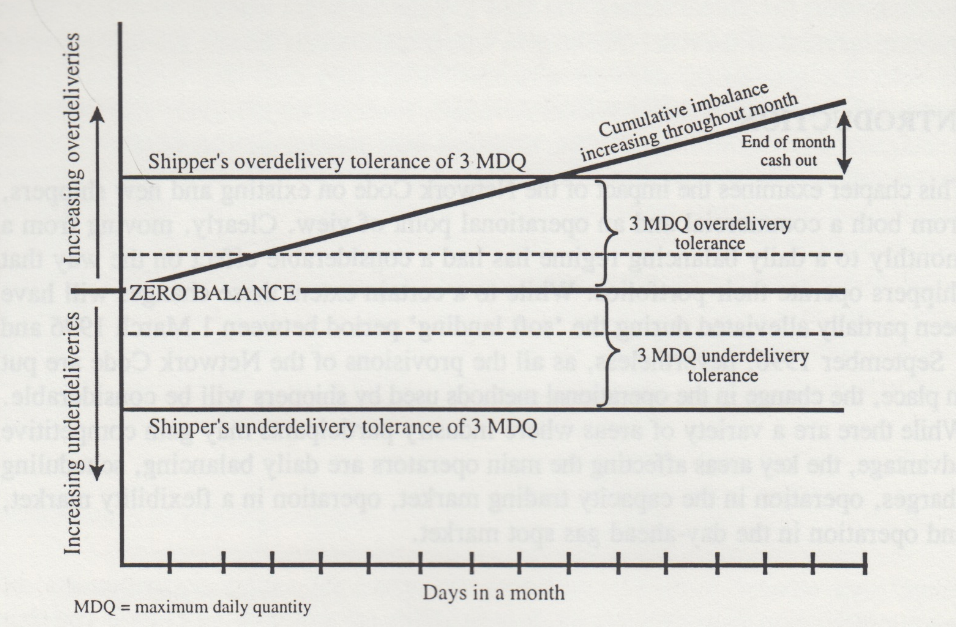
The old contractual regime

The old contractual regime, currently known as legacy contracts, was based on the principle of monthly balancing, as shown in Figure 5.1.

Figure 5.1 shows how monthly balancing worked using a particular scenario where a shipper has consistently over-delivered on each day of the month, so that an over-delivery imbalance has built up to such an extent that the shipper imbalance tolerance (SIT) has been exceeded. Gas within the SIT would normally be carried over to the next month, with any gas outside the tolerance being purchased by BG. The theory of these early legacy contracts was that the purchase price of this gas would be sufficiently low to discourage shippers from over-delivery, although the drop in gas prices experienced lately has left the pricing signals a little peculiar.

In essence the concept of monthly balancing required the shipper to balance its demands and offtakes over a period of a month within certain end-of-month tolerances. The first of these contracts were introduced at the start of gas-to-gas competition in Great Britain in 1990. This was done when the competitive market made up a relatively small proportion of the overall British gas market with the remainder being supplied by BG plc. Therefore any daily imbalances in the system

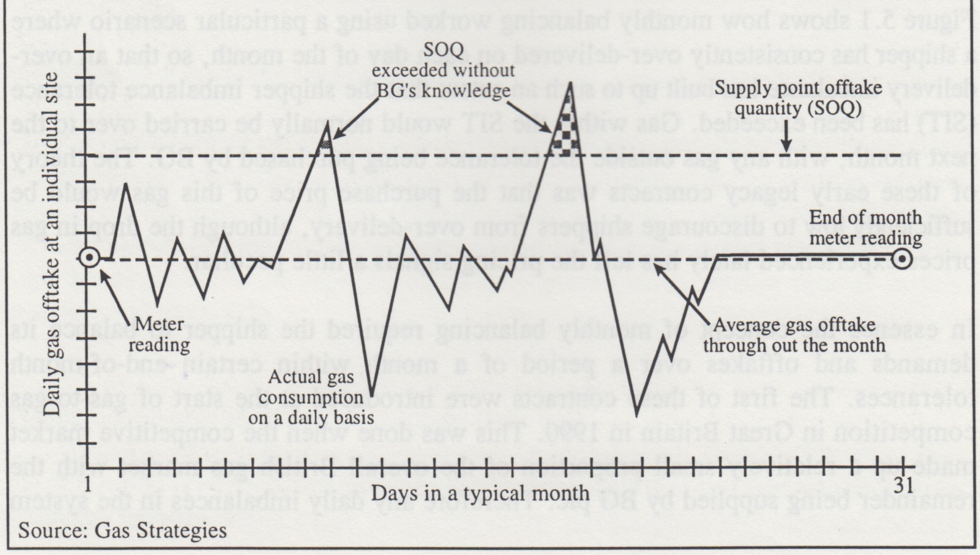
Figure 5.1: The pre-Network Code monthly balancing regime



Source: Gas Strategies

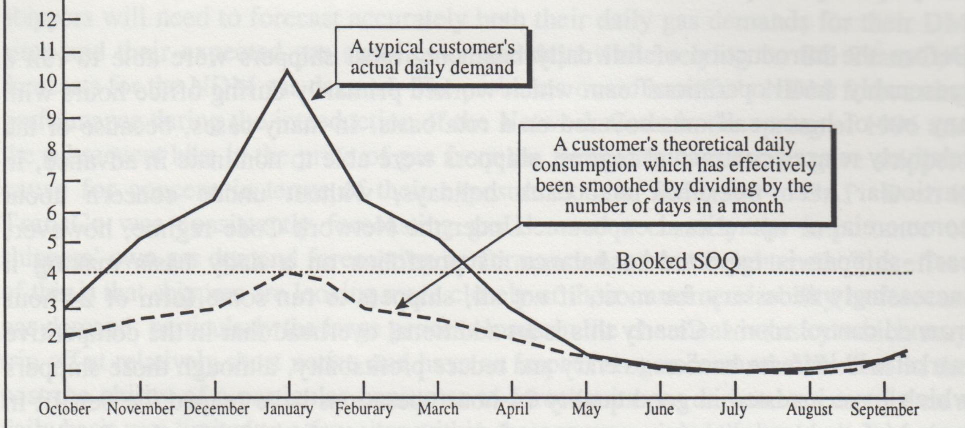
as a whole were absorbed by BG plc. The other significant point in relation to these legacy contracts was the difficulty that BG had in metering gas demands on a daily basis. While it was originally intended that each supply point (consumer) would be metered on a daily basis with a datalogger, practical and operational constraints meant that many of the sites within a shipper's portfolio would not have been datalogged. Therefore the only accurate measurement that BG had of shippers' use of capacity was the beginning and end of month meter readings. The effect of this problem is shown schematically in Figures 5.2 and 5.3.

Figure 5.2: The capacity booking problem



Source: Gas Strategies

Figure 5.3: The impact of monthly meter readings



Source: Gas Strategies

The root of the problem was that BG had originally intended all supply points to be datalogged, a decision that was made when the competitive market included only those sites consuming more than 25,000 therms a year. However, once this ceased to be the case it was difficult for BG to monitor the actual use of capacity at a specific supply point. Figure 5.2 shows the impact of a site's gas consumption going up and down during a cold spell, with the booked capacity known as its SOQ being exceeded without BG's knowledge. This resulted in under-recovery for BG. Perhaps of greater concern was a competitive downward pressure on many shippers in the market-place to underbook capacity in order to remain competitive. The result of this was that in many cases capacity at supply points tended to be underbooked by shippers. Consequently the net effect both of the shipper only having to balance on a monthly basis and the tendency for the estimate of the daily consumption of shippers' demands to be lower than was actually the case meant that BG plc was under-recovering its capacity costs and having to provide additional gas on peak days. When the competitive market was only a small proportion of the overall market the difficulties and costs caused by these problems to BG were not insurmountable. However, the introduction of full competition across all market sectors in Great Britain and the separation out of BG's marketing activities initially into Public Gas Supply and Business Gas (combined into British Gas Trading) meant that BG plc could no longer subsidise the competitive market in terms of making up any shortfalls on specific days either as a result of the monthly balancing or the existing capacity booking regime.

Daily balancing

Consequently, with the introduction of daily balancing and the removal of any balancing subsidies from BG plc, each individual shipper is now required to balance its existing supply/demand portfolio on every day throughout the year. The effect of such a paradigm shift on the way in which the contractual regime for gas transportation operates within Great Britain is huge and the reverberations will probably rumble on for the next one or two years, at least.

Daily operations

Before the introduction of full daily balancing most shippers were able to run a reasonably small operations team which worked primarily during office hours with any out-of-hours call-outs covered on a rota basis. In many cases, because of the relatively relaxed contractual regime, shippers were able to nominate in advance, in particular over weekends and bank holidays, without undue concern about commercial or operational exposure. Under the Network Code regime, however, each shipper is expected to balance its portfolios on a daily basis making it increasingly necessary for most, if not all, shippers to run some form of 24-hour manned control rooms. Clearly this is an additional overhead that in the competitive market will increase barriers to entry and reduce profitability, although those shippers which have invested in good quality 24-hour operations have reaped the benefit in terms of reduced balancing costs and increased profitability in the flexibility mechanism and day-ahead spot market.

Requirement to book for capacity used

Under the new regime the requirement to book the full capacity used by shippers' customers means in some cases, where capacity was either deliberately or mistakenly underbooked, that the total cost of transportation to shippers and hence to customers has gone up. The other effect of having to book correct capacity for customers is that it limits the ability of certain shippers to underbook capacity deliberately in order to gain an unfair competitive advantage. Furthermore, the peak gas requirements of shippers will go up as the correct capacity is booked. This means that shippers will have to ensure that they have sufficient supplies of peak gas to meet their peak gas demand days in the winter months which will in turn mean that the tendency of shippers to buy low swing gas and not to purchase any seasonal storage will decline. It would seem highly likely that both the price of high swing gas and the provision of gas during the cold winter months would increase. However, because of the high SMP (Buy) charges experienced in the flexibility market in March and May, some producers may be deliberately holding back swing in order to sell gas into the flexibility mechanism. This has had the effect of reducing the amount of swing available for purchase by shippers and increased their interest in storage, as well as pushing up spot and short-term gas prices.

DAILY BALANCING CHARGES

The impact of daily balancing charges on individual shippers will mean that in the case of a small error in daily balancing shippers will have to buy or sell gas from the NBP at the system average price (SAP) price of gas, whereas a large error in daily balancing on a particular day will ensure that shippers have to buy or sell gas at the respective SMP (Buy) and SMP (Sell) prices. While no one knows exactly how these prices will develop over time, as the current gas bubble decreases and the price of spot gas stabilises it seems highly likely that the impact of the SAP, SMP (Buy), and

SMP (Sell) prices will increase substantially, particularly during the winter months. Consequently, the failure of any shipper to balance accurately on a day, particularly during the winter months, will have an adverse effect on its profitability, since poor performance by shippers will carry a considerable financial penalty. Therefore shippers will need to forecast accurately both their daily gas demands for their DM sites and their expected gas supplies on the day, while relying on BG TransCo's forecasts for the NDM gas demand. The problems over TransCo's NDM forecasting performance during the introduction of the Network Code in the spring of 1996 and the subsequent hike in the price of gas from the flexibility mechanism gave shippers cause for concern in terms of their exposure both to SMP and to SAP. Even if TransCo was consistently forecasting gas demand accurately the importance of shippers' own gas demand forecasting performance has been heightened. The effect of this is that shippers are looking more closely at their customers' ability to forecast gas demand, particularly the large process loads in the chemical industry which may trip off at relatively short notice and have an impact on gas demand. Whereas in the past the ability of a particular consumer to forecast its gas demand accurately on a daily basis was limited to a few sites within the country, under the code all DM sites will need to be able to forecast their gas demand accurately. Thus those customers which put time and effort into keeping their shippers informed of changes in their gas demand could well be given a price discount and those consumers which do not put in the required effort could end up paying a premium. Whatever the ultimate effect, either the customer or the shipper will have to pay for errors in demand forecasting.

Scheduling charges

Scheduling charges as described in Chapter 2 are an incentive for the shipper to ensure that the nominations both at the input and output points and from the NBP are accurate. While scheduling charges are currently not onerous, at 1% of the SAP, they are an additional charge that shippers and/or consumers will have to pay for failure to match nominations and deliveries accurately. A sharp rise in SAP would also have an impact on the charges incurred under these provisions in the Network Code, although to a lesser extent than SMP.

OPERATING IN THE CAPACITY TRADING MARKET

Under the terms of the Network Code shippers are able to trade capacity with each other, at both entry and exit points.

Capacity trading at the entry point

The ability to trade capacity at the entry point is particularly useful for shippers which purchase 12 months worth of capacity from TransCo (the minimum allowable by TransCo) and subsequently find, as a result of a long-term offshore failure or an operational or contractual difficulty, that the booked capacity is no longer being fully used. Clearly no commercial organisation will want to hold capacity that it is not going to use. Therefore a secondary market in capacity will, and is in fact already beginning to, develop where shippers are able to trade capacity with each other. Those shippers that are able to identify and trade capacity surpluses, either on the day or over longer periods, will be able to gain a competitive advantage in terms of maximising revenue from existing booked capacity. Similarly a shipper that has a short-term need for capacity would do well to go to the secondary capacity trading market first, to purchase that capacity from another shipper rather than to purchase 12 months of capacity from BG TransCo.

Another area where capacity trades at the entry point are developing is in conjunction with flexibility bids. If the NBP is particularly short of gas and a shipper has excess gas but insufficient entry capacity to deliver that gas, then the shipper has three choices:

- deliver the gas anyway, and pay a flexibility overrun charge at a premium to the daily capacity charge;
- try to buy some spare capacity from another player within-day to support the flexibility bid;
- trade the gas at the beach to another shipper which does have spare capacity.

It is also clear that a link will develop between the price of gas in the flexibility market and the price of secondary capacity. Again, those operators best able to anticipate the price of accepted bids in the flexibility market will be able to take the appropriate action, gain competitive advantage and be more profitable.

Considerable care is required in trading and monitoring capacity, to ensure that sufficient capacity is available to meet the needs of the business, because where a shipper trades capacity, and consequently exceeds its remaining capacity, it will incur capacity overrun charges. These penalties, at currently twice the capacity charge, would probably wipe out any competitive gains made by capacity trading.

OPERATING IN THE FLEXIBILITY MARKET

The ability of shippers to monitor the trends within the flexibility market and to be able to gain competitive advantage from them will be a key factor in increasing shippers' profitability. An example of this would be the ability to price a shipper's flexibility bids seasonally to take advantage of the increased likelihood of higher priced gas bids being accepted during the winter months when gas is likely to be short and prices high. Similarly the ability to identify an operational constraint on TransCo within-day, which may cause TransCo to come to the flexibility market and request additional gas in order to balance the system on the day, would give a shipper competitive advantage in pricing gas. It would seem likely that if shippers are going to take part successfully in the flexibility market, the capacity trading market, and the day-ahead spot market, they will need additional expertise. In fact, even before the introduction of the Network Code, some shippers had gone out into the market-place and recruited either gas traders or experienced commodity traders, from within

Great Britain or from North America, in order to have the expertise available to meet the requirements of the market.

The flexibility market has proved far more volatile than TransCo expected, with suggestions being made by some operators that others have deliberately withheld gas to enable them to participate in the flexibility mechanism. Certainly when prices in the flexibility mechanism have peaked there has been little or no gas available in the day-ahead spot market. Consequently it seems fair to assume that seasonal shortages of gas will drive up the flexibility price allowing disproportionately high profits to be made by those operators with spare gas to sell on peak days.

Moreover, the operation of the flexibility mechanism is largely dependent upon TransCo's ability to forecast gas demand accurately and to notify shippers as soon as possible of any expected changes in gas demand.

Clearly those players in the market-place which are able to anticipate these peaks in prices will be able to gain competitive advantage by withholding gas on the spot market (or even buying if possible) and selling the following day on the flexibility market.

OPERATING IN A DAY-AHEAD SPOT MARKET

While at the time of writing this report the introduction of the International Petroleum Exchange (IPE) screen based trading system had been delayed, the day-ahead spot gas market has continued to develop at a rapid pace. Therefore it would seem that the day-ahead spot market is here to stay. Clearly the ability of shippers to trade surplus gas or to purchase additional gas on short-term contracts at spot prices has enabled them to maximise the profitability of their portfolios. Before the introduction of the Network Code the spot market tended to be a telephone based market, run by commercial negotiators in their spare time with relatively simple contracts and a relatively simplistic approach to pricing. However, as the market develops, in particular with regard to the IPE screen based trading system, the expectation is that the spot market, both in the short and medium term, will become more sophisticated. Its development will, however, be impeded by the current delay in the IPE screen based market and the lack of a standard gas contract, as well as the difficulties associated with closing out beach deliveries correctly. Therefore it is hoped that the development of the IPE NBP market planned for early 1997 will go ahead as planned. Consequently, it is important for shippers to estimate their daily gas demand and gas availability accurately, so that the availability of gas for spot deals can be quantified. Again, activity in these markets will enhance the shipper's ability to maximise profitability through the various gas trading and capacity trading mechanisms. Failure to undertake these processes will mean that certain shippers will be limiting their profitability in an increasingly competitive market-place. Also, from the point of view of the country as a whole, the ability of the UK gas market to develop a successful and secure trading environment quickly can only enhance its ability to become the trading hub of Europe when the Interconnector is complete.

MEETING THE PEAK GAS REQUIREMENTS

Following the introduction of the Network Code the subsequent move to daily balancing and the requirement for more accurate daily demand forecasting by shippers has increased the requirement for shippers to purchase either higher swing gas or storage. Therefore the ability of shippers to meet their peak gas requirements will ultimately ensure a change in the market-place, in terms of the price and take-up both of storage and of swing.

Gas purchase

Now that shippers are required to provide their peak gas requirements on a day or face potentially high penalties when 'cashed out', the purchasing strategies employed by shippers may move back to higher swing contracts rather than the current low swing contracts which have predominated during the early 1990s. However, the ability of producers to charge a substantial premium for high swing gas at the beach has been affected by the gas bubble, although the hike in flexibility mechanism prices seen in the first half of 1996 has increased the value of swing in the eyes of both producers and shippers.

Purchase of additional storage

The requirement for shippers to meet their peak gas requirements will ensure that the cost of storage against the cost of peak gas from a high swing gas purchase contract will be thoroughly examined. While in the past many shippers have argued that the cost of storage provided by BG TransCo (Storage) is high, the ability of shippers to minimise their gas purchase costs and to mitigate any balancing charges by purchasing seasonal storage is something that will be assessed with ever greater attention. While it is probably unfortunate that BG Storage is seeking to enter the commercial market-place at a time when the price of gas has been depressed, the high prices experienced in the flexibility mechanism have done it no harm at all.

Booking of correct entry capacity

Under the provisions of the old legacy contracts shippers did not need to make arrangements to meet their full peak gas requirements, because of TransCo's inability to measure a shipper's peak gas consumption. This has changed as a result of provisions introduced by the Network Code.

Under the legacy contracts it was possible for shippers effectively to flatten their peak gas requirements through a combination of underbooking capacity at the supply points and BG's inability to measure what was offtaken accurately on any day unless dataloggers were fitted and working. Under the Network Code shippers are required to balance daily, and the failure either to book correct capacity or to provide sufficient gas on the day will be penalised with overrun charges at a premium to the normal rate for the additional capacity required and energy balancing charges respectively. While it is not in any shipper's interests to overbook capacity, it is not in any shipper's interests to incur balancing or overrun charges either. Therefore the requirement for shippers to forecast their daily and seasonal gas demands accurately will increase, so that they are able to book entry capacity accurately and make decisions about the sourcing of gas supplies to meet their requirements, either from gas at the beach or from storage.

FLEXIBILITY IS THE KEY

This chapter has briefly touched on some of the areas where the more flexible and entrepreneurial shippers might gain competitive advantage. In a highly competitive market there will be four principal keys to success.

Good computer systems The ability of shippers either to buy in or develop good computer systems in-house both for the daily operations of the Network Code and functioning in the various trading markets will be essential.

Cheap gas While it may sound obvious, those shippers which have been able to purchase gas either at a sensibly low price or on relatively short-term contracts will be more successful than those which are hooked into expensive long-term contracts. The alternative is to renegotiate with producers. This may be an almost impossible task, with most producers taking an extremely tough line, although producers should be aware that one day the boot may be on the other foot, and that shippers have long memories!

Good staff Those operators with well trained and supervised staff, able to respond to the commercial challenges of the day, will be successful.

Flexibility Finally the ability of players to be extremely flexible in a fast developing market is important. Bureaucratic and slow management structures need to to be swept away so that the commercial, operational, and strategic challenges of the day may be met.

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CHAPTER 6: GAS STORAGE

INTRODUCTION

While a storage service was technically available before the introduction of the Network Code, shippers' need to use it was limited because of the relatively relaxed operating regime of monthly balancing. However, with the introduction of the Network Code and also the introduction of full daily balancing, more shippers are showing an interest in the purchase of storage services from BG or in the construction of their own storage facilities.

This chapter examines the type and cost of storage services provided by BG, and where information has been available, gives the results of a cursory examination of what other storage providers might be bringing to the market-place in the next few years. While TransCo currently provides both transport and storage services to the shipping community, the storage services provided by TransCo are separately accounted for and it is expected that ultimately the service will be unbundled. Therefore, for the purposes of this report the department that currently provides storage services will be referred to as BG Storage.

Definitions

Space

Space is used to describe the physical volume of gas that can be stored in a particular storage facility. The charge made by BG Storage for space varies from facility to facility as a result of the different costs associated with each site.

Deliverability

Deliverability is used to describe the maximum quantity of gas that a customer can withdraw from storage in any one day. The deliverability charge is a rate per kWh. It is a fixed charge which has to be paid irrespective of the actual usage.

Injection

Injection is used by BG Storage to describe the process of filling a storage facility. It may be that gas can only be delivered at certain times of the year, or on certain days (for example, when the LNG liquefaction plant is running). BG Storage makes a commodity charge in pence per kWh based on the quantity of gas actually delivered.

Withdrawal

Withdrawal is used to describe the process of withdrawing gas from a storage facility, in a fashion similar to the concept of storage injection. Again BG Storage makes a commodity based charge for gas actually withdrawn.

TYPES OF STORAGE FACILITY AVAILABLE

BG Storage is the main provider of seasonal storage in Great Britain, and has three types of storage.

The Rough field

Rough is an old depleted gas field off the coast near the Easington terminal. It has a huge storage capability of around 30.3TWh. Because of its size it also has a high deliverability rate of 455GWh/d. The combination of Rough's size and the low cost to users means it can provide swing at a reasonably competitive price compared with the usual premium placed on swing by producers.

Salt cavity

Gas can also be stored in salt cavities. These are large underground cavities which have been leached out to create gas storage facilities. BG Storage salt cavities are located at Hornsea and feed directly into the NTS at that point. One of the main advantages of salt cavity storage is that the user is able to inject and withdraw gas at relatively short notice. The usable space in BG Storage's salt cavities at Hornsea is 2.8TWh, with a maximum delivery rate of 186GWh/d. It is in the area of salt cavity storage that BG Storage is most likely to experience any competition, for a variety of reasons, the first of which is that the barrier to entry in terms of cost for constructing new salt cavity storage is lower than for LNG facilities or large offshore fields like Rough. Secondly, it is possible to construct new salt cavity storage to operate at higher pressures and injection and withdrawal rates. These higher space and deliverability rates would not only enable users to store gas for seasonal use, but also allow the user to operate the storage facility strategically in the flexibility mechanism and the spot market. In fact Utilicorp and Stavely Industries have formed a joint venture which entails the operation of a salt cavity facility in the north-west of England, which may be the first non-BG Storage project.

Liquid natural gas

BG Storage currently operates five LNG sites at strategic points on the TransCo network. Originally LNG sites were located at the extremities of the pipeline system. The reason for their strategic location was to provide peak gas supplies at the points in the system where pressures in the NTS were at their lowest, hence their location at Dynevor Arms in South Wales, Avonmouth in the south-west, and the Isle of Grain in the south-east. These locations also happen to be areas of high gas demand. The second reason for locating LNG sites at the extremities of the NTS was to minimise reinforcement of the pipeline system. As the NTS's capacity would only be constrained for a small number of days each year, it was easier and cheaper to use LNG to maintain security of supplies than to construct new pipelines to reinforce the NTS.

One of the main benefits of LNG sites is their high deliverability which totals 812GWh/d across all five sites, and their strategic locality as already mentioned, which enables the sites to provide a peak gas supply to shippers, a supplement to network capacity, and insurance against emergencies and supply shortfall through the operating margins.

Historically each of the storage sites was specifically designed by BG to do a certain job at that particular location, and therefore each site has slightly differing characteristics. A summary of these physical characteristics is given in Table 6.1.

Table 6.1. Physical characteristics of each storage facility

Storage facility	Volume (GWh)	Injection (GWh/d)	Withdrawal (GWh/d)
Avonmouth	827	2.6	165
Dynevor Arms	276	2.9	55
Glenmavis	551	3.7	110
Isle of Grain	1,213	5.4	243
Partington	1,195	5.2	239
Hornsea	2,789	21.4	186
Rough	30,334	209.2	455
Total	**37,185**	**250.4**	**1,453**

Source: BG Storage

TYPES OF STORAGE SERVICE AVAILABLE

Firm storage services

A firm storage service consists of a combination of space and deliverability in a set ratio known as the duration,

$$\text{where duration} = \frac{\text{booked space}}{\text{booked deliverability}}$$

The duration is an indication of how long it would take to empty the facility at the maximum output rate rather than a means of restricting the number of days for which the storage service can actually be used. A summary of the characteristics of firm storage services is shown in Table 6.2.

Constrained storage services

The idea behind constrained storage services is primarily that TransCo wishes to constrain the use of these services so that the original purpose of the LNG is retained, i.e. to reinforce the gas supply in that local area on days of exceptionally high gas demand. Any organisation which books capacity in a constrained LNG

Table 6.2: Characteristics of firm storage services

Facility	Space (GWh)	Deliverability (GWh/d)	Duration (days) Minimum	Maximum
Glenmavis	551.45	110.29	5	5
Partington	1,194.85	238.97	5	5
Hornsea	2,788.50	188.07	10	20
Rough	18,610.84	455.00	30	120

Source: BG Storage

facility makes a commitment to TransCo to remove some of its gas from storage on days of exceptional gas demand. In order to do this it is necessary for the purchaser of storage to maintain a minimum quantity of gas in store. Clearly no purchaser of storage will want to do this for nothing, so TransCo offers an incentive by providing a transmission benefit. At the time of writing this report the three storage facilities able to provide a constrained storage service are Dynevor Arms, Isle of Grain and Avonmouth, although this number may increase as demand on the system rises and TransCo seeks to avoid additional reinforcement for peak loads by using constrained LNG as an alternative.

Transmission benefits

The transmission benefits paid by TransCo are currently subtracted from the price of deliverability of the particular storage service concerned, and are described in Table 6.3.

Table 6.3: Transmission benefits of storage*

	pence per peak day kWh/year		
	Deliverability charge	Transmission benefit	Final charge
Dynevor Arms	1.452	(0.329)	1.123
Isle of Grain	0.730	(0.219)	0.511
Avonmouth	1.076	(0.402)	0.674

* Prices are based on information from Storage Prices 1996 and on transmission benefits from 1 October 1996.

Source: BG TransCo

As one would expect, these sites are located at the extremities of the TransCo NTS. Consequently on days of exceptionally high gas demand, some of the gas supplied to the local area is provided via one of these facilities. In the event that gas was not available, pressures could drop in the local area and the system could fail. The concept of using LNG to reinforce gas supplies to the local system is known as transmission support. Each purchaser of storage from a constrained LNG site agrees to keep a minimum amount in store for use by TransCo. Table 6.4 shows these minimum levels for the 1996/97 winter.

Table 6.4: Characteristics of constrained LNG			
	Minimum % of available space*		
Week commencing 6.00am on:	**Avonmouth**	**Dynevor Arms**	**Isle of Grain**
1 October 1996 to 14 January 1997	48	33	49
21 January 1997	42	29	43
28 January 1997	35	24	35
4 February 1997	27	19	28
11 February 1997	16	11	17
18 February 1997	7	5	7
25 February 1997	2	1	2
4 March 1997 to 30 April 1997	0	0	0

* For each week in the 'winter period' a user's gas-in-storage in each constrained LNG facility shall be not less than the percentage of the user's available storage space indicated.

Source: BG Storage

TransCo is not able to make renominations on a shipper's storage on a whim; gas demand in the applicable LDZ has to be above a certain predetermined level. Again, for the 1996/97 winter these levels are described in Table 6.5.

Table 6.5: Demand threshold at which TransCo can renominate storage, 1996/97

Facility	Constrained LDZ	Demand (GWh/d)
Avonmouth	South-western	202.6
Dynevor Arms	South Wales	134.3
Isle of Grain	South-eastern	404.1

Source: BG Storage

Interruptible storage services

The concept of an interruptible storage service is reasonably straightforward. Any space booked in that facility carries with it the contractual right to inject gas into that space. Similarly, any gas that has been injected may be withdrawn on an interruptible basis only. TransCo may trigger interruption if there is insufficient deliverability, or operational system constraints that would limit its ability to deliver gas from Rough into the NTS. This right of interruption can only be taken up on days when the gas demand is 85% of peak.

Charges

The charges made by BG Storage to use any of the services described so far are given in Table 6.6.

Table 6.6: Service charges, 1996				
	Reserved space (p/kWh/yr)	Reserved deliverability (p/peak day kWh/yr)	Storage injection (p/kWh)	Storage withdrawal (p/kWh)
Firm				
Glenmavis	1.365	0.986	0.279	0.012
Partington	0.869	0.795	0.258	0.017
Hornsea: guide price	0.376	1.557	0.024	0.008
minimum price	0.291	1.208	0.024	0.008
Rough	0.135	21.898	0.021	0.007
Constrained				
Dynevor Arms	2.272	1.452	0.198	0.017
Isle of Grain	0.957	0.730	0.290	0.019
Avonmouth	1.170	1.076	0.190	0.019
Interruptible				
Rough	0.135	not applicable	0.021	0.007

Prices do not include NTS entry charges or transmission benefits for constrained LNG services.

Source: BG Storage

Storage is purchased from BG Storage in two principal ways – directly from the tariff and via the tender process. BG Storage has requested that storage purchases from Hornsea salt cavity should be undertaken by tender. This was partially as a result of the expected popularity of the Hornsea salt cavity facility. BG Storage established a guide price and a minimum price below which tenders would not be accepted. Those operators which subsequently choose to tender for Hornsea gas storage are ranked in descending order of price, with all successful bidders paying the price bid by the lowest ranked user.

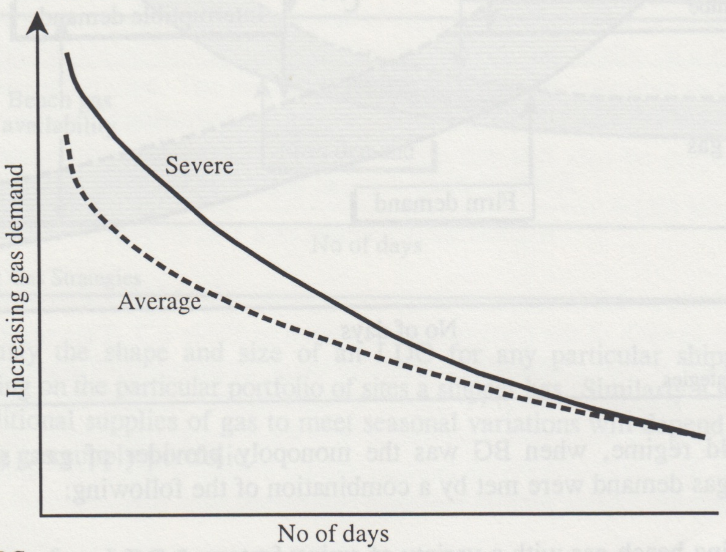
LOAD DURATION CURVES

The construction and interpretation of load duration curves (LDCs) is a vast subject and, therefore, this report provides a general description of what LDCs are and how they work, rather than an in-depth analysis of them.

Historical background and construction

Before the introduction of competition in Great Britain, when BG was the monopoly purchaser and seller of gas, one of the planning tools used by BG's planners was the construction of LDCs. When planning the gas supply system, BG based its approach on probabilities. Daily gas demand is dependent upon a range of variable parameters such as weather conditions, load growth, economic well-being, etc. The provision of gas supplies is also uncertain in terms of the potential for offshore failures and onshore pipeline breaks or system faults. Therefore from a planning point of view it was necessary to balance the expected sources of supply with the expected demands on the supply, to a level of security required. Consequently BG chose to design the system for a 1 in 20 day and a 1 in 50 winter, where the values of 20 and 50 denote the number of years between failures. Having established an acceptable risk level, it was then necessary for BG to construct a theoretical LDC that would reflect a 1 in 20 day and a 1 in 50 winter. This was done by measuring for a particular underlying base annual load the various total demands that would have occurred in a large number of years with different weather patterns. This analysis produced a statistical distribution of volumes from which the 1 in 50 level could be deduced.

Figure 6.1: Construction of average and severe LDCs



Source: BG

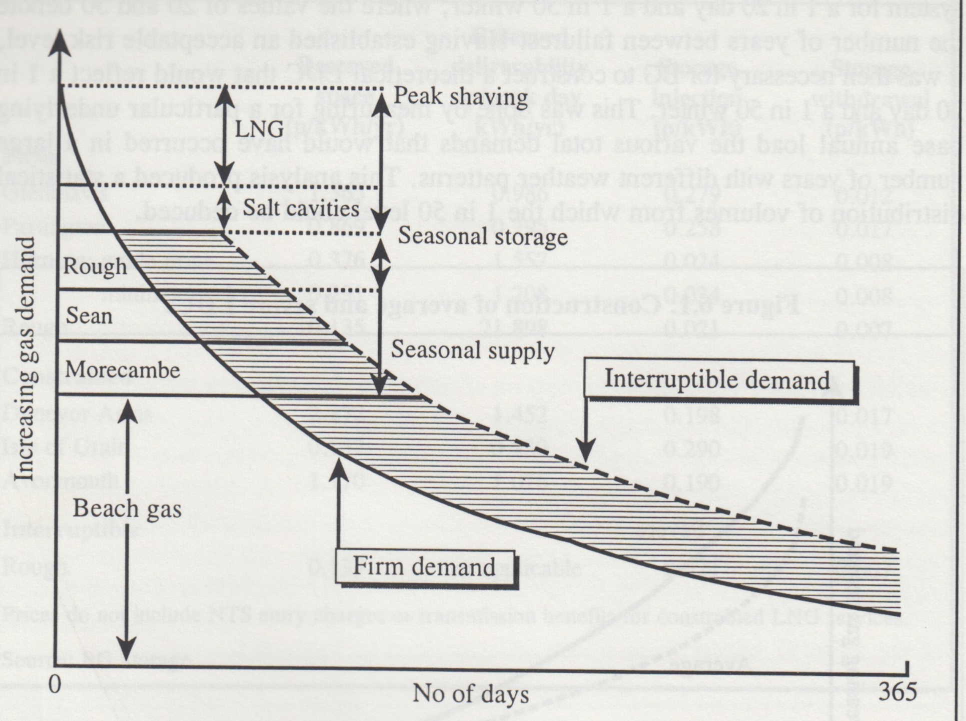
Figure 6.1 is a schematic of two typical LDCs, with one curve based on data for an average winter, and the other based on data for a severe winter.

The typical LDC shown in Figure 6.2 has a number of particular characteristics. The maximum point represents a 'needle peak' which is associated with the maximum peak day. The needle peak will be of a relatively short duration and historically any gas supply shortfall on these days would be met from the LNG facilities at the extremities of the system. While LNG facilities may have been expensive to build and operate, these facilities were only used for a few days a year, if at all. Consequently LNG was seen more as a gas insurance policy than an engineering facility to be used as a commercial tool. The levels of risk chosen as acceptable by BG when originally designing the system are summarised below.

1 in 20 peak day This is defined as the risk of failure to meet gas demand on the 1 in 20 peak day.

1 in 50 winter period This is defined as the risk of failure to meet peak demand over a winter period defined by the 1 in 50 LDC. A 1 in 50 winter is primarily associated with the annual availability of gas to meet high levels of gas demand over a substantial period.

Figure 6.2: Typical 1 in 50 LDC (based on BG as a monopoly)



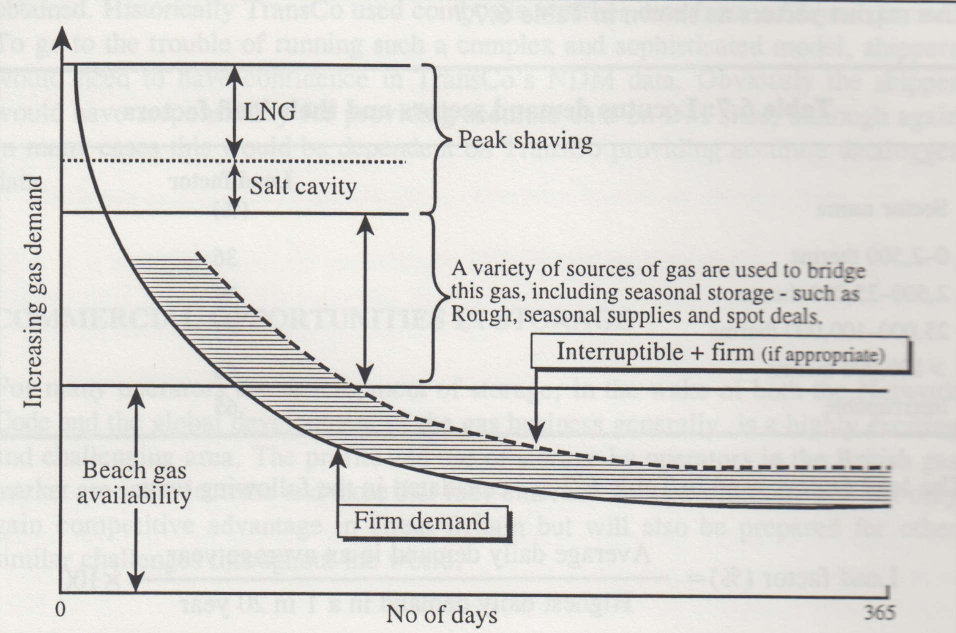
Source: Gas Strategies

Under the old regime, when BG was the monopoly provider of gas, seasonal variations in gas demand were met by a combination of the following:

- purchasing beach gas with a variety of swing factors;
- use of seasonal gas fields such as Sean and initially Morecambe;
- the Rough storage facility;
- interruption of interruptible customers;
- use of peak shaving facilities such as salt cavity and LNG storage.

However, under the new regime, TransCo no longer has direct control over all these facilities and is subject much more to commercial constraints as well as the constraints of operating in a competitive market. Also, under the Network Code rules shippers are now seeking to balance deliveries and offtakes on the day. Therefore, the ability of shippers to construct their own LDCs and to understand their significance has increased. A typical LDC for a shipper is shown in Figure 6.3.

Figure 6.3: Typical LDC for a shipper



Source: Gas Strategies

Obviously the shape and size of an LDC for any particular shipper will vary depending on the particular portfolio of sites a shipper has. Similarly a shipper's need for additional supplies of gas to meet seasonal variations will depend largely on its existing gas supply portfolio.

Creation of an LDC for an individual shipper

As a result of the relatively relaxed rules associated with the old monthly balancing legacy contracts and the potential for underbooking capacity, most shippers have not needed to produce sophisticated LDCs similar to the ones used by BG when it was a monopoly purchaser and seller of gas. The only obligation on shippers was to meet their 'difficult day' or 'storage day' requirements. However, as the gas market in the UK has become progressively deregulated the need for individual shippers to use these planning tools has increased. Therefore, as the transportation regime develops in Great Britain, the need to produce more sophisticated LDCs will also increase.

Use of BG's Locutus program

One option open to shippers is to use the BG Storage Locutus load curve program. Basically Locutus is a simple spreadsheet model which was originally written to familiarise shippers with the whole concept of LDCs, and to provide a simple means of modelling gas supply and demand. While the Locutus program is probably too simplistic to model all aspects of the new end-user categories in the Network Code, it does give users a good starting point. BG Storage is hoping to issue an updated version of this program in early 1997, to take account of the introduction of the Network Code.

The original version of Locutus held a predefined set of data for 10 LDCs, which consist of one SNT (seasonal normal temperature) and one severe (1 in 50) curve for five market sectors as shown in Table 6.7.

Table 6.7: Locutus demand sectors and their load factors

Sector name	Load factor (%)
0–2,500 therms	36
2,500–25,000 therms	39
25,000–100,000 therms	43
>100,000 therms	48
Interruptible	65

The load factors used in Table 6.7 are calculated in the following way:

$$\text{Load factor (\%)} = \frac{\text{Average daily demand in an average year}}{\text{Highest daily demand in a 1 in 20 year}} \times 100$$

In order to generate an LDC, it is necessary to ascertain the total annual demand for an average year in each of the market sectors shown in Table 6.7. This need not be too difficult since annual consumption data are made available by TransCo for all NDM sites, and shippers will have access to datalogger readings for DM sites. Obviously the use of only one load factor for each market sector is an over-generalisation. The new version of Locutus should enable shippers to input more sophisticated portfolio data, such as end user categories.

Once the data have been entered into the program Locutus produces two LDCs:

- a firm LDC based only on the loads associated with firm sales;
- a firm and interruptible LDC which is the daily sum for all of the market sectors.

The program then produces two LDCs; one for an average winter, and one for a severe winter.

Having constructed the LDCs Locutus then allows the user to model a variety of supply/demand matching scenarios by varying the quantities of beach gas, storage, and interruption available.

Own creation of LDCs

A shipper may also construct its own LDCs in a similar fashion using a simple spreadsheet and any load management data at its disposal. Clearly the size and complexity of the data available dictate whether or not this is a difficult or easy task.

It is also possible for a shipper to construct a more sophisticated LDC based on TransCo's NDM demand algorithm data, providing that the weather data can be obtained. Historically TransCo used composite weather data from a 65-year period. To go to the trouble of running such a complex and sophisticated model, shippers would need to have confidence in TransCo's NDM data. Obviously the shipper would have responsibility for providing accurate data on DM sites, although again in many cases this would be dependent on TransCo providing accurate datalogger data.

COMMERCIAL OPPORTUNITIES IN STORAGE

For many operators the development of storage, in the wake of both the Network Code and the global development of the gas business generally, is a highly exciting and challenging area. The profits and use of storage by operators in the British gas market are set to increase and those that fully embrace the opportunities will not only gain competitive advantage in Great Britain but will also be prepared for other similar challenges throughout the world.

Storage as a trading tool

With the growth in the spot market and increased activity in the flexibility mechanism, storage will no longer be simply a seasonal supply/demand insurance policy. In future, storage will be used as much to enhance a shipper's flexibility in gas trading as for seasonal load balancing. The ability of shippers to cycle their gas storage through many injection and withdrawal cycles will be the key to increased profitability.

Storage in conjunction with gas purchase contracts

Gas storage may also be used to assist in any potential take-or-pay problems that may occur towards the end of the contractual year. While the development of gas storage will not solve BG Trading's take-or-pay problems, many shippers would benefit from the addition of gas storage to their portfolios.

Increased security of supplies

At some stage in the future, gas from the former Soviet Union and many of the other east European countries may flow into Great Britain. Because of the distance it must travel and the relative political instability of its source, some of this supply may be less secure than many British operators are used to. Therefore the addition of storage capacity, possibly in the form of a depleted gas field, may well become commonplace.

CHAPTER 7: SUPPLY POINT ADMINISTRATION

INTRODUCTION

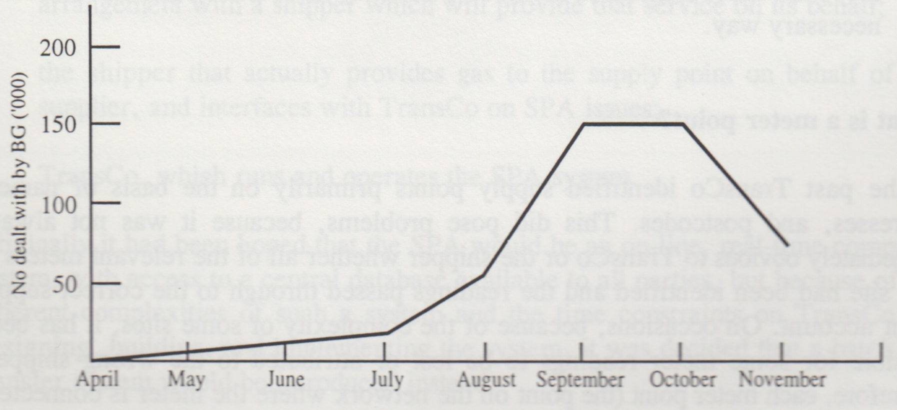
The term supply point administration (SPA) is used to describe the location or point at which gas is supplied to an end user, otherwise known as the customer.

SPA is a complex process, particularly in terms of the transfer of data between a shipper and TransCo. This chapter briefly outlines the role and processes involved to give an overview of their type and scale.

The historical background

The introduction and withdrawal of supply points either from BG Trading to a shipper or from one shipper to another has been an area that TransCo has struggled to manage. This is not altogether surprising since at the beginning of competition in 1990 the data on these supply points were held on 13 different computer systems (i.e. the 12 regions, plus BG head office for large industrial loads). Not only that, but the data were often held in different file formats if they were held electronically at all. That meant that most of the early processing needed to be done on paper. With the rapid growth of the competitive market the requests for gas transportation increased. This problem was further compounded by the reduction in the tariff threshold from 25,000 therms a year to 2,500 therms a year, which effectively increased the potential size of the competitive market from 30,000 to 300,000 sites. The effect of this change is clearly shown by the massive increase in the number of requests received by TransCo in 1992, as shown in Figure 7.1.

Figure 7.1: Transportation quotation requests per month, April-November 1992



Source: BG

Since the core business of TransCo is to transport gas on behalf of others from the beach to end users, TransCo needs to know:

- which shippers are responsible for which site;
- how much gas is likely to be used on a 1 in 20 day at that site;
- how much gas is likely to be consumed in a year;
- the actual location of the site in terms of address and postcode;
- other site specific information, such as any emergency contact names and telephone numbers.

Consequently, with the increasing size of the competitive market, and the expectation that with the introduction of the domestic market the number of supply points could rise to 19m, TransCo decided to implement a new supply point administration based on a sites and meters database (SAMD).

What is a supply point?

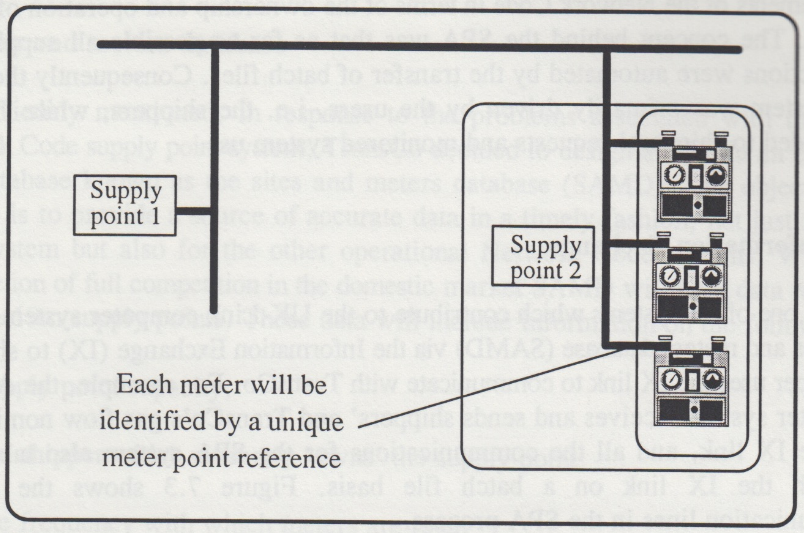
The term supply point is used to describe one or more meter points which combine to form a single end user. A single site might be a single supply point, although some premises can be supplied by more than one supply point. It should be noted that a single supply point is not able to supply more than one premises. The definition of a premises has been a considerable challenge to TransCo since, as a monopoly supplier, a tight definition of premises was not required, whereas under the Network Code whether a site is one or more premises does have cost implications. To paraphrase the definition of a supply point from the TransCo SPA self-study guide:

> A single premises in this context means a property, which can be a building or a collection of buildings, and which must fulfil a set of criteria: the buildings must be owned by one body, in close geographical proximity to one another; they must share a common enclosure; and they must serve each other in some necessary way.

What is a meter point?

In the past TransCo identified supply points primarily on the basis of names, addresses, and postcodes. This did pose problems, because it was not always immediately obvious to TransCo or the shipper whether all of the relevant meters at that site had been identified and the readings passed through to the correct supply point account. On occasions, because of the complexity of some sites, it has been possible for some meter readings to be lost or attributed to the wrong shipper. Therefore, each meter point (the point on the network where the meter is connected) is given a unique number. This number will not change even if the meters are replaced. An example of this is shown in Figure 7.2.

Figure 7.2: Supply points and meter points



Source: BG

The main operators involved in supply point administration

There are four main parties involved in the SPA:

- the customers or consumers (i.e. individuals or organisations) that consume the gas. They will, or at least should, know how much gas they are going to use, probably from monitoring their daily energy usage if a large consumer, or from past bills if a smaller energy user;
- the gas marketing company, sometimes called the gas supplier, which is responsible for actually talking to the end user to find out how much gas is wanted, if it is wanted on a firm or interruptible basis, and so on. Sometimes the supplier will also be a shipper, on other occasions it will have an arrangement with a shipper which will provide that service on its behalf;
- the shipper that actually provides gas to the supply point on behalf of the supplier, and interfaces with TransCo on SPA issues;
- TransCo, which runs and operates the SPA system.

Originally it had been hoped that the SPA would be an on-line, real-time computer system, with access to a central database available to all parties, but because of the inherent complexities of such a system and the time constraints on TransCo for designing, building, and implementing the system, it was decided that a batch file transfer system would be introduced instead.

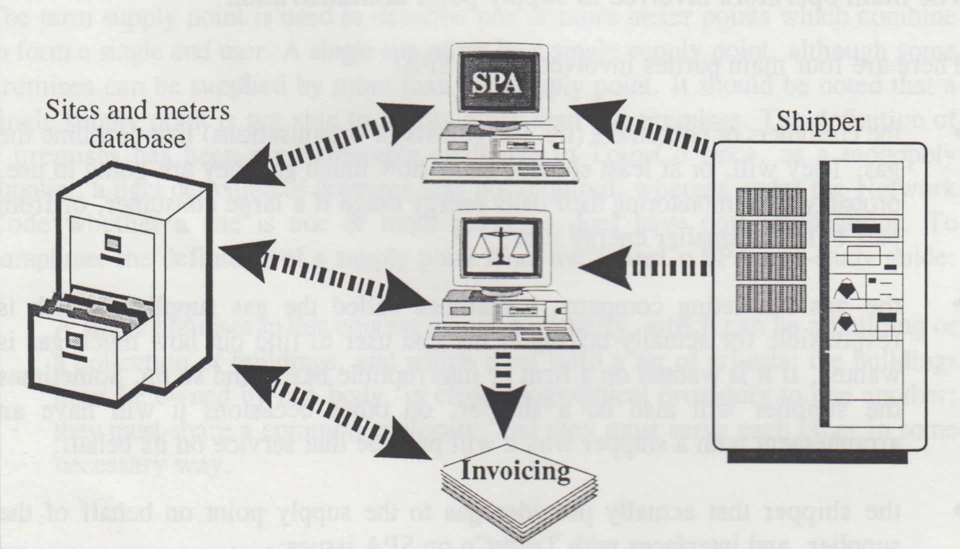
The supply point administration computer system

The SPA computer system was developed by TransCo to meet the evolving requirements of the Network Code in terms of the ownership and operation of supply points. The concept behind the SPA was that as far as possible all supply point transactions were automated by the transfer of batch files. Consequently the use of the system was primarily driven by the users, i.e. the shippers, while TransCo responded to shippers' requests and monitored system use.

The Information Exchange

SPA is one of the systems which contribute to the UK-Link computer system linking the sites and meters database (SAMD) via the Information Exchange (IX) to shippers. A shipper uses the IX link to communicate with TransCo. For example, the AT-Link computer system receives and sends shippers' and TransCo's gas flow nominations via the IX link, and all the communications for the SPA system also take place through the IX link on a batch file basis. Figure 7.3 shows the various communication lines in the SPA process.

Figure 7.3: The Information Exchange



Source: BG

Batch file communication

In an ideal world communication into and out from the SPA system would take place using batch files. Batch files can be accepted or rejected by TransCo. Rejection occurs for a variety of reasons, for example, if a record in a batch file contains invalid data or wrong data, or if mandatory data are not included. In theory TransCo is supposed to supply details of all rejected transmissions and the reason for rejection in each case. However, certain transactions may be referred to other TransCo offices such as the local district office for validation, and are known as referrals. Typically this would occur when TransCo wanted to check its ability to supply a particular load or whether it was appropriate to aggregate certain meters.

The sites and meters database

As previously mentioned, in response to the problems associated with the pre-Network Code supply point system, TransCo decided to design and build an entirely new database known as the sites and meters database (SAMD). The objective of SAMD is to provide a source of accurate data in a timely fashion, not just for the SPA system but also for the other operational Network Code systems. With the introduction of full competition in the domestic market SAMD will hold data relating to some 19m supply points. These data will include information on the following:

- supply point capacity;
- the shipper which currently 'owns' the supply point;
- the frequency with which meters are read;
- the organisation that reads the meter;
- firm or interruptible supply;
- type of supply, i.e. DM/NDM;
- any information on aggregation.

THE PROCESS OF INTRODUCING A SUPPLY POINT

Communication with the end user (customer)

The first thing the shipper has to do is to talk to the end user and obtain as much information as possible about the characteristics of the gas required, whether it is to be a firm or interruptible load, and what is the highest expected daily load. The site's meter number also needs to be ascertained. Once some or all of this information has been obtained the process of finding out the transportation charges can begin. This is called supply point nomination.

Supply point nominations for sites consuming more than 73,200kWh (2,500 therms)

For end users consuming more than 73,200kWh a year shippers nominate supply points by quoting the meter point number or numbers together with the postcode. Shippers can also specify some additional measures where TransCo offers an alternative. For instance, are meters to be read annually, every six months, or daily (above the appropriate minimum frequency), or is a datalogger required? In theory shippers can even specify who will read the meter, although this may be subject to change. They can also specify the type of gas nomination, whether it is a DM or NDM site, and whether it is supplying offtake quantity or hourly quantity.

Supply point nominations for sites consuming less than 73,200kWh (2,500 therms)

For supply points consuming less than 73,200kWh (2,500 therms) a year, supply point nominations are not necessary, unless the shipper requests a new aggregation. For these sites a confirmation-only process is needed, because they are within the domestic market. Therefore the provision of specific daily capacity for these sites is based on a site supply point offtake quantity (SOQ). If the issue of capacity is not relevant, then the only concern is whether the proposed site is likely to be supplied by the existing shipper. TransCo handles this by informing the existing shipper by way of issuing an automatic withdrawal notice. The arrival of this withdrawal notice gives the existing shipper the choice of objecting to the transfer (its existing supply agreement may not have expired), making a supply point nomination for any part of the existing contract that has not been lost to a competitor, or doing nothing, in which case the supply point transfers as planned. There are a variety of rules associated with this process which limit the time periods over which these actions can take place, although it is not appropriate to go into great detail in this report.

Site works

Sometimes a supply point nomination involves not only a new supply point but a request for an increase in capacity for an existing supply point. This may require the design and construction of new pipework between the supply point and the transportation system. The term used by TransCo for additional work to provide an appropriate level of gas supply is site works. The need for site works will vary, but will often be in response to one of the following:

- increased SOQ (peak day) requirement;
- request for a higher pressure;
- request for a new supply to a certain part of an existing site;
- request for gas on a greenfield site.

Quite often a request for a quotation for site works will involve visits by TransCo staff to the site. Currently the whole area of site works, and who actually does the work, is under review by TransCo. The most likely outcome of this is that the shipper or customer will be able to choose who does the site works.

The TransCo offer

When TransCo receives a supply point nomination, TransCo staff calculate the relevant transportation charges, taking into account information provided on gas consumption, capacity, exit zone, LDZ, the required meter-reading frequency, and whether it is a firm or interruptible end user. Within five days of receiving the supply point nomination, TransCo must make an offer. It might be necessary at this stage for TransCo to make certain validation checks concerning matters such as the size and number of meters, etc. Should this need arise, then TransCo has 21 working days to make an offer. Once the offer has been formally made it remains valid for up to six months from the date of issue.

Shipper's acceptance of the offer

Once the shipper has received the proposed charges in the offer, the shipper must then confirm acceptance of the offer before taking responsibility for gas consumption and taking ownership of the supply point. This is done by the shipper sending confirmation requests, accepting the terms quoted in the offer, and officially requesting ownership of a supply point with less than 73,200kWh capacity. The shipper also has to give advance notice before the requested start date. (Fourteen working days is the minimum, unless a supply point is being voluntarily withdrawn, in which case only seven days notice is required.) Once TransCo has received this acceptance, TransCo will assign a confirmation number to each acceptable confirmation. These numbers are unique to the shipper, so if a site is transferred to a new shipper at a later date then a new confirmation number will be provided.

TransCo's withdrawal notice to the existing shipper

Once TransCo receives a notice of confirmation it immediately sends a notice of withdrawal to the existing shipper. If for any reason the existing shipper wishes to object it has up to seven working days before the date on which ownership will change to do so. If no objection is forthcoming the supply point will transfer on the requested date, but there is always the possibility that an objection will be raised. If that happens the shippers involved have seven working days from the date of objection or until D7 (i.e. the seventh working day), whichever is the sooner, to resolve the matter, otherwise the confirmation will lapse.

THE CESSATION OF A SUPPLY POINT

If shippers want to stop providing gas to a supply point they can advise other shippers of their intent by withdrawing voluntarily, with one of two options. The first is 'without isolation' and the second is 'with isolation'. In 'without isolation' cases the existing shipper notifies TransCo of what it wants to do; that is withdraw from a particular supply point. Supply point details are then made available to other shippers, although the existing shipper is still responsible for transportation charges until the transfer of ownership to another shipper. 'With isolation' means that the gas supply is shut off, but the shipper must give TransCo 11 working days notice and must be on site when the supply is isolated, unless it is the consumer who has requested the isolation. With this option the shipper limits liability for transportation charges but continues to retain responsibility in the case of damage or loss at the supply point. The shipper also remains responsible for LDZ capacity charges and the capacity element of the customer charge until the end of the contract year for daily-metered supplies. However, the shipper may claim a refund if the supply point is subsequently reconnected in the same contract year.

CHANGING SUPPLY POINT CHARACTERISTICS

Amendments of flow details

Shippers can ask for a change to supply point details and, if they do, any subsequent amendments are recorded by TransCo. Amendments can be made, for example, to the maximum hourly consumption for DM supply points, or the supply hourly quantity. Change can also be requested for the maximum daily consumption at DM supply points or what is called the supply offtake quantity.

Amending the supply point type

Shippers can request a change in the supply type, to show whether a supply point above a consumption threshold is firm or interruptible. Shipper-nominated interruptible supply points can have their gas interrupted for a standard number of days if there is insufficient capacity in the transportation system to meet demand. TransCo has a role in this, to specify points as interruptible, and these supply points can have their gas supply interrupted during the year for an agreed number of days in excess of the standard number, although the number of days would be specific to each supply point.

During the month of August TransCo considers the level of interruptibility required over the next gas year to ensure the integrity of the gas transportation and storage system. The next gas year starts on the following 1 October. However, any changes made outside the annual cycle are related to the site's individual anniversary. This date is known as the 'eligible status change date'. The annual update process is the means by which TransCo reviews other aspects of the gas transportation and storage system, and occurs during August. Following this, and during the first five working days of September, shippers must send information on each supply point relating to a number of parameters, including supply point type, end user category, annual quantity recalculated, supply offtake quantity (SOQ) for NDMs, and exit zone capacity for NDMs. An emergency contacts review also takes place during the months of March and April.

PROBLEMS ASSOCIATED WITH SPA

The process of creating and maintaining sensible and accurate supply point portfolios for shippers has been a difficult area for TransCo. The rapid development of the competitive gas market in Great Britain, particularly as a result of the tariff threshold reduction from 25,000 therms a year to 2,500 therms a year, has created problems that have carried through to the Network Code. The type of problems that typically occur are as follows:

- a supply point not appearing in a shipper's portfolio, despite the shipper having signed a contract with the customer and introduced the site with TransCo;
- another shipper's supply point appearing in an incorrect shipper's portfolio;
- supply points without shippers;
- supply points appearing in more than one shipper's portfolio;
- incorrect or incomplete data on the database;
- not all of a supply point's meter numbers appearing on the database.

In order to solve some of these problems TransCo implemented a programme known as portfolio reconciliation.

Portfolio reconciliation

The objective of portfolio reconciliation was to correct the population of the shippers' databases in anticipation of the Network Code. In the event, the task of reconciling all of the problems associated with populating shippers' databases with the correct data proved a tough one. Therefore, the process of reconciling shippers' supply portfolios continued after the introduction of the code although, to be fair to all parties, the new portfolios were substantially improved.

Calculation of NDM demand attribution

As a result of the poor quality of shippers' supply portfolio information, the early operation of the Network Code was hindered by incorrect demand attribution for NDM sites. While some of these difficulties may be attributed to software problems, the inaccuracies associated with the supply point portfolios also contributed.

CHAPTER 8: THE IMPACT ON END USERS

INTRODUCTION

This chapter outlines the effect that the introduction of gas-to-gas competition has had on the various sectors within the gas market by highlighting its financial, commercial and strategic impact as well as examining the immediate effects of the introduction of the Network Code in the early part of 1996.

LARGE PROCESS USER AND POWER GENERATION MARKET

In many respects, before the introduction of gas-to-gas competition in 1990 and the privatisation of the electricity industry in the UK the market for gas-fired power generation simply did not exist. The main reason for this was that organisations were not allowed to burn gas, seen as a primary fuel, for the production of electricity. However, with the introduction of competition into the electricity market and the removal of these constraints there has been a huge growth in the use of gas for electricity generation in the UK. One of the first gas-fired power stations to be built in the independent sector was the Corby power station. Since then a great many power stations have been built by independent organisations such as Lakeland Power in Cumbria, IVO (the Scandinavian power company) on the Humber, as well as those built by National Power and PowerGen, including Ryehouse, Little Barford, and Connah's Quay. This huge increase in the use of gas in power generation has also had an effect on the gas market in Great Britain. Initially the use of gas for power generation had a retrograde effect, in that the regulatory bodies had hoped gas would be used to open up the industrial and commercial market via the 90/10 rule, whereas it was actually being used for power generation and consequently was not available for use in the industrial and commercial markets. Corby is a classic example of this, where 90% of the Bruce field gas was purchased by BG Trading leaving 10% available for third-party use. The Corby project snapped up this gas which never entered the industrial and commercial market as competitive gas. This situation of gas-fired power stations effectively sucking gas away from the industrial and commercial market as a result of the 90/10 rule was subsequently rectified when BG was forced to release more of its own gas through its release gas programme.

Financial impact

The financial impact of gas-to-gas competition on these large power generation projects has also been huge, since many producers were highly enthusiastic in seeking to sell gas to large power generation projects over 10, 15, or even 25-year terms. The opportunity to sell gas to a secure demand, which would enable field development costs to be underwritten, in many ways gave producers a measure of security against their concerns over a fragmenting gas sales market. Therefore, when a power generator went out to buy gas for a project it no longer had just one gas supplier to provide that gas, i.e. BG Trading, but was able to approach a variety of different suppliers and examine all the various options. Clearly this increased level of competition in the power generation market did push down the price of gas and meant that those producers which were seeking to sell gas were prepared to be creative in the services that they provided.

Commercial impact

The commercial impact of the power generators and large process load users, such as ICI, entering the competitive gas market has also been significant. The major power generators were originally part of the Central Electricity Generating Board (CEGB) and as such had a nationalised industry culture and were primarily technically driven. With the advent of competition, both in the electricity market and in the gas market, these organisations were forced to think in a more commercial manner. The effect on large organisations such as National Power and PowerGen of moving into a competitive gas market was inexorably to draw them into a more commercialised business culture. Whereas previously gas had been bought as a commodity and needed little commercial acumen to purchase it, since it was basically at one price for the quantities used, in the new commercial environment these large organisations started to develop commercial business teams which thought in an entrepreneurial fashion. This has led organisations such as National Power and PowerGen to move into other related business areas, such as gas trading, as well as moving upstream to purchase gas or shares in offshore fields and so on. So the impact of gas-to-gas competition, combined with the privatisation of the electricity industry, has increased the commercialisation of these organisations to the extent that they are in many respects leading the way in the development of their particular sectors of the gas market.

Strategic impact

The strategic impact of gas-to-gas competition in the large process user/power generation market has been linked with the commercial development of these businesses. Clearly those organisations that have wanted to remain competitive have had to develop gas-fired power generation in order to maintain their competitive edge in the electricity pool. Similarly these organisations have recognised their need to move upstream and gain expertise and assets offshore. Both National Power and PowerGen have purchased large quantities of gas offshore, although the two large power generators have done this in quite different ways. National Power has purchased gas from a portfolio of fields landing at a variety of TransCo entry points, whereas PowerGen has bought large quantities of gas off the west coast of Great Britain to be landed at Connah's Quay. However, the strategic principles are largely the same, that is that these companies sought to integrate their businesses vertically and gain access to the raw materials. Both National Power and PowerGen did try early in 1996 to become vertically integrated downstream by purchasing a regional electricity company (REC). While this strategic move was blocked by the MMC, nevertheless it is interesting that the power industry is seeking to become vertically integrated. One of the largest RECs, Eastern Electricity, has also sought vertical integration and has purchased power generating capacity from National Power. It would seem highly likely that Eastern Electricity will seek to develop its strategic position in Great Britain further by developing more gas-fired power generation or even converting some of the power stations it purchased from National Power.

It seems highly likely that large process users such as ICI and the power generators will continue to develop their strategic and competitive advantage in the gas market by becoming large purchasers of gas and large traders of gas on the developing spot market. It also seems likely that these same companies will continue to develop the capacity trading market which, as holders of large capacity, they must be in a position to lead if not dominate in the longer term. Finally the all-important question is whether these large power generators will be able to take advantage of their capability to produce electricity as well as to be large users of gas. The possibilities for hedging gas and electricity prices and taking advantage of a strong strategic position should be considerable.

The impact of the Network Code

Whereas in the early days of gas-to-gas competition power stations were on a relatively relaxed balancing regime, at least monthly and in some cases yearly, with the introduction of the Network Code the power generators have been expected to balance on a daily basis to quite tight tolerances, in the order of 5% (i.e. 2% of inputs plus 3% of outputs). This has meant that while the power generators have been in an extremely strong position in terms of knowing their daily gas demand, having access to real-time telemetry, and not being subject to the large weather-related gas demand swings that many other shippers encounter, they have also been expected to balance to much tighter tolerances. Earlier in the consultation process on the code the large power generators did take these issues up with the regulator and gained a small concession, but the regulator's argument seems to be that those that can balance will balance, and because of the accuracy of the demand information that power generators have they are expected to balance to a much tighter tolerance. With the introduction of the code, not only have the power generators had to balance on a daily basis but they have also had to nominate their offtakes accurately in order to avoid scheduling charges. So in some ways the introduction of the code has had a retrograde effect on them in that the guidelines are tougher, although this does need to be set against the increased opportunities that are there for those operators which are smart enough to take advantage of them. These increased opportunities include the opportunity for gas and capacity trading, and the opportunity to take part in the flexibility mechanism.

THE IMPACT ON INDUSTRIAL AND COMMERCIAL END USERS

Financial impact

For a variety of reasons, the industrial and commercial market has gained from the introduction of gas-to-gas competition more than any other. First, gas-to-gas competition began earlier in the industrial and commercial market than anywhere else. Consequently those end users that were bold enough to take a chance with some of these new gas suppliers did receive considerable discounts on the price they had been paying BG. Initially the market in the industrial and commercial sector was a BG-minus market, in that the early shippers were primarily seeking to undercut BG's prices. However, as the market developed it soon become a shipper-versus-shipper market, with the price of gas dropping considerably. The effect of this competition, combined with the emergence of the gas bubble, has resulted in considerably reduced energy prices in the industrial and commercial market, so much so that some European competitors have been complaining that the cost of energy in Great Britain is unreasonably low. This seems a somewhat ironic statement bearing in mind the reticence there has been in mainland Europe to embrace the competitive gas and electricity markets.

Commercial impact

While many energy buyers in the industrial and commercial market have not changed drastically as a result of competition, nevertheless many have become much more active in securing the most economic gas supply possible. Whereas before the introduction of a competitive market the choice was one supplier and one price, now it is commonplace for purchasers of gas in this market to go out to tender and to drive an extremely hard bargain. Many of these buyers are becoming much more commercially orientated in their energy purchases and despite the complexities of the Network Code have picked up a remarkable understanding of it. In a similar fashion to the large power generators, the industrial and commercial users have begun to develop commercial acumen in their particular market segment. Some of the larger users have started to look at combining a cheap baseload price to meet their process load requirements with a spot-related price for their peak gas requirements. Also, where operators have the flexibility, various derivatives of the old interruptible contracts have begun to emerge, with users seeing interruption no longer as a nuisance but as an opportunity to drive down the price of their gas. In fact, at its lowest point some interruptible users were buying gas at a price of 7p/therm and, bearing in mind that the spot beach price was 10p/therm, this must have been a good deal. Another feature that has developed in this market has been the emergence of user groups which are much more alive to the financial, strategic, and commercial issues developing in the gas market. Organisations such as the Major Energy Users Council (MEUC) and the Association of Electricity Producers have taken an active and vocal role in the development of the Network Code and the competitive gas market.

Strategic impact

While the strategic impact on the industrial and commercial market is not as great as on the large process user and power generation market, nevertheless the considerable reduction in energy costs has given British industry a competitive advantage that it otherwise would not have had in European and world markets.

The impact of the Network Code

In a similar fashion to the large process user and power generator market, the impact of daily balancing and scheduling penalties on the industrial and commercial market will only begin to be felt as the Network Code becomes fully operational. Nevertheless, it has already become apparent to many users that by improving the accuracy of their own demand forecasts and gas scheduling there can be a knock-on effect in terms of lower energy prices. Many shippers are effectively beginning to offer 'bundled' or 'unbundled' services. The 'bundled' service will offer gas priced at a commodity level to take account of poor demand forecasting and any scheduling penalties and imbalance charges that may be incurred as a result of a large industrial user not informing its shipper of a change in demand, whereas the unbundled service also being offered by shippers separates out all of the charges which the shipper may incur as a result of a large industrial user's poor demand forecasting or scheduling. Consequently those users which feel that they are able to forecast their gas demands accurately and provide their shippers with information that enables the shippers to keep their costs low, are being rewarded by a lower price of gas. Those which do not have the expertise or just cannot be bothered will pay a higher price.

THE IMPACT ON THE DOMESTIC MARKET

Introduction

The ability of BG's competitors to gain access to the large domestic market in Great Britain has been seen by many as the jewel in the crown. While BG has fought a strong rearguard action in seeking to limit its exposure to gas-to-gas competition in the domestic market, the shippers and industry pressure groups such as the Gas Consumers Council (GCC) have been strong advocates of competition in the domestic market provided that the appropriate safety and legislative safeguards have been put in place. During 1995 many of the legal and commercial blockages to the introduction of domestic competition were cleared so that the domestic market could open up, albeit on a trial basis, on 1 April 1996. The south-west of the country was chosen for the trial on the grounds that it was a uniquely defined geographical area and, under the transportation charges, was likely to pick up the highest charges. Therefore, exposing this area of the country to competition first, when the market is likely to be at its fiercest and most competitive, should ensure that the prices offered to consumers in the south-west are some of the most competitive that the market will see.

Financial impact

The financial impact of gas-to-gas competition in the domestic market is only just beginning to be felt, under the pilot scheme in the south-west. However, the costs of gas in the south-west are coming down and most competitors are offering between 10% and 20% off BG's bills. A variety of packages are being offered by many of the suppliers, which include Amerada Hess, Total Gas Marketing, Calortex, Sweb Gas, and many more. By early 1997 the penetration into this market was approximately 18%. Some commentators felt this was as good as could be expected while others were clearly disappointed. Whatever the outcome of the trial it is fair to say that the door has opened wide in terms of competition in the domestic market. Householders will no longer be prepared simply to pay a standard price for their gas and, in the long term, prices must continue to be competitive with so many gas suppliers in the market-place. BG Trading has been given an RPI–X price cap again by the regulator, making the domestic market still more competitive, so by tough regulation of BG Trading Ofgas has been able to drive down prices in the domestic gas market. Competition may actually be limited if Ofgas drives too hard a bargain with BG Trading and existing or new suppliers look at the potential gains in the domestic market and decide to put their energy and money elsewhere. Therefore Ofgas clearly has a tough balancing regime of its own which is to regulate the monopoly seller of gas in the domestic market, BG Trading, with a tough but fair regulatory regime while not stifling competition before it truly emerges.

Commercial impact

Apart from the incentive of price most householders will probably not change their commercial behaviour to any large extent as a result of gas-to-gas competition except that, as it takes root, more individuals will be prepared to shop around. However, with the introduction of gas-to-gas competition and electricity competition in the domestic market looming in 1998, it seems highly likely that some of the utilities will consider offering joint energy packages, and using the synergy of simultaneous meter reading and billing from one source for both electricity and gas (and even possibly water in the case of ScottishPower's takeover of Southern Water), in order to be more competitive. So from the point of view of the customer in the domestic market the choice on offer will increase and, it is hoped, the price will continue to remain competitive.

Problems in the domestic market

One of the main problems that has occurred in the domestic market has been concern over the doorstep selling techniques that have been used by various companies. Nevertheless the introduction of competition, and the tough environment that these companies operate in, has resulted in some strange selling techniques being applied by some of the organisations concerned. Fortunately industry watchdogs such as the Gas Consumers Council, and the media, have been quick to pounce on these problems and the appropriate organisations have taken remedial action.

THE IMPACT ON THE SAFETY AND SECURITY OF SUPPLIES

The safety and security of supplies remains very much TransCo's responsibility. Therefore, with increasing competition and TransCo's position in a tough regulatory environment, have come concerns over TransCo's ability to maintain the safety and security of the gas supply system. While at present this continues to be operated in a safe and secure manner, it is often asked for how much longer TransCo can be seen to reduce its staffing levels and cut costs without having an impact on security. Clearly any problem in relation to the security of supplies or gas safety will not only have an impact on TransCo but will have a huge knock-on effect on all gas suppliers in the industry. If anything, BG Trading is still seen very much as a safe pair of hands, in the domestic market in particular. Therefore any possible supply problems with TransCo are likely to benefit BG Trading! Consequently industry watchdogs such as the Gas Consumers Council and Ofgas are monitoring TransCo's safety record with interest.

[illegible] Trading Ofgas has been able to drive down prices in the domestic gas market. Competition may actually be limited if Ofgas drives too hard a bargain with BG Trading and existing or new suppliers look at the potential gains in the domestic market and decide to put their energy and money elsewhere. Therefore Ofgas clearly has a tough balancing regime of its own which is to regulate the monopoly seller of gas in the domestic market, BG Trading, with a tough but fair regulatory regime while not stifling competition before it truly emerges.

Commercial impact

Apart from the incentive of price most householders will probably not change their commercial behaviour to any large extent as a result of gas-to-gas competition except that, as it takes root, more individuals will be prepared to shop around. However, with the introduction of gas-to-gas competition and electricity competition in the domestic market looming in 1998, it seems highly likely that some of the utilities will consider offering joint energy packages, and using the synergy of simultaneous meter reading and billing from one source for both electricity and gas (and even possibly water in the case of ScottishPower's takeover of Southern Water), in order to be more competitive. So from the point of view of the customer in the domestic market the choice on offer will increase and, it is hoped, the price will continue to remain competitive.

Problems in the domestic market

One of the main problems that has occurred in the domestic market has been concern over the doorstep selling techniques that have been used by various companies. Nevertheless the introduction of competition, and the tough environment that these companies operate in, has resulted in some strange selling techniques being applied by some of the organisations concerned. Fortunately industry watchdogs such as the Gas Consumers Council, and the media, have been quick to pounce on these problems and the appropriate organisations have taken remedial action.

THE IMPACT ON THE SAFETY AND SECURITY OF SUPPLIES

The safety and security of supplies remains very much TransCo's responsibility. Therefore, with increasing competition and TransCo's position in a tough regulatory environment, have come concerns over TransCo's ability to maintain the safety and security of the gas supply system. While at present this continues to be operated in a safe and secure manner, it is often asked for how much longer TransCo can be seen to reduce its staffing levels and cut costs without having an impact on security. Clearly any problem in relation to the security of supplies or gas safety will not only have an impact on TransCo but will have a huge knock-on effect on all gas suppliers in the industry. If anything, BG Trading is still seen very much as a safe pair of

CHAPTER 9: THE FUTURE

INTRODUCTION

With the introduction of gas-to-gas competition in 1990 the door was opened wide to competition in Great Britain. Since then the competitive market in gas has grown at an almost exponential rate, with the handful of customers in the first year growing ultimately to a planned 19m in 1998 on the full introduction of gas-to-gas competition in the domestic market. This will be one of the largest changes in any of the gas markets.

The market within Great Britain is still continuing to develop. Its future is an exciting one, since the British gas industry has led the way in the introduction of competition in Europe. With the construction and commissioning of the Interconnector due to be complete by 1998 it seems highly likely that Bacton could well become the centre of a European gas trading hub. Therefore with these exciting possibilities in mind this chapter addresses some of the areas that might change over the next five to 10 years.

THE NETWORK CODE

While the Network Code has been successfully introduced in 1996, the demands on shippers to balance on a daily basis will continue to increase with the decreased imbalance tolerances allowed by TransCo. This has already been hard-wired into the code, and although some changes may be made as a result of TransCo's poor performance in various areas, ultimately shippers will be expected to balance on a much smaller tolerance. One of the effects will be an increase in activity in the flexibility mechanism, at least initially, which will increase the price of SMP and consequently expose shippers to higher balancing charges if they are out of balance. One of the results of this that has already been seen is the increased use of storage. This will continue as the price flexibility of gas increases.

There will also be an increase in the level of unbundling of TransCo's services. With such a tough regulatory regime, one of the regulator's fundamental beliefs is that where competition can be introduced it should be. Therefore any area of TransCo's operation that can be subjected to the competitive forces rather than the regulator's steely gaze will be.

With the introduction of full daily balancing and potentially higher prices on the flexibility mechanism it seems likely that some small independent shippers will not survive. Already some of the smaller shippers have been merged with larger ones, with Gas Direct being taken over by Quadrant, and Flogas being taken over by Kinetica. Just as with petrol sales, the smaller shippers will simply not have the purchasing power or the ability to absorb the relatively high overheads for running 24-hour operations to compete effectively as a shipper and a gas seller. This will be quite a sad change, as the introduction of entrepreneurial gas sales organisations has been one of the lighter aspects of gas competition being introduced in the UK.

PRICES

At present gas purchase prices at the beach in Great Britain are in the order of 13p/therm, and gas is being sold for 17p/therm for the first quarter of 1997. These prices are still considerably lower than the cost of gas on mainland Europe, primarily as a result of the gas bubble. Consequently, at least until the Interconnector is in full operation, it seems likely that these gas prices will continue at a relatively low level, although prices are forecast to rise.

DEVELOPING MARKETS

One of the most exciting aspects of the introduction of competition in the UK has been the number of new markets that have developed as a result of gas-to-gas competition.

The developing gas spot market

The gas spot market in Great Britain is developing quite rapidly. It currently operates on a telephone basis, although it is likely that at least part of an International Petroleum Exchange (IPE) screen-based gas trading system will be in operation in early 1997. This will be another step forward in increasing the liquidity of the gas spot market in Great Britain and the transparency of prices. While spot prices are published by organisations such as PH Energy Analysis via the Heren Index, nevertheless a completely transparent trading system can only help improve the quantity of gas being traded in the market-place.

Development of a futures and derivatives market

With the introduction of a spot market and the increasing likelihood of a screen-based gas trading system developing in Great Britain, it can only be a matter of time before both a futures and a derivatives market develop. The fact that so many of the merchant banks were showing an interest in the IPE screen-based trading system shows that there are many companies waiting in the wings to provide a service to the gas industry that will make possible hedging of the potential financial risks associated with purchasing a commodity in a volatile market.

Capacity trading

It seems highly likely that a capacity trading market will be one of the first to develop, since the facility is already available in Great Britain on the TransCo UK-Link computer system. At the moment what appears to be constraining the development of the market is the fact that capacity is available as an infinite commodity as a result of the Network Code, although this seems likely to change with the introduction of the three-node model and capacity being seen much more as a finite commodity. Once this happens, it becomes much more highly valued and trading will increase.

Other areas

With the development of these markets it also seems likely that other areas of the energy industry will continue to unbundle at a remarkable rate. The Network Code has been written with a view to the unbundling of meter readings, and it seems likely that other areas will follow in the near future.

THE INTRODUCTION OF THE INTERCONNECTOR

The introduction of the Interconnector linking Bacton to mainland Europe will have a huge impact on the gas industry in Great Britain. Initially it will allow for the export of gas from Great Britain to mainland Europe. This will have two effects. First it will allow for the depletion of the gas bubble, and may even solve some of BG Trading's take-or-pay problems. Second it will allow gas prices to rise from the relatively low levels of 1996 to something consistent with a discount on the European levels.

The introduction of a huge new market to Great Britain at a time when mainland Europe is again looking at the introduction of competition can only be good for those companies involved in the competitive gas industry in Great Britain, since the operational and commercial skills honed in the tough home environment of Great Britain will be exportable, along with gas, to Europe. Therefore those companies with a strategic eye on the future will be seeking to develop relationships with partners in joint ventures, or acquisitions in Europe. With the level of fairly cheap gas in the UK continuing, it seems only a matter of time before the industrial pressure groups in mainland Europe drive the market there towards competition. On the other hand, there are strong pressure groups from the existing industry hierarchy seeking to stifle competition before it is born.

Looking further into the future the Interconnector also provides Great Britain with an alternative source of gas, from eastern Europe and the former Soviet Union, which will put a ceiling on the maximum price payable for gas in Great Britain. In fact, it is likely that the commercial impact of the Interconnnector on the British gas industry will ultimately have an operational impact on the way in which TransCo and other operators in the market think. With the possibility of purchasing cheap gas from eastern Europe, many will want to purchase this gas and yet take account of the potential problems associated with its low security. Therefore the development of onshore and offshore storage, along the lines of Rough and Hornsea, and other large scale gas storage facilities, is likely to become much more common in Great Britain.

CONCLUSION

Finally, then, while the introduction of gas-to-gas competition and the hard landing of the Network Code are two of the biggest changes to hit the British gas industry since the conversion from town gas to natural gas in the late 1960s and early 1970s it would be fair to say the introduction of the Network Code is nowhere near the end but only the beginning of the beginning, and that the gas industry not just in Great Britain but in Europe as a whole has an exciting future.

GLOSSARY

The following list is a shortened version of the definitions used by British Gas TransCo in *Network Code Glossary* and is used by kind permission of British Gas TransCo.

Ad-hoc invoice	An ad-hoc invoicing facility will be provided so that charges which are not fully systematised can be billed to system users.
Adjustment invoice	An adjustment invoice is used where the correction of invoice data has a corresponding financial effect thereby eliminating the need to reopen the primary invoice. A separate adjustment invoice will be produced for each invoice type (e.g. capacity, commodity) where adjustments have been made.
Aggregate LDZ capacity charge	The sum of the LDZ capacity charges applicable to each supply point.
Allocation	Allocation is where total measured gas flows are allocated to individual shippers for balancing and billing purposes. The amount of gas input and output by each shipper is allocated to agreed methods.
Allocation agent	An allocation agent calculates the amount of gas that each shipper puts into the system and enters input allocation claims on behalf of shippers.
Allocation agreement	An agreement where gas is supplied through a single meter by more than one shipper.
Annual load profile (ALP)	The ratio of consumption at SNW on a day to the daily average consumption over a whole year at SNW. Defined for each day by TransCo for each EUC but published in advance.
Annual quantity (AQ)	Annual quantity corrected to SNT.
AT-Link	Application Transfer-Link is the system upon which the majority of the energy balancing processes involved in the transport and storage of gas are conducted.
Balance	The balancing of gas used by consumers with the gas which is put in by the producers. The safety end efficiency of the system depends on a consistent balancing of the system.

Booked capacity	Booked capacity is any capacity that a shipper buys from TransCo.
Calorific value (CV)	Calorific value is the energy in megajoules (MJ) produced by the combustion of 1 cu metre of gas.
Capacity	Capacity is the amount of gas that can be held within the physical structures (pipelines and storage facilities) that make up the NTS.
Capacity (entry)	Entry capacity is the amount of gas that a shipper is entitled to put into the system at a particular input point (terminal) on a day.
Capacity (exit)	Exit capacity is the amount of gas that a shipper is entitled to withdraw from the NTS in order to meet the requirements of its customers on a day.
Capacity (LDZ)	LDZ capacity is the shipper's entitlement to offtake gas at its customers' premises within each LDZ on a day.
Capacity (space)	The amount of energy that can be stored at a storage facility.
Capacity (deliverability)	The daily rate at which energy can be withdrawn from a storage facility.
Capacity bid	A bid by a shipper to buy capacity against another shipper's capacity offer.
Capacity booking	The process by which a shipper reserves a daily entitlement to transport and/or store gas for the following 12 months.
Capacity charge	A charge determined by the amount of a user's registered system entry capacity; registered NTS exit capacity; or registered LDZ capacity at a system point
Capacity deal (or trade)	The transaction resulting when a selling shipper selects a capacity bid against its offer, effecting the transfer of capacity entitlement.
Capacity offer	An offer by a shipper to trade (sell) a quantity (range) of capacity for a specific period.
Capacity trading	Capacity trading is the process by which shippers with spare 'capacity' sell it to other shippers which require more 'capacity' through a process of offers and bids.
Capacity tranche	Capacity tranche is quantity of capacity (in kWh), usually entry or exit capacity, which a shipper may book for a defined period, typically 12 months.

Commodity charge	Is a charge in respect of use of the system determined by the quantity of the gas flow at a system point.
Constrained LNG storage	Constrained LNG storage is that LNG storage which, while booked for a shipper, may be nominated for withdrawal by BG TransCo to maintain supply security at specific points on the system.
D	The 'gas day' (starting at 6.00 am). Therefore 'D-1' is the day before the gas day, 'D-2' is two days before the gas day and so on. 'D+1' is the day after the gas day.
Daily adjustment factor (DAF)	A measure of weather sensitivity of demand for each EUC.
Daily balancing	Shipper inputs and outputs are balanced at the end of each 'gas flow day' and the appropriate imbalance charges are calculated.
Daily cash out	Imbalance and scheduling charges are calculated and carried out on a daily basis.
Daily imbalance	Is the difference in quantity on a day between the amount of gas delivered to the system and the amount offtaken (taking into account trade nominations and flexibility quantities).
Daily metered (DM)	A category of end customer.
Daily reconciliation variance	The difference between the actual daily energy quantity for the meter and the allocated daily energy quantity for the meter. This is determined for each day within the reconciliation period.
Datalogger	Dataloggers are devices fitted to meters which can record, store and transmit readings and measurements.
Deliverability	Deliverability is the maximum quantity of gas that can be withdrawn from storage on a single day. $$\text{Duration} = \frac{\text{Space}}{\text{Deliverability}}$$
Demand attribution	The 'before the day' process by which the total NDM forecast for an LDZ is subdivided into output nominations applying to each shipper, in accordance with a formula. Or the 'after the day' process by which all the NDM loads in an LDZ are allocated between the shippers, in accordance with the same formula.

DM nomination	The calculated output nomination for all DMs for a given shipper within an LDZ. The shipper's forecast (or nomination) of the daily offtake of one (or a group) of its customers.
Daily metered aggregate (DMA)	A group of smaller DM sites within each exit zone for which each shipper nominates its aggregate daily offtake.
Daily metered consumer (DMC)	A DM site that consumes large quantities of gas (i.e. >58.6m kWh a year). TransCo needs separate gas nominations for very large consumers of gas to enable it to schedule the network accurately.
End-user category (EUC)	A category in which each NDM consumer is placed for demand attribution purposes.
Entry point	The point at which gas enters the gas transportation system. This could be at sub-terminal, storage facility, or onshore field.
Exit zone	An exit zone is a geographical gas distribution area (wholly contained within an LDZ) that groups together supply points which, on a peak day, receive gas from a specified NTS offtake point(s) and which attract the same exit capacity charge rate.
Flexibility charge	In relation to an accepted bid flexibility charge is the flexibility quantity × the accepted price.
Flexibility market or Flexibility mechanism	The flexibility market is a market based method by which TransCo is able to select which shippers should provide extra gas to, or remove gas from, the network. Shippers make bids to buy or sell gas for these purposes, and when operating conditions require TransCo will then choose the best (according to price) of these.
Forecast total demand	The forecast gas requirements produced by system control for both DM and NDM within an LDZ (including projected shrinkage losses on the LDZ system).
Gas flow nomination (GFN)	Gas flow nomination is the process by which a shipper informs TransCo of its requirements for input and offtake for the following day so that TransCo can plan and control the daily operation and safety of the pipeline system.

Gas marketers	Gas marketers are middle men who contract with shippers and sell to consumers.
Gas suppliers	Same as a gas marketer.
Gas traders	Gas traders buy and sell gas to one another before it reaches the consumer.
Gas trading	Gas trading is a method by which shippers sell/buy gas between themselves. This may be to make up a shortfall in gas supply on a day, or may be used because the shippers have insufficient entry or exit capacity. Gas trades occur at the NBP.
Imbalance	A comparison between a shipper's total allocated inputs and total allocated outputs. More precisely: Inputs–outputs ± accepted flexibility bids where: 'Inputs' = the aggregate of the shipper's inputs to the NBP.
Local distribution zone (LDZ)	A geographical zone for which the total input and output demand can be measured each day. Inputs to the LDZ are based on groups of offtakes from the NTS.
LDZ capacity invoice	The LDZ capacity invoice includes LDZ capacity charges.
Liquefied natural gas (LNG)	There are five LNG sites around the NTS, where gas is cooled until it becomes a liquid (−160°C) and is then stored in insulated metal tanks.
National offtake	A metering point defining the boundary between the NTS and the LDZ. For any given LDZ the sum of the meter readings of the appropriate national offtakes defines the measured gas into that LDZ.
National balancing point (NBP)	An imaginary point through which all gas passes in accounting and balancing terms.
National transmission system (NTS)	The national transmission system is the high pressure network of pipes that transports the gas between the terminals, storage facilities, and specific regional sites for local distribution.
NTS/LDZ offtake	An NTS exit point comprising all the individual system points at which gas flows from the NTS into an LDZ, or that part of an LDZ located in a particular exit zone.

Net capacity	The measure of capacity which is defined as the capacity booked by a shipper plus or minus any capacity trades. It is against the net capacity level that shipper's overruns are judged. Net capacity is only relevant to entry and exit capacity, where trading is permitted.
The network	see national transmission system.
Network Code	The Network Code is a set of business rules within a legal framework which defines the rights and obligations of TransCo and the shippers and forms the basis of all contracts between them.
Nomination	A unique request for a specific quantity of gas for a day between two points on the pipeline system.
Nomination scheduling	The process of reducing aggregate nominations because of a constraint at an 'entry' or 'exit' point to the NTS.
Non-daily metered (NDM)	A site that is not measured on a daily basis.
Non-daily metered aggregate	These are a number of NDM sites, with annual consumption 2.198m kWh, that have been aggregated by LDZ for nominations and balancing.
Ofgas	Office of Gas Supply (see under Regulator).
Overrun	The gas quantity difference between a shipper's allocated quantity and shipper service capacity quantity at entry, DM exit, or storage point, when the allocation breaches the booked capacity.
Peak shaving	Peak shaving refers to storage which is designed to be used to cover short-term peak demands for gas. This usually takes the form of LNG storage.
Producer	Producers are the companies which explore for gas, drill the wells, and flow the gas from the sea bed. They send the gas along undersea pipes and hand it over to the terminal operators.
Profile algorithm	The formula used by demand attribution to divide the NDM forecast, or the NDM allocation, among the shippers.
Regulator	The regulator is the Office of Gas Supply (Ofgas), a non-ministerial government agency which regulates the onshore gas industry in the UK.

Renomination	A nomination of gas after the nomination cut-off time. This can be a change to an existing nomination or a new nomination.
Renomination acceptance period (RAP)	A period during which shippers can make renominations. TransCo System Control will open a RAP, e.g. when forecast demand changes above certain threshold values occur, or when a shipper requests one following a change in a customer's demand.
Rough storage	There is one Rough storage facility which is a depleted gas field just offshore near Easington on the Humber.
Salt storage	This refers here to the salt (cavity) storage facility, situated near Hornsea in East Yorkshire, which has been made by creating several holes, 1,800 metres below ground, by dissolving layers of salt.
Scaling factor	A separate factor applied in each LDZ: $\dfrac{\text{All LDZ demand} - \text{LDZ DM demand}}{\text{calculated aggregate NDM demand}}$
Scheduling	Scheduling is the process by which TransCo decides how best to transport and store the nominated gas, taking into account the various routes which are available and any constraints on the network.
Scheduling charge	A charge derived by applying a rate to the scheduling difference above tolerance (if any). Input scheduling charges are assessed at the entry point level and output scheduling charges are assessed at the DMC or DMA level. The charge is calculated daily and is based on the SAP.
Scheduling difference	The difference between the shipper's nominated and allocated quantities.
Secondary market	The 'secondary market' is the capacity trading market.
Seasonal normal weather (SNW)	Seasonal normal weather in an average year.
Service	A service is the recorded agreement between TransCo and a system user for the provision of either gas transportation into or out of the NTS or the usage of storage facilities.
Shipper	A shipper is a company that contracts with TransCo for the use of Network Code transportation and storage services.

Shipper's agent	The shipper's agent is employed by a shipper to perform operational tasks (e.g. nominations) within the Network Code on behalf of the shipper.
Site nominations	Site nomination is the process by which a shipper informs TransCo when it wishes to supply gas to a new customer. TransCo maintains a record of all the sites within Britain to which gas can be transported.
Supply hourly quantity (SHQ)	The maximum hourly offtake at a supply point.
Supply meter point	An individual supply exit point at which gas may be offtaken from the system to supply particular premises.
Supply point administration (SPA)	SPA maintains the records of every consumer linked to the network, in particular which shipper it is supplied by, how much it uses in an average year, and who to contact in an emergency.
Space	This is the measure of the quantity of gas, in terms of energy, which can be placed into storage.
Storage	Storage is the gas storage service that TransCo offers to shippers.
Supply offtake quantity (SOQ)	The maximum daily offtake at a supply point.
Supply point	The metered point at a site where gas is supplied from the TransCo system to the end user by a single shipper.
System	The pipeline system operated by TransCo for the conveyance of gas.
System average price (SAP)	System average price of gas will be calculated each day by summing quantity × price for each accepted flexibility bid and then dividing by the sum of the quantities of each accepted bid.
System entry point	A system point comprising one or more individual system entry points
System exit point	A system point comprising one or more individual system exit points.
System marginal price (SMP)	System marginal price is the highest price paid for flexibility gas bought by the system or the lowest price received for flexibility gas sold by the system.

Therm	The imperial unit of measurement for a quantity of gas. The metric unit that is now used is the kilowatt hour (kWh).
TransCo	The business unit within BG which provides transportation and storage services.
Transporter nominated interruptible (TNI)	A site where TransCo has the right to interrupt supplies for transportation reasons.
Tolerance	The percentage definition used to identify whether an imbalance or scheduling difference qualifies for a particular charge.
Transporter	The transporter is TransCo which is the business unit within British Gas which transports gas from the terminals to consumers on behalf of shippers.
UK-Link	The IT system and shipper–TransCo network to support the business functions of the Network Code. UK-Link is the overall title for the five main workstreams involved in the Network Code (SPA, Invoicing 95, Information Exchange, Sites and Meters, and AT-Link).
Unconstrained storage	Storage that when booked by a shipper cannot be nominated by TransCo.
User daily quantity output	The quantity of gas treated as offtaken by a user on a day at a supply point component or a connected system exit point.
Volume	Gas volumes will be expressed in million cu metres referred to standard conditions of temperature and pressure.
Weather correction factor (WCF)	A factor incorporated into the profile algorithm used by demand attribution to attribute demand to NDM end-user categories.

$$\frac{\text{LDZ demand} - \text{LDZ demand at SNW}}{\text{LDZ demand at SNW}}$$

ABBREVIATIONS

ALP	annual load profile
AQ	annual quantity
BG	British gas
CV	calorific value
DAF	daily adjustment factor
DM	daily metered
DMA	daily metered aggregate
DMC	daily metered consumer
EUC	end-user category
kWh	kilowatt/hour (3,600 Joules)
LDZ	local distribution zone
LNG	liquefied natural gas
m cu metres	million cubic metres
MJ	million joules
MMC	Monopolies and Mergers Commission
MW	1 million watts
NBP	national balancing point
NDM	non-daily metered
NDMA	non-daily metered aggregate
NTS	national transmission system
Ofgas	Office of Gas Supply
OFT	Office of Fair Trading
SDMC(I)	interruptible supply point component
SHQ	supply hourly quantity
SMP	system marginal price
SNI	shipper nominated interruptible
SPA	supply point administration

SOQ	supply offtake quantity
TNI	transporter nominated interruptible
UDQI	user daily quantity input
UDQO	user daily quantity output
VLDMC	very large daily metered consumer
WACOG	weighted average cost of gas
WCF	weather correction factor