Trading Natural Gas in the UK

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1. INTRODUCTION

The objective of this paper is to provide an overview of the UK[1] gas market, how it has developed, where it stands currently and how it is likely to develop in the future. It provides a historical context in which to place the various contractual mechanisms by which gas is traded and points out some of the pitfalls and the issues of which companies should be aware in entering the UK gas market. It also offers some opinions on how gas trading might develop in the future.

We look at the regulatory and contractual regime before and after the 1986 Gas Act watershed, when BG was privatised and Ofgas was set up. It considers the BGplc/Centrica demerger and looks briefly at the 'take-or pay' issue.

Although the paper covers the introduction of Transco's Network Code and its rapid evolution since March 1996, it does not provide a clause by clause analysis of the Code and all of the 346 proposed amendments thereto (of which more than 200 have been adopted), but explains how different elements of the gas regime fit together in the operation of the market.

We shall track the growth of the whole trading background, regulated and unregulated, against which the Network Code must be considered by looking at the spot and futures markets. We shall look at the interconnectors and offer some views as to how the UK market might evolve in a European context.

This study takes into account the New Gas Trading Arrangements (NGTA) which came into effect on October 1st 1999.

[1] Throughout the paper references to the UK can be read as Great Britain since Northern Ireland is under a separate system of regulation. A brief description of the position in Northern Ireland and the Irish Republic is given in Section 8.1.

2. HISTORICAL CONTEXT

[There was] a period of stiff competition between companies supplying gas to London. With no defined limits on their supply area, companies lowered prices and used armies of canvassers to gain clients. Oxford Street and Tottenham Court Road were supplied by four different companies from five different gas stations. Payment was by fixed rental rather than by volume, so company workmen sometimes connected clients to other companies' mains while still charging them rental. Quality suffered, but there was also a large increase in demand for gas.[2]

To analyse the current situation in the UK gas market, it is necessary to understand a bit of the history of how competition has developed. The above quotation refers to the 1830–40 period when gas street lighting and gas lighting in private residences were introduced. It is not necessary to look quite that far back to find a context for recent gas developments, but it is amusing to remember this period and draw parallels with the current situation in the liberalised residential sector.

The UK gas market became a public discussion point in the period from 1967 to 1977 during the switch-over from town gas, made from coal, to natural gas, following the discovery of natural gas in the UK sector. The catch-phrase 'You're cooking with gas' found its way into common parlance at this time.

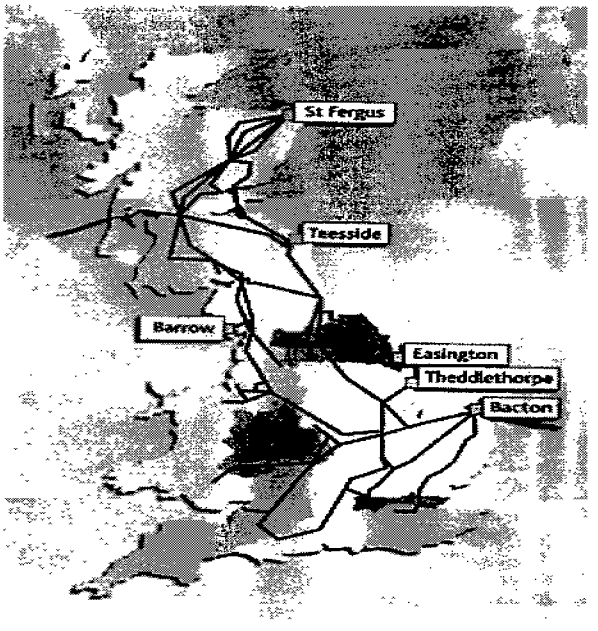

Figure 2.1: The National Transmission System of Transco, the Largest PGT Operator. Source Transco

[2] Quote from 'The London Encyclopaedia' edited by Ben Weinreb and Christopher Hibbert.

Against this background, an Act of Parliament was introduced in the late 1960s to prevent individual companies building or adding to gas transmission systems and a single National Transmission System (NTS) was placed in the care of the nationalised Gas Council, citing safety and economies of scale as good reasons for strong centralised control. In 1972, the Gas Act renamed the Gas Council as the British Gas Corporation (BGC), which bought gas on behalf of twelve area distribution boards.

But it was not until the Thatcher government of the mid-1980s, with the 'Don't forget to tell Sid' advertising campaign, that the full force of a tide turning against nationalised industries was felt in the onshore gas distribution sector. This came about as a consequence of the 1986 Gas Act, the privatisation of BGC and the setting up of Ofgas, the Office of Gas Supply, a non-ministerial government agency, which regulated the *onshore* gas industry in the UK.[3] *Offshore* gas was initially regulated by the Department of Energy and later by the DTI, after the responsibilities of the Department of Energy were reallocated to other government departments.

The transition from monopoly control to a fully competitive gas market has been the subject of numerous green papers, regulatory referrals, reports and Gas Acts. Rather than chronicle each in detail, which would be as tedious to write as to read, the following highlights the main points and the major milestones.

Before 1986, BGC held a monopoly position in the UK effectively setting the gas purchase price from producers, the sales price to consumers, the supply/demand balance (assisted by 'take-or-pay' arrangements and interruptible contracts) and all storage. Gas was transported under open access transportation contracts that linked the beach delivery point to the specific meter of the offtake customer. Supply to and from the NTS was delivered by producers and users on a monthly basis, with daily balancing being under the central control of BGC.

In 1986 BGC was privatised, as provided for under The Oil and Gas Enterprise Act of 1982, as a step towards the introduction of competition and the phasing out of the BGC monopoly. The 1986 Gas Act, the prime purpose of which was to transfer the assets of BGC to BGplc (BG), shares in which were sold to the public in November 1986, also provided for third-party access to the national pipeline network – an act which was to prove only one small step on the road to full competition.

At this time, gas sales agreements were between the upstream producers and BGC to whom all the gas field joint venture partners had made the same sales commitment, with the Common Stream Agreement ensuring all partners had the operational ability to perform under the sales contracts and the same forces driving decisions, such as field development/maintenance programmes, to avoid BGC delivery shortfall penalties.

The majority of contracts hailing from this period are field or licence-specific (i.e. the producer could not, and still cannot in the surviving contracts, substitute gas from alternative sources of supply, even when there was, or still is, a commercial

[3] Natural Gas and electricity in Northern Ireland is regulated by OFREG, The Office for the Regulation of Electricity and Gas, based in Belfast whose Director General is Douglas McIldoon.

incentive to do so). The prices tended to be expressed in p/therm, escalating with, usually, fuel oil prices and/or an inflation index like PPI. Coal prices were also a common feature of contracts at that time.

In November 1987, BG was referred to the Monopolies and Mergers Commission (MMC) by the Office of Fair Trading (OFT) which had received complaints from industrial consumers that they had no real competition to BG and that price relief was only being given by BG to customers who had an alternative source of supply. The MMC recommended in 1988 that such discrimination be stopped. Specifically, the MMC proposed that BG introduce price transparency by publishing price schedules for the large industrial and commercial consumers, that no discrimination in the setting of such prices be allowed, that the exercise of interruption rights under contracts be even-handed, that common pipeline carriage terms be published and that the 90/10 rule be introduced. This last provision, that BG be prevented from contracting for more than 90 per cent of the production of any new gas field, did much to overcome the inertia of upstream producers, who had been reluctant to be the first to be seen to challenge, in practice, the secure offtake of the BG monopoly.

By late 1989/1990 competition had been introduced, first in the over 25,000 therms per annum industrial market then, later, in the over 2,500 therms market. BG still had the statutory obligation to supply to users taking up to 25,000 therms, so continued to make purchase commitments, but found themselves increasingly under-cut by emerging competitors, who took advantage of the fact that BG was obliged to publish its price schedules for the year ahead; an obligation of which it was relieved only in June 1995.

In 1990, Quadrant, a Shell/Esso joint venture, agreed a transportation agreement with BG closely followed by AGAS (initially Associated Heat Services, but later bought by Elf and re-named Elf Gas & Power), BP and Mobil, to become the first third-party suppliers of gas to the UK market. The first third-party sales also occurred in 1990, competition in which built up rapidly, including oil companies who produce gas in the North Sea, Regional Electricity Companies (RECs) and energy trading companies.

Despite the fact that BG more than complied with the recommendations of the MMC report, the OFT decided in October 1991 that too much of the 'liberated' gas was being tied up by large power projects for combined-cycle gas turbines and that self-sustaining gas competition had not yet been achieved. The OFT recommended some further steps, namely, that BG release gas from its existing purchase contracts to its competitors, that the storage and transportation arms of BG be hived off as a separate company able to deal impartially with all gas marketers, that the tariff monopoly be abolished and that BG's share of the industrial market be limited to 40 per cent by statute. BG and OFT negotiated about these recommendations and in March 1992, BG signed a formal list of undertakings including:

- To use best endeavours to secure competition in the contract gas market;
- To introduce a separate pricing regime for transportation;
- To publish a transparent pricing regime by 1 October 1992;
- That the trading arm of BG be separated from storage and transportation, and be treated as an independent gas shipper by 1 January 1993, subject to the same terms as all other shippers;
- To produce a paper by 1 January 1993 discussing the future of gas storage;

- To set up a separate transportation and storage entity by 1 January 1994, with separate accounts from 1 December 1993; and,
- To ensure that, by 1995, no more than 40 per cent of gas to industrial contract customers buying over 25,000 therms per annum would be supplied by BG.

The piecemeal regulatory changes enacted and proposed during this period, despite the opportunities such changes opened up, left BG reeling and caused considerable confusion in the market. The result was that BG, Ofgas and the Secretary of State commissioned in August 1992 yet another investigation of the supply, storage and transport of gas in the UK, to be carried out by the MMC. Before this study was fully underway, the Energy Secretary reduced the tariff threshold from customers of 25,000 therms/year or more to 2,500 therms/year, effectively increasing the customer base fortyfold. BG administration was stretched to breaking point, attracting much bad publicity for the company.

The MMC report was published in August 1993 and was generally accepted by the Secretary of State in December 1993 with some amendments. Essentially this announced, firstly, that domestic competition was to be advanced to between April 1996 and 1998 in phases and, secondly, that BG was required to separate transportation from its other activities and place it behind a 'Chinese Wall' (though it stopped short of imposing complete demerger).

The timing of the report was auspicious for the stated objective of maximising industrial competitiveness and promoting consumer welfare by encouraging lower prices: gas prices were already under pressure from major North Sea gas finds and 'new brooms' had been appointed at the DTI's Oil and Gas Directorate and at Ofgas who were anxious to make their mark on a market in transition.

In practice, the market was opened up to competition in eight phases between April 1996 and May 1998, beginning with the South West of England in April 1996, the South East in February / March 1997, Scotland and the North East in November 1997 and the remaining regions between January and May 1998.

3. BG DEMERGER

Although it was not a requirement of the Secretary of State, BG announced in March 1994 that it would fully demerge its three main businesses (transportation and storage, exploration and production and international downstream), an event which was fully implemented on 17 February 1997. Two new companies were formed, BG plc and Centrica.

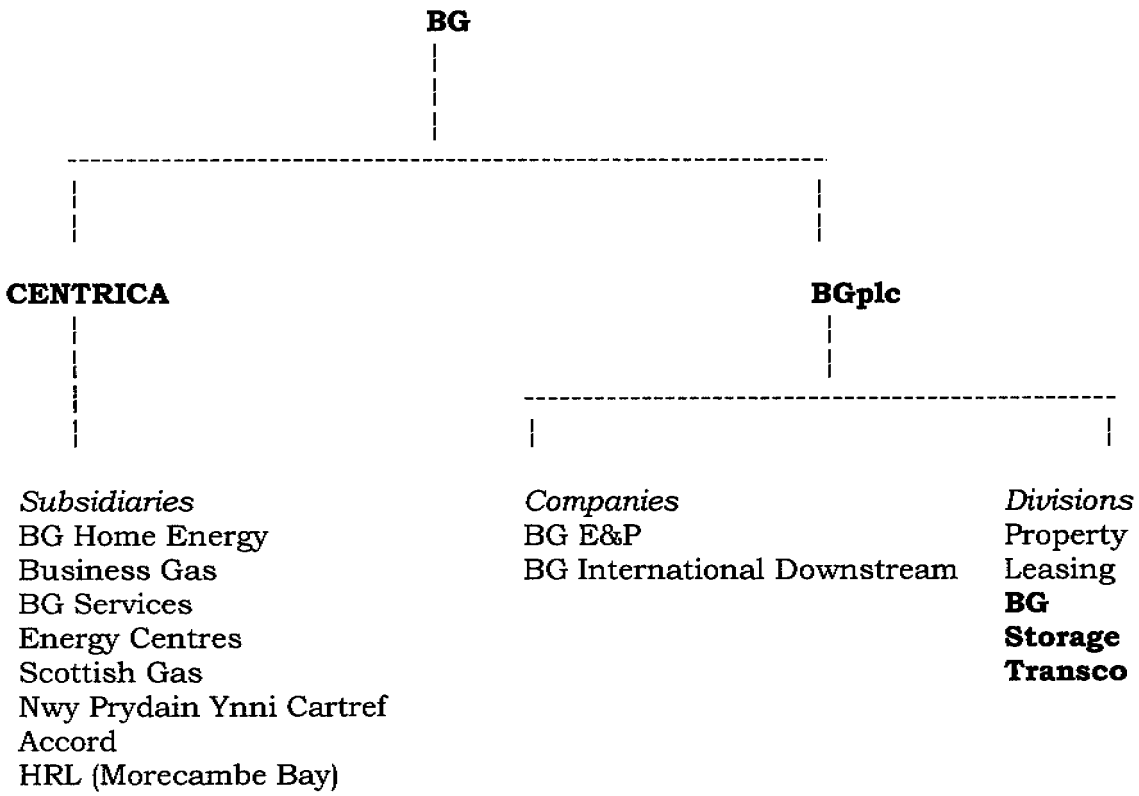

Figure 3.1: BG Demerged Structure 1997

3.1 CENTRICA

Centrica has a number of subsidiaries, which are shown above. The Morecambe Bay gas field was the only E&P asset to transfer to Centrica, taking with it significant liabilities.

The Oil Taxation Office's (OTO) tax reference price for setting Petroleum Revenue Tax (PRT), Royalty and Corporation Tax (CT) on South Morecambe at the beach was negotiated and agreed with BG before demerger. Market prices had fallen by 30 per cent by the time Centrica took over South Morecambe. One of Centrica's first tasks was to renegotiate this price with the OTO, which they did with some success: the OTO agreed to use market prices on the day for PRT purposes from 1997, and for royalty and CT from 1998.

Renegotiating the 'take-or-pay' contracts, that Centrica also inherited from BG, with the upstream producers, was not quite so easy, despite the pressure which the Secretary of State brought to bear on producers to assist the process.

The origin of the problem, signalled to the market by the end of 1995, was the prolonged process by which competition was introduced during the 1980s and 90s. While the transition from monopoly to competition was underway, BG continued to enter into 'old style' long-term contracts to buy at fixed prices, escalated by indices like PPI, sufficient to feed their monopoly market share. By the time Centrica took over, its access to gas, for which it had to pay whether or not it took delivery, far out-stripped its new competitive market share and prices had fallen from over 20p/therm to under 10p/therm. But, during Centrica's first year of existence,[4] the following agreements were reached:

1. A price reduction on 6 billion therms (16 BCM) from Conoco, Elf and Total in exchange for £365 million from Centrica;
2. Phillips, Fina and Agip renegotiated their contracts at cost to Centrica of £43 million; and,
3. Chevron was induced to end its 1/2 billion therms contract early in September 1998 at a cost of '<1 per cent of net assets'.

Precise details of these settlements remain patchy, but Centrica reported in its 1998 accounts exceptional charges of £63 million in 1998, £608 million in 1997 and £705 million in 1996 for gas contract renegotiations. That the 'take-or-pay' *volume* issue is largely resolved is evidenced by Centrica entering into a new 50 mcf/d ten-year contract with Enron in February 1998, at prices related to the market at the time of delivery. The extent to which a baseload volume is still tied in at prices in excess of the current market will emerge from future years' accounts.

Increasingly, Centrica is evolving from being simply a gas company into an all-round supplier of utilities to consumers, the latest evidence of which is its plan to acquire the Automobile Association.

3.2 BGplc

BGplc was the second company to emerge from the old BG on 17 February 1997. This is comprised of BG Exploration and Production (E&P), BG International Downstream (two separate companies), the Property Division, the Leasing Group, BG Storage and Transco, the last four of which are divisions of BGplc, not separate companies. It was announced in February 1999 that the E&P and International Downstream divisions are to merge.

BG E&P is a competitor in the upstream sector with oil and gas assets in the North Sea, Argentina, Brazil, Bolivia, Ireland, Italy, Egypt, Indonesia, Kazakhstan, Malaysia, Pakistan, the Philippines, Qatar, Russia, Tunisia and Thailand.

BG International Downstream includes LNG shipping, international pipelines, gas distribution and trading and the development of gas supply to power stations in many of the countries in which the E&P division operates, but also including Singapore and the USA.

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[4] In the months preceding demerger, BG renegotiated contracts with BP, BG E&P and Mobil, on Centrica's behalf.

Leasing and property are of little relevance to the objectives of this paper, but the activities of Transco and BG Storage form the basis of much of the remainder of this discussion.

In July 1999, BGplc announced plans to invest £5billion in its international ventures, and was quoted in the *Financial Times* as saying: 'As we go forward Transco will continue to drive the performance of the Group. But the real growth in earnings will come from the international business.' In order to facilitate this plan, BG plc are proposing to re-structure and re-finance the group. A new holding company, BG Group plc, will be incorporated and Transco will become a subsidiary of the group, ring-fenced for regulatory purposes. All of the other existing BGplc businesses will be carried on in separate subsidiaries of the new holding company.

Existing BGplc shareholders will be given equity in BGplc and bonds in the Transco subsidiary, an equity/debt mix which more sensibly reflects the high gearing which the nature of the regulated business can support (but see Section 5.7).

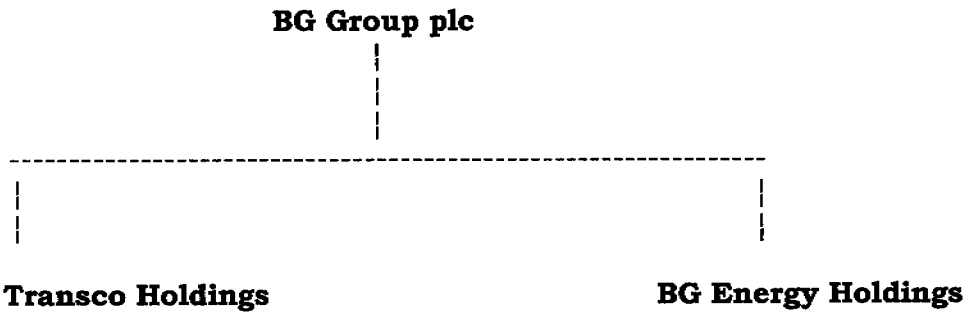

Figure 3.2: Proposed New Structure for BGplc

4. OFGAS

Before considering gas trading, Transco and BG Storage, it is necessary to understand the regulatory apparatus that oversees and directs these activities.

Ofgas was set up in 1986 as a non-ministerial government department[5] when BG was privatised. It is important to remember that in 1986, although a path had been cleared for the introduction of competition, at that point BG was still a monopoly buyer and seller. As such it required regulation and a regulatory body was also needed to ensure that the transition to competition happened as quickly and smoothly as possible. Ofgas was the chosen ministerial tool to fulfil these objectives. Ofgas' remit is set down in the 1986 Gas Act, as amended by the 1995 Gas Act, but can be summarised as:

a. to regulate the BG monopoly or other dominant elements in the gas industry;
b. to increase competition in the gas industry; (the 1995 Gas Act specifically makes it a duty of Ofgas to 'secure effective competition'.) and
c. to act as a competition authority to those parts of the industry which are subject to competition, by the issuing or withholding of licences.

It is independent of government and the industry. However, the Director General of Gas Supply (DGGS)[6] is appointed by government, usually for five years.

The framework for competition, the 1995 Gas Act, was drafted as amendments to the 1986 Act. A bill was introduced in early 1995, passed in November and came into force at midnight at the end of February/beginning March 1996.[7] Under this act, control by Ofgas is exercised through licences. These are needed to transport (Public Gas Transporter (PGT) licence), ship (shipper licence) and supply (supplier licence) gas. Ofgas chose to isolate gas transportation as the portion of the supply chain which would benefit from remaining as a monopoly and declared it illegal for the same corporate entity to have a licence to transport and a licence to ship/supply at the same time. (BGplc chose a subsidiary company to carry out its transportation function separate from shipping/supply from March 1996 until full demerger in February 1997).

Certain standard licence conditions must be incorporated in each licence, but there may be other (limited) amendments introduced by Ofgas, who can exercise some discretion without the need for a public hearing, but must act within the framework of the Gas Act. Price control is a 'special' licence condition. Ofgas can appeal to the MMC if licensees resist any changes that Ofgas proposes. The government can veto licence modifications, but can't propose new ones other than through legislation.[8]

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[5] A first-hand description of the factors influencing Ofgas during market liberalisation can be found in 'Liberalisation of the Gas Market', a paper by John Michell and Clare Spottiswoode 1998.

[6] The first DGGS at Ofgas was Sir James McKinnon. He was replaced by Clare Spottiswoode in 1993, who was subsequently replaced by Callum McCarthy in 1998, who also replaced Steven Littlechild as DG of Offer, the electricity regulatory authority, on 1 January 1999.

[7] It is an historical curiosity that the Network Code did not take effect until 06.00 hours on 1 March, so for six hours the mechanism for implementing the Act did not exist.

[8] In the September 1998 Conclusions Document entitled 'An on-the-day Commodity Market for the Gas Balancing Regime', it is stated that 'Only Shippers and Transco are able to propose modifications to the Network Code. Unlike licence terms, Ofgas is not able to propose modifications to the Network Code, although all modifications require the consent of the DGGS.'

The 1996/97 'Select Committee on Trade and Industry First Report: Customer Protection' stated:

> The DGGS has a duty to protect the interests of consumers in respect of prices charged and supply terms, the quality of supply of services and the exercise of Suppliers' rights to enter Customers' premises. In respect of the quality of supply of services, she must also take into account the interests of those who are chronically sick, disabled or of pensionable age.

In response, Clare Spottiswoode, the then DGGS, said: 'competition is far and away the best way of helping customers, both through standards of service and price.'

Two issues qualify the pursuit of competition: safety is a responsibility which is placed squarely on the shoulders of the PGT licensee, the most significant of whom is Transco; and security of supply to the consumer is an obligation of the supply licensee in that, once they have contracted to supply gas, they must continue to do so unless their customer cancels the agreement, except in case of non-payment of bills. Ofgas can impose on suppliers the obligation to take on the commitments of any failing supplier or shipper.

Third-party access rights to the PGT networks are contained in the Gas Act and the Licences. The underlying principle is that there should be:

1. non- discriminatory terms;
2. low cost, but still safe, reliable, efficient access; and
3. an obligation on the PGT to comply with the capacity extension needs of customers (qualified by economic criteria).

The Network Code (NC) was the mechanism chosen by Ofgas to ensure third-party access to the NTS on safe, fair and equal terms.

5. THE NETWORK CODE

It should be made clear at the outset that the Network Code is evolving constantly as the UK gas market matures. Since its introduction in March 1996, there have been 346 amendments proposed to the NC and more will be required over the summer of 1999 in preparation for the introduction of a new market mechanism in October 1999 (described in Section 5.7). Traders and operations personnel reading this paper will, by necessity, be more familiar and up-to-date with the details than any writer could hope to be. Such readers will also be aware that, regardless of how the rules are written, there has been and continues to be a certain amount of co-operative pragmatism in their practical application.

However, for the rest of us who are not concerned with keeping up to date with the minutiae, the broad principles of the NC are included for two reasons: it will give the management of companies with gas operations a flavour of the 24 hour nature of the market and the potential financial consequences of parsimony in this area; and, it is an indicator of the complexity of the detailed issues which will have to be addressed in achieving a fully integrated international market in Europe.

The Ofgas document entitled 'Network Code – the Summary' states that 'A "Network Code" is a legal document which forms the basis of the arrangement between a PGT and the Shippers whose gas it transports.' The Network Code of Transco, that division of BG plc that is the custodian of the NTS, is of over-riding significance. All subsequent references to the NC in this paper are to Transco's NC. Some smaller PGTs exist in local areas such as new housing estates, small towns and villages, but they are not of interest for the purposes of this paper. There is a Transco NC governing the use of the NTS by each shipper. Shipping/supply competition began before the Network Code was introduced in March 1996 based on ad hoc agreements, but now the shippers' licences oblige them to adhere to the NC, and any modifications thereto, under the supervision of Ofgas.

Let us first consider some of the terminology:

'Shipping' is the aggregation, facilitation and conveying of gas on behalf of a supplier from a processing terminal, through the NTS to a customer. This is now fully competitive and is 'administrative', not physical, transportation. The trading arm of Centrica, which has 60 per cent of the market, is required to have a shipper's licence and sign a NC under its arm's length relationship with Transco. There are currently approximately sixty shippers.

'Supply' is a separate function from shipping, but some suppliers are also shippers within the same legal entity. Supply, broadly, describes retailers selling gas to final consumers. Combined, supply plus shipping covers purchasing, shipping, flow management and transportation to customer, customer handling at retail level-service and billing.

'Customers' are power stations, industry, commercial companies, domestic/residential purchasers. There are currently more than 20 million domestic customers in the UK market.

The other category of player that we will mention at this stage to distinguish them from shipper/suppliers, are the upstream *'producers'*. As noted earlier, the

regulation of offshore gas is under the control of the DTI, not Ofgas. Exploration licences are granted in regular competitive licensing rounds and production is subject to the approval of a so-called 'Annex B', development plan. Involvement of offshore producers in the gas chain normally stops at beach terminals at which offshore production is landed, i.e. risk and title pass from the seller to a gas shipper with a Transco NC at the point of entry into NTS. Many producers are also shippers and some are also suppliers. The impact of the producers on the onshore gas regime is dealt with in Section 5.5 when we consider Claims Validation.[9]

In March 1996 the Network Code (NC), the next stage on the road to full gas competition, was implemented after much consultation and many delays and involved a mammoth task of achieving co-operation amongst players used to 'take it or leave it' negotiations with the old BG. A significant aspect of the NC was a move from monthly balancing to daily balancing. The philosophy underlying the NC is that, while Transco has the obligation for physical daily balancing of the NTS, with all the safety issues that entails, Shippers have the financial responsibility to balance their own deliveries and offtake every day i.e. to ensure that their input to the NTS equals their offtake from the NTS plus or minus storage injections and withdrawals.

The Network Code of Transco is a heavy and somewhat indigestible document. There are various ways of carving it up to aid the digestion process. The one we have chosen is to consider the daily chronological sequence of events.

Starting with a licence requirement for daily balancing, we have considered the process of nominating and renominating volumes into and out of the NTS, an activity which commences before the gas day. We have then considered the nomination of capacity in the system, booking of which takes place currently before the gas day.

During the gas day the actual physical balancing of gas for safety reasons is discussed. Physical balancing is achieved currently by Transco during the day by management of the Flexibility Mechanism, interruptible contracts, storage and linepack. Each of these is considered in turn.

After the gas day, the allocation of gas which actually flowed, as opposed to what was expected or contracted to flow, is considered. We consider the process of allocating claims and retroactive balancing. We look at the imbalance tolerances and the system of costs and penalties applying to those shippers who are found, after the day, to be out of balance.

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[9] One unexpected impact of the opening up of gas competition merits a mention, but is not central to the purpose of this paper. That is the effect of the demise of the BG monopoly on the joint venture partners in gas fields or, even more so, in oil fields with associated gas. When all of the partners were party to the same, jointly negotiated gas sales contract with BG, issues such as the timing of maintenance shutdowns or the exercising of any flexibility in the gas/oil production ratio were straightforward. Each partner faced the same commercial situation when taking decisions that might lead, for example, to BG delivery shortfall penalties. When joint venture partners contract to different gas buyers, possibly to one of their partners, or possibly even the field operator, under different price and volume terms, these same issues open up the potential for commercial conflict within the joint venture group.

We then go on to look at the changes to the whole process which are under review currently, specifically the incentivisation of Transco and the replacement of the Flexibility Mechanism with an On-the-Day Commodity Market.

We then look at how the NC might continue to evolve.

5.1 Daily Balancing

Gas comes into the NTS on a continuous basis from deliveries from offshore gas fields to the beach processing terminals, from onshore gas fields and from withdrawals from storage.[10] Gas leaves the system also on a continual basis directly to large users, such as power stations, by injection into storage, or by deliveries into Local Distribution Zones (LDZs). There are thirteen LDZs in the NTS, which are geographically discreet groups of offtake sites amongst which gas cannot be transferred directly. Within LDZs there are a number of offtake sites, some of which are not metered on a daily basis (NDMs) and some of which are daily metered sites (DMs). For balancing purposes, consumption of the NDMs is obtained by subtracting DM consumption from total LDZ consumption which is then allocated to shippers supplying their individual customers within the LDZ, according to an agreed formula. This is because there are around 20 million gas consumers in Great Britain and metering them all on a daily basis is an impractical proposition.

Wholesale prices change daily, whereas retail prices, linked to competitive tariffs, do not, although some retail prices are now specifically linked to wholesale prices as the market has become more volatile. Industrial and commercial contracts often change price once per year, although the move away from fixed prices to prices which are linked to a daily market index is well underway in new contracts and in some renegotiated Centrica contracts. In any event, the mismatch in pricing philosophy up and down the gas chain opens up a big financial exposure that has to be managed by one or more of the players. An equally significant financial exposure, which has to be managed by continual vigilance, lies in the detailed mechanism of the Network Code calculations themselves.[11]

Transco cannot currently make a profit or loss on daily balancing[12] i.e. it has cash neutrality. Any such arising is currently pro-rated across shippers in proportion to the use of the system *on the day in question* by a process of smearing.

Daily volume balancing takes place at the so-called National Balancing Point (NBP); this is a notional point which, in reality, does not exist as an *identifiable* physical location. Balance is dependent on such variable items as the weather and the operational performance of offshore gas fields, or oil fields that have associated gas, and therefore it involves an iterative process of nominations by shippers to Transco, commencing at 1p.m. on day minus one and finishing at 03.59 on the delivery day. Renominations during the gas day help shippers stay in balance.

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[10] Gas also enters and leaves the NTS through the Bacton Zeebrugge interconnector and leaves via the Moffat to Dundalk and Ballylumford interconnector.

[11] See Transco's 'Network Code - the Summary' and 'Network Code - the Calculations'.

[12] But see Section 5.7.

5.2 NOMINATIONS/RENOMINATIONS

All nominations and renominations are entered into the process via UK Link, the gas balancing portion of which is known as ATLink, the Transco computer system available only to shippers (and selected other parties involved in the market, e.g. see CVSL in Section 5.5, who have NC agreements. Gas days run from 6 a.m. to 6 a.m. The NC describes the commencement of the process as shippers nominating for transport to DM sites by 1 p.m. on the day before the gas delivery day (D) i.e. 1 p.m. on D-1. In practice, shippers now tend to nominate all outputs at this stage, since there are now more opportunities to revise nominations than there were in the early days of the NC.

According to the NC, by 13.00hrs on D-1, Transco estimates total gas demand for D, based on weather data supplied by the Meteorological Office and, using the NDM demand formula and the 1 p.m. DM nominations, Transco informs each shipper of its expected demand for the D, by 14.00hrs on D-1.

By 15.30 hrs. on D-1, the shipper nominates its withdrawals from or injections to storage on D and by 16.00hrs its gas input at terminals on D. These nominations are then compared with the expected availability of capacity in various locations in the NTS on day D and nominations which cannot be accommodated are returned to the shipper for revision. Such revision might involve two shippers trading volumes[13] between themselves to match their available capacity to their volumes and submitting matched revised gas trade nominations to Transco, although the obligation to match renominations has now been relaxed by Mod 305.[14] Transco is only involved in approving the nomination for the flow of gas and do not get involved in the contractual processes between the shippers or the transfer of cash resulting from the trade.

It should be re-iterated that this describes how the NC was envisaged to work in theory. In practice, nomination has evolved into a more iterative and pragmatic process.

For nominations to be valid, they must be accepted by Transco. Nominations which might be rejected are, for example, gas trades unconfirmed by one side of the trade, or if the nomination is for the use of capacity which is physically constrained.[15]

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[13] See Section 6.1 for gas trade standard terms and conditions.

[14] A shipper who has nominated gas at the NBP but cannot perform on the day, can trade with another shipper to correct the imbalance, as indicated above. Each shipper was initially allowed to transact such 'Mod 169' trades, up to 6 times per day, matching downstream renominations with beach gas. A further modification to the NC increased this to 12 per day, but, as a further temporary interim measure until a more substantial overhaul of the system takes place, the Mod 305, the necessity of balancing renominations removed the constraint altogether. This allows a shipper to renominate to Transco as the result of a trade or reforecast and transfer the matching right/obligation to another shipper. End of day imbalance still carries financial consequences, but this additional flexibility provides the opportunity to manage imbalances more effectively over the course of the gas day. Scheduling charges and penalties, which are less on offtakes than on inputs, have been reduced during the period of operation of the NC.

[15] An accusation which has been levelled at some shippers is that they have deliberately over-nominated to supply gas at the physically constrained St. Fergus terminal and been pro-rationed, forcing Transco to make flexibility buys through unconstrained capacity at

From 18.00 hours on D-1 until 03.59 on D, shippers can amend nominations or submit new ones as new information concerning demand or gas field performance becomes available.

This limited iteration proved inadequate for balancing purposes, so two additional Demand Attribution Runs (DARs) for D, at 10.10 am on gas day D and again at 16.20 p.m. on gas day D (equivalent to the 13.00 hrs D-1 run attributing demand to DMs and NDMs), were added. It is now proposed that Transco should also produce DAR for day D at 1 p.m. on D, on receipt of the updated weather information that will form the first DAR for D+1.

5.3 Capacity Booking

The NC also outlines terms for NTS capacity booking, for entry capacity, exit capacity and Local Distribution Zone (LDZ) capacity. Transco can make a profit from the capacity booking system, subject to Ofgas limits, as BG Storage can from the operation of its storage facilities. Any additional surplus or deficit generated is pro-rated across shippers as part of smear charges. Capacity can be booked in annual blocks with Transco, up to 100 per cent of total available capacity. Booking sufficient capacity is the responsibility of the shipper, who books entry, exit and LDZ capacity by reference to its requirements at its Daily Metered Sites (DMs), from which Non Daily Metered (NDM) capacity requirements are inferred.

The system of capacity booking and trading is under active review in the summer of 1999 against a background of the complete overhaul of the mechanisms for daily balancing under the NC. It is envisaged that this overhaul, as described in the Ofgas document, 'The New Gas Trading Arrangements: May 1999', comes to fruition in October 1999.

Capacity was originally booked for Gas Years (October to October) by 1 October, 1 December and 1 March, but can now be booked at any time for a rolling one-year period. Excess capacity can be traded via UK Link, usually in daily blocks, but all risks and obligations for such capacity, even after selling to another shipper, remain for the original shipper's account. Renomination of gas volumes or trading of gas volumes or flexibility bids for gas volumes originally had to be accompanied by a capacity adjustment, since unused capacity is still charged for by Transco and excess use, or 'over-run', capacity is charged at penal rates. (See also Section 5.6 for capacity over-run charges)

A criticism of the system for capacity trading has been that some shippers with excess capacity have withheld it from shippers wishing to put extra gas through the system, e.g. as a result of a Flexibility Mechanism or OTC transaction, allegedly to benefit from driving SMPs to more extreme levels, if this benefited their overall position. In order to prevent this capacity 'market manipulation', Transco has introduced a 'use it or lose' modification, such that if a shipper needs capacity Transco has the right to sell an *interruptible* service in excess of the 100 per cent firm when any shipper has an excess to current use. This has encouraged a more

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Bacton, thereby driving up the Bacton price and providing a lucrative inter-terminal arbitrage opportunity. It is difficult to assess if there is any truth in this allegation.

liquid market in capacity trades. The market price of traded capacity is reported in publications such as Heren (see Section 6.3).

Full details of a new capacity booking and trading regime before, during and after the gas day are still being decided by Ofgas in consultation with the industry. Ofgas' objectives for the new process are spelled out in the May 1999 document. This states that:

> Ofgas believes that market participants should be encouraged to book capacity prior to flowing gas and that Shippers should not be able to nominate above their booked capacity.....An overrun charge that is greater than the cost of booking capacity prior to flowing gas should provide a great enough incentive not to flow gas without holding capacity, and to buy sufficient capacity in the secondary market.

Ofgas goes on to say: 'Ofgas continues to advocate a price auction in order to ration capacity in an efficient, non-discriminatory way.'

A further issue related to capacity that remains unresolved, is the question of future planning. Capital investment in future capacity needs is in the hands of Transco, but, since the price of capacity is subject to regulatory control, the price signals necessary to plan capacity expansion accurately, in terms of timing and location, are distorted. Producers entering into field development decisions involving capital outlay several years in advance of production, need re-assurance that capacity will be available when required in the future. The issue has been recognised, but its resolution has been shelved until the short-term problems of introducing the new regime have been overcome in time for its introduction in October 1999.

5.4 Physical Balancing in the NTS by Transco

Section 5.2 considered the process of nominating and renominating gas to Transco. This section considers the tools at Transco's disposal to manage linepack, or gas pressure, safely and efficiently.

5.4.1 The Flexibility Mechanism

The Flexibility Mechanism is now no more than an historic curiosity as it will be replaced on 1 October 1999 by the On the Day Commodity Market, as will be discussed in Section 5.7. However some description of its operation is included here because it has been a key plank in physical system balancing for Transco (along with interruptible contracts and the use of storage), even though its actual contribution to that balancing has been less significant than was originally envisaged when the NC was introduced. It has represented the sharp-end interface between the physical balancing regime and the development of the market in its widest sense. The Flexibility experience should not be forgotten when the incentivisation of Transco is considered in Section 5.7.

By 18.00 hrs on D-1, shippers can indicate, via ATLink, to Transco that they are able to increase or decrease their deliveries to NBP on D, specifying the price, quantity, location and time of the increase or decrease. This is the so-called Flexibility Mechanism, which is not a true market, since it is only available to the

shippers to 'trade' with Transco, although all shippers can see the bids and offers which are accepted by Transco on ATLink. Shippers can amend or withdraw these 'bids' or 'offers' at any time (unless, of course they have been accepted). These bids or offers may take the form of a willingness to increase or decrease offtake, or increase or decrease input. If Transco needs to take action to balance the system it accepts the best bids or offers, usually based on price, but sometimes based on location, if specific local action is required. Once a bid/offer is accepted, all alternatives for that bid/offer are removed from the system. The successful bid/offer is published to the other shippers and the successful shipper arranges for it to be implemented. Any bids/offers for D, not accepted by Transco by 4.00 hrs on D, lapse automatically.

Throughout gas day D, Transco provides estimates of closing linepack (i.e. gas pressure in the NTS) and indicates that it is about to take corrective action through the Flexibility Mechanism. Shippers then scramble to enter flexibility bids or offers into ATLink and Transco aims to act within 15 to 30 minutes.

In its Winter 97/98 Operations Review, Transco reported that the Flexibility Mechanism was used by approximately 30 shippers and was the source of only 2 per cent of total NTS throughput, although, of all the system imbalances addressed by Transco, 99.8 per cent was through the Flexibility Mechanism and only 0.2 per cent was through the use of storage. Storage injections/withdrawals lack the immediacy and precision of the flexibility mechanism.

5.4.2 Interruptible Contracts

Certain large DM sites, or very large DM sites (VLDMs) such as power stations, have entered into contracts for delivery which are interruptible at short notice i.e. if particular constraints exist in parts of the NTS, or if overall depletion of peak storage threatens security of supply for the balance of the winter. Interruptible sites are exempt for certain capacity charges and Transco's right to use interruption is limited to an agreed number of days per year.

In its 1997/98 Winter Review, Transco reported that it had 1658 interruptible supply points and during that winter only seven sites were interrupted for more than two days. However Transco also reported that eight shippers had invoked their interruptible contracts 30 more times than had Transco during the same winter period; but this was for commercial, not balancing, reasons, i.e. to take advantage of more favourable prices in the spot market than were available under the interruptible contracts. Industry sources report that this came as an unpleasant surprise to large consumers, such as some hospitals, who had used interruptible contracts as a means of accessing cheap gas, safe in the knowledge that interruption was a rare occurrence in practice.

Transco came in for some criticism when it interrupted gas deliverability from Rough on 16 December 1997, as it was entitled to do because demand was forecast to exceed 85 per cent of peak day demand (the trigger point or V factor set down in the NC), sending gas prices on the Flexibility Mechanism to £4.96/th on 16 December and £4.97 on 17 December. In the event, the forecast was wrong and 85 per cent was not exceeded. Some gas shippers who had made firm sales commitments based on their interruptible purchase contracts from Rough, argued that because Rough capacity was under-subscribed, the spare should be made available to interruptible customers. An amendment to the NC was proposed but

was rejected by Ofgas on the grounds that it would discriminate against the shippers who had paid the full price to book firm Rough capacity (see Section 5.6).

Buying under an interruptible contract is analogous to selling a call option and picking up the option premium as a price discount. To complain when the option is exercised seems commercially naïve, but, on the other hand, interrupting a hospital is not good for public relations for those who have purchased the option to interrupt. It seems likely that interruptible contracts may find their way into the courts, before both buyers and sellers fully appreciate the true nature of these agreements in a 'free' market. However this may be avoided, depending on the findings of a review of exit capacity and interruption planned for late 1999. The objective is to achieve a range of interruptible services which are fairly priced in consideration of the extent of interruption allowed.

5.4.3 Storage

Renominations, the Flexibility Mechanism and Interruptions are not the only mechanisms for handling imbalances. A further mechanism originally available to Transco is injections and withdrawals from storage of Balancing Margins Gas (BMG), which was gas reserved in storage to help maintain the daily physical balance. This has now been eliminated and Transco books storage with BG Storage like any other market player and books charges back to shippers through the cash neutrality mechanism i.e. smearing charges.

BG Storage controls five LNG sites with a total of fourteen tanks at Bristol, Strathclyde, Rochester, Manchester and mid-Glamorgan , a salt cavity at Hornsea, Yorkshire and the depleted Rough field, offshore from Easington. (The Rough field was operated by BG E&P on BG Storage's behalf until 1 August 1998 when control was taken over by BG Storage.)

Transco's need for storage is designed to cope with the highest demand that can be expected in a '1 in 20' peak daily demand i.e.'the level of demand that has a probability of being exceeded in one *year* in twenty, based on historical weather data for at least 50 years'. [16] Its requirements for storage are determined using projections of expected beach availability and storage bookings by other companies.

Such storage can be booked by shippers from BG Storage by specifying their requirements for the following year commencing 1 May. (Storage Years run from May to April, rather than from October to September as does the Gas Year). Transco books storage according to the same timetable. Initially it was envisaged that storage capacity could still be requested between 1 May and 30 November for the following year, but with less chance of success, but the opening up of storage to the market as part of the summer 1999 review process will make this problematic.

For the 1998/99 storage year, the tender for Hornsea storage was oversubscribed 2.3 times, and after a slow start, 97 per cent of Rough storage space was taken up. There were 37 customers for storage space.

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[16] It is interesting to note this quote which is from the annual report of BGplc. The definition is different from the one contained in the Network Code Summary: i.e. 'the highest demand that can be expected both on one single day in 20 years and, in one single year in 50.'

Ofgas is promoting the development of a freely traded secondary market in storage very vigorously to reduce the dominance of Centrica and Transco in the storage market and to take BG storage out of the commercial loop. BG agreed to sell the rights to store gas for five years at Rough and Hornsea, the LNG facilities were excluded from the auction, starting with the Storage Year commencing 1 May 1999. The reserve price for these rights was £52.5 million. For the 1999/2000 storage year, Hornsea has again been oversubscribed, this time by 300 per cent. Take up on Rough was only 41 per cent, which is attributed to the comparative inflexibility of the Rough system. In both cases, booking storage capacity includes injection and withdrawal rights.

While it is self-evident that there is no point in booking storage without injection and withdrawal rights (Deliverability), these separate services have now been unbundled. It is the distinction between the different parts of the service which accounts for Rough's comparative unpopularity compared with Hornsea. Generally speaking, the gas tends to be injected more slowly than withdrawal for historic reasons. In the 'old days' before competition, gas tended to be injected slowly over the summer and withdrawn more rapidly in winter to meet the surge in demand on cold days. Hence compressors were more geared for withdrawal than injection, although this is being put right gradually with system upgrades.

In order to guarantee quick withdrawal on demand under the current regime where injection, storage and withdrawal are bundled, shippers have to book considerably more storage than they would otherwise require at Rough compared with Hornsea. So, although, Hornsea looks more expensive per unit than Rough, to use Rough requires the booking of considerably more units. It is BG Storage's aim to increase cycling, i.e. faster gas turnover, and unbundling of deliverability and storage would promote this objective.

No formal storage market is being set up, but the expectation is that, if the market needs such a facility, then the market will propose its format.

No storage bidder is allowed to buy more than 20 per cent of the capacity rights on offer, which leaves Centrica, with 75 per cent of the residential market, nominally short of storage capacity, but its needs are usually met from the flexible working practices allowed by the Morecambe field.

5.4.4 Linepack and Tolerances

Linepack is defined by Ofgas as 'The variation in pipeline pressure that can accommodate differences in inputs and offtakes to the system', i.e. the NTS. At the moment, shippers are allowed a delivery tolerance on their daily balances (see Section 5.6.1). The summer 1999 review of the trading regime is considering removing the allowed tolerance and replacing this with a system of shippers buying the flexibility they require from Transco in the form of linepack. Since linepack is analogous to very short-term, within-day storage, it has been suggested that linepack prices be linked to the price of storage. Ofgas considers this unlikely to occur before April 2000.

5.5 Claims and Allocation

A claim is an agreed allocation among those shippers inputting gas at the same terminal on a given day. Claims Validation Services Limited (CVSL)[17] functions through a Claims Validation Agent (CVA) who operates at the terminals, allocating metered gas flows amongst shippers, traders and producers. Shippers and traders are obliged to become principals of CVSL, but, initially producers were not. Shippers make nominations directly to Transco to ship gas in the NTS using UK Link. After the gas day Transco, or CVSL on its behalf, must reconcile these nominated volumes with the metered volumes actually received. Terminal inputters send a claim to Transco as part of this process via their CVA i.e. the CVA for the terminal agrees the allocation among terminal inputters and submits an aggregate claim to Transco. This claim will only be accepted by Transco if it totals the actual amount metered into the system at that point on that day. In the absence of a valid claim being made by the 15th of the following month, in theory, Transco will produce a default allocation of the metered volume in proportion to nominations made before the gas flowed.

In practice, Transco has proved reluctant to apply these remedies and has extended deadlines to allow CVSL to handle the more difficult reconciliations that arose in the early days of operation.

Initially, the process of agreeing a claim amongst its principals was a difficult one for the CVA. Because producers were not obliged to be principals of the CVSL (and since they were regulated by the DTI, not Ofgas, Ofgas could not legislate to ensure their co-operation) they were reluctant to provide their data to the CVA, whom they regarded as a third party, not bound by the confidentiality considerations of their field Joint Operating Agreements (JOAs), Lifting Agreements and so on.

In the days when upstream producers all had field-specific contracts with the same buyer, this would not have presented a problem. But now producers are aggregating their entitlements across fields, selling to different buyers from those of their joint venture partners and sometimes substituting spot gas into their term sales contracts. As a result the CVAs found it difficult to reach a consensus claim with their principals to submit to Transco. Some gas was being double-counted and some missed altogether. The default claim, which Transco uses, theoretically, in the event that an agreed claim is not submitted by the CVA for a particular terminal, could be vastly different from the actual flow, with all the imbalance consequences for shippers that that entails. There was also the problem of establishing contractual sales quantities for payment purposes when the Transco allocation differed from the quantity which a producer can verify to its buyer it had delivered. Any imbalance which is an overclaim between the Transco default claim and the rejected composite CVA claim is pro-rated over the shippers at the terminal; any underclaim is retained by Transco and goes into the cash neutrality 'pot'.

A working party involving Transco, the DTI, Ofgas, CVSL and UKOOA was set up to try to find a way of accessing producer data, but producers, speaking through UKOOA, held out for indemnities against third-party liabilities which may arise as

[17] There were originally three CVAs involved. The IPE, Coopers & Lybrand and a consultancy group who were eventually wound up. This was reviewed after 12 months of operation and a single CVA was introduced at that time.

a result of providing this data. As is the way with 30+ people committees, numerous meetings, minutes and reports were produced, but by the end of 1997, no real progress had been made.

The root cause of the problem was that, unlike oil, the transfer of title to gas does not take place under a regime that generates a negotiable document of title transfer, like a shipping Bill of Lading. With the upstream producers proving reluctant to provide data on their daily input to the NTS entry point, i.e. the beach terminal, shippers and traders were exposed to differences in quantities supposedly delivered to them under their purchase contracts from the producers, but still liable for the financial consequences of imbalance against a default claim quantity generated by Transco. Inevitably, the spot market in gas shifted from trading at the beach terminals like Bacton and St. Fergus and moved 'inland' to the NBP where no such problem existed.

Eventually good sense prevailed. The working party investigating the issue was cut down to six people; three from the producers' lobby and three from the shipping lobby. By May 1998, a fully termed agreement had been drafted setting down terms whereby the producers would provide the CVA with a daily statement of their entitlement to gas entering the system at the beach terminal within three days of receiving this from their terminal operator, or Entry Point Operator, in gas parlance. The principle of 'no consequentials' underlies the agreement and producers only have a financial liability for erroneous data if they have been guilty of 'wilful misconduct' in providing it.

Over the summer of 1998 some 220 companies signed this agreement and its provisions came into effect on 1 October 1998. The producers are not obliged by statute to sign the agreement, but the impracticality of operating their shipper's licence, if they have one, or getting a shipper to buy from them, if they do not, encouraged compliance. Signatories to the agreement are obliged to get their assignees to sign the agreement if they sell their field interest and there are expedited provisions for bringing new fields into the CVSL net. Once signed, any producer who does not provide the required data is liable for litigation. While generally of standard format, the provisions of the agreement remain confidential to the signatories.

Despite the resolution of this issue, there has been no general move back to spot trading at the beach, although such deals do exist. While the debate was raging, the NBP became established as the standard trading 'hub'. Since standardisation of terms is a prerequisite for a liquid market, it seems unlikely that beach trading will be a serious threat to the dominance of NBP trades.

5.6 Retroactive Balancing: Costs and Penalties

This chapter has so far looked at how gas nominations and capacity bookings are made to the system, how they can be altered during and after the day by various renomination and trading mechanisms. It has also looked at the process of reconciliation of actual input and offtake from the system after the day by Transco. This sub-section considers the costs for individual shippers of not being in balance once the reconciliation process is complete.

The system of calculating costs and penalties for use of the NTS is complex and changing rapidly, so the following should be treated only as a conceptual overview of imbalance penalties.

If a shipper is out of balance once retroactive allocations of actual deliveries in the system are made (theoretically calculated in the period commencing at six a.m. on calendar day +1, i.e. the end of gas day D, through to, in extremis, 15th of month plus one, but in practice usually within a week of the end of the gas day), Transco notionally has the right to rectify this through deemed purchases and sales on the shipper's behalf after the event, based on the flexibility bids and offers relevant to the gas day in question. In practice, shippers trade amongst themselves after the event to keep such imbalances to a minimum, although with the perfect price discovery implied by retroactive trading, this method of achieving balance does not necessarily alleviate the financial pain to a shipper which finds itself on the wrong side of an imbalance.

5.6.1 Imbalances

As indicated above the shipper is responsible for the financial consequences of, among other things, not being in balance on volume and transportation capacity.

Volume. There is currently a shipper's tolerance, although, as noted above, the elimination of tolerances is under discussion in the summer 1999 review. It is proposed that this be reduced by 25 per cent on 1 October 1999, then removed altogether in April 2000. This tolerance is currently calculated as a percentage of different categories of throughput, and an absolute tolerance of 7500 therms. Imbalances within the shipper's tolerance over 7500 therms (the first 7500 therms being carried forward to month end for settlement) are currently cashed out at the System Average Price (SAP) which is a weighted average of all actual Flexibility transactions for that gas day. Imbalances outside the shipper's tolerance are settled at the System Marginal Price (SMP) which is the lowest flexibility transaction on that gas day for excess volume and the highest flexibility transaction on that gas day for a shortfall in volume. If there are no flexibility transactions on that day the arithmetic mean of the last seven days transactions is used.

Transportation Capacity. No tolerance is allowed. The charge rate for over-run capacity was initially the equivalent to paying for twelve months capacity at twice the standard rate! This led to some suspicion that over-delivered shippers were not claiming their gas, since it was cheaper to give it away than to pay capacity over-run charges.

The high cost of transportation capacity over-runs led the industry to complain that this is a large disincentive to put gas on the market to dampen down price spikes in the Flexibility Mechanism. It was proposed that treating a volume over-run as a capacity over-run automatically, and charging at a rate more in line with those of volume over-runs would be beneficial to system balancing. As a result, an NC amendment has reduced the capacity over-run charges to eight times the daily rate; still significant, but useable as a solution to dampen down the more extreme SMP results.

While the proposed new regime to be introduced in October 1999 has not yet finalised the details of how imbalance charges will work in future, Ofgas' stated intention is that they should,

> accurately target balancing costs to those parties that have caused them and be reflective of supply/demand fundamentals. To this end, we suggested that

the cash-out price be composed of two elements, a commodity price, reflecting the price of gas on-the-day and used for clearing net imbalances, and a flexibility charge, reflecting the cost of managing within-day 'stock' changes.

This is significant. Whereas the NC, since it was introduced, has incentivised shippers to be in balance at the end of the day, since charges were calculated in relation to shippers' daily closing balances, future charges are moving towards allocation in accordance with within-day balances, subject to an improvement in the quality and availability of within-day data. A gas trading/marketing operation is already labour-intensive. It is questionable if the added precision in charge allocation will be sufficient to justify the extra workload that within-day balancing implies. This will be heavily influenced by the absolute size of the charges involved.

5.6.2 Imbalance charges

In the early days of the NC, imbalance charges could be alarmingly high. For example, on 24 February 1997, Transco was forced to sell gas to balance the system using the Flexibility Mechanism at a price of **minus** 293p per therm at a time when the general price level was circa 10p/therm i.e. they had to pay to give gas away! Hence any shipper who supplied more gas than they were allowed to the system on that day would have received for the excess over tolerance the System Marginal Price (SMP) of -293p/therm. These circumstances recurred on 15 March 1997 as a result of compression failure at Rough. The SMP on that occasion was nearly **minus** £15/therm. The actual volume traded was insignificant, but it set the price for calculating imbalance charges for all shippers who were out of balance beyond the allowed tolerance. This single day's event was the final straw that pushed Warren Bell, who had planned a large injection to Rough, into bankruptcy. Force Majeure doesn't apply here.

Again there was a suspicion that some shippers were claiming zero input to the system, since it was cheaper to give the gas away than to pay the penalties. Under the new CVA agreement, such dissembling, if in fact it did occur, would no longer be possible. One of the consequences of these early extremes was that an NC amendment put a lower limit of 0p/therm on the SMP.

In the second winter of operation, flexibility prices soared to 496/497p/therm on 16/17 December 1997 when contracts from Rough were interrupted as a consequence of demand exceeding 85 per cent of peak day, as already mentioned in Section 5.4.1, coinciding with unexpectedly low supply from some offshore fields.

A better system of volume tracking by the CVA has helped minimise the volumes at risk from SMP, as has the more frequent reporting on the system status during the gas day by Transco with the result that, during winter 98/99 SMP price extremes have dampened considerably and circa 30p/therm was the most extreme price seen and SMPs only reached that level on 3–4 days.

5.7 The Incentivisation of Transco

In its May 1999 document Ofgas stated: 'One of the concerns about the current balancing and capacity regimes is that there are inadequate incentives for Transco to reduce its operational costs or to maximise short run capacity availability.' It was also pointed out that there was no incentive for Transco to provide accurate information and that a mechanism be designed to incentivise long-term planning

and investment by Transco. The industry and Transco are very wary of this but, nevertheless, Ofgas appear determined to introduce some form of experimental incentivisation from 1 October 1999.

This is a risky move. As Transco itself stated in reply: 'Transco believes that its role will fundamentally change from residual gas balancer to trader...'

It is unclear who precisely will benefit from Transco incentivisation. Transco is currently a division of BGplc, not a separate company, although this will be changed in the re-structuring proposed in June 1999, but not yet implemented, where Transco will become a subsidiary of BG Group plc. (See Section 3.2) While Transco is cash neutral, the implications for BGplc shareholders are similarly neutral. If/when Transco generates significant profits or losses from OCM trading, this will presumably influence the value of Transco bonds, assuming they are tradable, but will also impact BG Group plc shareholders in the accounts consolidation process. This will have consequences for the BG Group plc share price and/or dividend payments. In any event, it is envisaged that an initial test might involve an incentive capped at a level without a corresponding penalty. If a full Profit and Loss activity was to be introduced at some point in the future, the question of which entity would guarantee Transco's credit for OCM trading purposes would arise very quickly.

The main problem with a move from cash neutrality to a commercially motivated operator is the need for prescriptive and rigid guidelines to ensure, firstly, that Transco is not speculating and, secondly, that it continues to behave impartially.

Despite guidelines which will undoubtedly prohibit Transco from speculating in the OCM, it will be very difficult to prove after the event whether there was a genuine operational reason for an OCM buy/sell by Transco, or if it was using its inside knowledge to trade at a profit. Transco has a number of tools at its disposal to maintain intra-day balance, as outlined in Section 5.4. It will be very difficult to legislate which of these tools will be operationally optimal for corrective action at any given moment, when there are different commercial consequences for Transco in, say, a contract interruption compared with an OCM purchase.

This paper referred earlier to the co-operative pragmatism that has evolved between Transco and the shippers in keeping the system running efficiently. Such pragmatism has been exhibited, for example, in extending deadlines to allow problems to be resolved without cost. If such pragmatism is exhibited by a commercial entity, and there are winning and losing shippers as a result, Transco will be accused, rightly or wrongly, of manipulating the system for its own benefit. There are a number of instructive precedents in the UK oil sector. Oil pipeline system operators and shipping schedulers who are also oil traders are regularly accused of Machiavellian, self-interested actions, despite the existence of Chinese Walls between activities. To avoid this, it would not be unreasonable to expect Transco to stick rigidly to its operating guidelines which could reintroduce the large spikes in pricing which a little flexibility has shown every indication of eliminating from the system.

Ofgas has an overall objective of allocating costs to the shippers from whom they arise. Incentivising Transco runs the risk of charges being allocated, indirectly, to where it suits Transco commercially for them to land.

Ofgas would be well advised to think long and hard about what size of cost reduction they hope to achieve, before they open up this potentially substantial, but unquantifiable, can of worms.

5.8 On-the-Day Commodity Market (OCM)

Although the OCM is basically a replacement for the Flexibility Mechanism, and is primarily a tool designed to facilitate NTS daily balancing, it requires separate consideration because, unlike the Flexibility Mechanism, it is a true market. Although its use initially will be restricted to shippers, it is envisaged that eventually any party might be able to participate.

Ofgas began in November 1997 to explore in earnest the feasibility of an OCM as the new basis of an energy balancing regime. Industry consultation revealed a broad consensus that this was a sensible way forward, although with some disagreement as to the detailed approach and timing. In September 1998, Ofgas published 'An on-the-day Commodity Market for the Gas Balancing Regime. A Conclusions Document.' The objective of this paper was to introduce NC amendments in 1999 and to develop IT systems which would allow this OCM to go live on 1 October 1999, although it remains to be seen if this timetable can be met.

The Ofgas OCM vision, endorsed in principle by Transco and the shippers, is a 'screen-based, cleared, trading system for gas at the NBP, run by an independent market operator. The market would be used by shippers and Transco (as an equal market participant) to source gas for gas balancing.' The main difference between the OCM and the Flexibility Mechanism is that shippers would be able to trade on-the-day gas amongst themselves via ATLink, instead of just with Transco. Also trading would be 'real time' and would remove the necessity of leaving firm bids or offers on the table for prolonged periods of time to see if Transco was going to 'take them out', a risk which would be anathema to any trader in the OTC market.

The OCM story is still unfolding. In mid-June 1999 Transco completed its tender process to find an OCM operator and has appointed ENMO to the role under a one-year contract. ENMO is a partnership between the National Grid subsidiary, ESIS, and Altra Technology Inc. of the USA. The May 1999 Ofgas document still envisages the market going live on 1 October 1999. Various working parties are committed to implementation within the tight timetable. Not surprisingly, IT is one of the rate-determining steps.

The prospects for a market designed by committee and operated by statute should be regarded with some scepticism. History has shown that market structures that have been imposed on market participants have very little chance of success, as any regulated exchange introducing a new contract will testify. But, in the case of this OCM, the prospects for success are good, as a system balancing mechanism, although its rushed introduction suggests that there may be teething problems.

The need for daily balancing for operational and financial reasons guarantees a baseload volume to the OCM. While forecasting daily field output and weather-related daily demand remains an inexact science, there will always be a need to trade to ensure daily balance. The format currently envisaged is sufficiently close to the OTC 'day ahead' contract and has an administrative advantage over the OTC contract, that the volume at the very front end of the OTC forward curve could transfer from the OTC market to the OCM.

However, the question of Transco's motivation for being in the OCM, as discussed in Section 5.7, is a threat to its liquidity. The primary objective of the OCM is to assist *physical* daily balance, but Ofgas is also seeking 'a liquid and transparent on-the-day market, bringing significant benefits through the reduction in gas balancing costs...Ofgas is keen to ensure that participation in the OCM is as broad as possible.' It is difficult to foresee why any trading company would go to all the trouble of obtaining a shipper's licence to trade in a market where there is a dominant player, Transco, of ambiguous motivation and in possession of inside information. At present Transco can only accept bids/offers and cannot place them. The working parties in session over summer 1999 are discussing the pros and cons of Ofgas' proposal to change this situation.

5.9 The Network Code – Continued Evolution

Operationally, the NC and the system of daily balancing have been successful: gas has continued to flow and there have been no major system failures. Transco reported a 99.94 per cent service reliability index for winter 97/98, which relates to the physical supply of gas to consumers.

Experience has revealed that some inadequacies still exist in the regime and the NC has continued to evolve and is likely to continue to do so as new circumstances arise. Interestingly, industry focus on this issue is less urgent, since the amendments that have already taken place have dampened the extreme results that the Flexibility Mechanism was generating earlier in the process. Given the need for integration of the OCM clearing mechanism with ATLink, particularly against the background of the Y2K upgrades needed by UKLink, industry sources are sceptical that the 1 October 1999 timetable can be met.

The experience of the first three winters of operation under the NC regime (96/97, 97/98 and 98/99) has already given rise to 346 proposed amendments to the NC. It is difficult to foresee what amendments will be required as the spot market for gas becomes more and more active and as business across the interconnector builds up, possibly towards a fully integrated European gas term, spot and futures market. But this will be an issue for the future.

6. THE OVER-THE-COUNTER (OTC) SPOT MARKET

The OTC spot market is an unregulated market made up of bilateral transactions between shippers. By definition, trades at the NBP have to involve two shippers since only a shipper's licence entitles a party to 'own' gas at the NBP. Trades at the beach, for example, Bacton or St. Fergus, can be carried out between a shipper and a producer, but at least one party has to be involved in getting gas into the NTS, for which a shipper's licence is needed.

The earliest trades were reported in 1992 when a delay to Powergen's Humber plant start-up forced them to sell gas that they had contracted to buy from the Pickerill field. Heren started publishing deal information in January 1994, but liquidity took a quantum leap when Accord was set-up as a joint venture trading company between BG and the American Natural Gas Clearing House (NGC) in the summer of 1994. In this period all trade was at the beach. The introduction of the NC meant that NBP trades became more common and, when the question of erroneous gas allocations at the beach became an issue for the CVSL, the majority of trades moved to the NBP to avoid the liability issue. Despite resolution of this issue, approximately 90 per cent of trades are still done at the NBP.

Theoretically, a bilateral contract can be done on any terms to which both counterparties agree, but it is a prerequisite of a liquid contract that terms are standardised so that long or short positions can be traded-on without lengthy negotiation of details and without the exposures which may arise from not having back-to-back contracts.

For the gas market at the NBP, the General Terms and Conditions (GT&Cs) that have been adopted voluntarily by the industry are those entitled 'Short Term Flat NBP Trading Terms and Conditions 1997'. A copy of these is attached in Appendix One. Bilateral transactions refer to these terms in the deal confirmation, together with company specific amendments thereto.

The significance of 'Flat' in the title is that there is no interruption and no volume tolerance allowed. (Under beach contracts a 2 per cent volume tolerance is allowed, but this is rarely exercised.)

A deal is normally transacted over the telephone, with or without the assistance of a broker, and confirmed by the seller in writing quickly thereafter, but not later than within three banking days of the transaction, for countersignature by the buyer. If the seller has not sent the signed confirmation within the required time, the buyer sends confirmation for counter-signature by the seller. A transaction confirmation is normally one sheet of paper containing the following information:

1. Confirmation that the deal is being done within the NBP '97 GT&Cs and the Network Code;
2. Buyer's and Seller's names and ATLink references;
3. The supply period;
4. The daily quantity;
5. The Contract Price (this can be expressed as a 'fixed and flat' price i.e. so many pence per therm, or it can be determined by reference to a market index of prices in effect on the day that gas flows. Heren is the market leader in price reporting, but increasingly, deals are being done by reference to the index quoted by the International Petroleum Exchange – see Sections 6.3 and 7.

6. Compensation mechanism for breach within clauses 4.2 or 4.3 (this refers to breaches of contract by seller or buyer respectively and provides two alternative methods by which the innocent party is entitled to compensation, either by reference to the difference between the Contract Price and the SMP or the difference between the Contract Price and the SAP); and,
7. Any special conditions or amendments to the NBP '97 GT&Cs.

6.1 NBP '97 GT&Cs

The additional terms specified in the GT&Cs make it clear that the transaction is governed by English law under the exclusive jurisdiction of the English courts and that, in the event of conflict, the transaction confirmation takes precedence over the GT&Cs.

Both parties give a warranty that they have all the necessary licences to trade and are a party to the NC. Contracts are made in therms, whereas NC nominations are made in kilowatt hours so a standard conversion of kWh =29.3071x Therms is agreed. The procedure for submitting matching gas trade nominations to Transco via ATLink are set down. Failure to do so, except in the case of Force Majeure (FM), would be a material breach activating the compensation procedure agreed in the transaction confirmation.

Unlike oil and LPG, VAT on the gas contract is not zero rated and is payable by the buyer. More significantly, the price on which PRT is levied is agreed between the companies and the OTO on an individual basis, aimed at assessing tax on arm's length sales at the price actually realised by the producing company. So there are not the same constraints on (or opportunities for optimisation for) producers/shippers trading gas, as there are on oil producers constrained by the 24 hour PRT nomination regime.

Payment is made, typically, in sterling by the 20th of M+1 (M being the delivery month) or ten days after receipt of statement, if later. Unlike oil, the split weekend provision does not apply i.e. if payment is due on Sunday or a Monday bank holiday, it must be paid on the previous Friday. Again unlike physical oil, the setting off of payments under the transaction in question against other transactions between the counterparties is allowed, although this is common for oil 'paper' transactions governed by International Swaps and Derivative Association Terms (ISDAs).

The Force Majeure provisions are interesting. FM is described as an event beyond the control of the affected party *resulting in inability to get a trade nomination into or accepted by Transco*. A field or exit point shutdown does not constitute FM, since any party using the NTS cannot identify 'its own gas', and is not relieved of its obligation to supply or remove gas from the system because its source of supply or offtake is inoperative. It is only in the case of, for example, ATLink going down, that the party is relieved of liability for the duration of the FM incident, subject to proper notification procedures being followed. The party is required to make reasonable endeavours to overcome the FM, but, if it continues for seven days or more, either party can give three banking days notice of termination.

Term and termination provisions are similar to ISDA 'Events of Default', being exercisable if there is, for example, a financial, breach of contract. Accrued rights and obligations are protected at the date of termination and an early termination

payment is made by reference to a Gas Reference Price which is an average of Heren and Argus prices plus Libor.

The other provisions are standard for most contracts i.e. no consequentials, no waiver, assignment and so on.

6.2 Credit And Performance Risk

As usual when dealing in an informal and unregulated market, each party takes on the credit and performance risk of the other party. The norm in gas transactions between counterparties who will not extend open credit, is for the buyer to raise a letter of credit (LC), usually a stand-by LC. In other words, if a buyer does not pay up, the seller has recourse to the buyer's bank for up to the amount in question. In some cases payment is automatically made by the buyer's bank to the seller on presentation of transfer documents. This differs from a traditional oil 'irrevocable documentary LC', where payment is automatically made through the bank on presentation of the documents of transfer of risk and title, which, in the case of oil, would be a negotiable bill of lading for a Free on Board (FOB) sale into a ship or a terminal transfer certificate for a Free-in-Pipe (FIP) pump-over. (The latter is common for deliveries of Forties to BP Grangemouth from Hound Point and deliveries of Ekofisk to Phillips/ICI PIP refinery at Seal Sands).

No equivalent negotiable document exists for the transfer of risk and title to gas so payment is made by the bank against the presentation of the seller's invoice alone.

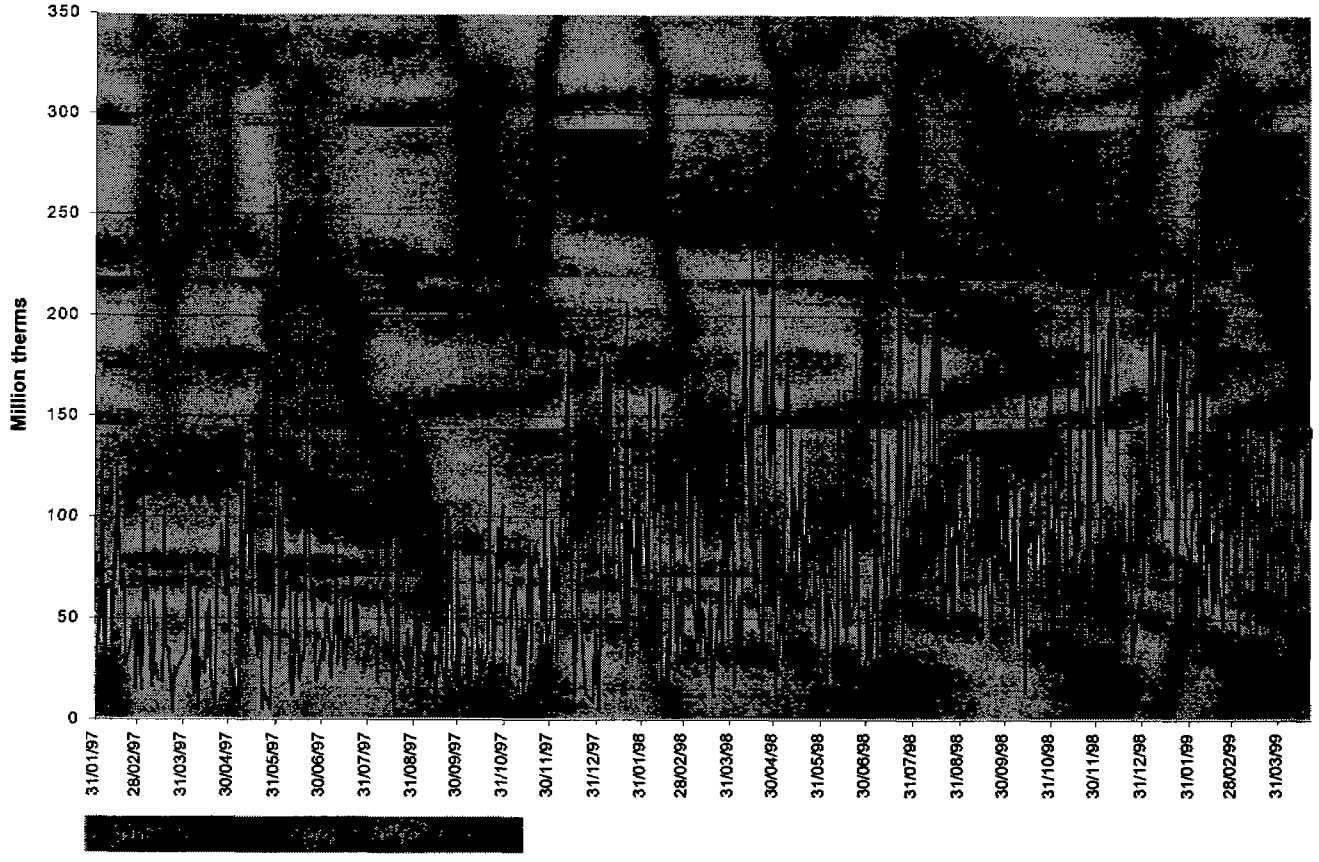
6.3 Heren

The market leader in price reporting is 'The British Spot Gas Markets' report, published daily by PH Energy Analysis Ltd. This service has been in existence since 1995 and has developed alongside the emerging market. Heren provides a market commentary and assesses prices by telephoning traders throughout the day and at market close every evening. Market close is something of a moving target for the informal spot market and tends to be when activity quietens down for the day, some time after what most industries would consider to be normal office closing hours. The report assesses a snapshot of prices at that single point in time that could be achieved for gas to be delivered in:

Day ahead;
Weekend;
Balance of month;
Each of the next 6 months;
Each of the next 10 quarter; and,
The next three years gas.

Bid/Offer assessments are given at the NBP and a midpoint differential between NBP and Bacton and NBP and St. Fergus. For each delivery month, Heren also produces an index at NBP and Bacton, which is a cumulative weighted average of prices for deals actually done. (For Heren methodology, see Appendix 2) Heren also reports IPE prices, activity in the flexibility 'market' and day-ahead prices for Beach Terminal capacity.

Since Heren and its rivals, Argus and Platts, assess market price levels, there is an element of subjectivity in their reporting as they sift through rumour, hearsay and mistaken misinformation to get at a true market level. Many spot market players are moving towards setting contract prices for their transactions by reference to prices on the IPE.



7. THE INTERNATIONAL PETROLEUM EXCHANGE (IPE) GAS FUTURES CONTRACT

The IPE was set up in 1980, and started trading gasoil futures in 1981. It now trades gasoil, Brent (including options contracts on both these products) and, since January 1997, natural gas futures. Of the IPE's turnover, 70 per cent is accounted for by Brent, a contract which eventually got off the ground in 1988, after an earlier unsuccessful launch which had been based on physical delivery. Future plans include an electricity contract and a new contract proposal is already before the UK authorities to trade CO_2 Emissions.

The IPE is a Recognised Investment Exchange within the meaning of the Financial Services Act (FSA) of 1986. All members are either directly authorised by the Financial Services Authority or are members of the Securities and Futures Authority, a self-regulating organisation, recognised under the terms of the FSA 1986. All IPE members are either members of the London Clearing House (LCH), or have a clearing agreement with another member who is a member of the LCH.

The LCH guarantees the financial performance of all IPE contracts registered with it by its clearing members. It acts as a central counterparty to every transaction and requires clearing members to produce an initial margin (good faith deposit on every transaction) and a variation margin based on a 'mark to market' of the transaction against the closing price each evening. This process is supported by a £150 million reserve fund, provided by the owners of the LCH.

The IPE natural gas contract commenced trading on 31/1/97 and is building a regular, volume of daily trades, though still a fraction of the volume on the OTC market. (See Figure 7.1) The IPE offers buyers and sellers of its contract the right to settle their purchases and sales, either by cash settlement (entering into an equal and opposite futures trade and paying or receiving the price difference between their purchase and sales trades), or by effecting physical delivery at the NBP.

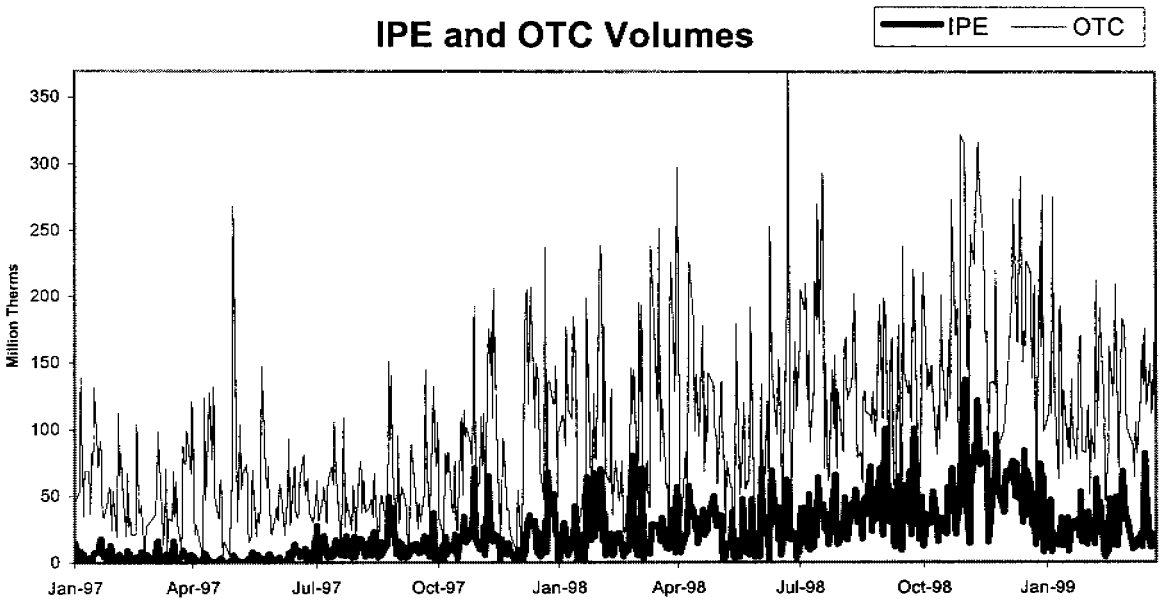


Figure 7.1

The natural gas contract is a traditional futures contract traded through a broker or, less usually, by direct trader access via an Electronic Trading System (ETS) i.e. there is no open-outcry pit. As with all other futures contracts it operates with a system of initial (good faith dealing deposit) and variation (difference between the price at which the trade was made and the daily closing price) margin calls to eliminate credit exposure to users.

The LCH is a Restricted User of the NTS with limited exposure to the NC. It does not book capacity itself, although it does input matched throughput nominations via ATLink.

The contract is expressed in p/therm with the minimum tick price of 0.01p/therm/lot. One lot represent 1000 therms/day for delivery during each day of the trading month, but it is only possible to deal in a minimum of five lots per trade. It was initially tradable 12 months forward, but this was extended to 15 months forward in March 1998. Each month's contract expires two business days before the start of the delivery month. It can only be traded thereafter as a Balance of Month (BOM) contract with the volume eroding over the month as daily physical delivery takes place. Trades which are not cash settled go to physical delivery with the IPE, or more correctly, by the LCH assuming the contract holders' rights and liabilities under the NC.

If the buyer or seller of an IPE Balance of Month contract does not perform on the day, the LCH picks up the imbalance charges and seeks to recover them from the defaulter. The other side of the matched trade is not approached in this process, because the exchange protects them from the consequences of physical or financial non-performance by the party with whom their trade was matched. To cover the cost of such defaults, sellers post a security, currently £24/lot,[18] when entering into a trade. If a buyer defaults, the LCH recovers the cost from the initial and variation margin.

In reality, while the Natural Gas Futures Contract has so far proved a qualified success, the use of the BOM contract has been minimal. Industry sources attribute this to competition from the OTC spot market for prompt, current month delivery, which is easier to use and does not require the tying up of capital in margins and deposits. The IPE adds nothing to the spot market but anonymity and credit security, which appears insufficient to compensate for the extra administration involved in using it.

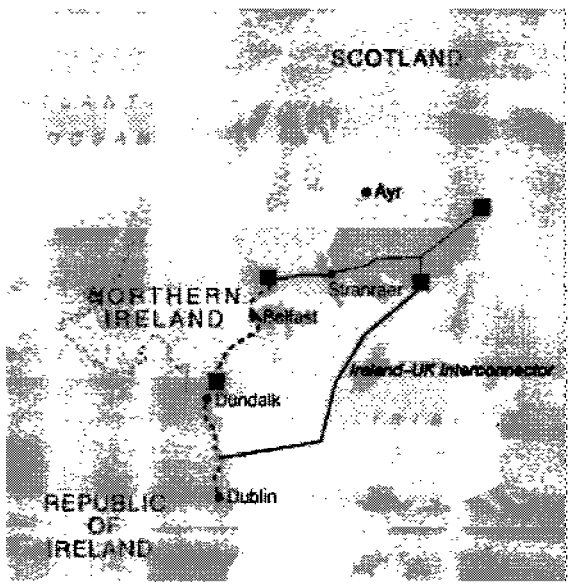
[18] £24/lot is the rate applying to a monthly contract delivering 1000 therms/day during each day of the month. The rate for intermonth spreads and a daily contract is £12/lot and, for interday spreads, £10/lot.

8. THE INTERCONNECTORS

No look at the UK gas market would be complete without a mention of the interconnectors which take gas out of or into the NTS via Ireland and continental Europe.

8.1 THE IRISH INTERCONNECTOR

The 24" pipeline links into the UK mainland NTS at Moffat, and runs to Twynholm, where it splits, with one branch taking gas to the Irish Republic and the other branch running 135 kilometres to Belfast, leaving Scotland at South Cairn. Capacity on this pipeline is currently constrained by Moffat compression. A project to upgrade this station is due for completion in 2000.



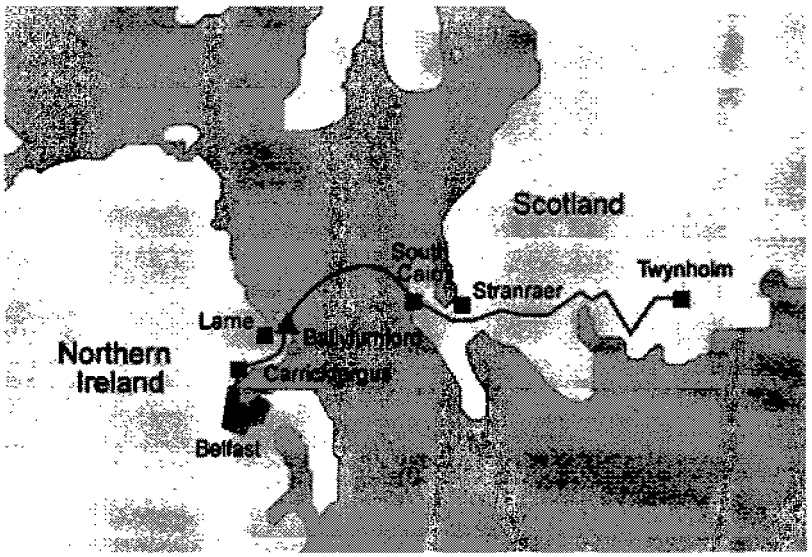
Source: BG

The Irish market is rapidly switching from coal to gas. In 1992 British Gas bought the Ballylumford power station in County Antrim for conversion to gas as a first step in supplying gas to the Northern Irish downstream market. It established a new subsidiary, Phoenix Natural Gas (PNG), to carry out this project, which was completed in April 1997. PNG is now owned 50 per cent by BGplc and 50 per cent by an American company called Keyspan. Using abandoned coal trenches to lay the pipes with the minimum of disruption, PNG has extended gas connections throughout the Greater Belfast area, and has ambitious plans to extend further, promising a rapid growth in the Northern Irish gas demand. In 1996, PNG and Premier Transco were granted the first licences to develop a natural gas network in Northern Ireland.

For the purpose of this paper, the interesting element was the building of an interconnector between the mainland of Great Britain and Northern Ireland and the Republic. This project was completed by Premier Transco, a sister company to PNG, which is owned 50 per cent by BGplc and 50 per cent by Keyspan.

Keyspan is also in discussions with Bord Gais, the Irish Republic's gas company, about forming a joint venture to build a north–south gas link. Bord Gais has the alternative of building its own undersea line from Scotland. Recent posturing in the

press, suggests that the direct link to Scotland may be more economic because of already high gas and electricity prices in Northern Ireland, as a consequence of contractual arrangements with power generating companies arising from privatisation in 1992, which will be compounded by the introduction of the climate change levy.



The announcement of the discovery of the Corrib field off the west coat of Ireland also has a bearing on the decision. Enterprise Oil plc, the field operator, estimates that Corrib alone could supply more than half of the republic's current gas demand.

Offsetting any supposed economic disincentive to build the north–south line, is the political agenda to create an integrated all-Ireland energy market with expected consequences for the peace process. Supply of power in Northern Ireland will open to outside competition on July 1 1999 and the Republic on 1 February 2000. A limited north–south line already exists between Tandragee in the north and Louth in the south.

8.2 The UK-Continent Interconnector

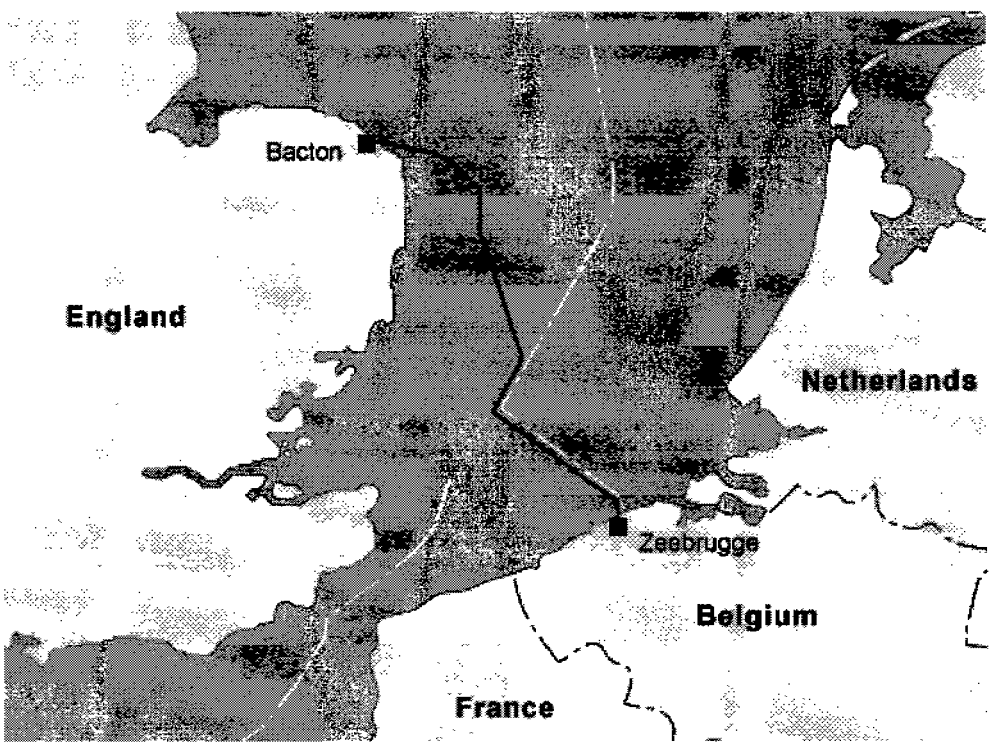
When it comes to consideration of the Bacton/Zeebrugge interconnector, the choice is between writing a book or writing a few paragraphs about the consequences of linking the UK to Continental Europe.[19] Since this paper is mainly concerned with the development of UK gas market mechanisms, the latter option has been taken.

[19] Recommended for further reading, is 'Gas to Europe: The Strategies of Four Major Suppliers', edited by Robert Mabro and Ian Wybrew-Bond.

The UK-Continent Gas Interconnector links the NTS into mainland Europe. Becoming operational in October 1998, the 40" diameter line runs 146 miles from Bacton in Norfolk to Zeebrugge in Belgium. It has a capacity of 20bcm per year in UK to Europe flow and 8.5bcm per year in Europe to UK flow. In reality, trade flow may be in both directions at the same time, with the balances being netted off to determine the actual direction of physical flow.

Ownership of the line has changed several times since construction began in 1996 but is currently: BG 25 per cent; BP 10 per cent; Conoco UK Ltd 10 per cent; Elf UK 10 per cent; Gazprom 10 per cent; Distrigas 10 per cent; Ruhrgas 10 per cent Amerada Hess Ltd 5 per cent; National Power 5 per cent; and SNAM 5 per cent. Each company trades its capacity in the line, which does not necessarily coincide with its ownership percentage of the line hardware, independently of its partners. There is no single pipeline company to whom application can be made for tariff terms.

The German company, Wingas, was the first to sign contracts to buy *gas* from BG from the interconnector: 35 bcf per year commencing in 1998 and a further 35 bcf per year in 2000. BG has sold 0.5 billion cubic metres of gas *transportation capacity* per year for ten years to Entrade B.V. in the Netherlands and a further 8 bcm per year for 10–20 years to other third parties.



Source: Interconnector (UK) Ltd

As yet there are no standard general terms and conditions for trading gas or capacity in the interconnector. However, an industry working party has generated draft general terms and conditions for trading gas at the 'Zeebrugge Hub', which is a notional point within the so-called 'IZTD', the Interconnector Zeebrugge Terminal Distrigas, where Distrigas measures natural gas entering and leaving the Distrigas transmission system from and to the interconnector.

The document as drafted, envisages that Distrigas,[20] as Hub Operator, will take on the responsibility for administering daily balancing by accepting or rejecting 'Accurate Trade Nominations' given in accordance with the 'Operating Procedures under the Hub Services Agreement' between Distrigas and the buyer and Distrigas and the seller of each transaction. The document obliges the parties to act, with respect to volume nominations, in accordance with the umbrella agreement, the Hub Operating Agreement between the parties individually and Distrigas. It also suggests some financial penalties for defaults or breaches of contract which are 120–50 per cent (depending on the time of year) of relevant published average market prices. Prices are expressed in €/Gj, unlike the UK terms NBP GT&Cs which are expressed in p/therm, involving another inconvenient conversion for trades across regimes.

A more significant difference between UK and Zeebrugge terms is that the NBP GT&Cs are governed by English Law, whereas Zeebrugge terms are governed, not surprisingly, by Belgian Law. It is unlikely that a trader would be deterred from dealing by such a difference. In the case of Force Majeure, whereas a NBP trade can only rely on contractual relief in the case of an event beyond the control of the affected party *resulting in inability to get a trade nomination into or accepted by Transco,* the Zeebrugge terms allow relief for '*any* event beyond the control of a Party acting in accordance with the standards of a Reasonable and Prudent Operator'. Hence, any trader, say, purchasing gas in the UK and selling it on through the interconnector at Zeebrugge will carry the financial risk if his buyer claims Force Majeure as a result of a continental European event.

Regardless of how enthusiastic are the interested parties in achieving a liberalised integrated trading regime throughout the EU and beyond, the devil lies in such detail.

These terms and conditions are likely to be subject to prolonged debate, despite the public willingness of interested parties to be seen to co-operate (though it is not necessarily their private view), in the context of the 1998 EU Gas Directive.[21] Interestingly, some companies are shy of being seen to be involved in discussing standard market GT&Cs for fear of infringing Articles 85 and 86 of the Treaty of Rome concerning antitrust.

The EU gas directive is primarily aimed at promoting access, competition and choice of supplier for the consumer, but this need not necessarily be achieved by facilitating the development of a spot market. Some of the individual countries' monopoly suppliers/transporters regard the developing UK regime with considerable trepidation, arguing that a move to gas-to-gas spot market competition, as opposed to gas-to-oil competition within a framework of long-term

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[20] Distrigas is a private Belgian company, specialising in gas transportation, in which the Belgian government holds a golden share.

[21] The 1998 EU Gas Directive was drafted in the context of promoting competition to supply consumers, within the wider EU spirit of the free movement of goods and services within the community. It promotes a level tariff playing field for third-party access to transportation, whether regulated by individual governments or negotiated bilaterally. It came into effect in August 1998 and must produce changes in national laws by August 2000, with some exceptions. The opening up of markets to consumers equating to 20 per cent of national consumption is required by August 2000, 28 per cent by mid-2003 and 33 per cent by 2008. As with most EU legislation, there are numerous caveats and special cases.

contracts, will invite price instability with negative implications for transportation capacity planning and production project planning.

It is undeniable that spot markets are associated with increased price volatility, although the line of causation is debatable, but spot markets also deliver the trading tools to manage that volatility, if companies are prepared to accept hedging as an integral part of the business planning process. It is in the transition period from one philosophical approach to the other, when trading tools are still developing and market liquidity is patchy, that casualties are incurred. Companies who are not prepared to adapt are the most likely to suffer losses and be swallowed up by those who keep pace with, or anticipate, the inevitable.

With the EU gas directive on liberalisation of European gas still several years away from being effective in trading terms, it is likely that a liquid, standardised spot market in interconnector gas is likely to build only very slowly over the next 3–5 years.

In its first winter of operation, we have seen some Scandinavian sales into the UK via the interconnector. This move, as much to do with strong sterling as high gas prices, surprised the market with reverse flow in December 1998 which capped firm prices in the UK and forged a direct link between lagged, oil-related gas prices in Europe and UK gas prices.

The significance to the UK of this pipeline for the development of an integrated European market mechanism cannot be over-emphasised. The UK has one big advantage in becoming the seat of European spot gas trading: it got there first. The UK has a functioning spot contract and futures gas market. It has a published pricing infrastructure and it has recognised general terms and conditions for trade in general usage. It also has a workable hub at Bacton at the gateway to mainland Europe, the interconnector. This advantage could easily be squandered by ill-advised regulatory interference, which is why the rushed development of the OCM is a cause for concern. The advantage could also be neutralised very quickly by barriers to entry at Zeebrugge or at other key points in the European infrastructural network.

9. THE FUTURE

Under the Thatcher government, the political will to liberalise the gas industry in the UK was strong. BG was privatised in 1986 at the same time that Ofgas was charged with the role of pushing competition forward. But it took ten years to get from this promising start to the introduction of the Network Code in its initial imperfect form and a further two years to reach full domestic competition. Once the monopoly hurdle was removed (although the residual dominance of BG cannot be ignored), the pace of change in market practice speeded up and is showing some signs that a move towards 'commoditisation' of gas in the UK is well underway. The introduction of the OCM could help this process, but the incentivisation of Transco could throw up all sorts of barriers to entry, particularly when the market is opened up to non-shippers.

The early days of the Network Code and the alarming spikes in SMPs were not conducive to baseload hedging by shippers, all but the more sophisticated of whom had sufficient difficulty managing their physical balance to avoid penalties, to be unduly concerned about financial optimisation at the margin. Similarly, there was little role for speculators in a market, the underlying commodity of which could produce such unpredictable results.

In many cases, the gas experts within companies had grown up under the old regime and were not versed in the risk management philosophy of, say, the oil or financial futures markets. Similarly there was imperfect knowledge of the rules of the gas game amongst the players in the more established commodity and financial markets, with some notable exceptions. A rapid cross-fertilisation of disciplines has taken place which bodes well for the growth in liquidity of the OCM, the OTC spot market and the futures market, complete with options and the type of short-term swaps required to perfect the market for hedging purposes.

In the case of the IPE futures market, its responsiveness to change may well be inhibited in the short term by its current preoccupation with demutualisation, although there is a suggestion that an on-the-day futures contract to rival the OCM could be introduced. The new ownership of the IPE, whoever that turns out to be, is likely to be able to move faster in recognising and adjusting to the clues to direction given by the developing OTC market, than was possible under the current mutual structure.

At a local UK level, there is considerable scope for domestic growth, development and fine-tuning of the market mechanisms. The pundits agree that domestic demand is promising, assisted by the interconnector with Ireland and by the increased share of gas of the energy market with the move to cleaner fuels.

The deregulation of electricity will have a huge impact on how gas trading tools develop and it seems likely that there will be a rise in arbitrage trading between the two markets. Slightly more esoteric is the possibility of arbitrage opportunities opening up with the nascent market for weather derivatives: the impact of weather on gas demand is obvious, but liquidity in this tool relies on sufficient non-energy appetite from weather dependent manufacturing and leisure industries developing to provide a two-sided market.

On the negative side, the retrograde signals given by the current government in favour of coal are a reminder of how much hard won ground can be cut back with the stroke of a legislator's pen.

More significantly, it will be interesting to see how the regulator will view market developments which evolve of their own volition rather than being pushed forward in the pursuit of the government's objective to introduce competition for the benefit of the consumer. Ofgas is very concerned that the new OCM operates efficiently and has sufficient liquidity to ease physical system balancing. But it is less clear how developments in the OTC and futures markets will be regarded, particularly when they are subject to speculative interests with different, but no less legitimate objectives than the promotion of competition for the consumers' benefit.

The experience in oil, particularly the high profile Brent contract, suggests that UKplc benefits from the siting of commodity and financial markets in London and that gas might enjoy, if not government protection, then at least regulatory indifference. This to a certain extent, will depend on how much international business is capable of being attracted to the UK and this in turn depends on the success of the interconnector and other links to the continental mainland and the liberalisation of gas in Europe.

It was noted at the beginning of this section that it took between ten and twelve years to achieve competition in the UK, despite the iron political will to do so. How much longer will it take to achieve true competition in Europe, where government commitments to competition and integration are across the whole spectrum from totally committed to downright obstructive?

In Europe, the majority of gas is still contracted at lagged, oil-related prices. This would suggest that the spot market might be slow to develop there. However, such contracts normally contain a tolerance provision in the volume to be delivered. This can take the form of a minimum contractual quantity or a fixed volume to be delivered plus or minus a percentage. This is akin to the seller granting the buyer a free 'put or call option' on the marginal volume. Given the lagged nature of pricing under these old-style contracts, there is considerable scope for the term contract price to diverge substantially from the spot market price on the day of delivery. When, say, the contract price is lower than the spot price, the buyer can call on this extra tolerance volume and sell it at a profit in the spot market and vice versa.

The value of this accident of contractual structure as a learning exercise for potential future spot players cannot be exaggerated and will be instrumental in overcoming the management inertia which can delay the progress of any new market tool. This will fulfil the role of catalyst that was taken by the 90:10 rule in the UK.[22]

There are still large quantities of gas moving under long-term contracts in the UK, but contract renewals and contracts for new production are increasingly being undertaken at spot gas related prices, though the spot market is not yet sufficiently developed or liquid enough to be relied upon as a secure offtake mechanism for the disposal of uncontracted gas.

Consideration of the Network Code in Chapter 5 gave some clue to the complexity of the issues yet to be resolved across Europe, without the benefit of a single focused entity, like Ofgas in the UK or the FERC in the USA, cutting through the obstructions to a fully integrated market. The prospects for integration are not good

[22] See Chapter 2, 1998 MMC recommendation.

if the iterative process followed by Ofgas and the UK gas industry were to be the mechanism for change followed by the EU.

It is more likely that industry will set the pace and the rationalisations and mergers which are proceeding apace throughout Europe suggest that the liberalisation and integration timetable may not be as slow as feared.

APPENDIX ONE

SHORT TERM FLAT NBP

Trading Terms & Conditions

1997

("NBP 1997")

1. Definitions and Interpretation

1.1 The following words or phrases, where they appear in these terms and conditions or in a Confirmation, shall have the meanings respectively ascribed to them:

"Accurate Trade Nomination" shall mean in respect of a Day and a quantity of Gas, a Trade Nomination made by a Party which complies with the Code Credit Limits and Clause 4.1.3 before 0400 hours on the Day (being in the case of the Seller a Disposing Trade Nomination and in the case of the Buyer an Acquiring Trade Nomination) for the Daily Quantity identifying the other Party as the person making the corresponding Trade Nomination;

"Acquiring Trade Nomination" shall have the meaning specified in the Network Code;

"Affiliate" shall mean any holding company or subsidiary company of a Party or any company which is a subsidiary company of the holding company of a Party and the expressions "holding company" and "subsidiary" shall have the meanings respectively ascribed to them by section 736 Companies Act 1985;

"Argus Gas Price" shall mean the bid price where the non-defaulting Party is the Buyer or the offer price where the non-defaulting Party is the Seller as published on a Day for the remainder of the Supply Period by Petroleum Argus Ltd in Petroleum Argus European Natural Gas;

"Banking Day" shall mean a day (other than a Saturday or a Sunday) on which the clearing banks in London are open for business;

"Buyer" shall mean the Party required to make Acquiring Trade Nominations pursuant to the Transaction;

"Code Contingency" shall have the meaning specified in the Network Code;

"Code Credit Limit" shall have the meaning specified in the Network Code;

"Confirmation" shall mean a document that incorporates these terms and conditions by reference and confirms the details of the Transaction. The Confirmation shall be substantially in the form of the Schedule hereto;

"Contingency Procedures" shall have the meaning specified in the Network Code;

"Contract Price" shall mean the sum agreed as such for the Transaction, exclusive of VAT and other applicable taxes;

"Daily Imbalance" shall have the meaning specified in the Network Code;

"Daily Quantity" shall mean the daily quantity of Gas agreed between the Parties as such for the Transaction;

"Day" shall mean the period beginning at 0600 hours on a day and ending at 0600 hours on the following day;

"Disposing Trade Nomination" shall have the meaning specified in the Network Code;

"Early Termination Payment" shall be an amount payable on termination in accordance with Clauses 10.4, 10.5 and 10.6;

"Force Majeure" shall mean any event or circumstance beyond the reasonable control of a Party which totally prevents a Trade Nomination from being submitted by such Party to Transco or from being received and taken into account by Transco in determining such Party's Daily Imbalance;

"Gas" shall have the meaning specified in the Network Code;

"Gas Flow Day" shall have the meaning specified in the Network Code;

"Heren Gas Price" shall mean the bid price where the non-defaulting Party is the Buyer or the offer price where the non-defaulting Party is the Seller as published on a Day for the remainder of the Supply Period by PH Energy Analysis Ltd. in British Spot Gas Markets;

"IPE" shall mean the International Petroleum Exchange;

"IPE Gas Price" shall mean the IPE settlement price as published by the IPE on that Day for the remainder of the Supply Period;

"LIBOR" shall mean, in respect of a month, the one month London Interbank Offered Rate (expressed as a percentage per annum) in sterling as notified by National Westminster Bank plc at which a deposit of a principal sum equal to the relevant sum in question under these terms and conditions would have been offered by such bank to prime banks in the London Interbank Market at such banks' request at or about 1100 hours on the first Banking Day in such Month for a period commencing on such Banking Day and ending on the first Banking Day in the next succeeding Month;

"Month" shall mean a period beginning at 0600 hours on the first day of a calendar month and ending at 0600 hours on the first day of the following calendar month;

"Monthly Statement" shall have the meaning specified in Clause 6.1;

"NBP Trade" shall mean, in respect of a quantity of Gas, (where:

(a) in respect of any Day two Users make corresponding Trade Nominations in respect of that quantity of Gas subject to and in accordance with Section C6 of the Network Code, and

(b) neither Trade Nomination is amended or withdrawn thereafter), the deduction by Transco of that quantity of Gas in determining for that Day the Daily Imbalance of the User making the Disposing Trade Nomination and the addition by Transco of that quantity of Gas in determining for the same Day the Daily Imbalance of the User making the Acquiring Trade Nomination;

"Network Code" shall mean the document, as modified from time to time, setting out transportation arrangements established by Transco pursuant to its public gas transporter's licence;

"Party" shall mean one or other of the parties to the Transaction;

"Pricing Indices" shall mean the Heren Gas Price and the Argus Gas Price and the IPE Gas Price;

"Seller" shall mean the Party required to make Disposing Trade Nominations pursuant to the Transaction;

"Supply Period" shall mean the period during which, pursuant to the Transaction, the Parties shall make NBP Trades, such period commencing and terminating on the Days agreed for the Transaction;

"System Average Price" shall have the meaning specified in the Network Code;

"System Marginal Buy Price" and "System Marginal Sell Price" shall have the respective meanings specified in the Network Code;

"Therm" shall mean one hundred and five million five hundred and six thousand joules (105,506,000 J);

"Trade Nomination" shall have the meaning specified in the Network Code;

"Transaction" shall mean an oral or written agreement to undertake one or more NBP Trades such agreement to include, inter alia, these terms and conditions, details of the Supply Period, the Daily Quantity, and the Contract Price;

"Transco" shall mean BG plc or any successor to the BG plc public gas transporter licence;

"UK Link" shall have the meaning specified in the Network Code;

"User" shall have the meaning specified in the Network Code;

"Week" shall mean a period of seven (7) days beginning at 0600 hours on any Sunday and ending at 0600 hours on the following Sunday.

1.2 Any reference in these terms and conditions to a Transaction includes any permitted assignment, novation, supplement or amendment thereto.

1.3 Any reference to a Clause or Clauses is a reference to a clause or clauses in these terms and conditions.

1.4 Words in the singular may be interpreted as including the plural, and vice versa.

1.5 Any reference in these terms and conditions to a statute or statutory instrument or order is a reference to that statute, statutory instrument or order as from time to time amended, re-enacted or supplemented.

1.6 In the event of conflict between the terms of a Confirmation and these terms and conditions, the terms of the Confirmation shall prevail.

1.7 Any reference in the Transaction to a quantity of Gas shall mean a quantity expressed in Therms.

1.8 Any reference in the Transaction or the Confirmation to time shall be to the time in London.

2. Confirmation Procedure

2.1 The Seller shall, within three (3) Banking Days of a Transaction being entered into, send by facsimile transmission to the Buyer a signed Confirmation recording the details of the Transaction.

2.2 If the Buyer is satisfied that the Confirmation accurately reflects the terms of the Transaction the Buyer shall sign and return the Confirmation by facsimile transmission to the Seller within three (3) Banking Days of receipt of the Confirmation.

2.3 If the Buyer is not so satisfied, the Buyer shall inform the Seller of any inaccuracies. The Seller shall, if it agrees that the Confirmation is inaccurate, issue a new Confirmation and the provisions of Clause 2.1 shall apply.

2.4 If the Buyer does not return the Confirmation, duly signed, in accordance with Clause 2.2, or notify the Seller of any inaccuracy in accordance with Clause 2.3, the Buyer shall be deemed to accept the Confirmation.

2.5 If the Buyer has not received a Confirmation from the Seller within three (3) Banking Days of a Transaction being entered into, the Buyer shall send the Seller a Confirmation, and Clauses 2.2, 2.3 and 2.4 shall apply mutatis mutandis in relation to such Confirmation by replacing in such clauses all references to "Buyer" with "Seller" and "Seller" with "Buyer".

2.6 Subject to Clause 2.4, on signature by both Parties, the Confirmation shall, save in the event of manifest error, prevail over any oral or written agreement in respect of the Transaction.

2.7 The Parties hereby consent to the recording of telephone conversations in respect of the Transaction.

2.8 Failure or persistent failure by the Seller or the Buyer to send a Confirmation shall not be a material breach of the Transaction.

3. Representations and Warranties

Each Party represents and warrants to the other that it has obtained and will maintain at all times during the Supply Period all licences, authorisations, permits, consents and other approvals necessary to enable it to fulfil its obligations under the Transaction and that it is and will remain a party to the Network Code.

4. NBP Trades

4.1 **Trade Nominations**

4.1.1 Each Party shall in respect of a Day within the Supply Period for which the Daily Quantity is greater than zero make an Accurate Trade Nomination;

4.1.2 If, on any such Day, UK Link is affected by a Code Contingency and which affects a Party, such Party shall submit its Trade Nomination by the means and in the manner provided for in the Contingency Procedures;

4.1.3 Trade Nominations shall be made in kilowatt hours, for which purpose the conversion from Therms shall be calculated in accordance with the following formula:

$K = 29.3071 \times T$ rounded to the nearest kilowatt hour, an exact half being rounded upwards; where "K" is the quantity expressed in kilowatt hours and "T" is the quantity expressed in Therms.

4.1.4 Where in respect of a Day the Trade Nominations submitted by the Parties pursuant to the Transaction are considered not to be effective and are rejected by Transco in accordance with section C6 of the Network Code:

(a) a breach by the Buyer shall be deemed to have occurred if the last Accurate Trade Nomination notified to Transco in respect of the Transaction was made by the Seller; and

(b) a breach by the Seller shall be deemed to have occurred if the last Accurate Trade Nomination notified to Transco in respect of the Transaction was made by the Buyer.

4.1.5 Where Transco has accepted an Accurate Trade Nomination, neither Party shall, unless otherwise agreed by the Parties, amend or withdraw such Accurate Trade Nomination;

4.1.6 The Parties shall use their reasonable endeavours to make Accurate Trade Nominations by, in the case of the Seller 1300 hours on the Day before the Gas Flow Day and, in the case of the Buyer, by 1600 hours on the Day before the Gas Flow Day.

4.2 **NBP Trade: breach by the Seller**

Save and except in respect of an event of Force Majeure, if for any Day the Seller is in breach of Clauses 4.1.1, 4.1.2 or 4.1.5, the Seller shall pay to the Buyer either:

A. the sum, where positive, of (SMBP-CP) x DQ where "SMBP" is the System Marginal Buy Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity; or

B. the sum, where positive, of (SAP-CP) x DQ where "SAP" is the System Average Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity, unless the Buyer can show that the actual loss suffered in respect of that Day was greater, in which circumstances the Seller shall pay to the Buyer such sum as represents the Buyer's actual loss, such payment to be no greater than the amount calculated in accordance with 4.2A.

The Parties shall specify for the Transaction the basis of compensation payable in the event of a breach.

Payment in accordance with the provisions of this Clause 4.2 shall be in full and final satisfaction of the rights of the Buyer and the sole remedy available to the Buyer in respect of a breach by the Seller of Clause 4.1 howsoever caused and even where caused by the negligence or breach of duty of the Seller except for any other remedies expressly provided in the Transaction.

4.3 **NBP Trade: breach by the Buyer**

Save and except in respect of an event of Force Majeure, if for any Day the Buyer is in breach of Clauses

4.1.1, 4.1.2 or 4.1.5, the Buyer shall pay to the Seller, either:

A. the sum, where positive, of (CP-SMSP) x DQ where "SMSP" is the System Marginal Sell Price for that Day, "CP" is the Contract Price and "DQ" is the Daily Quantity; or

B. the sum, where positive, of (CP-SAP) x DQ where "SAP" is the System Average Price for that Day, "CP" is the Contract Price, "DQ" is the Daily Quantity, unless the Seller can show that the actual loss suffered in respect of that Day was greater, in which circumstances the Buyer shall pay to the Seller such sum as represents the Seller's actual loss, such payment to be no greater than the amount calculated in accordance with 4.3A.

The Parties shall specify for the Transaction the basis of compensation payable in the event of a breach.

Payment in accordance with the provisions of this Clause 4.3 shall be in full and final satisfaction of the rights of the Seller and the sole remedy available to the Seller in respect of a breach by the Buyer of Clause 4.1 howsoever caused and even where caused by the negligence or breach of duty of the Buyer except for any other remedies expressly provided in the Transaction.

4.4 **Payment of Compensation**

Any amount due under either:

(a) Clauses 4.2A or 4.3A; or

(b) Clauses 4.2B or 4.3B where the amount for the purpose of this Clause 4.4 shall be on the basis of SAP, unless the Seller under Clause 4.2B or the Buyer under clause 4.3B has agreed in writing to a greater level of actual loss;

may, at the election of the non-breaching Party, be set-off against amounts due or becoming due under Clause 6.

5. The Contract Price

In respect of a Transaction:

5.1 the Buyer shall pay the Seller in arrears for each NBP Trade a sum calculated by multiplying the Contract Price by the Daily Quantity;

5.2 the Buyer shall pay any VAT in relation to each NBP Trade on receipt of appropriate tax invoices from the Seller and shall ensure that all royalties, taxes, duties and other sums legally payable by the Buyer arising as a result of each NBP Trade are paid;

5.3 the Seller shall ensure that all royalties, taxes, duties and other sums legally payable by the Seller arising as a result of each NBP Trade are paid.

6. Billing and Payment

6.1 On or before the tenth (10th) day of the Month following each Month which is wholly or partly in the Supply Period the Seller shall send to the Buyer a statement ("Monthly Statement") which shall show for the preceding Month:

▶ 6.1.1 the quantity of Gas in respect of which NBP Trades have been effected on each Day in that Month;

▶ 6.1.2 the quantity of Gas in respect of which the Contract Price is payable and the resultant sum owing to the Seller;

▶ 6.1.3 the Contract Price;

▶ 6.1.4 any amount owing from one Party to the other or already paid or set-off under Clause 4.4 or 6.7;

▶ 6.1.5 the net amount payable from one Party to the other after taking into account all the matters set out above, and

▶ 6.1.6 VAT and any other applicable taxes.

6.2 On the twentieth (20th) day of the Month in which the Monthly Statement is received by the Buyer or the tenth (10th) day after receipt, whichever is the later ("the due date"), the Buyer or the Seller, as the case may be, shall pay to the other Party the net amount payable in accordance with the Monthly Statement.

6.3 Payment shall be made by the due date in sterling by direct bank transfer or equivalent transfer of immediately available funds to the Party to whom it is due and to the credit of the account specified by that Party.

6.4 If the due date for payment is not a Banking Day then payment shall be made on the previous Banking Day.

6.5 If a Party disputes any sum shown in the Monthly Statement as being payable by that Party, it shall make payment of any undisputed amount on or before the due date for payment and shall give notice of the amount in dispute and the reasons therefor to the other Party. The Parties shall seek to settle the disputed amount as soon as possible.

6.6 If a Party fails to pay to the other Party by the due date for payment any amount due:

▶ 6.6.1 interest shall be payable on that amount at a rate equal to the base lending rate for sterling of National Westminster Bank plc applicable from time to time plus three (3) percent compounded annually from the date when the payment is due until and including the date the payment is made;

▶ 6.6.2 the Party to whom the amount is due may terminate the Transaction in accordance with Clause 10.2;

▶ 6.6.3 the Party to whom the amount is due may, upon notice to the Party who has failed to pay, suspend the Transaction until such time as payment is received.

6.7 A Party shall be entitled to set off against any undisputed amounts which it is due to pay to the other Party in respect of any or all Transactions with such Party, any undisputed amounts that it is due to receive from such Party.

7. Force Majeure

7.1 If a Party is by reason of Force Majeure rendered unable wholly or in part to carry out its obligations in accordance with Clause 4, then upon notice in writing of such Force Majeure from the Party affected to the other Party as soon as reasonably practicable after the occurrence of the event or circumstances relied on, the Party affected shall be relieved of liability to the extent that it is in breach by reason of Force Majeure and for the period during which such Force Majeure persists, provided that:

▶ 7.1.1 the Party seeking relief under this Clause 7 shall advise the other Party as soon as practicable of the event or circumstance constituting Force Majeure together with its estimate of the likely effect of such Force Majeure on its ability to perform its obligations hereunder and of the likely period of such Force Majeure; and

▶ 7.1.2 the Party affected shall use all reasonable endeavours to terminate or overcome the event or circumstance constituting Force Majeure.

7.2 Either Party may terminate a Transaction by giving three (3) Banking Days notice to the other if Force Majeure in respect of that Transaction continues for seven (7) Days or more.

8. Information and Confidentiality

The terms and conditions of the Transaction and all information provided thereunder shall be treated as confidential and shall not be disclosed without the prior written consent of the other Party, save that consent shall not be required for disclosure:

8.1 to directors, employees or Affiliates of either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

8.2 to persons professionally engaged by either Party, provided that they in turn are required by that Party to treat the information disclosed as confidential;

8.3 to any government department or agency having jurisdiction over that Party;

8.4 to any bank or other financial institution in relation to the financing of either Party's business activities, provided that the bank or other financial institution, as the case may be, is required by that Party to treat the information disclosed as confidential;

8.5 to the extent required by any applicable laws, judicial process or the rules and regulations of any recognised stock exchange;

8.6 to any intending assignee of the rights and interests of either Party under the Transaction provided that such intending assignee in turn is required by that Party to treat the information disclosed as confidential;

8.7 to Transco for the performance of the Transaction;

8.8 to the extent that such information is in or lawfully comes into the public domain other than by breach of this Clause 8; or

8.9 to price reporting agencies in respect of Contract Price, Supply Period and Daily Quantity only.

9 Assignment

9.1 Subject to Clause 9.2, neither Party shall assign to any person any of its rights or obligations in respect of a Transaction without the written consent of the other Party, which consent shall not be unreasonably withheld. For these purposes it shall be unreasonable to withhold consent in the case of an assignee that is demonstrably capable of fulfilling the obligations of the assignor in respect of a Transaction.

9.2 A Party may assign its rights and obligations in respect of a Transaction to an Affiliate on notice to, but without the consent of the other Party provided that the assignor shall not be relieved of any obligations that such Affiliate fails to perform.

10 Term and Termination

10.1 The non-defaulting Party may terminate the Transaction forthwith by giving notice to the other Party:

- 10.1.1 in the event of the other Party becoming insolvent, ceasing to trade or having a receiver, liquidator, administrator or administrative receiver appointed over some or all of its assets or if proceedings are commenced for its dissolution or winding up (other than a voluntary winding up for the purposes of solvent amalgamation or reconstruction); or
- 10.1.2 in the event of the other Party being in breach of Clause 3; or
- 10.1.3 in the event of the other Party failing to provide or maintain security for performance of its financial obligations as agreed at the date of the Transaction; or
- 10.1.4 in the event of a material adverse change in the financial standing of the other Party when compared to such Party's financial standing as at the date of the Transaction which change affects its ability to perform its financial obligations in respect of the Transaction, and such Party fails to provide reasonable security for the performance of its financial obligations in respect of the Transaction within three (3) Banking Days of the other Party's request therefor.

10.2 The non-defaulting Party may terminate the Transaction by giving five (5) Banking Days' notice to the other Party in the event that other Party:

- 10.2.1 is materially in breach of any of its obligations under the Transaction;
- 10.2.2 fails to pay the amount specified in the Monthly Statement in accordance with Clause 6; provided that the Party in breach has failed to remedy the breach before expiry of the notice period. In the case of the breach being remedied, the notice is deemed not to have been given.

For the purpose of this Clause 10.2 a persistent failure by one Party to make Trade Nominations in respect of a Transaction shall be deemed to constitute a material breach.

10.3 The termination of the Transaction, however occurring, shall not affect any rights or obligations that may have accrued to either Party prior to termination.

10.4 Following termination in accordance with Clauses 10.1.1, 10.1.2 or 10.2, one Party shall pay to the other the Early Termination Payment within five (5) Banking Days of notification of the amount of the Early Termination Payment in accordance with Clauses 10.5, 10.6 and 10.7.

10.5 The Early Termination Payment shall be the amount (if any) calculated by the non-defaulting party as follows:

(MV-RV)-I where the non-defaulting party is the Buyer, or

(RV-MV)-I where the non-defaulting party is the Seller

where:

(a) subject to Clause 10.6, "MV" is the market value of the Transaction calculated as follows:

sum of (D x DQ) x GRP

where:

"D" is the number of Days from the date of termination to the end of the Supply Period on which the Parties had agreed in accordance with the Transaction to enter into NBP Trades;

"DQ" is the Daily Quantity for each D;

"GRP" is the Gas Reference Price, which is the average of the Pricing Indices published on the date of termination for each D.

(b) "RV" is the remaining contract value calculated as follows:

(D x DQ) x CP

where:

"D" is the number of Days from the date of termination to the end of the Supply Period on which the Parties had agreed in accordance with the Transaction to enter into NBP Trades;

"DQ" is the Daily Quantity for each D;

"CP" is the Contract Price;

(c) "I" is the amount by which the sum of MV-RV or RV-MV as applicable is discounted to reflect the present day value as at the termination date. The rate of interest for the purpose of this calculation shall be equal to LIBOR as quoted at the date of termination or the first Banking Day after the date of termination from the due date for payment of each future invoice and the deemed due date for payment of future invoices shall be the 20th of each month.

10.6 Where none or only one of the Pricing Indices is available to calculate the Early Termination Payment, then the Early Termination Payment shall be calculated by taking the average of three reasoned quotations, such reasons to be reasonable, from three experts appointed by the non-defaulting Party.

11 Liabilities

Except as otherwise expressly provided herein, neither Party shall be liable to the other, whether in contract, tort or otherwise at law, for any loss of use, profits, contracts, production, revenue or for business interruption or for any consequential or indirect loss or damage of whatsoever nature and howsoever arising and even where caused by the negligence or breach of duty of either Party.

12 Waiver

No waiver by either Party of any breach by the other in respect of a Transaction shall operate or be construed as a waiver of any other breach.

13 Variation

No variation to the provisions of a Transaction shall be valid unless it is in writing and signed by an authorised representative of each Party.

14 Entirety

On signature of the Confirmation by both Parties or deemed acceptance of the Confirmation in accordance with Clause 2.4, the Confirmation shall be the entire agreement between the Parties in relation to the Transaction and supersede and extinguish any representations previously given or made other than those included in these terms and conditions and the Confirmation.

15 Severability

If any of the provisions of the Transaction are found by a court or authority of competent jurisdiction to be void or unenforceable, such provision shall be deemed to be deleted from the Transaction and the remaining provisions shall continue in full force and effect. The Parties shall in such event seek to agree upon a valid and enforceable provision to replace the provision found to be void or unenforceable.

16 Notices

Any notice or other communication to be given or made in respect of the Transaction by one Party to the other shall be given or made in writing to the other at that Party's registered office or such other address or contact number as that Party shall notify to the other from time to time and shall be deemed to have been received:

16.1 if delivered by hand, on the Banking Day delivered or on the first Banking Day following the date of delivery if delivered on a day other than a Banking Day;

16.2 if sent by first class post, on the second Banking Day after the day of posting or, if sent from outside the United Kingdom, on the fifth Banking Day following the day of posting;

16.3 in the case of a facsimile transmission, on the day of transmission if that day is a Banking Day or on the first Banking Day after transmission if that day is not a Banking Day and provided that a valid transmission report confirming good receipt is generated.

Where a notice is sent by facsimile, the Party giving the notice shall (but without prejudice to Clause 16.3), if so requested by the other Party, resend the notice as soon as reasonably practicable by facsimile.

17 Applicable Law

The Transaction shall be governed by and construed in accordance with English Law and the Parties shall submit to the exclusive jurisdiction of the English Courts.

CONFIRMATION

INSTRUCTIONS FOR USE

SELLER

1. Complete the Seller's details, name of the Buyer, Supply Period, Daily Quantity, Contract Price, method of compensation and any special conditions.
2. Sign the Confirmation.
3. Send the Confirmation to the Buyer by fax **within 3 Banking Days of the Transaction.**

BUYER

1. On receipt of a Confirmation, check the details. If correct, sign and return to the Seller by fax **within 3 Banking Days of receipt of the Confirmation.** Refer any inaccuracies to the Seller immediately.
2. IF YOU DO NOT SIGN AND RETURN THE CONFIRMATION WITHIN THREE BANKING DAYS OF RECEIPT, YOU WILL BE DEEMED TO ACCEPT ITS TERMS
3. If you do not receive a Confirmation within 3 Banking Days of the Transaction, complete the details and send the Seller the Confirmation.

The **SELLER** and the **BUYER** named below hereby agree that this Confirmation confirms the details of an agreement to undertake NBP Trades in accordance with the Short Term Flat NBP Trading Terms and Conditions Ref. NBP 1997 and C6 of the Network Code.

SELLER: .....

(including AT LINK Reference) .....

BUYER: .....

(including AT LINK Reference) .....

SUPPLY PERIOD: .....

DAILY QUANTITY: .....

CONTRACT PRICE: .....

COMPENSATION FOR BREACH WITHIN CLAUSES 4.2 OR 4.3:

SMP in accordance with option A ☐

SAP or actual loss in accordance with option B ☐

SPECIAL CONDITIONS: .....

.....

Date and time of Transaction: .....

Signed Signed

....

Duly Authorised Representative of the Seller *Duly Authorised Representative of the Buyer*

APPENDIX TWO

THE HEREN INDEX

The Heren Index is a monthly index of value for the natural gas at
(A) The National Balancing Point and
(B) At the entry point to the National Transmission System at Bacton terminal

Expressed in pence per therm (1 therm = 100,000 British thermal units), the index is derived from actual transactions for flat gas (no swing and 100% take or pay) flowing at a given rate throughout the month in question (Index Month). The Index is the volume-weighted average of transaction prices.

METHODOLOGY

The transaction on which the Index is based are those which took place in the calendar month proceeding the Index Month. Thus, for the March 1998 Index, only March deals which took place in the period 1-28 February were eligible.

Information is gathered by PH Energy Analysis Ltd during the course of reporting the short term market for its daily publication ***British Spot Gas Markets.***

Because the bulk of deals currently takes place at the NBP, the actual Heren Index calculation is based on NBP trades.

The Heren Index for Bacton is calculated by reference to the NBP Index, and is usually calculated by adding or subtracting the current market differential between Bacton and the NBP. Typically Bacton trades at a premium of 0.05-0.1 p/th to the NBP.

This information is subject to PH Energy Analysis' usual tests of reliability:

1. Confirmation is sought from both parties to the deal.
2. If, as is usually the case, both counter-parties are unwilling to confirm, confirmation is accepted from one side only. However, corroboration is also sought from other market participants.
3. If no confirmation is available, the deal may still be included if it is accepted by the wider market, and if PH Energy Analysis itself regards it as reliable.
4. In addition to price and volume, which are essential for inclusion in the Index, PH Energy ensures that deals include in the Index are stand-alone deals.
5. In the event of a wide range of prices being reported, and in the absence of any reasonable explanation, PH Energy Analysis would discard the top 10% and the low 10% of transactions by value. This action would only be taken if the range of prices from top to bottom exceeded 15%.

The Heren Index has been produced since April 1995.

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