EUROPEAN COMMISSION
DIRECTORATE-GENERAL FOR ENERGY AND TRANSPORT

DIRECTORATE C - Conventional Energies
Electricity & Gas

Ofgem's Submission to the European Commission (DGTREN) Report

Note: This document follows the structure and format set out by the European Commission

2005

Contents

1 Foreword

This report is Ofgem's submission to the European Commission describing the functioning of gas and electricity markets in Great Britain. It is one of the inputs on the basis of which the Commission has prepared its own report on the functioning of the electricity and gas markets across Europe, as required under the Electricity and Gas Directives.

Although gas and electricity markets in Great Britain are, in general, functioning well to deliver choice and value for money for consumers, the operation of wider European markets also has an impact on GB consumers. Wholesale gas prices in Britain are affected by those in neighbouring markets in which competition may be less well-established or liberalisation less complete. The commercial and physical links between British and other gas markets will be strengthened significantly by plans for new gas pipelines and LNG import terminals, and European rules and regulations will impinge increasingly on Britain's markets.

For these reasons, Ofgem considers that the Commission's report on the functioning of gas and electricity markets across Europe is an important opportunity to take stock of progress towards the single market, and to review barriers to further progress. Ofgem is supporting the Commission's work through publication of its own review of the GB market and, through the European energy regulators' group ERGEG, providing expert advice to the Commission on the wider European picture.

2 Summary and major developments in the last year

Basic organisational structure of the regulator

The Gas and Electricity Markets Authority, known as Ofgem, is the regulator for the gas and electricity markets in Great Britain.[1] It is a non-ministerial government department, led and directed by a board whose members are appointed by the Secretary of State for Trade and Industry. The board must consist of a chairman and at least two other members; it currently consists of the chairman, seven non-executive members, the chief executive, and Ofgem's three executive managing directors.

Ofgem's legal powers and relationship with Government

Ofgem's functions, duties and powers are set out in legislation covering Great Britain.[2] Ofgem's principal objective is to protect the interests of present and future consumers of gas and electricity, wherever appropriate by promoting effective competition. It must also have regard to: the need to secure that all reasonable demands for electricity and, so far as is economical, gas are met; the need to secure that licence holders are able to finance the activities which are the subject of certain regulatory and statutory obligations; and the interests of those consumers who are disabled or chronically sick, of pensionable age, on low incomes, or living in rural areas. Ofgem must also carry out its functions in the manner it considers is best calculated to: promote efficiency and economy on the part of market participants; protect the public from dangers related to the energy and gas markets; contribute to the achievement of sustainable development; and secure a diverse and viable long term energy supply. Furthermore, Ofgem must have regard to the impact of the gas and electricity industries on the environment, and to the Government's recently re-issued social and environmental guidance to Ofgem. Finally, Ofgem must have regard to the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles as appear to it to represent the best regulatory practice.

Ofgem has the power to grant licences[3] to companies active in the gas and electricity industries. The conditions of these licences are, in addition to statutory duties placed on market participants and Ofgem's competition law powers (see below), the means through which Ofgem carries out its work—for example, the limits on the revenues of the network monopolies are specified in conditions of their licences.

Ofgem is empowered to enforce compliance with the conditions of licences and certain statutory obligations by the imposition of financial penalties of up to 10% of licensees' annual turnover, issuing enforcement orders, or revoking licences. The conditions in licences can be varied by agreement with the licensee. In the absence of agreement, Ofgem may ask the Competition Commission to consider whether modification of a licence would be in the public interest. The Competition Commission has the power, ultimately, to impose licence

---

[1] This report covers only Great Britain.

[2] Principally: the Gas Act 1986, the Electricity Act 1989, the Competition Act 1998, the Utilities Act 2000, the Enterprise Act 2002 and the Energy Act 2004.

[3] Ofgem licenses: supply, shipping, and transport of gas; supply, distribution, transmission, and generation of electricity; and gas and electricity interconnectors. It does not licence gas storage or gas production nor does it have responsibility for gas production infrastructure. Some activities (for example, some smaller generators are exempt from the requirement to hold a licence).

modifications. The Secretary of State for Trade and Industry has the power to veto licence modifications.

In addition, many of the detailed rules for the operation of the gas and electricity markets are contained in 'industry codes'. Parties to the codes (such as licensees and the energy consumer body, energywatch), can propose modifications to the codes. Ofgem's role is to accept or veto proposals for change made initially by parties to the code.

Ofgem has powers to investigate complaints of anti-competitive behaviour and to take action to enforce compliance with competition law—eg, to impose financial penalties of up to 10% of annual turnover if it finds that there has been an infringement of the Competition Act 1998. Competition powers are exercised concurrently with the Office of Fair Trading, and where an agreement or conduct may have an impact upon competition in the markets regulated by Ofgem, the Office of Fair Trading and Ofgem will agree which authority is best placed to take forward an investigation.

Ofgem may also make a market investigation reference to the Competition Commission where it has reasonable grounds for suspecting that competition in the electricity or gas markets is being prevented, restricted or distorted.

Ofgem reports to the Secretary of State for Trade and Industry by way of an annual report on its activities. The Secretary of State lays a copy of that report before Parliament. The Secretary of State for Trade and Industry is "the responsible Minister" (eg, answering Parliamentary Questions relating to Ofgem's work), but Ofgem is often called on to give evidence to Parliamentary committees directly. The members of Ofgem's governing board are appointed by the Secretary of State (in consultation with the chairman of Ofgem's board) for fixed terms.

Jurisdiction of other Government agencies

The Government is accountable for UK energy policy goals, and setting the framework which delivers them. This framework is based around: competitive markets for electricity and gas production and supply, independent economic regulation of monopoly network businesses (electricity and gas transmission and distribution). However, there remain some specific Government functions in current legislation such as: consents for power stations, defining the extent of the regulated industry by deciding on exemptions from the requirement of licences, appointing the members of the Gas and Electricity Markets Authority, and having the power to veto any proposal by Ofgem to modify licences. Wider social and environmental policy in relation to energy is also an area Government addresses. The Government also tackles the growing international energy agenda, especially EU liberalisation and imports of oil and gas

Within Government, the DTI leads on energy policy although many other Government departments, and the Devolved Administrations, have considerable energy policy interest. Most notably, DEFRA leads on energy efficiency, fuel poverty and the environment in general. The Sustainable Energy Policy Network (SEPN), whose Ministerial Group is co-chaired by the Secretary of States for Trade and Industry and Environment, Food and Rural Affairs, provides a focal point for those involved in Energy Policy. Other bodies such as the Carbon Trust and the Energy Savings Trust are independent, not for profit organisations funded by the Government.

The following paragraphs describe the interests of other parts of Government that have the most direct relevance to Ofgem's core functions.

The Secretary of State for Trade and Industry has a number of powers relating to the operation of the gas and electricity industries. The Secretary of State licences and regulates gas production and the associated off-shore gas industry (Ofgem has no role here). Large power stations (over 50 MW) require consent from the Secretary of State, which may include any conditions (eg, regarding operation) as appear appropriate to the Secretary of State. This power is currently used to require developers of larger power stations to show that they have explored opportunities to use combined heat and power, and it has in the past been used to prevent construction of gas-fired generation.

The Secretary of State has a number of powers relating to electricity network tariffs. The level of transmission charges levied on renewable generators in a certain region can in effect be capped if it appears to the Secretary of State that that region has a high potential for renewable generation, the development of which would otherwise be hindered by high transmission charges. The Secretary of State has a power to introduce a scheme that has the effect of subsidising distribution costs if it appears to him that the costs of distributing electricity in a particular area are significantly higher, on a per customer basis, than in another area. The subsidy is levied (via transmission charges) on all suppliers of electricity. The Government intends to use this power to maintain a historic subsidy of distribution charges in the North of Scotland (which would otherwise be around double the average charges in Great Britain) that was recently removed due to incompatibility with European law.

If the Secretary of State considers that any group of customers are treated less favourably than other groups as respects charges for gas or electricity, he has the power to require that charges are adjusted in order to reduce or eliminate the less favourable treatment. This power has never been used.

In addition, the work of the Health and Safety Executive is highly relevant to Ofgem, for example in respect of the need to replace parts of the gas network on safety grounds, as is the work of the Scottish Environmental Protection Agency and the Environment Agency, for example in respect of emissions from power stations.

Recent developments in the gas and electricity markets

Major projects during the year meant that Ofgem's public profile was high in 2004-2005. These included the five year price review for the electricity distribution network companies, the probe into high gas prices, National Grid Transco's (NGT's) sale of gas distribution businesses and the achievement, on 1 April 2005, of uniting the Scottish electricity market with that of England and Wales.

These projects alone will deliver major benefits to consumers.

- The electricity distribution price control review allows for investment of £5.7 billion over the next five years, an increase of 48 per cent on current levels. It also provides for improvements in network reliability as well as facilitating the growth in distributed generation. At the same time, charges will be kept to a minimum, averaging 6p a month in real terms.
- We estimate that consumers will benefit by about £225 million, in net present value terms, between 2005 and 2023 from the sale of the gas distribution networks, as we should be better able to compare company performance.
- In Scotland, consumers should benefit from greater competition following the creation of an all-British electricity market. Scottish generating companies, including renewable generators, should also benefit from being able to sell their electricity to a wider market.

- Finally, we provided comfort to domestic and industrial consumers, who saw significant increases in gas prices last year, that this was not being caused by manipulation of the GB gas market, deliberate or otherwise.

In the 2004 Energy Act, Ofgem was given an additional secondary duty – that of contributing to sustainability. This duty, together with our enhanced social and environmental guidance from the Secretary of State and the framework of the White Paper, has led Ofgem to ensure that these matters are considered as comprehensively as possible.

We have been fully committed to a wider ranging environmental agenda - from our work on contributing to the launch of the EU Emissions Trading Scheme and the new Energy Efficiency Commitment, to fast-forwarding the regulatory regime to enable an upgrade of the transmission lines in Scotland to bring electricity, primarily wind power, south. On social issues, an Ofgem-brokered commitment saw debt and disconnection levels reduced substantially.

Our commitment to Europe was seen in both our leadership and support of key initiatives and seconding Ofgem personnel to Brussels to be at the heart of European energy issues. Also, Ofgem was a fully committed member of the Commission's gas and electricity regulators' advisory group, ERGEG, which pushed through a voluntary agreement that will enhance substantially information on gas storage.

Our interest in European gas issues is driven by the need to ensure that British consumers' interests are served fully. To that end, we were pleased that our Chairman, Sir John Mogg, was asked to become the Vice-Chair of ERGEG during the year, and Chair of the Gas Working Group. These bodies report to the Council of European Energy Regulators (CEER), where Sir John is also Vice-President. We will continue to exert influence on the development of markets across Europe, and export best practice.

Ofgem is a keen supporter of the inquiries into both electricity and gas markets across Europe by the EU competition directorate which were announced in June 2005. Again, we have had a central role both in promoting the need for a gas review, but also in providing senior personnel on secondment to assist in this project. We justify such an investment by the need to promote the best interests of British consumers.

Operational evolution and handling management change were key issues. Last year, we announced that, after achieving an 8 per cent cost reduction in 2004-2005, we would operate under an RPI-X efficiency cost control. During 2004-2005, our Authority Audit Committee decided that RPI-3 per cent a year will be imposed on Ofgem for the next five years.

3 Regulation and Performance of the Electricity Market

3.1 Regulatory Issues

3.1.1 Degree of market opening

Gas and electricity markets in Great Britain are fully liberalised.

3.1.2 Management and Allocation of interconnection capacity and mechanisms to deal with congestion

Management of congestion on interconnectors

The GB electricity system is interconnected with France and Northern Ireland. The existence of these interconnectors and the current proposals for new interconnectors (Wales to Republic of Ireland and England to the Netherlands) suggests that new interconnection capacity will be provided by the market when these investments become commercially viable.

The requirements of the Directives and the electricity Regulation regarding interconnectors are being met in GB by issuing licences to participate in the operation of interconnectors. For example, standard licence condition 11 requires the licensee to offer to enter into an agreement for access to its interconnector on transparent, objective and non-discriminatory terms.[4] Standard licence condition 13 requires the licensee to make available the maximum physical capacity of its interconnector. This includes the development of procedures on the primary market to facilitate the secondary trade of capacity and the requirement to allow and facilitate capacity rights to be traded on the secondary market. If capacity is reduced for technical reasons the mechanism for reducing the capacity allocation should be open, transparent and non-discriminatory. Ofgem has powers to monitor and enforce compliance with these licence conditions.

The DTI is currently consulting on the licences it proposes to issue to the operators of the existing interconnectors.

Ofgem considers that effective secondary trading and anti-hoarding mechanisms are required, with each interconnector operator needing to demonstrate that there is a transparent mechanism that allows spare capacity to be made available to the market. The ultimate objective is to ensure that capacity is not hoarded and that unused capacity can be obtained in a transparent market based manner by third parties so as to maximise the use of the interconnector concerned. The actual methodology under which interconnector capacity is made available in both the primary and secondary market is for the interconnector owner/operator to decide.

Once the interconnector licences are in place this methodology will need to meet the requirements of the relevant conditions of the interconnector licences. If this were not to be the case, the Authority would expect the affected prospective interconnector users to make Ofgem aware of the situation, which Ofgem would then investigate and take any appropriate action.

[4] The DTI has proposed to switch this condition off in the licence for the Moyle Interconnector on the basis that the operator fulfils the European requirements with respect to third party access (through its Northern Irish licence).

In terms of publication requirements for this information, the DTI and Ofgem consider that there should be an equivalence in the information requirements on LNG and interconnectors as required of similar facilities in gas and electricity markets respectively, for example, electricity generators or other connection points to the NTS in gas (wholesale market information requirements are discussed below).

Under the current regulatory and contractual framework, the risk of contractual congestion on the electricity interconnector with France is addressed by use-it-or-lose-it provisions which aim to prevent the hoarding of capacity. The Commission de Régulation de l'Énergie has some concerns about the practical operation of these arrangements which are under discussion.

Ofgem does not routinely analyse physical congestion on interconnectors in the absence of complaints from market participants. However, the interconnector with France has recently flowed at maximum capacity for less than 1% of the time suggesting the link is not currently congested and primary capacity rights to use the interconnector are made available to all through a series of rolling auctions offering annual, seasonal, quarterly, monthly, weekend, and daily capacity.

Prevailing wholesale prices in the two markets are such that the interconnector with Northern Ireland currently only exports from GB. As such, any congestion on this interconnector would have no adverse consequences on consumers in GB. Ofgem does not routinely collect or analyse data relating to this interconnector. However, Ofgem is not aware of any complaints from market participants relating to gaining access to the interconnector.

Management of congestion on national networks

TSOs are responsible for managing congestion on their networks. Both gas and electricity system operators are under a statutory obligation to develop and maintain efficient systems, as are gas and electricity distributors.

The electricity system operator has commercial incentives to reduce the cost of congestion under its system operator incentive schemes. Under the scheme, the SO is allowed a certain amount of revenue to fund its system operation actions and is allowed to keep a proportion of nay savings but must fund a proportion of any cost over-runs (both subject to caps/collars). This mechanism also operates to incentivise the system operator to maximise the technical availability of its network. Under the current scheme for financial year 2005/6 the total revenue allowance was based on a forecast for congestion costs of £50m. In comparison with the total revenue allowance for transmission owners of around £1,280m, congestion costs are around 4% of network costs. The management of congestion is integrated with the functioning of the wholesale market in that access to the transmission network is financially firm, and the system operator must pay (through contracts or the balancing mechanisms) to constrain generators (or customers) on or off in order to manage network congestion.

The electricity system operator is required to publish information about the longer-term development of its network that will allow new customers to assess the opportunities for connecting to the network in various locations.

Congestion on electricity distribution networks is not an operational issue because networks are passively operated. Distribution network owners are required to make available information about their networks that will allow new customers to assess the opportunities for connecting to the network in various locations.

3.1.3 The regulation of the tasks of transmission and distribution companies

There are three transmission system owners in Great Britain:

- National Grid Company, which owns the high voltage transmission system in England and Wales;
- ScottishPower Transmission, which owns the high voltage transmission system in the South of Scotland; and
- Scottish Hydro-electric Transmission, which owns the transmission system in the North of Scotland.

National Grid Company also acts as the system operator for all of the transmission systems in Great Britain.

There are seventeen licensed distribution network operators (DNOs) in Great Britain. Fourteen DNOs were established as part of the privatisation process in 1990 and were the only providers of distribution network services in each area for several years. However, the Utilities Act 2000 changed the legislative and regulatory framework to enable each DNO to own and operate network assets in any area of Great Britain. These changes have also facilitated the entry of new DNOs which own and operate extensions of the existing networks.

Ofgem regulates the level and structure of charges levied for using the monopoly transmission networks and the quality of service provided by these companies.

Price controls and incentives

The level of distribution and transmission charges and the quality of service provided by these companies are regulated using price controls and various incentive regimes[5]. These price controls typically last for five years. The price controls are established by Ofgem independently of other Government departments. Nevertheless, Ofgem is required to have regard to the social and environmental guidance issued by Government and any orders issued in respect of assistance for areas with high distribution costs.

For the fourteen DNOs established at privatisation and the transmission network companies, establishing these price controls and incentive regimes involves collecting a range of information on operating costs, capital expenditure, financial issues and performance outputs for each of the companies which is then analysed. Where applicable, the information that is collected from each network company is normalised to ensure as far as possible comparability across companies and then it will be used to assist in determining the relative performance of each network company and to establish efficient cost and performance benchmarks using a variety of statistical techniques.

In addition to the benchmarking process, Ofgem also uses independent consultants to undertake efficiency studies on specific aspects of costs and network performance. These studies will typically examine the scope for improvements in costs or performance. For example, during the recent Distribution price control review, Ofgem commissioned a study of total factor productivity to evaluate the scope for further efficiency improvements[6] and commissioned a review of the efficiency of part of their operations.

[5] Electricity Distribution Price Control Review: Final Proposals, November 2004 265/04
[6] Productivity improvements in Distribution Network Operators - Final report, December 2003 156/03

Setting cost allowances or performance targets in this manner is not a purely mechanistic process. Ofgem will also consider a number of other factors to ensure that the resultant cost allowances or performance targets are both sustainable and robust.

Quality of supply targets (discussed below) are also set for each licensee, and, where relevant, efficient costs of achieving these targets are included in the cost assessment.

Based upon our assessment of costs and outputs, Ofgem establishes cost allowances and performance targets which form the basis of the price controls and incentive framework. Together, these elements determine the total amount of revenue (allowed revenue) that each network company may earn in each year and the network company is required by the regulatory regime to set charges for use of the network such that it complies with the limits on allowed revenue that have been set.

The business information available for new entrant companies is limited and the costs of undertaking detailed efficiency studies to establish cost allowances and performance targets often outweigh the benefits to consumers. Ofgem has therefore introduced a system of relative price regulation to ensure that the charges for use of these networks are no more than the charges that would be paid by an equivalent customer that is connected to the incumbent regional network.

Transmission

Since the New Electricity Trading Arrangements (NETA) went live, NGC have two distinct roles – that of transmission asset owner (TO) and system operator (SO). Therefore, Ofgem proposed separate price controls for each part of the business from 1 April 2001. Since the British Electricity Trading and Transmission Arrangements (BETTA)[7] became effective on 1st April 2005 NGC has undertaken the role of the role of SO across the whole of GB - Great Britain System Operator (GBSO). The Scottish Transmission Licensees assume the sole role of TOs. The interactions between the GBSO and TOs are governed by the SO TO Code (STC)

Transmission Asset Owner

The following section focuses on NGC price controls as similar arrangements apply to Scottish Power Transmission and Scottish Hydro-electric Transmission, following the introduction of BETTA.

As the holder of Transmission Licences in Great Britain, the GB transmission licensees are required by the Electricity Act 1989, as amended by the Utilities Act 2000 and the Energy Act 2004, to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity. The transmission licensees are also required by Schedule 9 of the Electricity Act to have regard to the effects of its activities on the environment.

The Maximum Allowed Revenue (MAR) for Transmission Owners (TO) is set by the Authority at the time of price control review (PCR). Ofgem undertakes the PCR every 5 years. The present

[7] BETTA, proposed by Ofgem and the Department of Trade and Industry (DTI), creates a fully competitive British-wide (bringing together England & Wales and Scotland) wholesale electricity market for the first time

price control for NGC TO covers the five years period from 1 April 2001 to 31 March 2006[8]. It is based on the RPI-X formula, with X set at 1.5. The main components of price controls are operating expenditure (OPEX), depreciation and cost of capital. At the start of price controls the company submits all the relevant data to the regulator in the form of Business Plan Questionnaire (BPQ). During price control review process Ofgem makes use of independent consultants to undertake efficiency studies on specific aspects of costs and network performance. These studies will typically examine the scope for improvements in costs or performance given the business practise of the companies.

System Operator

National Grid in its role as GB System Operator keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). National Grid is incentivised on the procurement and utilisation of services to maintain, in an efficient and economic manner, the energy and system balance and other costs associated with operating the system.

Under the external SO incentive schemes that have been in place since NETA was introduced, Ofgem sets a target revenue that NGC is allowed to recover. The target revenue includes actual costs of electricity balancing and system balancing, adjusted by incentive payments or receipts relating to these costs. The value of any incentive payments or receipts depends upon NGC's performance in relation to a cost target set in advance. If NGC's costs are below the target, it keeps a proportion (set by the upside sharing factor) of the reduction in costs as an incentive payment. Conversely, if its costs are above the target, NGC is charged a proportion (set by the downside sharing factor) of the costs in excess of the target. NGC's overall gains or losses on its balancing costs are limited by applying a cap on payments and a floor on losses. This type of scheme is called a sliding scale or profit sharing scheme.

The current SO incentive revenue target is £377.5 million. The incentive scheme runs from 1 April 2005 for 12 months[9].

Previous incentive schemes, put in place by Ofgem, have been very successful in reducing the costs of system operation on behalf of customers. Since the introduction of the new electricity trading arrangements (NETA) in 2001, NGC has, through more efficient system operation, consistently outperformed its incentive scheme target. Ofgem has, against this background, been able to reduce the incentive scheme target by around £70 million (from approximately £485 million to £415 million for the current incentive scheme). NGC and customers have therefore shared the benefits of successive schemes in improving the efficiency of system operation.

Standards of performance

Transmission network companies must provide the Authority with an annual report which covers the electricity transmission system's performance in terms of availability, system security and quality of service10.

---

[8] The current Price controls for NGC are going to be extended by one year, and for Scottish Licensees have been extended by two years. The rationale for these extensions is to align the price controls for all transmission licensees (gas and electricity) from 2007 on. For more information see:
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7071_10204.pdf

[9] See NGC System Operator incentive scheme from April 2005,
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10404_6505.pdf

[10] See *Report to the Authority for the Gas & Electricity Markets 2004/2005* -
http://www.nationalgrid.com/uk/library/documents/pdfs/Report.pdf

Most outputs are specified in the licence. If NGC does not meet its requirement to operate an efficient and reliable network it can face financial penalties of up to 10% of its annual revenue. Largely in response to this it has maintained one of the most reliable systems in Europe (unsupplied energy during 2004-5 was 888MWh, which equals 0.0003% of total energy supplied).

In addition, NGC is subject to a "Reliability Incentive"[11]. This sets a target for the "quantity of unsupplied energy in MWh". Whenever there is a black-out or fault, it is estimated how high demand would have been. These hypothetical demands are summed up to give the total quantity of unsupplied energy. Ofgem has set a target level for this and NGC is rewarded/ penalised if it over/underperforms relative to the target. The maximum penalty is £12m while the maximum reward is £8m.

Structure of charges

The cost of installing, operating and maintaining the transmission system for the TOs is reflected in Transmission Use of System (TNUoS) Charges[12]. As GBSO, NGC levies TNUoS charges on the behalf of all the three Transmission Licensees. The TNUoS charge is split 27:73 between generators and demand. There are separate generation and demand methodologies.

The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. In calculating the level of TNUoS charge, the GBSO uses a simplified model of the transmission system to represent the long run marginal cost of providing a network infrastructure at different geographical locations. Therefore the model produces locationally differentiated charges for both generation and demand, which are expressed in £/kW of capacity. The GBSO runs the model once every year and updates its transmission charges on 1 April every year.

There are 21 charging zones for generation and 14 zones for demand. For 2005/06 the demand charge varies between €0.05/kW[13] and €28.8/kW whereas the generation charge varies between €-11.52/kW and €33.12/kW. Six generation zones have a negative TNUoS charge. This means that generators in these zones are paid by the GBSO for using the transmission system.

Connection charges enable National Grid to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the GB transmission system. Connection charges relate to the costs of assets required to connect an individual User to the GB transmission system, which are not and would not normally be used by any other connected party ("shallow" basis).[14] Certain of the assets associated with connections may be provided by users themselves.

National Grid, as GBSO, recovers the costs of balancing the System through Balancing Services Use of System charges. The main components of BSUoS are (1) balancing costs within Balancing

[11] See *Electricity transmission network reliability incentive schemes. Final proposals.* December 2004 http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9472_tx_incentives.pdf
[12] See *The Statement of the Use of System Charging Methodology – Effective from 1 April 2005*, http://www.nationalgrid.com/uk/indinfo/charging/pdfs/UOSCM_I1R0_GB_Final.pdf
[13] To aid comparison with the situation in other Member States, all relevant charges and tariffs in this report have been converted from £ to €, at a rate of £1=€1.44
[14] See The Statement of the Connection Charging Methodology, http://www.nationalgrid.com/uk/indinfo/charging/pdfs/GBCCMI1R0.pdf

Mechanism (BM) (this includes both electricity and system balancing - the costs incurred by NGC in accepting bids and offers in BM), (2) NGC's balancing costs outside the BM (NGC makes contracts with market participants to provide ancillary services), (3) any incentive payment that NGC receives for reducing losses. The fourth main component of BSUoS is the internal SO incentive (essentially labour and other costs relating to SO activities). BSUoS charges are levied on the basis of metered volume to participants, with overall charges split 50:50 between generation and demand.

Distribution

Structure of charges

In July 2004, Ofgem implemented changes to the regulatory framework to establish an obligation on all DNOs to produce separate connection and use of system charging methodologies to be approved by Ofgem. Each methodology must meet four relevant objectives:

- that compliance with the charging methodology facilitates the efficient discharge of the obligations imposed upon it under the Electricity Act and by the licence;
- that compliance with the charging methodology facilitates effective competition in the generation and supply of electricity, and does not restrict, distort or prevent competition in the transmission or distribution of electricity;
- that compliance with the charging methodology results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the distribution business; and
- that the charging methodology, as far as is reasonably practicable, properly takes account of the developments in the distribution business.

In October 2004, Ofgem consulted with the electricity industry on the form and content of the draft use of system and connection charging methodologies submitted by each DNO. In light of response to the consultation, DNOs then submitted revised charging methodology statements to the Authority for approval at the end of November 2004. Each methodology was assessed against the relevant objectives and In February 2005, the Authority approved the initial charging methodologies to take effect from 1 April 2005[15].

Ofgem has put in place a process for modifying the approved charging methodologies where the modifications can be demonstrated to better meet the relevant objectives. The process requires each DNO to consult interested parties on the proposed modifications and consider the views expressed. Once the consultation process has been concluded, the proposed modification of the methodology is submitted to the Authority for approval.

Each DNO must comply with its approved charging methodologies when setting charges for connection and use of system. Ofgem has also imposed obligations on each DNO to publish statements of these charges in an approved form and made available to interested parties and

---

[15] Authority approval letters:
http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges&levelids=,1_10638#top10638
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11318_DNO_covernote.pdf

any other person that requests the information. In addition to setting out the charges that may be levied for use of or connection to the distribution system. The use of system and connection charging statement will also set out the general terms and conditions associated with use of the distribution system, the network charges, terms and processes for obtaining a connection.

Assistance for high cost distribution areas

The Energy Act 2004 established statutory provisions that enable the Secretary of State to make orders that charges levied by the GBSO shall be set to recover an amount of money from all suppliers that will be passed on to consumers connected to a distribution system on which the costs of distributing electricity are relatively high. These arrangements are focused largely at those customers connected to largely rural networks to ensure that they are not unduly disadvantaged by high electricity costs.

These arrangements are established by the Secretary of State independently of Ofgem.

Level of charges

Table 3.1 Average network charge payable by different customer groups in Great Britain:

Customer type	Transmission charges (c/kWh)	Distribution charges (c/kWh)	Total network charge (c/kWh)
Domestic customer[1]	0.00 – 0.72	1.67 – 3.47	2.24 – 4.10
Small industrial customer[2]	0.00 – 0.89	1.06 – 2.29 (E&W) 2.76 – 4.33 (Scot)	1.64 – 3.11 (E&W) 3.01 – 4.39 (Scot)
Large industrial customer[3]	0.00 – 0.00[4]	0.46 – 1.18	0.46 – 1.18

Notes:
1) Domestic customer – is a household customer with annual consumption of 3 500 KWh/ year
2) Small industrial customer – is a commercial customer with annual consumption of 50 MWh / year, subscribed maximum power 50 KW
3) Large industrial customer – is an industrial customer with annual consumption of 24 GWh/ year, subscribed maximum power 4000 KW, assumed to be connected at 11kV
4) The transmission charge for large customers is less than 0.01c/kWh

Outputs reporting framework

Ofgem introduced output reporting for the electricity distribution companies from 1 April 2001, following the third electricity distribution price control review. Under the relevant licence conditions, Ofgem drew up Regulatory Instructions and Guidance (“RIGs”) which defined the outputs and provided the framework under which the data is collected and reported.

The 14 licensed Distribution Network Operators are required to report annually on:

- the number and duration of interruptions to supply;
- the speed of telephone response;
- medium-term performance (fault rates and causes)
- connections performance; and
- environmental issues.

In addition the companies are required to provide details of customers on a weekly basis who have contacted them during an interruption or to report an emergency. This enables Ofgem to carry out surveys of the quality of telephone response provided by Distribution Network Operators.

The current version of the RIGs is version 5, which was published in March 2005. The key difference with this version is the introduction of more detailed reporting on supply interruptions and new reporting for connections and environmental performance.

Further reading:

'Quality of Service Regulatory Instructions and Guidance – version 5'; Ofgem document 94/05; March 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10735_9405app.pdf

'Electricity Distribution Price Control – Final Proposals'; Ofgem document 265/04; November 2004August 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9416_26504.pdf

Quality of service incentives

Ofgem first introduced an initial incentive scheme for quality of service from 1 April 2002 to 31 March 2005. The scheme linked companies' revenue to three key areas of quality of service:

- the number and duration of interruptions to customers' supplies; and
- the quality of telephone response provided to customers.

Each of the distribution businesses could be penalised annually, by up to 1.75 per cent of revenue if it failed to meet its targets for the number and duration of interruptions. Companies could earn additional revenue if they outperformed their targets for 2004/05 based on their rate of performance up to that date.

Companies could be rewarded or penalised by up to 0.125% of price controlled revenue dependent on their relative performance in a monthly customer survey of the quality of telephone response.

There has been a 15 per cent improvement in the number of interruptions per 100 customers and a 19 per cent improvement in the average number of customer minutes lost per customer over the period of the incentive scheme (excluding the impact of exceptional events). On average a customer experiences 0.7 interruptions per year and is interrupted for approximately 68 minutes excluding exceptional events.

With exceptional events included, there was still a 10 per cent improvement in the number of interruptions but the duration of interruptions was much more variable due to the impact of the October 2002 storms and further storms and flooding in Great Britain.

A revised incentive scheme has been introduced as part of the new distribution price control from 1 April 2005. Ofgem has increased financial exposure to the interruption incentives to 3 per cent of revenue and introduced tighter interruption targets. On average the Distribution Network Operators are required to achieve a 4% improvement in the number of interruptions and 13% in the duration by 2010. The current worst performers have significantly larger improvements to make so there should be a narrowing of performance differences over time.

Further reading:

'2003/04 Electricity Distribution Quality of Service Report'; Ofgem publication 260/04; November 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9361_26004.pdf

'Electricity Distribution Price Control – Final Proposals'; Chapter 4; Ofgem document 265/04; November 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9416_26504.pdf

Standards of Performance

The Standards of Performance for electricity Distribution Network Operators were first introduced in 1991. Since then they have been revised on a number of occasions to tighten the standards, increase compensation payments or to introduce new standards.

Guaranteed Standards of Performance ("GSOPs") set service levels that must be met in each individual case. If a Distribution Network Operator fails to provide the level of service specified, it must make a payment to the customer affected (e.g. for not restoring supply within a specified timeframe). This is subject to a number of exemptions.

Overall Standards of Performance cover set minimum average levels of performance. These were removed from 1 April 2005 and replaced by additional output measures and incentives (discussed earlier).

The latest GSOPs for Distribution Network Operators came into effect from 1 April 2005 as part of the new electricity distribution price control. They are summarised in Table 3.2.

Table 3.2 : Guaranteed standards of performance

Standard	Service	Performance Level	Payment
GS1[1,2,3]	Restoration of supply: normal weather conditions	Supplies must be restored within 18 hours, subject to certain exemptions, otherwise a payment must be made	€72 domestic customers €144 non-domestic, plus €36 for each further 12 hours
GS2a[1,2,3]	Restoration of supply: category 1 (medium) weather events	Supplies must be restored within 24 hours, subject to certain exemptions, otherwise a payment must be made	€36 plus €36 for each further 12 hours up to maximum of €288
GS2b[1,2,3]	Restoration of supply: category 2 (large) weather events	Supplies must be restored within 48 hours, subject to certain exemptions, otherwise a payment must be made	€36 plus €36 for each further 12 hours up to maximum of €288
GS2c[1,2,3]	Restoration of supply: category 3 (very large) weather events	Supplies must be restored within the period calculated using the following formula: $48 \times \left(\frac{\text{total number of customers interrupted}}{\text{category 3 threshold number of customers}} \right)^2$	€36 plus €36 for each further 12 hours up to maximum of €288
GS3[1,3]	Restoration of supply: Highlands and Islands	Supplies must be restored within 18 hours, subject to certain exemptions, otherwise a payment must be made	€72 domestic customers €144 non-domestic, plus €36 for each further 12 hours
GS4[1]	Multiple Interruptions	Four or more separate interruptions each lasting 3 or more hours in any single year (1 April – 31 March)	€72
GS5	Respond to failure of distributors fuse	All distributors to respond within 3 hours on weekdays (at least) 7 am to 7 pm, and within 4 hours at weekends between (at least 9 am to 5 pm)	€36
GS6	Estimating charges for connection	5 working days for simple jobs and 15 working days for most others	€57.6
GS7[1]	Notice of planned interruption to supply	Customers must be given at least 2 days notice	€72 domestic customers, €57.6non-domestic
GS8	Investigation of voltage complaints	Visit within 7 working days or substantive reply within 5	€72
GS9	Making and keeping appointments	Companies must offer and keep a morning or afternoon appointment, or a timed appointment if requested by the customer	€72
GS10	Notifying customers of payments owed under the standards & making payments	Payment to be made within 10 working days	€72

1. Customers need to claim under these standards, whereas payments are automatic for the other standards
2. The categories of weather are defined in the table below.
3. GS1 and 2 apply to all areas of GB other than the Highlands and Islands. A separate standard applies for this area

Ofgem collects performance data from Distribution Network Operators on an annual basis. The data is verified and then forwarded to the consumer council ("energywatch") for publication, in accordance with the Electricity Act 1989.

Further reading

'Electricity Distribution Price Control – Final Proposals'; Chapter 4; Ofgem document 265/04; November 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9416_26504.pdf

'Revised standards of performance arrangements for electricity distributors - Consultation on the draft Statutory Instrument for Guaranteed Standards and revocation of the Overall Standards of Performance'; Ofgem document 03/05; January 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9762_0305.pdf

Quality of service reports

To date, Ofgem has published three reports on the quality of service in electricity distribution. These reports set out information on how the Distribution Network Operators have performed against their targets for the number and duration of supply interruptions and against other performance benchmarks that Ofgem has calculated. It also sets out information on fault rates and the quality of telephone response. Ofgem will continue to publish annual reports on the quality of service in future.

Further reading

'2003/04 Electricity Distribution Quality of Service Report'; Ofgem publication 260/04; November 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9361_26004.pdf

'2002/03 Electricity Distribution Quality of Supply Report'; Ofgem publication 149/04; July 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7685_149_04_quality_of_service_report.pdf

'2001/02 Electricity Distribution Quality of Service Report'; Ofgem publication 51/03; June 2003

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/3664_OfgemQualityofSupplyReport2001-02_Final_18June_1.pdf

Balancing of the transmission system

From 1 April 2005, there has been a single electricity market and balancing area covering the whole of Great Britain (GB), with Northern Ireland forming a separate electricity market under the jurisdiction of its own regulator. In the description that follows, we focus solely on the GB system.

In GB, the primary responsibility for balancing lies with market participants, including electricity generators and suppliers. National Grid Company (NGC), in its role as System Operator (SO) for the GB electricity transmission system, has a role as residual balancer and, as such, it can buy and sell energy to correct residual imbalances and thus ensure that the system remains in balance within prescribed limits at all times. NGC is only allowed to trade electricity for balancing purposes; it is not allowed to trade speculatively.

NGC's role as residual balancer

The Balancing Mechanism (BM) was designed as a tool to assist NGC in keeping the transmission system in balance in real time by providing a mechanism for it to adjust levels of generation and demand through the acceptance of Bids and Offers submitted to the BM (electricity balancing). NGC also uses the BM to ensure that the system remains within safe operating limits, and that the pattern of generation and demand is consistent with any transmission system constraints (system balancing). System balancing actions also include, but are not limited to, frequency control actions. At Gate Closure for the BM, which occurs one hour before the start of each half-hour balancing period (known as a settlement period), NGC, in its role as SO, takes control of balancing the system and the only trading that takes place is between NGC and market participants via the BM.

As well as the BM, NGC has commercial freedom to balance the system through trading in the short term markets and can use a range of other contractual tools to balance the system. It can, for example, enter into balancing services contracts, forward trades (typically non-locational) and pre gate closure balancing trades (PGBT) with generators, suppliers and customers. Ofgem has oversight over the types of balancing services contracts into which NGC can enter and its tendering processes. This oversight arises because the Authority has the power to approve or reject amendments to NGC's Procurement Guidelines[16], which contain details of the balancing services that NGC intends to procure and how it intends to procure them.

NGC's balancing costs, which comprise the costs it incurs in procuring balancing services, both pre-Gate Closure and in the BM, are subject to a financial incentive scheme, which is intended to align the interests of NGC with those of consumers. The incentive works by providing NGC with financial benefits, subject to a cap, if it manages to reduce its balancing costs below a target level that, after extensive consultation with NGC and market participants, is set by Ofgem and included in NGC's transmission licence. The incentive scheme also provides financial penalties, if NGC's balancing costs exceed the target level. NGC also has an obligation under its transmission licence to operate the system in an economic, efficient and co-ordinated manner.

Commercial incentives to balance – cash out arrangements

There is no centrally mandated day-ahead market or intra-day market on which market participants must trade. Instead, they are free to contract bilaterally with each other up to Gate Closure for each settlement period. There are numerous possibilities for intra-day trading to take place between market participants, either on a bilateral basis, via brokers (such as Spectron[17]) or on organised exchanges (such as the UK Power Exchange (UKPX)[18]). All of these trading possibilities in principle allow market participants to trade electricity for an individual settlement period i.e. on the same basis as the balancing interval.

At Gate Closure, participants have to notify NGC of the volumes of electricity that they have contracted for that period and their intended level of consumption or generation over the period. They can also choose (but are not obliged) to submit Bids and Offers into the BM for each settlement period, which NGC can then use to balance the system. A Bid or Offer specifies the price that the party wishes to be paid (or is willing to pay) to move away from their existing generation or consumption level (as specified to NGC at Gate Closure) and the volume by

[16] The Procurement Guidelines are produced in accordance with condition C16 of NGC's transmission licence.
[17] See www.spectrongroup.com for more details.
[18] See www.ukpx.co.uk for more details.

which they are prepared to move (i.e. if a party's bid or offer is accepted, it is paid as bid). Bids and Offers apply to individual half-hour settlement periods so BSC parties can vary the Bids and Offers they submit (price and volume) across the course of a day as well as between days. Bids and Offers are financially firm on both BSC parties and NGC. BSC parties are exposed to imbalance prices (see below) if they fail to deliver an accepted Bid or Offer and NGC has to pay BSC parties compensation if it accepts a Bid/Offer and then decides it does not require it.

Under the rules of the BSC, a Party's imbalance volume is equal to the difference between its notified contract volume, including accepted Bids and Offers, and its loss-adjusted metered volume. If these two volumes do not match, the Party is producing (or consuming) electricity which it has not sold (or bought) and this electricity is, therefore, not covered by contracts and the Party will be paid (or pay) for it at the prevailing cash out or imbalance prices. Consequently, these are the prices that:

- are paid by participants who are "short" i.e. suppliers whose customers' metered demand is greater than their contracted electricity purchases and generators whose output is less than their contracted electricity sales;
- are received by participants who are "long" i.e. suppliers whose customers' metered demand is less than their contracted electricity purchases and generators whose output is greater than their contracted electricity sales;

Cash-out prices are designed to target the costs that NGC, as SO, has incurred in keeping the transmission system in energy balance on those Parties who are out of balance. By exposing market participants that do not balance their positions to the costs of electricity balancing incurred by NGC, the cash out arrangements provide commercial incentives for them to balance their contractual and physical position. In this respect, the arrangements are important for ensuring that the market delivers security of supply by providing incentives for market participants to balance demand and supply.

For every settlement period, there are two cash out prices: the System Buy Price (SBP) and the System Sell Price (SSP). Parties that are short are charged SBP for their imbalance volumes and Parties that are long receive SSP for their imbalance volumes. How the SBP and the SSP are derived depends on whether the transmission system, as a whole, was long or short. If the system is short, then the SBP reflects the price that NGC has paid for purchasing for electricity balancing purposes (i.e. the costs associated with system balancing are excluded),[19] whilst the SSP is calculated from the average price of short-term energy trades. Conversely, if the system is long, then the SBP is derived from the average price of short-term energy trades whilst the SSP reflects the price NGC has received for selling electricity for balancing purposes. Table 3.3 summarises how the imbalance prices are calculated.

[19] The calculation of cash out prices is a detailed process, as outlined in the BSC. The process involves removing from the calculation actions which have been identified as having been taken for system balancing purposes. Cash out prices are then calculated as a weighted average price of the remaining electricity balancing actions, rather than as a weighted average of all the balancing actions taken by NGC.

Table 3.3 – Calculation of electricity imbalance charges

System Position	Party Long	Party Short
Long	Receives SSP, calculated as volume-weighted average of energy sold by the SO which is derived to be for electricity balancing purposes	Pays SBP, calculated from the short-term market price
Short	Receives SSP, calculated from the short-term market price	Pays SBP, calculated as volume-weighted average of electricity bought by the SO which is derived to be for electricity balancing purposes

Except in the case of Trading Units (see below), separate cash out calculations are carried out for generation and consumption. This means that vertically integrated companies with generation and supply arms cannot net off their generation and consumption imbalances but have to pay for them separately.

Table 3.4 below shows average annual SSP and SBP values and the average spread between SSP and SBP since NETA go-live.

Table 3.4 – Average annual energy imbalance prices

(€/MWh)	Average SSP	Average SBP	Average SSP-SBP spread
2001/02[20]	13.24	55.67	42.42
2002/03	15.79	41.86	26.06
2003/04	22.39	33.50	11.13
2004/05	27.53	40.06	12.52
2005/06[21]	37.42	51.92	14.48

Process for revising the cash out arrangements

Electricity cash out prices are primarily determined by rules set out in the Balancing and Settlement Code (BSC) but also depend on the Balancing Services Adjustment Data (BSAD) Methodology Statement[22] published by NGC. Broadly, the BSC outlines the methodology for calculating cash-out prices and how pre- and post-Gate Closure balancing actions are treated in calculations. The BSAD methodology statement sets out how information on balancing actions taken pre-Gate Closure will be compiled and submitted for the purposes of determining cash out prices.

The BSC Panel, in conjunction with ELEXON (which is a wholly owned non-profit making subsidiary of NGC, ring-fenced from its other activities), manages the rules and governance of the Balancing Mechanism and Settlement process as contained within the BSC which includes

[20] 2001/02 data also includes the period from 27 March 2001 (NETA go-live) until 31 March 2001 inclusive

[21] 2005/06 data is from 1 April 2005 until 5 July 2005 inclusive.

[22] The BSAD methodology Statement is produced in accordance with condition C16 of NGC's transmission licence.

the implementation of the Modification Procedures. The BSC Panel consists of elected representatives of BSC Parties and its primary role is to provide Ofgem with recommendations regarding proposed modifications to the BSC rules. The role of ELEXON is defined within the BSC and consists of providing and procuring facilities, resources and services (including those required by the Panel and the Panel Committees) required for the proper, effective and efficient implementation of the BSC. If a modification to the BSC is approved, ELEXON is also responsible for overseeing the implementation of that amendment (including any consequential changes to systems, procedures and documentation).

Modifications to the BSC can be raised by any signatory to the BSC, which effectively means all generators and suppliers and NGC, and by certain designated consumer representatives. Ofgem cannot propose modifications. Any proposed modifications to the arrangements must be progressed through the BSC modification procedure. This involves assessing whether the modification would better facilitate achievement of the following objectives (which are included in NGC's transmission licence):

a) the efficient discharge by NGC of the obligations imposed upon it by its transmission licence;
b) the efficient, economic and co-ordinated operation by NGC of the GB transmission system;
c) promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity;
d) promoting efficiency in the implementation and administration of the balancing and settlement arrangements

To allow decisions regarding modifications to be reached in a transparent and inclusive manner, a full consultation is carried out on each proposed modification. Following the consultation, a modification report is sent to Ofgem which contains the results of the assessment of the modification, the responses of market participants to the consultation and a recommendation from the BSC Panel to approve or reject the modification. The Authority then reaches a decision on whether to approve or reject the proposal – note that it cannot propose an alternative solution. In reaching its decision, the Authority carefully considers the proposed revisions within the context of the predefined objectives of the BSC (listed above) and, if appropriate, its wider statutory duties[23]. It is not required to accept the recommendation of the BSC Panel but must explain the reasoning underlining its decision. Ofgem's decisions on modifications to the BSC and the other industry codes can be appealed to the Competition Commission (for example, if Ofgem does not accept the recommendation of the BSC Panel).

NGC is required, under the terms of its transmission licence[24], to review and to seek to revise the BSAD Methodology Statement whenever it changes the way in which it procures its balancing services such that a modification is required to make cash out prices more closely reflect its actions. Market participants can suggest areas for modification to NGC and/or the Authority, and NGC will then consider whether or not to take these forward. Proposed revisions are consulted upon for at least 28 days with BSC Parties. After consideration of the responses received, and within seven days of the close of the consultation period, NGC submits a report in relation to the proposed revisions to the Authority for decision. NGC is free to make the proposed revisions 28 days after submitting its report to the Authority, unless the Authority has

[23] Ofgem's statutory duties are wider than the matters that the Panel must take into consideration and include, amongst other things, its principle objective to protect the interests of consumers wherever possible through the promotion of effective competition.
[24] Condition C16 of the transmission licence.

directed either an earlier implementation date or that the proposed revisions should not be made.[25]

Small generators

Prior to implementation of NETA, all licensed generators were required to join the Pool[26], but licence-exempt smaller generators were able to choose between joining the Pool and contracting their output to a local supplier. These arrangements allowed suppliers contracting with smaller generators to reduce their transmission charges, which created so called 'embedded benefits'. Virtually all smaller generators chose this non-pooled option.

Under NETA, smaller generators have essentially three trading options available to them. They can:

a) continue to contract with a local supplier and continue to receive embedded benefits;
b) participate in the BM and imbalance process directly as a BSC Party; or
c) participate in the BM indirectly through another BSC Party.

Almost all small generators have chosen the first option, particularly since the BSC rules have been modified to allow any grouping of suppliers and small generators within the same distribution network to be considered as a single entity (a Trading Unit) for balancing purposes. This means that it is the net exports or imports of the Trading Unit that are used to calculate its imbalance exposure, which, in turn, allows small generators to derive the maximum possible level of embedded benefits. Over time, a number of other modifications to the BSC rules have been introduced to facilitate further the development of consolidation services, whereby the output of a number of small generators are aggregated together thus leading to a likely reduction in their combined imbalance exposure.[27]

New entrants

There are no special arrangements for new entrants.

Interaction with other market systems

The GB market is connected, via DC links, to the electricity markets in both Northern Ireland and France. Participants in these markets can trade in GB and participate in the BM via special arrangements for interconnector trading.

The interconnector with France (the IFA) is jointly owned and operated by NGC and Réseau de Transport d'Electricité (RTE), the owner and operator of the French electricity transmission network. Capacity on the interconnector is offered for sale via a series of auctions covering different time periods, with the capacity for flows in the direction England to France and France to England being separately traded. To be eligible to make use of interconnector capacity, capacity holders are required to be a party to the BSC and must also link their use of the

---

[25] The same governance procedures apply in respect to NGC's Procurement Guidelines, referred to earlier in this document.
[26] The electricity trading arrangements prior to the introduction of NETA were referred to as the Pool.
[27] Examples of such modifications include: Modification Proposal P7 "Allocation of Supplier demand to the same BM Unit in a GSP group for all suppliers in the same company", Modification Proposal P55 "BSC Conflicts with Consolidation of Embedded Generation in Central Volume Allocation" and Modification Proposal P67 "Facilitation of further consolidation options for licence exempt generators (DTI Consolidation Working Group 'Option 4')". See www.elexon.co.uk for further details.

interconnector to a Contrat de Responsable d'Equilibre in accordance with RTE's Settlement Arrangements.

Like all other market participants, interconnector users are exposed to the cash-out arrangements. However, the settlement arrangements are slightly different to those for other parties in that the imbalance exposure for the interconnector as a whole is assigned to a so-called Interconnector Error Administrator, who is then responsible for allocating it to individual interconnector users. The basis on which this allocation is done does not fall within the remit of the BSC. Interconnector users can submit Bids and Offers to the BM in the same way as other parties, but they can only be accepted with the consent of both NCG and RTE.

The interconnector with Northern Ireland (known as the Moyle interconnector) is owned by Moyle Interconnector Limited (MIL) and operated by System Operator Northern Ireland (SONI), who also administers the sale of capacity on the interconnector on behalf of MIL[28]. Of its transfer capacity, 125MW is currently contracted to Northern Ireland as replacement for generation. The rest of the available link capacity (275MW) has been auctioned to energy traders in Ireland.

Nomination timetable

In general, data may be submitted to NGC at any time from several months in advance of the day to which it applies until Gate Closure for a particular settlement period. However, all participants have to provide an initial indication of their intended generation or consumption pattern for the next day by 11:00 on the day-ahead, so that NGC can undertake operational planning studies.

Data that is submitted to NGC remains operational until replaced by a subsequent data submission. Thus, participants do not have to resubmit technical data, such as their ramping rates, for every half-hour but can simply submit a single set of data. Participants are required to use reasonable endeavours to ensure that the data held by NGC at all times, including after Gate Closure, is accurate. However, data submitted after Gate Closure e.g. a notification of a plant failure, will not be taken into account in calculating a participant's imbalance position.

The process and timetable for settlement of imbalances

The first stage in the settlement process is to assign initial volumes of generation, consumption and contract volumes to each participant. This enables their imbalance volumes to be calculated and involves the collection, processing[29] and aggregation of meter data and contract notifications. At the same time, the cash out prices have to be calculated from:

a) data provided by NGC on the BM Bids and Offers it has accepted and the balancing services it has utilised; and
b) short-term market trading information, which is collected from a number of specified trading platforms.

A series of steps are undertaken following the identification of an imbalance. There is an initial settlement run, followed by three separate reconciliations and then a final reconciliation. The reconciliation runs are required to ensure that the appropriate imbalance volumes are used and that the associated payments are therefore accurate and reflective. Perhaps the most important

[28] See www.soni.ltd.uk for further details.
[29] Most small consumers do not have meters that record their half-hourly consumption values. Instead, these values have to be derived from the load profile assigned to that consumer.

need for reconciliation arises from the time delays involved in obtaining meter data from small customers, with which to update and refine estimates of a supplier's actual consumption. In addition, participants may dispute the imbalance volumes they are initially allocated. Consequently, the settlement process spans a significant period from interim data being provided to participants 5 working days after the settlement day to the funds transfers resulting from the final reconciliation run which occur approximately 283 working days later i.e. 288 working days after the settlement day. The settlement timetable is as follows:

- Day+5II "Interim Information"
- Day+16 SF
- Day+36 R1
- Day+81 R2
- Day+147 R3
- Day+288 RF "Run Final"

One final point to note is that invoices are not issued for each settlement day. Instead, invoices are aggregated together so that one invoice is issued covering all the settlement days in the first half of a month and a second invoice is issued covering the second half of the month.

Information provided by the TSO in relation to the BM

Information in relation to the operation of the BM is provided on the Balancing Mechanism Reporting Service (BMRS) website[30] by the Balancing Mechanism Reporting Agent (BMRA). The BMRS website provides near real time and historic data about the BM.

NGC is required to send a variety of data items (defined in the Grid Code) to the BMRA and to ELEXON (for publication on the BMRS) for reporting purposes. The specific data items required to be sent are listed in Section Q of the BSC. Generally, the type of data that NGC is required to send includes zonal and national demand forecasts, zonal and national generation forecasts, zonal and national imbalances and information in relation to the actions that it has taken to balance the system.

[30] See www.bmreports.com.

3.1.4 Effective unbundling

Table 3.5 Ownership structure of network companies in Great Britain.

Network company	Activity	Owner
National Grid Company	Electricity Transmission Ownership in England & Wales and System Operation across GB	National Grid Transco plc
ScottishPower Transmission	Electricity Transmission Ownership in South of Scotland	ScottishPower plc
Scottish Hydro-electric Power Transmission	Electricity Transmission Ownership in North of Scotland	Scottish & Southern Energy plc
NEDL	Electricity Distribution	Mid American Holdings
YEDL	Electricity Distribution	Mid American Holdings
Central Networks (East)	Electricity Distribution	E-on
Central Networks (West)	Electricity Distribution	E-on
EDF Energy (EPN)	Electricity Distribution	EDF Energy
EDF Energy (LPN)	Electricity Distribution	EDF Energy
EDF Energy (SPN)	Electricity Distribution	EDF Energy
SP Manweb	Electricity Distribution	ScottishPower plc
SP Distribution	Electricity Distribution	ScottishPower plc
Western Power Distribution (South Wales)	Electricity Distribution	PPL
Western Power Distribution (South West)	Electricity Distribution	PPL
United Utilities Electricity	Electricity Distribution	United Utilities plc
Scottish Hydro-Electric Power Distribution	Electricity Distribution	Scottish & Southern Energy plc
Southern Electric Power Distribution	Electricity Distribution	Scottish & Southern Energy plc
Global Utility Connections	Electricity Distribution	Cannon & Kirk plc
Laing Energy Limited	Electricity Distribution	Laing O'Rourke Plc
Independent Power Networks Limited	Electricity Distribution	INEXUS Group (Holdings) Limited

The licences of distribution and transmission companies require that they:

- do not undertake transactions that create a cross-subsidy with another entity;
- enter into agreements on an arms length basis and on normal commercial terms;
- carry out activities only for the purposes of distribution or transmission (whichever is appropriate), subject to the *de minimis* activities provisions which allow a small amount of non distribution or transmission activities (whichever is appropriate) to be undertaken.

In addition, the transmission licence of NGC (who operates the GB transmission system) prevents NGC and all affiliated and related undertakings from owning electricity supply or generation interests.[31]

Infringement of these and other licence obligations may result, after going through due process, in enforcement action and financial penalties. The financial penalty cannot exceed 10% of annual turnover.

In setting price controls for distribution and transmission companies an important issue for Ofgem is to consider the costs that a network company shares with other companies within its group. This includes head office costs and the activities it has outsourced to other entities. These costs must be charged according to the principles listed above. However, Ofgem leaves it to the distribution and transmission companies concerned to determine how it organises its business in relation to outsourcing work and sharing of common costs within the framework of obligations imposed by its licence.

The fourteen DNOs established at privatisation and the transmission network companies have financial ring-fence conditions in their licence. One of these conditions has the effect, subject to a *de minimis* provision, of restricting the business activities that the company can carry out, to those for which it is licensed e.g. distribution. As a consequence, each company's company law accounts will largely only include the activities of the network company. In addition for the fourteen DNOs established at privatisation and the transmission network companies, the licenses also include specific regulatory accounts conditions. For example, amongst other things, these obligations require that the regulatory accounts are published, are subject to audit requirements and must be accompanied by an audit opinion, addressed to the Authority, from an appropriate auditor setting out that the accounts have been prepared in accordance with the requirements of the relevant network licence. For most companies Ofgem has also introduced another licence condition in relation to price control review information that requires the companies to prepare detailed information on their activities in accordance with published guidelines.

The licences of the fourteen DNOs established at privatisation require that licensees must maintain managerial and operational systems preventing any relevant (ie, affiliated or related) supplier or shipper having access to confidential information except in certain specified circumstances (which are detailed in the licence condition). The network company must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas or the shipping of gas or the generation of electricity. The transmission network companies responsible for transmission ownership activities in Scotland (who have affiliated generation and supply interests) are required by Special Conditions C, D and E of their respective Transmission Licences to restrict the use of transmission related information and to introduce arrangements to provide for the managerial and operational independence of the transmission network business.

The licences of the fourteen DNOs established at privatisation and the transmission network companies also require that the licensees appoint a compliance officer who will facilitate compliance by the licensee with the licence conditions relating to the restriction on the use of certain information and the independence of the network business.

[31] The licensee cannot purchase or otherwise acquire electricity except for system operation purposes, and it must procure that no affiliate or related undertaking purchases or otherwise acquires electricity.

A distribution licensee is required to use reasonable endeavours to comply with a statement that it produces setting out how it intends to comply with, amongst other things, the requirement not to restrict, prevent or distort competition. This compliance statement must also set out how the licensee shall maintain the branding of the distribution business so that it is fully independent from the branding used by any relevant supplier or shipper.

During 2003 and early 2004 several energy groups owning both electricity distribution and supply businesses proposed changes to their supply and/or distribution brands. In many cases these proposals reduced the difference between the branding of their respective supply and distribution businesses. Some of these proposed changes have now been implemented. These changes gave rise to concerns that competition in energy supply may be adversely affected by the re-branding that was occurring. In response to these concerns, Ofgem reviewed whether the approaches to branding by a number of distribution licensees with supply businesses complied with the relevant electricity distribution licence condition concerning brand separation. As part of this review, it was necessary to consider what, if any, the effect of any similarity of any such branding may have had on competition. Further information on this issue may be found at
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9973_branding_open_letter.pdf

On the basis of the information that was available to Ofgem there did not appear to be robust evidence to suggest that the current branding practices adopted by supply and distribution businesses has operated to restrict, prevent or distort competition in the domestic electricity supply market.

Ofgem continues to believe that separation between the supply and distribution business in common ownership is important and will therefore continue to monitor the effect of branding between related distribution and supply businesses. Should evidence arise that indicates conduct in relation to branding is giving rise to anti-competitive concerns Ofgem will consider whether any action is required under either SLC 39, or under other statutory powers available to it including those contained in the Competition Act 1998 or the Enterprise Act 2002.

Further reading

Electricity Distribution Price Control Review, Final Proposals, November 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9416_26504.pdf

The role of regulatory accounts in regulated industries, final proposals, April 2001

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/219_10april01.pdf

Regulatory Accounts, Final Proposals, November 2000

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/221_29nov00.pdf

3.2 Competition Issues

3.2.1 Description of the wholesale market

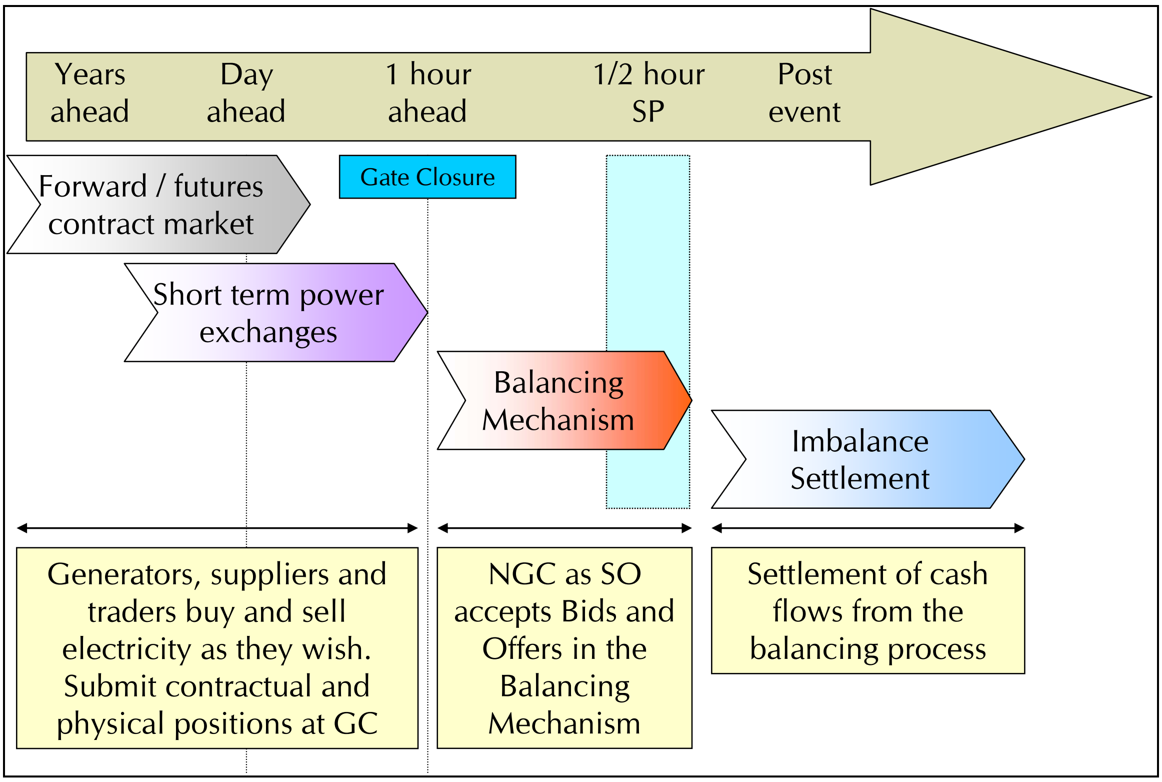
On 1 April 2005, the prevailing trading arrangements in England and Wales (NETA) were extended to additionally cover Scotland such that a set of common electricity trading and transmission arrangements were introduced across England, Wales and Scotland creating a single wholesale market for electricity in Great Britain. There is a separate market in Northern Ireland and hence the GB market is a sub-national market.

With the objective of enabling the further development of a competitive electricity market in Great Britain, the new arrangements established:

- a common set of trading rules allowing electricity to be traded freely across GB;
- rules for access to, and charging for, the transmission network; and
- a GB wide system operator (SO) independent of generation and supply interests.

The GB wholesale market is based on bilateral trading between generators, suppliers, traders and customers across a series of markets. Consequently, generators are required to self-despatch their plant rather than have them centrally dispatched by the SO. Broadly speaking, the wholesale market can be broken down principally into over the counter trading and power exchange trading, followed by BM activity and imbalance settlement as outlined below[32]:

Table 3.6 – Wholesale market stages



[32] Participation in over the counter trading, power exchange trading and in the BM is optional, while participation in imbalance settlement is mandatory.

Over the counter trading (OTC)

Over the counter trading encompasses both bilateral deals struck directly between two market participants and brokered deals, where an intermediary (the broker) brings together a buyer and seller. OTC trading typically operates from a year or more ahead of real time up until 24 hours ahead of real-time. Examples of typical contracts include annual contracts (contracts for the delivery of a given volume of power at a specified price throughout a year), seasonal contracts (summer/winter), quarterly contracts and monthly contracts. However, this market is also used for non-standard contracts designed to match a consumer's anticipated demand profile.

Power exchanges

Although trading on power exchanges can extend out as far as the contract market, trading on them tends to be concentrated in the final 24 hours preceding Gate Closure. Generators and suppliers trade short term on power exchanges to fine tune their positions as their demand and supply forecasts become more accurate in the run-up to real time. Trading on power exchanges is via a set of standardised contracts. For example, the UKPX trades the following contracts:

<u>Spot</u>

- Half-Hour – 49.5 hours prior to start of delivery (2 full days open at any time)
- Two-Hour Block – 49.5 hours prior to start of delivery (2 full days open at any time)
- Four-Hour Block – Rolling seven days

<u>Prompt</u>

Peak and baseload contracts for blocks of four hours, in the following combinations:

- Blocks 1 + 2 – Rolling seven days
- Blocks 3 + 4 – Rolling seven days
- Extended Peak Load contracts – Rolling seven days
- Off Peak – Rolling seven days
- Base Load Day – Rolling seven days
- Peak Load Day – Rolling seven days
- Weekend – Rolling two weekends
- Base Load Week - Rolling four weeks

<u>Forwards</u>

- Months - Rolling 6 months
- Quarters - Rolling 4 quarters
- Seasons - Rolling 10 seasons

The emergence of power exchanges and on-line brokerages has led to greater transparency of future prices and has increased the availability and range of products that can be traded.

Details relating to the operation of the BM and imbalance settlement have been provided in the 'balancing section of part 3.1.3 of this report and so are not repeated here.

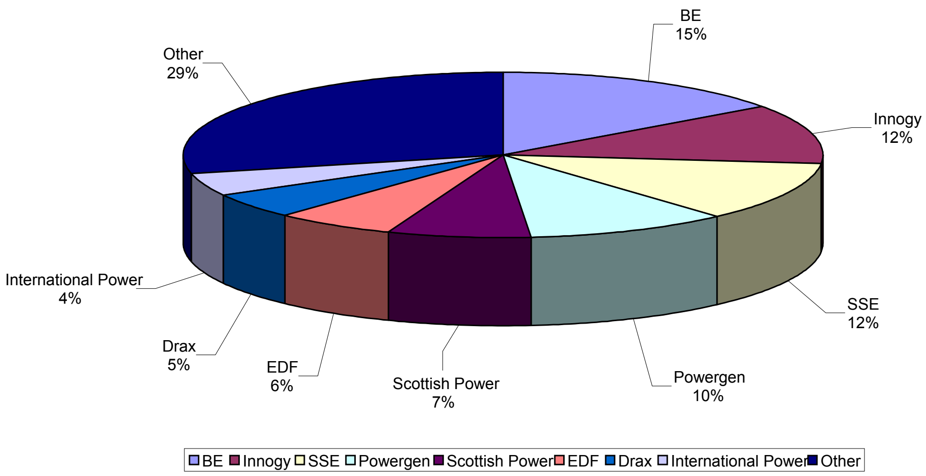
Consumption and demand

The peak demand for electricity in GB during 2004/05 was 59.5GW whilst demand over the course of the year was 354.2TWh.[33]

Generation capacity

The total installed capacity on the GB system at the beginning of 2005/06 was 77.4 GW. As shown in figure 3.7 below, eight companies had market shares exceeding 5% and, of these, the largest three companies held 39% of the installed capacity.

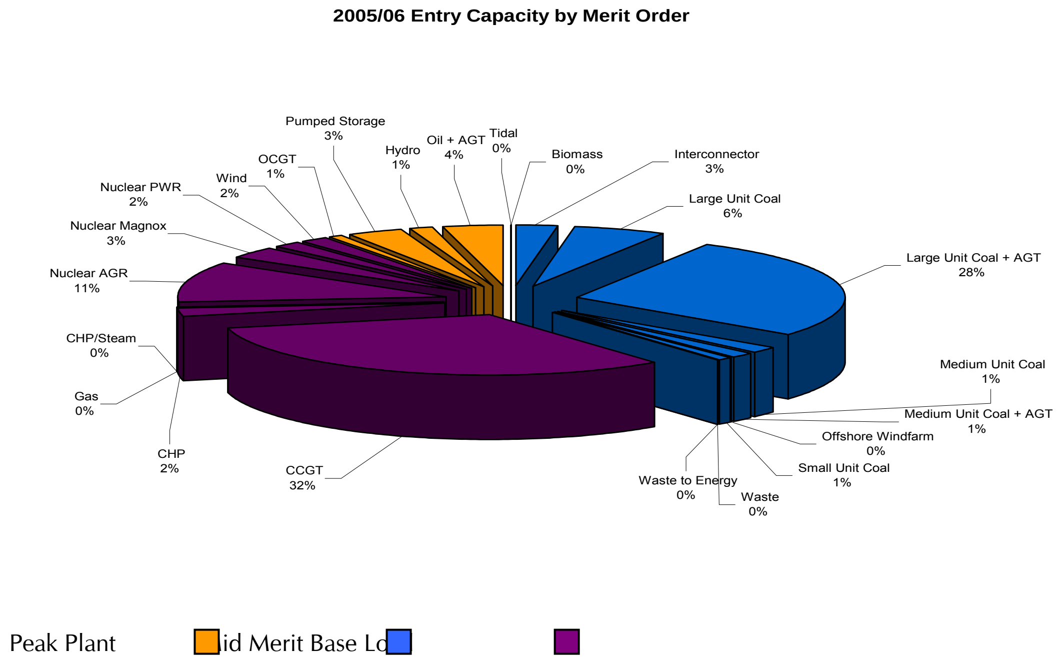
Figure 3.7 – Percentage of Transmission Entry Capacity (TEC) Values by Generation Owner (source: NGC Seven Year Statement, table 3.5)



A breakdown of the wholesale electricity market by fuel type is outlined in figure 3.8. In terms of merit order, 51.3 per cent of entry capacity is generated by base load plant, 39.5 per cent is generated by mid merit plant and 9.2 per cent is generated by peak plant.

[33] This information is taken from NGC's Seven Year Statement, May 2005.

Figure 3.8 – 2005/06 TEC Values by Merit Order (source: NGC Seven Year Statement, table3.5)



Ancillary services

As discussed in Section 3.1.3, NGC makes use of a range of balancing services including:

a) contracted balancing services such as frequency response, reserve, reactive power and black start. These are typically in option contract format;
b) forward energy contracts; and
c) offers and bids in the BM.

In this section, we focus on contracted balancing services, which are classified as either mandatory or commercial. As part of the terms for their connection to the system, generators are required to provide mandatory contracted balancing services according to the terms set out in the Grid Code. The mandatory services cover basic levels of reactive power and frequency response and payments for them are based on administered prices. Commercial services are either directly negotiated between NGC and the service provider or procured via a tender process. They include various types of reserve, enhanced reactive power and frequency response services, black start and intertrip arrangements (which allow NGC automatically to reduce generation or demand).

Table 3.9 How NGC seeks to procure balancing services.

BALANCING SERVICE	MEANS OF PROCUREMENT	TIMESCALES
ANCILLARY SERVICES		
Part 1 Services		
Reactive Power	Contracts derived from Market tenders and Bilateral contracts	Evergreen
Frequency Response	Bilateral contracts	Evergreen
Part 2 Services		
• Black Start	Bilateral contracts	Up to life of asset
• Fast Start	Bilateral contracts	Up to life of asset
Commercial Ancillary Services		
Enhanced Reactive Services	Contracts derived from Market tenders	Min Annual
Frequency Response	Bilateral contracts	Min Seasonal
Reserve		
• Fast Reserve	Bilateral contracts or contracts derived from market tenders	Min monthly via bilateral contract or tender process
• Standing Reserve	Contracts derived from Market tenders.	As required
• Warming	Bilateral contracts	Min Annual
• Commercial Intertrip	Bilateral contracts	As required
• System to system services including Emergency Assistance	Bilateral contracts	Evergreen
• Maximum Generation Service	Bilateral contracts entered into pursuant under CUSC	As required
BALANCING MECHANISM OFFERS AND BIDS	Services are procured under the provisions of the Balancing and Settlement Code	N/A
OTHER SERVICES		
Reactive Power	Contracts derived from Market tenders	Min Annual
Frequency Response	Bilateral contracts	Min Seasonal
Standing Reserve	Contracts derived from Market tenders	As required
Fast Reserve	Bilateral contracts or contracts derived from market tenders	Min monthly via bilateral contract or tender
Demand Intertrip	Bilateral contracts	As required
Energy Related Products	Procured via Markets/Bilateral contracts	As required

Source: **NGC's Procurement Guidelines**

Further detailed information in relation to NGC's balancing services can be found at www.nationalgrid.com/uk/indinfo/balancing/index.html.

Information in relation to each market participant's share of the various ancillary services markets is commercially sensitive and is not publicly available. However, NGC publishes aggregate information regarding the balancing services that it has procured on both a monthly and an annual basis. In addition, for some of the services (those that influence cash out prices), NGC provides utilisation reports. These reports can be found on NGC's website at http://www.nationalgrid.com/uk/indinfo/balancing/.

Table 3.10 is reproduced from section 6 of NGC's May 2005 Monthly Balancing Services Summary as an illustration of the volume of balancing services procured and their cost on a monthly basis.

Table 3.10 – NGC monthly balancing services summary for May 2005 (source: NGC Monthly Balancing Services Summary 2005/2006, May 2005)

Balancing Service	Info Provision	Value
Reactive Power Market	Utilisation Volume (MA) Utilisation Volume (DefaultPM) Total Spend (MA) Total Spend (Default PM)	1,210,300 Mvarh 2,100,785 Mvarh €3.45m €5.18m
Standing Reserve	Average availability payments: Non-Working Days Working Days Total Spend Total Volume	 €6.69/MW/h €6.69/MW/h €7.48m 9,848 MWh
Mandatory Frequency Response	Holding Volumes & Prices: Average Volume held MW Average price £/MW/h Total Holding Spend Total Response Energy Payment Spend	Pri / Sec / High 518 357 910 €3.80 €4.03 €0.86 €6.04m (€1.15)m
Commercial Frequency Response	No. Of Contracts Total Spend	6 €4.32m
Fast Start	Average Capability Rate Total Spend	€15.49/h €1.29m
Black Start	Total Spend	€2.88m
Warming	Total Cost of Warming & Hot Standby MWh Utilised during period (warming)	€0.57m 134,040MWh
Fast Reserve Non-Tendered	Total Spend on Availability	€7.48m
SO to SO	Volume Imported Volume Exported	32 GWh 29 GWh
All Other Services	Total Spend	€4.60m
Forward Trading	April & May traded gross volume Net cost of forward trading OTC – Power Exchange & Energy Buy Volume Sell Volume OTC – BMU Specific Buy Volume Sell Volume	103,852 MW €3.31m 23,823 MWh 18,560 MWh 56,264 MWh 5200 MWh

Balancing Service	Info Provision	Value
PGBT's	No. of PGBT's entered into: Sourced Agreed Average PGBT Prices £/MWh: Buy Sell Volume MWh: Buy Sell Total Cost of PGBT's	 0 0 €0/MWh €0/MWh 0 MWh 0 MWh €0M
Summary	**Total**	**€46.65m**

Volume of electricity traded

Exchange trade

Total traded volume on the UKPX for the 12 months to May 05 was 8.2TWh for all packages, where the total traded volume comprises prompt and spot market trades.

Balancing Mechanism

NGC's actions in the Balancing Mechanism over financial year 2004/05 amounted to around 3.4TWh of offer acceptances to increase generation, and around 8TWh of bids to reduce generation.

Over-the-counter trade

On the basis of volumes reported to Heren, trading in over the counter electricity products for financial year 2004/05 stood at around 743.3TWh of delivered volume for all packages. The most heavily traded product during this period was Winter '04 Baseload with around 151.2TWh.

Trading Platform trade

The Spectron online trading platform recorded a total of almost 35.8TWh of delivered volume for financial year 2004/05. The two reported products, "Day-ahead" and "Month-ahead" accounted for around 23.1TWh and over 12.6TWh respectively. Ofgem does not have information on volumes traded on other platforms.

Long-term contract trade

Ofgem has no non-confidential information on the extent of long-term contracting.

Demand side participation

Suppliers provide demand side pressure in price formation by partaking directly in the wholesale market as they contract with generators and traders. The demand side can also participate in the Balancing Mechanism and compete with generators to provide balancing services. For example:

- Demand side participation within the frequency response service was 2.8TWh in 2002/03. This represents a 29% share of the total market for frequency response.

- 571 MW of demand was contracted for standing reserve in 2003/04. This represents a 29% share in of the total market for standing reserve.

- NGC has developed a demand turndown service, which was identified as a potential contingency reserve via the reduction of load by large demand users[34]. In the initial trials of this service, the average availability of demand that could be turned down was 66 MW in the morning and 48 MW in the afternoon.

Member State integration

The GB transmission system is currently connected to the transmission systems in France (2000 MW) and Northern Ireland (500 MW[35]). There are plans to build an interconnector to the Netherlands (1320 MW by 2010) and the Republic of Ireland is in the process of evaluating an interconnector to GB (500-1000 MW), see section 5.1 for further details.

Capacity on the French interconnector is sold to market participants via auctions that are jointly organised by the TSOs in the two markets (RTE and NGC). Separate auctions are held for capacity in the two directions (France to GB and GB to France). Capacity can be bought for varying lengths of time, ranging from three years down to one day. Auctions are held each business day for daily capacity for each day of the year. Periodic auctions are held for capacity of between one day and one year (medium term capacity). Capacity is offered in tranches of 1MW (Units) and Users can choose how many Units they bid for in each auction. All capacity from France to England remaining after the tender process and all available capacity from England to France will be offered in the annual, daily and periodic auctions.

Capacity rights are subject to a "use it or lose it" rule. Two days before the start of each Contract Day, Users with Units longer than a Contract Day will need to give the Operators notice of their intended level of use of the Interconnector on the forthcoming Contract Day (taking into account reassignment, reallocation, contract volumes and bids/offers). To the extent that Users indicate that capacity will be unused, and subject to outages, the Operators will make the capacity available in the daily auction. The original User will still be required to pay for the capacity. It will not receive any proceeds from the auction.

Capacity rights on the Northern Ireland interconnector are also auctioned, although some of the available capacity is reserved for green power. However, whilst 125 MW of the link is not auctioned because of a contract between the Northern Ireland TSO (NIE) and Scottish Power, which runs until 2006, NIE has sold energy equivalent to this capacity in Northern Ireland thus enabling market participants effectively to gain access to the entire available interconnector capacity. Although this interconnector can operate with power flows in either direction, under normal circumstances the flow of power is from Scotland to Northern Ireland.

---

[34] See the 'Demand Side' information site on Ofgem's website (www.ofgem.gov.uk) or http://www.nationalgrid.com/uk/indinfo/balancing/pdfs/DT(Winter04-05).pdf for more information.
[35] Due to transmission constraints on the Northern Ireland system, only 400 MW can currently be exported from GB.

Recent mergers and acquisitions

Under the Enterprise Act 2002 the Office of Fair Trading (OFT)[36] has a function to obtain and review information relating to merger situations and a duty to refer to the Competition Commission (CC) for further investigation any relevant mergers which it believes have resulted or may be expected to result in substantial lessening of the competition in the UK market.

The following merger and acquisition cases in relation to electricity generation have been presented to and cleared by the OFT since 2003:

- Acquisition by ScottishPower plc of the remaining 50% share in South Coast Power Ltd. Cleared 23/11/2004.

  Ofgem did not consider that the acquisition would result in a substantial lessening of competition in Great Britain given the small increase in ScottishPower's position post-merger.

- Acquisition by Scottish and Southern Energy plc of Fiddler's Ferry and Ferrybridge Power Stations. Cleared 15/10/2004.

  Following a public consultation on this merger and taking into account the level of competition present in the generation sector and the relatively small increase in SSE's position post-merger, Ofgem did not consider that the acquisition would result in a substantial lessening of competition in Great Britain.[37]

- Acquisition by Centrica plc of Killingholme Power Limited. Cleared 16/09/2004.

  Following a public consultation on this merger and having taken into account the level of competition present in the generation sector and the relatively small increase in Centrica's position in this sector post-merger, Ofgem did not consider that this acquisition raised any significant concerns for competition in the electricity sector, or in relation to vertical integration.[38]

- Acquisition by ScottishPower PLC of Damhead Creek Limited. Cleared 04/08/2004.

  Following a public consultation on this merger and having taken into account the level of competition present in the generation sector and the relatively small increase in ScottishPower's position in this sector, Ofgem did not consider that this acquisition raised any significant concerns for competition in the electricity sector, or in relation to vertical integration.[39]

- Acquisition by SSE of Medway Power Ltd and AES Medway Operations Ltd. Cleared 13/11/2003.

---

[36] See www.oft.gov.uk.
[37] See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9360_25904.pdf for more details.
[38] See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8768_22504_Advice.pdf for more details.
[39] See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8340_200_04_SP_damhead.pdf for more details.

Ofgem's view was that the proposed acquisition did not raise any significant competition concerns. [40]

- Acquisition by International Power Plc of AES Drax Holdings Ltd. Cleared 27/10/2003.

  Ofgem's view was that the proposed acquisition did not raise any significant competition concerns. [41]

Further details of these mergers can be found on the 'Mergers' sections of the OFT website.

3.2.2 Description of the retail market

Retail supply

End users in the energy market are classified by the Utilities Act 2000 according to the purpose of their energy use rather than according to the amount of energy they consume. Customers classified as domestic use energy for mainly domestic purposes at domestic premises and those classified as non domestic customers use energy for business and industrial purposes.

Presently, there are six large supplier groups participating in the domestic market - Powergen (owned by E.ON), npower (owned by RWE AG), EdF, Scottish and Southern Energy plc (SSE,) Scottish Power UK plc and Centrica (which owns BGT).

There are approximately 26 million customers in the domestic electricity sector of which the six large supply groups account for about 99% of the market. There are also a number of supply companies who are independent of these groups involved in the domestic electricity retail market, although these have no more than 1% market share between them.

Table 3.11 below shows the most recent national market share data of the large supplier groups in the electricity domestic market.

Table 3.11: GB domestic electricity retail market shares – March 2005

Group	Electricity
Centrica	22%
Powergen	21%
SSE	15%
Npower	15%
EdF	13%
Scottish Power	13%

Source: electricity distribution companies

[40] See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5133_SSE_Medway_report_OFT_24nov03.pdf for more details.

[41] See http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/5031_IP_Drax_report_6nov03.pdf for more details.

Ofgem's last review of competition in the non domestic market [42] considered a range of indicators of competitiveness for different groups of customers. The review found that different supply sectors vary in terms of concentration, with evidence of market entry, a range of prices and substantial switching activity. The review concluded that the non domestic market was broadly competitive but that there was scope for customers to take greater initiatives to address certain issues concerning supplier behaviour. At that time, Ofgem stated that it did not intend to conduct a further review unless evidence was presented that might alter these conclusions.

Ofgem collects market share information Ofgem can provide on the non domestic market is acquired from a third party who collects the date from suppliers. This data is presented in Table 3.12 below.

Table 3.12: GB non domestic electricity retail market shares by volume of supplied electricity (Nov 2004)

	sub 100kW	100 kW	1MW
Centrica	27.54%	3.06%	0.34%
npower	22.16%	23.02%	24.29%
Powergen	16.09%	23.51%	28.17%
SSE	10.66%	15.18%	7.36%
EDF Energy	8.70%	9.36%	6.05%
ScottishPower	7.55%	3.76%	4.18%
British Energy	-	14.73%	18.85%
GdF	-	3.99%	9.55%

Source: Datamonitor

Market shares and new entry

In domestic electricity, there are six main supplier groups all with a share of above 5%. There has been a significant amount of new entry into this market; at least twenty suppliers have entered and exited since April 1999. However, the number of independent suppliers has reduced significantly over time as these have generally been bought up by the main supplier groups. The acquisition of Atlantic Electric and Gas in April 2004 by SSE was the most recent. At present, there are six independent companies in the domestic electricity market. These companies have grown organically by gaining their customers competitively rather than company acquisition.

Centrica, the former gas monopoly supplier is the largest entrant in the market and has a significant presence with a national market share of 22%. It has gained its customers mostly through organic growth. The former PESs have also entered into regions other than their former monopoly areas. On average, new entrants have gained about 35% of the regional incumbent's market share. The incumbents still have about 65% of market share in their areas on average. Entry by the independent suppliers has been on a less significant scale. They have in total approximately 1% of the national market.

The top three suppliers by market share are Centrica, E.ON and SSE who together have 58% of the market.

[42] Review of competition in the non-domestic gas and electricity supply sectors, Initial findings 72/03.

In the non-domestic market there are at least five suppliers with a market share above 5% in each of the sectors of the market in table 3.12. The top three suppliers in each sector have between them more than 60% share of that sector. There has been new entry.

Integration between supply and generation

The 6 large supplier groups in the domestic market are vertically integrated i.e. they are part of a group with both generation and supply activities. Between them, the six supplier groups account for 55% of generation output. None of the independent domestic suppliers is vertically integrated. In addition to the six large supplier groups, other non-domestic suppliers are also vertically-integrated (such as British Energy). About 70% of generation is accounted for by vertically-integrated suppliers.

Independence from network companies

The GB transmission system operator's transmission licence prevents it from having an interest in electricity generation or supply, either directly or through an affiliate company.

The Utilities Act 2000 amended the Gas Act 1986 and the Electricity Act 1989 and prohibited a supply licence holder from holding a distribution or transmission licence in a single legal entity. Apart from npower and Centrica all the large suppliers have an affiliate connection to DSOs, in that they belong to company groups that own distribution companies. In addition, SSE and Scottish Power belong to groups that own transmission assets (but do not operate their respective transmission systems).

None of the independent new entrants since the introduction of competition have had affiliations to either TSOs or DSOs. There have been over twenty independent suppliers in electricity since the introduction of competition; in the domestic markets, however, only six of these are currently active.

Customer switching

Ofgem primarily collects data on the number of customers switching between suppliers in the domestic electricity retail market. It therefore does not have switching data by volume.

The most recent estimate Ofgem has on the level of switching in the domestic electricity market since the opening of the market is obtained from a customer survey carried out in March 2005. This survey found that, in electricity 48% of customers have switched at least once since market opening[43].

[43] Ofgem Customer Experience Survey, March 2005.

On average 300,000 customers change supplier every quarter in electricity. Table 3.13 below shows the number of domestic customers who switched in electricity over the last 12 months

Table 3.13 : Number of GB domestic electricity customers who switched (March 2005)

	Electricity
Apr-04	333,778
May-04	303,322
Jun-04	307,032
Jul-04	304,766
Aug-04	296,694
Sep-04	305,585
Oct-04	363,408
Nov-04	394,570
Dec-04	355,221
Jan-05	291,128
Feb-05	241,744
Mar-05	371,487

Source: Electricity distribution companies

Summary of switching procedures

The Customer Switching Processes used in the retail electricity market is initiated following agreement between a supplier and a customer to enter into a contract. Once the customer has decided that they wish to switch supplier, they can either directly approach an alternative supplier, use a third party supplier price comparison service (energywatch has put in place processes to accredit these comparison services) or delegate the responsibility for negotiation to a broker or consultant (which is used in the case of a number of I&C customers). Alternatively, the customer may be contacted directly by supplier, e.g. on the doorstep and asked whether they wished to transfer supplier.

The rules and processes used with regard to customer switching in the electricity market are found pre-dominantly in a supplier's Standard Licence Conditions, the Master Registration Agreement (MRA) and its subsidiary documents. Other supporting processes are found in the Balancing and Settlement Code (BSC).

Once the terms and conditions for supply are agreed, the customer has a period of time to consider the contract and decide whether to cancel it – the Cooling Off Period. This period is a legal obligation with regard to domestic customers and is seven business days. However, many domestic suppliers have extended this period to 14 days and some I&C suppliers have also adopted the cooling off period. If the customer does not cancel the contract, the new supplier using a shared network called the Data Transfer Network notifies the relevant distributor of the intended transfer who then performs a simple validation check. If successful the distributor stores the transfers details on a central system called MPAS (Metering Point Administration Service) and then contacts the old supplier to notify them of the specific meter point (MPAN – meter point administration number) to be transferred and the intended supply start date. The old supplier then has five business days to object to the transfer. If no objection is raised then the transfer and intended supply start date are agreed and the new supplier must appoint agents (e.g. a data collector, data aggregator and meter operator) to fulfil its duties (i.e. collecting meter readings, provision and maintenance of a meter etc) as prescribed in the supplier's Standard Licence Conditions, the BSC and the MRA.

The last task the new supplier must complete is to procure and submit a change of supplier meter reading that falls within +/- 5 working days of the Supply Start Date (SSD) by SSD +8 days.

Current retail price levels

Ofgem monitors domestic suppliers' prices across GB. In April 2002, Ofgem lifted all remaining price controls in the retail market. Prices are therefore determined by market conditions with suppliers setting their own prices according to their commercial strategy.

Suppliers set prices on a regional basis. The incumbent supplier is generally the most expensive supplier in a region with entrants pricing at varying discounts to this price. On average, the competitors' price is about €28.8 - €43.2 cheaper than the incumbent. The average incumbent standard credit electricity bill is €430.56 – across the 14 regions, the incumbent bill ranges between €387.36 and €475.2. Table 3 below provides a summary of electricity prices in the domestic sector.

There are three main methods of payment offered by suppliers. Customers on standard credit receive a bill, typically on a quarterly basis, for the energy they have already consumed. The bill can be settled by cash, cheque or cards. Prepayment, where customers generally use a card, key or token meter to pay upfront for the electricity they consume. This ends to be the most expensive payment method. Direct debit, whereby the customer pays for their energy bills directly through their bank account, tends to be the cheapest of the payment methods.

Table 3.14: GB domestic electricity annual bills[44]

	GB Range	Average Incumbent	Average Best Offer
Direct Debit	€345.6-€501.12	€436.32	€384.48
Standard Credit	€368.64-€515.52	€453.6	€408.96
Prepayment	€367.2-€557.28	€462.24	€401.76

Source: Ofgem

The breakdown of the average domestic electricity bill consists of the following components: generation costs which include distribution and transmission losses. Generation costs here have been adjusted to reflect distribution and transmission losses as they account for about 10% of generation costs. The network component of the bill includes the distribution and metering costs, transmission costs and balancing services use of system charges. The Energy Efficiency Commitment[45] and the Renewables Obligation[46] are separate schemes which are part of the government's low carbon goals. Supply costs and margin make up the remainder of the bill. Table 3.15 provides the estimated breakdown of the domestic bill into these components.

[44] Bills are based on average annual consumption – 3500kWh

[45] This is an estimate of how much it costs a supplier per customer per fuel to meet their EEC which is set by the Department for the Environment, Food and Rural Affairs (DEFRA).

[46] The Renewables Obligation is the government's main mechanism for supporting renewable energy. It aims to provide a substantial market incentive for all eligible forms of renewable energy.

Table 3.15: Estimated breakdown of domestic electricity bill[47]

Components of bill	Proportion of bill
Generation costs	37%
Distribution and metering costs	25%
Transmission costs	3%
Balance services use of system charges	1%
Energy Efficiency Commitment	1%
Renewables Obligation	2%
Supply costs and margin	26%
VAT	5%

Ofgem does not actively collect data on prices in the non-domestic sector.
The pricing information provided in the following table is obtained from Cornwall Energy Associates. These prices represent Cornwall Energy Associates' assessments of delivered electricity prices to industrial and commercial customer types in Great Britain for annual supply arrangements commencing April 2005.

Table 3.16: Assessed prices for year long contract from April 2005 - electricity

	c/kWh
Small Commercial (79 MWh per year)	10.54
Medium Commercial (8 GWh per year)	6.40
Large Industrial (53 GWh per year)	5.93

Source: Cornwall Energy Associates

The price assessments are provided on a per unit basis and reflect the total costs of the energy supply chain from wholesale energy market to customer meter. The breakdown of these costs is provided in Table 3.17 below.

Table 3.17: Breakdown of non domestic prices

	Wholesale Costs	Network Costs	Supply Costs & Margin	Taxes & Obligations
Small Commercial (79 MWh per year)	44%	42%	6%	8%
Industrial (8 GWh per year)	72%	19%	3%	6%
Large industrial (53 GWh per year)	78%	15%	1%	6%

Source: Cornwall Energy Associates

[47] Ofgem's April 2004 publication; Domestic Competitive Market Review has a more detailed discussion of the bill breakdown.

The DTI publishes a digest of non-domestic prices on its website. The most recent publication is for June 2005 prices which is available at:
http://www.dti.gov.uk/energy/inform/energy_prices/qep_jun05.pdf

All final prices in the GB wide retail energy market are determined by market forces as price controls on domestic suppliers were lifted totally in April 2002. There are however elements of the final price which are attributable to the regulated aspects of the market, in particular network charges.

3.2.3 Measures to avoid abuses of dominance

Wholesale markets

Ofgem's competition powers are described in section 2 above.

Market surveillance

Ofgem's market surveillance teams monitor the gas and electricity markets, including the wholesale electricity market and the Balancing Mechanism. They routinely assess whether there is any evidence of anti-competitive behaviour or breaches of statutory or licence provisions. On the basis of active surveillance and monitoring of the markets, Ofgem can investigate the behaviour of market participants if anti-competitive conduct is suspected and, where necessary, enforce domestic and European competition law.

Additionally, the Financial Services Authority (FSA)[48] has responsibilities for the operation of financial markets in the UK. The FSA works to prevent abuse or distortion of financial markets, including power exchanges such as the IPE. The FSA has the power to fine persons who have abused the market, where "market abuse" is defined under the Financial Services Market Act 2000.

General competition law framework

The Office of Fair Trading (OFT) has responsibilities for the enforcement of competition law in the UK, under the provisions of the Competition Act 1998 (CA98) and the Enterprise Act 2002. Ofgem has concurrent powers to apply and enforce Articles 81 and 82 of the EC Treaty (Article 81 and Article 82 respectively) as well as the Chapter I and II prohibitions of CA98 in the gas and electricity sectors.

In the context of the wholesale electricity market, Ofgem can, in principle, take action against a generator manipulating the market under CA98 if that market manipulation is considered to be anti competitive. Under Article 81/Chapter I it is necessary to demonstrate that there is an agreement (formal or informal) or a concerted practice between the undertakings (in this case generating parties) which has the effect of preventing, restricting or distorting competition. Under Article 82/Chapter II, it is necessary first to demonstrate that an undertaking is dominant in a relevant market; and, second, that it is abusing that dominant position. If dominance were established, the next step would be to demonstrate that the conduct was abusive.

[48] http://www.fsa.gov.uk/

The CA98 confers on Ofgem powers to apply and enforce Articles 81 and 82 of the EC Treaty as well as the Chapter I and II prohibitions in relation to the gas and electricity sectors. The application of these powers include the ability:

- to investigate suspected infringements
- to impose interim measures during the investigation
- to give directions to bring an infringement to an end
- to apply Article 81(3) to agreements which infringe Article 81(1) and section 9 to agreements which infringe the Chapter I prohibition
- to accept binding commitments to address competition concerns, where appropriate
- to impose financial penalties on undertakings of up to 10 per cent of an undertaking's worldwide turnover in the business year preceding the date of the decision.

As with their powers under the Competition Act 1998, the Authority and other sectoral regulators have concurrent jurisdiction with the Office of Fair Trading under the Enterprise Act 2002 to make market investigation references within their regulated sector.

Generation licences

In addition to Ofgem's powers under the CA98 in relation to potential anti-competitive behaviour, electricity generation licences, which must be held by all generators with a certain capacity,[49] contain some limited conditions that could be used to tackle certain types of anti-competitive conduct on the part of generators. These include discrimination in the sale of electricity and cross-subsidisation. The electricity generation licence obliges generators to provide information to Ofgem to allow it to ascertain whether, in making or declining to make generating units available, the generators are pursuing a course of conduct likely to have the effect of restricting, distorting or preventing competition.[50]

There have been no formal investigations or enforcement activities under these licence conditions.

Transparency

Licensed generators are obliged to comply with the Grid Code under SLC 5 of the electricity generation licence. The Grid Code is an industry code covering all material technical aspects relating to connections, operation and use of the GB transmission system and lines and plant connected to that system. The Grid Code places certain obligations on signatories to submit accurate estimates of the physical properties of its generating units.

Operating Code No. 1 ("OC1") is concerned with the production of short term, medium term and long term demand forecasts to facilitate the safe, secure and efficient operation of the GB transmission system. In accordance with OC1, larger generators (along with other users of the transmission system) are required to provide information to National Grid Company Plc ("NGC") (system operator for the GB transmission system) for the purpose of demand forecasting. Specifically, they are required to notify NGC of the planned MW operational profiles of their stations.

---

[49] A power station which is capable of providing 100MW or more to the total system in England and Wales, 50 MW or more in SPTL's area and 5MW or more in SHETL's area are required to have a generation licence.

[50] This power only applies to a small number of generation licences in which the relevant aspects of standard licence condition 18 ("Generating unit availability") are turned on. Ofgem has in the past accepted requests from generators for this condition to be switched off.

Operating Code No. 2 ("OC2") is concerned with the exchange of specified information to facilitate and co-ordinate the planning for the safe, secure and efficient operation of the NGC Transmission System, Network Operators' Systems and Generators' systems. In accordance with OC2, larger generators (along with other users of the transmission system) are required to provide suitable and sufficient information for NGC and users to plan the safe and secure operation of their systems and facilitate the co-ordination of outages where they may interact. OC2 has three main elements:

- the exchange of information on generator unit and system outages for outage coordination and system security studies;
- provision of Output Useable[51] by generators to provide NGC and users with information on national and zonal generation and demand balance; and
- the exchange of specific technical parameters to allow system security studies to carried out.

This information has to be provided iteratively on a weekly resolution from 1 to 5 years ahead and iteratively on a daily resolution from 2 to 49 days ahead of real time.

Balancing Code No.1 ("BC1") requires NGC to be notified by participants of their expected physical positions for each half hour balancing period (i.e. their planned generation output and metered demand) by Gate Closure for that period. Balancing Code No.2 ("BC2") requires NGC to be notified by participants of any variation in notified physical input or output, other than variations arising from the issue of Bid-Offer Acceptances, at and after Gate Closure.

Ofgem has responsibility for the compliance of individual companies with licence conditions and statutory duties. The regulatory regime places operational responsibility on both NGC and Elexon to monitor market participants' actions and report any non-compliance with rules (for example a breach of information provided to the system operator). If market participants breach information disclosure rules they will breach the provisions in an industry code (either the grid code or BSC) which will subsequently be a breach of the terms of the licence held by that party. Ofgem enforces compliance with the conditions of the licences it issues, and, in the event of licence breach Ofgem has the ability to impose financial penalties and can ultimately revoke a company's licence.

Bidding behaviour

Ofgem takes the view that competition in the wholesale market reduces the potential for market abuse both in these markets and the Balancing Mechanism. In cases where Ofgem considers that generators' bidding strategies suggest that the market manipulation may be occurring, Ofgem would seek to investigate and, where appropriate, take enforcement action under its competition law powers outlined above.

Virtual power plant auctions

There have been no virtual power plant auctions in GB.

Retail markets

[51] That portion of Registered Capacity which is expected to be available and which is not unavailable due to a Planned Outage.

Ofgem considers all possible regulatory approaches prior to assessing behaviour in the retail markets, including the consideration of general competition law (including the Competition Act 1998), consumer protection legislation and sector specific regulation.

Ofgem's competition powers are described in section 2 above.

Transparency

Standard Licence Conditions (SLCs) in gas and electricity supply licences are the principal means by which Ofgem can require suppliers to meet minimum requirements for the provision of information and contract terms. The Gas Supply Licence and Electricity Supply Licence Standard Conditions set out the obligations of supply licensees that promote transparency.

SLC 40 of the electricity and gas supply licences sets out the obligation of the supplier to provide their customers with information about the amount of energy they have used either by reading the customers meter or if that is unavailable provide an estimate. This information can be provided with the customer's bill.

Contract structure

SLC 42 of the electricity and gas supply licences sets out the format which a domestic supply contract must comply. This stipulates that a supply licensee may not supply a domestic premises except under a domestic supply contract or a deemed contract. The domestic supply contract should be in a standard format and set out all the terms and conditions including terms as to price and provisions for terminating the contract

SLC 46 of the electricity and gas supply licences relates to the notification terms of terminating a domestic supply contract. The supplier may not enter into a supply contract without including terms which allow the customer to terminate the contract at any time so long as he has given a valid notice of termination and paid, if applicable a termination fee to the supplier.

A notice of termination is valid provided it is given at least 28 days prior to the date the termination is to take effect subject to an alternative supplier commencing supply of the premises i.e. when the customer switches supplier or the premises does not require a supply any longer. The supplier may charge a termination fee, except where some specific situations are not met. The termination fee should however not be greater than what the supplier will reasonably require.

Suppliers can offer longer term contracts so long as it is for a specified period of more than 12 months and that the principal terms of the contract may not be altered without the agreement of the customer. The customer may also terminate the contract within five working days of the date of the contract.

Provision of information.

SLC 44 of the electricity and gas supply licences obliges the supplier to take all reasonable steps to draw the customer's attention to the principal terms of the supply contract. SLC 40 of the electricity and gas supply licences also obliges suppliers to provide their customers with information particularly on the terms and conditions of their supply contract and also how to contact the Consumer Council and their role in resolving customer complaints.

Competition policy actions

Ofgem has considered a few cases in the retail sector under the Competition Act 98 (the CA 98). Of these, most cases were closed prior to undertaking a formal investigation under the Act. So far, there has been one case in which a formal investigation was carried out.

CA 98 London Electricity plc (LE) non-infringement decision

Following a complaint made under the CA 98, Ofgem investigated a London Electricity (LE) offer designed to win back former customers. The offer paid returning customers up to €108 over one year and was detailed in a letter sent to former LE customers in June 2002. The complainant alleged that this conduct was potentially in breach of the Chapter II prohibition of the Act.

Based on an analysis of the documents and information gathered during the investigation, Ofgem has found that LE's supply offer was not anti-competitive as there was a severely limited take-up. The offer was limited in terms of both the number of customers contacted by LE and the length of time for which the offer was open to those customers.

Ofgem found that there has been no infringement of the Chapter II prohibition of the Act in respect of this offer. Full details of this investigation can be found in the published decision document available on the Ofgem website.[52]

[52] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/4525_ca98_ni_decision_120903.pdf

4 Regulation and Performance of the Natural Gas market

4.1 Regulatory Issues

4.1.1 Degree of market opening

Gas and electricity markets in Great Britain are fully liberalised.

4.1.2 Management and allocation of interconnection capacity and mechanisms to deal with congestion

Management of congestion on interconnectors

The GB gas system is interconnected with Belgium and Northern Ireland and Ireland. A further gas interconnector between GB and the Netherlands is under construction, as is a capacity increase on the Belgium interconnector. The existence of these interconnectors and the current proposals for capacity increases and new interconnectors suggests that new interconnection capacity will be provided by the market when it is commercially viable.

The requirements of the Directives and the electricity Regulation regarding interconnectors are being met in GB by issuing licences to participate in the operation of interconnectors. For example, standard licence condition 11 requires the licensee to offer to enter into agreements for access to its interconnector on transparent, objective and non-discriminatory terms. Standard licence condition 13 requires the licensee to make available the maximum capacity of its interconnector. This includes the development of procedures on the primary market to facilitate the secondary trade of capacity and the requirement to allow and facilitate capacity rights to be traded on the secondary market. If capacity is reduced for technical reasons the mechanism for reducing the capacity allocation should also be open, transparent and non-discriminatory.

The operator of the proposed gas interconnector between England and the Netherlands has received its licence from Ofgem, and the DTI is currently consulting on the licences it proposes to issue to the operators of the existing interconnectors.

Ofgem considers that effective secondary trading and anti-hoarding mechanisms are required, with each interconnector operator needing to demonstrate that there is a transparent mechanism that allows spare capacity to be made available to the market. The ultimate objective is to ensure that capacity is not hoarded and that unused capacity can be obtained in a transparent market based manner by third parties so as to maximise the use of the interconnector concerned. The actual methodology under which interconnector capacity is made available in both the primary and secondary market is for the interconnector owner/operator to decide.

Once the interconnector licences are in place this methodology will need to meet the requirements of the relevant conditions of the interconnector licences. If this were not to be the case, Ofgem would expect the affected prospective interconnector users to make Ofgem aware of the situation, which Ofgem would then investigate and take any appropriate action.

In terms of publication requirements for this information, the DTI and Ofgem consider that there should be an equivalence in the information requirements on LNG and interconnectors as required of similar facilities in gas and electricity markets respectively, for example, generators in electricity or other connection points to the NTS in gas (wholesale market information requirements are discussed below).

Under the current regulatory and contractual framework, there are no use-it-or-lose-it provisions on the interconnector with Belgium. However, the interconnector operator currently facilitates the secondary trading of unwanted capacity by way of a bulletin board on its website. Ofgem does not routinely analyse physical congestion on interconnectors in the absence of complaints from market participants. However, data from 2004 suggests that physical congestion on the interconnector with Belgium was very low: for around 1% of the time flows were above 95% of maximum capacity at times when gas prices suggest that additional capacity would have been used.

Prevailing wholesale prices in the two markets are such that the interconnector with Ireland only exports from GB. As such, any congestion on this interconnector would have no adverse consequences on consumers in GB. Ofgem does not routinely collect or analyse data relating to this interconnector.

Management of congestion on national networks

Transmission system operators are responsible for managing congestion on their networks. Both gas and electricity system operators are under a statutory obligation to develop and maintain economic and efficient systems, as are gas and electricity distributors.

The gas national transmission system operator faces commercial incentives to reduce the cost of congestion at entry points as it is required to auction firm access rights and to fund the cost of buying back any rights to network access that it has sold but which cannot be delivered due to congestion. Under the system operator price control, the SO is allowed a certain amount of revenue (currently £18m per annum) to fund the cost of capacity buy-backs. It is allowed to keep a proportion of any savings, but must fund a proportion of the cost of any over-runs. This mechanism also operates to incentivise the system operator to maximise the technical availability of its network.

The transmission system operator is required to offer a defined quantity of entry access under its price control, but may also make additional entry volumes available, on which it is able to earn a higher rate of return than its regulatory cost of capital if there is a market demand for the capacity. In addition, it is obliged to make additional capacity available if the auction results satisfy the requirements of the specified capacity release mechanism, for example, that the results demonstrate a sustained demand above the baseline. At present there is no sustained congestion (ie, demand above the baseline volume) at existing entry points, so there is no obligation on the system operator to release incremental capacity. At one entry terminal there is some demand for additional capacity (but not enough to trigger the obligation to increase availability). The system operator is currently investing in new infrastructure to permit access to its network at a new entry point in Milford Haven, responding to demand for access from the LNG terminals under construction there. Entry capacity at Milford Haven has been sold to start from the last quarter of 2007.

A number of large industrial and commercial gas consumers pay a reduced gas transportation charge in return for allowing the system operator to interrupt their gas supplies, typically for up to 15 days per year. This provides the transmission system operator with an important tool to manage network congestion. Any customers interrupted on more than 15 days receive an additional payment, which is funded from the transmission system operator incentive scheme. However, the total costs of the additional interruption are small (the incentive target is around

£1.6m per annum). The treatment of exit capacity is being further developed in coordination with the forthcoming transmission price control review.

The transmission system operator can also constrain the use of Liquefied Natural Gas (LNG) in certain storage facilities. Shippers that book capacity in these constrained LNG sites undertake an obligation to provide transmission support gas to the system operator on days of very high demand. In recognition of this, shippers get a discount from the charge for the storage service. The target cost for constrained LNG costs incurred by the system operator are currently £6.6m.

The combined target costs of congestion management facing the transmission system operator under the current arrangements are therefore in the order of £26m per annum (excluding the costs of interruption up to 15 days per site which do not fall on the system operator but are recovered from all customers under the current arrangements). This is small in comparison with the total cost of the gas transmission network, which is around £0.6 billion (the total allowed revenue from charges to network users for use of the transmission network).

A number of large industrial and commercial gas consumers pay a reduced gas transportation charge in return for allowing the distribution network owners to interrupt their gas supplies on up to 15 days per year. This provides the distribution network owners with an important tool to manage network congestion. Any customers interrupted on more than 15 days receive an additional payment, which is funded from the distribution network owners' exit incentive scheme. However, the total costs of the additional interruption are small (the combined DNO incentive target is around £1.6m per annum) in comparison with the total cost of the gas distribution gas networks, which is around £2.1 billion. The exit capacity regime is being further developed in coordination with the forthcoming distribution price control review.

4.1.3 The regulation of the tasks of transmission and distribution companies

There is one gas National Transmission system owned and operated by Transco plc a subsidiary of National Grid Group. There are eight licensed gas distribution networks (DNs)[53] in Great Britain. DN operators transport gas from the National Transmission System (NTS) using a low pressure system to serve domestic customers, business consumers and Independent Gas Transporters (IGTs).

In 1995 the Gas Act 1986 was amended to allow for the creation of Independent Gas Transporters (IGTs) which develop, operate and maintain local gas transportation network extensions onto the DNs (or other IGTs).

Price controls

Ofgem regulates the level and structure of charges levied for using the monopoly DNs and the quality of service provided by these companies. The level of charges and quality of service provided by gas transporters, with the exception of IGTs, is regulated using price controls and various incentive regimes[54].

In establishing price controls and incentive regimes, a range of information is collected on operating costs, capital expenditure, financial issues and performance outputs for the NTS and each DN which is then analysed.

[53] In gas distribution, there is no distinction between asset owners and system operators. DN owners both own and operate the system.
[54] *Review of Transco's Price Control from 2002: Final Proposals*, Ofgem, September 2001 56/01.

Ofgem also uses independent consultants to undertake efficiency studies on specific aspects of costs and network performance. These studies will typically examine the scope for improvements in costs or performance. Setting cost allowances or performance targets in this manner is not a purely mechanistic process. Ofgem will also consider a number of other factors to ensure that the resultant cost allowances or performance targets are both sustainable and robust.

Based upon our assessment of costs and outputs, Ofgem establishes cost allowances and performance targets which form the basis of the price controls and incentive framework. Together, these elements determine the total amount of revenue (allowed revenue) that each network company may earn in each year and the network company is required by the regulatory regime to set charges for use of the network such that it complies with the limits on allowed revenue that have been set.

Until 1 April 2004 the DNs were regulated under a single price control. On 1 April 2004, Transco's Gas Transporter licence was modified and separate price controls for each of the DNs were introduced[55]. For the remaining part of the current control, allowed revenue has been disaggregated and allocated to the eight DNs. Going forward, however, a separate price control review will be undertaken for each DN.

Ofgem sets price controls which are typically five years long.

Now that four of the DNs are no longer owned by Transco, Ofgem will be better able to use comparative regulation in its gas distribution price controls.

As part of the next price control review, information will be collected from the NTS and each DN company and where applicable normalised to ensure as far as possible comparability across companies and then it will be used to assist in determining the relative performance of each DN and to establish efficient cost and performance benchmarks using a variety of statistical techniques.

The price control establishes allowed revenue for the NTS and each DN to be recovered through transportation charges.

The NTS, DN and IGT licensees are responsible for establishing a set of network charges in accordance with the principles set out in their GT licence. The NTS, DN and the IGT licensees must adhere to the obligations in their charging methodology[56], the licence and the Gas Act.

Periodic reviews are undertaken on the structure of charges to ensure the distribution charging boundary and distribution charging methods are in accordance with the requirements of the licences[57]. The charging boundary is the boundary between transportation activities and connection activities. The distribution charges are sub-divided into system related and customer related activities.

The business information available for IGTs is limited and the costs of undertaking detailed efficiency studies to establish cost allowances and performance targets often outweigh the benefits to consumers. Ofgem has therefore introduced a system of relative price regulation to

[55] *Separation of Transco's distribution price control: Final Proposals,* Ofgem, June 2003, 38/03.
[56] Standard Special Condition A5 of current GT licence.
[57] *Review of Transco's structure of distribution charges: Consultation Paper,* Ofgem, May 2004.

ensure that the charges for the use of these networks are no more than the charges that would be paid by an equivalent customer that is connected to a DN. The Relative Price Control came into effect on 1 January 2004[58].

Outputs reporting framework

Ofgem introduced output reporting for Transco in April 2002, following the last price control review. Under the relevant licence conditions, Ofgem drew up Regulatory Instructions and Guidance ("RIGs") which defined the outputs and provided the framework under which the data is collected and reported.

The original framework required Transco to report on (i) the number and duration of non-contractual interruptions to supply, (ii) the resolution of shipper queries, (iii) the reliability of the M-number CD-ROM service and (iv) some environmental outputs. Since 2002, the reporting framework (via the RIGs) has been amended twice.

The current version of the RIGs is version 3, which was published in March 2005. The key difference with this version is the introduction of the requirement for all Distribution Network owners (there are now four DN owners including Transco following the recent sales process) to undertake customer surveys of a sample of those customers that have experienced a non-contractual interruption to supply, and report the results of these surveys to Ofgem. The surveys cover performance in three key areas – (i) communication, (ii) the inconvenience caused to customers by the interruption and (iii) the efficiency and professionalism with which the work was carried out to restore supplies.

The requirement to report the number and duration of interruptions remains. However, the data reported under this output to date is not as robust as we would want, and we have made a number of improvements to the RIGs to ensure that it is more robust in the future. For this reason, Ofgem cannot provide trend data for continuity. Nevertheless, the data we do have conforms to broad industry estimates for the number and duration of interruptions of around 1 customer in every 100 experiencing an interruption, lasting for around 12 hours.

Further reading:

'Gas Distribution Quality of Service Regulatory Instructions and Guidance – version 3'; Ofgem document 100/05; March 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10970_10005.pdf

'Quality of Service for Gas Distribution Networks – initial consultation'; Ofgem document 192/04; August 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8177_QoS_gas_dist_networks_consultation.pdf

[58] See pages 23-28 for an overview of RPC in *The Regulation of Independent Gas Transporter Charging; Final Proposals,* Ofgem, July 2003.

Quality of service indicators (standards of Performance)

Ofgem introduced Standards of Performance for gas transporters to further protect the interests of customers in 2002. Guaranteed Standards of Performance ("GSOPs") set service levels that must be met in each individual case. If a GT fails to provide the level of service specified, it must make a payment to the customer affected (e.g. for not restoring supply within a specified timeframe). This is subject to a number of exemptions. Overall Standards of Performance ("OSOPs") cover areas where customers in general have a right to expect a pre-determined level of service, but in areas where it is not appropriate to place guarantees for individual customers (e.g. for answering telephone calls). These therefore set minimum average levels of performance.

A revised framework of Standards came into effect in May 2005. However, for both GSOPs and OSOPs, the recent changes were consequential to the DN sales process, and the principal framework was introduced in April 2002 as part of the last Transco price control review. The Standards are summarised in the tables below:

Table 4.1: Guaranteed Standards of Performance (from May 2005)

No.	Standard	Payment
GS1	Restoring domestic customers' supplies within 24 hours after an unplanned interruption.	€43.2 per day (up to a cap of €1,440)
GS2	Reinstatement of customers' premises within 10 working days	€72 domestic (€144 non-domestic) Extra payment for each 5 additional working days
GS3	Providing alternative heating and cooking facilities following unplanned interruption	€34.56 (domestic)
GS4a	Provision of standard connection quotations ≤ 275 kWh/h within 6 working days	€14.4 per day (cap is the lesser of €360 or the quotation sum
GS4b	Provision of non-standard connection quotations ≤ 275 kWh/h within 11 working days	€14.4 per day (cap is the lesser of €360 or the quotation sum)
GS4c	Provision of non-standard connection quotations > 275 kWh/h within 21 working days	€28.8 per day (cap is the lesser of €720 or the quotation sum)
GS4d	Accuracy of quotations - where a quotation is found to be inaccurate GT shall refund any overcharge that has been made.	N/A
GS4e	Respond to a land enquiry in respect of a new connection or alteration of an existing connection within 5 working days	€57.6 per day (Cap is €360 for connections ≤ 275 kWh per hour, €720 for connections > 275 kWh per hour)
GS4f	Date for commencement and substantial completion of connection work (≤275 kWh per hour)	€28.8 per day (Cap per customer is the lesser of €360or the contract cost)
GS4g	Date for commencement and substantial completion of connection work (>275 kWh per hour)	€57.6 (Cap per customer is the lesser of €720 or the contract cost)
GS4h	Completion of the work on the agreed date	Payment per day and cap depend on contract cost
GS5	Notifying customers and making payments owed under the standards	€28.8

Table 4.2: Overall Standards of Performance (from May 2005)

No.	Standard	Requirement
OS1	Answering telephone calls (not IGTs)	90%
OS2	Notifying customers of planned supply interruptions	95%
OS3	Informing customers of when they are due to be reconnected	97%
OS4	Responding to complaints	90%
OS5	Responding to gas emergencies (not IGTs)	97%

Ofgem collects performance data from gas transporters on an annual basis. The data is verified and then forwarded to the consumer council ("energywatch") for publication, in accordance with the Gas Act 1986. Energywatch's first report is due to be published this summer.

Further reading

'Review of Transco's price control from 2002 – final proposals'; Chapter 3; Ofgem publication 56/01; September 2001
'Revised Overall Standards of Performance arrangements for gas transporters – consultation on the draft determinations'; Ofgem publication 96/05; March 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/10760_9605.pdf

'Revised Standards of Performance arrangements for licensed gas distributors – consultation on the draft Statutory Instrument'; Ofgem publication 04/05; January 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9763_0405.pdf

Quality of service reports

To date, Ofgem has published two reports on the quality of service in gas distribution. These reports have put into the public domain information on how Transco performed with respect to the quality of service output measures set out in the RIGs. However, so far, these have excluded information on the number and duration of interruptions due to poor quality data reported under this output. Ofgem expects to be in a position to publish this data in future reports.

Further reading

'2002/03 Gas distribution quality of supply report'; Ofgem publication 71/04; March 2004

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/6642_7104.pdf

'2003/04 Gas distribution quality of service report'; Ofgem publication 119/05; April 2005

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/11148_11905.pdf

Network tariffs

Table 4.3

Customer Annual Quantity in MWh	National average network charges for DNs (€ per annum)[59]	NTS Network charges (€ per annum)[60]	Load Factor used (%)[61]
116300	141657	45149	52
116	523	63	32
23	136	12	36

At present, there are minimal regional differences in network charges, any differences owing to differences in Load Factors alone. This is set to change with the introduction of DN specific charges from October 2005.[62] This will better reflect the changes in the industry structure following the sale of four DNs by Transco in June 2005.

Balancing

There is a single gas market and a single high pressure balancing area covering the whole of Great Britain (GB), with Northern Ireland forming a separate gas market under the jurisdiction of its own regulator. In the description that follows, we focus solely on the GB system.

In GB, the primary responsibility for balancing lies with gas shippers. Transco, in its role as System Operator (SO) for the GB high-pressure national gas transmission system (NTS), has a role as residual balancer and, as such, it can buy and sell gas to correct residual imbalances and thus ensure that the system remains in balance at all times. Note that Transco is only allowed to trade gas for balancing purposes, it is not allowed to trade speculatively. On the lower pressure Distribution Networks (DN), each distribution network owner[63] is responsible for achieving balance on its own system.

Transco's role as residual balancer

In determining what balancing actions it needs to take, Transco, as SO of the NTS, is bound by its safety case, and the provisions of the Uniform Network Code (UNC).[64] The primary tool that Transco uses to balance the system is the On-the-day Commodity Market (OCM). In this market it can physically purchase gas (either at the notional National Balancing Point – NBP – or at a specific location) or take title to gas (the name on the contract becomes Transco's). As its name

[59] Current charges effective from 1st April 2005, DN charges calculated from *LDZ Transportation Charges for the Distribution Networks,* Transco, 31 March 2005.
[60] these figures include only exit charges
[61] Approximate Average Load Factors of DNs based on typical load factors for loads of this size from Transco data 2004.
[62] See pricing consultation 80 available from www.Transco.co.uk under pricing publications. Also, see Letter: *Gas Distribution charges from October 2005* available from www.ofgem.gov.uk under Area of Work: Gas Distribution charges.
[63] As well as owning the NTS, Transco also owns four of the eight distribution networks.
[64] All public gas transporters, including gas distribution network owners, are bound by the terms of the UNC.

suggests, the OCM deals exclusively with intraday trades. However, it differs from the Balancing Mechanism in electricity, in that market participants are able to trade bilaterally on the OCM rather than only being able to trade with the SO.

Transco can also use a range of other tools to help it balance the system. For example, it can trade forward to alleviate imbalances, although it has not yet exercised this ability. It can also buy-back transmission capacity entry rights that it has previously sold, thus reducing the volumes of gas that shippers can inject into the system. Ofgem has oversight over the types of balancing tools that Transco can use and their tendering processes. This oversight arises because the Authority has the power to veto amendments to Transco's Procurement Guidelines, which contain details of the balancing services that Transco intends to procure and how it intends to procure them.

In gas, there is no Gate Closure for the wholesale market, unlike the electricity market, and market participants can continue trading throughout each daily balancing period and, indeed, can continue to trade out their imbalance volumes for up to 15 days after the end of the month in which the relevant gas day occurs[65]. However, participants have to notify their intended inputs and offtakes to Transco ahead of time.

Commercial incentives to balance – cash out arrangements

The current gas balancing arrangements are designed to provide shippers with commercial incentives to balance their inputs to and offtakes from the NTS over the course of each daily balancing period, which corresponds to a gas day[66]. A shipper's imbalance volume is equal to the difference between its aggregated final inputs and offtakes and this is cashed-out at prices determined by trades on the OCM. No tolerance levels exist in respect of imbalance charges.

Different imbalance prices apply depending on whether a shipper is short gas (its offtakes are greater than its inputs) or long gas (its offtakes are less than its inputs). A shipper that is short gas pays the system marginal buy price (SMPbuy) which is the higher of:

- the highest price of any trade to which Transco is a party on the OCM, excluding any trades that it takes for locational reasons; and

- the average price of gas traded on the OCM (SAP) plus a fixed value set at 0.0413c/kWh, which is based on the price for injecting gas into the Hornsea storage site in 2000. Note that if Transco does not purchase any gas, SMPbuy defaults to this price.

Conversely, a shipper that is long gas is paid the system marginal sell price (SMPsell) which is the lower of:

- the lowest price of any trade to which Transco is a party on the OCM, excluding any trades that it takes for locational reasons; and

- SAP minus a fixed value set at 0.0466/kWh, which is based on the price for delivering gas from the Hornsea storage site in 2000. As for SMPbuy, the SAP related price is the default SMPsell price if Transco does not sell any gas.

[65] After the day trading is a concept that does not exist in the electricity arrangements.
[66] That is, in each 24 hour period beginning at 6am each day.

The use of prices from the Hornsea storage site is intended to provide a suitable proxy for the costs of system flexibility.

Table 4.4 below shows average annual SMP Sell, SAP and SMP Buy values since 1 April 2001.

Table 4.4 – Average annual energy imbalance prices

(c/therm)	Average SMP Sell	Average SAP	Average SMP Buy
2001/02	25.97	27.67	29.27
2002/03	20.67	22.29	23.77
2003/04	27.82	29.54	31.13
2004/05	35.89	37.98	39.58
2005/06[67]	39.97	42.01	44.02

Imbalance tolerances

The introduction of the OCM and commercial incentives on Transco to reduce the costs of gas balancing was part of the New Gas Trading Arrangements (NGTA), which were introduced in stages from October 1999. The NGTA reforms also improved incentives on shippers to balance their own positions through a phased reduction of imbalance tolerances.[68]

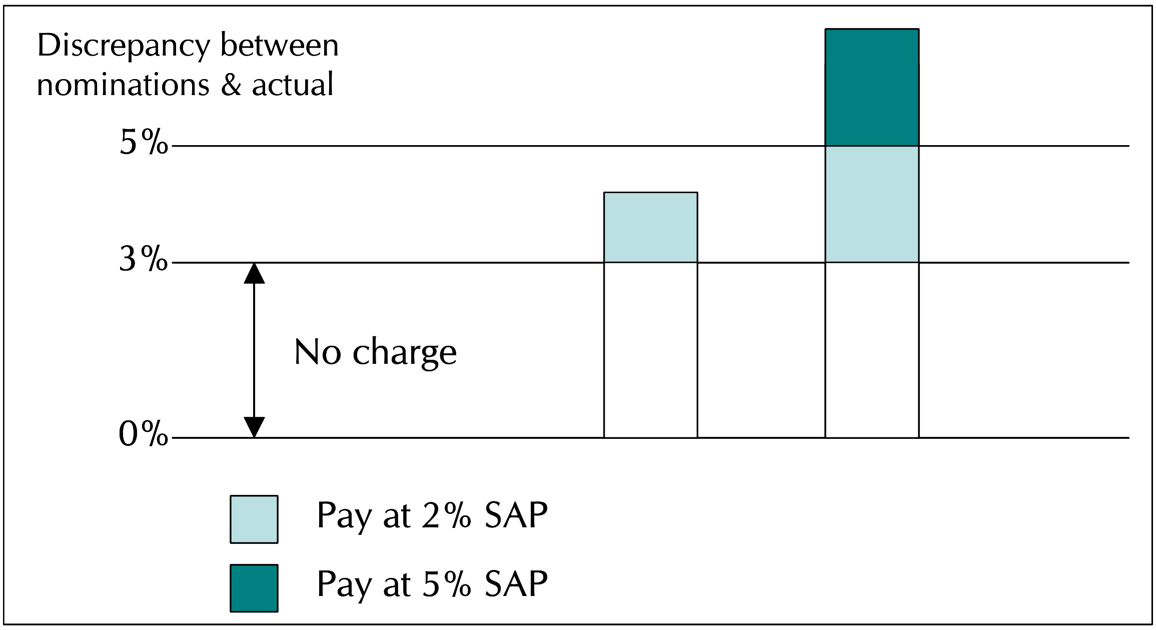
Since the introduction of the OCM there have been a number of modifications to the way in which cash out prices have been calculated. These include modifications for the removal of tolerances[69] and revised definitions of cash out prices.[70]

Scheduling charges

In addition to imbalance charges, the cash out arrangements in gas include a scheduling charge. The scheduling charge is designed to provide incentives for shippers to make accurate input and offtake nominations, irrespective of whether the nominations match. If a shipper's actual inputs or offtakes differ from its final nominations, it has to pay scheduling charges if the difference is greater than its scheduling tolerance. The rules for calculating input and output scheduling charges are different. Figure 4.1 illustrates how a shipper's input scheduling charge is calculated. Output scheduling charges are payable at 1 per cent of SAP outside the shipper's tolerance volume, with different tolerances applying to different types of exit points.

[67] 2005/06 data is from 1 April 2005 until 5 July 2005 inclusive.
[68] A shipper whose imbalance volume was less than its imbalance tolerance was exposed to an average rather than a marginal cash out price.
[69] On 1 October 2002, network code modification proposal 0511 "Removal of NDM forecast deviation from imbalance calculations" was implemented. This removed the last of the imbalance tolerances.
[70] On 1 April 2001, network code modification proposal 0433 "Changes to system cash-out prices" was implemented. This amended the cash-out arrangements to those described below.

Figure 4.1 – Calculation of input scheduling charges



Process for revising the cash out arrangements

Gas cash out prices are determined by rules set out in the UNC. Modifications to the UNC can be raised by any signatory to the UNC, which effectively means all shippers and transporters, and by certain designated consumer representatives. Ofgem cannot propose modifications. Any proposed modifications to the arrangements must be progressed through the UNC modification procedure. This involves assessing whether the modification would better facilitate achievement of the following objectives (which are included in Transco's public gas transporter's licence):

a.) the efficient and economic operation of the pipe-line system to which this licence relates;
b.) so far as is consistent with sub-paragraph (a), the coordinated, efficient and economical operation of (i) the combined pipe-line system, and/or (ii) the pipe-line system of one or more other relevant gas transporters;
c.) so far as is consistent with sub-paragraphs (a) and (b), the efficient discharge of the licensee's obligations under this licence;
d.) so far as is consistent with sub-paragraphs (a) to (c) the securing of effective competition:
    i. between relevant shippers;
    ii. between relevant suppliers; and/or
    iii. between DN operators (who have entered into transportation arrangements with other relevant gas transporters) and relevant shippers;
e.) so far as is consistent with sub-paragraphs (a) to (d), the provision of reasonable economic incentives for relevant suppliers to secure domestic customer supply security standards (within the meaning of paragraph 4 of standard condition 32A (Security of Supply – Domestic Customers) of the standard conditions of Gas Suppliers' licences) are satisfied as respects the availability of gas to their domestic customers; and
f.) so far as is consistent with sub-paragraphs (a) to (e), the promotion of efficiency in the implementation and administration of the network code and/or the uniform network code.

Reviews of modification proposals are normally channelled through the Modification Panel, which has been set up to ensure that all interested parties' views are represented. To allow decisions regarding modifications to be reached in a transparent and inclusive manner, a full consultation is carried out on each proposed modification. Following the consultation, a modification report is sent to Ofgem which contains the results of the assessment of the modification, the responses of market participants to the consultation and a recommendation from the Modification Panel to approve or reject the modification. The Authority then reaches a decision on whether to approve or reject the proposal – note that it cannot propose an alternative solution. In reaching its decision, the Authority carefully considers the proposed revisions within the context of the predefined objectives of the UNC (listed above) and, if appropriate, its wider statutory duties[71]. It is not required to accept the recommendation of the Modification Panel but must explain the reasoning underlining its decision. Ofgem's decisions on modifications to the UNC and the other industry codes can be appealed to the Competition Commission (for example, if Ofgem does not accept the recommendation of the Modification Panel).

Interaction between balancing areas

The GB national transmission system is interconnected with a number of other gas markets:

- Northern Ireland and the Republic of Ireland, which have a combined capacity of around 11,600mcm/year from Scotland to Ireland; and
- Belgium via the Bacton-Zeebrugge interconnector, which currently has an import capacity of around 8.5bcm/year, although this is being increased to 23.5bcm/year.

Further interconnectors are in development, which are discussed further in section 5.2. Given the increasing reliance on imports that the UK is likely to face in the coming years, interconnectors play an important part in delivering supplies to customers.

The process and timetable for settlement of imbalances

The first stage in the settlement process is to assign input and offtake volumes at each entry and exit point (distribution zone) to each shipper. This enables their imbalance volumes to be calculated and involves the collection, processing[72] and aggregation of meter data and nominations. These values are finalised on the 15th working day of the calendar month following that in which the relevant gas day occurs for injection data and 5 working days after the relevant gas day for offtake data. At the same time, the cash out prices have to be calculated from OCM trading data.

Following receipt of each party's reconciliations, the quantity associated with these reconciliations is calculated and assigned to a contract (System Clearing Contract) which is considered to have been entered into for the purposes of returning the relevant party to a balanced position.[73]

[71] Ofgem's statutory duties are wider than the matters that the Panel must take into consideration and include, amongst other things, its principle objective to protect the interests of consumers wherever possible through the promotion of effective competition.

[72] Most small consumers do not have meters that record their daily consumption values. Instead, Transco estimates these values.

[73] further detail may be found in section E of the UNC at http://www.gasgovernance.com/unc.asp

4.1.4 Access to storage, Linepack and other Ancillary services

Third party access (TPA) to storage in GB is implemented through national legislation passed before the Directive 2003/55/EC and through article 19 of the Gas Directive transposed into national law (sections 19A–D of the Gas Act 1986). The two largest storage facilities in GB and all LNG storage facilities provide TPA, with the other facilities being exempt from the requirement to offer TPA. Centrica provides negotiated TPA to the Rough storage facility under the Gas Act 1986 (and undertakings resulting from its purchase of the storage company (see below)). SSE provides negotiated TPA to the Hornsea facility under the Gas Act 1986. Transco (the owner of the high pressure national transmission system) provides TPA to its LNG storage sites by means of auctions which are regulated under the network code, indirectly via Transco's gas transportation licence, and the Gas Act 1986.

Table 4.5: Summary of services and nature of three largest storage facilities

Facility name	SSO	Services	Purpose
Transco LNG - Partington	Transco	Bundled services of space and injectability/deliverability a service which includes an obligation for the SSO to allocate the gas which has been nominated and injection and withdrawal are possible at any time	Short term storage facility
Rough Centrica Storage LTD	Centrica	Bundled services of space and injectability/deliverability a service which includes an obligation for the SSO to allocate the gas which has been nominated and injection and withdrawal are possible at any time	Long range storage facility
SSE Hornsea	SSE	offers bundled services of space and injectability/deliverability a service which includes an obligation for the SSO to allocate the gas which has been nominated and injection and withdrawal are possible at any time	Medium range storage facility

Technical information on all storage facilities is in Table 4.6 below

Table 4.6: Technical information on all storage facilities

Facility name	Owner	Space (GWh)	Deliverability (GWh/d)	Injectability (GWh/d)
Rough	Centrica Storage Limited	34835	455	160
Hornsea	Scottish and Southern Energy (SSE)	3422	195	21.6
Total TPA under Article 19		38257	650	181.6
TPA % share of total storage		88	53	66
Partington	Transco LNG	2087	219	2.4
Total 3 largest storage facilties		40344	869	184
3 largest % share of total storage		93	71	67
Other non-TPA storage:				
Hatfield Moor	ScottishPower	1260	25	25
Hole House	Energy Merchants Gas Storage (UK)	300	30	60
Avonmouth	Transco LNG	876	156	2.3
Glenmavis	Transco LNG	505	101	1.6
Dynevor Arms	Transco LNG	304	49	2.6
Total storage (non-LNG)		39817	705	266.6
Total storage (LNG)		3772	525	8.9
TOTAL STORAGE (ALL)		43589	1230	275.5

Centrica Storage Ltd is wholly owned by Centrica and operates physically, legally and financially separately from the rest of the Centrica group. Centrica group is a vertically integrated company with interests throughout the value chain. Transco LNG storage is a regulated and ring-fenced business unit within Transco. Transco is both the transmission asset owner and system operator of the National Transmission System in GB. SSE Hornsea Limited (SSEHL) is a legally distinct entity. In addition to the Hornsea facility SSE also has interests in the supply of gas to domestic and industrial customers. SSE is a vertically operated company in the electricity market with interests in the generation, distribution, transmission and supply of electricity.

As a condition of Centrica's acquisition of the Rough storage facility Centrica Plc and Centrica Storage Limited gave under takings to the Secretary of State for Trade and Industry Pursuant to Section 88 of the Fair Trading Act 1973 (With reference to the Enterprise Act 2002). Paragraph 5 and 6 of the undertakings state that Centrica must maintain legal, financial and physical separation between its storage business and all other parts of the group; ensure that no commercially sensitive information arising from the operation of Rough is passed to other parts of Centrica; and make any disclosure of information relating to the storage operations to all market participants simultaneously.

Non-discriminatory access to Transco's LNG sites is provided for under s19D of the Gas Act 1986, the network code, and indirectly through Transco's gas transportation licence.

Both Centrica Storage Limited and SSEHL are subject to the provisions of s19B of the Gas Act 1986 which provide for negotiated TPA on a non-discriminatory basis. There are no rules specifically addressing confidentiality of information, but this is covered by the terms of the respective storage contracts. The terms and conditions relating to storage use may be found at:

http://www.centrica-sl.co.uk/Storage/StorageServicesContract.html
http://www.scottish-southern.co.uk/ssegroup/SSEGasStorage/StorageServicesContract.asp

All of the storage sites offering TPA provide storage services on the basis of a standard bundled unit of space, deliverability, and injection. Firm and interruptible products are offered. In addition, unbundled rights may be traded on the secondary market.

The price of a SBU in the Rough storage facility is usually indexed to published summer\winter differentials in the price of gas. Transco LNG holds annual auctions for the sale of storage capacity on a pay as bid basis and publishes the weighted average price paid to the wider market. SSEHL does not publish prices, it negotiates with each customer on a case by case basis.

All sell capacity in a non discriminatory fashion to anyone who approaches them. Ofgem has not received any complaints that this is not happening. In the case of Rough a number of new entrants to both the gas and electricity markets have secured capacity.

4.1.5 Effective Unbundling

Unbundling requirements on the network companies

The licences of the NTS and the DNs (and shortly the IGTs) require that they:

- do not undertake transactions that create a cross-subsidy with another entity;
- only enter into agreements on an arms length basis and on normal commercial terms;
- carry out activities only for the purposes of gas transportation, metering and meter reading subject to the *de minimis* activities provisions which allow a small amount of non gas transportation, metering and meter reading activities to be undertaken.

Legal ownership for DSOs and TSOs

The fully integrated monopoly British Gas was privatised in 1986. In 1993, following a Monopolies and Mergers Commission report the company was re-structured. In 1997, the company demerged into two separate companies, BG plc and Centrica. Transco was part of BG plc and in 1999 Transco became a public limited company - BG Transco plc. In 2000, Transco demerged from BG plc and became part of the Lattice Group plc. In 2002, Lattice Group plc merged with National Grid to form National Grid Transco plc - the UK's largest utility. Transco is currently a wholly owned subsidiary of National Grid Transco.

Transco owns the NTS and has retained four DNs in Great Britain. Transco has a separate licence for the NTS business and the four retained DN businesses but there is no legal separation between the licensees. Special Conditions in the licences have been designed to replicate the effects of legal separation[74]. The other four DNs that were sold are owned by Scotia Gas Networks Ltd (who own two), Gas Networks Ltd and MGN Gas Networks Ltd. In addition, there are also fourteen licensed Independent Gas Transporters (IGTs).

Transco's NTS licence (but not the other gas transportation licences) contains conditions which have the effect of precluding Transco and any other related or affiliated company from having commercial interests in the sale of gas in GB, thereby guaranteeing the independence of the TSO from commercial interests in the wholesale market.

Ownership structure of TSOs and DSOs

Until 1 June 2005, Transco owned the vast majority of the gas network across Great Britain, constituting the NTS and eight DNs transporting gas to over twenty million customers across GB. In May 2003 NGT the owner of Transco plc announced it would consider the sale of one or more of its DNs if the transaction maximised shareholder value. On 1 June 2005 the transaction was completed having gained the consent of the Gas and Electricity Markets Authority.[75] The decision followed an extensive consultation process undertaken by Ofgem from July 2003[76].

---

[74] For the NTS business Special Conditions C19, C20 and C21 require business separation statements, appointments of compliance officer and separate managerial boards. The RDN Special conditions E9 and E10 in the licence seeks to ensure Transco NTS and Transco RDN act as separate entities and enter into quasi-contractual relationships.

[75] *National Grid Transco- Sale of gas distribution networks: Transco plc applications to dispose of four gas distribution networks, Authority Decision,* Ofgem, February 2005.

[76] *National Grid Transco- Potential sale of gas distribution network businesses, Final Impact Assessment,* Ofgem, November 2004, 255/04a. For other documents on the distribution network sale consultation process go to Ofgem's website www.Ofgem.gov.uk and select under Area of Work: gas distribution network sale.

Transco retained four of the DNs that cover the East of England, London, North West and West Midlands areas. The Independent DNs are those covering Scotland, North of England, Wales and West and South of England. The three purchasers were Scotia Gas Networks Ltd, Gas Networks Ltd and MGN Gas Networks Ltd. Scotia Gas Networks Ltd own both the Scotland and the South of England DNs.

There are currently approximately six hundred thousand customers connected to IGTs. This figure is projected to increase to one million by 2008.[77]

Independence of production and supply affiliates

The licence of the national transmission system operator prevents the licensee and all affiliated companies from having an interest in gas supply or trading (except for system balancing purposes).

The transportation licences of the NTS and the eight DN companies require full managerial and operational systems independence preventing any relevant supplier or shipper, any trading business, its meter-related service business, and its meter reading business from having access to confidential information except in certain specified circumstances. The network company must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas or the shipping of gas or the generation of electricity.

With the exception of Scottish and Southern Energy, the owners of the NTS and DNs do not have production or supply affiliates.

The NTS and the DNs are required by their gas transportation licence to use best endeavours to comply with a statement that they produce setting out how it intends to comply with, amongst other things, the requirement not to restrict, prevent or distort competition.[78] This compliance statement must also set out how the licensee shall maintain the branding of the transportation business so that it is fully independent from the branding used by any relevant supplier or shipper, trading business, its meter-related services business and its meter reading business (Ofgem may consent to a relaxation of this requirement).

Ofgem has not been required to address in detail the issue of branding separation between a gas transporter and a relevant gas supplier. However, during 2003 and early 2004 several energy groups owning both electricity distribution and supply businesses proposed changes to their supply and/or distribution brands. In many cases these proposals reduced the difference between the branding of their respective supply and electricity distribution businesses. Some of these proposed changes have now been implemented. These changes gave rise to concerns that competition in energy supply may be adversely affected by the re-branding that was occurring. In response to these concerns, Ofgem reviewed whether the approaches to branding by a number of distribution licensees with supply businesses complied with the relevant electricity distribution licence condition concerning brand separation. As part of this review, it was necessary to consider what, if any, the effect of any similarity of any such branding may have had on competition. Further information on this issue may be found in section 3.1.4.

[77] Transco data 2004.
[78] Standard Special Condition A33: Restriction on Use of Information and Independence of the Transportation business.

The NTS and the DN licensees (and shortly the IGTs) have financial ring-fence conditions in their licence. One of these conditions has the effect, subject to a *de minimis* provision, of restricting the business activities that the company can carry out, to those for which it is licensed e.g. gas transportation. As a consequence, each company's company law accounts will largely only include the activities of the network company. In addition for Transco's NTS and the eight DNs, the licenses also include specific regulatory accounts conditions. For example, amongst other things, these conditions require that the regulatory accounts are published, are subject to audit requirements and must be accompanied by an audit opinion, addressed to the Authority, from an appropriate auditor setting out that the accounts have been prepared in accordance with the requirements of the relevant network licence. For Transco's NTS and the eight DNs, Ofgem has also introduced another licence condition in relation to price control review information that requires the companies to prepare detailed information on their activities in accordance with published guidelines[79]. Ofgem is now developing these accounting and reporting guidelines.

The prohibition of cross subsidies licence condition[80] in the gas transporters licences requires that there cannot be cross subsidies between the licensee and any other affiliate or related business of the licensee. In addition, it also requires that there cannot be cross subsidies between the four DNs retained by Transco.

Role of the compliance officer

The NTS and the DNs are required by their licences to have a compliance officer[81] whose duties include facilitating compliance by the licensee with the licence conditions relating to the restriction on the use of certain information and the independence of the transportation business[82].

The NTS and the DN licensees must maintain managerial and operational systems preventing any relevant shippers, relevant suppliers, any trading business, its metering services and its meter reading businesses having access to confidential information except in certain specified circumstances (which are set out in the licence). The transportation business must always be managed and operated to ensure it does not restrict, prevent or distort competition in the supply of electricity or gas, the shipping of gas, generation of electricity, any trading business or the supply of meter-related services or meter reading.

Shared costs and outsourcing

In setting price controls for the NTS and the DN companies an important issue for Ofgem to consider is the costs that the network company shares with other companies in its group e.g. head office costs and the activities it outsources to other entities. However, Ofgem leaves it to the NTS or DN company concerned to determine how it organises its business in relation to the outsourcing of work and sharing of common costs, subject to them remaining compliant with their licence which requires them:

- not to undertake transactions that create a cross subsidy with another entity;

[79] Standard Special Condition A30: Regulatory Accounts. Part C.
[80] Standard Special Condition A35: Prohibition of Cross Subsidies.
[81] Standard Special Condition A34. Appointment of the Compliance Officer.
[82] Standard Special Condition: A33. Restriction on Use of Information and Independence of the Transportation business.

- to only enter into agreements on an arms length basis and on normal commercial terms; and
- to carry out activities only for the purposes of gas transportation, metering and meter reading subject to a *de minimis* limit.

Failure to comply with management or accounts unbundling requirements

If a gas transporter breaches its licence, Ofgem can take enforcement action. Enforcement action for a breach of a licence could include, after going through due process, the imposition of a financial penalty on the licensee. The financial penalty cannot exceed 10% of the gas transporters annual turnover.

Further reading

Review of Transco's Price Control from 2002, Final Proposals, September 2001

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/9416_26504.pdf

The role of regulatory accounts in regulated industries, final proposals, April 2001

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/219_10april01.pdf

Regulatory Accounts, Final Proposals, November 2000

http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/221_29nov00.pdf

4.2 Competition Issues

4.2.1 Description of the wholesale market[83]

The GB wholesale market is based on bilateral trading between gas producers, shippers, suppliers, traders and customers across a series of markets. Broadly speaking, the wholesale market can be broken down into over the counter trading and power exchange trading.

Over the counter trading (OTC)

Over the counter trading encompasses both bilateral deals struck directly between two market participants and brokered deals, where an intermediary (the broker) brings together a buyer and seller. OTC trading typically operates from a year or more ahead of real time up until 24 hours ahead of real-time. Examples of typical contracts include annual contracts (contracts for the delivery of a given volume of gas at a specified price throughout a year), seasonal contracts (summer/winter), quarterly contracts and monthly contracts. However, this market is also used for non-standard contracts designed to match a consumer's anticipated demand profile.

Exchanges, including the OCM

Although trading on exchanges can extend out as far as the contract market, trading on them tends to be concentrated towards real-time. Shippers trade short term on the exchanges to keep in balance as their demand and supply forecasts become more accurate in the run-up to real time. Trading on exchanges is via a set of standardised contracts. For example, the IPE trades the following contracts:

Season contracts
- strips of six individual and consecutive contract months. Season contracts are always an (April - September) strip or (October – March) strip.

Quarter contracts
- strips of three individual and consecutive contract months. Quarter contracts always comprise a strip of (Jan - Feb - Mar) or (Apr - May - Jun) or (Jul - Aug - Sep) or (Oct - Nov - Dec).

Month contracts
- strips made up of individual and consecutive calendar days. A monthly contract is 28, 29, 30 or 31 individual day contracts, determined by the precise number of calendar days in the month. Month contracts are listed 9, 10 or 11 consecutive months into the future.

Balance of the Month (BOM) contracts
- a string of individual day contracts with the precise number determined by the number of days still outstanding in the current month. The BOM contract therefore reduces in size on a daily basis, generating a daily contract representing the delivery obligation of that day. Only one BOM contract is listed for any unexpired days remaining in the current month.

[83] Defined as covering any transaction of gas between market participants other than final end use customers.

Day contracts

- listed from day ahead (D-1) to seven days ahead (D-7).

Wholesale gas market – indicators to be reported

Consumption and demand

Transco's Ten Year Statement[84] provides information in relation to forecast and actual annual gas demand. For 2004/05, annual actual (not weather-corrected) gas demand was 104.7 bcm. This represented a decrease of 0.5 bcm from 2003/04.

Gas supply

Information in relation to actual and forecast annual gas supplies is also provided in Transco's Ten Year Statement. For 2004/05, Transco anticipated that 91.8 bcm would be provided by beach supplies i.e. UK Continental Shelf (UKCS) production and the remaining 12.9 bcm by imports[85].

Apart from imports from the Norwegian North Seas, which reach GB via dedicated lines, it is difficult to determine the ultimate source of the GB's pipeline imports because gas arrives at Zeebrugge from many different locations. From 2005/06 onwards, GB will also be importing LNG via a number of terminals that are being developed (the first, at the Isle of Grain, received its first supplies in July 2005).

In terms of gas production, 7 companies have market shares of at least 5 per cent and the largest three companies have a combined market share of 36.3 per cent. Information on the proportion of production and import capacity allocated to the largest three companies is not available.

Gas production in GB is largely dominated by the oil majors. Consequently, seven of the largest ten production companies are not British (and non-European) and one, Shell, is an Anglo-Dutch company. There are also numerous smaller foreign players. These companies participate in the GB markets in a host of different ways.

Volume of gas traded

Exchange trade

Trade on the International Petroleum Exchange (IPE) reached 648,665 lots in calendar year 2004. In physical terms, total traded volume amounts to around 55.3bcm – equivalent to around 579.8 TWh.

On-the-day-commodity market trade

Trade on the OCM in calendar year 2004 summed to around 105.3TWh. This trade comprised around 90.2TWh of "Within-day" trade and around 15.1TWh of "Day-ahead" trade.

---

[84] References to Transco's Ten Year Statement refer to the version published in December 2004, which is available at http://www.transco.uk.com/.
[85] Anticipated actual supply is provided in figure 4.6B of Transco's Ten Year Statement.

Over-the-counter trade

On the basis of information provided by the price reporter Here, trading in over-the-counter gas products in calendar year 2004 amounted to some 488 TWh. The two most popular packages traded during this period were "Q4 '04 + Q1 '05" and "Q2 '05 + Q3 '05", recording around 70 TWh and 49 TWh respectively. Other notable packages include the well traded "Within-day" with 25 TWh and "Day-ahead" with 21 TWh.

Trading Platform trade

Volumes traded over the Spectron online platform for the last six months of 2003 amounted to a little over 548 TWh (Ofgem does not have a complete up-to-date dataset for Spectron trades).

Long-term contract trade

Ofgem has no non-confidential information on the extent of long-term contracts.

Member State integration

The GB market is becoming increasingly reliant on imports from other countries, given that its demand for gas is now outstripping its domestic supplies. At present, the UK/Zeebrugge interconnector allows up to 20bcm/year of exports from and around 8.5bcm/year in imports into the UK. The import capacity of the UK/Zeebrugge interconnector is being increased over the coming years to 23.5bcm/year and another interconnector, the BBL, is planned to come on-stream in 2006/07 with a capacity off 15bcm/year.

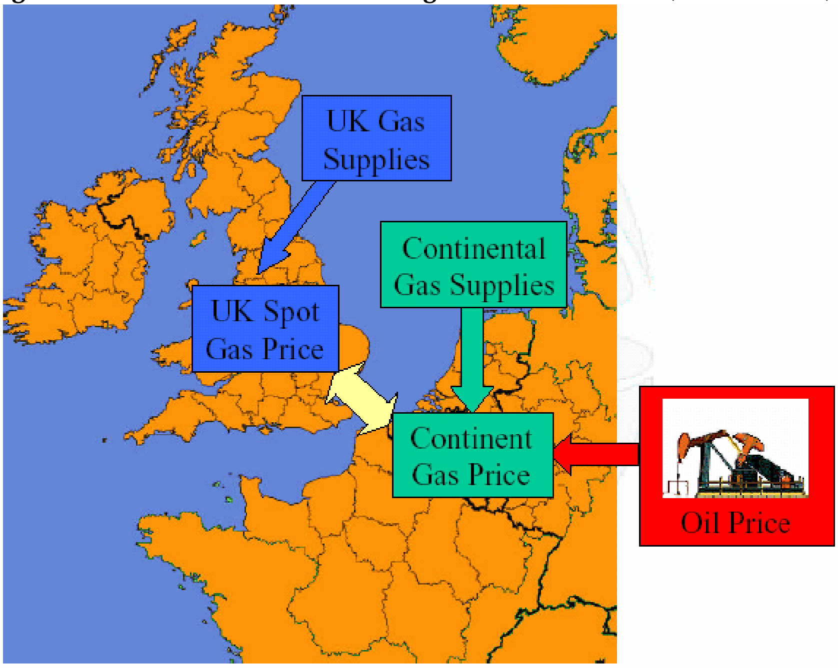
In terms of the UK/Zeebrugge interconnector, each shipper has a share of the Forward Flow and Reverse Flow Standard Capacity. Originally, 9 Shippers acquired Capacity Rights in the UK/Zeebrugge interconnector for a period of 20 years from 1 October 1998 through to 30 September 2018. These Capacity Rights can be permanently transferred (in whole or in part) to another party through an Assignment, or temporarily transferred to another party for a specified period of time via either a Sub-Let or a Capacity Transfer[86]. Currently 16 Shippers hold primary capacity rights to the interconnector.

Although on aggregate the Interconnector is either in Forward Flow or Reverse Flow, an individual Shipper can utilise their Capacity Rights in the opposite direction such that they are "flowing" as a counter-flow. Subject to the physical Flow Direction of the Interconnector and operational conditions, Interconnector UK (IUK) may make additional Interruptible Capacity available to Shippers. Interruptible Capacity is shared between Shippers in proportion to their Standard Capacity.

Given the existing interconnection, prices in the GB gas market are often correlated with those on continental Europe, which, in turn, are typically linked to oil-product prices. However, when the interconnector is full (for either imports and exports) or not operational, GB prices can de-couple from those elsewhere in Europe.

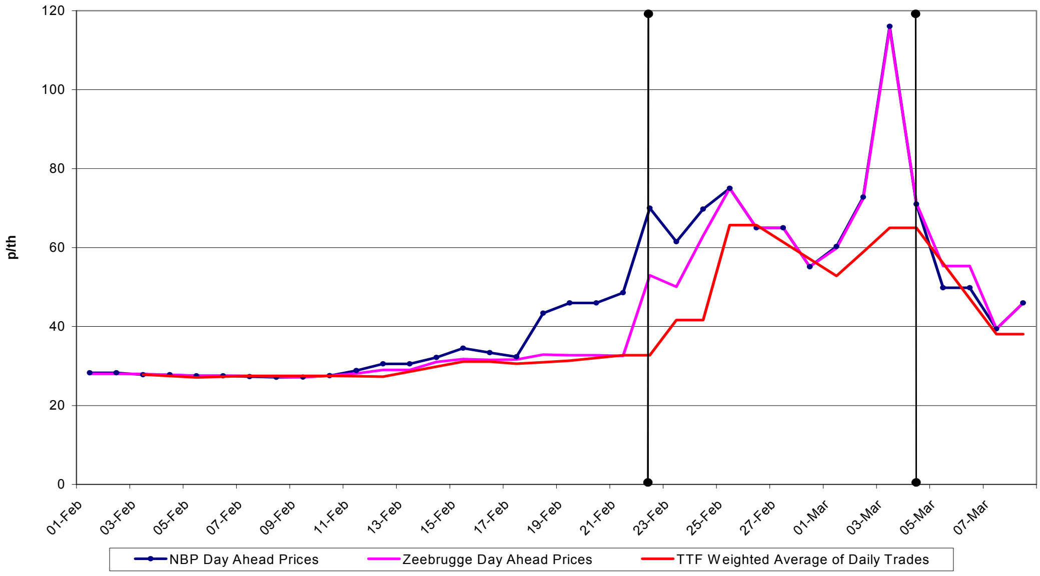
[86] See http://www.interconnector.com for more details.

Figure 4.2 – Interconnector UK high level schematic (source: IUK)



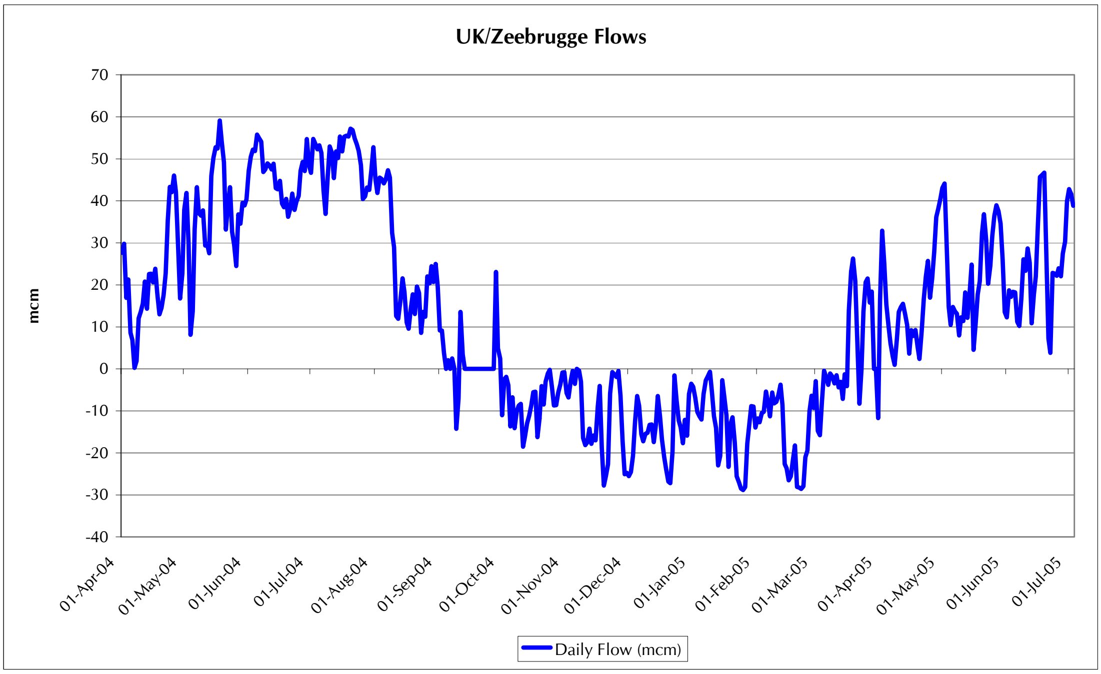
To illustrate the substantial correlation between UK and continental gas prices, figure 4.3 depicts the daily day-ahead price both at the National Balancing Point (NBP) and at the Zeebrugge hub.

Figure 4.3 – UK and continental day-ahead gas prices (source: Heren)



In terms of the volumes of imports and exports between the UK and continental Europe, figure 4.4 shows daily flows across the UK/Zeebrugge interconnector between April 2004 and the beginning of July 2005. The chart indicates that, following the typical pattern, the interconnector is used to export gas from GB over the summer but is used for imports over the winter.

Figure 4.4 – Daily flows on UK/Zeebrugge Interconnector (source: IUK)[87]



Conduct in the wholesale gas market

Competition law

Ofgem's competition law powers are set out in section 2.

Shippers' licence

In addition to the Ofgem's powers to apply its powers under the CA98 in relation to potential anti-competitive behaviour, the licences of gas shippers prohibit certain types of anti-competitive conduct on the part of gas shippers. In particular, there is a prohibition on knowingly or recklessly pursuing any course of conduct that is likely to prejudice the safe and efficient operation by a relevant transporter of its pipe-line system, the safe, economic, and efficient balancing by that transporter of its system, or the due functioning of the arrangements provided for in the UNC.

Availability of gas to the market

Whilst all market participants who wish physically to transport gas on the NTS require a shipper's licence to do so, they are able to participate on the traded markets, simply by signing up to the UNC and agreeing to abide by its balancing provisions. It is through access to the traded markets that non-incumbents, including new entrants, can purchase gas. There are no other mechanisms (such as gas release programmes) to ensure the availability of gas to non-incumbents – given the volumes of gas that are traded on a daily basis, there is no need for such interventionist measures.

[87] Please note that positive values indicate forward flows out of the UK to the continent.

Transparency

As discussed above, the shippers' licence prohibits shippers from providing a false impression of the amount of gas they will deliver. There are also licence conditions requiring shippers to provide information to the relevant transporter with regard metering, premises served and gas illegally taken.

Market participants have to provide operational data i.e. on their intended inputs to and offtakes from the NTS, under the terms of the UNC. For customers without daily meters, the TSO is responsible for producing demand forecasts and nominations, against which their imbalances are measured.

In terms of gas nominations, users will nominate quantities of gas for delivery to and offtake from the transmission system each day in accordance with the UNC for the purposes of enabling Transco NTS to plan and carry out the operation of the NTS and Operational Balancing.

The following timetable, as detailed in section C of the UNC provides the key points in the preceding gas day by which users are required to provide certain nomination information for the following gas flow day.

Table 4.7 – nomination timetable (source: Joint Office of Gas Transporters (UNC))

Daily Metered Output Nomination Time:	13:00
Non-Daily Metered Output Nomination Time:	14:00
Input Nomination Time:	16:00
Scheduling Start Time:	16:00
Nomination Finalisation Time:	17:00
Renomination Start Time:	17:30

A recent DTI information initiative, focused on communications information release between the offshore and onshore gas industries, resulted in a voluntary arrangement for the disclosure of offshore information. The implementation of the DTI information initiative has been split into three phases. These are summarised in Table 4.8 below.

Table 4.8 – Summary of DTI information initiative

Phase/category	Information	Recipient	Timing	Aggregation	Publication
Phase 1	Demand Forecasts; Indicated Demand, Generation and Imbalance; System Information, Price.	Producers to Transco NTS	Ahead of day, daily, monthly	Aggregation on zonal, national and system basis	11 November 2003
Phase 2	Field data, annual production, peak production, gas quality, annual delivery, peak delivery, maximum capacity, delivery profile	Producers and terminal operators to Transco NTS	Voluntary questionnaires sent out annually as part of annual NGT's Ten Year Statement consultation process	Aggregation on terminal, zonal, national and system basis	NGT 2004 TBE[88] Ten Year Statement
Phase 3 Category 1	Real time flows into the NTS	Transco NTS to the market	Hourly[89]	Aggregation on national and zonal[90] basis	July 2005
Phase 3 Category 2	Forecast flows into the NTS	Transco NTS to the market	Ahead of day Updated hourly through the day	Aggregation on national and zonal basis	Q1 2005
Phase 3 Category 3	Deliverability, reflecting planned maintenance	Transco NTS to the market	Ahead of time Quarterly, with material updates as they become known to Transco NTS	Aggregation on national and zonal basis	1 October 2004
Phase 3 Category 4	Daily flows into the NTS	Transco NTS to market	Daily at 16:00 hours on D+1	By sub-terminal	1 October 2004

[88] Transporting Britain's Energy.
[89] Originally these flows were to be made available on a real time basis, however, it was subsequently agreed that they would be made available hourly.
[90] Aggregation to be done into two zones, "north" and "south". North comprising of St. Fergus, Barrow, Teesside, Burton Point, Partington and Glenmavis, south comprising of Easington (including Rough), Theddlethorpe, Bacton, Isle of Grain, Dynevor, Avonmouth and Hornsea.

Market surveillance

Ofgem's market surveillance teams monitor the gas and electricity markets, including the wholesale gas market. They routinely assess whether there is any evidence of anti-competitive behaviour or breaches of statutory provisions. On the basis of active surveillance and monitoring of the markets, Ofgem can investigate the behaviour of market participants if anti-competitive conduct is suspected and, where necessary, enforce domestic and European competition law.

Additionally, the Financial Services Authority (FSA)[91] has responsibilities for the operation of financial markets in the UK. The FSA works to prevent abuse or distortion of financial markets, including power exchanges such as the IPE. The FSA has the power to fine persons who have abused the market, where "market abuse" is defined under the Financial Services Market Act 2000.

4.2.2 Description of the retail market

There are currently six large supplier groups in the gas domestic market which reflects consolidation in the retail market. These groups are the same as the six largest domestic suppliers in the electricity market.

End users in the energy market are classified by the Utilities Act 2000 are classified according to the purpose of their energy use rather than by the amount of energy they consume. Customers classified as domestic use energy for domestic purposes at domestic premises and those classified as non domestic customers use energy for business and industrial purposes.

There are approximately 21 million domestic customers with gas in GB of which, the six supply groups account for about 99% of the market. There are also a few independent companies involved in domestic gas supply, although these have less than 1% market share between them.

Table 4.9 below shows the most recent national market share data of the supplier groups in gas.

Table 4.9: GB gas supplier groups – national market share (March 2005)

Group	Gas
Centrica	54%
Powergen	14%
SSE	9%
npower	9%
EdF	5%
Scottish Power	9%

Source: gas suppliers

Ofgem's last recent review of the non domestic gas supply sector conducted in July 2003 concluded that the non domestic sector was broadly competitive and did not require continued detailed monitoring.[92] Ofgem has acquired data on the gas non domestic sector from a third party.

[91] http://www.fsa.gov.uk/
[92] Review of competition in the non-domestic gas and electricity supply sectors, Initial findings 72/03.

Table 4.10: market share of large gas suppliers by volume supplied (Nov 2004)

	Small firm	large firm	Interruptible
Powergen	24.07%	15.32%	5.10%
Centrica	21.46%	14.00%	9.56%
Shell Gas Direct	16.05%	15.13%	9.15%
TotalFina Elf	13.81%	23.43%	21.60%
Npower	6.10%	3.21%	3.18%
GdF	4.57%	11.63%	18.98%
BP Gas	-	6.77%	15.21%
Statoil UK	-	6.98%	13.29%

Source: Datamonitor

Market shares and new entry

In domestic gas, there are six large supplier groups all with a share of above 5%. There has been a significant level of new entry into this market since market opening. The former monopoly electricity suppliers have been the most successful entrants, although there has been successful independent entry as well. At present there are two independent companies in the domestic gas market. These companies have achieved growth organically by gaining their customers rather than acquiring them.

The number of independent suppliers since the introduction of competition has fallen significantly. Penetration by the independent entrants has been on a relatively smaller scale compared to the large supplier groups. They account for just less than 1 percent of the national gas domestic market. The market share of the top three domestic suppliers, Centrica, Powergen and npower is 77%.

The Gas Act 1995 separated the activities of gas transportation from gas shipping and gas supply. Therefore, a transportation licence holder cannot hold either a shipper or a supply licence (the operator of the national gas transmission system, Transco, cannot hold shipping or supply licences anywhere within its overall group structure; other holders of transportation licences (ie, the gas distribution companies) can hold such licences within the same wider corporate group, but not within the same legal entity).

There have not been any new entrants with affiliations to gas TSO's or DSO's. There have been about twenty new entrants including all the former monopoly electricity suppliers since the introduction of competition.

Vertical integration

Five of the six large gas suppliers in the domestic market have gas production interests; either contractually or by equity. In the non domestic market, all the large suppliers are gas producers.

Estimates of customer switching

Ofgem collects data on the number of customers switching between suppliers in the market. We therefore do not have switching data by volume.

The most recent estimate available on the level of switching in the domestic gas market since the opening of the market is obtained from a customer survey carried out in March 2005. In gas, 47% of customers have switched in total since market opening.

Customers switch to and from incumbents to new entrants and also between new entrants themselves. On average 300,000 customers change supplier every quarter in the market. Table 4.11 below shows the number of domestic customers who switched in gas over the last 12 months.

Table 4.11: Domestic gas customers who have switched (March 2005)

	Gas
Apr-04	283,025
May-04	265,796
Jun-04	296,992
Jul-04	275,282
Aug-04	260,536
Sep-04	275,701
Oct-04	338,054
Nov-04	370,006
Dec-04	330,206
Jan-05	281,108
Feb-05	180,984
Mar-05	301,525

Source: Gas suppliers

Summary of switching procedures

The rules and processes used with regard to customer switching in the gas market are found predominantly in a supplier's Standard Licence Conditions, the Unified Network Code, and its subsidiary documents.

Once the terms and conditions for supply are agreed, the customer has a period of time to consider the contract and decide whether to cancel it – the Cooling Off Period. This period is a legal obligation with regard to domestic customers and is seven business days. However, many domestic suppliers have extended this period to 14 days and some I&C suppliers have also adopted the cooling off period. If the customer does not cancel the contract, the new supplier (via its shipper) notifies the relevant transporter of the intended transfer. The transporter performs a simple validation check and if successful contacts the old supplier to notify them of the specific meter point (MPRN – meter point registration number) to be transferred and the intended supply start date. The old supplier then has seven business days to object to the transfer. If no objection is raised then the transfer and intended supply start date are agreed. The last task the new supplier must complete is to procure and submit a change of supplier meter reading that falls within +/- 5 working days of the Supply Start Date (SSD) by SSD +10 days.

Competition issues

Ofgem does not presently have any information to suggest that the retail market is foreclosed by long-term contracts.

Ofgem presently has no evidence of anti-competitive bundling or discriminatory practices in the gas retail market. Ofgem has concurrent powers with the OFT to apply and enforce the Competition Act 1998 (CA 98). Ofgem along with the OFT has issued advice and information explaining how the CA 98 will be applied and enforced in the energy sector. This document is available on the OFT website at:

http://www.oft.gov.uk/NR/rdonlyres/9BB4783C-1805-4DBE-8BE5-B507D11FCECE/0/oft428.pdf [93]

Current retail price levels

Centrica is the incumbent in the domestic market. The incumbent final bill for an average domestic customer is about £503. However, competitors' bills can be up to £60 cheaper. Suppliers offer three main methods of payment; prepayment, standard credit and direct debit. Direct debit, tends to be the cheapest of the payment methods.

Table 4.12: GB domestic gas annual bills[94]

	GB Range	Incumbent	Best Offer
Direct Debit	€554–€721	€654	€554
Standard Credit	€635–724	€724	€635
Prepayment	€609–740	€724	€609

Source: Ofgem

Table 4.13 below provides the estimated breakdown of the costs that make up the final average domestic gas bill. Cost of gas here includes storage costs, transportation and metering costs make up the network costs element of the bill. The Energy Efficiency Commitment[95] is part of the government's climate change programme. Supply costs consist of marketing, billing etc. and also include the supply margin. All energy bills are subject to 5% VAT.

Table 4.13: Estimated breakdown of domestic gas bill[96]

Components of bill	**Proportion of bill**
Cost of gas	49%
Transportation and metering costs	32%
Energy Efficiency Commitment	1%
Supply costs and margin	12%
VAT	5%

93 OFT Competition Law Guidelines: Application in the energy sector.

94 Based on 23260kWh annual consumption

95 This is an estimate of how much it costs a supplier per customer per fuel to meet their EEC which is set by the Department for the Environment, Food and Rural Affairs (DEFRA).

96 Ofgem's April 2004 publication; Domestic Competitive Market Review has a more detailed discussion of the bill breakdown.

The pricing information provided in Table 4.14 is obtained from Cornwall Energy Associates. These prices represent Cornwall Energy Associates' assessments of delivered gas prices to industrial and commercial customer types in Great Britain for annual supply arrangements commencing April 2005.

Table 4.14: Assessed prices for year long contract from April 2005 – gas

	c/kWh
Small Commercial (38 MWh per year)	3.03
Medium Commercial (352 MWh per year)	2.83
Interruptible (58,614 MWh per year)	2.14

Source: Cornwall Energy Associates

The price assessments are provided on a per unit basis and reflect the total costs of the energy supply chain from wholesale energy market to customer meter. The breakdown of these costs is provided in table 4.15 below.

Table 4.15: Breakdown of gas prices

	Wholesale Costs	Network Costs	Supply Costs & Margin	Taxes & obligations
Small Commercial (38 MWh per year)	64%	21%	8%	7%
Medium Commercial (352 MWh per year)	69%	16%	8%	8%
Interruptible (58,614 MWh per year)	91%	6%	1%	2%

Source: Cornwall Energy Associates

The wholesale cost of gas is the largest proportion of bills across all three consumption levels. As consumption rises, this cost takes a larger proportion of bills. Supply costs and grid costs take on a smaller proportion of bills as consumption rises. Note that the largest consumers are assumed to benefit from an 80% discount on the Climate Change Levy.

Supply price controls were completely lifted in April 2002. Prices in the retail market are determined in the market although a proportion of the bill consists of regulated end-user tariffs such as transportation and metering costs.

5 Security of Supply

5.1 Electricity[97]

Ongoing supply-demand situation

Peak electricity demand conditions

NGC's Seven Year Statement[98] provides information in relation to outturn and forecast peak electricity demand levels. In its latest statement, NGC outlines that actual GB peak demand in the winter of 2004/05 (at 59.9-GW) was 100MW higher than in the previous winter, but was 700MW lower than in 2002/03. Correcting historical actual demands to Average Cold Spell (ACS) conditions eliminates the weather effects and gives a better indication of the underlying pattern of annual peak demand. Correcting winter weekday demands to ACS conditions yields a provisional peak of 61.5GW in 2004/05, reflecting growth of 700MW on the 2003/04 ACS outturn, and 1.5GW on 2002/03.

On the basis of the information provided in NGC's Seven Year Statement, current levels of peak electricity demand and expectations up until 2008/09 are shown in Table 5.1.

Table 5.1 – ACS peak demand forecasts (source: NGC Seven Year Statement, table 2.1)

Forecast	2004/05	2005/06	2006/07	2007/08	2008/09
ACS Peak Demand incl Station Demand (GW)	61.5	62.6	63.8	64.8	65.7
ACS Peak Demand excl Station Demand (GW)	61.0	62.1	63.3	64.3	65.2

[97] This section may make reference to supply demand forecasts compiled by TSOs where appropriate
[98] References to NGC's Seven Year Statement refer to the version published in May 2005, which is available at http://www.nationalgrid.com/uk/library/documents/sys05/default.asp.

Generation capacity

NGC's Seven Year Statement provides information in relation to the Transmission Entry Capacity (TEC)[99] at each power station for each year between 2005/06 and 2011/12. On the basis of the information provided in NGC's Seven Year Statement, TEC expectations up until 2008/09 are shown in Table 5.2.

Table 5.2 – Power Station Transmission Entry Capacities (source: NGC Seven Year Statement, table 3.5)

	2005/06	2006/07	2007/08	2008/09
TEC (GW)	77.4	77.7	83.8	85.8

Generation investment

Section 36 of the Electricity Act 1989 specifies that a generating station of over 50MW capacity shall not be constructed, extended or operated except in accordance with a consent granted by the Secretary of State within England and Wales and the Scottish Executive in Scotland. The relevant office takes into account views on particular applications, including views of the local planning authority and, in certain circumstances, may call a public inquiry into a proposal. When granted, consent lasts for five years within which time a project must show signs of construction.

Generation projects also require consent under Section 14 of the Energy Act 1976:

- Section 14(1) prohibits the establishment or conversion of an electricity generating station fuelled by oil or natural gas unless notice has been given to the Secretary of State. The Secretary of State may direct, having regard to current energy policies, that the proposal not be carried out or be carried out in accordance with specified conditions.

- Section 14(2) makes similar provisions in respect of the making or extension of contracts for obtaining of natural gas to such a station. Stations less than 10MW, and contracts of up to a year's duration, are exempted by Orders under the Act.

- Section 14(3) allows the Secretary of State to halt any proposals notified to him, if he considers it expedient, having due regard to current energy policy. This clause may be exercised, for instance, to prevent a project being built which has had Section 36 consent for five years but which, in the opinion of the Secretary of State, has shown no evidence of construction.

The Seven Year Statement prepared by NGC provides details of those generation projects for which Section 36 consent has been granted as well as details of those generation projects for which Section 36 consent is being considered. 17,650 MW of new generating capacity has been proposed, of which 8,819 MW has Section 36 consent. Only one station (a 3 MW hydro plant) has been refused Section 36 consent. Wind farms (both on- and off-shore) account for 5,941

[99] The Transmission Entry Capacity of a power station is the maximum amount of active power deliverable by the Power Station at the Grid Entry Point (or in the case of an Embedded Power Station at the User System Entry Point), as declared by the Generator, expressed in whole MW. The maximum active power deliverable is the maximum amount deliverable simultaneously by the Generating Units and/or CCGT Modules less the MW consumed by the Generating Units and/or CCGT Modules in producing that active power and less any auxiliary demand supplied through the station transformers.

MW of the proposed capacity, whilst the capacity of proposed CCGT's is 8,885 MW plus 1,413 MW of CHP projects. The remaining proposed capacity is split between hydro (134 MW), solid fuels of various types (1040 MW), other renewables (77 MW) and an OCGT (160 MW) that is currently on hold.

The NGC Seven Year Statement also provides information in relation to forthcoming generation projects which are actually in the process of construction. As can be seen from Table 5.3 below, a total of 1779MW of new generation capacity will be completed over the next three years.

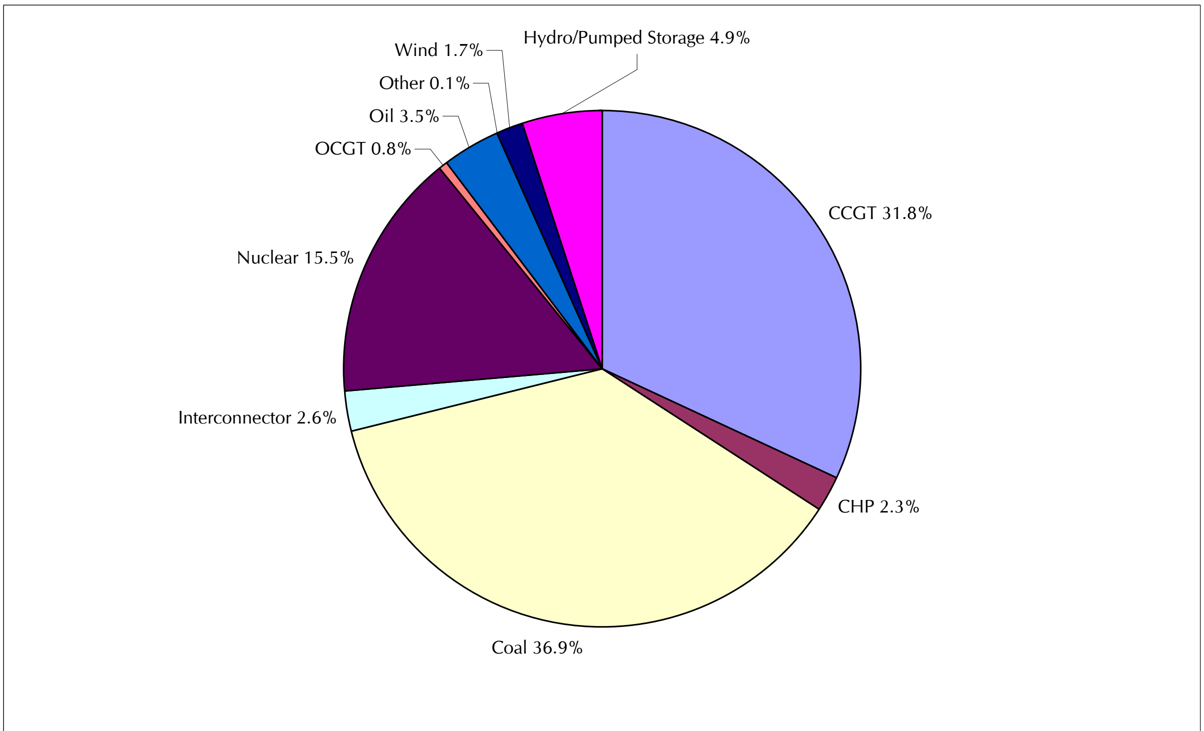
Table 5.3 – Changes in Power Station Capacity (TEC (MW)) (source: NGC Seven Year Statement, table 3.7)

Station Name	2006	2007	2008
Hadyard Hill windfarm	144	0	0
Heysham Offshore Windfarm	140	0	0
Marchwood CCGT	0	935	0
Immingham CHP stage 2	0	560	0

Generation mix

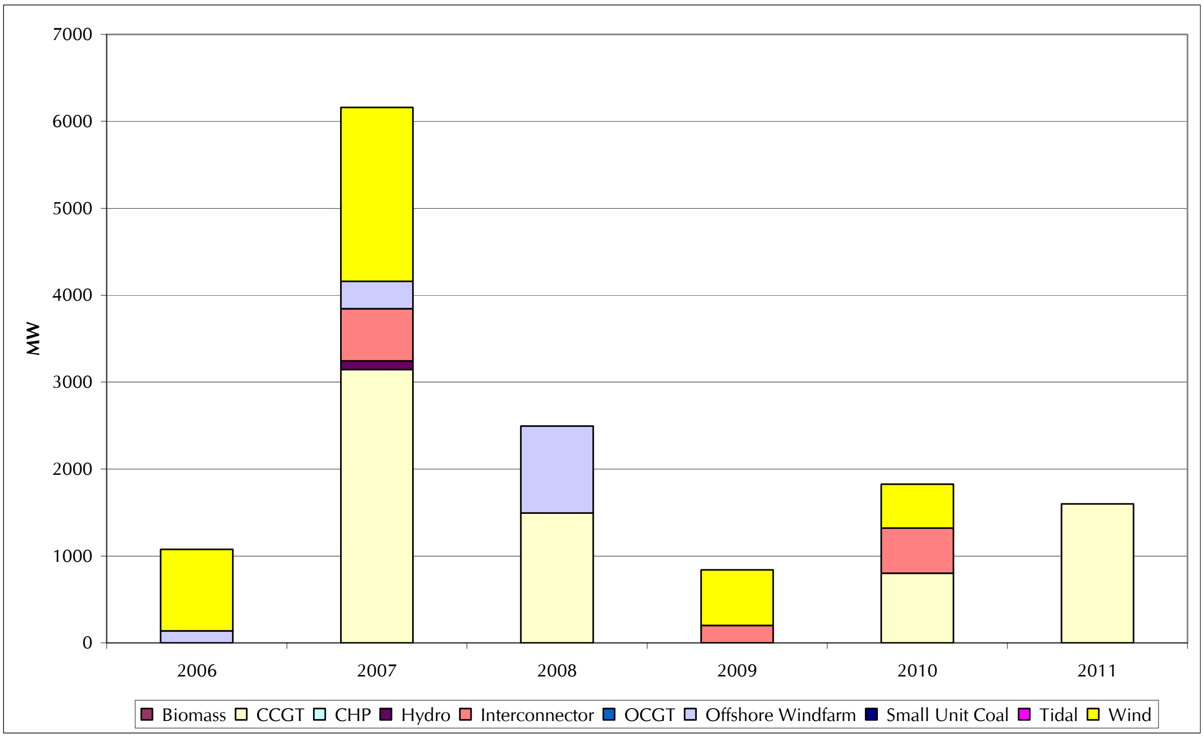
The generation fuel mix in 2005/06 across a total TEC of 77.4GW, based on information provided in NGC's Seven Year Statement, is displayed in Figure 5.1 below.

Figure 5.1 – Generation mix by plant type (source: NGC Seven Year Statement, table 3.14)



As discussed above and shown over time in Figure 5.2, the proposed new generating capacity is predominantly gas fired (CCGTs or CHPs) or windfarms. This combined with scheduled nuclear retirements and possible coal-fired retirements, will make the GB electricity market increasingly dependent on gas and renewables.

Figure 5.2 – Anticipated changes to the generation mix (source: NGC Seven Year Statement, table 3.7)



Generation commissions/retirements

On the basis of information in NGC's Seven Year Statement[100], in 2004 there were 1460MW of CCGT capacity additions and 355MW of wind generation capacity additions. No power stations were disconnected or irreversibly closed in 2004[101]. However, 600MW or CCGT generation capacity was mothballed i.e. reversibly closed, during 2004[102]. Therefore, the net position was as follows:

- +0.8GW of CCGT capacity; and
- +3.6GW of wind capacity

Authorisation criteria for new generation investments

This is outlined in the '*Generation investment*' section earlier in this chapter and so is not repeated here.

Investment incentives

There are no explicit investment incentives in the form of capacity payments or options. As regards the balancing arrangements, they have been designed to provide a level playing field for all generators but there are no specific provisions for new generating plants.

[100] Source: Table 3.7 of NGC's Seven Year Statement.
[101] Source: Table 3.10 of NGC's Seven Year Statement.
[102] Source: Table 3.11 of NGC's Seven Year Statement.

The contractual freedom and bilateral pricing associated with the current trading arrangements ensures that prices are broadly cost-reflective as generators seek out purchasers for their power and suppliers and customers seek the most competitive terms from generators. It is Ofgem's view that the market signals provided by these cost reflective prices produce appropriate indications as to the need for investment. There have been a number of major announcements by both existing generators (eg, RWE, E.ON, Centrica) and new entrants (eg, ESBI) that new capacity will be built in the coming years. The reintroduction of a capacity mechanism would only work to distort the market signals created by electricity prices and distort the effectiveness of the market arrangements in delivering security of supply efficiently.

Infrastructure projects

Two interconnection projects between the UK and other countries are currently under development. The other countries involved are the Netherlands and Ireland. Details of these projects, based on information provided on NGC's website, are outlined below.

The Netherlands

National Grid Transco and NLink - a subsidiary of TenneT, the transmission system operator in the Netherlands - are developing a project for an interconnector between Britain and the Netherlands. BritNed would have a capacity of between 1000-1300MW, be around 200km long, and cost between €300-400m. The project is in development and a final decision on whether to proceed with the link is expected in 2005.

Ireland

National Grid and ESB, the grid operator in Eire, have recently completed a feasibility study into the construction of a sub sea interconnector between Ireland and Wales. The results are being analysed before a decision is made on whether to develop the project further.

Regulatory framework for interconnectors

The new EU Gas and Electricity Directives and Electricity Regulation introduce, amongst other things, the requirement for a regulated third party access (RTPA) regime for interconnectors. The Directives and Regulation allow exemption from RTPA by the relevant regulatory authorities, subject to veto by the European Commission. With respect to interconnectors, the Directives and Regulation were implemented in Great Britain via the Energy Act 2004.

The Energy Act 2004 introduced a licensing regime for all gas and electricity interconnectors, which is administered by Ofgem. The requirements of the EU legislation concerning third party access and, where appropriate, exemptions from these requirements are given effect via this licensing route. Where exemption from these requirements is granted, this is done by "switching off" certain of the standard interconnector licence conditions via an exemption order. This exemption procedure enables Ofgem to accede to any Commission request that it should amend or withdraw its decision to issue an exemption without the need for Ofgem to go through a licence modification procedure.

5.2 Gas

Ongoing supply-demand situation

Gas demand

Transco's Ten Year Statement[103] provides information in relation to forecast and actual annual gas demand. Relevant data is reproduced in Table 5.4 below.

Table 5.4 – UK Supply Surplus (source: Transco Ten Year Statement, figure 4.6A)

(bcm)	2004/05	2005/06	2006/07	2007/08
Total demand	104.7	106.5	108.2	111.7

Gas supply

Information in relation to actual and forecast annual gas supplies is also provided in Transco's Ten Year Statement. Table 5.5 reproduces relevant information from this source.

Table 5.5 – UK Supply Surplus (source: Transco Ten Year Statement, figure 4.6A)

(bcm)	2004/05	2005/06	2006/07	2007/08
UKCS	91.2	87.6	83.6	79.7
UKCS Upside	0.0	0.0	0.0	0.0
Existing Import Infrastructure	18.5	18.5	18.5	18.5
Additional Import Infrastructure	4.4	12.4	63.4	86.0
Total	114.1	118.5	165.5	184.2

[103] References to Transco's Ten Year Statement refer to the version published in December 2004, which is available at http://www.transco.uk.com/.

Production and import investment

Transco's Ten Year Statement provides information in relation to proposed import and storage projects. Table 5.6 outlines the proposed import projects expected over the course of the next three years.

Table 5.6 – UK import projects (source: Transco Ten Year Statement, table 4.5A)

Import Project	Developer	Location	New capacity (bcm p.a.)	Date	Status
Bacton-Zeebrugge upgrades	IUK	Zeebrugge to Bacton	Additional 8	2005/06	Under construction
			Additional 7	2006/07	Under construction
Langeled (Ormen Lange)	OL Partners	Sleipner to Easington	25	2006/07	Under construction
FLAGS – Statfjord late life project	Gassco	Use of existing UKCS infrastructure	4	2006/07	Connection project to be completed
Dutch Interconnector (BBL)	Gasunie / Eon / Fluxys	Balgzand to Bacton	15	2006/07	Under construction
Isle of Grain LNG	NGT	Isle of Grain	4.4	2005	Commissioning
			Additional 10.5 - 14	2008	Open season for additional capacity held
Milford Haven (Dragon LNG)	Petroplus / BG / Petronas	Milford Haven	6	2007/08	TPA exemption secured
Milford Haven (South Hook LNG)	Qatar Petroleum / ExxonMobil	Milford Haven	10.5	2007/08	TPA exemption secured

These import projects could, therefore, provide additional import capacity of approximately 110bcm/year: 59 bcm of additional pipeline import capacity and 35 bcm of LNG capacity.

Eight new storage projects have been proposed, with a total capacity of 3800 mcm.

Table 5.7 – UK storage projects (source: Transco Ten Year Statement, table 4.5B)

Storage Project	Developer	Location	Size (mcm)	Date	Status
Aldbrough	Statoil / SSE	Aldbrough	420	2007/08	Under Construction
Cheshire	Scottish Power	Byley	300	2007/08	Planning permission being challenged in the High court
Humbly Grove	Star Energy	Humbly	280	2005/06	Under Construction
Welton	Star Energy	Grove	435	2007/08	Planning submitted
Bletchingley	Star Energy	Lincolnshire	~ 875	2009	Conceptual
Albury	Star Energy	Surrey	~ 875	2010	Conceptual
Weald Basin	Star Energy	Surrey	110	2007	Conceptual
Fleetwood	Canatxx	Fleetwood	~ 500	2008+	Public Inquiry (Oct 2005)

Supplier of last resort ("SoLR")

From time to time, companies in competitive markets fail. On the one hand, failure is regrettable, in that investors lose money, jobs are lost and inconvenience is caused to customers. On the other hand, failure can be a sign that competition is working effectively. This is because in many cases it is the degree of rivalry between companies and the extent to which customers exercise choice that inevitably leads to success for some companies and failure for others.

This logic applies as much in relation to the gas and electricity supply markets as it does to other markets. It is therefore inevitable that some gas and electricity suppliers will fail. The difference between gas and electricity and other sectors of the economy is that gas and electricity are services that are generally regarded as essential. This is why it is important that Ofgem, in conjunction with other bodies where appropriate, takes all reasonable steps to address the consequences of gas and electricity suppliers failing. Not every failure will require regulatory intervention – the business may be sold in a trade sale. However, it is for Ofgem to take all reasonable steps within its available powers to secure continuity of supply for all customers.

Ofgem has published guidance documents[104] in relation to the issues that Ofgem would need to consider in the event of the failure of a gas or electricity supplier or a gas shipper. The guidance outlines that, while Ofgem considers that trade sales are generally more desirable than regulatory intervention, in the event of a supply company failure the current regulatory regime gives Ofgem some discretion as to when it revokes a licence, and how it selects and appoints a SoLR. The process in place can be found in the referenced documents. There are a number of

[104] See: 'Supplier of Last Resort (SoLR) – Guidance on current arrangements', Ofgem March 2001 and 'Supplier of Last Resort – Revised Guidance', Ofgem, November 2003.

examples of the existing arrangements working smoothly to deal with supplier failure, with Independent Energy, Enron Direct, Atlantic, and TXU all being sold with no interruptions to customers or the operation of the market.

Incentives to increase production/ import capacity

The trading arrangements provide commercial incentives on gas shippers and suppliers to balance their inputs to, and offtakes from, the system by the end of the day. These incentives are created by the 'cash out' arrangements that set the price that shippers pay for any imbalances at the end of the day. These arrangements are important for ensuring that the market delivers secure supplies by providing incentives for gas producers, suppliers and storage operators to contract to meet their customers' demands and manage the risk of gas supply failures. Aside from the commercial incentives created by the cash out arrangements, there are no incentives to increase production.

In respect of NTS system entry capacity, mechanisms exist which are designed to:

- Provide shippers with the opportunity to secure long-term rights to NTS entry capacity through an auction process;
- Release long-term entry capacity rights in response to signals received and, where appropriate, invest to meet the expected supply pattern.

This is done by auctioning entry capacity to shippers and by providing Transco with an incentive (Entry Capacity Investment incentive) to provide an efficient level of investment in response to customer demand.

Transco periodically makes available, via an auction, quantities of capacity, known as baseline capacity. In January 2003 a cleared price auction was introduced to enable capacity to be bought in blocks of calendar quarters for a period from two years in advance of a gas year up to thirteen years ahead. Demand can be placed for quantities that in aggregate exceed the baseline quantity offered. That process is achieved by shippers placing bids for volumes against a range of prices published by Transco. If sufficient sustained demand above baseline is demonstrated then Transco can apply to the Authority for approval to allocate extra quantities of entry capacity. Transco's decision whether to seek approval will be based on the existence of sufficient demand and the satisfaction of the conditions of Transco's Incremental Entry Capacity Release Methodology (for details of IECR methodology please refer to the document "Incremental Entry Capacity Release Statement" contained on the website www.transco.uk.com under Publications). If additional capacity is released then Transco will be allowed additional revenue in accordance with its Entry Capacity Investment incentive.

Availability of storage for public service reasons

No such requirement exists in relation to the availability of storage for public service reasons.

However, Transco has identified a group of gas customers that, in a network gas supply emergency, can be physically isolated in a short period of time to ensure that they do not continue to consume gas (referred to as 'customers protected by isolation'). Subsequently, Transco established a series of 'safety monitor' levels at each storage site to ensure that sufficient gas remains in store to account for the demand of all customers that Transco cannot physically isolate in the required timescale (referred to as 'customers protected by the safety monitor').

In practice, Transco monitors storage stocks at each facility against the safety monitor and, if it appeared to Transco that the safety monitor would be likely to be breached, it would exercise its judgement regarding the risks associated with such a breach and take action accordingly. For instance, Transco may determine that it would be appropriate to consider re-allocation of the monitor levels between storage facilities. In the event that the safety monitor was breached, Transco would instigate a network gas supply emergency and, pursuant to the emergency provisions set out in Transco's network code, it would take action to ensure that the required volume of loads protected by isolation were no longer taking gas. This would ensure there was sufficient gas available to protect other customers.

Infrastructure projects

As highlighted earlier, several major infrastructure projects are expected to be completed in the coming years. These projects are listed in above and so are not listed here again.

Several of these projects are interconnections between other countries. These interconnectors will operate under a regulatory framework which is consistent with that outlined for electricity interconnectors in section 5.1. Consequently, details of the framework are not repeated here.

6 Public Service Issues

Activities such as transmission, distribution and supply (and their equivalent activities in gas) are licensed activities. The concept of public service obligations is not explicitly defined, but the licences place obligations on the holder. One of Ofgem's duties is to act in a manner best calculated to secure that licence holders are able to finance the carrying out of the activities which they are authorised or required by their licence to carry on.

These duties for non-network activities are placed in a non-discriminatory manner on all relevant licensees in the context of a fully liberalised market. Duties placed in respect of network activities are taken account of in setting price controls.

The notion of 'services of general economic interest' exists in the UK as an exclusion to the Chapter I and Chapter II prohibitions of the Competition Act 1998. The relevant statutory requirements and licence conditions include, for example:

Statutory Requirements

- Under section 9(2) of the Electricity Act 1989 (as amended) the holder of a transmission licence is obliged to develop and maintain an efficient, coordinated and economical system of electricity transmission and facilitate competition in the supply and generation of electricity.
- Under section 9(1) of the Electricity Act 1989 (as amended) distribution licensees are obliged to develop and maintain an efficient, coordinated and economical electricity system.
- Under Section 10 of the Gas Act 1986 (as amended) there is a duty to connect premises within 23 metres of the gas main without charge
- Under section 9(1)1(a) of the Gas Act 1986 (as amended) there is a duty to run an economic and efficient and coordinated system and there are a number of incentive arrangements under the Gas Transporter licence to assist the transmission asset owner/system operator in this role.

Licence Conditions

- Standard Licence Condition (SLC) 25 ensures the efficient use of gas and electricity.
- SLC 35 provides a code of Practice on payment of bills and guidance, which offers special help to those who cannot pay bills through misfortune or inability to budget, including allowing them to pay by instalments or have a prepayment meter installed.
- SLC36 provides a code of Practice on use of prepayment meters. The licence holder must offer information in respect of use of prepayment meters to domestic customers.
- SLC37 states the provision of services for persons who are of pensionable age etc. The licence holder must provide special services to these customers including a Priority Service Register (PSR). Under the PSR, eligible customers can get special help with meter reading, easier to read bills, help with using appliances, and passwords for callers.
- SLC37 (gas only) states that pensioners not to have gas cut off in winter.
- SLC38 states the provision of services for persons who are blind or deaf. The licence holder must provide special services to these customers.
- SLC39 states the licence holder must set up and publicise a procedure for dealing with complaints.

Fuel Mix disclosure

In March 2005 a new standard licence condition was inserted into electricity supply licences to implement the requirements of Directive 2003/54/EC, requiring each electricity supplier to provide details to its customers of the mix of fuels used to produce the electricity it supplies together with certain environmental information.

In summary, suppliers are required to provide customers, at least once per year, details of the fuels used to generate the electricity that they supply. These are categorised as coal, natural gas, nuclear, renewable and other. They must also provide information on the environmental impact of this generation (carbon dioxide emissions and radioactive waste).

Ofgem is currently consulting on non-binding guidance to encourage good practice by suppliers when complying with the licence condition.

Appropriate treatment of vulnerable customers

Energy suppliers have a range of regulatory obligations towards vulnerable consumers which include making available a range of payment methods, sensitive treatment for customers in debt, providing help to improve energy efficiency, and services under the Priority Service Register. These obligations, together with other help from companies through voluntary corporate social responsibility initiatives, contribute to achievement of the Government's targets on the elimination of fuel poverty. On 30 June 2005, Ofgem issued its Social Action Strategy outlining its approach and plans for working with a range of interested parties to help tackle fuel poverty and vulnerability.

The Strategy supplements Ofgem's broad approach of promoting competitive energy markets and regulating network monopolies, by focussing on four key areas:

- compliance with regulatory obligations and effective monitoring and reporting by the companies
- encouraging best practice among energy suppliers, using research to identify effective approaches to fuel poverty and vulnerable customers
- influencing the debate about measures to help tackle fuel poverty
- how best to inform consumers about ways to lower their energy bills

In 2004 there were 2553 gas disconnections and 727 electricity disconnections for non payment.

Ongoing maintenance of end user price regulation

Supply price controls were completely lifted in April 2002. Retail prices are determined through competition in the market, although a significant proportion of suppliers cost base, recovered through unregulated changes to end users, consists of regulated tariffs such as transportation and metering costs paid by suppliers paid to the network monopolies.

Transparent terms and conditions for supply contracts

The relevant licence conditions include, for example:

- SLC 42 of the electricity and gas supply licences sets out the format which a domestic supply contract must comply. This stipulates that a supply licensee may not supply a domestic premises except under a domestic supply contract or a deemed contract. The domestic supply contract should be in a standard format and set out all the terms and conditions including terms as to price and provisions for terminating the contract

- SLC 44 of the electricity and gas supply licences obliges the supplier to take all reasonable steps to draw the customer's attention to the principal terms of the supply contract. SLC 40 of the electricity and gas supply licences also obliges suppliers to provide their customers with information particularly on the terms and conditions of their supply contract and also how to contact the Consumer Council and their role in resolving customer complaints.
- SLC 46 of the electricity and gas supply licences relates to the notification terms of terminating a domestic supply contract. The supplier may not enter into a supply contract without including terms which allow the customer to terminate the contract at any time so long as he has given a valid notice of termination and paid, if applicable a termination fee to the supplier.

There are no specific obligations on non domestic supply in the licence conditions; except on the terms of deemed contracts. SLC 28 of the electricity and gas supply licences obliges the supplier to ensure that the terms of its deemed contracts are not unduly onerous The formal definition of a deemed contract is contained within the relevant SLC's of the electricity and gas supply licences, but, in essence, a deemed contract relates to the supply of gas or electricity to a customer that has never switched since the beginning of the liberalisation and market opening process.