

INDUSTRY BRIEF

CRI
CENTRE FOR
THE STUDY OF
REGULATED
INDUSTRIES

**REGULATION OF THE
UK ELECTRICITY INDUSTRY**

2002 edition

Gillian Simmonds



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PREFACE

The CRI is pleased to publish the 2002 edition of its industry brief on the *Regulation of the UK Electricity Industry*, having updated it for developments since the 1998 edition. It has been prepared by Gillian Simmonds, a Research Officer at the CRI, and supersedes the first edition which was prepared by Carole Hicks, then a Research Officer at the CRI. The brief is part of a set of CRI industry briefs for the utilities and network industries, covering water, energy, transport and communications.

The structure and regulation of the electricity industry has changed considerably since 1998, including developments such as the new electricity trading arrangements (NETA), competition in electricity supply and the Utilities Act 2000, which created, amongst other things, separate, independent arrangements for consumer representation (*energywatch*) and the Gas and Electricity Markets Authority (the 'Authority'), which took over the powers and duties of the Director General. The new 2002 edition is, therefore, substantially a new document, rather than a 'revision'.

The CRI would welcome comments on the Brief, which can be taken into account as CRI Industry Briefs have to be updated from time to time in line with developments in the Industry, and will be published as a 'revised' or subsequent 'edition'. Comments should be addressed to:

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The CRI publishes work on regulation by a wide variety of authors, covering a range of regulatory topics and disciplines, in its International, Occasional and Technical Paper series. The purpose is to promote debate and better understanding about the regulatory framework and the processes of decision making and accountability. Enquiries or manuscripts to be considered for publication should be addressed as above.

The views of authors are their own, and do not necessarily represent those of the CRI.

Peter Vass
Director, CRI
May 2002

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1 HISTORICAL OVERVIEW

England, Wales and Scotland

Pre-privatisation¹

Following the Second World War, the UK had some 560 electricity suppliers, of which approximately one-third were privately owned. Under an Act of 1943, electricity supply in the north of Scotland was placed under the North of Scotland Hydro-Electric Board (the Hydro-Electric Board), a public corporation established to develop the water power resources of the Highlands. Under the Electricity Act of 1947, the electricity industry in England, Wales and south of Scotland was reorganised and nationalised. The act established the British Electricity Authority (BEA) as a public corporation responsible for the generation and transmission of electricity, as well as for the policy and finances of the supply industry. The act also created 14 area boards – 12 in England and Wales and 2 in the south of Scotland – each constituted as a separate public corporation responsible for the distribution and retail of electricity in its own region. The Electricity Reorganisation (Scotland) Act 1954 established the independent south of Scotland Electricity Board (SSEB) from the two Scottish area boards and the BEA's two Scottish generating divisions. Like the Hydro-Electric Board, the SSEB was responsible for all three functions of generation, transmission and distribution. At this time, the BEA was renamed the Central Electricity Authority (CEA).

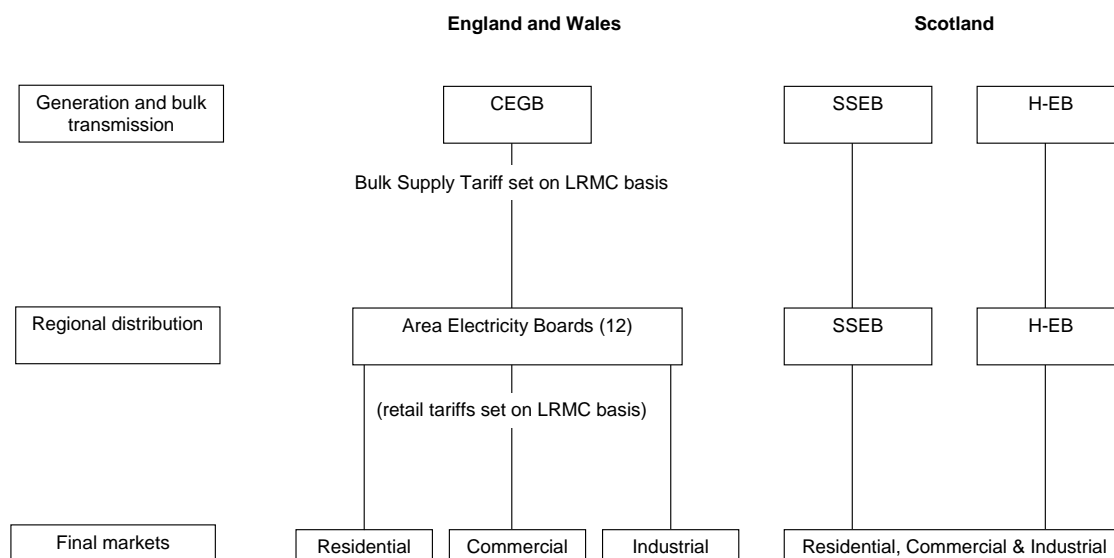
The Electricity Act of 1957 further reorganised the electricity industry in England and Wales. In order to introduce greater decentralisation, the CEA was replaced by two new statutory bodies – the Central Electricity Generating Board (CEGB) and the Electricity Council. The CEGB owned and operated the transmission system and the generating stations in England and Wales. The CEGB was responsible for the bulk supply of electricity to the 12 area boards in England and Wales, and its duties included planning the provision of new generation and transmission capacity. Under the act, the area boards were accorded greater autonomy, particularly for financial matters, and continued to have responsibility for the distribution and retail of electricity in their respective areas. The Electricity Council exercised a co-ordinating role on matters of industry-wide concern. The council, in addition to three full time members, included the chairs of the 12 area boards and three representatives from the CEGB. The council also had certain specific duties, including offering advice to the government on behalf of the industry as a whole, and promoting and assisting the maintenance and development, by the electricity boards in England and Wales, of an efficient, co-ordinated and economical system of electricity supply.

¹ This section is drawn primarily from Hicks C (1998), Regulation of the UK Electricity Industry, Centre for the study of Regulated Industries; and Organisation of the Electricity Supply Industry in England and Wales – A thumb-nail sketch, originally issued by the Electricity Council as leaflet RP1(a) in February 1984.

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The pre-privatisation structure of the electricity industry in Great Britain was, therefore, characterised by extensive vertical integration of generation, transmission, distribution and supply. The structure of the nationalised industry in England and Wales was dominated by one large generation and transmission company, the CEGB, which sold electricity in bulk to 12 area distribution boards, each of which served a closed supply area or franchise. In Scotland, there were two vertically integrated boards that exercised regional monopolies, but co-operated closely in the use of their generating plant to ensure that demand was met at least cost (see **Figure 1**).²

Figure 1: Structure of the nationalised electricity supply industry



Privatisation

The Electricity Act 1989 (which received Royal Assent on 27 July) laid the legislative foundations for the restructuring and privatisation of the electricity industry in Great Britain. The act made provision for a change in ownership from the state to private investors, the introduction of competitive markets, and a system of independent regulation. In contrast to the privatisations of the gas and telecommunications sectors, the electricity industry was restructured prior to privatisation. This was in response to widespread criticism of previous sell-offs, where it appeared that a public monopoly was basically transformed into a private monopoly.³

On 31 March 1990, a new industry structure was introduced into England and Wales (see **Figure 2**). This restructuring:⁴

² Electricity Association (1999), The UK Electricity System.

³ McGowan F (1993), Electricity – The Experience of Offer, in [Eds] Gilland T and Vass P (1993) Regulatory Review 1993, Centre for the study of Regulated Industries.

⁴ Hicks C (1998), Regulation of the UK Electricity Industry, CRI.

- Split the CEBG into 3 generating companies and a transmission company: National Power, Powergen, Nuclear Electric and the National Grid Company (NGC). Fossil-fuelled power stations were transferred to National Power and Powergen, the nuclear power stations were transferred to Nuclear Electric, and the transmission system and the Dinorwig and Ffestiniog pumped storage power stations in Wales were transferred to the NGC. The NGC also took control of the interconnectors with Scotland and France.
- Replaced the area boards with twelve regional electricity companies (RECs). The local distribution systems were transferred to the RECs and each REC was obliged to supply on request all reasonable demands for electricity in its authorised area. Some minor modifications to the area boards' boundaries were made in defining the RECs' authorised supply areas. The RECs jointly owned the NGC, with each REC holding a stake proportionate to its size.
- Established the electricity pool as the wholesale market mechanism through which electricity was traded in England and Wales.
- Abolished the Electricity Council.
- Created a system of independent regulation, headed by the director general of electricity supply, covering England, Wales and Scotland, and supported by a regulatory office, the Office of Electricity Regulation (Offer), to regulate the newly privatised electricity industry.⁵
- Set up a series of regional consumer committees, the electricity consumer's committees, to replace the electricity consultative councils.

While the key reform in the privatisation of the electricity industry was the breaking of vertical linkages to allow the introduction of competition into some parts of the industry, some vertical integration remained. The RECs were established as integrated distributors and suppliers and were also allowed limited involvement in generation of up to 15% of their sales volume. National Power and Powergen were also allowed to supply to some customers directly.⁶

In Scotland, also on 31 March 1990, the SSEB and the Hydro-Electric Board were replaced by ScottishPower and Scottish Hydro-Electric (the latter merged with Southern Electric in 1998 to become Scottish and Southern Energy). In Scotland, vertical integration was maintained in the new structure. As in England and Wales, nuclear generation was assigned to a separate company, Scottish Nuclear, which became part of British Energy in 1996 (see **Figure 2**).⁷

The 12 RECs in England and Wales, Powergen, National Power, ScottishPower and Scottish Hydro-Electric were sold by public flotation on the stock market. On 11 December 1990, the 12 RECs were floated on the London Stock Exchange. This was followed, on 12 March 1991, by the flotation of National Power and Powergen, with 60% of the shares of each sold. The government sold its remaining 40% of the shares

⁵ Offer was founded in 1989 and was primarily based in Birmingham and Glasgow, with the latter office dealing with the special characteristics of the Scottish system. In 1999, the regulatory offices for electricity and gas (Offer and Ofgas) were merged to form the Office of Gas and Electricity Markets (Ofgem).

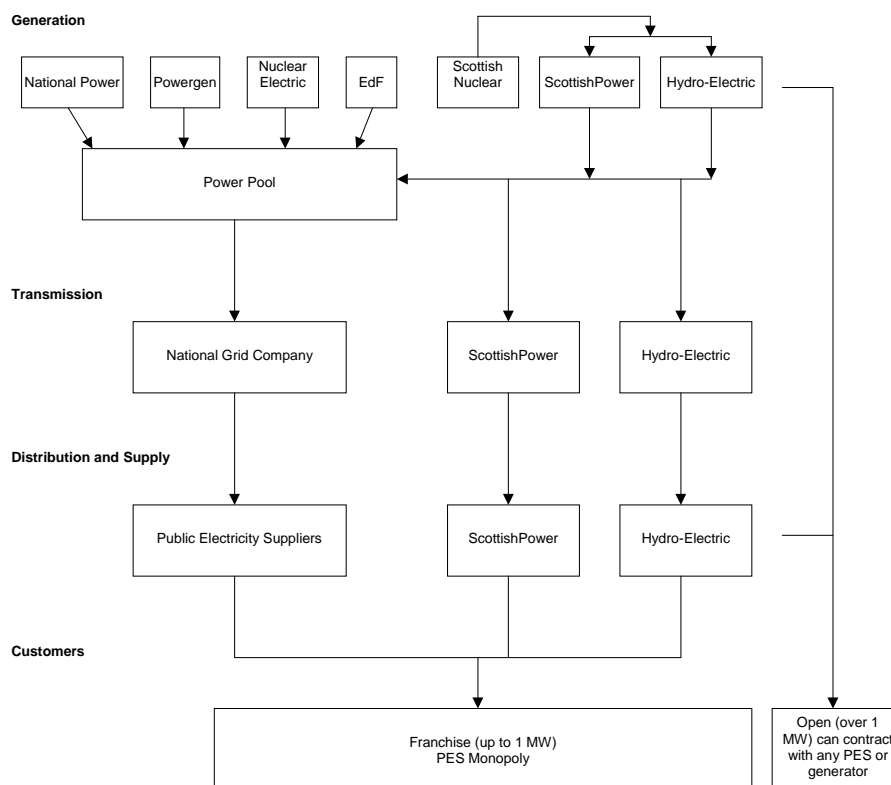
⁶ Hicks C (1998), Regulation of the UK Electricity Industry, CRI.

⁷ Electricity Association (1999), The UK Electricity System.

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of Powergen and National Power in March 1995, retaining a special share. On 18 June 1991, Scottish Hydro-Electric and ScottishPower were floated. At this stage, the two nuclear companies, Nuclear Electric and Scottish Nuclear, remained in public ownership.

Figure 2: Structure of electricity industry at privatisation



- The electricity pool

One of the innovations in the electricity sector at privatisation was the establishment of the electricity pool of England and Wales. The pool was one of the first mechanisms of its kind and, therefore, there was limited experience in other countries to draw on in its creation and in the rules associated with it. In its development, considerable weight was given to the arrangements operated pre-privatisation by the CEBG, when the electricity system was publicly-owned and centrally planned. The principles of the pool were relatively simple and largely inherited from the CEBG merit order. The pool was:

- a set of rules defining how electricity in the market was to be traded;
- the actual system through which generators had to offer wholesale electricity, and from which those who wanted to purchase wholesale electricity had to buy;
- the mechanism by which wholesale electricity prices were set, for each half hour, and plant was dispatched;
- the settlement system, by which generators were paid and suppliers were charged.

The pool was set up to facilitate a competitive bidding process between generators that set the price paid for electricity each half hour of the day and established which

generators would run to meet forecast demand. The pool was an unincorporated association of its members. Its members, wholesale buyers and sellers of electricity, controlled how the pool was run and decided if and how the pool should change. The NGC operated the pool and administered the pool's settlement system on behalf of pool members.

The pool required generators, each day on a day-ahead basis, to provide details of the price at which they were prepared to make generation available. NGC, on behalf of the pool members, provided an estimate of system demand at the day-ahead, calculated a schedule of generation to meet this estimate, and determined pool prices. NGC also was responsible, under its licence, for dispatching plant on the day, taking into account into account the day-ahead schedule, but modifying it as necessary, for example, to take into account unexpected changes in demand or failures by generating plant and to resolve system constraints.

Pool prices tended to be peaky and volatile. To hedge against pool price uncertainty, the bulk of electricity was sold through bilateral financial contracts with suppliers – contracts for differences (CfDs). These over-the-counter contracts were negotiated directly between the parties concerned. The majority of CfDs were struck against the pool purchase price, but they could be struck against any component of the pool price.

Further restructuring, competition and consolidation

- Generation⁸

In 1990, there were six major power producers in Great Britain – National Power, Powergen and Nuclear Electric in England and Wales; and ScottishPower, Scottish Hydro-Electric and Scottish Nuclear in Scotland.

While the National Grid Company was initially jointly owned by the RECs, in December 1995 it too was floated on the stock market as an independent company. Before flotation, the pumped storage business was transferred to a new company, First Hydro, which was then sold to US generator, Edison Mission Energy.

In July 1996, the government privatised parts of the two state-owned nuclear companies, Nuclear Electric and Scottish Nuclear. A holding company, British Energy was created, with Nuclear Electric and Scottish Nuclear as wholly-owned subsidiaries. Both companies continued to operate as separate entities, with their own boards of directors. At that time the older nuclear stations were transferred to Magnox Electricity, which has subsequently become part of British Nuclear Fuels (BNFL).

The first independent power generation projects, all CCGTs, were backed by the regional electricity companies (RECs). The RECs participated in these projects on a joint venture basis and entered into long term agreements to purchase the off-take from the plants. However, the RECs were only allowed to meet 15% of their demand through own generation. Eastern Group (now TXU Europe) was the only REC which

⁸ This section is drawn from Electricity Association (2001), *Electricity Companies in the United Kingdom – A brief chronology*; Electricity Association (2001), *Electricity Industry Review 5*; and Electricity Association (2002), *Electricity Industry 6*.

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obtained consent to relax this limit and took 100% control of two medium size CCGT power stations. A number of new players have also entered the generation market. These include the US-based power producers AES, Edison Mission Energy, NRG, Entergy and Enron.

Enforced (and later, voluntary) divestment by Powergen and Innogy has also stimulated competition, creating an impetus for changes in ownership and the participation of new entrants. In 1994, the DGES obtained an undertaking from National Power (Innogy) and Powergen to divest 4 GW and 2 GW (around 9% of capacity) respectively.⁹ By July 1996, both generators had met this undertaking by selling plant to Eastern Electricity, making it the fourth largest generator with a share of around 9.5%. Further divestments have been made since then:

- In 1999, the two generators agreed to divest a further 4 GW of coal-fired capacity each in order to obtain regulatory consent for the purchase of REC businesses. Edison Mission Energy bought two of Powergen's coal-fired power stations, Fiddler's Ferry and Ferrybridge, under a 99 year lease agreement, while AES, acquired National Power's largest station, Drax. These acquisitions turned AES and Edison Mission Energy into significant players in the generation market.
- In March 2000, National Power sold Eggborough power station (2 GW) to British Energy and Killingholme gas-fired station (650 MW) to NRG Energy Inc. The sale of these stations was part of a de-merger by National Power to create two separate companies, Innogy and International Power.
- Powergen divested Cottam Power Station to London Electricity in September 2000. This sale was in line with Powergen's strategy to reduce debt and become a business focussed on the UK and US with reduced dependence on profits from UK generation.

There have also been changes in the ownership of independent plant through the buying out of co-owners in consortia owning new CCGTs. For example, Edison Mission Energy became the sole owner of Roosecote after buying Norweb's remaining stake in the plant. In April 2000, Electricité de France (EdF), owner of London Electricity, entered the UK generation market. London Electricity bought the CCGT Sutton Bridge plant from Enron and later in the same year acquired from Powergen the coal-fired Cottam power station. In 2001, EdF purchased the West Burton coal-fired plant from TXU Europe. The Company has thus grown from a position of interconnector supplier to becoming one of the major players in the UK generation market (with access to almost 5 GW of capacity).

Centrica, the major gas and electricity supplier, has also recently entered the generation market, purchasing a 60% stake in Humber Power in May 2001 and acquiring TXU's two CCGTs on 20 year leases in June 2001 (see **Appendix 1** for a chronology of developments in the generation sector).

⁹ Concerns about the unusual patterns of pool prices led to a number of regulatory investigations which ultimately resulted in plant divestment by National Power (Innogy) and Powergen.

- Supply¹⁰

The supply market was opened up to competition in three phases, culminating in May 1999 when all consumers became eligible to choose their suppliers, as follows:

- from April 1990, customers with peak loads of more than 1 MW (about 45% of the non-domestic market) were able to choose their supplier;
- from 1 April 1994, customers with peak loads of more than 100 kW were able to choose their supplier;
- between September 1998 and May 1999, the remaining part of the electricity market (that is, below the 100 kW peak load) was opened up to competition.

Since the opening up of the industrial and commercial market (that is, the above 100 kW market) to competition, there has been a substantial development in competitive activity. Ofgem estimated that, in 1999/2000, customers accounting for 80% of the output in the 1 MW market in England and Wales chose to take their supply from a company other than their local PES (as compared with 43% in 1990/1991), and customers accounting for 67% of the output in the 100 kW to 1 MW market in England and Wales chose to take their supply from a company other than their local PES.

The opening up of the domestic market (that is, the below 100 kW market) to competition has also met with success. By August/September 2001, 38% of domestic electricity customers had switched supplier one or more times since the introduction of competition. The former PES suppliers have lost, on average, 10% per annum of their supply service area market share (measured in terms of customer numbers) since the introduction of competition. By the end of September 2001, the former PESs had lost an average of approximately 30% of customers in their own areas.

After an initial increase in the numbers of licensed electricity suppliers operating in the electricity supply market, the recent increase in merger and acquisition activity suggests a trend toward consolidation of the electricity supply market. There are now only seven supplier groups created from the former PESs through takeovers and mergers, compared to 14 PESs at the outset of privatisation (see **Figure 3**). The Electricity Association (2002) point to falling prices and relentless competition as spurring on companies to seek opportunities for consolidation to become more competitive. Certainly, with the exception of British Gas Trading which has acquired all its customers through sales, the companies with the largest market shares today are those which own more than one ex-PES supply business (see **Appendix 3** for a breakdown of ownership and market shares).

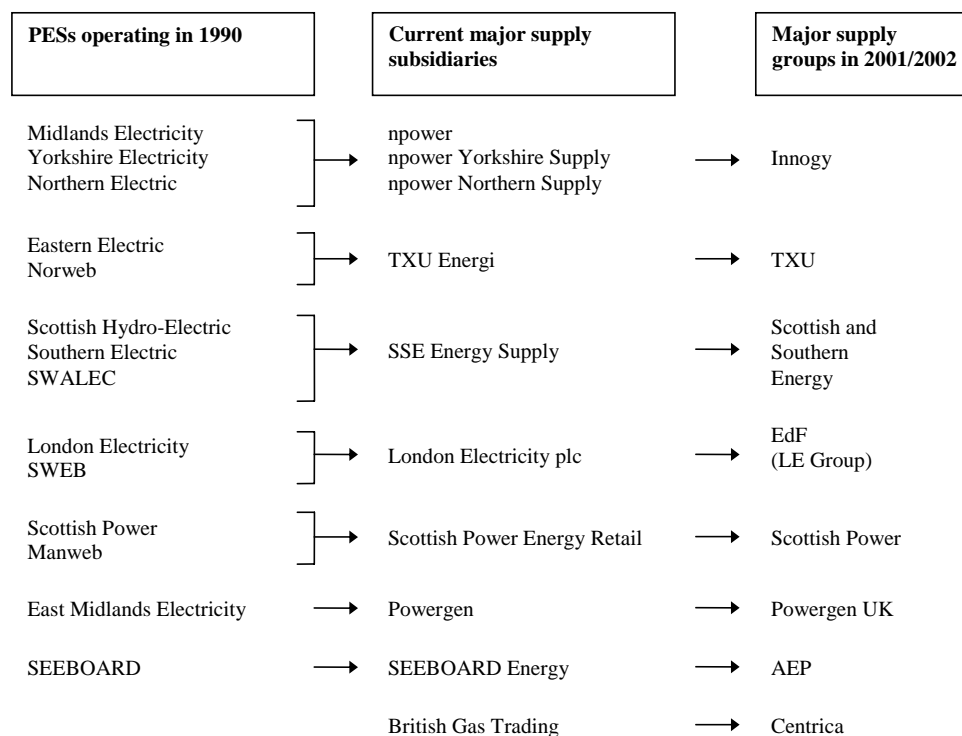
ScottishPower was the first company to expand its business by taking over another PES, acquiring Manweb in October 1995. Southern Electric and Scottish Hydro Electric subsequently merged in December 1998 and formed a new holding company, Scottish and Southern Energy. Scottish and Southern Energy subsequently bought SWALEC's supply business in August 2000. In July 1999, London Electricity took over SWEB's supply business (see **Appendix 3** for a breakdown of ownership).

¹⁰ This section is drawn from DTI (2001), Digest of UK Energy Statistics 2001; Electricity Association (2001), Electricity Industry Review 5; and Electricity Association (2002), Electricity Industry 6.

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There has also been a trend toward integration of generation and supply in recent years. In July 1998, Powergen bought East Midlands Electricity, while National Power bought Midlands Electricity's supply business. After National Power decided to demerge into Innogy and International Power, Innogy began expanding its supply business and acquired Yorkshire's supply business in February 2001 and in November 2001, Northern Electric's supply business. TXU Europe has also expanded its supply business by buying Norweb Energi in August 2000. Only one former PES, SEEBOARD, owned by American Electric Power, has remained.

Figure 3: Major supply groups currently operating in the UK electricity market



Innogy, through the acquisition of Midlands Electricity, Yorkshire Electricity and Northern Electric's supply businesses has increased its customer base, emerging as the largest supplier with a market share of 19%. British Gas Trading is the second largest supplier, followed by TXU and Scottish and Southern Energy. British Gas Trading has been the most successful company in attracting customers through sales. All other major suppliers have acquired former PES supply businesses, with their customer bases. New licensed suppliers, such as Virgin Energy, Saga, Union Energy, Severn Trent Energy and others, have so far relatively small numbers of customers. Together they account for only 300,000 customers.

Regulatory reform (Utilities Act 2000)

The Utilities Act 2000, which received Royal Assent on 28 March 2000, substantially reformed both the institutional framework for the regulation of the electricity industry, and the legislative parameters dictating the structure of the industry.

With regard to the changes to the institutional and regulatory framework, the Utilities Act made provisions for:

- the replacement of an individual regulator, the director general of electricity supply, with a regulatory board, the Gas and Electricity Markets Authority;
- the merging of the regulatory offices for the gas and electricity sectors into a single regulatory office, the Office of Gas and Electricity Markets (Ofgem);
- the replacement of the former electricity consumer committees with an independent gas and electricity consumer council, known as *energywatch*;
- changes in the primary duties of the Secretary of State for Trade and Industry and the regulatory authority and a shift in responsibilities between the secretary of state and Ofgem;
- new powers for the regulatory authority and the secretary of state.

These changes were effected, in the main, through changes to the Electricity Act 1989. The Utilities Act 2000 significantly, also abolished the concept of the public electricity supplier and introduced a single Great Britain-wide licence for all suppliers, thus putting all suppliers on the same legal footing. The Act also introduced a legal requirement for the separation of the former PES electricity supply and electricity distribution businesses, and introduced a statutory requirement for distribution to become a separately licensable activity. These changes have, and will continue to have, a substantial impact on ownership structures in the industry.

The Utilities Act 2000 also made provision for the implementation of new electricity trading arrangements to replace the electricity pool, established at privatisation. A number of problems with the pool had been identified over its decade of operation, including:

- a lack of competition in price setting, because although there had been substantial new entry into the generation market, the majority of new entrants were CCGTs with long-term off-take contracts and, therefore, price setting remained dominated by the three main portfolio generators – Powergen, National Power (Innogy) and Eastern;
- a relative lack of supplier pressure and of customer and demand side participation in the arrangements;
- the complexity of bidding and price setting;
- the limitations of the capacity payment mechanism, which has been open to abuse and provided a relatively poor signal for the longer-term need for capacity;
- the manipulation of pool prices;
- inefficient interactions between gas and electricity markets;
- inflexible rules and governance arrangements, resulting a slow pace of reform.

Many of these problems identified in the 1990s – such as the lack of competition in price setting and manipulation of pool prices – were caused by dominance of the generation market rather than by the pool itself; and were addressed through earlier regulatory responses, such as the enforced divestment of generation capacity by National Power and Powergen.

The new electricity trading arrangements (NETA), introduced on 27 March 2001, are based on bilateral trading between generators, suppliers, traders and customers through forwards and futures markets and short-term power exchanges. The main differences between NETA and the electricity pool are:

- **self-dispatch** – each generator is responsible for determining the level of output from each of its units as opposed to the NGC scheduling on behalf of all generators as under the pool;
- **paid as bid** – all trades are valued at the bid price for that trade rather than at the bid price for the most expensive trade for a given time period;
- **firmness of markets** – any difference between physical consumption or production and contracted positions at 3.5 hours is cashed out through the balancing mechanism at a penal rate (the pool was non-firm, resulting in reduced incentives to tailor contract positions to actual patterns of consumption and production and hence reduced liquidity in contract markets);
- **ex-post price** – the cash-out price is determined after the event, as opposed to in the pool where the cash-out price was known to a high degree of certainty at the day ahead stage;
- **trading closer to the event** – under NETA, trading continues up to 3.5 hours ahead of real time, allowing market participants greater opportunity to tailor their contracted position to match their physical position (under the pool, offers were made between 19 and 43 hours ahead of real time).¹¹

NETA is discussed in detail in **Chapter 3 on Industry and Market Structure**.

Northern Ireland

Pre-privatisation

Prior to 1973, the electricity industry in Northern Ireland was comprised of the Belfast Corporation Electricity Department, the Londonderry Development Commission Electricity Department, the Electricity Board for Northern Ireland and the Northern Ireland Joint Electricity Authority. Under the terms of the Electricity Supply (Northern Ireland) Order 1972, these bodies were merged to form the Northern Ireland Electricity Service, which subsequently became Northern Ireland Electricity (NIE). NIE had sole responsibility for the generation, transmission, distribution and supply of electricity throughout Northern Ireland. The Electricity Supply (Amendment) (Northern Ireland) Order 1987 permitted others to generate electricity. While some industrial undertakings took advantage of this to generate a significant proportion of their own electricity requirements, there were no independent generators supplying electricity to NIE or directly to consumers through the grid.¹²

Before privatisation, the electricity industry in Northern Ireland effectively, therefore, consisted of one vertically integrated, publicly owned monopoly, Northern Ireland Electricity (NIE). NIE owned and operated four power stations, with a total capacity of 2,300 MW and was responsible for the transmission, distribution and supply of electricity within the region.

¹¹ Green A (2000), *The New Electricity Trading Arrangements*, PricewaterhouseCoopers.

¹² HMSO (1991), *Privatisation of Northern Ireland Electricity*, Cm 1469.

*Restructuring and privatisation*¹³

The Electricity (Northern Ireland) Order 1992 made provisions for the restructuring and privatisation of the electricity supply industry in Northern Ireland; and established a framework for the regulation of the newly privatised industry. A director general of electricity supply for Northern Ireland (DGESNI) was appointed, under the Electricity (Northern Ireland) Order 1992, as separate to the director general of electricity supply for England, Scotland and Wales. The DGESNI was supported by the Office of Electricity Regulation for Northern Ireland (Offer NI, which became the Office for the Regulation of Electricity and Gas (OFREG) in June 1996). The 1992 Order and the associated licences and codes set up a different structure for the electricity industry in Northern Ireland from that adopted in either England and Wales or Scotland.

The process of restructuring and privatisation in Northern Ireland took place in two stages between 1992 and 1993. The privatisation was carried out on the government's behalf by the Northern Ireland Department of Economic Development (now the Department of Enterprise, Trade and Investment). It was the first privatisation of a public utility in Northern Ireland, and the first in the United Kingdom to employ a combination of trade sales and flotation.¹⁴ In April 1992, NIE's four generation stations were sold to private investors. The largest generating station, Ballylumford, was purchased by British Gas and is now operated by a subsidiary, Premier Power. Two other stations were bought by a consortium of Tractebel and the AES Corporation and were operated as a subsidiary, Nigen (now wholly owned by AES and trading as AES Ltd). The fourth power station (Coolkeeragh) entered the private sector as a result of a successful management buy-out.¹⁵ The remainder of the electricity industry, consisting of transmission, distribution and supply, was put into the control of a single company, Northern Ireland Electricity plc.¹⁶ Shares in NIE plc were floated on the London Stock Exchange in June 1993, a process which completed the transfer of the electricity industry into private ownership. A further reorganisation carried out by NIE in 1998 resulted in the creation of a holding company, Viridian Group.

The sale of the generating stations was underwritten by contracts between the generators and NIE plc in respect of each generating unit. These contractually bound the four generating companies to NIE to provide electricity when required for a period related to the economic life of the generating sets. The contracts can be cancelled by the DGESNI at dates varying between late 1996 and 2010. Consequently, although ownership of the generating stations was dispersed, competitive pressure was not yet generally capable of affecting price paid for generation because it was mainly governed by the contract terms.

¹³ This section is drawn primarily from the annual reports of Offer NI (now Ofreg).

¹⁴ Committee of Public Accounts (1995), Sixteenth Report: The privatisation of Northern Ireland Electricity.

¹⁵ Electricity Association (1999), The UK electricity system.

¹⁶ Hicks C (1998), Regulation of the UK electricity industry, CRI.

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At privatisation, NIE was established as the independent system operator with responsibility for both the transmission and distribution systems. It also had sole responsibility for the power procurement function – that is, NIE had a monopoly on the purchase of electricity from the generating companies and was the body from whom any supplier was required to purchase electricity either for its own use or to sell on to other customers. A separate supply business was also established within the company and NIE was granted the only public electricity supply licence in Northern Ireland. Unlike in Great Britain, however, there was no franchise limit restricting customers' ability to purchase electricity from a supplier other than NIE. It was, therefore, theoretically and practically possible for second-tier supply licences to be issued to anyone who wished to supply electricity bought from NIE to customers. Electricity was resold to suppliers, at the time usually NIE's supply business, at a published bulk supply tariff which set a wholesale price of electricity for any specific time on the basis of the likely cost of production given the level of electricity demand.

The electricity system in Northern Ireland was isolated from other networks until March 1995, when the interconnector with ESB in the Republic of Ireland was re-energised (the north/south interconnector). The north/south interconnector has a theoretical available transfer capacity of 330 MW, although not all of this is currently available for trading. The Moyle interconnector, with a theoretical capacity of 500 MW, was developed as a strategic infrastructure project to link the NI electricity system with the systems of Great Britain and the European mainland. The Moyle interconnector became available for use for trading in January 2002.

*Competition in generation and supply*¹⁷

As mentioned, Northern Ireland has, since privatisation, had full market opening in electricity supply. Competition in generation and supply has, however, been constrained by the contracts that were entered into at the time of generator sell-off in 1992 and the consequent lack of freedom of trade in electricity generation. As all suppliers had to buy their electricity from NIE's power procurement business (PPB), and all generators had to sell their output to the PPB, there was, in practice, little incentive for second-tier suppliers to enter the electricity supply market.¹⁸

Since 1998, the market in green electricity has been fully open to competition, with both NIE supply and second-tier suppliers being able to purchase electricity directly from renewables generators, by-passing the PPB. By May 2001, only NIE's supply business had responded to this opportunity on a province-wide basis, although there were examples of local green generators supplying their own local customers.

Effective competition in Northern Ireland has largely been led by the EU directive for the Internal Market in Electricity (IME directive). The IME directive required 26.5% of the market to be open by 1999, rising to 35% in 2003. In line with this, the government has introduced new terms for competition in generation and supply in Northern Ireland. The IME directive was implemented in Northern Ireland in July

¹⁷ This section is drawn from DTI (2001), Energy Report 2000; Ofreg (2001), Electricity Market Opening – Time to win; and Electricity Association (2002), Electricity Industry Review 6.

¹⁸ A few UK wide chains who wanted a single supplier for the whole of the UK were the only customers of any significance to use this provision.

1999, with approximately 26% of the generation and supply market being opened to competition. In practice, market opening means that eligible customers (initially, those customers with an annual consumption of at least 2.5 GWh, totalling approximately 240 customers) can purchase electricity either directly from the generators or through second-tier suppliers (while they are no longer required to purchase through the PPB, they may if they wish and many still buy some and some buy all of their electricity from the PPB). As required by the IME directive, the eligible market was extended to approximately 30% in April 2000 and to 32% in October 2000. The most recent extension of market opening to 35% took place in April 2001, resulting in customers using above 0.79 GWh per annum being classified as eligible (approximately 720 customers). Trading in the open market was facilitated by the auctioning to suppliers, at a discount, of 100 MW of surplus capacity contracted to NIE and, by the release from contract, of some 300 MW of capacity as a result of the restructuring of the long-term generator contracts.

The generation sources used to supply the competitive market have been largely made up of those generators which originally supplied the whole market under contract to NIE. With the implementation of the IME directive in the Republic of Ireland in 2000 and the completion of the Moyle interconnector, opportunities exist for eligible customers to trade with independent generators located outside Northern Ireland.

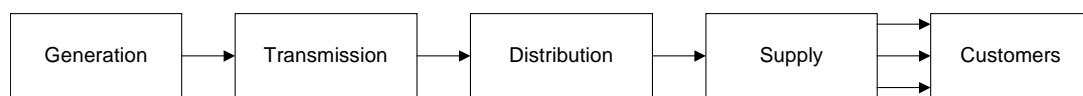
While the implementation of the IME directive has had the effect of diluting the requirement, put in place at privatisation, to sell all wholesale generated electricity to NIE for onward sale to customers, the remaining 65% of non-eligible customers continue to be supplied almost exclusively by NIE supply. Until such time as all the contracts entered into in 1992 are amended or set aside, the electricity market in Northern Ireland will not be as competitive as the rest of the UK.

2 THE ELECTRICITY INDUSTRY

The electricity industry is comprised of:

- *generation*, the production of electricity in power stations;
- *transmission*, where electricity is transported at high voltage over long distances;
- *distribution*, where electricity is taken at lower voltages over shorter distances to end-users;
- *supply (or retailing)*, where electricity services are sold to customers (see **Figure 4**).

Figure 4: The electricity delivery chain



The specific character of these activities in the United Kingdom is discussed below.

Generation

Generation is concerned with the production of electricity in power stations. Power stations are classified both by the type of energy source used at the station, for example coal, oil, gas, nuclear, wind or hydro-electric, and by the technology used to generate electricity (see **Figure 5**).

Figure 5: Types of generating station¹

Conventional steam stations	Stations which generate electricity by burning fossil fuels (coal, petroleum oil or gas) to convert water into steam, which then powers steam turbines.
Nuclear stations	Steam stations where the heat needed to produce the steam comes from nuclear fission.
Open-Cycle Gas Turbines (OCGT)	Use pressurised combustion gases from fuel burned in one or more combustion chambers to turn a series of bladed fan wheels and rotate the shaft on which they are mounted. This then drives the generator. The fuel burnt is usually natural gas or oil.
Combined Cycle Gas Turbines (CCGT)	Combine in the same plant gas turbines and steam turbines connected to one or more electrical generators. This enables electricity to be produced at higher efficiencies than is otherwise possible when either gas or steam turbines are used in isolation. The gas turbine (usually fuelled by natural gas or oil) produces mechanical power (to drive the generator) and waste heat. The hot exhaust gases (waste heat) are fed to a boiler, where steam is raised at pressure to drive a conventional steam turbine which is also connected to an electrical generator.
Natural flow hydro-electric stations	Use natural water flows to turn turbines.
Pumped storage hydro-electric stations	Use electricity to pump water into a high level reservoir. This water is then released to generate electricity at peak times. Where the reservoir is open, some natural flow electricity is also generated by the stations. As electricity is used in the pumping process, pumped storage stations are net consumers of electricity.
Other stations	Includes wind turbines and stations burning fuels such as landfill gas, sewage sludge and waste.

¹ Sourced from DTI (2001), Digest of United Kingdom Energy Statistics 2001.

Demand for electricity varies both diurnally and seasonally, following consumers' patterns of usage. Demand is greater in winter than in summer, reflecting both the increased lighting load and the increased heating load. During a typical winter's day, demand builds up between 06:30 and 09:00 to the start of the working day; reaches a plateau between 09:00 and 16:00 (reflecting the commercial and industrial demand

during the working day); and rises to a peak between 16:30 and 17:30, reflecting an increased domestic demand and an increased demand for lighting. On a typical summer's day, the onset of the evening lighting load is delayed and the absence of the heating load leads to a lower overall demand.

Electricity cannot be stored, only generated when required. To match the variable demand, therefore, certain generating sets may either be switched off or brought on line at different times of the day.¹⁹ The operation of a generating set which runs for all or most of the time is known as base load. Operation which occurs only for short periods of peak demand is known as peak, and operation falling between base load and peak is described as mid-merit. Mid-merit plant will be turned on and off at least once in 24 hours. Mid-merit and peak generation together are described as non-base load. Whether a particular plant operates at baseload, mid-merit or peak depends on a combination of technical and commercial factors. Nuclear power stations, for example, are difficult and expensive to turn on and off and the costs saved by not generating are small. They are, therefore, uneconomic to operate other than at base load. Most other types of plant are more flexible. Old coal-fired plant operated at base load when new, but much is now mid-merit. It has been displaced, in part, by new, more thermally efficient combined-cycle gas turbine (CCGT) plant. This CCGT plant is also technically capable of operating at mid-merit. Where CCGT plant has a take-or-pay gas contract there is a strong incentive to generate as much as possible and operate at baseload. Some plant, such as pumped storage, is designed to operate solely at times of peak demand.²⁰

The main trend in the UK generation market during the last five years has been the expansion of gas-fired capacity at the expense of coal. This reflects a growth in CCGT capacity in England and Wales and a significant increase in gas burn in converted oil stations in Scotland and Northern Ireland.²¹ There was, however, a break in the tradition in generation pattern in 2000, with generation from coal-fired power stations increasing by 13%, having fallen at an average rate of 9.5% per annum in the previous four years. Generation from gas rose by only 2.5%, having recorded average growth of 22% per annum over the previous four years.²² Generation from nuclear sources fell by 10.5% having grown at 2% per year over the previous 4 years. The main cause of this turn around was that increased outages for repairs, maintenance and safety case work reduced nuclear output; and coal-fired power stations were called upon to make up for this. Later in the year, rising gas prices meant that coal-fired stations were able to outbid some of the gas-fired power stations to supply the electricity pool.²³ This trend continued in 2001, with electricity supplied from coal rising by 8.5% and that supplied from nuclear stations rising by 5.9%. Electricity supplied from gas-fired stations fell by 3.9%.²⁴

¹⁹ A generating set is a generating unit that can be operated independently. There may be several generating sets in a single power station.

²⁰ Hicks C (1998), Regulation of the UK Electricity Industry, CRI.

²¹ Electricity Association (2001), Electricity Industry Review 5, January 2001.

²² This low rate of growth was despite four new CCGT stations coming on stream during the year.

²³ DTI (2001), Digest of United Kingdom Energy Statistics 2001.

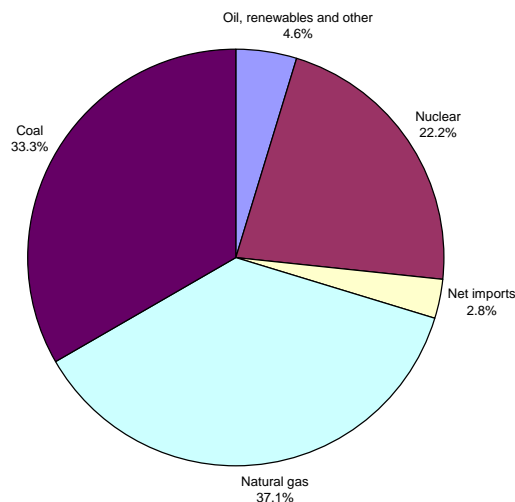
²⁴ DTI (2001), Energy Trends, September 2001.

Gas' share of electricity supplied (net) plus imports moved up sharply from 19% in 1995 to 39% in 2000, but fell back by 1.75 percentage points in 2001 to 37%.²⁵ Coal's share fell from 45% to 31% between 1995 and 2000, but rose again to 33% in 2001. Nuclear's share rose to a peak in 1997, but then fell back and in 2000 recorded a share of 21%, 3 percentage points lower than in 1995. In 2001, nuclear's share rose by 1 percentage point to 22% (see **Figure 6** and **Figure 7**).²⁶

Figure 6: Electricity available by fuel type (1980-2000) expressed in TWh²⁷

	1980	1990	1998	1999	2000
Coal	190.0	208.0	117.0	101.2	114.6
Oil	33.9	21.3	5.9	5.3	5.1
Gas	1.6	1.6	116.3	139.8	143.7
Nuclear	32.3	58.7	90.6	87.7	78.3
Hydro	7.3	7.9	5.1	5.3	5.1
Other fuels			7.8	8.6	8.3
Net imports	-	11.9	12.5	14.2	14.2
Total	265.1	309.4	355.2	362.1	369.3

Figure 7: Fuel used in electricity generation on an output basis (2001)²⁸



²⁵ High gas prices have discouraged gas-fired generation.

²⁶ DTI (2001), Digest of United Kingdom Energy Statistics 2001; and DTI (2001), Energy Trends, September 2001.

²⁷ DTI (2001), UK Energy in Brief, December 2001.

²⁸ DTI (2001), Energy Trends, September 2001.

Prior to 1986, when the interconnector between France and England became operational, virtually all electricity available came from home supply. In 2000, net imports from France, combined with net imports into Northern Ireland from the Irish Republic over the interconnector reinstated in 1996, amounted to 3.8% of total electricity available.²⁹ The new electricity trading arrangements have, however, led to a reduction in imports of electricity from France, resulting in net imports falling by 1 percentage point to 2.8% in 2001

Transmission³⁰

Transmission is the transfer of electricity from individual generation stations to distribution system entry points or, in certain cases, direct to end-users' premises. Transmission systems consist mainly of overhead lines, underground cables and substations connecting transmission systems to distribution systems. To reduce transmission losses, electricity is transmitted at very high voltages (at 400kV and 275kV in England and Wales, 400kV, 275kV and 132kV in Scotland, and 275kV and 110kV in Northern Ireland). In England and Wales, the transmission system is known as the national grid. Scotland has two transmission systems, one covering the north and the other the south of the country. The two systems are connected to each other by a series of interconnectors. The southern transmission system is also connected to the national grid in England and Wales by a further interconnector which allows the export and import of electricity to and from England and Wales.³¹ A similar interconnection allowing for imports and exports exists between France and the national grid. This interconnector is almost always used to import electricity into England and Wales.³² In Northern Ireland, there is a single transmission system which is connected to the transmission system in the Republic of Ireland; and to the transmission systems in Great Britain via an interconnector between Islandmagee in Northern Ireland and Auchencrosh in Scotland.

Traditionally the United Kingdom has relied almost exclusively on electricity generated by large power stations connected directly to the high voltage transmission system and centrally-dispatched (although, under the new electricity trading arrangements, generation is self-dispatched). The interconnecting of separate utilities with a high voltage transmission system has enabled the pooling of both generation and demand and has provided for a consistent high quality of supply (for example, in terms of frequency variations, voltage level, voltage waveforms, voltage fluctuations and harmonic levels) across the system. Generation may also, however, be embedded in the local distribution network rather than connected to the high voltage transmission system. The implications of embedded generation are discussed in more detail in the section which follows.

²⁹ DTI (2001), Digest of United Kingdom Energy Statistics 2001.

³⁰ This section is drawn primarily from Hicks, C (1998), Regulation of the UK Electricity Industry.

³¹ The interconnection between Scotland and England and Wales consists of 6 circuits – two double circuit overhead lines, one in the west and one in the east, operating at 400kV and 275kV, and two single circuit overhead lines operating at 132kV.

³² The cross-channel link with France is a direct current link consisting of four pairs of cables connecting converter stations at Sellindge in Kent and Les Mandarin near Calais.

Distribution³³

Distribution systems are the low voltage networks of overhead wires, underground cables and substations constructed to bring electricity to end users. Grid supply transformers connect the transmission systems with the distribution systems at what are termed either 'grid supply points' or 'distribution entry points'. Electricity is then transferred from these distribution entry points to end-users (termed **distribution**). Prior to January 1995, the great majority of customers, mainly households, received their electricity at 240v. This has now changed to 230v to comply with EU harmonisation. Large industrial and commercial customers are supplied at higher voltages, typically 11kV. A few very large customers are connected directly to the transmission grids.

Traditionally, the distribution networks have operated passively, delivering power from the transmission network, through the distribution network to the end customer, as described above. However, the recent focus on embedded generation, in response, in part, to the government's environmental targets, may change the way in which the distribution networks operate.³⁴ Embedded generation is generating plant connected at distribution rather than transmission voltages. In England and Wales, embedded generation is, therefore, connected at 132kV or below. In Scotland 132kV is a transmission voltage, and embedded generation is that which is connected at lower voltages.³⁵ Embedded generation is typically smaller generation plant, such as combined heat and power (CHP) or renewable generation (for example, small hydro, wind or solar power) – that is, the type of plant which is currently being promoted through government initiatives which aim to achieve its environmental targets under its Kyoto obligations. If there were to be substantial growth in embedded generation plant, the distribution networks would be required to be more active, allowing electricity to flow in two directions – to the electricity user for consumption and on to the network when the user is exporting excess generation capacity.

Supply

The supply (or retailing) of electricity involves the purchase of electricity in bulk from generators and its sale on to customers. It also involves customer services, billing and the collection of customer accounts.³⁶ Suppliers are required to contract with distributors to move electricity purchased through the distribution networks to the customers' premises.

³³ This section is drawn primarily from Hicks, C (1998), Regulation of the UK Electricity Industry.

³⁴ The government's environmental targets are currently to achieve 10 GW of CHP by 2010 and to generate 10% of electricity from renewable sources by the same date.

³⁵ Ofgem (2001), Embedded Generation: Price controls, incentives and connection charging – A preliminary consultation document, September 2001.

³⁶ Hicks C (1998), Regulation of the UK Electricity Industry.

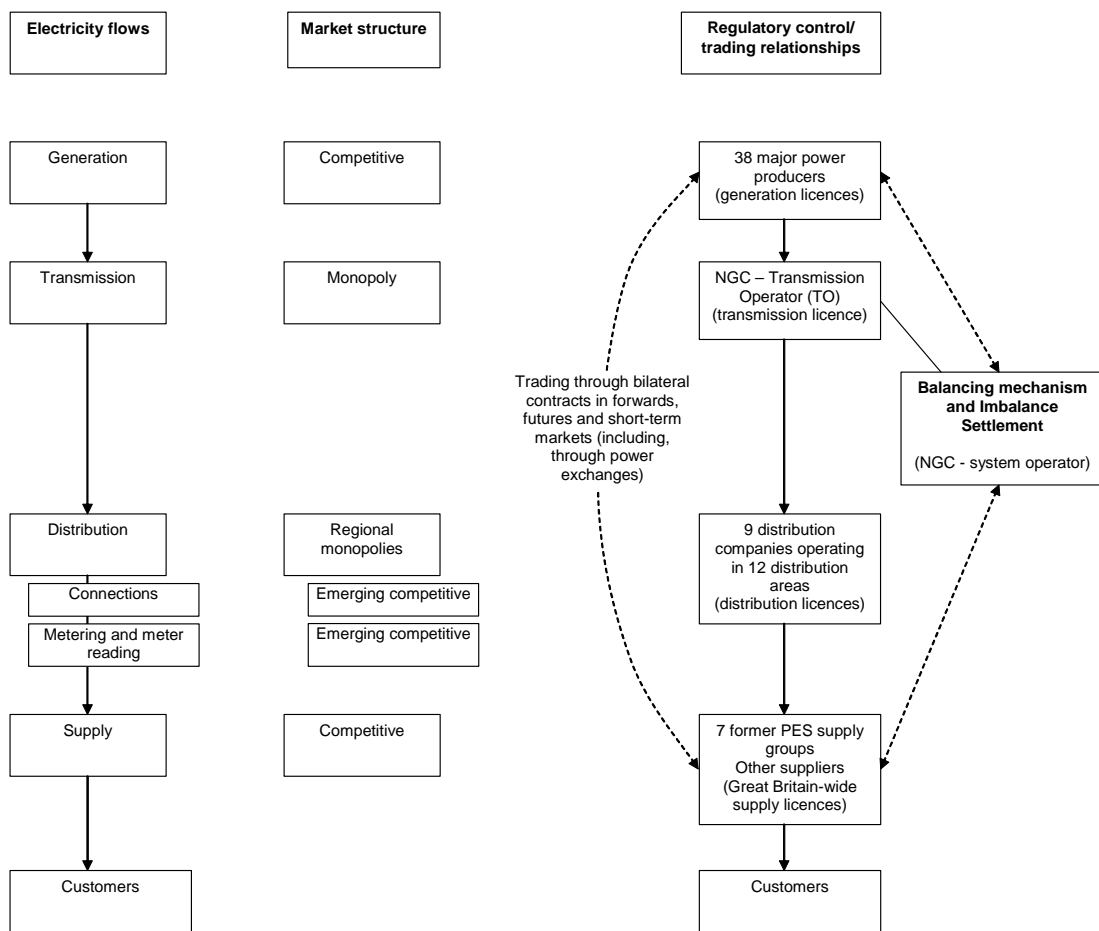
3 INDUSTRY AND MARKET STRUCTURE

This section separately provides a description of the structure of the electricity industry in England and Wales, Scotland and Northern Ireland. The current market structure, the relationships between the different players and the contractual arrangements governing those relationships are discussed.

England and Wales

Figure 8 demonstrates the current industry and market structure for the electricity industry in England and Wales.

Figure 8: Structure of electricity industry in England and Wales



Generation

In 1990, at privatisation, there were three major power producers in England and Wales – National Power (now Innogy), Powergen and Nuclear Electric.³⁷ At this time, approximately 75% of the UK's total electricity generating capacity was owned by National Power and Powergen.³⁸ Since privatisation, the generation market has changed from a highly concentrated market with a few portfolio generators, to a market with many diverse generating companies, including independent power producers. The reorganisation of the industry, new entry into the generation market and enforced and voluntary divestment of capacity by Innogy and Powergen has significantly reduced the concentration of generation capacity ownership in England and Wales, and brought changes in companies' market shares.³⁹ There are now 38 generators regarded as major power producers in England and Wales.⁴⁰ For a description of the development of the structure of generation sector over time see the earlier chapter entitled **Historical Overview** and the associated **Appendix 1**.

In 2000, the largest generators in England and Wales were AES, British Energy, BNFL Magnox Generation, Edison Mission Energy, Innogy, Powergen, and TXU Europe (formerly Eastern Energy). There are also a growing number of small producers, together with a large number of small autogenerators who produce power for their own use.⁴¹ A list of current generators operating in the UK can be found in **Appendix 2**.

British Energy, with 9.3 GW of generating capacity in England and Wales, and a further 2.2 GW in Scotland, had emerged as the biggest UK generator in terms of capacity in 2000. Innogy (8.2 GW) and Powergen (8.1 GW) were the second and third largest generators, but their combined capacity accounted for about a quarter (24.6%) of total registered capacity in England and Wales compared with a share of 85% in 1990/1991. TXU Europe (6.8 GW) and Edison Mission Energy (6.3 GW) were the fourth and fifth largest, accounting for 10.2% and 9.6% of the total.⁴² AES followed with a share of 7.4%. BNFL Magnox Generation and London Electricity had similar shares of about 4%, and another 4% of capacity was provided by the interconnectors. A group of about 20 small generating companies provided 19% of the remaining capacity, half of them having a minority stake in several CCGT stations.⁴³

These changes in the generation market have eroded the output shares of the main portfolio generators. In 1990/1991, Innogy and Powergen provided 45.5% and 28.4% respectively of total output in England and Wales. Their share declined to 14.0% and 14.9% respectively by 1999/2000, and even further to 11% and 6.8% by November

³⁷ Electricity Association (2001), Electricity Industry Review 5.

³⁸ Beckett, R (2001), Financial and Operating Review 1999/2000.

³⁹ Electricity Association (2001), Electricity Industry Review 5.

⁴⁰ Electricity Association (2002), Electricity Industry Review 6.

⁴¹ DTI (2001), Energy Report 2000.

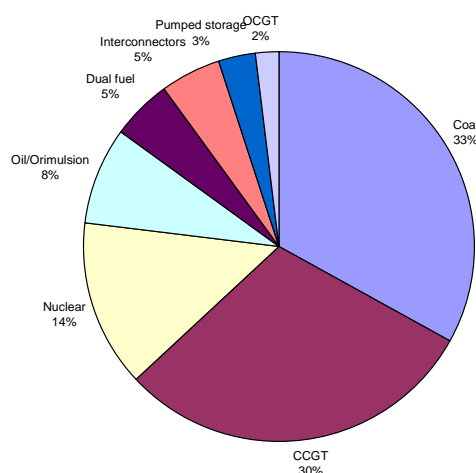
⁴² Although TXU Europe has since divested plant as part of its business restructuring.

⁴³ Electricity Association (2001), Electricity Industry Review 5.

2000. The new entrants saw their combined market share rise from 0% to 41.3% in 1999/2000 and 56.7% in November 2000.⁴⁴

The generation capacity mix in England and Wales has been reshaped from one dominated by coal-fired plant to a balanced generation mix. In 1990/91 coal-fired stations accounted for more than 70% of total registered capacity in England and Wales, but closures and mothballing reduced their share to a third (33%) by May 2000. CCGT now represents the second biggest tranche of capacity in England and Wales, accounting for 30% of total capacity compared with 6% five years ago. Nuclear capacity represents 14% of the total in England and Wales (see **Figure 9**).

Figure 9: Generation capacity mix in England and Wales (as at May 2000)⁴⁵



The government's stricter consent policy on gas-fired power plant, imposed in October 1998 and known as the 'gas moratorium', significantly slowed down the development of gas-fired generation. The policy resulted from concerns that the UK's electricity sector was becoming too reliant on gas too quickly, and that certain features of the electricity market made new gas-fired power plant very attractive to the detriment of the coal industry. During the moratorium, decisions were made on applications for 39 projects, all but two of them gas-fired. There is still considerable interest in the CCGT projects and the government's decision to lift the gas moratorium in November 2000, ahead of NETA's implementation, opened the door to a new wave of gas projects. National Grid's seven year statement 2000 showed some 18.1 GW of new CCGT capacity registered with the National Grid, either awaiting consents or which had had its consents deferred in the last couple of years. Following the lifting of the moratorium, six large power stations with a total capacity of 5,105 MW, which had originally been refused clearance, received the government's consent in November 2000.⁴⁶

⁴⁴ Electricity Association (2001), Electricity Industry Review 5.

⁴⁵ Electricity Association (2001), Electricity Industry Review 5.

⁴⁶ These are AES's 380 MW plant at Partington, Intergen's 800 MW Spalding plant, GE's 1,000 MW plant at Fleetwood, ABB's 425 MW plant at Raversham, Enron's 1,200 MW plant planned for the Isle of Grain and NRG's 1,300 MW plant at Langage. Consent was also granted to Conoco Global Power Development for a 475 MW gas-fired CHP plant at South Killingholme.

In recent years, there has been a shift toward vertical integration in the electricity industry, with some generators acquiring supply business and some former-PESs acquiring generation businesses.⁴⁷

Transmission

The transmission system in England and Wales is the largest transmission system in the UK, comprising 14,600 circuit kilometres of 400kV and 275kV overhead lines and cables. The natural monopoly owner and operator of this high voltage transmission network is the National Grid Company (NGC).

As an effective monopoly, NGC is closely regulated. The key documents governing the operation of NGC are the Electricity Act 1989 (as amended), its transmission licence, and the grid code. Under the Electricity Act 1989, NGC has statutory duties to maintain an efficient, co-ordinated and economical electricity transmission system; and to facilitate competition in generation and supply.

NGC principally has two roles, that of transmission asset owner (TO) and that of system operator (SO). As TO, the NGC is required to ensure the maintenance and long-term development of, and investment in, the transmission system. As SO, the NGC is required to balance generation with demand in real-time to maintain system security. It does so through its operation of the balancing mechanism, by procuring balancing services (either under long term contract or through the acceptance of bids and offers submitted into the balancing mechanism) and through the dispatch of transmission assets. Arrangements for the definition and settlement of balancing energy are set down in the balancing and settlement code (BSC).⁴⁸ The BSC includes arrangements for the settlement of imbalance energy and for the settlement of certain actions taken in order to assist NGC as system operator in balancing the system in real time.⁴⁹

Under its transmission licence, National Grid is obliged to offer non-discriminatory terms for connection to and use of its transmission system. Arrangements for connection to and use of NGC's transmission system are set down in and governed by the connection and use of system code (CUSC). The CUSC, and its associated schedules and exhibits, represent the contractual relationship between NGC and users of the transmission system in England and Wales. The CUSC also sets down the arrangements for payment for certain balancing services procured by NGC outside the balancing mechanism, and arrangements for the connection to and use of interconnectors.⁵⁰

⁴⁷ DTI (2001), Digest of United Kingdom energy statistics 2001.

⁴⁸ The BSC is the responsibility of Elexon, a wholly-owned subsidiary of NGC.

⁴⁹ Ofgem (2001), The Development of British Electricity Trading and Transmission Arrangements (BETTA) – A consultation, December 2001.

⁵⁰ Ofgem (2001), The Development of British Electricity Trading and Transmission Arrangements (BETTA) – A consultation, December 2001.

The grid code governs the technical aspects of connecting, and operating and use of, the transmission system. NGC and connecting parties are required to comply with the grid code.

NGC also owns and operates jointly with Electricité de France the interconnector connecting the transmission systems of England and France; and owns jointly with Scottish Power and Scottish and Southern Energy the interconnector with Scotland.

The UK-France interconnector is a 2000 MW high voltage direct current (HVDC), which has been used as a base load importing line, providing a substantial net flow of power of about 17 TWh per year. From 1 April 2001, the UK-France interconnector has been made available to third parties through competitive bidding processes.⁵¹

The Anglo-Scottish interconnector has a nominal (planning) capacity of 1,600 MW and is in the process of being upgraded to 2,200 MW. Like the link with France, the Scottish interconnector has been used predominantly as an import line into England. However, the Scottish link has a slightly lower average load factor than the French interconnector. This partly reflects constraints on the grid in England and Wales, which restrict flows at certain periods (flows are typically constrained to 1,200MW). The full capacity will become available when National Grid completes its proposed line in north Yorkshire. The British grid systems agreement (BGSA) provides a contractual framework within which National Grid and the two Scottish grid operators agree to share responsibility for the technical issues associated with interconnecting their respective transmission systems. The BGSA has undergone a review as part of the development of the new electricity trading arrangements (NETA).⁵²

Wholesale market⁵³

The new electricity trading arrangements (NETA), based on bilateral trading between generators, suppliers, traders and customers, were introduced on 27 March 2001 replacing the electricity pool as the wholesale market in England and Wales. The new arrangements operate like other commodity markets, whilst making provision for the electricity system to be kept in physical balance at all times so as to maintain security and quality of supply. NETA is comprised of the following elements:

- forwards and futures markets that allow contracts for electricity to be struck up to several years ahead;⁵⁴

⁵¹ Electricity Association (2001), Electricity Industry Review 5.

⁵² Electricity Association (2001), Electricity Industry Review 5.

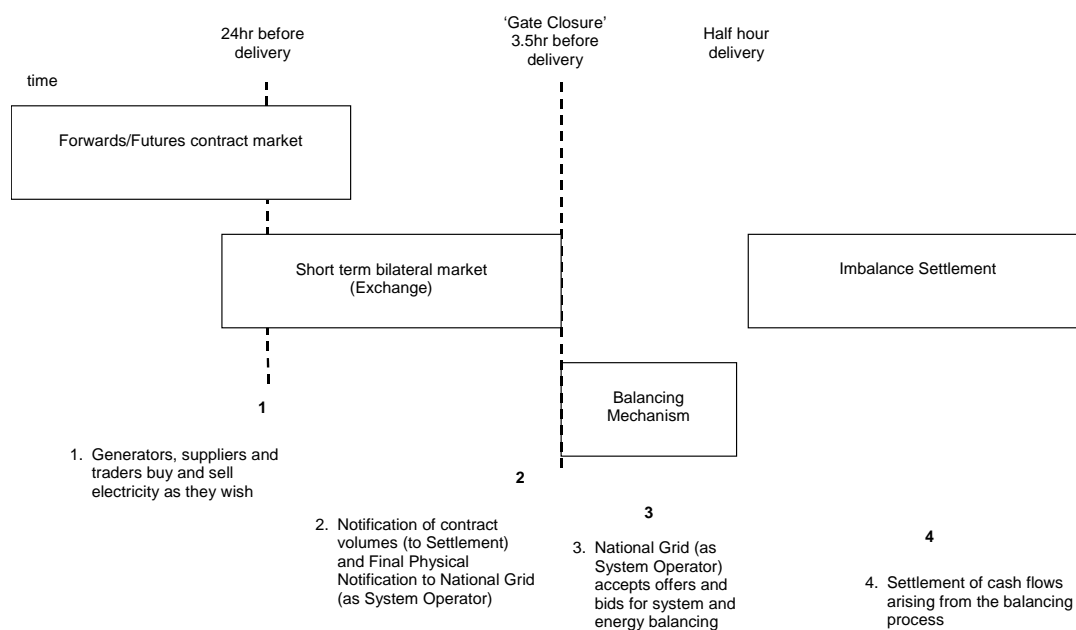
⁵³ This section is drawn primarily from Ofgem (2001), The new electricity trading arrangements – A review of the first three months, August 2001; and Electricity Association (2002), Electricity Industry Review 6.

⁵⁴ The forward contract market is where customers and suppliers can enter into contracts for electricity directly with generators. This is a bilateral market where market players negotiate with each other directly and agree to trade a quantity of electricity for physical delivery at an agreed location and over a period of time. The contracts are ‘take or pay’. The futures market allows derivatives to be traded in a regulated market. These are legally binding agreements between a buyer and a seller to deliver and take delivery (take-or-pay) on a specified future date a quantity of electricity at a price agreed today.

UK ELECTRICITY REGULATION

- short-term power exchanges which give participants the opportunity to ‘fine tune’ their contract positions in a simple and accessible way;
- a balancing mechanism, which opens at gate closure (3.5 hours before real time), in which the NGC, as system operator (SO), accepts offers of and bids for electricity to enable it to balance the transmission system;
- a settlement process for the settlement of accepted balancing mechanism offers and bids, and for recovering the SO’s costs of balancing the system and charging participants whose contracted positions do not match their metered volumes of electricity (see **Figure 10**).

Figure 10: Diagrammatic representation of NETA



Under NETA, the bulk of electricity is traded in forward, futures and short-term markets through bilateral contracts. These markets allow contracts for electricity to be struck over a scale of time ranging from within-day to several years ahead, enabling participants to secure cover for their likely output or demand at competitive prices. Only small volumes, around 3% of total energy traded, has been traded through the balancing mechanism, used by NGC to balance the system.

Since the introduction of NETA, three main power exchanges have developed – the UK Power Exchange (UKPX), the UK Automated Power Exchange (APX) and the International Petroleum Exchange (IPE). Of these, the UKPX and UKAPX provide spot markets, while the UKPX and IPE both offer futures contracts. The vast majority of trading on the exchanges has been through the spot markets, with participants actively using these markets to fine tune their contractual position as their uncertainty reduces.

To help the SO to assess the likely physical balance of the system, participants are required to notify the SO of their expected physical position (that is, their planned generation output and metered demand) for each half hour trading period, by 11:00 am one day ahead (referred to as initial physical notifications (IPNs)). Final physical notifications (FPNs) must be submitted to the SO by gate closure, at present

3.5 hours before real time. The participants may also notify their willingness to deviate from their intended operating level in exchange for payment, and submit bids and offers into the balancing mechanism.

While participation in the balancing mechanism is on a voluntary basis, those wishing to participate must sign the balancing and settlement code (BSC), which provides a set of rules to ensure efficient balancing of the system.

As well as achieving an overall physical balance of electricity supply and demand (the costs of which are, as mentioned, charged to out of balance generators and suppliers), the SO may also need to accept bids and offers at short notice to maintain the quality of supply at different locations to overcome transmission constraints. These system costs are recovered from all signatories to the BSC through balancing services use of system (BSUoS) charges on the basis of their metered generation and consumption.

The position of all BSC participants is assessed through the imbalance settlement system to determine whether their metered output or consumption of electricity matches their contracted position. Participants who are out of balance, potentially imposing balancing costs on the SO, are charged imbalance prices. The price paid or charged to 'out of balance' market participants varies depending on whether they are over-contracted (or long) or under-contracted (or short). The imbalance prices are based on the average prices that NGC has to pay participants in the balancing mechanism, as well as the costs of any balancing contracts used by the SO to maintain a balance of overall supply and demand.

NGC, as SO, faces commercial incentives to manage the total costs of system operation on behalf of customers. Under these incentives, NGC is set a target level of system operation costs. If NGC manages to beat this target, NGC keeps a proportion of the difference, subject to a cap. If actual costs exceed this target, NGC must pay a proportion of the difference, again subject to a cap.

The BSC covers the rules that govern the balancing mechanism and the imbalance settlement process. The BSC includes flexible governance arrangements to allow for modification of the rules in light of the operational experience of NETA. Elexon, a wholly owned, but uncontrolled, subsidiary of NGC, was established to be responsible for the operation of the BSC. Elexon's role covers the management of the contracts with providers of NETA services, administration of the new arrangements and processing of proposed modifications of the BSC and market rules. Modifications will be reviewed and agreed by a panel representing generators, suppliers, retail customers, Ofgem, NGC, distributors and independent advisors.

One of the key features of NETA is that, unlike the former pool where NGC centrally dispatched generating plant, generators now self-dispatch and are subject to imbalance prices if their generation does not match their contractual output. This increased exposure to the risk of plant failure has resulting in a greater emphasis on the reliability of generating plant.

Another key element of NETA is that the demand-side is fully incorporated into the new balancing arrangements. Suppliers and customers may offer load reductions to the balancing mechanism in direct competition with generators. This should

encourage suppliers to try to understand their customer demand more fully in order manage their out of balance position and make them more responsive to customers' demand requirements. Large customers seem to be playing a more active role in the market. NGC has entered into contracts with large demand-side sites and is beginning to call on offers from customers in the balancing mechanism.

*Distribution*⁵⁵

Distribution remains a monopoly business and, under the Utilities Act 2000, it has become a separately licensable activity. There are currently nine distribution companies operating in 12 authorised distribution areas. Distribution companies hold separate licences in respect of each area and are governed by the terms of their distribution licences (see **Appendix 4**).

As each former PES distribution business continues to constitute an effective regional monopoly, it is closely regulated and subject to controls on the prices it can charge and the quality of supply it must provide. They are under a statutory duty to connect any customer requiring electricity within a defined area and to maintain that connection. The Utilities Act places statutory duties on distribution network operators, requiring them to facilitate competition in generation and supply, to develop and maintain an efficient, co-ordinated and economical system of distribution, and to be non-discriminatory in all practices.

Consolidation has taken place in the distribution business, with potential benefits of economies of scale, reductions of costs and increased operational efficiency. Some former PESs which have sold their supply businesses have evolved into distribution service and support companies. SWEB, after the sale of its supply business, formed a new distribution company, Western Power Distribution. In September 2000, the company expanded and bought Infracore, SWALEC's distribution business. Midlands Electricity became GPU Power UK following the sale of its supply business to National Power. London Electricity and TXU Europe joined forces in a distribution venture, 24seven, to manage and operate their combined distribution assets, while ownership of these assets and the licenses were retained by the parent organisations. LE Group subsequently purchased TXU Europe's distribution business in January 2002, renaming the company EPN Distribution Ltd. Innogy has also bought Northern Electric's supply business in exchange for selling to Northern Electric its 94.5% interest in Yorkshire's distribution business. Northern Electric thus now owns two distribution businesses.

While distribution is a natural monopoly, in line with Ofgem's policy to separate out potentially competitive activities from monopoly activities, connections, metering and meter reading activities, traditionally considered to be part of the distribution business, are being targeted for competition. These are discussed in more detail below.

⁵⁵ This section is drawn from Electricity Association (2002), Electricity Industry Review 6.

- Metering and meter reading services

Metering services (which include meter provision and meter operation) are provided by meter operators and are not a statutory monopoly. The provisions of the Electricity Act 1989 (as amended) allow for any competent party to provide metering services, including customers. In the electricity sector, the ex-PES distribution companies are the de facto monopoly metering service providers for non-half-hourly meter points. In respect of half-hourly meter points, there are a range of different providers, including ex-PES distributors operating 'out of area', and independent third parties.

The ex-PES distributors also have a licence obligation to provide metering services for all meter points, if requested by the relevant supplier. There are also obligations to publish statements of charges for metering services in a transparent form, and to ensure that such charges do not distort competition.

Electricity distributors are obliged by the terms of their licences to provide certain services in order to enable suppliers to supply customers. Electricity distributors, for example, are obliged to provide a metering point administration service. This service enables suppliers, among other things, to administer the transfer of customers between suppliers.

Ex-PES suppliers also have a supply obligation to make available a prepayment meter infrastructure service to all suppliers, on a non-discriminatory basis. This enables other suppliers to have access to services to provide domestic customers with a prepayment meter facility.

In April 2000, agent competition was introduced to the electricity market, allowing suppliers to choose who provides them with metering services. Suppliers are now able to contract with any accredited metering service provider for the functions of meter operator, data collector and data aggregator.

While the distribution network operators continue to dominate the market for metering and meter reading, some former PESs have sold off their metering businesses. TXU sold its metering business (excluding all meter assets) to Siemens and SEEBOARD sold its metering business (including half-hourly meter assets) to Invensys.

- Connections

Each former PES distribution business has a duty to connect customers within its authorised area at the request of a customer or supplier acting on the customer's behalf. In addition, the new distribution licence requires that standard terms of connection are offered to each customer and that each distribution business publishes a connection charging statement, setting out the methods and principles used to calculate connection charges.

Following consultation with Offer in 1995, the former PES distribution businesses opened some areas of connection work to competitive providers. Work open to competition is termed contestable, while work which remains the domain of the monopoly distributor is termed non-contestable.

However, electricity connections continue to be provided almost exclusively by the former PES distribution businesses operating within their authorised areas. The principal barriers preventing the development of effective competition relate to the policies and procedures adopted by each former PES distribution business in dealing with other providers of connections services. Ofgem has developed a strategy to facilitate the development of competition in connections. This is discussed in more detail under the section on **Review of Competition** in **Chapter 5**.

*Supply*⁵⁶

The supply businesses purchase electricity in bulk and sell to customers. Under NETA, this is achieved by suppliers contracting with generators bilaterally to meet their own contracted demand. Suppliers are required to forecast their own demand and face strong commercial incentives under the Balancing and Settlement Code to balance their own portfolio through their contracts.

Prior to the implementation of the Utilities Act 2000, there were two different types of suppliers operating in Great Britain – public electricity suppliers (PESs) and second-tier suppliers. The PESs (12 in England and Wales) were first established at privatisation from the old area boards. The PESs had a statutory duty to supply customers within their authorised areas and, in addition to their supply activities, were responsible for distribution in their authorised areas. With the progressive opening of the supply market to competition between 1990 and 1999, first the industrial and commercial market (from 1990, for those with peak loads greater than 1 MW and from 1994, for those with peak loads greater than 100 kW) and then the domestic market (between 1998 and 1999, for those below the 100 kW peak load), an increasing number of second-tier suppliers entered into the market, competing for PES market share.

The Utilities Act 2000 abolished the use of PES and second-tier licences, and introduced a Great Britain-wide licence, allowing all suppliers to supply customers nationwide. The Utilities Act also made provision for the separation of supply and distribution activities, requiring the separation of the former PESs supply and distribution businesses, and requiring these activities to be separately licensable. Thus, all suppliers are now on the same legal footing and the distribution activities of the former PESs have become separate businesses. Because of their dominance in their supply service areas (former PES authorised areas), the ex-PES suppliers continue to have certain additional obligations in their licences. These special conditions include a requirement to make available a prepayment meter payment infrastructure within their supply service areas and, until April 2002, regulatory price controls.

Today, any company holding an electricity supply licence can sell electricity, and all customers are free to choose their own supplier. There is no duty to supply, but each supplier has a duty to make available its terms of supply on request from customers. Suppliers supply electricity to customers using other company's distribution

⁵⁶ This section is drawn from Ofgem (2001), Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001; and Electricity Association (2002), Electricity Industry Review 6.

networks, which are offered on non-discriminatory terms, and paying distribution network operators for the use of the system. Suppliers who are authorised to supply domestic customers are required to meet all reasonable demands for the supply of electricity made by domestic customers within the areas that they operate. They are also required to ensure that they have sufficient electricity at their disposal to meet their customer requirements. This obligation is met through contracts with generators or by establishing their own generation.

There are currently 12 active licensed suppliers in England and Wales. In supply service area market share of the former PESs has declined steadily at 10% per annum and by the end of September 2001, they had lost an average of about 30% of customers in their own areas. One of the main trends in the domestic electricity supply market over the last year has been increasing consolidation through mergers and acquisitions. This has had a major impact on the relative market shares of the competing suppliers, with Innogy's acquisition of Yorkshire Electricity and Northern Electric and Gas making it largest domestic electricity supplier in Great Britain, with around one fifth of the market. British Gas Trading and TXU Energi closely follow Innogy (see **Appendix 3**). The four largest suppliers – Innogy, British Gas Trading, TXU and Scottish and Southern Energy – together hold almost two-thirds of the market. A number of major generators are active in the supply market, some, such as Innogy, through acquiring the former PESs supply businesses.

Scotland

The Scottish electricity industry had an integrated structure prior to privatisation, which continued after vesting. Two companies, Scottish Power and Scottish and Southern Energy (formed from a merger between Scottish Hydro-Electric and Southern Electric) cover the full range of electricity provision from electricity generation, transmission and distribution, through to supply. Scottish Power and Scottish and Southern Energy also have access to each others generating capacity under the long term contracts put into place at privatisation to provide the companies with a more balanced portfolio. The third main company operating in Scotland, British Energy, is a nuclear generator contracted for the full output of its Scottish nuclear plant to the other two companies until 2005.

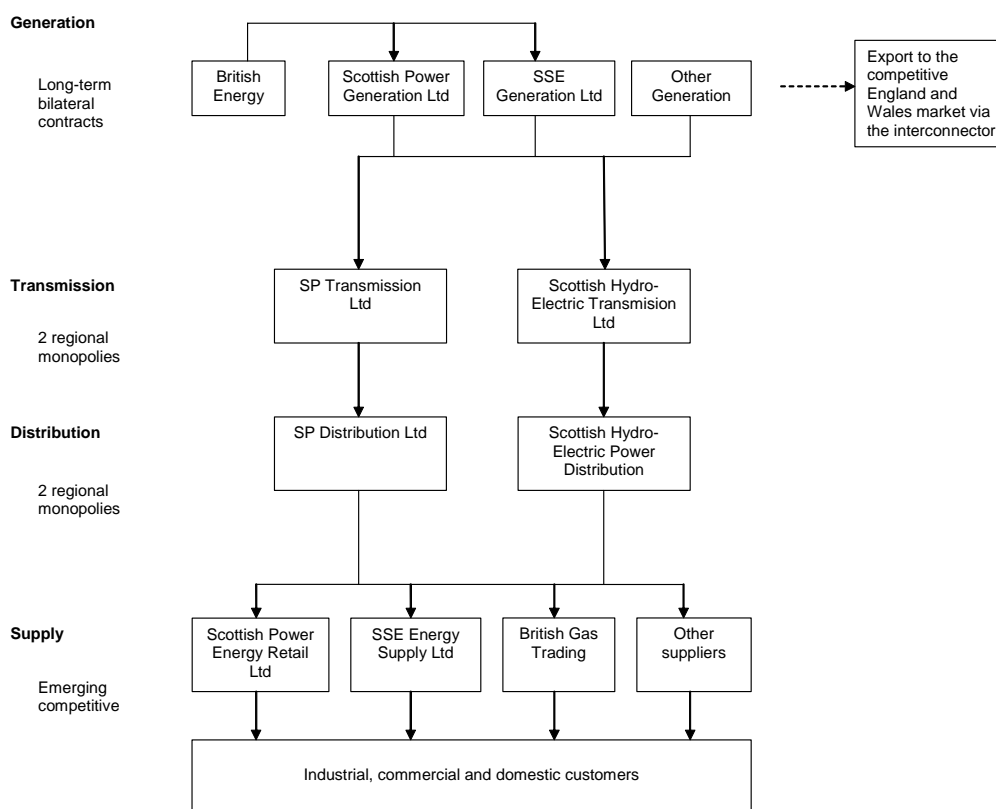
While the electricity market in Scotland has remained relatively stable over the past decade, there is a limited amount of competition in generation, and rather more in supply from Centrica, trading as Scottish Gas, and other suppliers.

Before September 2001, Scottish Power plc and Scottish and Southern Energy plc were vertically integrated companies, with Scottish generation, transmission, distribution and supply activities being held under composite licences. The companies were authorised by their composite licences to generate on a Great Britain basis, to transmit within their authorised transmission area and to supply electricity within their authorised supply area. In addition, each company held a second-tier licence. From 1 October 2001, Scottish Power plc and Scottish and Southern Energy plc, by virtue of the effect of the licensing and transfer schemes made by the secretary of state, each separated their Great Britain electricity interests into a number of separate licensed

legal entities. Within each company, generation, transmission, distribution and supply activities have now been allocated to the entity licensed for that purpose.

Figure 11 demonstrates the current structure of the electricity industry in Scotland.

Figure 11: Structure of the electricity industry in Scotland



Generation⁵⁷

The generation market has remained broadly unchanged since vesting. The three generating companies established at privatisation – Scottish Power (licensed as Scottish Power Generation Ltd), Scottish and Southern Energy (licensed as SSE Generation Ltd), and British Energy – continue to dominate the generating market. This is largely due to the limited opportunity for investment in Scotland as a result of its excess generating capacity.

At privatisation, the contractual structure of the electricity industry was reviewed and a number of contracts were put in place to provide for the sharing of electricity generated between Scottish Power and Scottish and Southern Energy (then Scottish Hydro-Electric). The objective of these contracts was to maintain the benefits of plant and fuel diversity by sharing the use of generating stations. The five contracts which remain in operation are:

⁵⁷ This section is drawn from Ofgem (2001), *The Development of British Electricity Trading and Transmission Arrangements (BETTA) – A consultation*; Electricity Association’s (2001), *Electricity Industry Review 5*; and Electricity Association (2002), *Electricity Industry Review 6*.

- the coal agreement, which entitles SSE Generation Ltd to one-sixth (576 MW) of the capacity of Scottish Power Generation Ltd's coal-fired stations (expiring in April 2004);
- the Peterhead agreement, which entitles Scottish Power Generation Ltd to one-half (642 MW) of the net capacity of SSE Generation Ltd's Peterhead station at privatisation (expiring in 2012);
- the hydro agreement, which provides for the sale of 400 GWh of SSE Generation Ltd's hydro-based generation to Scottish Power Generation Ltd (expires in April 2039);
- the Scottish interconnector agreement, which provides Scottish Hydro-Electric Transmission Ltd with access to the NGC interconnector through SP Transmission Ltd's transmission system (this contract is of indefinite duration);
- the system operation agreement, which facilitates the effective operation of the other restructuring contracts and of the two transmission systems (this is contract of indefinite duration).

The Nuclear Energy agreement, also put in place at privatisation, provides for the sale of all British Energy's output in Scotland to Scottish Power Generation Ltd (74.9%) and SSE Generation Ltd (25.1%). This contract is due to expire on 31 March 2005.

ScottishPower and Scottish and Southern Energy schedule generation in their own areas from plant available to them, either owned or under contract. ScottishPower's own generation capacity comprises two large coal-fired plants, hydro plant and wind turbines totalling 4,050 MW. The generation portfolio owned by Scottish and Southern Energy comprises the gas-fired Peterhead plant, a large number of hydro plants and wind turbine, amounting to 2,888 MW. Both companies have also invested in generation capacity in England and Wales. British Energy's two Scottish nuclear power stations provide the bulk of baseload in Scotland, accounting for about 50% of output. Scottish and Southern Energy's Peterhead power station provides the mid-merit, while ScottishPower's coal-fired stations act as swing generators. Exports to England and Wales provide a substantial additional market for Scottish generators.

Generation capacity in Scotland has always been more diverse than in England and Wales due to the presence of a large hydro-electric component. ScottishPower's two coal fired stations, Longannet and Cockerzie, accounted for 35% of total capacity in 1999/00, while British Energy's two nuclear power stations, Hunterston and Torness, accounted for 27%. Gas-fired power stations in Scotland with the largest, Peterhead, owned by Scottish and Southern Energy, accounted for 19% of total capacity. Hydro capacity largely owned by Scottish and Southern Energy represents 19% of the total and other renewables capacity 1%.

While ownership in Scotland has remained relatively stable, there has been some new entry into the generation market. The first new entrant into the Scottish market was Fife Power, the 134 MW gas-fired plant, which began operating in 1998. Powergen is the main customer for this output. Another new entrant is the 130 MW CCGT combined heat and power plant developed by IVO and Mitsubishi at BP's Grangemouth installation. There are also a significant number of renewable generation projects planned under the Scottish renewable orders (SROs), particular wind turbines and small-scale hydro.

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There is no directly competitive wholesale market for generation in Scotland. Suppliers wishing to purchase wholesale electricity in Scotland must negotiate with those holding generation plant in Scotland, acquire generation plant in Scotland, or import electricity from England and Wales via the interconnector. Scottish Power Generation Ltd and SSE Generation Ltd control, directly or by contract, 98% of generation sources in Scotland, as well as the bulk of interconnector capacity in England and Wales. They are bound to grant contracts to suppliers for wholesale electricity at prices indexed to that in England and Wales on the basis of a price administered by Ofgem. However, the lack of a fully competitive wholesale market and the absence of transparent rules governing the use of the interconnector acts as an impediment to new and existing suppliers.

Ofgem proposes to introduce a Great Britain-wide set of arrangements for wholesale trading, termed British electricity trading and transmission arrangements (BETTA) to remedy this situation. The principal components of BETTA are:

- the introduction of a common set of trading, balancing and settlement arrangements across Great Britain, based on those applying in England and Wales at the time of implementation;
- the introduction of a common set of transmission pricing arrangements and contractual provisions for transmission access across Great Britain, based on those applying in England and Wales at the time of implementation;
- the introduction of common independent balancing arrangements, through the creation of a single Great Britain system operator that is separate from generation and supply interests.

BETTA is unlikely to be introduced before 2004 and consequently a set of interim arrangements have been proposed. These include changes to:

- interconnector access arrangements;
- connection policy;
- transmission use of system and interconnector charging arrangements;
- the present administered wholesale and imbalance price arrangements which lapse on 31 March 2002.

*Transmission*⁵⁸

There are two transmission systems in Scotland. Scottish and Southern Energy, licensed as Scottish Hydro-Electric Transmission Ltd, owns and operates the transmission system in the north, comprising 4,808 circuit kilometres of 275kV and 132kV overhead lines and cables. Scottish Power, licensed as SP Transmission Ltd, owns and operates the system in the south of Scotland, comprising 4,098 circuit kilometres of 400kV, 275kV and 132 kV of overhead lines and cables.

The Scottish network is connected, via a 1,600 MW interconnector, to NGC's transmission system in England and Wales. Access to the interconnector was

⁵⁸ This section is drawn from Ofgem (2001), *The Development of British Electricity Trading and Transmission Arrangements (BETTA) – A consultation*; and Electricity Association's (2001), *Electricity Industry Review 5*.

addressed in a number of contractual and licence arrangements put in place at privatisation and thereafter. These contractual arrangements include:

- the British grid systems agreement between NGC and SP Transmission Ltd and Scottish Hydro-Electric Transmission Ltd, which provides a contractual framework within which the three system operators agree to share responsibility for technical issues associated with interconnecting their respective transmission systems (of indefinite duration);
- the use of interconnector agreements 1991 and 1994 between NGC and SP Transmission Ltd and Scottish Hydro-Electric Transmission Ltd, which provides the Scottish transmission licensees with the entire existing capacity of the NGC interconnector and facilitates upgrades to the interconnector (expiring in 2034).

Under the Scottish utility agreement, the initial 850 MW of capacity is split 54:46 between the companies, while the subsequent 750 MW upgrade is split 75:25. BNFL also has access to the link on a long term basis. The generation capacity in Scotland currently exceeds demand and companies export surplus output to England and Wales through the interconnector. As a consequence of constraints on the grid in England and Wales, flows through the interconnector are typically constrained to 1,200 MW. The full capacity will become available when NGC completes its proposed line in North Yorkshire. The two Scottish companies intend to upgrade the interconnector's capacity to 2,200 MW once NGC has resolved these bottlenecks. The proposed upgrade is also to be split 75:25 between the Scottish companies and there are plans for a further increase to 2,500 MW.

Under the terms of their transmission licence, ScottishPower and Scottish and Southern Energy are required to offer non-discriminatory terms and make interconnector capacity available to any party which wishes to trade through the link. The two transmission companies are required to publish an access and allocation code in respect of the interconnector.

There is no equivalent to the connection and use of system code (CUSC) in Scotland and, consequently there are no published statements outlining generic provisions for connection to and use of the transmission systems of SP Transmission Ltd and Scottish Hydro-Electric Transmission Ltd. Parties seeking access to either of the Scottish transmission systems must enter into a bilateral agreement for connection to and use of the transmission system with the relevant licensee. However, since the demerger of Scottish Power UK plc and SSE plc into separately licensed legal entities from 1 October 2001, the same bilateral contracts must exist between the Scottish transmission licensees and their host generation businesses as exist between the transmission licensees and any other independent generators. The two transmission companies are required, under their licences, to produce annual statements, approved by Ofgem, of charges to be applied to parties seeking access to their transmission systems.

As for NGC, the two transmission licensees are required to develop and maintain an efficient, co-ordinated and economical system of electricity transmission. In meeting these obligations, each transmission company must take balancing actions. The generation and supply businesses of Scottish Power UK plc and Scottish and Southern

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Energy plc are not subject to the same balancing arrangements within their own settlement areas as other independent generators and suppliers competing in Scotland. At present, SP Transmission Ltd and Scottish Hydro-Electric Transmission Ltd provide system and energy balancing services in their respective areas. Their grid codes require them to call on any generators to provide these services, but in practice Scottish Power Generation Ltd and SSE Generation Ltd will provide these services. As a result of this obligation to balance the system, the two host generating companies are never exposed to imbalances when trading with suppliers in their own areas. However, all independent supply and generation companies are potentially exposed to imbalance volumes.

The arrangements for the definition and settlement of balancing energy are set down in the settlement agreement for Scotland and associated arrangements. The trading code for Scotland facilitates the short term trading of electricity, ancillary services and interconnector capacity within Scotland between the trading code members (currently, these are Scottish Power Generation Ltd, SSE Generation Ltd, BNFL, Powergen, and Grangemouth CHP Ltd). Ofgem approves the trading code and any revisions to it. Licensed generators and suppliers are required to comply with the trading code.

Separate grid codes for each transmission licensee set down the planning and operating procedures, and principles and standards governing the transmission companies' relationship with users of the transmission systems.

Distribution

Scottish Power and Scottish and Southern are the owners and operators of the two local distribution systems in Scotland. Their distribution businesses, SP Distribution Ltd and Scottish Hydro-Electric Power Distribution Ltd, are the nominated licence holders for distribution activities in Scotland.

The distribution companies have statutory duties to develop and maintain an efficient, co-ordinated and economical system of electricity distribution, and to facilitate competition in the supply and generation of electricity.

As in England and Wales, the two ex-PES distribution businesses continue to be the main providers of metering and meter reading services in Scotland, and have the same legal responsibilities with regard to the provision and maintenance of metering and data services.

*Supply*⁵⁹

As in England and Wales, competition in domestic electricity supply was rolled out between September 1998 and May 1999. Prior to the implementation of the Utilities Act 2000, suppliers operated under two types of licences – public electricity supply (PES) and second-tier licences – with different legal terms and conditions attached. Scottish Power and Scottish and Southern Energy each held a PES licence for their authorised areas. Each company also held a second-tier licence for each others'

⁵⁹ This section is drawn primarily from Ofgem (2001), Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001.

authorised area. Third party access to the transmission and distribution systems on a non-discriminatory basis enabled other second-tier suppliers to compete for market share in Scotland.

The Utilities Act has removed the concept of the PES, introducing a single licence for all suppliers. All suppliers, thus now operate in the market on the same legal terms. With the demerger of Scottish Power and Scottish and Southern Energy into separate legal entities, their supply businesses, Scottish Power Energy Retail Ltd and SSE Energy Supply Ltd, are now the holders of the supply licences. While Scottish Power Energy Retail Ltd holds a Great Britain-wide licence, SSE Energy Supply Ltd does not. There are currently 10 licensed suppliers active in the electricity supply market in Scotland.

Competition in supply is much less developed in Scotland than in England and Wales. While Scottish Power Energy Retail Ltd and SSE Energy Supply Ltd have seen their market shares decline, they still retained 77% of the Scottish supply market (in terms of customers supplied) by the end of June 2001 (with 53% and 24% of market share respectively). The only other company which has gained significant market share in Scotland is British Gas Trading, with 19% of the market share by customers supplied.

Northern Ireland

The structure of the electricity industry in Northern Ireland is quite different from that in Great Britain. In practice, there are two partially interconnected market structures (as illustrated in **Figure 12**). On the one hand, there is the 'franchise' or non-competitive market, set up at privatisation, which although allows any licensed supplier to sell electricity to final customers in Northern Ireland, restricts trade in electricity generation. For the 'franchise' or non-eligible customers (currently 65% of the market by volume), generators are required to sell their output to the power procurement business (PPB) of Northern Ireland Electricity (NIE) and customers are required to purchase their electricity from the PPB, either through NIE's supply business or via a second-tier supplier. Few second-tier suppliers have entered the 'franchise' market and NIE supply, as the sole holder of a public electricity supply licence, is the main supplier operating in this market. On the other hand, there is the competitive market, established through the implementation of the EU directive on the Internal Market in Electricity (IME directive), which is based on bilateral trades between independent generators (IPPs) and suppliers (STs). In addition to being able to purchase electricity through the PPB, eligible customers (those consuming more than 0.79 GWh per annum) may purchase electricity from generators either directly or through second-tier suppliers.

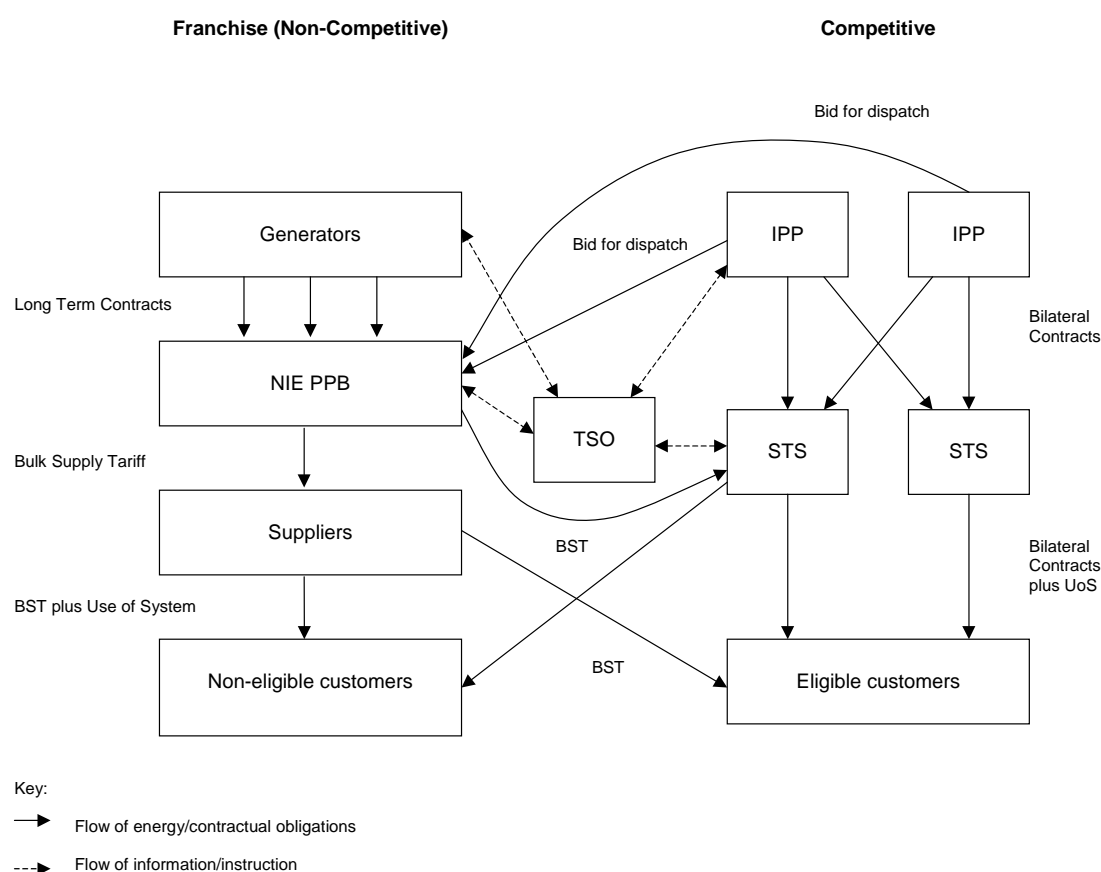
The primary elements of the Northern Ireland electricity industry are:

- generation, which is in the hands of three private sector companies, who own the four major power stations;

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- power procurement, transmission and distribution, over which NIE has monopoly control;⁶⁰
- supply, for which NIE holds the only public electricity supply licence, but is open to second-tier supply;
- interconnectors, connecting the Northern Ireland electricity system to the electricity systems in the Republic of Ireland and Great Britain, which are open to third party users and allocate capacity in an open, transparent and competitive way.

Figure 12: The structure of the Northern Ireland electricity industry



Generation

The generation business in Northern Ireland consists of four power plants – Ballylumford owned by Premier Power (a subsidiary of British Gas), Kilroot and Belfast West owned by AES Ltd (formerly Nigen), and Coolkeeragh owned privately by investors and management – with Ballylumford and Kilroot producing almost 90% of Northern Ireland’s generation output.⁶¹

⁶⁰ Following a capital reorganisation in 1998, the regulated businesses of NIE were separated from the unregulated businesses and a new holding company, Viridian Group plc, was established, leaving NIE to concentrate on regulated businesses.

⁶¹ Electricity Association (2001), Electricity Industry Review 5.

At privatisation, Northern Ireland relied mainly on coal and oil as generating fuels. With the conversion of Ballylumford to gas-fired generation and the retirement of a number of generation units in Belfast West and Coolkeeragh, the generation mix has changed significantly. Gas-fired capacity now accounts for 45% of the total, coal-fired for about 24%, oil-fired capacity for 18% and gas oil for 11%. Renewables capacity accounts for the balance (2%).

A series of power purchase agreements (PPAs), and related generating unit agreements (GUAs), were struck between NIE's power procurement business (PPB) and the generating companies at privatisation. Under these long-term contracts, the generating companies were required to sell their entire output to the PPB, which then sold electricity on to licensed suppliers, including NIE's own supply business. This secured the position of the generating companies, but also deterred new entry into the generating market.⁶²

The generation market is being opened to competition with the implementation of the IME directive. As part of this implementation process, some generating units were taken out of contract with the PPB and can now trade directly with suppliers to eligible customers. The eligible customer market in Northern Ireland is thus based on bilateral trades between independent generators (IPPs) and suppliers (STSs). As suppliers can purchase from the PPB, the existence of the PPB effectively caps the price which the generators can charge (however, the present cap set by the PPB is itself high, being a function of the PPB's high cost contracts with inefficient plant).

Power procurement business (PPB)

There is no wholesale electricity market in Northern Ireland. Instead, at privatisation, the PPB was set up as a separate regulated business under NIE's combined transmission and public electricity supply licence. Under the supply competition code, the PPB's role is to act as the buyer for the purchase of wholesale electricity in Northern Ireland, and to sell this wholesale electricity to licensed suppliers (including NIE's own supply business).⁶³ Owing to NIE's dominance in the Northern Ireland market, the PPB is obliged to sell its electricity to all suppliers and final customers at a single set of published and regulated prices known as the bulk supply tariff (BST). It is accordingly prohibited from striking individual deals with each purchaser.

The PPAs, which were put into place prior to privatisation and continue in force until expiry or cancellation in 2010-2012, set out the terms under which power is sold by the generators to the PPB and include two types of payment – payments for the availability of generation capacity and payments for the supply of energy.⁶⁴ Availability payments are made irrespective of whether a generation unit is called to run and aim to provide a financial incentive to the generators to make available the required capacity to ensure security of supply. Energy payments relate to physical delivery, reimbursing the costs of running generating units and sending out the electricity. Prices in these contracts are comparatively high.

⁶² Electricity Association (2001), Electricity Industry Review 5.

⁶³ The supply competition code, which was introduced in April 1992, sets out the trading arrangements for bulk supplies of electricity.

⁶⁴ The PPAs are a 'pass through cost' and form the largest element of cost under the BST.

Transmission systems operator

The IME directive brought about a change in market structure, requiring that the NIE's systems operation business (which was formerly considered to be part of the PPB) be separated from the PPB. Viridian (the parent company of NIE) established the systems operation business as a separate subsidiary known as system operator Northern Ireland (SONI) on 1 May 2000. SONI's management structure separates it from the rest of Viridian's regulated and unregulated energy businesses.

The role of the TSO is pivotal in the development of market structures for the liberalisation of generation and supply markets in the Northern Ireland electricity sector. The roles of the TSO are of two types – physical and financial – and occur both in real time and over a longer-term planning horizon. At present, the TSO is responsible for dispatch of generation, for the management of outages, the levying of system support services charges, the operation of the financial and physical settlement system, management of interconnector flows and for maintenance of operational security standards. While in Northern Ireland, the TSO does not have direct control of the transmission system planning function, it does co-operate with NIE's transmission and distribution business in this area.

Oreg is currently consulting on the ownership and legal status of the TSO, with a view to separating the TSO from NIE to ensure its independence of all other commercial interests in the industry.⁶⁵ The separation of the TSO business will require clarification of the role of the TSO in planning investment in the transmission network.

Transmission and distribution

In Northern Ireland, the transmission and distribution networks are treated as a single system for transferring electricity from power stations to customers' premises. NIE is the monopoly owner and operator of these transmission and distribution assets.

With regard to the transmission system, NIE is required to publish annual statements which show forecast electricity demand, generation capacity, and loading on its transmission system for the seven years ahead. The grid code governs the technical aspects of the transmission system. In Northern Ireland, the grid code also contains metering codes which cover both the operation of generation and tariff metering. These are to ensure a predictable metering system for the contracts set up at restructuring between the generators and NIE. With regard to the distribution system, NIE is required to offer terms for connection on request and to comply with the technical requirements for the distribution system.

⁶⁵ See Oreg (2002), An Independent Transmission System Operator for Northern Ireland – A consultation paper issued by the director general for electricity supply (Northern Ireland), March 2002).

Supply

While NIE is the only public electricity supplier in Northern Ireland, electricity supply has been open to competition since privatisation. Under the Electricity (Northern Ireland) Order 1992, second-tier suppliers are free to compete for all customers. In addition to NIE's PES licence, 13 licences have been issued to second-tier suppliers. However, in 2001, only two of these second-tier suppliers were active in the supply market. While second-tier suppliers are allowed to sell electricity to any customer in Northern Ireland, prior to July 1999, all suppliers had to buy their power from NIE's PPB. Since July 1999, in line with the IME directive, the market has been divided into two – eligible and non-eligible customers. If suppliers sell to eligible customers, or if they sell renewable electricity, they are entitled to purchase their electricity from any generator.⁶⁶ If they sell to customers who are not eligible, they must – unless they sell renewable electricity – buy their electricity from the PPB at the bulk supply tariff (BST).

While theoretically the supply market is 100% open, competition has failed to develop in the 'franchise' market. This is largely due to the fact that a second-tier supplier selling to a 'franchise' customer faces the same generation costs and the same transmission and distribution costs as the NIE PES. The only area of cost over which the second-tier supplier could compete is the 5-7% represented by the supply component of the final price. As NIE's PES business has a tight price control with profit based on a margin of 0.5% of turnover, there is not much scope for creating competitive gains which could be passed on to customers as price reductions. NIE supply is thus the main supplier of the 'franchise' or non-eligible market (approximately 65% of the market by volume), although a small number of ineligible customers are also supplied by second-tier suppliers.

*Interconnectors*⁶⁷

Northern Ireland has two main interconnectors – the north/south interconnector, which connects the Northern Ireland electricity system with the electricity system in the Republic of Ireland and has been in use for trading since it was restored in 1995, and the Moyle interconnector, which links the Northern Ireland electricity system to the systems in Great Britain and has been available for use for trading since 1 January 2002.

The main north/south interconnector has a theoretical available transfer capacity of 330 MW, although not all of this is currently available for trading. Investments are scheduled which will strengthen the theoretical capacity of the main north/south interconnector to 660 MW. In addition, two present standby connections to the west are being upgraded to become full system interconnectors, each with a capacity of 125 MW.

⁶⁶ The renewables market in Northern Ireland is fully open to competition and, therefore, purchases from renewable generators may be made directly by suppliers.

⁶⁷ This section is drawn from Ofreg (2001), Moyle and north/south interconnectors – trading arrangements from 1 April 2002, A consultation paper issued by the DGESNI, June 2001 and Ofreg (2001), Proposals for Moyle and north/south interconnectors – Trading arrangements from 1 April 2002, A decision paper by the DGESNI, November 2001.

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Until February 2000, the north/south interconnector was mainly used for providing mutual support for the two electricity systems and limited trading between the utilities. In February 2000, with both the Northern Ireland and the Republic of Ireland electricity markets open to competition (under the IME directive), the potential increased for cross-border trade via the north/south interconnector. Ofreg and the Republic of Ireland regulatory body, the Commission for Electricity Regulation, agreed interim interconnector trading arrangements in order to adopt a harmonised approach with third party access capacity allocated by auction. The north/south interconnector capacity rights for 100 MW capacity from February 2000 to March 2001 were awarded via an auction. A reserve price of £100/MW per month was set with capacity allocated in 1 MW tranches. The north/south export capacity rights from April 2001 to March 2002 were auctioned on similar terms as before with 120 MW being made available.

The Moyle interconnector has a theoretical capacity of 500 MW. NIE's PPB has contracted with Scottish Power for 125 MW of the 500 MW capacity. This electricity supply agreement (for a period of 70 months from the date of commissioning) leaves the remaining capacity available for use by third parties on a non-discriminatory basis. Between January 2002 and 31 March 2002, 300 MW of transfer capacity was available with 175 MW of capacity being auctioned to third parties. Capacity was allocated in tranches of 5 MW with a reserve price of £1000/MW per month, and a pay-as-bid price attached to each capacity block. The PPB paid this reserve price for its 125 MW of reserved capacity during the first three months of 2002.

From the 1 April 2002, a new trading model was introduced for the Moyle and north/south interconnectors. This model aims to ensure the allocation of capacity in an open, transparent and competitive manner. Under the new model, the available transfer capacity is determined by the System Operator Northern Ireland (SONI) in co-operation with the transmission system operators in Scotland and the Republic of Ireland. SONI is responsible, with regulatory oversight, for allocating the Moyle interconnector capacity in both directions (import and export) and that for north-south flows (export) on the north/south interconnector (the Republic of Ireland transmission system operator is responsible for making capacity allocation arrangements for any south-north flows). Interconnector capacity is allocated via pay-as-bid auctions. Secondary trading in acquired rights is permitted so that original holders of capacity have the opportunity to re-assign and sell on their capacity.

4 REGULATION

The framework for the regulation of the UK electricity industry is laid down principally by sector-specific legislation – the Electricity Act 1989 (as amended) in Great Britain and the Electricity (Northern Ireland) Order 1992 (as amended) in Northern Ireland – and the licences issued under it. However, the regulators of the electricity industry also have recourse to powers under general competition legislation – the Competition Act 1998 and the Fair Trading Act 1973.

The regulatory models adopted at privatisation were broadly consistent across the utility sectors, being comprised of an independent economic regulator supported by a regulatory office. In the case of the electricity sector, this took the form of a director general of electricity supply (DGES), supported by the Office of Electricity Regulation (Offer), in Great Britain; and a legally separate post of director general of electricity supply for Northern Ireland (DGESNI), supported by the Office of Electricity Supply for Northern Ireland (Offer NI). Since privatisation, changes have occurred to the structure and powers of the regulators in both Great Britain and Northern Ireland. In Northern Ireland, the DGESNI took on the joint post of director general of gas supply for Northern Ireland in 1996. At this time, Offer NI became the Office for the Regulation of Electricity and Gas (Ofreg). In Great Britain, the Utilities Act 2000, which received Royal Assent on 28 July 2000, has substantially transformed the framework for energy utility regulation. The Act merges the former gas and electricity regulators, replacing the individual regulators for the gas and electricity sectors with a regulatory authority, the Gas and Electricity Markets Authority, supported by the Office for Gas and Electricity Markets (Ofgem). The Act also made changes to the primary duties of the regulator, provided new powers to the regulatory authority, and made changes to customer representation in the energy sector.

The Competition Act 1998, which came into full effect on 1 March 2000, also provided for new powers in the regulation of the electricity industry. The Act gave the Authority and the DGESNI concurrent powers with the director general of fair trading. The Office of Fair Trading and the sector regulators, Ofgem and Ofreg, will enforce the prohibitions in the Act using their concurrent powers, which include the ability to impose financial penalties for infringements of prohibitions in the Act.

While the primary focus in the electricity sector has been on economic regulation of sector activities (principally a role fulfilled by the sector regulators), the nature of the electricity product – that is, a good with inherent social and economic utility, which is also one of the major sector contributors to environmental pollution – means that there is also a strong need for environmental and social regulation.

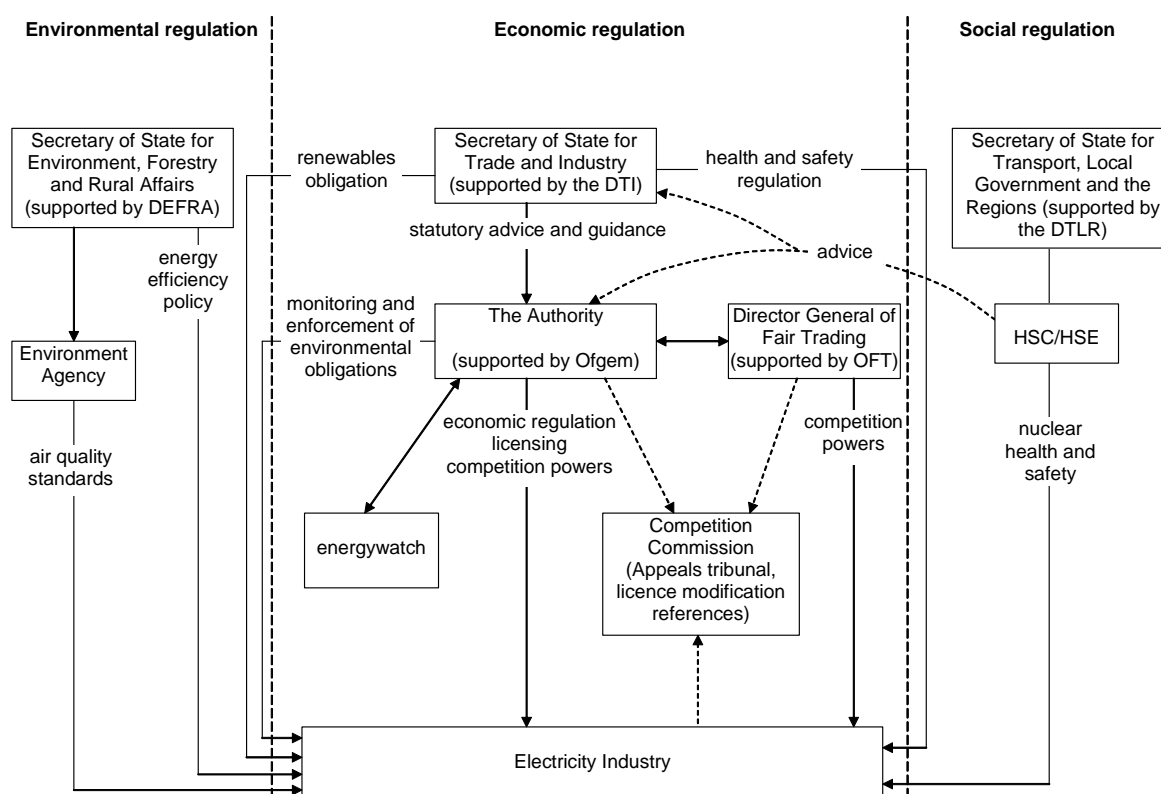
The sections which follow detail the institutional governance of the electricity sector, focusing on the structure and powers of the key institutions responsible for regulating economic, environmental and social activities in the electricity sector; and the electricity licensing regime.

- Institutional governance of the electricity industry

England Wales and Scotland

The institutional framework for regulation of the electricity industry in Great Britain is set out in **Figure 13** and discussed in the text that follows.

Figure 13: Institutional framework for regulation of the electricity industry in Great Britain



Economic regulation

As mentioned, the statutory framework for electricity utility regulation in England, Scotland and Wales is laid down principally by the Electricity Act 1989 (as amended). The Competition Act 1998 and the Utilities Act 2000 have transformed the framework for energy utility regulation in Great Britain.⁶⁸ Notably, the main changes to the regulatory framework for the electricity sector are:

⁶⁸ These provisions set out in the Utilities Act 2000 as regard electricity were given effect, in the main, through amendments to the Electricity Act 1989.

- the replacement of an individual regulator, the director general of electricity supply, with a regulatory board, the Gas and Electricity Markets Authority (the Authority);
- the merging of the regulatory offices for the gas and electricity sectors, the Office of Gas Supply and the Office of Electricity Regulation (Offer) respectively, into a single regulatory office, the Office of Gas and Electricity Markets (Ofgem);
- the replacement of the electricity consumer committees with an independent gas and electricity consumer council, known as *energywatch*;
- changes to the primary duties of the secretary of state and the regulatory authority, and a shift in the division of responsibilities between the secretary of state and the regulatory authority;
- new powers for both the secretary of state and the regulatory authority.

The current arrangements for the regulation of the electricity sector in Great Britain are described below, with reference to the changes made under the Utilities Act 2000.

The electricity industry is regulated primarily by the Gas and Electricity Markets Authority, a body corporate comprised of a chair and ten other members.⁶⁹ The Authority is supported by a non-ministerial government department, the Office of Gas and Electricity Markets (Ofgem).⁷⁰ The Authority was established in December 2000, replacing the former individual directors general for gas supply and electricity supply at the head of Ofgem, becoming the board of Ofgem.⁷¹ Callum McCarthy, who had held both director general posts since January 1999, became the chair of the Authority, and the chief executive of Ofgem. While the Authority is responsible for the statutory responsibilities under the Acts and for developing strategy and policy, Ofgem is responsible for day-to-day operations and implementing policy.⁷²

Reflecting the government's imperative to place the interests of consumers at the heart of utility regulation, the Utilities Act 2000 placed a new primary duty on Ofgem and the Secretary of State for Trade and Industry "to protect the interests of consumers in relation to electricity conveyed by distribution systems, wherever appropriate by promoting effective competition". In fulfilling this duty, Ofgem and the secretary of state are required to have regard to the needs to secure that all reasonable demands for electricity are met, and to secure that licence holders are able to finance their activities which are subject to obligations under the Electricity Act

⁶⁹ Under the Utilities Act 2000, the Authority must comprise, at a minimum, the chair and two other members appointed by the secretary of state.

⁷⁰ Ofgem was established on 16 June 1999, when the former regulatory offices, the Office of Gas Supply and the Office of Electricity Regulation, were combined and renamed in anticipation of the Utilities Act 2000.

⁷¹ The Authority formally assumed its powers on 20 December 2000 under the Utilities Act 2000 (Commencement No. 4 and Transitional Provisions) Order 2000, which transferred the powers of the director general of electricity supply and the director general of gas supply to the Authority. The Order replaced the previous duties of the directors general which affected the manner in which the regulatory functions are exercised.

⁷² While the Authority holds the powers legislated for under the Utilities Act 2000, Ofgem is the body responsible for implementing the Authority's functions and also acts as the public face of the Authority. As a consequence, for the remainder of this document, unless differentiation is specifically required for clarification, references to Ofgem can be taken to mean references to the Authority.

UK ELECTRICITY REGULATION

1989.⁷³ Furthermore, in performing these duties, they are required to have particular regard to the interests of individuals who are disabled or chronically sick, of pensionable age, or with low incomes, and those living in rural areas.

The secretary of state and Ofgem also have a duty to protect the public from dangers arising from the generation, transmission, distribution or supply of electricity, to secure a diverse and viable long-term energy supply, and, in carrying out their functions, have regard to the effect on the environment of activities connected with electricity generation, transmission, distribution and supply (for full details of the duties of the secretary of state and Ofgem, see **Appendix 5**).

Ofgem is also responsible for carrying out other functions established under the Electricity Act 1989 and the Utilities Act 2000. Most significantly, Ofgem has been conferred the power to grant licences for transmission, generation, supply and distribution activities; and is responsible for general monitoring, supervision and enforcement of the licensing regime. To fulfil its functions in relation to securing compliance with the licensing regime, Ofgem has the power, under Section 28 of the Electricity Act 1989, to obtain information from licensees and others in relation to potential breaches of licence. Each electricity licence also includes conditions requiring licensees to provide information requested by Ofgem to fulfil its duties under the Electricity Act 1989 and the Utilities Act 2000 and to enforce the requirements of the licences.⁷⁴ With respect to its powers in relation to the licensing regime, Ofgem also has the power to modify the standard conditions of licences, which are set by the secretary of state (the licensing regime is discussed in further detail in the section which follows).

The Utilities Act also provided the secretary of state with new powers and responsibilities, including a power to raise a cross-subsidy in favour of identifiable groups of disadvantaged customers in the energy sector, a power to make regulations to promote energy efficiency, and a responsibility to provide guidance on the social and environmental objectives of the sector. Ofgem has a duty to have regard to this social and environmental guidance, but to-date the secretary of state has failed to provide such guidance to the regulator (although draft guidance was issued in May 2001).

- Competition law and the Competition Commission⁷⁵

Ofgem also has concurrent powers with the director general of fair trading (DGFT) to apply the Competition Act 1998 and the Fair Trading Act 1973 to the electricity sector in Great Britain.⁷⁶

⁷³ Utilities Act 2000, Section 13.

⁷⁴ Office of Fair Trading (2001), The Competition Act 1998 – The application in the energy sector, OFT 428, March 2001.

⁷⁵ This section is drawn primarily from The Competition Act 1998 - Concurrent application to the regulated industries, OFT 405, January 2001; and The Competition Act 1998 – The application in the energy sector, OFT 428, March 2001.

⁷⁶ For concurrency of powers, see the Competition Act 1998 (Concurrency) Regulations 2000 and The Competition Act 1998 – Concurrent application to regulated industries, OFT 405, January 2001. For

The Competition Act 1998, which came into full effect on 1 March 2000, replaced or amended legislation, including the Restrictive Trade Practices Act 1976, the Resale Prices Act 1976 and the majority of the Competition Act 1980. The Chapter I and II prohibitions of the Act are based on the provisions of Articles 81 and 82 of the EC Treaty. Chapter I prohibits agreements between undertakings, decisions by associations of undertakings or concerted practices which have the object or effect of preventing, restricting or distorting competition in the UK or may affect trade within the UK. Chapter II prohibits conduct by one or more undertakings which amounts to the abuse of a dominant position in the market in the UK which may affect trade within the UK.

The Office of Fair Trading (OFT) and Ofgem enforce the Chapter I and II prohibitions using their concurrent powers. These powers include the ability to consider complaints about breach of the prohibitions, to impose interim measures to prevent serious and irreparable damage, to grant exemptions to the Chapter I prohibition, to carry out investigations both on their own initiative and in response to complaints, to give and enforce directions to bring an infringement of a prohibition in the Act to an end, and to impose financial penalties of up to 10% of the turnover of the undertaking concerned, for every year of the infringement up to a maximum of three years.

While Ofgem shares most powers with the DGFT to apply and enforce the Competition Act in the electricity sector, the DGFT alone has powers to make and amend the Director's rules, which set out the procedures to be followed when applying the Competition Act and contain provisions for the co-ordination of the performance of concurrent functions under the Competition Act, and to provide guidance on the appropriate level of penalties under the Act.⁷⁷ Where the DGFT and Ofgem have concurrent jurisdiction over an agreement or conduct that relates to the electricity sector, Ofgem will in most cases be responsible for dealing with the case.

The Competition Act 1998 amends the Electricity Act 1989 so that, while Ofgem should continue to have regard to its sectoral duties when carrying out its utility functions, Ofgem should not do so when exercising concurrent powers under the Act. Ofgem may, however, have regard to matters covered by its sectoral duties provided they are matters to which the DGFT could have regard in exercising his powers under the Act. Ofgem is also required under the Act to ensure that the handling of cases is consistent with EU law. The Competition Act 1998 also amends the sector-specific legislation to provide, where it is more appropriate to use powers under the Competition Act, that Ofgem's duty to take licence enforcement action under the Electricity Act 1989 does not apply.

In addition to the Competition Act 1998, the competition law framework which deals with monopolies in the Fair Trading Act 1973 has been retained. This allows scale or complex monopolies to be examined by Ofgem and the DGFT who may then make a

application of the Competition Act 1998 to the energy sector in Great Britain, see The Competition Act 1998 – The application in the energy sector, OFT 428, March 2001.

⁷⁷ These are set out in the Competition Act 1998 (Director's Rules) Order 2000 (SI 2000, No 293), and the Competition Act 1998 (Concurrency) Regulations 2000 (SI 2000, No 260).

reference to the Competition Commission for it to investigate whether a monopoly situation operates, or may be expected to operate, against the public interest.

The Competition Commission was established by the Competition Act 1998, replacing the Monopolies and Mergers Commission (MMC) on 1 April 1999. The role of the Competition Commission in the electricity sector is two fold – it conducts inquiries on matters referred to it concerning monopolies, mergers and the economic regulation of the electricity companies, including licence modification proposals, and its appeals tribunal hears appeals against decisions made under the prohibition provisions of the Competition Act 1998.⁷⁸

With regard to its investigating and reporting role, the Competition Commission conducts investigations in the electricity sector in response to references made to it by the secretary of state, the DGFT and Ofgem. In most cases, the Competition Commission will be asked to decide whether the matter referred to it is against the public interest. After a report has been made, if the Competition Commission makes no adverse public interest finding, no action is taken. In the case of utility licence modifications, the Utilities Act 2000 confers powers to the Competition Commission to veto licence modifications developed by a regulator following a reference if, in its opinion, they do not remedy or prevent the adverse effects identified by the Commission in its report on the reference.

With regard to its appeals function, the Competition Commission may hear appeals on a range of decisions taken by the DGFT or Ofgem, including on whether a prohibition has been infringed, whether to grant an individual exemption, in respect of the conditions, obligations or period of an individual exemption, as regard the conditions subject to which a parallel exemption under EC law is to have effect, cancelling an exemption, and as to the imposition of a penalty or as to the amount of any such penalty. The appeals tribunal may confirm or set aside all or part of a decision, remit the matter to the DGFT or Ofgem, impose, revoke or vary the amount of any penalty, grant or cancel an individual exemption or vary any condition or obligation, or make any other decision that the DGFT or the regulator could have made.

*Environmental regulation*⁷⁹

While Ofgem does have a duty to have regard to the effect on the environment of activities related to the generation, transmission, distribution and supply of electricity, environmental regulation of the electricity sector is principally undertaken by other bodies. As sector regulator, however, Ofgem has a responsibility to implement and monitor environmental programmes. Ofgem is also required, under the Utilities Act 2000, to have regard to guidance issued by the secretary of state on the government's environmental policy priorities (see **Chapter 7 on Environmental Regulation**).

⁷⁸ The Competition Commission comprises a reporting panel, which conducts inquiries into merger, monopoly and regulatory references, an appeals panel, which hears appeals against prohibition decisions, and specialist panels for electricity, telecommunications, water and newspapers, which assist in some of the regulatory inquiries.

⁷⁹ This section is drawn from Ofgem (2001), Environmental Action Plan: Key organisations in environmental policy, August 2001; and Electricity Association (2001), Environmental Briefing – UK statutory environmental bodies, April 2001.

The Department of Environment, Food and Rural Affairs (DEFRA) plays a key role in the development of regulatory policy related to energy efficiency and the protection and improvement of air quality.⁸⁰ Specifically, DEFRA is responsible, from April 2002, for setting the overall energy efficiency targets for electricity supply companies under the energy efficiency commitment. The implementation and monitoring of suppliers' compliance with these targets is the responsibility of Ofgem (the energy efficiency commitment and the former energy efficiency standards of performance are discussed in more detail in **Chapter 7**). DEFRA is also responsible for co-ordinating the domestic climate change programme, which refers to, amongst others, policy areas on combined heat and power and the climate change levy.

The Department of Trade and Industry (DTI) has a major role to play in promoting renewable sources of electricity. Under the Utilities Act 2000, the government has been given the power to establish new arrangements to boost electricity generated from renewable sources. This takes the form of the renewables obligation (and the renewables obligation Scotland, determined by the Scottish Ministers), which places an obligation on licensed electricity suppliers in Great Britain to source a growing percentage of their total sales from eligible renewable sources. In accordance with the Utilities Act, Ofgem will administer, and monitor compliance with, these arrangements (the renewables obligation is discussed in more detail in **Chapter 7**).

The DTI also plays a role in planning policy which includes issuing regulations for construction consent for generating stations and overhead lines. The new Electricity Works Regulations 2000 (Environmental Impact Assessment (England and Wales)) came into force in September 2000 and covers applications for consent to construct, extend, operate a power station or install or keep installed overhead electricity lines. The Department for Transport, Local Government and the Regions (DTLR) and local authorities both have responsibilities in issuing planning permission, but Ofgem does not.

The Environment Agency, and its sister agency in Scotland, the Scottish Environmental Protection Agency, are the principal environmental regulators in Great Britain. One of the key responsibilities of these regulatory agencies in relation to the energy sector is to enforce the integrated pollution prevention control regulations. Under these regulations, the relevant environmental regulator issues authorisations for prescribed processes, including electricity generation. The Environment Agency is also responsible for setting emissions levels for power stations and has a regulatory function defined under the Environmental Protection Act 1990. The limits are designed to protect the environment from excessive emissions of sulphur dioxide, nitrogen oxides and particulate matter. The Agency's underlying approach is to ensure that best available techniques not involving excessive costs (BATNEEC) are used to prevent or minimise pollution to the environment as a whole.

The Environment Agency has signed a memorandum of understanding (MoU) with Ofgem, setting out the ways in which Ofgem and the Environment Agency will work together to co-ordinate their functions and activities relating to environmental

⁸⁰ DEFRA was established in 2001, taking over responsibility for environmental issues previously dealt with by the DETR and MAFF. This included taking over responsibility for the Environmental Protection Group and the Sustainable Development Unit of the DETR.

issues.⁸¹ The MoU sets out a range of shared environmental concerns on which Ofgem and the Environment Agency are likely to liaise, including:

- climate change measures;
- environmental consequences of power production;
- economic consequences of environmental regulation;
- provision of environmental information;
- inputs to international policy matters;
- provision of technical standards and guidance.

Health and safety

The Engineering Inspectorate of the DTI takes lead responsibility for health and safety within the electricity industry. They are responsible for ensuring safe supply of electricity, safe consumer connections and meter installation, the safety of the distribution and supply system and the general safety of the public. The Engineering Inspectorate enforces the Electricity Supply Regulations 1988 (as amended) and the Electricity Safety, Quality and Continuity Regulations 2001, which came into force on 1 October 2001.

Although the DTI takes the lead for health and safety in the electricity sector, the Health and Safety Commission/Health and Safety Executive (HSC/HSE), a non-departmental public body responsible to the DTLR, also plays a significant role. Under the Nuclear Installations Act 1965, the HSC/HSE has particular responsibility for nuclear safety. It also has key functions under the Control of Major Accident Hazards (COMAH) 1999 and the Control of Substances Hazardous to Health (COSHH) 1999 legislation. The Nuclear Safety Directorate of the HSE sets safety standards to be used at nuclear sites in the UK and is responsible for licensing of nuclear installations. HM Nuclear Installations Inspectorate, part of the Nuclear Safety Directorate, is responsible for regulating radioactive waste management and decommissioning nuclear licensed sites. In this regard, the Nuclear Installations Inspectorate consults the Environment Agency and the Scottish Environmental Protection Agency to ensure that all regulatory requirements are met in a consistent manner. A memorandum of understanding (MoU), outlining the working relationship between the Environment Agency and the HSE on nuclear safety, has been developed and published. The HSC also advises the Secretary of State for Trade and Industry and the Secretary of State for Scotland on nuclear safety policy for England and Wales and Scotland respectively.

The secretary of state and Ofgem also have a specific responsibility, under the Electricity Act 1989 (as amended), “to protect the public from dangers arising from the generation, transmission, distribution and supply of electricity”. In this regard, they are required to consult and take into account the advice given by the HSC on any

⁸¹ Ofgem and Environment Agency (2001), memorandum of understanding between Gas and Electricity Markets Authority and the Environment Agency Relating to Environmental Issues, May 2001.

electricity safety issue for which they are responsible. Ofgem and the HSC/HSE have published a MoU outlining this relationship.⁸²

Consumer representation

Consumer interests are represented in the regulatory process by an independent gas and electricity consumer council, *energywatch*. Energywatch was established by the Utilities Act 2000 and was launched formally on 1 November 2000, replacing the former electricity consumers' committees (established as part of the Office of Electricity Regulation by the Electricity Act 1989) and the Gas Consumers Council (established as independent of the Office of Gas Supply by the Gas Act 1986).

Energywatch is a non-departmental public body, independent of both the regulator and the companies. Energywatch is led by the council and its chair, Ann Robinson. In addition to the chair, the council consists of the chief executive of *energywatch*, Stephen Reid, the chairs of the Scotland and Wales committees and six ordinary members.

The role of *energywatch* is to represent the interests of all consumers, specifically (but not exclusively) individuals who are disabled or chronically sick, of pensionable age, with low incomes, or who reside in rural areas. In fulfilling this role, *energywatch* has the following functions:

- obtain and keep under review information about consumer matters, including matters affecting consumers in the different areas of Great Britain; and information about the views of consumers on such matters, including views of consumers in different areas (and undertake this both in respect of national issues and those which concern consumers in the regions of England, Wales and Scotland);
- make proposals or provide advice and information about consumer matters, and represent views of consumers on such matters to public authorities, licensees and other persons whose activities may affect the interests of consumers;
- provide information to gas and electricity consumers, including statistical information about the performance of licensees against prescribed standards of performance and energy efficiency obligations;
- publish advice and information about consumer matters that it thinks would promote the interests of consumers;
- investigate customer complaints which have not been resolved by the relevant licensees;
- investigate 'other' matters affecting consumers.⁸³

⁸² Ofgem, memorandum of understanding between the Gas and Electricity Markets Authority, the Health and Safety Commission, and the Health and Safety Executive.

⁸³ Sections 18 to 23, Utilities Act 2000; and Gas and Electricity Consumer Council, The Gas and Electricity Consumers' Council (GECC) – A consultation document from Ann Robinson, chair designate of GECC, February 2000.

Northern Ireland

Regulation of the electricity industry in Northern Ireland is the responsibility of the Department of Enterprise, Trade and Investment (DETI, formerly the Department of Economic Development) and the director general of electricity supply for Northern Ireland (DGESNI). Under the Electricity (Northern Ireland) Order 1992 (as amended), the DETI is responsible for appointing the DGESNI. This post is legally separate from the regulatory authority in Great Britain. The current DGESNI is Douglas McIlidoo. He is also director general of gas supply for Northern Ireland and is supported by the Office for the Regulation of Electricity and Gas (Ofreg), a non-ministerial department whose expenditure is voted by Parliament.⁸⁴

The duties and functions of DETI and the DGESNI are set out in the Electricity (Northern Ireland) Order 1992. The primary duties of DETI and the DGESNI are to secure that all reasonable demands for electricity are met, to secure that all licence holders are able to finance their activities, and to promote competition in the generation and supply of electricity. Subject to these primary duties, the DGESNI and DETI have duties to protect the interests of customers, to promote efficiency and economy on the part of licensed suppliers and transmission companies, to promote the efficient use of electricity, and to protect the public from dangers arising from the generation, transmission and supply of electricity. In performing these duties, the DGESNI and DETI are required to take into account the effect on the environment of activities connected with the generation, transmission and supply of electricity, as well as the health and safety of those employed in the electricity industry.⁸⁵

DETI and the DGESNI also have specific regulatory functions under the Electricity (Northern Ireland) Order. DETI is responsible for giving consent for new power stations and overhead lines, fuel stocking decisions, and the encouragement of renewable generation. DETI is also responsible for issuing licences, but has, under general authority, delegated this function to the DGESNI. The DGESNI is also responsible for monitoring compliance with the conditions of licences, enforcing them and, where appropriate, modifying the licences.

Under Article 28 of the 1992 order, the DGESNI has the power to obtain information from licensees and others in relation to potential breaches of licence. Where the DGESNI is satisfied that a licensee is contravening, or is likely to contravene, a licence condition, he is required to issue an enforcement order against the licensee. Failure to comply with such an enforcement order can expose the licensee to action (including a claim for damages) by any person who suffers loss or damage as a result of that failure.

Under the Competition Act 1998, the DGESNI is conferred the same powers as those conferred to Ofgem in Great Britain.

The Electricity (Northern Ireland) Order 1992 also made provision for the establishment of a consumer committee for electricity. Under the 1992 order, the

⁸⁴ Formerly the Office of Electricity Regulation (Offer NI).

⁸⁵ Electricity (Northern Ireland) Order 1992, Article 4, Paragraphs 2 to 6 and Article 6.

consumer committee is to be established by the DGESNI and is to consist of a chair appointed by the DGESNI after consultation with DETI, and such other members as the DGESNI, after consultation with the chair, may appoint. The Northern Ireland Consumer Committee for Electricity (NICCE) was set up in 1992 to represent all electricity users in Northern Ireland. It can raise any matter with NIE which relates to its policies and practices in the supply of electricity and report to the DGESNI on any matter it considers should be brought to his attention. The general duties of the consumer committee under the Electricity (Northern Ireland) Order 1992 are:

- to make representations to and consult with each public electricity supplier about all such matters as appear to the committee to affect the interests of customers or potential customers of that supplier;
- to keep under review matters affecting the interests of consumers of electricity supplied to premises;
- to advise the DGESNI on any matter relating to the supply of electricity on which the committee considers it should offer advice or which is referred to the committee by the DGESNI.

A new energy committee, established within the General Consumer Council for Northern Ireland (GCCNI), is proposed to replace the current arrangements for consumer representation in the electricity sector in Northern Ireland. The energy committee will have specific duties and functions in respect of electricity and gas customers and will be able to draw on the wider resources and expertise of the GCCNI.⁸⁶

⁸⁶ DETI (2001), News Release – Minister announces fresh start for energy consumer representation, August 2001.

- Regulatory instruments: licences

At privatisation, the Electricity Act 1989 and the Electricity (Northern Ireland) Order 1992 required that any company generating, transmitting or supplying electricity in the UK be authorised through either a licence or an exemption. These licences set out the obligations on and duties of each licence holder. While the licensing regime has been broadly similar in England and Wales, Scotland and Northern Ireland, the varied market structure and the different pace of development of the industry in the different regions has influenced the nature of the licences issued.

The implementation, on 1 October 2001, of the licensing provisions of the Utilities Act 2000 (Sections 28-43) has had a significant impact on the electricity licensing regime in Great Britain. Changes to the regime include:

- separation of supply and distribution businesses and the introduction of electricity distribution licences;
- with the separation of supply and distribution businesses, the introduction of a new definition of supply;
- replacement of public electricity supply licences and second-tier supply licences with one type of supply licence;
- introduction of standard conditions of licences;
- with the introduction of standard conditions, the shifting of responsibility for granting and modifying licences to the regulatory authority from the secretary of state;
- introduction of collective modification procedures for licences;
- introduction of a provision to transfer licences;
- the removal of the requirement for companies to obtain separate licences for operations in England and Wales and in Scotland.

This section discusses the current electricity licensing regime in Great Britain and Northern Ireland, highlighting the changes made to the licensing regime in Great Britain under the Utilities Act 2000.

England, Wales and Scotland

Sections 4 to 10 of the Electricity Act 1989 (as amended by the Utilities Act 2000) set out the legal framework for the present electricity licensing regime in Great Britain. Under the amended Electricity Act, all activities related to the generation, transmission, distribution or supply of electricity must be authorised by virtue of either a licence or an exemption.

Prior to the enactment of the Utilities Act 2000, the power to grant electricity licences could be exercised either by the secretary of state or by the director general of electricity supply, under a general authority from the secretary of state. The Utilities Act removes the secretary of state's power to grant electricity licences, giving Ofgem

sole power to grant licences. The secretary of state, however, retains the power to grant exemptions from electricity licensing under the Act.⁸⁷

The Utilities Act 2000 also introduces **standard licence conditions** for the electricity industry, bringing licensing provisions in the electricity sector in line with those in the gas sector.⁸⁸ The Act gives the secretary of state the power to determine and publish the standard conditions to be included in each type of licence. The new standard licence conditions were determined by the secretary of state and came into effect on 1 October 2001. After determination of the standard conditions, it is Ofgem who has the power to propose modifications to the standard conditions when granting a licence. The secretary of state has no further role in their modification, except power to veto any modifications proposed by Ofgem.

The new electricity licensing regime is thus comprised of a set of standard conditions for each type of licence – generation, transmission, distribution and supply. These standard conditions are divided into groups, which structure the licences around the key activities they govern. The licences group together those standard conditions that apply to all licensees and which are common across all licence types (for example, the licence fees conditions) (Section A), those that apply to all licensees of a particular type (Section B), those that apply to the domestic customer sector (Section C in supply), and those obligations falling on the dominant licensees (Section D in supply and Section C in distribution). The generation licence also has sections that are appropriate to companies generating in Scotland and those involved in nuclear generation; and the transmission licence has sections that contain conditions which are only appropriate to transmission licence holders operating in England and Wales or Scotland respectively.

The licences also include certain conditions which provide for other standard conditions of the same licence type to not be brought into operation, to be suspended or to be re-activated in circumstances specified in the condition. The existence of such provisions is intended to permit more flexible licensing arrangements. For example, while all electricity suppliers, by and large, have licences containing the same standard conditions, not all suppliers serve all segments of the electricity supply market. For those who choose to serve only the industrial and commercial segments, the conditions which regulate supply to the domestic market segment are rendered inoperative.⁸⁹

In addition to the standard licence conditions, there are special conditions, for example, price controls, which are applicable to specified licensees only and operate to provide additional regulatory protection or to promote competition. Furthermore, for certain licensees the standard conditions may be revised or amended to apply to the individual circumstances of the licensee in question. For example, in respect of the distribution and supply licences of the two Scottish companies, certain standard conditions have been amended.

⁸⁷ Explanatory notes to Utilities Act 2000, Chapter 27.

⁸⁸ Prior to the implementation of the Utilities Act, while licences issued for each type of activity were of a broadly standard format, there were no standard conditions of licences and variations existed between licences for the same type of activity.

⁸⁹ Explanatory notes to Utilities Act 2000, Chapter 27.

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Prior to amendments by the Utilities Act 2000, electricity licence conditions could be modified on an individual basis either with the consent of the licence holder, or without the consent following a licence modification reference to the Competition Commission. The Utilities Act 2000 revised the arrangements for the modification of electricity licence conditions, allowing Ofgem to modify the standard conditions of electricity licences with majority consent.⁹⁰ Under the act, the secretary of state is provided with powers to determine, by order, numerical values for the key parameters to be used for determining consent. Each modification proposal is subject to a two-limbed test, in which the level of opposition is compared with pre-determined blocking-minority thresholds. One of these thresholds measures the level of opposition by ‘relevant licence holders’ to the proposal on a simple numerical basis, the other on a market share basis.⁹¹ If either threshold is met or exceeded, Ofgem is not able to proceed with the proposed modification. Where sufficient opposition exists among relevant licence holders to block a modification, Ofgem may make a reference to the Competition Commission.⁹²

The DTI had proposed the following key criteria for the blocking-minority thresholds:

- the blocking-minority thresholds should be 20% in each case, except for electricity transmission licensees where no thresholds will be set;
- where a company or group of companies holds more than one licence in respect of which a relevant modification is proposed, only one vote will count for the simple numerical test;
- the entire market share of such a company or group of companies (in an individual relevant market) will count in the market share test.

For the measurement of market share, the market share for each type of licensee shall be determined as follows:

- electricity supply: number of metering points registered;
- electricity distribution: number of metering points;
- electricity generation: installed capacity (‘Genset Registered Capacity’).

Ofgem may make licence modification references to the Competition Commission either in the case of individual licences or in respect of collective licence modifications. Following a report on a reference, the Competition Commission will review Ofgem’s proposals to modify electricity licences. If it appears to the Commission that the proposed modifications are not requisite for the purpose of remedying or preventing the adverse effects specified in its report, the Commission is required to substitute its own licence modifications which are requisite for that purpose. The secretary of state, following a reference report by the Commission, may

⁹⁰ Utilities Act 2000, Section 35.

⁹¹ ‘Relevant licence holders’ are defined as, in the case of a modification which creates new conditions, all holders of the given licence type and, in the case of modification or omission of existing conditions, any licence holder in whose licence the relevant conditions are operative.

⁹² DTI (2001), Modification of Standard Conditions of Gas and Electricity Licences by the Gas and Electricity Markets Authority – “Collective licence modifications”, a second consultation by the Department of Trade and Industry, April 2001.

either modify the conditions of individual licences or modify collectively the standard conditions of all licences of a given type.⁹³

Generation licences

In addition to the general standard conditions applicable to all licensees, the generation licence consists of three groups of standard conditions – those which apply to all generation licensees (Section B), those which apply to companies generating in Scotland (Section C) and those which apply to nuclear generators (Section D).

The general licence conditions, applying to all generation licensees, include requirements:

- to comply with the provisions of every grid code and every distribution code in so far as applicable to it;
- when constructing or operating a generating station in England and Wales, to comply with the provisions of the fuel security code, to comply with the pooling and settlement agreement for the purposes of run-off until the provisions of the balancing and settlement code (BSC) relating to run-off become effective, and to be a party to the BSC framework agreement and comply with the BSC;
- to furnish Ofgem information reports as it may reasonably require or as may be necessary for the purpose of performing the functions conferred to it under the Electricity Act 1989 and the Utilities Act 2000;
- where applicable, a prohibition of discrimination in selling electricity and a prohibition of cross-subsidies;⁹⁴
- where applicable, to provide statements and information to Ofgem which enable it to keep under review the behaviour of the licensee to ascertain whether the licensee is pursuing a course of conduct in making or declining to make available generating units owned or operated by the licensee which is intended to have or likely to have the effect of restricting, distorting or preventing competition in the generation or supply of electricity;
- a requirement on the licensee, where constructing or operating a generating station in England and Wales, to be party to the CUSC framework agreement and to comply with the CUSC, and, if it is party to the master connection and use of system agreement (MCUSA), to execute such other documents to enable the MCUSA and its supplemental agreements and ancillary service agreements and any associated agreements derived from MCUSA to be amended appropriately into the CUSC framework agreement, CUSC bilateral agreements, construction agreements and, so far as is appropriate, associated agreements derived from CUSC so as to maintain continuity of contractual relationships.

For those companies operating in Scotland, there are supplementary standard conditions, which include a requirement on the licensee to comply with the provisions of the trading code insofar as applicable to it during any period that the licensee is a

⁹³ Explanatory notes to Utilities Act 2000, Chapter 27.

⁹⁴ For the purposes of this part of the condition, there shall be disregarded NFFO qualifying arrangements and Scottish renewables obligation, and any contract for supply of electricity vested in the licensee under the transfer scheme.

member of the trading system established by the trading code; a requirement on the licensee to comply with any security arrangements put in place for Scotland; and a requirement on the licensee to become a party to and comply with the provisions of the Settlement Agreement for Scotland once it comes into force.

Transmission licences

There is one transmission licence for England and Wales, held by the National Grid Company. In Scotland, there are two transmission licences – these are held by Scottish Hydro-Electric Transmission Ltd and SP Transmission Ltd (part of Scottish Power).

The transmission licence consists of, in addition to the general standard conditions applicable to all licensees, three groups of standard conditions – those which apply to all transmission licensees (Section B), those which apply to the transmission companies in England and Wales (Section C), and those which apply to the transmission companies in Scotland (Section D). In addition, the transmission licence contains sets of special conditions, applying separately to transmission in England and Wales and in Scotland.

The general licence conditions, applying to all transmission licensees include requirements to:

- prepare and at all times have in force and to implement and comply with the grid code;⁹⁵
- comply with the provisions of any other grid code and every distribution code in so far as applicable to it;
- furnish information and reports to Ofgem as it may require or as may be necessary for the purpose of performing its functions under the Electricity Act 1989 and the Utilities Act 2000;
- a prohibition of cross-subsidies between the licensee's transmission business and any other business of the licensee or an affiliate or related undertaking of the licensee.

For the National Grid Company, as the sole owner and operator of the transmission system in England and Wales, the following standard conditions apply:

- the licensee, or any affiliate or related undertaking of the licensee, shall not on its own account purchase or otherwise acquire electricity for the purpose of sale or other disposition to third parties except pursuant to the procurement or use of balancing services in connection with operating the licensee's transmission system, or with the consent of Ofgem;

⁹⁵ The licensee's grid code covers all material technical aspects relating to connections to and the operation and use of the licensee's transmission system or the operation of electric lines and electrical plant connected to the licensee's transmission system or any distribution system of any authorised distributor; and is designed to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in generation and supply, and to promote the security and efficiency of the electricity generation, transmission and distribution systems in England and Wales or Scotland.

- the licensee shall at all times have in force a balancing and settlement code (BSC), setting out the terms of the balancing and settlement arrangements;⁹⁶
- the licensee shall include in its grid code, procedures relating to the outage of generation sets and a balancing code specifying, among other matters, information to be submitted by authorised electricity operators to the licensee for the purposes of, and the making of offers and bids in, the balancing mechanism, and the issuing by the licensee of instructions by reference to such offers and bids;
- the licensee shall continue to be a party to the pooling and settlement agreement in its capacity as grid operator and ancillary services provider and will comply with that agreement for the purposes of run-off until the provisions of the BSC relating to run-off become effective;
- the licensee is required to determine a use of system charging methodology and a connection charging methodology approved by Ofgem and to keep these charging methodologies under review;
- in the provision of use of system or in the carrying out of works for the purpose of connection to the licensee's transmission system, the licensee shall not discriminate between any persons or class of persons;
- the licensee is required to offer terms on application – that is, on application made by any authorised electricity operator in the case of an application for use of system and any person in the case of an application for connection, the licensee shall offer to enter into the CUSC framework agreement; and on application made by any person, the licensee shall offer to enter into a bilateral agreement and/or construction agreement relating to connection or modification of existing connection;
- the licensee is required to establish arrangements for connection and use of system, and to prepare a connection and use of system code (CUSC) setting out the terms of the arrangements, the procedures for the modification of the CUSC and such other terms as are or may be appropriate for the purposes of the CUSC;
- the licensee is required to prepare an annual statement detailing each of the seven succeeding financial years circuit capacity, forecast power flows and loading on each part of the licensee's transmission system and fault levels for each transmission node, together with such further information as shall be reasonably necessary to enable any person seeking use of system to identify and evaluate the opportunities available when connecting to and making use of such system and a commentary prepared by the licensee indicating the licensee's views as to those parts of its transmission system most suited to new connections and transport of further quantities of electricity.

For those licensees operating in Scotland, the specific obligations require the licensee to, jointly with the other founder member, adopt a trading code designated by Ofgem and to comply with the terms of the trading code. The trading code shall include arrangements for:

⁹⁶ The balancing and settlement arrangements are arrangements pursuant to which BSC parties may make, and the licensee may accept, offers or bids to increase or decrease the quantities of electricity to be delivered to or taken off the total system at any time or during any period so as to assist the licensee in operating and balancing the transmission system. The BSC includes arrangements for the settlement of financial obligations arising from the acceptance of such offers or bids, and arrangements for the determination and allocation to BSC parties of the quantities of electricity delivered to and taken off the total system.

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- establishing facilities and procedures for effecting trading of electricity between the founder members and between the founder members and other persons who become members of the trading system;
- effecting trading of electricity between members of the trading system;
- establishing a trading committee to carry out the general management and supervision of the trading and its operation;
- the admission to membership of the trading system of any authorised electricity generator who operates a generating station of a net capacity not less than 50 MW and who applies for such membership and agrees to be bound by the provisions of the trading code and whose generation licence contains a condition requiring it to comply with the provisions of the trading code; and any licence holder specified by Ofgem who applies for such membership and agrees to be bound by the provisions of the trading code and whose licence contains a condition requiring it to comply with the provisions of the trading code;
- charging members for the costs of the trading system;
- administration procedures for the trading system.

The licensee is also required to establish and maintain the full managerial and operational independence of the transmission business and any external transmission activities from each other business of the licensee and of its affiliates and related undertakings.

As with NGC, the licensee is required to include in its grid code, procedures relating to outages of generation sets and a scheduling and dispatch code specifying procedures for the scheduling and dispatch of generating stations connected to the licensee's transmission system; to prepare a statement, approved by Ofgem, setting out the basis upon which charges will be made for the use of and connection to the licensee's transmission system; and to offer to enter into agreement for use of system on application. The licensee is also required to comply with the relevant provisions of the settlement agreement for Scotland.

Distribution licences

Under the Utilities Act 2000, the activity of distribution becomes a separately licensable activity for the first time. Certain obligations relating to distribution activities were previously included in the PES licence, and the licences of other electricity suppliers who operated distribution systems, but companies which operated electricity distribution systems without also being suppliers were not required to obtain a licence to do so. Now, with a new prohibition on unauthorised distribution activity, any person who distributes electricity for the purpose of giving a supply to any premises or enabling a supply to be so given is required to be licensed, unless exempted.

The distribution licence includes, in addition to the general standard conditions applicable across all types of licences, two groups of standard conditions – those which are applicable to all distribution licensees (Section B) and those obligations falling on the dominant licensees (Section C).

Standard conditions applicable to all distribution licensees include specific requirements governing the provision of use of system and connection to the licensee's distribution system. These include requirements to:

- prepare statements setting out the basis on which charges will be made for the provision of use of system and connections to the licensee's distribution system;
- adhere to the principles of non-discrimination in the provision of use of system and connection to system;
- on application, offer terms for use of system and connection to system;
- on application, offer to enter into an agreement authorising that person to connect metering equipment to its distribution system;
- the licensee is not permitted to enter into a use of system agreement with any electricity supplier that does not provide for the licensee to make payments in respect of the performance of the distribution business of the licensee to the electricity supplier for the benefit of any customer of that electricity supplier.

The standard conditions applicable to all distribution licensees also include specific requirements relating to the rules and agreements to which distribution licensees must adhere to. These are requirements to:

- prepare and at all times have in force and implement and comply with a distribution code;
- in so far as it distributes or offers to distribute electricity within any area of England and Wales, be a party to the BSC framework agreement and to comply with the BSC;
- in so far as it distributes or offers to distribute electricity within any area of Scotland or to the extent that the settlement agreement for Scotland may apply in respect of the activities of the distribution business, comply with the relevant provisions of the settlement agreement for Scotland;
- in so far as it distributes or offers to distribute electricity within any area in Scotland, comply with the provisions of the trading code during any period that the licensee is a member of the trading system established by the trading code;
- be party to and comply with the provisions of the master registration agreement;
- comply with the provisions of every grid code in so far as applicable to it;
- in so far as it distributes or offers to distribute electricity within any area of England or Wales, comply with the provisions of the fuel security code; and in so far as it distributes or offers to distribute electricity within any area of Scotland, enter into an agreement designated by the secretary of state for the purpose of establishing security arrangements in Scotland and to perform its obligations under any such agreement entered into;
- in so far as it distributes or offers to distribute to any premises situated in England and Wales, to be a party to and comply with the CUSC framework agreement and, if it is party to the MCUSA, to execute such other documents to enable the MCUSA and its supplemental agreements and ancillary agreements and any associated agreements derived from MCUSA to be amended appropriately into the CUSC framework agreement, CUSC bilateral agreements, construction agreements and, so far as is appropriate, associated agreements derived from CUSC so as to maintain continuity of contractual arrangement.

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Other standard conditions applying to all distribution licensees include requirements to:

- plan and develop its distribution system in accordance with specific engineering standards; draw up and submit to Ofgem for approval a statement setting out criteria by which the quality of performance of the licensee in maintaining its distribution system's security, availability and quality of service may be measured; and submit to Ofgem annually a report detailing the performance of the licensee during the previous financial year against these criteria;
- establish and maintain an enquiry service, without charge, for use by any person for the purposes of receiving reports and offering information, guidance or advice about any matter or incident which affects or is likely to affect the maintenance of the security, availability and quality of service of the licensee's distribution system, or arises from or in connection with the operation of the licensee's distribution system and which causes, or is likely to cause, danger or requires urgent attention;
- where a person other than the licensee is the owner of any electrical plant, electric lines or meter, inform that person of any incident where the licensee has reason to believe that there has been damage to such electrical plant, electric line or metering equipment, or that there has been interference with the metering equipment;
- prepare and submit to Ofgem for its approval codes of practice detailing the special services the licensee will make available for domestic customers who are of pensionable age or disabled or chronically sick, the special services the licensee will make available for domestic customers who are disabled by virtue of being blind or partially sighted, or deaf or hearing impaired, the principles and procedures the licensee will follow in respect of any person acting on its behalf who requires access to customers' premises, and the procedure for handling complaints from domestic customers;
- furnish to Ofgem information and reports, as Ofgem may require or as may be necessary for the purpose of performing its functions under the Electricity Act 1989 and the Utilities Act 2000;
- where Ofgem gives the licensee a direction to do so, to prepare and maintain a statement providing information which will assist any person who contemplates entering into distribution arrangements with the licensee to identify and evaluate the opportunities for doing so, and ensuring the general availability of such information in the public domain;

The standard conditions falling on dominant distribution licensees are laid out in Section C of the licence – distribution service obligations. These conditions include requirements on the licensee to:

- establish and maintain an accurate list of any convenience customers;
- prepare statements setting out the basis upon which charges will be made for the provision of each of the distributor metering and data services, and of the other terms upon which the service would be provided (and not to discriminate between any persons or class of persons in the provision of such services);
- on application by any person, enter into an agreement for the provision, within its distribution services area, of metering equipment; the installation, commissioning, testing, repair, maintenance, removal and replacement of metering equipment;

metering point administration services pursuant to and in accordance with the master registration agreement; and data transfer services;

- establish and subsequently operate and maintain the metering point administration service;⁹⁷
- in conjunction and co-operation with other distributors, prepare and maintain the master registration agreement;⁹⁸
- establish and maintain, in conjunction and co-operation with all other distributors, a data transfer service;
- ensure that the distribution business is independent of any other business of the licensee or of any affiliate or related undertaking of the licensee, including a restriction on the use of certain information and separate regulatory accounts and a prohibition on cross-subsidies;
- act in a manner calculated to secure that it has available to it all such resources to ensure that it, at all times, is able to properly and efficiently carry on the distribution business; and use all reasonable endeavours to ensure that it maintains at all times an investment grade issuer credit rating.

Supply licences

Prior to the implementation of the Utilities Act 2000, there were two types of electricity supply licences which could be granted under the Electricity Act 1989 – one issued to public electricity suppliers (PESs) in respect of their authorised areas (known as PES licences) and the other to any other person, including a PES wishing to supply outside its authorised area (known as a second-tier, or private electricity, supply licence). A PES licence was effectively that which was granted upon vesting to one of the successor companies corresponding with the fourteen area electricity boards which existed before privatisation. The PES licence included a number of obligations which were required because of the monopoly position of the PES in electricity distribution and supply at the time of vesting. The second-tier supply licence included fewer obligations.⁹⁹ In the case of Scotland, consolidated licences were issued, authorising the two Scottish PESs to carry out supply in addition to generation and transmission activities. Second-tier supply licences were issued separately for supply in England and Wales and for supply in Scotland. Hence, a

⁹⁷ The metering point administration service includes the maintenance of a register of technical and other data as is necessary to facilitate the supply by an electricity supplier to all premises connected to the licensee's distribution system within the distribution services area or, where requested, connected to another distribution system within the distribution services area, and to meet the reasonable requirements of electricity suppliers in respect of such premises for information and settlement purposes; the amendment of the register to reflect changes of electricity supplier in respect of any premises; the provision of such data contained in the register as is reasonable required and requested to any appropriately named person; and the maintenance of an enquiry service of the provision to any customer or an electricity supplier of such data contained in the register as is relevant to the supply of electricity to premises which are owned or occupied by the customer.

⁹⁸ The master registration agreement is an agreement made between on the one part, the licensee and all other distributors in their capacity as providers of metering point administration services, and on the other part, all electricity suppliers (or their agents) which require the provision of metering point administration services from at least one distributor.

⁹⁹ Ofgem (2000), Utilities Bill: Standard licence conditions. Volume 1: Consultation paper. February 2000.

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company wishing to supply Great Britain was required to hold one second-tier supply licence for England and Wales and one for Scotland.

The Utilities Act 2000 brought the PES and second-tier electricity supply licences together into a single type of supply licence and removed the concept of PES tariff supply, replacing it with contractual supply. Implicit in this is the removal of the requirement of companies to hold separate supply licences for operations in England and Wales and in Scotland. An electricity supply licence can, therefore, be granted for the whole of Great Britain or, if the supplier chooses, for a smaller area. A supply licence can be granted for either domestic or non-domestic customers. The licence conditions for suppliers of domestic customers are distinct from the licence conditions of suppliers of industrial and commercial customers, with those suppliers licensed to supply domestic customers being bound by significantly more conditions than those who do not supply domestic customers.

The general licence conditions applicable to all electricity suppliers include, in addition to conditions which require the suppliers to adhere to the trading rules, a requirement on the licensees to develop codes of practice on procedures with respect to site access and the efficient use of electricity.

The key obligations for domestic suppliers include requirements to:

- offer terms to supply on request;
- establish security arrangements;
- prepare and submit to Ofgem for its approval, codes of practice on the payment of electricity bills by its domestic consumers and dealing with customers in difficulty, the use of prepayment meters, the special services the licensee will make available for its domestic customers who are of pensionable age, disabled or chronically sick, the special services the licensee will make available for its domestic customers who are blind or partially sighted, or deaf or hearing impaired, and the procedure for handling complaints (further details of these codes of practice are provided in **Chapter 8 on Social Regulation**);
- supply its customers with appropriate information, including keeping them informed of the amount of electricity which the customer has consumed and providing information on the role of *energywatch* in resolving complaints;
- make available to domestic customers payments by a variety of means, including prepayment, by different methods, including cash and cheque, and at a reasonable range of intervals;
- take all reasonable steps to draw the attention of the customer to the principal terms of the domestic supply contract before entering into it;
- where practicable, make available to domestic customers supply through a prepayment meter in lieu of a deposit;
- in the terms on which the domestic supply contract is offered, include a term allowing the customer to terminate the contract at any time by giving the licensee valid notice and paying the licensee a termination fee, and a term relating to the termination of the contract on vacation of the domestic premises;
- set up appropriate procedures to prevent marketing abuse, including procedures for staff selection and training, sales agent identification, audit of doorstep and telephone sales and those in public places, ensuring that individuals are aware of and are content to have entered into a domestic supply contract following such

activities, cancelling contracts when requested by a customer, complaints, and identifying and remedying weaknesses in said marketing conditions.¹⁰⁰

Northern Ireland

Sections 8 to 18 of the Electricity (Northern Ireland) Order 1992 set out the legal framework for the electricity licensing regime in Northern Ireland. Under the 1992 order, the power to grant electricity licences rests with the Department of Enterprise, Trade and Investment (DETI). This function has, however, been delegated to the DGESNI and hence it is the DGESNI who exercises this power. The DGESNI may modify the conditions of a licence with the licensees consent (and after consultation) and may also, in certain circumstances, modify a licence following a report from the Competition Commission.

There are currently three types of licence granted in Northern Ireland – the combined transmission and public electricity supply licence granted to Northern Ireland Electricity (NIE), second tier supply licences and generation licences.

NIE's composite transmission and PES licence is arranged in three main parts, covering the conditions applicable to both licences, the conditions applicable to the transmission licence, and the conditions applicable to the PES licence. The conditions applicable to each licence include:

- general provisions relating to separate accounts for separate businesses, the prohibition of cross-subsidies and of discrimination, health and safety of employees, the provision of information to the DGESNI as required, payment of fees, restrictions on the disposal of relevant assets and the requirement for prior notification of the DGESNI and his consent, and restrictions on the use of confidential information;
- requirements to comply with the supply competition code and the Northern Ireland fuel security code;
- restrictions on the own-generation capacity of NIE and a prohibition on NIE from having any gas pipeline capacity;
- requirements to set out the basis of charges for use of the transmission system, the distribution system and the provision of top-up or stand-by (includes requirements for transparency, non-discrimination and to offer terms);
- a requirement to comply with the grid code and, where applicable, the distribution code;
- a requirement to comply with the transmission system and distribution system security and planning standards and quality of service, and to report to the DGESNI on performance;
- ring fencing of regulated businesses to the licensee.

In addition to these conditions, NIE is subject to the following conditions in respect of its power procurement function:

¹⁰⁰ This condition ceases to have effect on 31 March 2002. However, Ofgem has proposed to extend the condition for a further two years (expiring in March 2004).

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- a condition granting the licensee the power procurement business (PPB);
- a condition setting out the form of the bulk supply tariff, which must be approved by the DGESNI and including a requirement for non-discrimination between suppliers and NIE as a PES, and an obligation to supply any supplier on request;
- price controls, including the charge restrictions for the bulk supply tariff and the information to be provided to the DGESNI to monitor compliance with the price controls, the duration of the price controls, and an allowance for modification where there has been a relevant change of law;
- a requirement to comply with the provisions of the supply competition code, including an allowance for the DGESNI to modify the code;
- an obligation to purchase electricity at the best effective price reasonably obtainable having regard to the sources available (applying separately to electricity from qualifying renewable sources and any other generation source);
- provisions for the DGESNI to modify the supply competition code, the grid code and the Northern Ireland fuel security code and to cancel contracts to introduce an electricity trading system;
- a requirement for the power procurement manager to provide information as specified by the DGESNI.

In relation to its function as transmission system operator, the following conditions apply to NIE's transmission business:

- a condition granting the licensee the transmission system operating business;
- a condition governing the central dispatch and merit order of generating sets;
- a requirement to produce an annual statement of future capacity requirements for the succeeding seven years in a form approved by the DGESNI;
- a requirement to produce a statement, approved by the DGESNI, of interconnector capacity;
- a requirement of non-discrimination in the operation of the transmission system;
- a requirement for the economic purchasing of system support services;
- a requirement to provide information to other system operators as reasonably required;
- a requirement to meet relevant operating security standards and to provide information to the DGESNI to monitor compliance.

Other conditions applicable to NIE's transmission licence are:

- a condition governing the operator and financing of the landbank;
- price controls, including the charge restrictions for transmission charges and the information to be provided to the DGESNI to monitor compliance with the price controls, and the duration of the price controls;
- conditions governing the basis of charges for use of the interconnectors, including requirements for transparency, non-discrimination and to offer terms;
- a requirement to establish interim settlement arrangements for the purpose of providing for the identification and settlement of imbalances arising from bilateral contracts for the sale and purchase of electricity and related matters;
- a requirement to facilitate the development of trading arrangements, to provide for greater flexibility than is provided under the interim settlement arrangements for

the trading of electricity between authorised electricity operators and, further, to establish a trading market for electricity imbalances.

NIE's public electricity supply licence includes the following conditions:

- a requirement to conduct the supply and distribution businesses in a manner best calculated to achieve any standards of overall performance or standards of performance in connection with the promotion of efficient use of electricity;
- price controls, including the charge restrictions for supply and distribution charges and the information to be provided to the DGESNI to monitor compliance with the price controls and the duration of the price controls;
- a requirement to provide to the DGESNI, on request, comments on his information and advice;
- a requirement to provide details of their tariffs to the DGESNI and to provide explanatory details about their tariffs to customers;
- a requirement to purchase electricity at the best effective price reasonably obtainable having regard to the sources available (this requirement applies separately in relation to purchases of electricity from qualifying renewable generation and generation from any other source);
- a requirement for the approval by the DGESNI of conditions of supply for tariff customers and to notify customers of their right to apply to the DGESNI for determination of any dispute arising out of the proposed terms of supply;
- a restriction on the power consumption of company's apparatus on the tariff customer's side of the meter;
- a requirement to prepare codes of practice on payment of bills, methods of dealing with tariff customers in default, provision of services for persons who are of pensionable age or disabled, energy efficiency, and procedures for complaints handling;
- a requirement to meet with the consumer committee.

Four generation licences have been issued in Northern Ireland to Premier Power Ltd, AES Ltd (formerly NIGEN), and Coolkeeragh Power Ltd. The conditions of the licences include requirements to:

- keep separate accounts for separate businesses;
- a prohibition of cross-subsidies and of discrimination;
- comply with the provisions of the grid code and the distribution code, in so far as applicable to it;
- plan and develop each part of the licensee's system in accordance with the relevant standard;
- comply with the provisions of the Northern Ireland fuel security code;
- submit all available generating sets and interconnector transfers to central dispatch by the transmission system operator;
- offer terms, when requested by the transmission system operator, for the provision of system support services from any generating set of the licensee which is capable of operating;
- ensure that the operator for each of its generating stations is a person approved in writing by the regulator;
- related to compulsory acquisition of land;

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- powers to carry out roadworks;
- offer terms for connection and use of system;
- ensure the health and safety of employees;
- provide information to the DGESNI as he may require to perform his functions assigned or transferred to him under the Order;
- the licences allow the DETI to amend generating unit agreements or power station agreements;
- the licences prevent the licensee from terminating any of the cancellable generating unit agreements, unless the DGESNI has so directed;
- comply with the provisions of the supply competition code;
- the licences allow the DGESNI to introduce competitive trading arrangements for electricity and cancel contracts;
- provide information to the transmission system operator to enable it to comply with its obligations in relation to any authorised business or activity.

The second tier (or private electricity) supply licences include the following conditions:

- a requirement to offer terms for connection and use of system;
- a requirement to comply with the conditions of the grid code and the distribution code in so far as applicable to it;
- a requirement to comply with the provisions of the supply competition code in so far as applicable to it;
- a requirement to comply with any modified codes should wholesale electricity trading be introduced by the DGESNI;
- a requirement to plan and develop each part of the licensee's system in accordance with the relevant standard;
- a requirement to comply with the Northern Ireland fuel security code;
- a requirement to ensure the health and safety of employees;
- a requirement to furnish the DGESNI with information as required to fulfil his functions assigned or conferred under the Electricity (Northern Ireland) Order 1992;
- a requirement to pay the DGESNI specified fees.

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Price controls

The purpose of the price control is, where there is a lack of competition, to protect customers and to encourage an efficient industry. In the UK electricity sector, as for other UK utility privatisations, price controls have taken the form of a price cap set by the regulator. The formula adopted for setting these price caps relates the average price of a basket of industry's outputs to the consumer price index (the retail price index (RPI)). In their simplest form, price caps are expressed in terms of a RPI-X constraint on charges, where the X factor reflects expected efficiency gains and investment requirements. A cost pass-through, or Y factor, may also be added to allow significant cost items, which are outside the control of management, to be passed through directly to consumers in final prices.

The control may be set so that efficiency gains are required if the business is to maintain its profitability. Efficiency improvements achieved over and above those assumed in the price cap may be retained by companies. There is therefore an incentive for companies to make efficiency gains and reduce costs. Periodic reviews of the price caps ensure that the benefits of efficiency gains are passed on to customers over time. It is important, however, that the time period between price cap reviews is sufficient to allow the business to enjoy the benefits of additional efficiency savings so that there is an incentive on the business to make the productivity improvements in the first place. This mimics the competitive market, where to maintain profitability a company needs to make efficiency gains similar to its competitors. If it exceeds its competitors' productivity it may for a time make greater profits, but competitors will copy successful innovations and the initial advantage will dissipate.

England and Wales

- Transmission¹⁰¹

Figure 14: Transmission price caps in England and Wales

April 1990-March 1993	RPI-0
April 1993-March 1997	RPI-3
April 1997-March 2001	P ₀ =20% Then RPI-4 from April 1998
April 2001-March 2006	RPI-1.5

The workings of the price control have developed over time. At vesting, price controls related the total allowed revenue to the level of output, as measured by demand. Because of concerns that these controls included an incentive for NGC to boost peak demand for electricity, which were incompatible with energy efficiency, the revenue

¹⁰¹ This section is based on Hicks C (1998), Regulation of the UK Electricity Industry; Ofgem (2000), The Transmission Price Control Review of the National Grid Company from 2001 – Transmission asset owner, final proposals, September 2000; and Ofgem (2000), NGC System Operator Price Control and Incentive Schemes under NETA – Final proposals, December 2000.

yield controls were adjusted at the first review to a total revenue control. Specific future system demand levels were incorporated into the formula to remove any incentive on NGC to boost system peak demand. Additionally, the formula was adjusted to eliminate problems caused by the forecasting of RPI by the use of historic inflation.

At the second review (for the price controls operating from 1 April 1997 to 31 March 2001), the controls continued to be based on a limit to total allowed revenue, and stronger incentives were put in place for NGC to minimise certain cost elements for transmission services. The price limit on transmission charges was based on a RPI-X control related to total revenue. The formula was forward looking and incorporated a correction factor to adjust for forecast errors. An initial reduction of P_o of 20% in 1997/98 was followed by a price cap of RPI-4 for each of the next three years. From April 1997, certain costs associated with running a transmission system were transferred to the NGC rather than being recovered by the pool via uplift. NGC was given stronger incentives to minimise these costs and pass savings to customers. The transmission services incentive scheme was put in place for 12 months. The review also revised the structure of connection and use of system charges so as to protect locational signals for siting of new generation plant. This would mean that generators further away from sources of demand for electricity would pay higher transmission charges. This was challenged in the courts by some generators in the north of England. From April 1998 new incentive arrangements to apply for 1998/99 and 1999/2000 were put in place from the transmission services incentive scheme. These tightened targets and increased the sharing of savings with customers.

With the introduction of NETA, the activities of the transmission business involved two distinct roles – its role as transmission asset owner (TO) and its role as system operator (SO). Prior to 2001, NGC's transmission business was regulated by a single price control covering both system operation and the costs of developing and maintaining the transmission system (the TO role). In addition to the price control, there were a series of incentive schemes on external SO costs that are incurred in balancing the electricity system (for example, contracts for balancing services). Under each of these incentive schemes on external SO costs, a target level of costs was set. If actual costs were above or below the target, NGC would pay or keep a proportion of any difference.

From April 2001, reflecting NGC's new responsibilities following the introduction of NETA, the controls covering NGC's TO and SO roles were separated. The current price control, introduced from April 2001 for a duration of five years, applies only to the revenues of the TO business. The revenues of the SO part of the business are subject to separate incentive arrangements, which were put in place from April 2001 for the duration of a year.

The TO price control is concerned with the income from NGC's transmission network use-of-system charges and pre-vesting connection charges, and aims to allow NGC to finance the costs attributable to, and efficiently incurred by, the TO, including an appropriate return to its regulatory asset base. The TO price control is based on a RPI-X formula, with X set at 1.5.

Ofgem was concerned that an RPI-X form of control for the SO internal costs would encourage NGC to focus excessively on reducing its own costs at the expense of reducing total costs. As a result, the incentive scheme put in place aims to align the SO internal cost scheme with the existing SO external cost incentive mechanism, including both SO internal costs and SO external costs within an umbrella of a single incentive scheme. The incentive on SO costs took the form of a sliding scale. The scheme was initially introduced for a year, from NETA go-live to March 2002, in recognition of the need for NGC to develop its SO role under NETA.

- Distribution¹⁰²

Figure 15: Distribution price caps in England and Wales

April 1990-March 1995	RPI+0 to +2.5
April 1995-March 1996*	RPI-11; -14 or -17
April 1996-March 1997*	RPI-10; -11 or -13
April 1997-March 2000*	RPI-3
* Equivalent to an average reduction in X from +1.3 % per annum to -9.5% per annum for the full five years. The caps were re-determined from April 1996 from RPI-2.	

The charges made for the use of the distribution network are also regulated by a RPI-X control. Some activities, however, are excluded from the price controls. These include charges to customers connected at extra high voltage (that is, above 22 kV or above 66kV at substations), and charges for special and prepayment meters and for connecting customers to the system. Connection charges must be set so as to recover appropriate costs and a reasonable rate of return.

Until March 1995, the price control related the companies' distribution revenues entirely to the number of units (kWh) of electricity distributed. The initial values of X, which were set for five years, until March 1995, ranged from -2.5 to 0 (these translate into price caps ranging from RPI+2.5 to RPI-0). Real price increases were allowed, for all but one REC, because of the expected capital expenditure programmes on the REC's distribution networks, with only modest growth anticipated in the volume of units of electricity to be distributed.

From April 1995, regulated revenue was split into two components – that associated with metering and that with the rest of the distribution business. The price control was amended so that it was now based on revenue related to the number of customers served and number of units sold. The weights of units and customers in the new distribution price control were equal. Customer numbers were set in advance. The formula also included a loss adjustment factor, which adjusted for units lost during distribution. This gave an incentive to RECs to reduce these losses. As the control was forward looking it included a correction factor to adjust for forecasting errors. Historic inflation factors were in use in the formula from April 1995. In April 1995, prices were cut (relative to RPI) by between 11% and 17% with further cuts of between 10% and 13% in April 1996 and RPI-3 in the next three years. The price cuts

¹⁰² This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; and Ofgem (1999), Reviews of Public Electricity Suppliers 1998 to 2000 – Distribution price control review, final proposals, December 1999.

in the second year and afterwards were as a result of a revised price review in July 1995.

The distribution price controls were again revised in April 2000. The primary objectives of the most recent price review were to strengthen the incentives on companies to increase efficiency and reduce costs, so that prices to customers can be lowered, while recognising that sufficient revenue must be raised to maintain an appropriate quality of supply, to finance required new investment and to allow an appropriate return to capital providers. The aim of the review was to encourage the former PESs to achieve a balance between quality of supply, efficient capital investment, efficient operating expenditure, and efficient financial management.

The price control continues the RPI-X formula, although the price control review did point to certain weaknesses in the way in which RPI-X has been applied or features which could be improved. In particular, it was argued that ways need to be found to reduce the emphasis on periodic negotiation with the regulator, to increase the emphasis on outperforming peers, to address a potential imbalance between incentives to efficiency in respect of operating and capital costs, to maintain continuous pressure for improving efficiency, and to give clearer incentives in respect of quality of supply. A number of measures were adopted in the current price control to deal with some of these difficulties. Further to this, an on-going work programme on information and incentives was established to effect further improvements. The Information and Incentives Project was established to improve the incentives on companies during the new price control period, to ensure a proper balance between considerations of cost and quality of supply, and to reduce the burden and uncertainty associated with future reviews. Its specific work programme included the definition of a set of outputs to be incentivised (including a study of how the former PESs should measure and report consistent operating and financial data) and the determination of a set of financial rewards and penalties that will incentivise the former PESs to deliver these outputs. In addition to the above, the Information and Incentives Project will monitor companies between price control reviews, and review the incentives created by the regulatory framework.¹⁰³

The current price control, introduced on 1 April 2000 for a period of five years, results in an initial reduction in 2000/2001 of distribution prices in England and Wales by between 19% and 33%, and a further annual reduction of 3% below the rate of inflation until March 2005. Each former PES's new revenues comprise an allowance for operating costs, depreciation and return on capital. Each company was considered in terms of its absolute and relative cost efficiency (taking operating costs and capital expenditure into account) and was allowed a common weighted average cost of capital (6.5%). Companies were also considered by reference to the quality of service which they had provided. More reliance was placed on customer service during the 1999 review than in any previous review. Specific rewards and penalties were given for various aspects of performance, new stiffer targets were set, and Ofgem announced that a further 2% of revenues would be put at risk to factors relating to customer service from April 2002.

¹⁰³ See Ofgem (2002), Information and Incentives Project Regulatory Instructions and Guidance – Version 2, March 2002.

- Electricity supply

As mentioned, the aim of price controls, where consumer choice is restricted by a monopoly environment, is to simulate certain aspects of a competitive market, principally giving a business an incentive to operate efficiently and ensuring, over time, that its customers obtain the benefits of improvements in efficiency. It follows, therefore, that once competition has developed and customers are free to choose from whom they purchase, these price controls are no longer needed. Competition between suppliers for sales will put downward pressure on prices and create the necessary incentive for suppliers to operate efficiently.

In the electricity supply sector, following the model of the other UK privatisations, price controls were introduced for the regional supply companies at privatisation. With the introduction of competition between 1998 and 1999, the question that has emerged in the electricity supply sector is how to determine when competition is sufficiently developed to allow for the removal of price controls

Figure 16: Electricity supply price caps in England and Wales

April 1990-March 1994	RPI-0+Y
April 1994-March 1998	RPI-2+Y
April 1998-March 1999	RPI-X, with X varying between +3.2 and +11.8
April 1999-March 2000	RPI-3
Notes: * Y covers pass through of distribution, transmission and generation costs. The Y factor was removed from 1998 as controls became based on tariff caps. * The temporary cap on generation prices in England and Wales ended in 1996.	

Until April 1998, the former REC's supply charges were regulated by a RPI-X+Y revenue yield control. The Y factor, which had five components, enabled each REC to pass through to customers costs already regulated by another price control, that is:

- transmission costs (excluding exit charges for transferring electricity from the grid to the REC's own distribution network),
- distribution costs;

as well as costs which were outside the REC's control, that is:

- electricity purchase costs,
- the Fossil Fuel Levy,
- administration payments to the pool.

These costs amounted to approximately 95% of supply business costs. The RPI-X component limited that part of the maximum average supply charge that was not passed directly to customers.

The initial supply price control, until March 1994, controlled the maximum average charge per unit of electricity supplied by each company in sales in both its authorised area and elsewhere. It related the revenues entirely to the number of units (kWh) supplied and all of each REC's supplies were included within the scope of the price control. The initial values of X were set at zero for all RECs for the first four years.

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There was also a supplementary price control which expired on 31 March 1993 and applied only to the franchise market. It had the form RPI+F. Apart from the fossil fuel levy, it allowed the maximum average price per unit supplied to franchise customers to increase by no more than the rate of inflation. It was in effect a cap on total price rises to franchise customers in the first three years following privatisation.

The next set of controls, which took effect from April 1994, covered franchise customers only (that is, customers taking under 100kW). This supply price control related the revenues to a constant term plus an allowance per customer served and an allowance per unit sold. The constant term varied between RECs. Allowances per customer served and per unit sold were uniform across all RECs. The size of these allowances reflected the fact that broadly 75% of the costs were related to the number of customers and 25% to the number of kWh sold. For the period from April 1994 to March 1998, the price controls on the supply business margins of the companies in England and Wales were tightened to RPI-2. As the control was forward looking, it included a correction factor to adjust for forecasting errors. Historic inflation was also in use in the formula since April 1994. In addition, to encourage energy efficiency and stimulate investment in this area, the RECs were given an obligation and an allowance of £1 per franchise customer to be spent on energy efficiency projects.

The next supply price restraint ran from April 1998 for two years during the transition to competition in the supply market. The price controls applied only to the PESs. Second tier suppliers were not subject to any price restraint. The controls covered domestic and small non-domestic customers, known as designated customers, and took the form of maximum price restraints rather than the cost pass-through controls that applied prior to this. The cap on total price rises was based on the existing tariff levels adjusted for over- and under-recoveries and reflected the assessments of potential cost increases and reductions. These types of price controls are generally described as tariff caps. The cost increases arose from the data management costs associated with the opening of the supply market to competition. The cost reductions arose through the scope for reductions in coal purchase costs and the spreading of independent power contracts across the competitive market, the scheduled reductions in distribution and transmission charges that arose from the specific price controls, and an incentive target reduction in supply business operating costs. The price restraints varied between companies, ranging in 1998/1999 from 3.2% to 11.8% reductions on tariffs in England and Wales. From April 1999, prices were required to fall by RPI-3.

The restraints continued to include the £1 allowance for energy efficiency from each PES customer covered by the controls. In addition, the controls included a specific control on charges to domestic prepayment meter customers. Their charges were required to be reduced at the same rate as the charges on the corresponding domestic customers as from 1 April 1998. From April 1999, prices for prepayment meter customers were required to fall by RPI-3. This was to ensure that these customers benefited from competition to the same extent as other domestic customers. Specifically, the structure of the price restraints were an overall average revenue cap (using preset volumes of customers (as at 1 August 1997) and units (as at 1997/1998) in actual and allowed average revenue calculations), plus supplementary caps, including an average revenue cap on the PES standard domestic tariff, calculated at a consumption of 3,300 kWh, an average revenue cap on other domestic tariffs, an

average revenue cap on non-domestic tariffs, a prepayment meter customer cap, and a cap on domestic standing charges.

These price controls were set in place until 31 March 2000, where upon they were subject to review. The review concluded that the price control should be retained, but only for the primary domestic tariffs (standard and economy 7). As competition appeared already to be strong in the direct debit market, explicit price regulation was not set on the direct debit discount.¹⁰⁴

The next electricity retail price controls were introduced in April 2000 for two years. These price controls on the ex-PES suppliers took the form of a restriction on the weighted average unit price they could charge to standard domestic customers and the weighted average unit price they could charge to domestic economy 7 customers within their supply service areas.¹⁰⁵ Supplementary restrictions required that the individual components of the charge could not increase faster than the retail price index. An additional restriction limited the amount by which charges for in-area customers supplied on a prepayment contract could exceed the corresponding charges to customers supplied on a credit contract. This restriction was a £15 maximum surcharge, except in Eastern and Scottish Hydro regions where the surcharges were £11.22 and £0 respectively. The price controls applied to all ex-PES suppliers who had supply service obligations, for particular areas, regardless of the name the company used when supplying the domestic customer.¹⁰⁶

From 1 April 2002, Ofgem propose to replace regulation of electricity supply via price controls with the use of powers of investigation and enforcement under competition law. Consistent with Ofgem's commitments, this also resulted in the removal of the two remaining prescribed standards of performance in electricity supply, and the lifting of the requirement on ex-PES suppliers to submit regulatory accounts to Ofgem.¹⁰⁷ Ofgem will continue to monitor the behaviour of all suppliers and, in particular, dominant suppliers, and could take action should that behaviour be prohibited by competition law. Under its concurrent powers under the Competition Act 1998, Ofgem could bring action for anti-competitive practices such as excessive pricing and discriminatory predatory pricing.

The removal of all domestic electricity price controls has caused some controversy, with both consumer groups and parliament expressing concerns over Ofgem's decision to remove all price controls, in particular for prepayment customers. Consumer groups, including *energywatch*, have publicly slated the regulator for selling out consumers, in particular Scottish consumers and those from the more vulnerable sectors of society, such as prepayment consumers. Energywatch argue that competition is not sufficiently developed in either the prepayment sector or Scotland

¹⁰⁴ Ofgem annual report 1999.

¹⁰⁵ The restraints do not apply to other electricity suppliers or ex-PES suppliers' charges to non-domestic customers, direct debit customers, or to credit and prepayment customers outside each ex-PES suppliers' supply services area.

¹⁰⁶ Ofgem (2001), Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001.

¹⁰⁷ Ofgem (2001), Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001.

to warrant the removal of price controls, and that price increases are likely in the face of this decision.¹⁰⁸ Furthermore, nearly 40 MPs recently signed a Commons early day motion expressing concerns over Ofgem's decision and urging it to rethink its plans.¹⁰⁹

While Ofgem agrees that competition in Scotland is not fully developed and that prepayment meter users do not receive all the competitive benefits that other customers do, it argues that evidence shows that competition is sufficiently robust across all socio-economic groups and in all geographic locations to allow for the removal of supply price controls. Furthermore, Ofgem argue that the domestic supply market has reached a stage of development which requires a shift in regulatory approach away from price controls and toward other forms of regulation. In this way, Ofgem hopes to stimulate innovation within the electricity supply industry. In consequence, Ofgem's plans to remove all price controls from 1 April 2002 have gone ahead.

Scotland

Because of the difference in the structure of the industries in England and Wales and Scotland, the price controls imposed in Scotland have differed from the equivalent controls in England and Wales. The Scottish companies' prices have been subject to three separate controls – on transmission, distribution and supply.

- Transmission¹¹⁰

Figure 17: Scottish transmission price controls

April 1990-March 1994	Scottish Power Scottish Hydro-Electric	RPI-1 RPI-0.5
April 1994-March 1999	Scottish Power Scottish Hydro-Electric	RPI-1 RPI-1.5
April 2000-March 2005	Scottish Power Scottish and Southern Energy	RPI-0 RPI-0
Note: For the period between April 1999 and March 2000, the previous price control was extended to allow the same level of total revenue in real terms for 1999/2000 as was allowed in 1998/1999.		

Transmission charges for Scottish Power and Scottish and Southern Energy (formerly Scottish Hydro-Electric) are subject to RPI-X controls. Regulated transmission revenue includes all revenue arising from the provision of transmission services. Income from new connections and extensions to connections provided after 30 March 1990 is excluded from the price controls. Also initially excluded were the

¹⁰⁸ See energywatch (2001), Ofgem Says Markets are Working: Consumer Watchdog Disagrees; energywatch (2002), Watchdog Slams 'Failing' Regulator; and energywatch (2002), Ofgem Abandons Safeguards for Millions of Prepayment Customers.

¹⁰⁹ Milne R (2002), Prepayment At Risk If Price Controls End, Utility Week, 25 January 2002.

¹¹⁰ This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; Offer (1998), Scottish Transmission Price Controls – Consultation paper, February 1998; and Ofgem (1999), Review of Public Electricity Suppliers 1998 to 2000 – Scottish transmission price control review, final proposals, December 1999.

transmission units and revenues associated with transmission from the system of one Scottish company to that of the other and exports between Scotland and England.

The initial price controls, set before vesting and running until 1 April 1994, applied to allowed revenue per unit calculated on the basis of the actual number of units transmitted. From April 1994 to March 1999, the controls applied to allowed revenue per unit, calculated on pre-determined forecasts of these units. This change removed any incentive to increase the number of units transmitted, so promoting the prospects for energy efficiency. The forecasts were based upon the companies' own projections of quantity transmitted, with some revision following discussions with the companies. The forecasts assumed an annual rate of increase of units transmitted within Scotland of approximately 1% for Scottish Power and about 1.5% for Scottish Hydro-Electric. Also, from April 1994 the definition of regulated revenue was amended to include exports over the interconnector to England and Wales.

From April 1994 until March 2000, the transmission businesses were subject to a RPI-X price control, with maximum prices being set to yield allowable revenues on the footing of pre-set projections of the number of units transmitted. Any over- or under-recovery of revenues resulting from variances in actual quantities transmitted was corrected for in the allowed prices for the subsequent year. The initial X-values of 1.0 for Scottish Power and 0.5 for Hydro-Electric were tightened to 1.5 for Hydro-Electric and remained at the same level for Scottish Power for the period April 1994 to March 1999.

Under Scottish Hydro-Electric's licence, the company is required to transfer a hydro benefit each year from its generation business to its transmission business and domestic customers. The amounts were increased each year in line with inflation. Higher profits from the generation business were used to offset the potentially higher costs in transmission and distribution in Hydro-Electric's authorised area. The price control running from April 1994 did not alter the hydro benefit.

The DGES proposed a revised Scottish transmission price control for a one year interim period from April 1999 to March 2000 to allow new price controls on the transmission and distribution businesses to apply simultaneously from April 2000. For the one year interim period, he proposed the transmission price control be revised to hold maximum allowed revenue constant in real terms from 1998/1999 to 1999/2000.

While the former price controls had effectively been revenue caps (the price controls took the form of an RPI-X unit price control with provision for adjustment for over- and under-recovery by reference to previously projected quantities of units transmitted; as revenues did not vary with the actual volumes of units transmitted, the controls were tantamount to revenue caps), the current price controls, introduced in April 2000 and running until March 2005, are expressed as revenue controls, with unit prices varying according to the actual quantities transmitted. Under the current price controls, allowed revenue was set initially for Scottish Power and Scottish Hydro-Electric and adjusted by RPI-X in each subsequent year of the control with an annual correction for under- and over-recovery in any previous year. Under the final proposals, Scottish Power's maximum allowed transmission revenues were set to initially fall by 6% and those of Scottish Hydro-Electric were set to broadly remain constant in real terms. This was followed by annual adjustments in line with the rate

of change in RPI (that is, $X=0$). The present price control covers all charges made by the Scottish transmission companies, except those for rental charges to extra high voltage customers, entry connection charges for generators and revenues in respect of the use of the post-vesting interconnector upgrades and pre-vesting interconnector revenue under contract.

While the current price control covers the core transmission, system operator and pre-vesting interconnector activities, the price control review suggested that the review of Scottish trading arrangements could lead to the separation of some of these activities, as has been the case in the England and Wales, and the regulatory controls will need to be revised at this time.

- Scottish administered wholesale pricing arrangements¹¹¹

Since vesting, as part of the approved trading arrangements, ScottishPower and Scottish and Southern Energy (formerly Scottish Hydro-Electric) have agreed with Ofgem:

- a price cap for wholesale electricity trades between the host generators and suppliers (the Scottish wholesale price cap);
- top-up and spill prices to apply to the imbalance volumes incurred by independent generators and suppliers;
- that, until the introduction of renewable obligation certificates (ROCs), SP Generation and SSE Generation will buy generation from existing 2 MW generators at the energy component of the Scottish wholesale price cap. Thereafter, SSE Generation and SP Generation will not be required to purchase such generation at an administered price, provided that the output of the 2 MW generator is eligible for ROCs.

Prior to the introduction of NETA in March 2001, the Scottish wholesale price was defined as pool selling price plus transmission uplift minus 1% of the combined total. The Scottish top-up and spill prices used England and Wales pool related prices, with top-up charged at a wholesale price cap and spill prices being derived from a weighted average of three tranches. With the introduction of NETA, the Scottish wholesale price cap was redefined.

The current Scottish wholesale price cap, operating from 27 May 2001 until 31 March 2002, comprises an energy component plus the supplier element of the England and Wales balancing services uses of system (BSUoS) charge less 1.5% of the combined total (the latter adjusting for the absence of constraints in Scotland and the different treatment of loss).

The energy component of the Scottish wholesale price cap is calculated using:

¹¹¹ Ofgem (2001), Scottish Administered Wholesale Pricing Arrangements – A review of the present arrangements and consultation on prices to apply from 1 April 2002, December 2001; and Ofgem (2002), Scottish Administered Pricing Arrangements from 1 April 2002 – Ofgem proposals document, January 2002.

- 20% weighting of the cumulative over-the-counter baseload month ahead Petroleum Argus index;
- 20% weighting of the cumulative over-the-counter baseload month ahead Heren index;
- 20% weighting of the cumulative over-the-counter baseload month ahead Platts power index;
- 40% weighting of the cumulative over-the-counter baseload month ahead Andersen Spectron Power Index.

The flat monthly over-the-counter price is shaped to a half-hourly basis using UKPX power exchange half-hourly price profiles.

The price applied to top-up volumes to March 2002 is England and Wales system buy price plus the BSUoS supplier charge minus a residual cash flow reallocation term, capped at the Scottish wholesale price plus 5%, with a four weekly reconciliation period.

The spill price depends on whether a settlement area is in net spill or in net top-up in each half-hour and the total volume of spill in the particular settlement area. If the settlement area overall is short then the spill price paid by the host generator is equal to the capped top-up price. In the event that the total area spill is greater than the total area top-up then the price paid per MWh for spill volumes is calculated from a volume weighted average of the price payable under three tranches.¹¹²

The next Scottish wholesale price cap, balance and imbalance arrangements will operate from 1 April 2002 to 31 March 2004. Assuming a target date for the implementation of BETTA as April 2004, Ofgem proposed to retain the current arrangements for the next period. This was accepted by SSE Generation and SP Generation.

- Distribution¹¹³

Distribution charges are also subject to a RPI-X price control. A number of charges are excluded from the price control – charges for special and prepayment meters, connection charges, top-ups and standby charges, and charges to customers connected at extra high voltages. While these charges remain excluded, Ofgem has expressed in its latest review of distribution charges that it would consider whether extra high voltage charges and prepayment surcharges require revised arrangements in the future.

¹¹² The first tranche of spill is equivalent to the total area top-up and is paid the capped top-up price. The second tranche of spill is spill volumes in excess of the top-up volume and up to 20% of the quantity of supplies made to customers by suppliers acting out of area, and is paid England and Wales system sell price, with a floor in each half hour of £10 MWh. The third tranche of spill is spill volumes in excess of 20% of the quantity of supplies made to customers by suppliers acting out of area, and receives no payment.

¹¹³ This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; and Ofgem (1999), Review of Public Electricity Suppliers 1998 to 2000 – Distribution Price Control Review, Final proposals, December 1999.

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Until March 1995, the price control related the companies distribution revenues entirely to the number of units of electricity distributed. The initial value of the controls, which were set for five years, was RPI-0.5 for ScottishPower and RPI-0.3 for Hydro Electric.

From April 1995, regulated revenue was split into two components – that associated with metering and that with the rest of the distribution business. The price control was amended so that it was based on revenue related to the number of customers served and number of units sold. The weights of units and customers in the new distribution price control were equal. Customer numbers were set in advance. This was to remove any incentive on companies to sell more electricity whilst retaining a general incentive on companies to seek out and meet the needs of customers. The formula also included a loss adjustment factor, which adjusted for units lost during distribution. This aimed to incentivise the PESs to reduce these losses. This control system broadly corresponded with the system applied in England and Wales. The formulae were also forward looking and, therefore, included a correction factor. Historic inflation factors have been in use in the formula since April 1995.

From April 1995, the price control was tightened to RPI-2 for Scottish Power and RPI-1 for Hydro-Electric for the next five year period. The MMC referral by the DGES for Hydro-Electric's distribution price controls led to a significant use of the hydro benefit to reduce distribution charges. A reduction of 0.3% for 1995/1996, followed by RPI-2 for the following four years was determined.

From 1 April 2000, a new price control was put in place for 5 years. The price control proposed initial reductions in distribution prices of 13% for ScottishPower and of 4% for Hydro-Electric, followed by an annual reduction of 3% below the rate of inflation until March 2005.

- Supply¹¹⁴

As in England and Wales, up to April 1998 the Scottish companies could pass through to customers the charges for transmission and distribution which were separately regulated. Electricity purchase costs were also passed through. However, in Scotland the generation prices which could be passed onto franchise customers were explicitly limited. As Scottish Power and Hydro Electric are vertically integrated, the bulk of purchases of generation by the supply businesses were made either from their own generation or from other generators in Scotland on a contractual basis.

The initial supply charges control, which ran until March 1995, controlled the maximum average charge per unit of electricity supplied in the company's authorised area. Charges to customers in other suppliers' areas, or with a demand above 10 MW and customers with own generation were excluded. The initial controls were set at RPI-0.5 for Scottish Power and RPI-0.3 for Hydro-Electric. A second control covering customers whose demand was below 1 MW was also applied until March 1995.

¹¹⁴ This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; and Ofgem (2001), Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001.

From April 1995, prices to customers with a demand of 100 kW and above where no longer regulated. For franchise customers, the controls from April 1995 took the same form as the RECs in England and Wales. The allowed revenue included three components: a fixed element, and an amount per customer plus an amount per unit. The changes formula resulted in a 6% initial drop of supply charges for Scottish Power. The DGES proposed a smaller fixed sum for Hydro-Electric to hold supply charges at the same level in real terms relative to the previous year. Thereafter, controls were tightened by RPI-2 for both companies. As in England and Wales, an allowance of £1 per franchise customer was allowed for the two companies to spend on energy efficiency projects.

ScottishPower accepted these distribution and supply price controls. Hydro-Electric did not and the DGES referred them to the MMC. The MMC recommended a higher fixed sum for Hydro-Electric's supply price control formula and RPI-2 after 1995/1996. It also recommended that the generation cost component in the supply price formula should be limited by a yardstick based on the RECs electricity purchases for their franchised customers alone.

The next price control ran from April 1998. The controls for Scottish Power and Hydro-Electric were considered alongside those for the former PESs in England and Wales. These price controls ran for two years during the transition to competition in the supply market. The price controls applied only to the PESs (second-tier suppliers were not subject to any price restraint). They covered domestic and small domestic customers (designated customers) and took the form of maximum price restraints rather than the cost pass through controls that applied previously. The cap on total prices rose for those customers based on existing tariff levels adjusted for over and under recoveries and reflected assessments of potential cost increases and reductions. The energy efficiency allowance of £1 per designated customer continued. There were also likewise specific controls on charges to domestic pre-payment customers and tariff structures were required to meet a number of criteria.

The next price controls, which ran from 1 April 2000 to 31 March 2002, were also considered alongside those of the former PESs in England and Wales. As in England and Wales, they took the form of a restriction on the weighted average price that the former PESs can charge for to standard domestic customers and domestic economy 7 customers within their supply service areas. Supplementary restrictions required that the individual components of the charge could not increase faster than the RPI. An additional restriction limited the amount by which charges for in-area customers supplied on a pre-payment contract could exceed the corresponding charges to customers supplied on a credit contract. For ScottishPower the restriction was set at a £15 maximum surcharge. For Scottish Hydro-Electric the surcharge was £0.

As in England and Wales, Ofgem proposed to remove all supply price controls in Scotland from 1 April 2002. This has been particularly controversial in Scotland, where competition is much less fully developed. Electricity switching rates are lower in Scotland than in England and Wales, with 28% of electricity customers having switched compared to the national average of 38% for electricity. Furthermore, Scottish Power Energy Retail Ltd and SSE Energy Supply Ltd still retain 76% and 86% of their market share (by customers supplied) in their supply service area, and 77% of the overall market share in Scotland. Consumer groups have slated Ofgem for

their decision and motions have been laid before both the UK and Scottish parliaments, calling upon Ofgem to retain price controls to protect consumers in Scotland and vulnerable fuel consumers on prepayment meters throughout the UK.

While Ofgem has admitted that competition is not fully developed in Scotland, they argue that retail supply competition is sufficiently strong to allow price controls to be lifted. Ofgem believe that by bringing more competitive arrangements, like those which now exist in England and Wales, into the Scottish wholesale market, the current problems relating to higher electricity prices in Scotland can be addressed.

Northern Ireland

Prices in Northern Ireland are governed by four price controls, relating to power procurement, transmission system operation, transmission and distribution, and supply. The price controls on NIE's power procurement, transmission and supply businesses were set initially by the former Department of Economic Development at privatisation. The first revision to these controls by the DGESNI was from April 1997. The price control on NIE's transmission system operator (TSO) business was first introduced in 2000 in response to the requirement, under the IME directive, to separate, at least in management terms, the transmission system from generation and supply. At this stage, the TSO was established as a separate regulated business by transferring the functions previously carried out by systems operations under the power procurement business (PPB) and the price control revenues for the pre-2000 PPB were split to reflect the new market structure.

- Power procurement¹¹⁵

The level of the bulk supply tariff is regulated by a formula which limits the maximum average charge for each unit of electricity sold. The power procurement price controls were initially set for 10 years. The licence allowed the DGESNI to review them after a minimum of 5 years. The DGESNI decided that the controls should be revised from April 1997, at the same time as the other price controls on NIE were revised.

The present control came into operation on 1997 and runs for five years. At his review, the DGESNI retained the structure of the previous price control. The price control allows NIE to pass through 95% of the actual purchase costs of electricity plus 5% of a reference cost of electricity which is calculated using the RPI and fuel indices for coal, oil and gas. If NIE is able to beat this yardstick, it may retain the difference up to a limit (currently set at £2 million). Thus, there is an incentive on the PPB to purchase electricity at prices lower than the yardstick. The incentive on NIE to purchase below the yardstick was strengthened at the review. Within the yardstick, the mix of fuels was adjusted to reflect future fuel and capacity scenarios.

¹¹⁵ This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; and Ofreg (2002), Northern Ireland Electricity's Power Procurement Business Initial Consultation Paper – Price control proposals issued by the director general of electricity supply (NI) for the period April 2002-March 2004.

In addition, the PPB is permitted to levy an amount which rises with the RPI-3 in order to cover its own costs. There was also an initial reduction in prices in 1997/98 of 27.8%. There is also a maximum profit or loss allowance which is indexed to the RPI. If NIE's annual profit or loss arising from differences between actual unit costs incurred and the reference purchase cost exceeds this amount, the difference may be passed on to suppliers.

Excluded power procurement costs relating to the following may be passed in their entirety to suppliers:

- fuel security and fuel stocking directions;
- payments to the landbank business to ensure NIE does not suffer any losses in running the landbank;
- meeting non-fossil fuel obligations;
- costs of complying with the development of new wholesale competition arrangements;
- costs outside the control of the NIE as agreed by the DGESNI,

From the year 2000/2001, the PPB price control was modified to take account of the new roles placed on the systems operations (SONI) part of the previous PPB structure (now separately defined as the transmission system operator business in NIE's licence). The control was modified such that the NIE's PPB's own costs were recovered through an allowance per unit sold at the BST, and an allowance per unit sold at non-BST rates. Sales at the BST reflect the sales made to the non-liberalised element of the market, and non-BST sales are those made to other parties and are not made at a set or regulated tariff price. The allowance for BST sales for the period up to 31 March 2002 was set at 0.02 p/kWh, and for non-BST sales at 0.12 p/kWh. The objective of the greater revenue allowance for non-BST sales was to encourage PPB to maximise the use of its contracted generation plant by making additional sales over and above the BST sales to the Northern Ireland market, and hence make a contribution to lower electricity prices by reducing the gross level of the BST.

The proposed new price control for the PPB carries on this principle. Due to the current uncertainty with regard to the future of the PPB, the new price control will operate for a two year period, from April 2002 (with an option to be extended for one year). The new price control proposes to either remove or modify the yardstick term. Ofreg argue that the logic for retaining the yardstick has been partially eroded by the incentive on NIE to operate in a manner which ensures that it minimises the cost of wholesale generation purchase as a normal course of business. The yardstick has also been too easy to beat, resulting in NIE recovering the maximum allowable incentive payment on an annual basis. However, Ofreg may consider a modified yardstick term if it can be shown to provide an explicit incentive to effectively manage the generation contracts.

The price control also proposes to place a requirement on the PPB, from 2002/2003 to act as a purchaser of last resort for independent (non-NFFO) renewable output. Any energy produced and not sold by renewable independent power producers would be purchased at a fixed price by PPB (which would be based on a percentage of the market price of renewable energy and initially set at 3p). The PPB could then re-package and sell this renewable energy to suppliers, who could sell to final customers.

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The NIE incentive would be reflected in the difference between purchase and sale prices, the larger part of which should be retained as profit by PPB. The NIE would be indemnified against making a loss by the ability to pass through any costs not met through the public service obligation levy (which currently recovers the excess cost of NFFO renewable energy).

- Transmission system operator (TSO)¹¹⁶

The TSO price control applies to the TSO's system support service charges, which include ancillary service costs and fast start gas turbine charges and are recovered across all customers in the Northern Ireland market.

The existing price control sets a maximum revenue allowance for the TSO's system support services (set at £5.95 million (2000/2001 prices)), adjusted annually by the rate of inflation (RPI) less 0.5%.

Due to current uncertainty with regard to the future role of the TSO, the new price control is proposed to operate for two years, coming into effect on 1 April 2002. It is proposed that the TSO price control revenues be set as fixed (indexed) amounts in each year, rather than applying the current RPI-X incentive mechanism.

- Transmission and distribution¹¹⁷

Use of system charges on suppliers by NIE for delivering electricity to customers are regulated by an RPI+X formula. Connection charges, prepayment metering, charges for top-up and standby and other special charges are excluded from regulated revenues.

The price control formula contains three components: a fixed component which does not depend on the volume of units transmitted and distributed and which accounts for around 75% of regulated revenues and a variable component which varies in line with the volume of units transmitted and distributed and which accounts for around 25% of regulated revenues. The third component is an adjustment to the allowed revenue to give NIE an incentive to reduce the losses on the system.

The first transmission and distribution price control was set by government at the time of privatisation and ran until 31 March 1997. The fixed component of the formula consisted of a fixed amount of revenue which was allowed to grow at RPI+3.5%. The variable component consisted of a variable term in pence per unit distributed which was allowed to grow at RPI+1%.

¹¹⁶ This section is drawn from Ofreg (2002), Northern Ireland Electricity's Transmission System Operator Business Initial Consultation Paper – Price control proposals issued by the director general of electricity supply (NI) for the period April 2002-March 2004.

¹¹⁷ This section is drawn from Hicks C (1998), Regulation of the UK Electricity Industry; Ofreg (2000), Transmission and Distribution Price Control Review for Northern Ireland Electricity plc – A consultation paper, April 2000; and Ofreg (2001), Transmission and Distribution Price Control Review for Northern Ireland Electricity plc 2002-2007 – A consultation paper by the director general for gas and electricity supply for Northern Ireland, November 2001.

The present price control came into operation on 1 April 1997 and runs for five years. The existing price control also consists of a fixed component, but the definition of this fixed term has been altered by the DGESNI. The fixed component equals a customer allowance (in £ per customer) times a pre-set agreed number of projected customers in each year (rather than a monetary sum, as in the previous price control period). The customer allowance was allowed to grow at RPI-2% and the projected number of customers was set to grow at +1% per annum. This meant that the fixed component of revenue was allowed to grow at RPI-1%. As before, the variable component consisted of a variable term in pence per unit distributed. This variable term was allowed to grow at RPI-2% which was then multiplied by the number of units distributed.

The DGESNI's initial proposals for the current price control required NIE to cut its revenue by 30% in 1997/1998, followed by 2% per annum thereafter. NIE rejected this price control, triggering a reference to the Monopolies and Mergers Commission (now the Competition Commission). The MMC proposed that the allowed charge per unit should be reduced to a P_o of 25% in 1997/98 and an X value of -2 for each of the following years. The courts decided that the MMC figure could not be set aside by the DGESNI and, consequently, to prevent having to re-open the price control, the DGESNI accepted the MMC report.

The price control for the transmission and distribution business is currently under review, with a new price control proposed to come into effect on 1 April 2002. Ofreg issued a consultation paper on the new transmission and distribution price control in March 2002.¹¹⁸ The draft proposals set a RPI-X price control for NIE's T&D, with allowed revenue determined by a building block approach based on:

- efficient operating costs;
- capital expenditure forecasts and hence a path of regulatory asset values;
- the cost of capital to use as the appropriate return;
- incentive payments with respect to efficient asset management.

The draft proposals are expressed as a possible P_o reduction compared to prices in 2001/2002 together with an X factor of 2% per annum in the following four years.

- Supply¹¹⁹

NIE is allowed to pass on amounts charged to it by the PPB and transmission and distribution businesses, whose charges are already regulated. The supply element, mainly the costs of billing customers, is regulated by an RPI+X formula.

The present price control runs from April 1997 for five years. The control is based on three components: a fixed sum, customer numbers and units sold. Actual customer numbers are used. The price controls apply only to customers with a demand of 1MW or less. The earlier controls applied to all customers.

¹¹⁸ Ofreg (2002), Transmission and Distribution Price Control Review – Initial proposals for Northern Ireland Electricity plc, a consultation paper by the director general of electricity supply for Northern Ireland, March 2002.

¹¹⁹ This section is drawn from Hicks, C (1998), Regulation of the UK Electricity Industry.

An allowance of £1 per customer (increasing to £1.50 in 1999/2000 and to £2 in 2000/2001, inflation linked) was introduced for energy efficiency projects, plus an additional allowance for every unit NIE sells under a 'green' tariff for renewable sources of electricity.

The DGESNI initially proposed for the current supply business control, an initial price reduction of 43.9% in 1997/1998 and an X of -1.5 for the next three years (that is, a four year price control period). As in the case of the transmission and distribution price control, NIE rejected this proposal and a referral was made to the MMC (now the Competition Commission). The MMC recommended an initial price reduction of 42% in 1997/1998 and an X of -2 for the following four years. The DGESNI accepted the modifications proposed by the MMC for the supply business.

Review of competition

With its duty to protect the interests of consumers, wherever possible through effective competition, Ofgem conducts periodic reviews of the development of competition in key areas with the aim of deregulating where effective competition has been established, and identifying and remedying barriers to competition where it has not. Ofgem has recently undertaken reviews of competition in supply, electricity connections, metering and meter reading services and, with the introduction of the new electricity trading arrangements as a means of improving the effectiveness of competition, of the wholesale electricity market.

*Competition in domestic supply*¹²⁰

Since full opening of the domestic electricity supply market in May 1999, there has been substantial development in competition in the market. To guide its regulatory policy, Ofgem undertakes annual reviews of the development of domestic supply competition. Ofgem's most recent review, published in November 2001, had the specific objective of determining whether competition was sufficiently developed in the domestic supply market to warrant deregulation (specifically, the removal of price controls). To assess the development of competition, Ofgem considered a number of factors represented by a range of indicators, including:

- customers' experiences;
- customer switching behaviour;
- market shares;
- price and non-price offers;
- entry and exit of suppliers;
- barriers to entry.

¹²⁰ This section is drawn from Ofgem (2001), *Experience of the Competitive Domestic Electricity and Gas Markets – Research study conducted for Ofgem by MORI, November 2001*; and Ofgem (2001), *Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals, November 2001*.

The review found a high degree of awareness of different suppliers among electricity customers, with eight in ten being aware of at least two electricity suppliers. Awareness levels are higher among customers who have switched supplier and among those paying by direct debit (although awareness levels were not markedly different between customer groups). Satisfaction with suppliers was extremely high across different service areas, with no more than 3% dissatisfied. However, the review found that there was much ignorance and apparent confusion about the different prices offered by electricity suppliers, with only one third of customers having succeeded in making their own comparisons, and as much as half of switchers appearing to have changed supplier without directly making their own comparisons.

The review found that 38% of domestic electricity customers had, at August/September 2001, switched supplier one or more times since the introduction of competition. The incidence of switching electricity supplier among disadvantaged groups was found to be much closer to that of the population as a whole than in the previous year, with customers with very low incomes, disabled customers and single parent families switching at rates in excess of the average. Pensioners and electricity customers in rural areas continued to switch at lower than the average rate. Switching rates among customers who pay by prepayment meter had also caught up with, or were approaching, those paying by cash or cheque. However, they continued to lag behind direct debit payers in their propensity to switch. Geographically, there are also variations in switching, with Scotland lagging behind England and Wales. The lowest proportion of switchers was in the London Electricity area and the highest was in the East Midlands Electricity area.

The review found that there was significant variation in the development of competition among the fourteen ex-PES supply service areas, with the development of competition being slower in the more rural north of Scotland than in the more urbanised central and southern English areas. However, in average terms, the ex-PES suppliers had lost an in-area market share of 30% by September 2001. The ex-PES suppliers had lost a proportionately greater market share among customers paying by direct debit than among other types of customers.

The review also found that overall price competition was developing well in the domestic electricity market with a range of price offers and discounts on the ex-PES suppliers being offered to customers. Direct debit offers were particularly marked and prepayment customers typically had a more limited choice of discounts than customers on other payment methods. There was also a range of non-price offers, such as dual fuel deals and the development of established tariff schemes, such as green tariffs.

Since the previous review in December 2000, the number of active electricity suppliers had fallen slightly. Merger and acquisition activity accounted for some of this reduction, resulting in consolidation in the domestic electricity sector. As a result of its acquisitions, Innogy is now the largest domestic electricity supplier, supplying approximately one fifth of all Great Britain electricity customers (see **Figure 18**).

Figure 18: Market share of electricity suppliers in Great Britain

Parent company	Supply business subsidiary	Market share
Innogy Holdings	npower npower Yorkshire npower Northern	19%
Centrica	British Gas Trading	17%
TXU	TXU Energi	15%
Scottish and Southern Energy	SSE Energy Supply	14%
Electricité de France	London Electricity	10%
ScottishPower	Scottish Power Energy Retail	10%
Powergen UK	Powergen	8%
American Electric Power	SEEBOARD Energy	6%
Other suppliers		1%

While Ofgem does identify some existing barriers to competition, the review concludes that there is sufficient competition in the domestic electricity sector for Ofgem to remove price controls in favour of regulation via competition law. Ofgem argues that competition for prepayment and standard credit customers (currently the subject of price controls) is similar to that for direct debit customers. It is recognised, however, that the benefits from competition for these groups have not, to date, been as great as those which have accrued to direct debit customers. Ofgem proposes, however, to address these issues through initiatives other than price regulation. These include:

- supporting the debt-blocking trail to assist gas and electricity customers in debt wanting to switch suppliers;
- examining best practice in debt management and prevention, jointly with *energywatch*;
- pursuing, within its metering strategy, options for competition and innovation in prepayment metering.

Competition in Scotland is less developed than in England and Wales. Ofgem identifies the principal barrier to competition in Scotland as being the lack of a fully competitive wholesale generation market. Ofgem is presently reviewing the Scottish trading arrangements with a view to aligning arrangements in Scotland with those in England and Wales. It is anticipated that the British electricity trading arrangements (BETTA) will be implemented in Scotland by 2004.

As already mentioned, the conclusions drawn by Ofgem from its review have been challenged by *energywatch* and members of parliament. An alternative review by the House of Commons Committee on Public Accounts, based on a report by the NAO and evidence presented by, amongst others, the chairman of the Gas and Electricity Markets Authority and the chief executive of *energywatch*, concluded the following:

- while some customers had benefited from the introduction of competition, others were worse off overall, and that Ofgem needed to ensure that the competitive market was operating in the interests of customers and that all customers were adequately informed about the choices available;

- if the remaining customers switched suppliers, substantial savings could be achieved, but changing suppliers is a complicated process and many customers find it hard to compare prices and few shop around for the best deal;
- the number of complaints known to Ofgem about misleading selling techniques and erroneous transfers on the part of suppliers and their agents had fallen, but many more customers than those who complain have cause for dissatisfaction about the way they have been treated.¹²¹

The Committee on Public Accounts argued that while all customers have benefited from price caps, the majority have gained little from competition. They recognised that there was disagreement between Ofgem and *energywatch* with regard to the status of competition in the domestic supply market, with Ofgem believing that there is a prospect of real competition and *energywatch* believing that the market is not yet working effectively because of market dominance at the regional level and low numbers of customers changing supplier. They thus argued for Ofgem to demonstrate that the market is working effectively and will protect customers, including prepayment customers, by setting out in advance the criteria for making the decision, having regard to *energywatch's* concerns, and evaluating progress against these criteria before removing price caps.

Significantly, the evidence presented to the Committee of Public Accounts precedes that used by Ofgem to inform the conclusions drawn in its latest competition review. Ofgem consequently believe that they have shown that competition is significantly robust for all socio-economic groups to warrant the removal of all supply price controls. Furthermore, the conclusions drawn by the Committee are not shared by the industry, which, like Ofgem, argues that evidence suggests that competition is sufficiently developed to allow for the removal of price controls. The Electricity Association (2002) highlight the following:

- the extent of switching in the domestic electricity market is substantially greater than in many other markets which are not price capped;
- competition in generation and supply has been a significant factor in driving down electricity prices (not only price caps);
- switching has been widely spread among social groups and while competition for prepayment meter customers was initially slower to develop, from October 2000 to October 2001, PPM customers represented 24% of new switchers, only 1% point less than standard credit customers;
- price trends and switching rates, while important, are not the only factors relevant to the assessment of competition and other factors, such as the robustness of the market structure, strength and number of suppliers, entry of new players, customer awareness and the ability to switch supplier, also provide strong evidence of the health of the domestic electricity market.¹²²

¹²¹ See Select Committee on Public Accounts (2002), Eleventh Report – Office of Gas and Electricity Markets: Giving Domestic Customers a Choice of Electricity Supplier, January 2002; and National Audit Office (2001), Office of Gas and Electricity Markets – Giving domestic customers a choice of electricity supplier, January 2001.

¹²² Electricity Association (2002), Review of Domestic Competition and Supply Price Regulation – Comments of the Electricity Association, January 2002.

Competition in industrial and commercial supply

Industrial and commercial electricity supply, defined as constituting all customers with a maximum demand in excess of 100 kW, has been fully open to competition since 1994. In April 1990, the former PESs statutory monopoly to supply electricity to customers in the above 1 MW market was removed, and from April 1994 the threshold for the competitive market was reduced to include customers in the 100 kW to 1 MW market.

From 1990, the regulator has monitored the development of competition in these markets. The most recent review of competition in industrial and commercial supply, which was published in December 2000, assessed the status of competition in this market segment using the following indicators:

- the extent of entry and exit by suppliers;
- suppliers' performance, including their market share;
- suppliers' price offers, customer switching behaviour, and in particular, how customer choice reflect changes in suppliers' relative offers;
- barriers to entry in the market.¹²³

The review found that the while the number of suppliers licensed to operate in the market tended to increase up until October 1998, since then there had been a decrease in the number of suppliers actively competing in the market. This was as a result of consolidation among the former PESs. Since the review, this trend of consolidation through mergers and acquisitions has continued. Ofgem concluded, however, that the reduction in number of suppliers did not necessarily imply a reduction in competitive pressure, unless it was accompanied by other adverse indicators, such as reduced pressure on prices.

The review found a trend of falling market shares for the former PESs in their supply service areas (formerly, first-tier), both by volume and sites supplied. In Scotland, the two former PESs continued to retain a much larger share of their supply service area market compared with that in England and Wales. Ofgem concluded that the relatively even spread of market shares, and their relatively low level, was consistent with a competitive market. However, concerns were expressed about the position of Scotland.

During the period under review (April 1999 to April 2000), prices fell across most consumption volumes. There was also an increase in the range of prices on offer, suggesting that customers were able to shop around for competitive deals. This was less true for Scotland, where the range of prices offered were generally lower than the ranges offered in England and Wales. Other evidence suggested that the market was operating in a competitive manner as price reductions by some suppliers were accompanied by an increase in market share. Price was, however, not the only factor influencing choice of supplier in the market and other factors, such as brand and service level, were also significant.

¹²³ Ofgem (2000), A Review of the Development of Competition in Industrial and Commercial Electricity Supply, December 2000.

Ofgem concluded that competition was relatively well established in both the 100 kW and over 1 MW sectors in England and Wales, but competitive forces were weaker in Scotland. In Scotland, there were relatively fewer active suppliers in the former Scottish PESs service supply areas, the market shares of the former Scottish PESs remained comparatively high, and prices were higher, with a narrower range of price offers.

The primary barrier to entry to the market was considered to be administrative burdens, such as securing industry agreements (for transmission, distribution and metering) and systems testing, which raised entry costs and discouraged entry. While some of these administrative arrangements are necessarily complex, Ofgem has undertaken a number of initiatives to help reduce the administrative burden of market entry. These include initiatives to improve customer transfers between suppliers, initiatives requiring the distribution companies to facilitate competition by publishing appropriate statements of distribution use of system charges, and a review and proposals to reform the Scottish trading arrangements to facilitate entry into the Scottish market.

Competition in metering and meter reading services

Ofgem has developed a metering strategy which aims to enable suppliers and customers to exercise choice over how they obtain their metering and meter reading services. By facilitating such choice, Ofgem aims to enable buyers of metering services to take up more attractive offers from competing service providers. In structural terms, Ofgem is ultimately seeking to separate metering from monopoly distribution businesses and to allow for unlicensed metering businesses to provide services directly to suppliers or customers on commercial terms. The metering strategy focuses on two strands:

- regulation of incumbent service providers (that is the ex-PES distribution businesses);
- promotion of new entry and new investment.

The main initiatives in this regard have been:

- between 1998 and 1999, the introduction of disaggregated charges (that is, separate from distribution) for metering and meter reading;
- between 1999 and 2000, the introduction of PES ‘agent competition’ systems, to enable suppliers to choose alternative meter operators, data collectors and data aggregators.

In September 2000, Ofgem conducted a review of competition in metering and meter reading services in the gas and electricity sectors.¹²⁴ The review aimed to assess the markets for the buying and selling of meters, metering services, half-hourly electricity metering and data services, and meter reading and data services to inform the development of Ofgem’s metering strategy, and to set a benchmark against which the development of competition could be assessed in future.

¹²⁴ Ofgem (2000), Review of Competition in Metering and Meter Reading Services – Survey document, September 2000.

The review found, amongst others, that in the electricity sector:

- competition between meter manufacturers was relatively intense;
- while the ex-PES distribution companies, as the de facto monopoly providers of non-half-hourly electricity metering services to all suppliers, charge separately for these metering services, the charges are not clear and can not be easily compared;
- competition between half-hourly meter operators was relatively strong, but the cost and complexity of accreditation of meter operators acted as a significant market barrier to new entrants;
- competition in meter reading and data services was relatively robust considering the short time since the introduction of choice in the market, but the cost and complexity of accreditation and associated systems acted as a barrier, and concern was expressed about the appropriateness of prices.

In response to the review, and following further consultation, Ofgem has proposed the following strands of work:

- creating more transparent pricing information through the approval process for electricity distributor metering charges statements;¹²⁵
- initiating discussion on processes to support the development of metering competition in electricity, through the review of electricity metering arrangements;
- initiating an industry group to address HSE concerns about appropriate safeguards where significant numbers of customers wish to exercise their statutory right to own and install meters, through the Ofgem-chaired and HSE-attended technical issues sub-group of the RGMA;
- initiating discussion on standards as they may relate to new metering technology, to ensure that new meter types can be supported by other suppliers, through the Ofgem-chaired meter innovation working party (MIWP).

Under the balancing and settlement code (BSC), suppliers are required to use accredited meter operators, data collectors and data aggregators. As already noted, this system of accreditation in electricity is seen as a significant barrier to entry. Accreditation procedures can be changed through the BSC modification process. Elexon, as operator of the BSC, has set up an accreditation review project which aims to review current processes, evaluate options to improve them and recommend changes. As Elexon cannot itself propose changes to the BSC, interested industry participants will be required to work with Elexon to bring forward suitable modifications.

¹²⁵ Ofgem argues that cost-reflective metering charges, presented clearly for each service and distinct from distribution use of system (DUoS) charges are a necessary condition for the development of competition in metering services. Under the licences, ex-PES distribution businesses are required to publish a statement of charges in a form approved by Ofgem. Ofgem plans to use this approvals process to improve the transparency of existing charges and service definitions and to separate charges for individual services.

Competition in connections

In 1995, the former-PES distribution businesses opened some areas of connections work (termed contestable work) to competitive providers. With competition developing slowly in the connections market, in July 2000 Ofgem published a document setting out its proposals for the development of competition in connections to the former PES distribution systems.¹²⁶ The July 2000 document identified the principal factors affecting the development of competition as including:

- the split between contestable and non-contestable work, with the scope for contestable work being unduly restricted;
- unduly restrictive procedures for the approval of contractors, thus limiting the number of effective competitors;
- delays in the provision of information by the former PESs to independent contractors, resulting in customers opting to have their connection installed by the former PES rather than a third party.

Ofgem established two working groups – the electricity connections steering group and the unmetered connections sub-group – to address these concerns over the effectiveness of electricity connection competition. The groups are chaired by Ofgem and include representatives of distribution network operators, the Health and Safety Executive, consumer groups and new entrants into the connections market, for example, contractors.

As part of the strategy to address the barriers to competition to electricity connection, Ofgem proposed to undertake a connections competitive market review. The review, undertaken in December 2000 and published in May 2001, showed that host distribution network operators (the former PES distribution businesses) continued to provide, almost exclusively, electricity connections within their authorised areas.¹²⁷ As before, the principal barriers to the development of effective competition were identified as being related to the policies and procedures adopted by each distribution network operator in dealing with other potential providers of connection services.

The July 2000 and May 2001 documents made a number of recommendations, which have, through consultation and discussion, been reviewed and altered to develop a programme of work for Ofgem and other industry players to address the identified barriers. These recommendations and initiatives include:

- limiting the scope of non-contestable work as far as possible;
- establishing a national registration scheme for the approval of third party contractors;
- developing standard connection charging statements to improve clarity and comparison;
- developing standards of services, with associated liabilities, to ensure that information is provided in a timely and accurate manner;

¹²⁶ Ofgem (2000), *Competition in Connections to Electricity Distribution Systems – Ofgem’s proposals*, July 2000.

¹²⁷ Ofgem (2001), *Review of Competition in Gas and Electricity Connections*, May 2001.

- developing a national adoption agreement (for new developments and unmetered connection) to ensure that assets installed by a third party are adopted by distribution network operators in a non-discriminatory way.¹²⁸

A number of developments have occurred since. The scope of contestable work has been extended to include design, provision of materials, testing and installation, and live connections on new networks. Live connections on existing networks, determination of the point of connection to the distribution network, upstream reinforcement, diversion work and the statutory use of wayleaves remain non-contestable at present, primarily due to safety concerns.

As most of the distribution network operators already used Lloyds Register to approve third parties wishing to undertake work in their areas, it was agreed that a suitable way forward for the registration scheme would be for Lloyds to expand and develop the existing scheme from one tailored to the requirements of individual distribution network operators to one transferable across distributors' boundaries. The steering groups have produced a registration principles document, and Lloyds has, in conjunction with the steering groups, developed a modular based national registration scheme.

The steering group has developed a technical framework document, outlining national guidelines on safe working on the network and including any technical specifications inherent to specific distribution network operator areas. This aims to ensure that any asset adopted by a distribution network operator meets the same requirements as an asset installed by the distribution network operator itself, and provides the necessary linkage between the short-term responsibilities of the new entrant and the long-term interests of the distribution network operator and customers for a safe, reliable and cost efficient service life.

National adoption agreements are being developed. The adoption agreements require that competent new entrants carry out installations of electricity infrastructure in accordance with the registration scheme, the technical framework documents and the distribution network operator's specific safety rules. The adoption agreements also outline the liabilities associated with each party.

Review of NETA

Since going live on 27 March 2001, NETA has been the subject of two reviews by Ofgem. First, to ensure that NETA is delivering effective trading arrangements; and second, at the request of the Minister of State for Energy and Competitiveness in Europe, to assess the specific impact of NETA on smaller generators, such as renewables and CHP. The reviews covered the first three months of NETA operation. Ofgem's conclusions, drawn from these early indicators for the operation of NETA as a whole, were:

¹²⁸ Ofgem (2001), *Competition in Connections to Electricity Distribution Systems – An update document*, December 2001; and Ofgem (2002), *Review of Competition in Gas and Electricity Connections – Survey document*, February 2002.

- forward prices fell substantially on the UK over the counter market and the three new power exchanges (despite a rising wholesale gas cost that increased by approximately 12% over the year leading up to the review);
- prices under the day-ahead markets were less volatile than under the pool arrangements;
- NETA resulted in a large and rapid development of the wholesale market, with a number of power exchanges being established and significant developments in liquidity occurring in both these power exchanges and the over-the-counter market;¹²⁹
- a lack of liquidity in the within-day spot markets, reflecting the initial spread between system buy and system sell imbalance prices, portfolio generators self-insuring before gate closure against plant failure, a lack of reporting of individual participants' contractual positions from central systems and the timing of gate closure;¹³⁰
- a number of price reporters (for example, Heren, Platts and Reuters) have entered the market and forward prices are available through a range of media, at varying levels of costs;
- prices in the balancing mechanism and imbalance settlement process have been volatile as supply and demand has to be matched at very short notice and, in part, because the volumes of accepted bids and offers in the balancing mechanism have been very small.

Smaller generators have four options for trading under NETA:

- they may become a party to the balancing and settlement code (BSC);
- they may sell their output to a supplier who could be a specialised 'consolidator' managing the imbalance risk of several smaller generators (the supplier/consolidator would need a licence and to register the meters in the NETA central systems);
- they may sell the whole of their output to a supplier whose demand is in the same grid supply point group (that supplier would then net off the generator's output from its demand);
- they could split their output (for example, between predictable and unpredictable output) and sell it to different suppliers/consolidators.

With respect to smaller generators, the review found:

- very few smaller generators had chosen to become BSC signatories;
- the prices received for exports covering the first two months of NETA were substantially below those from the same period the year previously (typically by 17%);
- the output of smaller generators has fallen substantially, with export volume reduced by 44% compared to the same period the year previously. With

¹²⁹ The majority of forward trading under NETA has been conducted through the over the counter market. The vast majority of trading through the exchanges has been through the spot markets.

¹³⁰ To the extent that they reflect a problem, these issues are addressed through modifications to the BSC.

reductions in output and prices, revenues from the sale of electricity have also fallen;

- other than wind power generation, the performance of smaller generators does not appear to be significantly less predictable than that of other generators;
- consolidation services available during the first two months of NETA were insufficiently developed.

When NETA was devised, it was accepted that smaller generators should be allowed to sell their fixed and unpredictable output separately. This would allow them more flexibility to compete for better prices by, for example, contracting to sell fixed output to a supplier, while managing less predictable output more effectively by selling it via specialised consolidators. By consolidating the unpredictable output of small generators, it was thought that consolidators could protect small players from onerous penalties under the BSC. Such consolidation, however, failed to emerge on a large scale.

In response to the outcomes of the review on smaller generators, a consolidation working group (CWG) was set up by Ofgem to tackle obstacles to the development of consolidation services.¹³¹ The CWG identified that main obstacle to consolidation is the inability of small players to sell fixed volumes of energy without becoming party to the BSC, with its severe penalties for being out of balance.

A recent report by the CWG, published in February 2002, recommends a number of changes to the trading arrangements, which it claims will address the technical barriers to the development of effective consolidation services.¹³² All that remains is for the NETA players to make the appropriate modifications to the BSC, the master registration agreement, systems and processes.

An independent review of the first year of NETA's operation assesses the actual impact of NETA on the wholesale electricity market, against Ofgem's claims that competition has strengthened resulting in reductions in the wholesale price of electricity in the order of 20%-25%.¹³³

The review found that there have been significant reductions in the price of over-the-counter contracts, in particular for winter peak contracts, and while this would appear to support Ofgem's argument that NETA has been successful in reducing the scope for exercising market power, there have also been other changes in the electricity market which have occurred alongside the introduction of NETA which may have had an impact. In particular, the review concludes that changes in input fuel costs and market concentrations (a fall in market concentration will reduce the scope that generators have to exercise market power) have interacted with the introduction of NETA to cause the observed changes in wholesale electricity prices. It is difficult to isolate the effect of any one of these factors, and hence to determine what proportion of the price reductions should be attributed to NETA. However, it is likely that NETA

¹³¹ The CWG is an Ofgem-chaired group, including representation from smaller generators, consolidators, suppliers, DTI, DEFRA, Elexon and NGC.

¹³² Ofgem (2002), Report to the DTI of the Consolidation Working Group, February 2002.

¹³³ Oxera (2002), NETA: The First Year, The Utilities Journal, March 2002.

has placed downward pressure on prices, given that the pool prices were not seen to respond to falling input costs or changes in the generation market structure to the extent that might be expected.

The review also evaluated the performance of the balancing mechanism and the incentives it creates for market participants to remain in balance. The review concludes that the balancing mechanism appears to have settled, after its initial period of volatility. Furthermore, the system buy price is not only generally more volatile than the system sell price, but tends to be further from the wholesale electricity price. This implies a larger cash-out penalty for market participants which are short rather than long. As a result there are incentives for market participants to be long.

6 STANDARDS OF PERFORMANCE

England, Wales and Scotland

At privatisation, the Electricity Act 1989 empowered the director general of electricity supply (with the consent of the secretary of state) to make regulations setting guaranteed standards of performance for the public electricity suppliers (PESs). The Competition and Services (Utilities) Act 1992, through amendments to the Electricity Act 1989, further empowered the electricity regulator to determine standards of overall performance for the PESs. The Act also introduced a provision requiring each PES to conduct its business in such a way as could reasonably be expected to achieve the overall standards set for it. The Electricity (Standards of Performance) (Amendment) Regulations 2000 (SI 2000 No. 840) further prescribed a range of fixed penalties to be paid to consumers for failure to meet the specified guaranteed standards of performance.¹³⁴

These prescribed standards of service were incorporated into the PESs licences to protect the interests of consumers in the absence of competition. The standards were comprised of two types – guaranteed standards and overall standards – and covered a wide range of services relating to supply, distribution and metering services.¹³⁵ These prescribed standards of performance were first set by the director general in 1991, and then revised in 1993, 1995, 1998 and 2000.

As discussed, the Utilities Act 2000 abolished the concept of the PES and required the legal separation of the former PES electricity distribution and supply businesses. As a consequence, there was also a need for a separation of the standards of performance relating to distribution and supply. The Utilities Act provided for Ofgem, with the consent of the secretary of state, to make separate regulations for guaranteed standards of performance, and to separately determine overall standards of performance, for electricity distributors and electricity suppliers.^{136 137}

In the light of these changes, Ofgem began, in October 2000, a review of the standards of performance applying to the ex-PES electricity distribution and supply businesses. In reviewing these standards, Ofgem has focused on the distinction between those standards of performance applying to distribution, supply and metering activities. While the Utilities Act 2000 made provision for Ofgem to extend the standards of performance to all electricity distribution and supply companies, Ofgem

¹³⁴ Ofgem (2001), *Guaranteed and Overall Standards of Performance – Final proposals*, January 2001.

¹³⁵ **Guaranteed standards** set service levels that must be met in each individual case – if the company fails to provide the level of service required, it must make a payment to the affected customer. **Overall standards** cover areas of service where it is not appropriate to give individual guarantees, but where consumers in general have a right to expect companies to deliver predetermined, minimum levels of service.

¹³⁶ The new guaranteed standards, or amendments to existing guaranteed standards, are required under the Utilities Act to be contained in secondary legislation, approved by the secretary of state. The new overall standards of performance, or the amendment of existing overall standards, are made by Ofgem, through a statutory determination.

¹³⁷ Ofgem (2001), *Guaranteed and Overall Standards of Performance – Final proposals*, January 2001.

initially proposed to retain guaranteed and overall standards of performance for the ex-PES electricity distribution and supply businesses in relation to their old PES authorised areas only. However, certain standards relating to metering and meter reading were later extended to all supply businesses. For the monopoly distribution businesses, performance standards continue to be the subject of review under the Information and Incentives Project. For the ex-PES supply businesses, Ofgem proposed to retain, and introduce further, standards of performance in relation to their metering and meter reading activities. However, in relation to their supply activities, it is proposed to remove the remaining supply-related performance standards when supply price regulation is discontinued. These revised guaranteed and overall standards of performance have been set out in the Electricity (Standards of Performance) Regulations 2001, and in two subsequent amendments in 2001 and 2002, and came into force on 1 April 2002.

The following sections discuss, in more detail, the performance standards as they apply to each of these activities – distribution, supply and metering and meter reading.

Performance standards in distribution

In reviewing the standards of performance in the distribution sector, Ofgem proposed to continue the existing guaranteed and overall standards of performance, with certain amendments, for the ex-PES distribution businesses. These guaranteed standards of performance were laid out in the Electricity (Standards of Performance) Regulations [2001] (SI 2001/3265). At the time, however, Ofgem also proposed that further work on the future application of standards of performance in electricity distribution would be taken forward in conjunction with its ongoing work on the Information and Incentives Project. In January 2002, following consultation, Ofgem published draft regulations relating to the standards of performance for electricity distributors in relation to multiple interruptions.¹³⁸ This was followed, in March 2002, by the publication of a consultation on the draft determination of the overall standard and implementation arrangements for the guaranteed standard.¹³⁹ These standards, which aim to provide further protection to the ‘worst served’ electricity customers by providing for compensation for those who experience multiple interruptions to their power supply, came into effect from 1 April 2002.¹⁴⁰

Figures 19 and **20** detail respectively the guaranteed and overall standards of performance currently applicable to the ex-PES distribution businesses.

¹³⁸ Ofgem (2002), Development of Multiple Interruption and Other Standards for Electricity Distribution - Introduction of standards, January 2002.

¹³⁹ Ofgem (2002), Development of Multiple Interruption and Other Standards for Electricity Distribution – Consultation on draft determination of overall standard and implementation arrangements for guaranteed standard, March 2002.

¹⁴⁰ Prior to the introduction of these guaranteed and overall standards, compensation was only available to those customers who were off supply continuously for 18 hours or more.

Figure 19: Guaranteed standards of performance in electricity distribution¹⁴¹

Service	Required performance	Payment
Responding to failure of a supplier's fuse	Within 3 hours on a working day, and within 4 hours on any other day	£20
Restoring supplies after a fault	Must be restored within 18 hours For each further 12 hour period	£50 (domestic) £100 (non domestic) £25
Estimating charges for connection	Within 5 working days for simple jobs, and 15 working days for others	£40
Notice of planned supply interruption	Consumers must be given 2 days' notice	£20 (domestic) £40 (non domestic)
Investigation of voltage complaints	Visit within 7 working days, or substantive reply within 5 working days	£20
Making and keeping appointments	A morning or afternoon appointment, or a timed appointment if requested by the customer	£20
Notifying consumers of payments owed under the standards	Write to the customer and make payment within 10 working days	£20
Unplanned multiple interruptions	Applies where the supply to a customer's premises is interrupted for 4 periods each of not less than 3 hours during a relevant year	£50

Figure 20: Overall standards of performance in electricity distribution¹⁴²

Service	Required performance
All supplies, which are discontinued for more than 3 minutes as a result of a failure of, fault in or damage to the ex-PES distributor's distribution system, are to be restored within 18 hours from when the time at which the ex-PES distributor is made aware that a discontinuance has or could reasonably be expected to have occurred	99.5%
All voltage faults to be corrected within 6 months	100%
Connecting new tariff premises to the electricity distribution system: Within 30 working days (domestic) Within 40 working days (other)	100%
Responding to all customer letters within 10 working days	100%
Supply to the premises of a customer shall not be interrupted as a result of a failure of, fault in or damage to the ex-PES distributor's distribution system for more than 3 minutes on more than 5 occasions	Varies between 96% and 99%

¹⁴¹ The Electricity (Standards of Performance) Regulations 2001 (SI 2001/3265).

¹⁴² A further overall standard of performance which stipulated the required performance for each distribution company in relation to reconnecting supplies, following faults, within a 3 hour period was removed from 1 April 2002.

Performance standards for electricity supply businesses

In its review of guaranteed and overall standards of performance applicable to the ex-PES supply businesses, Ofgem proposed to remove the two exclusively supply-related standards in electricity when supply price regulation was discontinued in April 2002.¹⁴³ Other metering-related supply standards will be continued (with amendment) and extended, in certain cases, to all electricity suppliers.

- Supply-related standards of performance

In October 2000, Ofgem reviewed the guaranteed and overall standards of performance that were contained in electricity supply licences.¹⁴⁴ The document outlined proposals for the removal of a number of standards in electricity, including proposals for standards in supply. After consultation, Ofgem concluded in January 2001, that in a market where competition is firmly established there is a strong argument for discontinuation of prescribed standards of service.¹⁴⁵ They argued that such an approach was consistent with their declared policy of withdrawing from prescriptive regulations as competition develops and consumers are able to rely on the protection that it affords. Service standards continue to be regulated in other ways – for example, through inclusion in industry agreements.¹⁴⁶

The two electricity supply standards which remained were finally removed when supply price controls were discontinued in April 2002. Both standards were related to the response time of suppliers to customer enquiries as opposed to the quality of service provided. The first was a guaranteed standard of performance related to the time that it takes suppliers to respond to consumers' queries about charges and payments. Suppliers were required to provide a substantive reply and agreed refunds within five working days. If these standards were not met, the supplier was obliged to compensate the affected consumer to the sum of £20. The second was an overall standard of performance. This related more generally to the services that suppliers provide and operated to ensure that all letters received by the company received a response within 10 working days.¹⁴⁷

- Standards of performance relating to metering and meter reading

While metering and meter reading are competitive activities, competition in metering services is currently limited. Although, in the electricity sector, there are a range of meter service providers in the half-hourly market, the ex-PESs continue to be the de facto monopoly providers to the non-half-hourly market. Suppliers of domestic

¹⁴³ Ofgem (2001), *Guaranteed and Overall Standards of Performance – Further consultation*, June 2001.

¹⁴⁴ Ofgem (2000), *Guaranteed and Overall Standards of Performance – A consultation paper*, October 2000.

¹⁴⁵ Ofgem (2001), *Guaranteed and Overall Standards of Performance – Final proposals*, January 2001; and Ofgem (2001), *Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals*, November 2001.

¹⁴⁶ Ofgem (2001), *Guaranteed and Overall Standards of Performance – Final proposals*, January 2001.

¹⁴⁷ Ofgem (2001), *Review of Domestic Gas and Electricity Competition and Supply Price Regulation – Evidence and initial proposals*, November 2001.

consumers for electricity, therefore, have little choice of metering service provider. As a result, Ofgem considered the continuation of statutory guaranteed and overall standards of performance for metering services to be appropriate. They argue that this will ensure that consumers’ interests are protected, until such time as suppliers have a real choice of metering agent and/or service.¹⁴⁸

At the time of the review, Ofgem proposed that metering related standards be limited to ex-PES suppliers, with complementary guaranteed and overall standards in relation to meter provision and maintenance being placed on ex-PES distributors. However, the final regulations published in 2001, extend certain standards to all electricity suppliers.¹⁴⁹ Furthermore, Ofgem decided that such standards should not be applied to the distributors as it would complicate the market and be bureaucratically cumbersome. Instead, suppliers are required to enter into contractual negotiations with distributors, who have standard licence obligations to provide metering services in a non-discriminatory manner, to ensure that the performance standards are implemented effectively.

Figures 21 and 22 detail the guaranteed and overall standards related to metering and meter reading activities as they apply to electricity suppliers from 1 April 2002.

Figure 21: Guaranteed standards for electricity suppliers related to metering and meter reading¹⁵⁰

Service	Required performance	Payment
Responding to meter problems	Visit within 7 working days, or substantive reply within 5 working days	£20
Responding to prepayment meter faults	Within 3 hours on a working day, and 4 hours on any other day	£20
Making and keeping appointments on metering business	A morning or afternoon appointment, or a timed appointment if requested by the customer	£20
Notifying consumers of payments owed under the standards ¹⁵¹	Write to the customer and make payment within 10 working days	£20

¹⁴⁸ Ofgem (2001), Guaranteed and Overall Standards of Performance for Metering Services – Further consultation, July 2001.

¹⁴⁹ In the final regulations, all electricity suppliers have obligations to meet guaranteed standards related to responding to meter problems and prepayment meter faults, and to notifying customers of payments owed under the standards.

¹⁵⁰ The Electricity (Standards of Performance) (Amendment) Regulations 2001 (Statutory Instrument 2001 Number 3265).

¹⁵¹ Where payments are to be made by a relevant distributor to a customer, they are to be made to the electricity supplier of that customer for onward transmission to the customer.

Figure 22: Overall standards for electricity suppliers related to metering and meter reading

Service	Required performance
All consumers who have been disconnected for non-payment to be reconnected before the end of the working day after they have paid the bill, or made arrangements to pay	100%
Visiting to move the meter, when asked to do so by the customer within 15 working days	100%
Changing meters when necessary on change of tariff within 10 working days of a domestic customer's request, in all cases	100%
Responding to prepayment meter faults	
Within 3 hours on working days	98%
Within 4 hours on other days	95%

Northern Ireland

In Northern Ireland, the DGESNI is similarly empowered, under the Electricity (Northern Ireland) Order 1992 and the Competition and Service (Electricity) (Northern Ireland) Order 1992, to set guaranteed standards of performance which NIE must meet when responding to a customer's request, query or complaint, and overall standards of performance which NIE must meet in providing a service to customers as a whole.

Such standards of performance were first set for NIE in January 1994. The performance standards which operate currently came into force on 1 October 1999, following a review of the original standards. These standards had commenced in 1996, but were suspended when the director general's proposals, following a review of NIE's price control, were referred to the MMC. The current guaranteed and overall standards of performance are detailed in **Figures 23** and **24** below.

Figure 23: Guaranteed standards of performance

Service	Required performance	Payment
Replacement of NIE main fuse after failure	Within 3 hours on a working day, and within 4 hours on any other day	£25
Restoring supply after distribution faults	Within 24 hours of supplier becoming aware of fault	£50 domestic customers £125 non-domestic customers £25 for each additional 12 hours
Install meter and turn on electricity supply	Within 2 working days for domestic customers or within 4 working days for non-domestic customers	£25 plus £50 domestic or £125 non-domestic for failure to keep appointment
Providing an estimate for changing the position of meter or for new electricity supply	Within 7 working days for connections to existing lines and 15 working days for others	£50
Notice of planned interruption to supply	3 days	£25 domestic customers £50 non-domestic customers
Investigation of voltage complaints	Within 7 working days	£25 plus £25 for failure to keep an agreed appointment
Investigation of meter accuracy disputes	Within 7 working days	£25 plus £25 for failure to keep an agreed appointment
Responding to queries on charges or payments	Within 5 working days	£25
Morning and afternoon appointments to be offered and kept	Between 8.30am and 1.00pm or 12 noon – 5.00pm, Monday – Friday	£25
Making of payments owed under standards	Within 10 working days	£25
Dealing with pre-payment meter problems	Within 4 hours	£25

Figure 24: Overall standards of performance

Service	Required performance
Reconnection	87% within 3 hours 100% within 24 hours
Correction of voltage faults	100% within 6 months
Provision of new low voltage supplies	100% within 30 working days (domestic) 100% within 40 working days (non-domestic)
Reconnection after default	100% the next working day after arrears are paid
Meter relocation	100% within 15 working days
Changing meter	100% within 10 working days
Meter reading	99.5% at least once a year
Response to letters	100% within 10 working days

UK ELECTRICITY REGULATION

Since the implementation of the prescribed standards of performance, there has been a steady improvement in NIE's performance. In 1999/2000, NIE made 27 guaranteed standards payments, compared with 606 in 1994/1995, and achieved 9 out of 10 targets set for overall standards.

Given the improvements in standards which NIE has achieved in recent years, and the concern about price divergence from Great Britain, the director general has, in a recent review of the standards, expressed that he is not minded to seek further improvements in the generality of performance standards, unless they represent low cost improvements.¹⁵² However, the DGESNI did raise a number of issues for consideration, including:

- the extent to which the standards connected with restoration of supply need to offer greater protection to customers;
- the desirability of all guaranteed standards payments being made automatically, without claim, to customers (currently, payments related to guaranteed standards relating to restoration of supply and notice of planned interruption of supply are not made automatically);
- the desirability of new guaranteed and overall standards linked to frequent (multiple) interruptions of supply (as were introduced into Great Britain in April 2002);
- the importance of identifying the frequency of transient interruptions (those lasting less than one minute) and considering whether steps need to be taken to protect customers suffering these in significant volumes;
- the desirability of new overall standards linked to NIE's speed of response when answering telephone calls from customers;
- the desirability of measuring the levels of payments made to customers when guaranteed standards are breached.

¹⁵² Ofreg (2001), Review of Northern Ireland Electricity Plc's Guaranteed and Overall Standards of Performance – Consultation paper, March 2001.

7 ENVIRONMENTAL REGULATION

Burning fossil fuels in power stations gives rise to the emission of air pollutants, such as sulphur dioxide (SO₂), nitrogen oxide (NO_x), carbon dioxide (CO₂) and particulates. These pollutants have an effect on human health, and contribute to the acidification of the environment and to global climate change. Concern over these effects has given rise to the UK signing up to a number of international and European agreements, which aim to set limits on certain emissions. These agreements include:

- the EU's joint signing of the Kyoto Protocol to the Climate Change Convention in 1997, and the consequent adoption of a target for the UK to reduce total emissions of the six main greenhouse gases (including CO₂) by 12.5% compared to 1990 levels by the period 2008-2012 (the UK government has set its own target for reducing CO₂ emissions to 20% below 1990 levels by 2010);
- the adoption by the European Council in 1988 of the Large Combustion Plants directive on the control of emissions to the atmosphere, which sets down emission standards for all new plant in terms of concentrations of the pollutants in the flue gases and sets out the requirement for each EU member state to draw up a programme for the progressive reduction of total emissions of NO_x and SO₂ from existing plant, including all large power stations currently operating with coal or oil;¹⁵³
- the adoption of new targets for total national reductions in SO₂ and NO_x emissions in 1999 under the Gothenburg Protocol of the UNECE Geneva Convention on Long Range Transboundary Air Pollution, with UK targets being set at 625 kt per annum of SO₂ and 1,835 kt of NO_x;
- the adoption of the Acidification Strategy by the European Commission that will be implemented principally through the proposed National Emissions Ceilings directive, which aims to set tighter national emissions ceilings for SO₂ and NO_x for each member state.¹⁵⁴

The signing up of the UK government to progressively tighter emissions reductions targets, and the translation of this into UK legislation and policy strategy, can be taken as an indicator of the government's increasing commitment to the environment. The Utilities Act 2000 reflects this growing commitment, requiring the secretary of state to issue guidance to Ofgem on the government's environmental policies, so that Ofgem can make an appropriate contribution to the attainment of those policies. The government has stated:

“Economic regulation does not take place in a vacuum. The ways in which the utility regulators carry out their functions has consequences for the social and environmental, as well as economic, aspects of the pursuit of sustainable development. The government intends that the regulatory system should make an appropriate contribution towards achieving sustainable development. This means that economic

¹⁵³ The LCPD emission limits and targets are under review and an amendment has been proposed by the Environment Council of European Ministers.

¹⁵⁴ Under proposals made by Ministers in June 2000, UK emissions would be limited to 585 kt of SO₂ and 1,167 kt of NO_x by 2010.

regulation should be conducted in such a way which is alert to the government's wider social and environmental goals, and where possible supportive of them."¹⁵⁵

Despite this strong statement, two years on from the enactment of the Utilities Act, the government is yet to issue its social and environmental guidance to Ofgem. Draft guidance, issued in May 2001, sets out the government's key environmental objectives relevant to energy regulation. These include:

- meeting the UK's commitment under the Kyoto Protocol;
- the domestic goal of a 20% cut in carbon dioxide emissions by 2010;
- the government's target for 10% of electricity to be supplied from renewable sources by 2010, subject to the cost to consumers being acceptable;
- the government's target to increase the country's combined heat and power (CHP) capacity to at least 10Gwe by 2010;
- reducing air pollution and ensuring air quality continues to improve through the longer term.

To assist the government in achieving these targets, Ofgem will be required to take into account in its regulation of the energy sector, and to review its contribution to, the following key areas of concern:

- **energy efficiency** – in keeping with its duty to promote the efficient use of electricity and gas, Ofgem is required to consider energy efficiency implications at all points in the energy chain, including electricity generation (for example, the contribution made by CHP technology), electricity transmission and distribution (for example, the impact of losses and the ability of CHP and renewables generators to access the transmission and distribution network), and the end-use of electricity (for example, the impact of effective energy efficiency advice to domestic and business users);
- **energy efficiency commitment (EEC)** – although responsibility for setting energy efficiency targets and obligations has been shifted to the government, Ofgem has a role in administering and implementing the EEC, and should have regard to the EEC when considering its other regulatory decisions and the effect those decisions may have on the ability of suppliers to meet their EEC commitments;
- **energy services** – Ofgem is required to have regard to the benefits that are likely to result from the development of energy services and to promote consumer awareness of their financial benefits;
- **renewables** – Ofgem is required to have regard to the government's renewables target when exercising its functions and, in particular, should have regard to the access to the transmission and distribution network for renewable sources on reasonable and proportionate terms under the new electricity trading arrangements;

¹⁵⁵ DTI (2001), Draft Social and Environmental Guidance to the Gas and Electricity Markets Authority – A consultation document by the Department of Trade and Industry, May 2001.

- **embedded generation** – Ofgem is required to promote embedded generation, including CHP, as part of its duties to seek diverse and secure supplies of energy and to consider the environmental implications of economic regulation.

Regulatory measures applicable to the electricity industry which aim to assist the government in meeting its environmental policy targets include:

- demand-side measures which aim to improve end-use energy efficiency and promote energy services schemes (through the energy efficiency commitment (formerly energy efficiency standards of performance) and energy efficiency codes of practice);
- supply-side measures which aim to diversify generation sources and to increase the proportion of electricity supplied from renewable sources and CHP (through the renewables obligation and the renewables obligation Scotland) and to decrease the amount of emissions from existing and new power stations (through Integrated Pollution Prevention and Control).

Energy efficiency policy

The drivers for energy efficiency policy are twofold – environmental and social. Energy efficiency programmes aim, in part, to reduce the demand for energy, thereby reducing the environmental impacts of generation, transmission and distribution. There is, however, also a strong social dimension to energy efficiency policy, with energy efficiency programmes focusing, in particular, on the problems of the fuel poor. While socially driven energy efficiency programmes may also aim to reduce energy demand to provide, for example, those on low incomes with monetary savings, the primary aim of such energy efficiency programmes is to improve comfort. In the latter case, energy demand may remain constant, but targeted households will experience benefits through improved comfort in the form of warmer homes or better lighting.

There are two main energy efficiency obligations on electricity companies in Great Britain:

- an obligation to achieve specified energy savings for customers as set out first in the energy efficiency standards of performance, and now in the Energy Efficiency Commitment;
- an obligation to provide energy efficiency advice as set out in approved codes of practice.

Energy efficiency standards of performance (EESoP)¹⁵⁶

Under the Electricity Act 1989, the regulator was able to set and administer standards of performance in the area of energy efficiency. Initially, the regulator preferred to see how voluntary measures would operate and showed a lack of enthusiasm for such

¹⁵⁶ This section is drawn primarily from Ofgem (2000), Energy Efficiency Standards for Gas and Electricity Suppliers 2000-2002 – Final decisions, March 2000.

controls, an attitude which led to criticisms from proponents of energy efficiency.¹⁵⁷ It was not, therefore, until 1994 that the first energy efficiency standards of performance (known by their acronym, EESoP) were introduced in England and Wales (and a year later in Scotland). These standards, which ran until March 1998, imposed obligations on each of the former public electricity suppliers (PESs) to achieve specified energy savings for domestic and small business customers. Funding was granted through a special revenue allowance in the price control, equivalent to £1 per franchise customer per revenue year. The aggregate target for the 14 PESs for the first set of energy efficiency standards (EESoP 1) was 6,103 GWh in accredited savings, with an allowance of £101.7 million. EESoP 1 was followed by a similar programme, EESoP 2, running from April 1998 to March 2000. EESoP 2 was also applied solely to the former PESs, who had an aggregate target under the second set of standards of 2,713 GWh and an allowance of £48.1 million.

A value-for-money study, carried out by the National Audit Office (NAO) in 1998, concluded that EESoP 1 achieved a net present value saving of £250 million, with a further £80 million worth of comfort savings, in terms of warmer homes and better lighting. The Energy Saving Trust has further estimated the lifetime carbon dioxide savings from EESoP 1 and EESoP 2 combined at 10 million tonnes.

EESoP 3, which ran from 1 April 2000 to 31 March 2002, represented a departure from the first two energy efficiency standards programmes. For the first time, the standards applied to suppliers of both gas and electricity, and, within the electricity sector, to both the ex-PESs and those former second-tier suppliers who supplied electricity to designated customers (that is, domestic electricity customers and small business customers with electricity consumption below 12,000 GWh per annum).¹⁵⁸ Under EESoP 3, separate energy savings targets were set for the electricity and gas sectors, with electricity companies being required to achieve overall electricity savings of 5,050 GWh.

To take into account the fact that smaller suppliers face higher fixed costs per customer served and higher average costs when procuring energy efficiency goods and services, the scheme sets targets which were progressively tighter for companies of increasing size (measured in terms of customer numbers), with suppliers with less than 50,000 customers having an energy saving target of zero (unless they were a second-tier supplier affiliated to a PES).

In achieving their targets, companies had discretion over the mix of measures that they could carry out. Energy efficiency measures for electricity companies could include loft or wall insulation, draught proofing, cylinder lagging, energy efficient lighting, heating controls and efficient appliances. While separate targets were set for gas and electricity, flexibility was built into the scheme by allowing up to 25% of a company's energy savings target to be met through fuel substitution and savings of

¹⁵⁷ McGowan F (1993), *Electricity – The experience of Offer*, in [Eds] Gilland, T and Vass, P (1993), *Regulatory Review 1993*, Centre for the study of Regulated Industries.

¹⁵⁸ At the time of the implementation of EESoP 3, the standards were set for the ex-PESs under Section 41 of the Electricity Act 1989, and for the former second-tier suppliers under a new licence condition. Under the Utilities Act 2000, the energy efficiency commitment (formerly EESoP) is a statutory requirement for all suppliers of domestic electricity.

other fuels incidental to the main fuel savings (the latter being subject to a specific limit of 10%).

To address the problem of fuel poverty, energy companies were required, in meeting their targets, to pay particular regard to the interest of elderly and disabled customers, customers in rural areas and customers who may have bill payment difficulties.

The funding for the programme came from a charge of £1.20 per customer per annum during each of the two years of the standards programme. Based on this charge, it was estimated that energy suppliers (both electricity and gas) would spend approximately £110 million in domestic energy efficiency measures over the two year period of the programme. With local authorities, agencies, appliance retailers and consumers expected to contribute a further £40 million through matched funding and other partnership arrangements, the total cost of the programme was estimated to be approximately £150 million over the two year period. In comparison, the benefits to customers in terms of energy saved and improved comfort levels were estimated to amount to around £500 million. Furthermore, the programme was expected to result in savings of 7 million tonnes of carbon dioxide emissions.¹⁵⁹

*Energy efficiency commitment*¹⁶⁰

Under the Utilities Act 2000, the responsibility for setting the next energy efficiency programme was shifted from the regulator to the Department of Environment, Food and Rural Affairs (DEFRA). The new energy efficiency programme, known as the energy efficiency commitment (EEC), runs for three years from 1 April 2002. While DEFRA is responsible for setting the level of the overall obligation on companies and the broad criteria for the operation of the EEC, Ofgem is responsible for the detailed operation of the programme, including implementing the programme and monitoring and evaluating companies' compliance with the programme.

The obligations under the EEC apply to all suppliers of domestic electricity and gas, with companies which are licensed suppliers of both gas and electricity having one obligation for each licence.¹⁶¹ The total EEC obligation on all suppliers is approximately 62 TWh of fuel-weighted energy benefits.¹⁶²

As was the case for the EESoP programmes, targets are progressive, with the overall obligation being apportioned between suppliers on the basis of their numbers of customers. To help avoid barriers to new firms entering the market, and to recognise

¹⁵⁹ Ofgem (2001), Environmental Action Plan, August 2001.

¹⁶⁰ This section is drawn from DEFRA (2001), Energy Efficiency Commitment 2002-2005 – Consultation proposals, August 2001; and Ofgem (2001), Energy Efficiency Commitment Administration Procedures, December 2001.

¹⁶¹ Small businesses are excluded from the EEC, but will benefit from other energy efficiency programmes.

¹⁶² The obligation includes a deadweight component (that is, sales of measures that would have gone ahead anyway, without the stimulus of the EEC) and consequently the level of the EEC has been raised accordingly. When submitting schemes to Ofgem, however, suppliers are required to demonstrate their additionality.

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the possible higher cost of running energy efficiency programmes on a smaller scale, those suppliers with less than 15,000 customers are not subject to the EEC obligation.

Suppliers will meet their obligation by setting up energy efficiency schemes. As the target is in fuel standardised units, suppliers are able to use energy efficiency improvements from electricity, gas, coal, oil and liquid petroleum gas to meet their targets. Although the target is set on a supplier group's domestic electricity customer numbers, the efficiency schemes do not have to be contained to the supplier's own customers. The EEC allows for fuel substitution measures, where they result in a net saving to consumers, taking into account the carbon equivalence of the fuels involved before and after the measure is carried out. Programmes that promote new or additional uses of CHP are also eligible for approval.

Suppliers with an EESoP target will be able to carry over excess EESoP 3 action towards their EEC target (limited to not more than 10% of the supplier's target under the EEC). Suppliers are required to secure 50% of their energy savings from householders, including pensioners, in receipt of one or more income or disability benefits.¹⁶³ To ensure that suppliers put in place the necessary programmes for these priority groups, they are required to detail their priority group estimates when submitting schemes to Ofgem for approval.

Reflecting the government's policy priorities, the EEC provides an incentive for suppliers to provide energy service schemes.¹⁶⁴ Where a supplier achieves energy efficiency improvements through an energy service scheme, the supplier will be credited with an additional 50% of energy savings for up to 10% of its energy efficiency target.

Suppliers will have the option of trading either energy savings from approved measures or trading their obligations to another supplier. Ofgem will be responsible for overseeing trading arrangements, and the trading of obligations requires the written agreement of Ofgem.

The cost of the EEC to electricity and gas suppliers should not exceed the equivalent of 90p per customer, per quarter, per fuel. The government estimates that the average annual financial benefit for those in the priority group of lower income consumers benefiting from measures under the scheme, in lower energy bills or increased comfort, would build up to around £14.00 per year by 2005. The annual benefit, deriving from measures received under the scheme, for consumers outside the priority group would average almost £8.00 per annum by 2005. The average annual benefit, deriving from measures received under the scheme, for all consumers in aggregate would be around £10.00 per annum by 2005. These benefits would continue beyond

¹⁶³ These benefits include income support, housing benefit, council tax benefit, income based jobseekers allowance, attendance allowance, disabled living allowance, industrial injuries disablement benefit, war disablement pension, working families tax credit and disabled persons tax credit.

¹⁶⁴ Energy services means an agreement between a gas or electricity supplier and a customer to supply heating and lighting and/or motive power, or the provision of a package of energy efficiency measures, including the provision of consumer and household specific energy advice and audits, at least two measures to improve energy efficiency and, if necessary, the financial packages to fund these.

the EEC period. It is estimated that the EEC will cut greenhouse gas emissions by around 0.4 million tonnes of carbon a year by 2005.

It is expected that suppliers will have the option of trading excess energy savings onto the national emissions trading scheme as carbon savings. The rules and mechanisms for this will be devised by DEFRA.

Codes of practice

Under standard condition 25 of their licences, all electricity suppliers are required to develop a code of practice which sets out the ways in which they will promote and provide energy efficiency advice. As is the case with the energy efficiency commitment, these codes of practice are seen as a means of assisting the fuel poor in particular, with licensees having specific obligations to provide energy efficiency advice to customers on low incomes or those with payment difficulties. Such customers will be directed towards grant schemes such as 'warm front' (formerly the home energy efficiency scheme) and the EESoPs/EEC.

Each electricity supplier is required to prepare and submit to Ofgem for its approval a code of practice which provides customers with details of:

- information and advice, given or prepared by a suitably qualified person, on the efficient use of electricity, including on how to obtain practical help with the installation and financing of energy saving measures, the cost of using electrical appliances and information about the energy labelling of appliances, and day/night tariffs;
- arrangements, including a telephone information service, whereby customers may obtain further information;
- sources outside the supplier's own organisation from which customers can obtain further information and assistance in relation to measures that improve the efficient use of electricity (for example, energy efficiency advice centres, local *energywatch* agencies, central government agencies and other relevant organisations, including National Energy Action, the Energy Action Grants Agency, the Energy Savings Trust and Energy Action Scotland);
- information on financial assistance which is available to customers towards the cost of energy efficiency measures, including assistance from the supplier under EESoP/EEC and assistance available under 'warm front' ('warm deal' in Scotland).

In preparing their codes of practice, licensees are required to consult organisations with recognised expertise on energy efficiency, for example the Energy Saving Trust and National Energy Action.

Energy efficiency in Northern Ireland

As in Great Britain, NIE is obliged, under its licence, to produce a code of practice on the efficient use of electricity, and to provide an energy efficiency advice service. Unlike in Great Britain, NIE does not have any standards of performance for energy efficiency. While there is no legal obligation on NIE to produce any energy efficiency

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schemes, NIE is incentivised through its price control to encourage energy efficiency and reduce electricity demand. The NIE supply business receives a payment for all the kilowatt hours saved above a target of 110 Gigawatt hours set by the Energy Savings Trust (EST). In 2000, NIE's supply business earned an additional £312,000 profit – an amount which equated to about 6% of its profits for that year.

An energy efficiency levy was first introduced in Northern Ireland in 1997. In 1997/1998, the energy efficiency levy was collected at the rate of £1 per customer. The amount collected was increased to £1.50 per customer in 1999/2000 and to £2 per customer in 2000/2001, indexed to inflation. The levy was originally conceived as intending to save carbon emissions and costs, and was not focussed on fuel poverty. However, since the introduction of the levy, the issue of fuel poverty has moved up the government's policy agenda and an increasing proportion of the revenue from the levy is used on fuel poverty programmes.

While NIE has neither a monopoly of access to the levy, nor a legal obligation to produce the schemes which spend it, in practice NIE has been alone among electricity supply companies in coming up with schemes and projects. The revenue raised through the levy is thus invested by NIE supply in energy efficiency measures.

By 31 March 2001, the energy efficiency levy had raised £3.6 million and had attracted an additional £3 million. The programmes supported by the levy are audited by the Energy Savings Trust. By March 2001, each kWh saved by the levy had been at an average cost to customers of 0.73 pence compared to an average cost of producing and delivering a kWh of electricity of 10.45 pence to domestic customers. The measures put in place were calculated over their lifetime to save a total of 416 GWh, avoiding approximately 500,000 tonnes of CO₂ emissions and £29 million in fuel bills. By November 2001, 120,000 customers had directly benefited from these measures.

In September 2001, the Northern Ireland Assembly passed a motion encouraging the DGESNI to contribute to the eradication of fuel poverty by increasing the energy efficiency levy to £5 per customer, creating £3.6 million to tackle fuel poverty. As the levy is actually administered as a charge per kWh of electricity bought, the amount paid per customer would vary according to consumption. A levy of £5 would actually only cost an average domestic customer using 38,000 kWh per annum £1.62. As lower income households are disproportionately concentrated in the below average consumption bands, most of the fuel poor would themselves be paying much less than £1 per annum more than they may be paying at present.

The DGESNI has issued a consultation paper on how the increased levy could be used to target the fuel poor. Proposals include the following options:

- using the levy to finance directly fuel poverty projects (total house solutions) which might otherwise not be financed;
- using the levy to finance the electricity component in projects funded by others;
- directing the levy to fuel poverty electricity houses or all electric households;
- directing the levy to NIE's keypad customers, using the keypad as a way of identifying an electricity user constituency which has a high risk of being fuel poor, but also a newly enhanced capability of managing energy use better;

- using the levy to front end expenditure by, for example, meeting the finance costs of loans which will bring forward much greater resources earlier than a programme paid out of revenues;
- using the levy to attract in additional funds;
- using the levy to provide grants to incentivise private landlords, housing associations and so on;
- using the levy to complement NIE incentive earning energy efficiency schemes.

Renewables policy

The UK government has an ongoing commitment to stimulate the development of the UK renewable energy industry and has set a target for electricity from eligible renewable resources to make up 10% of sales from licensed suppliers by 2010, subject to the cost to the consumer being acceptable. As most renewable energy technologies are currently unable to compete directly on cost with conventional generational techniques, government has supported the development of renewables capacity and, more recently, a renewables market, through a series of measures.

In the past, the government's principal instruments for pursuing the development of renewables capacity were the Non-Fossil Fuel Obligation Orders for England and Wales and for Northern Ireland (NFFO and NI-NFFO, respectively), and the analogous Scottish renewables obligation (SRO) Orders.

Changes to the electricity industry under the Utilities Act 2000 mean that the NFFO/SRO regime is no longer feasible in Great Britain. The government has, therefore, replaced this regime with a new statutory obligation on all licensed electricity suppliers in Great Britain to source a specified and increasing proportion of their electricity supplies from eligible renewable sources. This obligation consists of the renewables obligation (RO) in England and Wales, determined by the UK parliament, and the corresponding renewables obligation Scotland (ROS) determined by the Scottish Parliament.¹⁶⁵ While there will be no further NFFO/SRO Orders, existing NFFO/SRO contracts will be honoured. In addition, locational flexibility will be available for most NFFO projects, where planning difficulties have been encountered.

The new renewables obligation is one of a series of measures to promote the development of renewables in Great Britain. Other policy strands include:

- exemption of renewables electricity from the climate change levy;
- an expanded support programme for new and renewable energy, including capital grants and an expanded research and development programme;
- development of regional strategies for renewable energy, with regional targets based on resource assessments, and a review of planning arrangements.

¹⁶⁵ The renewables obligation Scotland envisages that by 2010/11 renewables will contribute about 18% of Scottish electricity demand, an increase of 5% over the expected 2003 figure.

In Northern Ireland, the Department of Enterprise, Trade and Investment (DETI) is currently consulting on how best to further promote the uptake of renewables in Northern Ireland.¹⁶⁶

*Non-fossil fuel obligation and the Scottish renewables obligation*¹⁶⁷

Between 1990 and 2000, the government's principal mechanisms for supporting the development of renewable capacity were the non-fossil fuel obligation (NFFO) orders for England and Wales, the Northern Ireland non-fossil fuel obligation (NI-NFFO) orders, and the Scottish renewables obligation (SRO) orders issued under the Electricity Act 1989 and the electricity (Northern Ireland) order 1992. Under these orders, the former public electricity suppliers (PESs) were required to buy a specified amount of power from renewable generators at premium prices – that is, above the price of conventionally generated electricity – over a specified period. The higher costs of the NFFO/SRO renewables, expressed in this premium price, were met through the fossil fuel levy, which was raised by a charge on all electricity consumers and then distributed to the PESs to reimburse them for the difference between the price of conventional generation and the price agreed for the renewable supplies. Contracts to supply renewables capacity were awarded to generators through a tendering process conducted by the Department of Trade and Industry. The selected generators then contracted with the Non-Fossil Purchasing Agency (NFPA), a company set up by the former PESs to administer their obligations.¹⁶⁸

Between 1990 and 2000, five NFFO orders were made for England and Wales, three SRO orders were made for Scotland, and two NI-NFFO orders were made for Northern Ireland.¹⁶⁹ The first two NFFO orders provided support to projects for eight years, while the subsequent orders are offering support for 15 years. As at December 2000, there were 303 live projects from the five NFFO orders operational within England and Wales, with a total of 817.88 MW declared net capacity (DNC).¹⁷⁰ In Scotland, 24 schemes, with a total DNC of 71.6 MW, were operational under the three SRO orders; and in Northern Ireland, 18 schemes, with a total DNC of 17.5 MW, were operational under the two NI-NFFO orders. The dominant technologies supported by the renewables obligations have been landfill gas, waste combustion and wind. One of the major problems experienced in getting the renewables projects up and running has been related to getting planning permission. Of the contracted NFFO-1 projects, 81% were operational by March 2000, compared with only 67% of NFFO-2 and only 52% for NFFO-3 (each of these orders had completed the project development phase).

¹⁶⁶ See DETI (2001), *Renewable Energy in Northern Ireland – Realising the potential*.

¹⁶⁷ This section is drawn primarily from Electricity Association (2001), *Electricity Industry Review 5*, January 2001, and Electricity Association (2000), *Environmental Briefing – Renewable electricity in the United Kingdom*, Number 7.

¹⁶⁸ In Northern Ireland, NIE is legally required to secure specified amounts of power from renewable generators, who similarly bid for contracts through a competitive tendering process.

¹⁶⁹ DTI (2001), *Digest of United Kingdom Energy Statistics 2001* (updated January 2002).

¹⁷⁰ As the NFFO 1 and 2 contracts have expired, these projects are no longer monitored and consequently there is no accurate information on their status/output.

Renewables generation projects awarded contracts under NFFO-1 and NFFO-2 have been exposed to market forces since these contracts expired in 1998. The majority of generators involved have formed a renewables generators consortium to seek collective contracts with suppliers. While no new NFFO contracts will be awarded, support of existing NFFO contracts will continue. As a result, the government has extended the fossil fuel levy to support the generation projects from NFFO-3, NFFO-4 and NFFO-5. From 1 April 2002, the fossil fuel levy is set at zero for England and Wales and at 0.6% for Scotland (this represents a reduction from 0.3% and 1.2% respectively). The fossil fuel levy has been reduced as a result of a surplus of levy funds built up from previous years, and may again increase if required. To minimise the rate at which the fossil fuel levy is required to be set, eligible output from the SRO and the NFFO will be included in the renewables obligation. renewables obligation certificates (see below for detailed discussion) will be awarded for such output and auctioned on the open market, and revenue raised will be used to reduce the fossil fuel levy.

Renewables obligation¹⁷¹

As mentioned, the NFFO/SRO regime in Great Britain has been replaced by the statutory renewables obligation (RO) in England and Wales and the complementary renewables obligation Scotland (ROS).¹⁷² While orders under the NFFO/SRO regime were applicable to the former PESs only, under the RO/ROS orders, obligations are placed on all licensed electricity suppliers. The orders place an obligation on licensees in Great Britain to source a growing percentage of their total sales from eligible renewable sources (see **Figure 25** for a list of eligible sources of renewable energy).

The obligation for each supplier is calculated by applying a percentage obligation to that supplier's total electricity sales to customers (in England and Wales for the RO and in Scotland for the ROS) during each obligation period. The obligation on each supplier will rise from 3% of sales in the first obligation period (ending on 31 March 2003) to 10.4% of sales in the year ending 31 March 2011 (see **Figure 26**). It is proposed that the obligation will then remain at least constant at 10.4% of sales until 31 March 2027, but may well be increased to meet more ambitious targets for renewables beyond 2010.

¹⁷¹ This section is drawn from DTI (2001), *New and Renewable Energy Prospects for the 21st Century – The renewables obligation, statutory consultation*.

¹⁷² The determination of the ROS order has been devolved to the Scottish Parliament. However, the RO and ROS together aim to meet the UK's renewables target, and similar arrangements have been set up for England and Wales and Scotland under the RO and the ROS respectively. As a consequence, this section discusses the renewables obligation in general, highlighting differences where applicable.

Figure 25: Eligible renewable sources under the renewables obligation

Source	Eligibility
Landfill gas	✓
Sewage gas	✓
Energy from waste	Only non-fossil derived energy will be eligible Energy from incinerating mixed waste will not be eligible Energy from non-fossil derived element of mixed waste using advanced technologies will be eligible
Hydro exceeding 20 MW declared net capacity (dnc)	Only stations commissioned after the date the order is made
Hydro 20 MW or less dnc	✓
Onshore wind	✓
Offshore wind	✓
Co-firing of biomass	Eligible until 31 March 2011 for up to 25% of a supplier's obligation At least 75% of biomass fuel to be energy crops from 1 April 2006
Other biomass eg, agriculture and forestry residues	✓
Geothermal power	✓
Tidal and tidal stream power	✓
Wave power	✓
Photovoltaics	✓
Energy crops	✓

Figure 26: Obligation for electricity suppliers for each period

Period	Total Obligation as % of sales
2002/2003	3.0
2003/2004	4.3
2004/2005	4.9
2005/2006	5.5
2006/2007	6.7
2007/2008	7.9
2008/2009	9.1
2009/2010	9.7
2010/2011	10.4
2011/2012 to 2026/2027	10.4

Suppliers will demonstrate their compliance with their obligation by presenting renewables obligation certificates (ROCs) to Ofgem in respect of the year-long obligation periods.¹⁷³ ROCs will be issued to accredited generators for eligible renewable electricity generated within the United Kingdom, its territorial waters and Continental Shelf, and supplied to customers in Great Britain.¹⁷⁴ The ROCs will be

¹⁷³ Each ROC will represent 1MWh of eligible generation.

¹⁷⁴ Electricity generated from renewable sources in Great Britain, but exported to countries elsewhere (including Northern Ireland) will not be eligible for ROCs.

based on metered output and will be issued electronically to generators, or in the case of output sold through existing NFFO and SRO contracts, to suppliers.

The RO/ROS order also sets up a mechanism for trading in ROCs, providing for a supplier who supplies more renewable electricity than it is required to in the obligation period, to sell the 'green' value of this extra electricity, in the form of a certificate (ROC), to a supplier who has not supplied enough. The RO/ROS order also makes provision for limited banking of ROCs, with suppliers being able to meet up to 25% of their obligation by ROCs issued in the previous obligation period. Borrowing from future periods or banking for longer timescales is not permitted, however.

As an alternative to supplying renewable energy, suppliers may fulfil part, or all, of their obligation by paying a buyout price to Ofgem, which will be set at £30/MWh until 1 April 2003 and thereafter be adjusted in line with the retail price index (RPI). The proceeds of the buyout will be returned to suppliers by Ofgem, in proportion to the number of ROCs that each supplier presents to discharge its obligation compared to the total number of ROCs presented by all suppliers.¹⁷⁵ This aims to provide a financial incentive to fulfil the RO through presenting ROCs, rather than buying out.

In summary, suppliers can, therefore, meet their obligation by any combination of:

- purchasing renewable electricity directly (effectively purchasing ROCs from generators);
- purchasing ROCs from other suppliers who have exceeded their obligations;
- paying a buyout price to Ofgem.

If a supplier fails to present evidence of fulfilling their obligation, either through ROCs or through paying the buyout by the specified day, Ofgem may impose a penalty on the supplier concerned.

It is estimated that the obligation will increase the cost of electricity to consumers in Great Britain by around 0.5% each year until 2010, a total increase of a little under 5%, equal to about £780 million per year by 2010/11.

The future of renewable energy in Northern Ireland

While energy in Northern Ireland is a fully devolved matter, Northern Ireland is required to contribute to the United Kingdom targets for renewable energy. In October 2001, the Northern Ireland Department of Enterprise, Trade and Investment (DETI) consulted on the future of renewable energy in Northern Ireland.¹⁷⁶ Policy targets set by the European Union and the British government have not been disaggregated to the Northern Ireland level as of yet and the only existing official Northern Ireland target is to secure 45 MW by 2005. This would represent about 2% of Northern Ireland's generating capacity and about 3% of its electricity output, thus falling well short of the target figures set elsewhere.

¹⁷⁵ If a supplier chose to buyout part, or all, of the obligation, it would not receive any recycling of the buyout funds for the proportion they had bought out.

¹⁷⁶ DETI (2001), Renewable Energy in Northern Ireland – Realising the potential.

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The initial consultation by DETI refers to this 45 MW target, renewing its commitment to reaching the target by 2005 and estimating that a further 20 MW of renewable energy is required (that is, after subtracting the amount being generated from renewable sources since the target was set (that is, the electricity generated under the two Northern Ireland NFFO contracts, the electricity commissioned under the NIE eco energy tariff arrangements, and the electricity from non-grid connected projects)).¹⁷⁷

DETI is yet to set targets for the period beyond 2005. While DETI recognises the need to contribute to the UK renewable energy target, dominating the discussion on setting a suitably demanding and feasible target for Northern Ireland is the financial implications of such a target, against the background of already high electricity prices in Northern Ireland. A range of support mechanisms for renewable electricity are currently under consideration. These include:

- **market opportunities** – since 13 March 2000, the electricity market for renewable energy in Northern Ireland has been fully open to competition and, as a result, renewable energy developers can supply their own customers; and since 30 September 1999, the generation of not more than 10 MW and the supply of up to 1 MW from renewable sources, are exempt from electricity licensing requirements;
- **NI-NFFO** – the proposed continuation of the NFFO regime, but with modifications to address current weaknesses;
- **renewables obligation** – the appropriateness and feasibility of introducing a scheme similar to that which has been introduced in Great Britain;
- **green pricing systems** – the potential for further direct sales of electricity from renewable energy at a premium price (for example, NIE's eco energy tariff) and whether a green pricing system, in conjunction with an open market, could bring about sufficient electricity from renewable sources to meet a significantly enhanced target;
- **renewable energy feed in tariffs (REFITs)** – the possibility of introducing REFITs (that is, where utilities are obliged to purchase electricity from renewable energy generators at a guaranteed price) in Northern Ireland;
- **green credits trading** – the possibility of setting up a scheme for trading in green credits or certificates (for example, separating the price of electricity from its green value or benefit and selling the awarded green credits/certificates in a secondary market).

A range of secondary support mechanisms for the development of renewable energy are also under consideration. These include direct capital grant support, financial and tax incentives, and research, development and demonstration programmes.

¹⁷⁷ The NIE eco energy tariff provides consumers with the option of purchasing electricity from renewable sources.

Distributed or embedded generation

Embedded or distributed generation is electricity generation which is connected to the distribution network rather than the high voltage transmission network and typically includes smaller generation, such as renewable generation (including small hydro, wind and solar power) and smaller CHP. The development of embedded or distributed generation is, therefore, an important component of meeting the government's long-term environmental targets.

In response to government's priorities, Ofgem is thus playing a specific role in the development of regulatory and policy frameworks which do not inhibit the growth of distributed generation. Ofgem has identified the main obstacles to distributed generation as being the passive nature of existing distribution networks (that is, they were built to deliver power from the national transmission network to the end customer, rather than to allow for the flow of electricity in two directions as required by distributed generators) and difficulties and high costs smaller renewable generators experience when connecting to the distribution networks.

Proposals currently being considered by Ofgem include those related to changes to the regulatory regime in the short term and those related to the next distribution price control review. Specifically Ofgem aims, in the short term, to remove barriers to connection by:

- allowing generators the option of spreading the cost of connecting to the distribution network;
- making it easier for domestic CHP generators (customers with heating systems which can generate electricity) to connect to the networks by establishing a standard connections procedure;
- reimbursing distributed generators some of the initial connection fee when another generator connects to the same part of the network, which they have already paid for;
- providing clearer information from distributors on preparation of quotations for connections to the network;
- investigating the best ways to record and meter the amount of electricity that is used against the amount that is put back onto the distribution network by a home with domestic CHP.

In the next distribution price control review, Ofgem will investigate the specific implications of the price control for the development of distributed generation, and will develop appropriate incentives in the price control for distributors to connect distributed generation to their systems.

8 SOCIAL REGULATION

The Electricity Act 1989 (as amended by the Utilities Act 2000) creates a social dimension to the role of the economic regulator by requiring Ofgem, in fulfilling its duties, to have regard to the interests of certain disadvantaged groups in society, namely those individuals who are disabled or chronically sick, pensioners, those on low incomes, and those living in rural areas.

The Utilities Act 2000 also gave the secretary of state a new power to issue social guidance to Ofgem, reflecting the social policy priorities of the government. In this way, the government intends Ofgem to make a contribution, appropriate to its functions and duties, toward achieving the wider social objectives of government, without compromising the principle of arm's length regulation.¹⁷⁸ The government's social policy objectives, as they apply to the energy sector, are laid down principally in its fuel poverty strategy, which was issued for consultation on 23 February 2001. Households in fuel poverty are defined to mean those households that spend more than 10% of their household income on energy to maintain a satisfactorily warm home.¹⁷⁹ Fuel poverty is caused by several, interrelated factors – low income, the condition of the property, the efficiency of the heating system, the size of the property relative to the number of people living in it, and the cost of fuel. It is estimated that four and a half million households in Great Britain are in fuel poverty. The government is seeking an end to the blight of fuel poverty for vulnerable households by 2010.¹⁸⁰ In practice, this means the government is committed to introducing measures which should have the effect that no older household, no family with children, and no householder who is disabled or has a long term illness, need risk ill health due to a cold home. The government intends to tackle fuel poverty in other households once progress has been made on the priority vulnerable groups.

The secretary of state's draft social and environmental guidance to Ofgem, published in May 2001, reflects the social priorities laid out in the fuel poverty strategy, identifying the principal social objectives of government, as they relate to the energy sector, as being to tackle fuel poverty and social exclusion, to improve the health of the population overall, and to reduce the proportion of unfit housing stock.¹⁸¹ In assisting the government in achieving these social objectives, the secretary of state calls on Ofgem to:

¹⁷⁸ Ofgem (2001), Social Action Plan – Annual review, March 2001.

¹⁷⁹ The recommended temperature by the World Health Organisation for a satisfactorily heated home is 21°C in the living room and 18°C in other occupied rooms.

¹⁸⁰ The specific targets for each country are for England, by 2004, to have assisted 800,000 vulnerable households through the home energy efficiency scheme and to bring 400,000 social sector properties up to decent standard; for Scotland, by 2006, to ensure that all pensioner households and tenants in the social rented sector live in a centrally heated and well insulated home; for Wales, by 2003, to have assisted 37,000 households likely to be in fuel poverty through the home energy efficiency scheme; and for Northern Ireland, by 2006, to have assisted at least 40,000 households in fuel poverty through the new domestic energy efficiency scheme and partnership programmes.

¹⁸¹ DTI (2001), Draft Social and Environmental Guidance to the Gas and Electricity Markets Authority – A consultation document by the Department of Trade and Industry, May 2001.

- ensure that, in promoting effective competition, it considers carefully the benefits gained by all groups of consumers, especially the disadvantaged, and takes action against any abuses of market power which harm consumers;
- ensure that the benefits of competition in the supply market are broadly distributed, and in particular have regard to the desirability of greater choice of tariffs and payment options, improving the clarity of information on choices between different terms of supply to enable customers to make informed choices, ensuring that clear and acceptable procedures are in place to govern interruptions of supply for prepayment meter customers and reducing the risk of such interruptions, and promoting innovative approaches to the provision of services to poor customers and those suffering fuel poverty;
- assist in meeting the government's fuel poverty targets, by ensuring that fuel poor householders are aware of assistance available through Warm Front (formerly the home energy efficiency scheme) and the devolved administrations equivalent schemes, utilities energy efficiency commitment programmes and other company initiatives; have effective access to clear information and advice on energy efficiency; are aware of other advice and help available from external agencies; and have access to, and information about, tariffs which meet the needs of low-income and low-use households;
- have specific regard to methods and frequency of payment for services, debt and disconnection; as well as the implications of metering strategies for reducing fuel poverty and attaining environmental objectives.

In response to its duty to have regard to the interests of the disadvantaged groups in society, and in assisting the government in achieving its fuel poverty targets, Ofgem has outlined a programme of regulatory and policy initiatives, published in its social action plan and reviewed annually.¹⁸² The principal regulatory and policy actions under the social action plan have been:

- licence changes and revised guidance notes to improve the delivery of suppliers' social obligations, resulting in new codes of practice; and design and implementation of improved monitoring arrangements for suppliers' social obligations (discussed in more detail in following section)
- steps to put further downward pressure on prices through developments in competition, new electricity trading arrangements (NETA) and price controls (discussed in more detail in **Chapter 5 - Economic Regulation**);
- operation of the third energy efficiency standards of performance (EESoP) scheme, in which 65% of the funding is directed to disadvantaged customers (discussed in more detail in **Chapter 7 - Environmental Regulation**);
- improvements in access to competition, including through reviewing the development of competition;
- establishing an industry working group to develop processes to enable prepayment meter customers with debts to transfer supplier;
- establishing a working group to review the operation of Fuel Direct for customers in receipt of means-tested benefits, and to recommend improvements to the scheme;

¹⁸² Ofgem's Social Action Plan was first published in March 2000, with the first annual review taking place in March 2001, and the most recent in March 2002.

- encouraging suppliers to develop a range of innovative new schemes to help the fuel poor.

While the Utilities Act is not applicable in Northern Ireland, the devolved government has adopted specific targets for the elimination of fuel poverty in Northern Ireland under the UK fuel poverty strategy, and Ofreg has similarly developed social action plans outlining their regulatory and policy contribution to achieving these policy objectives.¹⁸³ Ofreg's social action plan for electricity identifies three main areas for action to assist disadvantaged customers. These are:

- creating downward pressure on electricity prices, primarily through price regulation, but also, where possible, through competition;
- protecting customers through reviewing, and where necessary, improving NIE's customer obligations;
- operating the existing energy efficiency programme and the energy efficiency levy, and reviewing the benefits.

Codes of practice

The social obligations of the electricity companies in both Great Britain and Northern Ireland are implemented primarily through approved codes of practice. Under the new standard conditions of their licences, all domestic electricity suppliers operating in Great Britain are required to produce codes of practice on:

- payments of bills and dealing with customers in difficulty, including arrangements for ensuring that a variety of payment methods are available (for example, through a prepayment meter, by cash and by cheque) at a reasonable range of intervals, arrangements for identifying customers in difficulty and distinguishing such customers from others in default, and procedures for dealing with customers having difficulty paying and the options available for these customers so as to avoid disconnection of supply;¹⁸⁴
- energy efficiency advice (discussed in more detail in **Chapter 7 - Environmental Regulation**);
- use of prepayment meters, including details of the licensee's policy on the installation of prepayment meters, general information on the operation, usefulness, advantages and disadvantages of prepayment meters, the licensee's

¹⁸³ Ofreg published its first social action plan in 1998 as an early response to the UK government's discussion paper "A Fair Deal for Customers". This social action plan was reviewed in 2001, in the consultation papers entitled Electricity and Gas Social Action Plans – Review 1998-2000 and proposals for next steps and Social Action Plans for Electricity and Gas Customers – Improving social obligations, a draft proposal document. The final proposals for further action were published in February 2002 in the Ofreg document Social Action Plans for Electricity and Gas Customers – Improving social obligations, a proposals document.

¹⁸⁴ The code is also required to include details of how the company will determine the suitability of prepayment as a method of payment for customers, and should also include a clear statement of the licensee's policy on securing the payment of future bills, including how this policy differs for new and existing customers, credit vetting procedures applied, and policies relating to monetary security deposits.

policy for the calibration of meters to recover debt and procedures for removal of such meters, and the levels of services provided to prepayment meter customers;¹⁸⁵

- services for customers who are elderly, disabled or chronically sick, including, for example, the provision of special controls and adapters for electrical appliances and meters, repositioning meters so as to make them accessible, the provision of special means of identifying representatives of the licensee, the provision of advice on energy efficiency and the use of electricity, redirecting bills to a nominated third party, and maintaining a register of priority customers (the priority service register);
- services for customers who are blind or deaf;
- complaint handling procedures, including details of how to contact the licensee to make a complaint, the procedure for reviewing complaints at a more senior level if the customer is still dissatisfied, timescales for each stage of complaint handling and investigation, details of how *energywatch* can assist in resolving complaints which the licensee has not resolved to the satisfaction of the customer, details of any relevant standards of performance, the arrangements for making payments to customers following a failure by the distributor to meet a guaranteed standard, and details of advice agencies.

Ofgem has issued regulatory guidance, stipulating the minimum requirements for the codes of practice. The supply companies are required to consult with *energywatch* prior to submitting the codes to Ofgem for approval, and have regard to any representations made by *energywatch* about the codes or the manner in which they are likely to be operated.

The codes of practice aim, in particular, to address fuel poverty and ensure that disadvantaged customers are appropriately dealt with. The new codes of practice deliver improvements in the following specific areas:

- increased access to payment facilities for customers paying frequently by cash;
- a new code for prepayment meter customers to ensure better information and services for such customers;
- a more proactive approach to the prevention of debt, through early contact with customers;
- a better dialogue with customers in debt and an obligation to take into account the customer's ability to pay when negotiating debt payments (for example, the codes now say that customers on benefit will not normally be asked to pay more than the fuel direct rate (currently £2.70 per week));
- improved provision and promotion of energy efficiency advice, in particular for customers on low incomes or those with payment difficulties (with such customers being directed toward grant schemes such as 'warm front' and the EEC);
- improved provision and promotion of services for vulnerable customers, and a code of practice for customers who are blind, partially sighted or hard of hearing.

¹⁸⁵ Levels of service including distance to token vending/key charging points, repair of token vending/key charging point, faulty cards/keys/tokens, repair of meter, emergency credit, and arrangements for contacting customers where there is concern that they may have self-disconnected.

Under their licence conditions, electricity supply companies are required to measure and report on their performance in relation to achieving their social obligations, and are required to submit information to the regulator in the form of monitoring returns. This enables Ofgem to assess suppliers' compliance with their obligations under the codes of practice. Suppliers are required to submit monitoring returns on the following indicators:

- numbers of customers on different payment schemes;
- the number of frequent payment outlets;
- the number of customers on the 'fuel direct' scheme;
- numbers of customers in debt;
- the size of the weekly debt repayment (for both prepayment meter and credit customers);
- disconnections, warrants of entry and security deposits;
- prepayment meter services;
- the take up of special services, in particular the priority service register and how companies promote it;
- the provision of energy advice, in particular for disadvantaged customers and customers with payment difficulties.¹⁸⁶

With the introduction of separate licences for distribution and supply of electricity, distributors are also required to submit new codes of practice covering their activities which affect vulnerable customers. In October 2001, Ofgem published guidance notes for electricity distributors' codes of practice, which includes details on the minimum requirements for codes of practice on:

- provision of services for persons who are of pensionable age, disabled or chronically sick, including arrangements for maintaining a register of customers who have special communication needs or depend on electricity for medical reasons, and who require advance notice of planned interruptions to supply of electricity;
- provision of services for persons who are blind or deaf, including arrangements for appropriate complaints handling procedures, and means of identification;
- procedures with respect to site access, including details of the nature and frequency of access likely to be required, the steps taken to ensure that representatives are fit and proper persons to visit customers' premises, and the measures in place for identifying representatives;
- complaint handling procedures.

As with the suppliers' codes of practice, distributors are required to consult *energywatch* in the preparation of their codes. These codes of practice have been approved by Ofgem for all the major companies and are now being published.

Similarly, in Northern Ireland, NIE's social obligations are enshrined in its licence and detailed in codes of practice. While Ofreg does not issue guidance on the content of the codes of practice, as in Great Britain, NIE is required to consult with the

¹⁸⁶ Ofgem (2001), Monitoring Domestic Electricity and Gas Suppliers' Performance Under Their Codes of Practice, February 2001.

consumer committee before submitting the codes to Ofreg for approval. Under NIE's public electricity supply licence, it is required to develop codes of practice on the following:

- payment of electricity bills, including appropriate guidance for the assistance of customers in difficulty;
- methods for dealing with tariff customers in default, including methods for distinguishing such tariff customers from others in default, detecting failures by such tariff customers to comply with arrangements entered into for paying by instalments charges for electricity supplied, making arrangements so as to take into account the tariff customer's ability to comply with them, and, where safe and practicable, offering a prepayment meter calibrated to recover any debt at a level the customer can afford;
- provision of services for persons who are of pensionable age or disabled, including making available, where appropriate, special controls and adaptors for electrical appliances and meters (including prepayment meters) and repositioning meters, providing special means of identifying representatives of the licensee, and giving advice on the use of electricity;¹⁸⁷
- services offered to prepayment meter customers, including instructions for the operation of the prepayment meter system, details of the advantages and disadvantages of prepayment meters, and details of any additional charges which may be payable for the use of prepayment meters and the basis on which these charges are calculated;
- efficient use of electricity (discussed in more detail in **Chapter 7 - Environmental Regulation**);
- complaint handling procedure.

Ofreg proposes to monitor consumer interest in the codes and will seek quarterly information from NIE on the number of 'quick step guides' issued, the number and type of codes issued, and will seek statistics from NIE on the range of services underpinning the codes.

Industry initiatives

In addition to the regulatory social obligations on electricity companies (as implemented through their licensed codes of practice), both Ofgem and Ofreg fulfil their social responsibilities through the promotion of corporate social responsibility by the electricity companies. This includes publicising the commercially driven social initiatives of the electricity companies and promoting best practice.

A range of initiatives have been undertaken by electricity companies, either in response to their obligation under the energy efficiency standards of performance (energy efficiency commitment) or spurred on by the social obligations under their licences. These initiatives aim to address some of the barriers that hinder progress in overcoming fuel poverty and include:

¹⁸⁷ While not specified in its licence, NIE keeps a register of such customers who qualify and request to be included.

- **more affordable tariffs**, for example, TXU's 'staywarm' scheme, which is a social tariff designed for those on benefit and includes 12 fixed payments and no meter reading; Yorkshire Electricity's 'heatplan', which includes a check on benefits and fixed levels of payments for electricity; and Scottish and Southern Energy's 'equipower' scheme, under which all customers pay the same unit price for electricity regardless of their chosen payment method (that is, an effective cross-subsidy between customers on the scheme);
- **targeting prepayment meter customers**, for example, London Electricity/SWEB's 'powerkey plus' scheme, which aims to reduce the prepayment surcharge by encouraging customers to manage aspects of powerkey meters more cost-effectively, and Powergen's initiative to reduce the prepayment surcharge from £15 to £8 and to abolish the surcharge by 2005;
- **tackling social exclusion**, through extending access to financial services to low-income households, thereby enabling such households to take advantage of the cheapest payment options such as direct debit (for example, BGT has linked up with the Bank of Scotland to provide special bank accounts giving customers on regular payment plans access to direct debit terms, Scottish Power and the Royal Bank of Scotland have set up a joint initiative promoting the benefits of a bank account to those without, and npower is funding work by National Energy Action and New Economics Foundation into the development of community investment partnerships, based on credit unions, in order to make a range of services available to low-income customers), and through the establishment of the electricity association fuel poverty task force;
- **targeted energy efficiency advice and resources**, for example, 'Age Concern Energy Services', a joint initiative between Powergen and Age Concern which targets energy efficiency initiatives at older people and offers free heating when temperatures drop below freezing; BGT's 'warm-a-life II' scheme which aims to help vulnerable households through referral to energy efficiency grant schemes, a free benefits check, a one off reduction in energy bills, and a guaranteed cap on the price of electricity to 2004; Scottish Power's 'NEST Makers' scheme, which provides advice through a network of local energy advisers; and npower's 'health through warmth' scheme which trains district nurses, health visitors and voluntary workers to offer energy efficiency advice and identify fuel poverty.

Other regulatory initiatives

Ofgem's metering strategy aims to promote competition and innovation in metering services. This, in turn, could provide customers with more choice and bring the costs of metering down – something which is particularly relevant for prepayment meter customers, where the costs of metering are generally higher and the technology involved, more complex.

In Northern Ireland, there has been a special focus on the plight of prepayment meter customers. As part of its new supply price control package, NIE has agreed to phase out their existing prepayment meters by October 2002 and replace them with a new technologically advanced prepayment method, called 'home energy direct', based on a keypad system and eliminating the current surcharge paid by prepayment meter

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customers (currently £18 per annum), thus enabling such customers to buy electricity at the same price as credit customers.

Appendix 1: Generation - changes in ownership and new plant and entrants

31 March 1990	CEGB was split into 3 generating companies – National Power (now Innogy), Powergen and Nuclear Electric – and a transmission company, the NGC (also owner of the pumped storage power stations in Wales). The NGC also took control of the interconnectors with Scotland and France.
12 March 1991	National Power and Powergen sold by public flotation (60% of shares)
6 March 1995	The government floated the remaining 40% share in National Power and Powergen on the LSE, but did retain a ‘special share’ in both companies.
December 1995	NGC, which was initially owned by the RECs, floated on the stock exchange. Before flotation, the pumped storage business was transferred to a new company, First Hydro, which was then sold to US generator, Edison Mission Energy.
31 March 1996	The nuclear generating industry was formally restructured in preparation for privatisation. A holding company, British Energy plc was created, together with two subsidiary companies, Nuclear Electric Ltd and Scottish Nuclear Ltd.
July 1996	Eastern Group leased a total of 6 GW of coal-fired electricity generation capacity from National Power (4 GW) and Powergen (2 GW). As a result, the pool price cap was lifted. British Energy was floated on the LSE by the government. The Magnox stations remained in the public sector under the ownership of Magnox Electric plc.
January 1998	The government transferred its shareholding in Magnox Electric to BNFL as the first stage of a merger of the two companies. Full integration of the combined business of the two companies was completed early in 2000.
October 1998	Government’s stricter consents policy on gas-fired power plant (the ‘gas moratorium’) was imposed, significantly slowing down the development of gas-fired generation.
June 1999	Ferrybridge and Fiddlers Ferry power stations were sold by Powergen to Edison Mission Energy
November 1999	National Power sold DRAX to AES
March 2000	National Power sold Eggborough power station to British Energy and Killingholme CCGT station to NRG
April 2000	EdF, owner of London Electricity, entered the UK generation market. London Electricity bought the CCGT Sutton Bridge plant from Enron.
9 August 2000	The government redeemed its golden share in National Power at its request.
August 2000	AES’ new coal fired station at Fifoots began to generate.
September 2000	EdF acquired from Powergen the coal-fired Cottam power station. Together with its earlier purchase in April, the company became one of the major players in the UK generation market with access to almost 3 GW of capacity.
2 October 2000	National Power split into Innogy Holdings and International Power, with Innogy taking over the UK business and International Power taking over the overseas business and the Deeside power station
15 November 2000	The ‘gas moratorium’ was lifted. Following the lifting of the moratorium, 6 large power stations with a total capacity of 5,101 MW, which had originally been refused clearance, received the government’s consent.
22 December 2000	The government redeemed its golden share in Powergen at the request of the company.
2001	EdF purchased the West Burton power station from TXU Europe, increasing its access to generation capacity to 5 GW
9 April 2001	E.ON (Germany) made agreed offer for Powergen, subject to regulatory approval.
May 2001	Centrica bought a 60% stake in Humber Power, with the remaining 40% owned by Total/Fina/Elf.
22 March 2002	RWE AG (Germany) announced agreed takeover of Innogy Holdings

Appendix 2: Generators operating in the UK (as at the end of May 2001)

AES	Innogy plc (formerly National Power)
Alcan	Intergen
Barking Power	Lakeland Power
BNFL Magnox Generation	London Electricity
British Energy	Medway Power
Citigen Ltd	National Grid
Coolkeeragh Power	NRG Energy
Corby Power	Powergen
Coryton Energy Company Ltd	Premier Power
Deeside Power	Regional Power Generators Ltd
Derwent Cogeneration	Scottish and Southern Energy plc
Edison Mission Energy	Scottish Power
Enfield Energy Centre Ltd	Seabank Power Ltd
Entergy	Sita Tyre Recycling Ltd
Fellside Heat and Power	South Coast Power
Fibrogen	South East London Combined Heat and Power Ltd
Fibropower Ltd	Western Power Generation
Fibrothetford	Teesside Power Ltd
Fife Power	TXU Europe Power Ltd (formerly Eastern Group)
Humber Power	

Appendix 3: Principal electricity supplier groups' shares of domestic electricity supply in Great Britain (by customers supplied)

Parent company	Supply business subsidiary	Former PES supply business	Market share
Innogy Holdings*	npower npower Yorkshire Supply npower Northern Supply	Midlands Electricity Yorkshire Electricity Northern Electric	19%
Centrica	British Gas Trading	-	17%
TXU	TXU Energi	Eastern Electricity Norweb Energi	15%
Scottish and Southern Energy**	SSE Energy Supply	Scottish Hydro-Electric Southern Electric SWALEC	14%
Electricité de France	LE Group	London Electricity SWEB	10%
ScottishPower	Scottish Power Energy Retail	ScottishPower Manweb	10%
Powergen UK***	Powergen	East Midlands Electricity	8%
American Electric Power	SEEBOARD Energy	SEEBOARD	6%
Other suppliers		-	1%

* Formerly National Power. RWE (of Germany) made an agreed offer for Innogy in March 2002 and completion is expected in 2002.

** Formed from a merger between Scottish Hydro-Electric and Southern Electric in December 1998.

*** E.ON (of Germany) made an agreed offer for Powergen in April 2001, subject to regulatory approval expected in 2002.

Appendix 4: Current distribution network operator groups

Distribution network operator groups	Distribution subsidiaries	Ex-PES distribution areas
LE Group	London Power Networks EPN Distribution	London Electricity Eastern Electricity
GPU Power UK	GPU Power Networks	Midlands Electricity
Northern Electric	Northern Electric Distribution NEDL Yorkshire Electricity Distribution	Northern Electric Yorkshire Electricity
Powergen	East Midlands Electricity Distribution	East Midlands Electricity
Scottish and Southern Energy	SSE Power Distribution	Scottish Hydro-Electric Southern Electric
ScottishPower	SP Distribution SP Manweb	ScottishPower Manweb
SEEBOARD	SEEBOARD Power Networks	SEEBOARD
United Utilities	United Utilities Electricity	Norweb
Western Power Distribution	Western Power Distribution	SWEB SWALEC

Appendix 5: Statutory duties of the secretary of state and the Authority under the Electricity Act 1989 (as amended by the Utilities Act 2000)

Principal objective of secretary of state and the authority in relation to electricity supply

- to protect the interests of consumers in relation to electricity conveyed by distribution systems, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity

Secondary duties of secretary of state and the authority in relation to electricity supply

- have regard to the need to secure that all reasonable demands for electricity are met
- have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under the Utilities Act 2000

In performing their duties, the secretary of state or the Authority shall have regard to the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes; and reside in rural areas.

Subject to the need to secure that all reasonable demands for electricity are satisfied and the need to secure that licence holders are able to finance their licence obligations, the secretary of state and the Authority shall carry out their functions in a manner which they consider is best calculated to promote efficiency and economy on the part of persons authorised by licences or exemptions to transmit, distribute or supply electricity and the efficient use of electricity conveyed by distribution systems; to protect the public from dangers arising from the generation, transmission, distribution or supply of electricity; and to secure a diverse and viable long-term energy supply. In carrying out these functions, the secretary of state and the Authority shall have regard to the effect on the environment of activities connected with generation, transmission, distribution or supply of electricity.

With respect to health and safety in relation to electricity, the secretary of state and the authority shall consult the Health and Safety Commission about all electricity safety issues and take into account any advice given by the Health and Safety Commission about any electricity safety issue.

Specific duty of the secretary of state

- the secretary of state shall from time to time issue guidance to the authority about its contribution toward the attainment of any social or environmental policies.

