



**REVIEW OF ELECTRICITY
TRADING ARRANGEMENTS**

BACKGROUND PAPER 1

**ELECTRICITY TRADING ARRANGEMENTS
IN ENGLAND AND WALES**

FEBRUARY 1998

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CONTENTS

	Page
1. INTRODUCTION	1
2. THE ELECTRICITY MARKET IN BRITAIN - BACKGROUND	3
3. TRADING INSIDE THE POOL	9
4. EXPERIENCE IN THE POOL TO DATE	20
5. TRADING OUTSIDE THE POOL	29
6. THE ELECTRICITY MARKET IN SCOTLAND	32
7. THE CONTRACTS MARKET	36
8. THE DEVELOPMENT OF COMPETITION IN GENERATION	41
9. THE DEVELOPMENT OF COMPETITION IN SUPPLY	50
10. ELECTRICITY AND GAS MARKET INTERACTIONS	53
APPENDIX 1 - Timetable	57

1. INTRODUCTION

1.1 On 23 October 1997¹, the Minister for Science, Energy and Industry announced that he had asked the Director General of Electricity Supply ('the DGES') to consider how a review of electricity trading arrangements ('the Review') might be undertaken. On 5 November 1997², OFFER issued a consultation paper setting out initial views on the objectives, scope and process of the Review and inviting the views of others. These views were taken into account in drawing up advice to the Minister and proposed Terms of Reference for the Review. The Minister agreed the proposed Terms of Reference and, on 28 January 1998, OFFER published the advice on the Terms of Reference³ which the DGES had presented to the Minister.

Process and Timetable

1.2 The Minister has indicated that he wishes to receive a report by early July 1998, in order to consider what, if any, changes in legislation are required, consistent with the timetable for possible legislation following the government's review of utility regulation.

1.3 To achieve openness and transparency the Review process will include the publication of background, working and consultation papers, explanatory workshops to ensure interested parties are familiar with key issues, public seminars to examine and debate options for change and interim conclusions, and the placing of all third party contributions in the public domain.

Organisation of the England and Wales Background Paper

1.4 This first background paper focuses on the present trading arrangements in England and Wales and related issues. (A second background paper, which is being published at the same time, covers electricity trading arrangements in other countries.)

1.5 Chapter 2 provides background information on the electricity market in Great Britain, including the structure of the industry and the regulatory framework. Chapters 3, 4, 5 and 6 respectively discuss trading inside the Pool, experience in the Pool to date, trading outside the Pool, and the electricity industry in Scotland. Chapter 7 covers the contracts markets. Chapters 8 and 9 outline the development of competition in generation and supply. Chapter 10 concludes the document with an analysis of the interactions between the electricity and gas markets in Britain.

¹ Minister's speech to Pool AGM, 23 October 1997.

² Review of Electricity Trading Arrangements – A Consultation Paper, OFFER, November 1997.

³ Review of Electricity Trading Arrangements: Advice on Terms of Reference, OFFER, January 1998.

Next Steps

- 1.6 A first explanatory workshop to discuss this background paper and the background paper on overseas experience is being held on 23 February at the National Exhibition Centre.
- 1.7 The timetable for publishing subsequent papers and holding additional workshops and seminars is set out in Appendix 1.

Consultation

- 1.8 If you wish to make comments or submissions relating to this background paper, it would be helpful to receive them by 6 March 1998. Responses should be addressed to:

Dr Eileen Marshall CBE
Office of Electricity Regulation
Hagley House
Hagley Road
Edgbaston
Birmingham B16 8QG

- 1.9 Responses will be place in OFFER's library.

2. THE ELECTRICITY MARKET IN GREAT BRITAIN - BACKGROUND

The structure of the electricity market

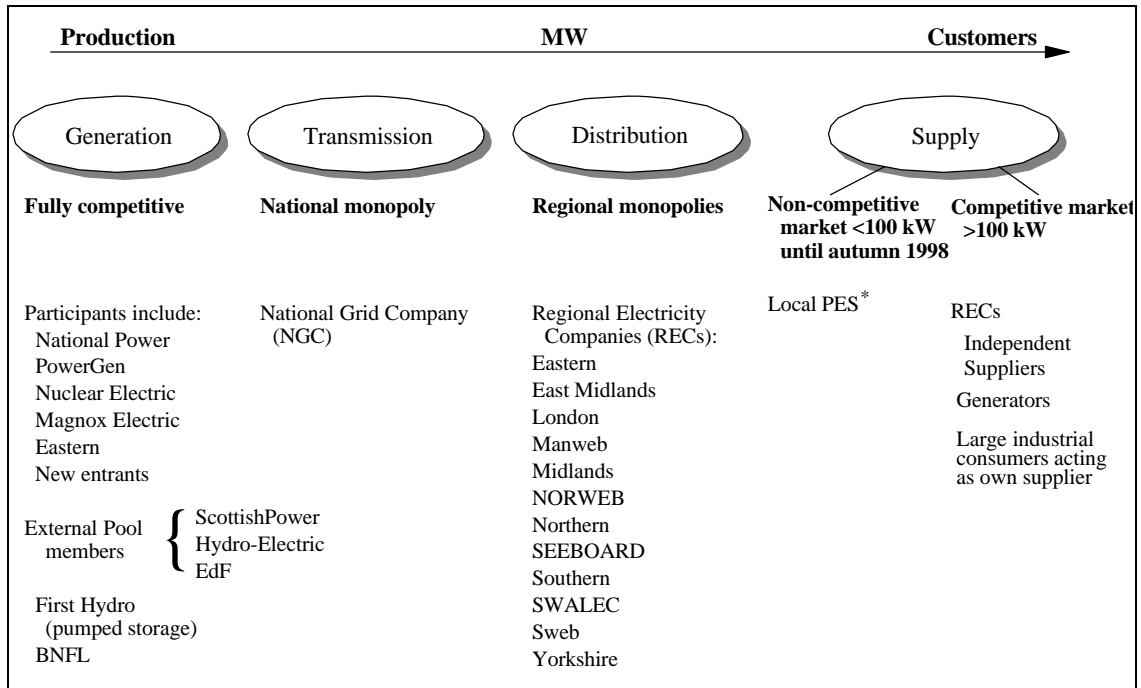
- 2.1 It is now ten years since the then government announced its plans for radical reform of the electricity industry. The February 1988 White Paper, “Privatising Electricity”, outlined the way in which the new industry structure would introduce competition and provide a framework in which more would develop.
- 2.2 The White Paper proposed the removal of the effective monopoly in electricity generation held by the Central Electricity Generating Board (CEGB) by dividing the CEGB’s generation assets into competing companies. It envisaged that new generating companies would enter the market, further increasing competition. A separate high voltage transmission grid company (The National Grid Company, “NGC”) was to be established to give new entrants in generation confidence that they would be treated fairly with regard to access to the transmission network. The grid company’s responsibilities would include calling up power stations in “merit order”, to provide incentives on generators to fuel and run their stations efficiently. The twelve Area Boards (renamed Regional Electricity Companies, “RECs”) were to be subjected to competition in the supply of electricity to final customers, whilst retaining their monopoly on the distribution of electricity within their authorised areas.
- 2.3 Alongside this competitive market structure a regulatory regime was to be established to promote competition and safeguard the interests of customers. Responsibility for regulation would rest with a Director General of Electricity Supply, who would enforce the provisions of licences issued to electricity companies. Price controls were expected to be an important part of the regulatory framework, but it was also recognised that in some areas, where competition was properly effective, such controls might not be necessary. The monopoly activities of transmission and distribution were to be “ring-fenced” from other activities in which competition was possible (such as generation) and from new non-core activities in which the electricity companies might choose to engage.
- 2.4 The withdrawal of the nuclear stations from privatisation and the creation of a separate nuclear generating company somewhat changed the structure of the generating market from that originally envisaged. However, the way in which the electricity industry in England and Wales was restructured generally followed the model outlined in the February 1988 White Paper.
- 2.5 The establishment of an electricity “Pool” as the primary wholesale market for electricity had not been fully worked through by February 1988, but was a cornerstone of the wholesale trading arrangements that were implemented. All licenced generators and suppliers have to trade through the Pool (see Chapter 3). Thus, the vast majority of electricity is bought and sold at the Pool price, which varies half-hourly. To reduce the risks to which this exposes them, generators and suppliers typically hedge most of their trades with contracts (see Chapter 7).

- 2.6 Trading through the Pool commenced on 1 April 1990 and on the previous day the properties, rights and liabilities of the nationalised electricity industries were transferred to their successor companies. This was known as “Vesting”. Privatisation of the electricity industry began with the public offering of shares in the RECs in December 1990. At privatisation, the RECs also each owned a share of NGC through their holdings in the National Grid Holding (NGH)⁴. Shares in National Power and PowerGen were sold in two tranches, 60% in March 1991 and the remaining 40% in March 1995.
- 2.7 Arrangements in Scotland differed from those in England and Wales. The pre-Vesting arrangements were retained and two vertically integrated companies (Scottish Power and Scottish Hydro-Electric) responsible for generation, transmission, distribution and supply to final customers, were created. Scottish Power and Scottish Hydro-Electric were floated in June 1991.
- 2.8 There have been considerable changes to the ownership of electricity companies and industry assets. In 1995 the RECs disposed of their interests in NGC via the flotation of a new company, the National Grid Group. At the same time, the RECs disposed of NGC’s generating assets, the pumped storage stations sited at Dinorwig and Ffestiniog in North Wales, to First Hydro owned by the US company Edison Mission Energy.
- 2.9 Following the removal by the Government of the RECs’ “Golden Shares” in 1995⁵, ownership of eleven of the twelve companies has changed. Seven of the companies were acquired by US electricity companies, two by water companies, and one by ScottishPower. In the case of Eastern Electricity, it was first acquired by Hanson in 1995 and then demerged from that company in 1996 to become part of The Energy Group.
- 2.10 British Energy, the holding company owning the more modern nuclear generating stations in England and Wales and Scotland was offered for sale in July 1996. As a result, only the older Magnox nuclear stations of the pre 1990 Electricity Supply Industry now remain in public ownership. Figure 1 shows the structure of the industry in England and Wales in February 1998.

⁴ The RECs’ shareholdings in NGH were allocated broadly in proportion to the Current Cost Accounting net assets of each REC as at 31 March 1989. The RECs’ interests in NGH at the time of flotation ranged from 5.4% to 12.5%.

⁵ The purpose of the Golden Shares was to prevent the takeover of the newly privatised electricity companies in the early years after Vesting.

Figure 1. Structure Of The England And Wales Electricity Industry In 1998



* PES (Public Electricity Supplier) see below.

- 2.11 A large number of companies are now active in generation. National Power, PowerGen, Nuclear Electric (the company responsible for the operation of British Energy's nuclear assets in England and Wales) and Magnox Electric are all successor companies to the CEGB⁶. All of the RECs also now have interests in generation. In addition to First Hydro, a number of new entrants have entered the market with a mix of generating technologies, including high load factor gas-fired stations, smaller peaking plants, renewables projects, and combined heat and power (CHP) schemes.
- 2.12 The high voltage transmission system remains owned and operated by NGC. The transmission system is connected to both those of Scotland (see Chapter 6) and France. The generation companies in Scotland and France have the right to trade through the Pool in England and Wales.
- 2.13 Low voltage distribution in England and Wales continues to be the sole responsibility of the twelve RECs (with the exception of a few private distribution systems), which own the distribution networks in their authorised areas. As with transmission, distribution is effectively a monopoly activity.
- 2.14 Supply of electricity to final customers is carried out by many different companies. All customers with a maximum demand in excess of 100 kW can choose their electricity supplier⁷. These customers have benefited from an increasingly

⁶ National Power and PowerGen now have a different mix of generating assets than in 1990, as discussed further in Chapter 8.

⁷ Customers who cannot choose their supplier are known as "franchise" customers.

competitive supply market in which some generators compete vigorously with RECs. As the supply market is opened fully to competition in 1998, with all customers having a choice of supplier, non-electricity companies, including gas companies such as British Gas, are expected to participate in the electricity supply market.

The legal and regulatory framework

2.15 The 1989 Electricity Act created the framework by which the privatised electricity industry was to be regulated. The Secretary of State and the DGES were given functions and responsibilities in relation to the electricity industry. Their primary duties are:

- To secure that all reasonable demands for electricity are satisfied;
- To secure that all licence holders are able to finance the carrying on of the activities which they are authorised by their licences to carry on; and
- To promote competition in the generation and supply of electricity.

2.16 Their secondary duties include:

- Protecting the interests of consumers of electricity supplied by persons authorised by licences to supply electricity;
- Promoting efficiency and economy on the part of persons authorised by licences to supply or transmit electricity and promoting the efficient use of electricity;
- Protecting the public from dangers arising from the generation, transmission or supply of electricity; and
- Securing the establishment and maintenance of machinery for promoting the health and safety of persons employed in the generation, transmission or supply of electricity.

2.17 In carrying out their duties, the Secretary of State and the DGES must take into account the effect on the physical environment of activities connected with the generation, transmission or supply of electricity.

2.18 The DGES also shares with the Director General of Fair Trading (DGFT) certain powers to investigate monopolies under the Fair Trading Act 1973 and anti-competitive conduct under the Competition Act 1980, which include the right to make references to the Monopolies and Mergers Commission (MMC). New legislation is now being considered by Parliament which will extend the shared powers of the DGFT and the DGES in relation to competition matters.

2.19 The Electricity Act specified the licensing arrangements by which companies would be permitted to operate within the new industry structure. Under the Act, a licence is generally required to generate, transmit or supply electricity. However, under certain limited circumstances it is possible to generate and or supply Electricity without the need for a licence. Holders of generation or supply licences are required to be Pool

Members (see 2.5). With regard to high voltage transmission, NGC has the only transmission licence in England and Wales whilst Scottish Power and Scottish Hydro-Electric each hold transmission licences in Scotland.

- 2.20 In addition, two types of licence to supply electricity exist. Each REC is authorised by a Public Electricity Supply Licence (a PES licence) to supply electricity in its authorised area. The PES licence also lays down the terms under which each REC distributes electricity to final customers. A Second Tier Supply Licence authorises the licensee to supply electricity to any premises, or class of premises, specified in the licence. All RECs hold second tier supply licences which enable them to supply non-franchise customers outside their authorised area. Several generators also hold second tier supply licences as do a number of independent suppliers. Regulation of supply is primarily effected by the conditions contained within the supply licences.
- 2.21 An important feature of the way in which the industry is regulated concerns the separation of different businesses. It is a condition of a REC's Public Electricity Supply Licence that it must separate its distribution business from its supply business and from other activities. Separate accounts must be prepared for each business in an approved form for submission to the DGES and in the case of RECs these accounts are published⁸.
- 2.22 In the areas of transmission and distribution, the relevant licences specify conditions under which NGC and the RECs may operate. The duties and obligations imposed on NGC under the terms of its Transmission Licence fall into two main categories. First, the requirements on NGC due to its role as Grid Operator and Settlements System Administrator⁹ and second the requirements due to its role as owner and operator of the high voltage transmission system. NGC also has a specific duty under the Electricity Act to facilitate competition in the supply and generation of electricity.
- 2.23 The licences of both NGC and the RECs specify limits on the charges that they may make for the use of their networks and (in the case of the RECs) for supply of Electricity to franchise customers. These charge restrictions take the form of "RPI-X" price controls. Under these controls, prices are allowed to increase by no more than the level of inflation (as indicated by changes in RPI, the retail price index) minus an efficiency factor, X. These price controls have been progressively tightened during periodic reviews of the charges. The Scottish companies are also subject to price control regulation.

⁸ Under the terms of their PES licences, RECs must publish separate accounts for their distribution and supply businesses. Under the terms of the licences under which they operate, National Power and PowerGen must submit to the DGES separate accounts for their generation and supply businesses. However, the generators are not obliged to publish their supply business accounts.

⁹ The Settlements System Administrator is responsible for the cash settlement of all trades through the Pool.

The EU Directive

- 2.24 In December 1996 the European Parliament issued a Directive concerning the common rules for the internal market in electricity. The Directive came into force on 19 February 1997, and is to be implemented by the majority of member states on 19 February 1999. The Directive establishes common rules for the generation, transmission, distribution and supply of electricity. It lays down rules relating to the organisation and functioning of the electricity sector, access to markets, the criteria and procedures applicable to calls for tenders and the granting of authorisations for new generating capacity, the operation of transmission and distribution systems and the opening of supply markets to competition.
- 2.25 The present arrangements in England and Wales meet most of the current requirements of the Electricity Directive, but still have to conform to the Directive requirements with respect to the distribution systems owned by persons other than RECs. The arrangements in Scotland will also need to comply with the Directive.
- 2.26 In many areas, arrangements in England and Wales exceed the conditions laid down in the Directive. For example, by 1999, all electricity customers in England and Wales will have a choice of supplier, something that is not at present envisaged under any timescale within the Directive.

The Environment

- 2.27 In 1991, the government drew up a National Plan under the Environmental Protection Act specifying limits on total annual emissions of sulphur dioxide (SO₂) and nitrogen oxides (NO_x) from National Power and PowerGen's then existing power stations. Limits on SO₂ were significantly tightened in March 1996. Emissions in 2005 must now be reduced by at least 85% from the level they were in 1980.
- 2.28 The European Union Environment Ministers agreed in March 1997 to reduce CO₂ emissions by 15% of 1990 levels by 2010. This is in addition to the agreement to stabilise emissions at the 1990 levels by 2000. The UK looks set to meet the 2000 objective.
- 2.29 At the December 1997 Kyoto climate change conference, 34 industrial nations agreed to cut greenhouse gas emissions by 6-8 per cent of 1990 levels in the period 2008 to 2012. The 15 member nations of the EU agreed to cuts averaging 8 per cent.

3. TRADING INSIDE THE POOL

- 3.1 The trading arrangements in England and Wales have evolved in several important respects from those that were put in place at Vesting. Further changes have been planned and several are in the process of implementation. This chapter concentrates on the trading arrangements as they currently exist in February 1998 but ends with a discussion of the key developments since 1990.

The Electricity Pool

- 3.2 The Electricity Pool is underpinned by a multilateral contract, known as the Pooling and Settlement Agreement (PSA), entered into by generators and suppliers, which provides the wholesale market mechanism for trading electricity. It defines the market trading rules and procedures that control a competitive bidding process between generators which sets the price paid for electricity for each half-hour period of the day. It also provides the supporting financial settlement processes that calculate suppliers' bills and ensure payment to generators. It does not, however, act as a market maker, buying or selling electricity.
- 3.3 Almost all electricity supplied in England and Wales is traded through the Pool (see Chapter 5 for a discussion of the exceptions). The licences required by most suppliers and generators contain a condition obliging their holders to join the Pool. However, the vast majority of electricity traded is hedged through bilateral financial contracts that are designed to minimise the exposure of the contracting parties to short term fluctuations in Pool prices. The role of contracts is discussed in Chapter 7.

Setting the Pool price

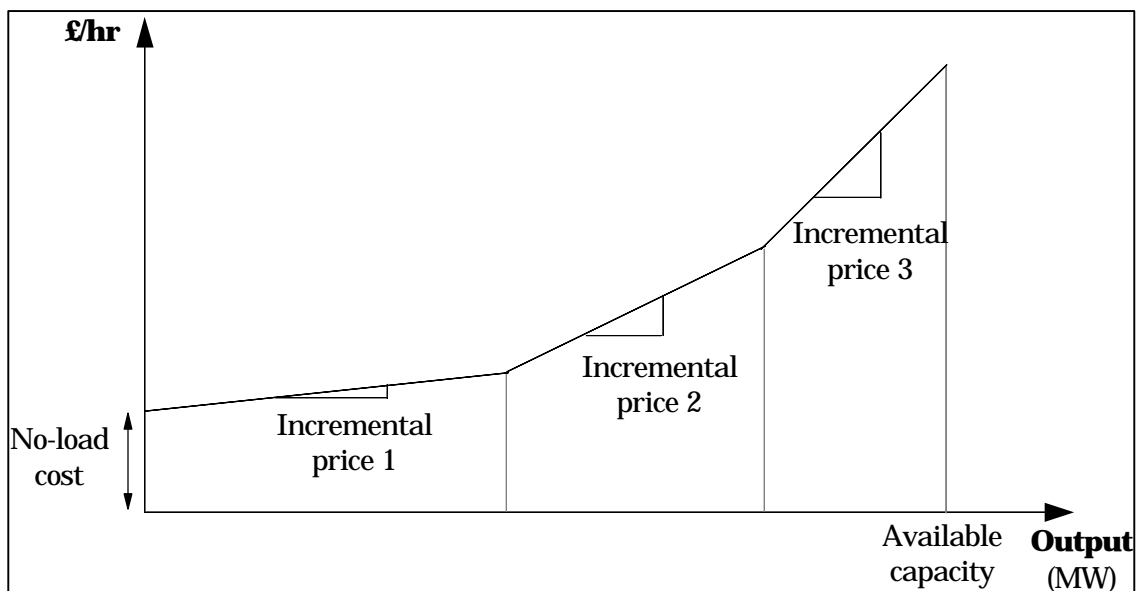
- 3.4 The Pool mechanism sets the wholesale price and establishes the generation merit order to meet the forecast demand (plus a reserve margin) at the day-ahead stage. NGC, as Grid Operator, is responsible for the scheduling and despatch¹⁰ of generation on the day to meet actual demand. The actual despatch of plant may not match that anticipated at the day-ahead stage due to: transmission constraints, changes in plant availability and differences between actual and forecast demand. Generally, generators are not penalised for failing to follow their despatch instructions or for altering their availabilities.
- 3.5 Pool prices are set on the basis of a competitive bidding process for generation. By 10.00am each day, generators (including the Scottish power companies and

¹⁰ Scheduling is the process of deciding in advance how plant should operate over a day to meet demand whilst despatch covers the issuing of specific instructions to generators on the output required from their plant at a particular time.

Electricité de France, EdF) submit bids for each half-hour of the following day. These contain, for each generating unit, the level of output on offer by half-hour and a number of price parameters (which apply throughout the day). In addition, any limitations of the plant are notified such as minimum generation levels and the rate at which a unit can increase or decrease output. Generators can adjust their availability bids at any stage but cannot alter their price bids once they have been submitted.

- 3.6 Each unit's bid contains five main price parameters: a start-up price, a no-load price and up to 3 incremental prices. The no-load and incremental prices define the price of operating the plant at different levels of output once the unit has been synchronised¹¹, see Figure 2. These parameters were chosen as being representative of the way that engineers characterise the cost curves of thermal stations, but there is no obligation on generators to submit cost-reflective bids.

Figure 2. Bid Prices



- 3.7 The Grid Operator produces a forecast of demand (plus reserve required) for each half-hour of the following day and then schedules the generators' bids to meet this demand. The demand is estimated by taking into account weather forecasts and past demand usage patterns. In addition, the Scottish generators, EdF and First Hydro¹² provide half-hourly forecasts of their demand requirements from the Pool. A computer system called GOAL (Generator Ordering and Loading) aims to produce

¹¹ The characteristics of the electricity produced by a station in terms of voltage and frequency have to be matched to that of the transmission grid before any power can be exported from the station. This process is known as synchronisation.

¹² The Scottish generators and EdF may wish to import electricity from the Pool into their systems, whilst First Hydro, which owns two pumped storage stations, may require electricity to pump water from its lower reservoirs to its upper reservoirs in order to be able to generate electricity at other times.

the lowest cost generation schedule for the day as a whole, taking into account all the plant limitations and generator bids. This is called the Unconstrained Schedule¹³.

- 3.8 Generally, the price of the most expensive unit scheduled to meet forecast demand in each half hour sets the price for energy, known as the System Marginal Price (SMP). However, plant whose output is constrained by the limitations included in its bid cannot set the price. For example, a plant that is only scheduled for its minimum generation level cannot set SMP.
- 3.9 In most half-hours, the SMP takes account of all the price parameters included in the bidding process but in some periods (“Table B” periods), typically those when demand is low, only incremental bid prices are considered. In such periods, plant may have to be despatched at a low level of output so that they are available to meet an anticipated pick-up in demand. The no-load and start-up prices of plant operating in Table B periods are transferred to all the other periods in the day (“Table A” periods) before the price setting calculation is performed.
- 3.10 To the SMP is added a component called the Capacity Payment. This is provided to give an incentive to generators to maintain an adequate margin of generation over the level of demand for electricity in order to cover for unexpected demand and generator failures on the system. This payment is the product of two factors: the Loss of Load Probability (LOLP) and the Value of Lost Load (VOLL). The Loss of Load Probability, calculated on a half-hourly basis, reflects the probability that, given the demand forecast and the generators’ bids and the uncertainty attached to these values, there will be insufficient plant available to meet demand. Pool standing data provides values for demand uncertainty and the reliability of the sets that were operating at Vesting (“Vesting Disappearance Ratios”). The reliability of sets that have been commissioned since then is updated in the light of historic data on their availability (“Live Disappearance Ratios”). The Value of Lost Load is intended to reflect the cost to consumers of an electricity outage; its value was set at 2000 £/MWh in 1990. Its value for 1997/98 is 2599 £/MWh, and it increases each April by the annual rate of inflation (RPI) measured to the preceding December.
- 3.11 Together, SMP and the Capacity Payment constitute the Pool Purchase Price (PPP). PPP values are calculated the day before the day of trading, i.e. *ex-ante*, and made available to Pool members electronically by 16:00 that day¹⁴. They are also published in the Financial Times the following morning, i.e. on the trading day.
- 3.12 Irrespective of their bid prices, all generators receive PPP for their deemed output (unless their plant is constrained-on, see below). The output that they are deemed to have produced takes into account any availability re-declarations that they have

¹³ It is so called because it takes no account of any constraints on the scheduling of plant that may be imposed by the layout and capacity of the high voltage transmission system.

¹⁴ Technically, these prices are *provisional prices* because disputes can arise which necessitate the process being repeated with new input data. However, all price setting runs involve forecast demand and bid data even when they take place after the event when actual data is known. Thus prices are always *ex-ante* prices.

made. However, from 25 February 1998, generators will be paid for their actual output rather than their deemed production.

- 3.13 **Unscheduled Availability Payments (USAV)** are made to plant which were available but which were not included in the Unconstrained Schedule. Although not generating, these plant contribute to the security of the system since they can be called upon to generate if required. Consequently the USAV payments they receive are closely related to Capacity Payments.

Transmission constraints and losses

- 3.14 Constraints on the transmission system can cause the actual half-hourly generation produced by a unit to differ from that anticipated in the Unconstrained Schedule. Units which were scheduled before taking constraints into account may have their output reduced or withdrawn (they are “constrained-off”). Other units may have their output increased or be despatched without being included in the Unconstrained Schedule (they are “constrained-on”). Although the costs of constraints are NGC’s responsibility, the mechanism used to calculate a generator’s revenue from constrained running is still determined by the Pool Rules.
- 3.15 As shown in Table 1, constrained-off units are paid the difference between the PPP they would have received and their bid price. Constrained-on plant are simply paid their bid price plus USAV. These payments will be higher in value than PPP if the unit was not included in the Unconstrained Schedule.

Table 1. Payments to Generators

		Actual schedule	
		In	Out
Unconstrained Schedule	In	PPP	PPP – bid price
	Out	Bid price + USAV	USAV

- 3.16 NGC, in its role as Ancillary Services Provider, can offer generators with plant which are of particular importance to the transmission system “constrained-on” contracts. Such contracts enable a plant to cover its costs. In return, NGC is guaranteed the availability of the unit and is aware of the costs that it will incur, if it calls upon the plant to run.
- 3.17 Transmission losses arise when electricity is transported because energy is lost due to resistance in the transmission wires and other transmission equipment. The cost of losses is at present borne by all suppliers on a uniform basis. It is typically about 2% of total Pool payments.

Ancillary Services

3.18 In addition to payments for energy and capacity, generators can also be rewarded for providing services that maintain the stability and reliability of electricity supplies. These are called Ancillary Services. There are four main types of Ancillary Services (excluding constraint contracts, discussed above): frequency support, reserve, voltage support including reactive power and black start.

Frequency support

3.19 NGC has a statutory duty, under its Transmission Licence, to maintain the frequency of the transmission system within the range 49.5-50.5 Hz. Sudden increases in demand or the failure of a generating unit can change the system's frequency and action may have to be taken to control it over very short time-scales. Most plant must provide some degree of automatic frequency support under the terms of their Supplemental Agreement¹⁵. Payment for this service is made under an Ancillary Service contract on the basis of the unit's response capability. In addition, some plant may be able to offer further frequency support over somewhat longer time-scales and load reduction can also be used to control the system frequency. These services are also rewarded via Ancillary Services contracts but the contracts are awarded on a competitive basis and the duration and terms of the contracts are negotiable.

Reserve

3.20 Reserve provides further frequency control and also provides security for the system. There are various types of reserve that are categorised according to the timescales involved. Contingency reserve refers to the margin of generation over forecast demand that is incorporated in the Unconstrained Schedule. It is provided by plant which have been notified in advance by the Grid Operator that they may be required to generate. These plant are remunerated for the costs of maintaining a state of preparedness through Ancillary Services payments.

3.21 Scheduled reserve, as its name suggests, can be scheduled by the Grid Operator as required. Plant that are not operating at full output, including interconnectors, can provide scheduled reserve. Payments for scheduled reserve are made primarily through the Pool, and recovered via Energy Uplift¹⁶.

3.22 Standing reserve covers the shortest timescale. To provide standing reserve, a response is required at least within 30 seconds. It can be provided by open cycle gas turbines, hydro or pumped storage plant, non-centrally despatched plant or load reduction. Contracts for standing reserve are awarded after an annual tendering

¹⁵ A Supplemental Agreement is the site specific Agreement between NGC and a generating plant covering its grid connection and use of the transmission system.

¹⁶ See 3.30 for a definition of Energy Uplift.

process.

Voltage support

- 3.23 NGC also has statutory obligations with regard to the maintenance of voltage levels on the transmission system. Unlike frequency control, which can be provided from any point on the grid, voltage control is a localised service. Closely associated with voltage control is the maintenance of reactive power, which is a measure of the time relationship between the peak delivery of current and voltage. Certain types of machinery, particularly motors, require this relationship to be fixed in order for them to function properly. Both voltage and reactive power are primarily maintained by plant that are generating. Payments to plant are currently made on a zonal basis. Under arrangements for a reactive power market mechanism, from 1 April 1998 NGC will invite tenders for the provision of reactive power. A default tariff will provide for payments to generators for their reactive power in the event of no bilateral contract with NGC being signed. In addition, some plant can provide reactive power without generating and may be awarded an Ancillary Services contract for so doing.

Black start

- 3.24 Black start is the procedure to recover from a total or partial failure of the transmission system. Nearly all power stations require an electrical supply to start-up. Stations that can provide Black Start capability have some form of auxiliary supplies that have sufficient capacity to restart the station without drawing on supplies from the grid. By having such capabilities strategically placed around the country, the whole system can be re-energised. Payment for this service is made under an Ancillary Service contract.

The role of interconnectors

- 3.25 There are electrical links or interconnections between the England and Wales system and two other independent systems: Scotland and France. Companies that trade electricity across an interconnector are known as External Pool Members of whom there are currently four. Three trade across the Scottish interconnector: ScottishPower, Hydro-Electric and British Nuclear Fuels; and one across the French interconnector, EdF.
- 3.26 Each External Pool Member is allocated a number of Generation Trading Blocks¹⁷ that are treated in most respects by the Pool as if they were normal generating units. The capacity of any interconnector is divided between the appropriate External Pool Members and the aggregate availability of the Trading Blocks of an External Pool Member cannot exceed the import capacity to England and Wales allocated to the member plus the total export demand expected on the interconnector. This approach

¹⁷ ScottishPower and Hydro-Electric have twelve each, BNFL one and EdF ten.

to availability bids, known as superposition, recognises that it is the physical flow (imports minus exports) on an interconnector which is limited by the capacity of the line and not the gross flow (imports plus exports). For example, on a 1000 MW interconnector, 1500 MW of imports to England and Wales could be scheduled, if simultaneously, 500 MW of exports were deemed to be occurring.

- 3.27 The price bids that Trading Blocks submit are subsets of those submitted by other generating units since the start-up and no-load prices must be zero and only one incremental bid is allowed. In addition, availability re-declarations of Trading Blocks are subject to a number of limitations. A re-declaration of an individual block can only be made if the aggregate availability declared by the External Member changes. Any increase in availability must be applied to trading blocks in order of increasing price. Conversely, any decrease in availability must be applied to trading blocks in order of decreasing price.

The demand-side in the Pool

- 3.28 For the purposes of balancing generation and demand, a reduction in demand is just as effective as an increase in generation.
- 3.29 Some consumers choose to have electricity contracts with suppliers whose prices are directly related to Pool prices. These consumers can, in principle, respond to Pool price signals by adjusting their demand since Pool prices are published a day ahead. Such responses do not affect the PPP but may influence Energy Uplift.
- 3.30 A limited number of large consumers, up to 30, can participate directly in the Pool as demand-side bidders. Demand-side bidders submit offers into the Pool specifying the price at which they are willing to reduce their demand.
- 3.31 A demand-side bid is essentially treated by the Pool as extra generation as far as energy is concerned and demand-side bidders can set SMP. However, demand-side bids are not taken into account in the LOLP calculation and hence do not affect Capacity Payments. The price bid offered by a demand-side bidder is identical in structure to a generator's bid and the availability bids specify the periods in which demand can be reduced and by how much. In addition, the demand that would be expected to be taken in the absence of demand reduction for each period has to be submitted.
- 3.32 A demand side bidder receives no payment for scheduled load reduction. For volumes bid in (but not scheduled), the demand-side bidder receives USAV Payments. The net effect of such payments is that the demand-side bidder pays SMP plus a capacity payment in which VOLL is replaced by its bid price, see Table 2.

Table 2. Payments Made and Received by Demand-Side Bidders When not Scheduled

Payments made for electricity taken	Payments received	Net payments made
SMP + LOLP(VOLL-SMP) + Pool Uplift ¹	LOLP(VOLL-bid)	SMP + LOLP(bid-SMP) + Pool Uplift ¹

Note: For a definition of Pool Uplift, see 3.30 below.

3.33 Demand-side bidders are required to self-despatch if scheduled. The Pool monitors despatch, but there are no formal penalties for failure to self-despatch.

Suppliers' payments

3.34 Suppliers buy electricity from the Pool at the Pool Selling Price. This is the sum of the Pool Purchase Price and Pool Uplift. Pool Uplift consists of two elements, Energy Uplift and USAV¹⁸. Energy Uplift covers, inter alia, the costs of additional generation required arising from differences between forecast and actual demand and between generators' availability bids and their actual availability.

3.35 Suppliers pay for the amount of electricity they are deemed to draw off at each Grid Supply Point¹⁹ (where electricity enters the distribution system), increased by a factor designed to take account of average losses on the transmission network.

3.36 Suppliers also pay Transmission Services Use of System Charges which comprise Transport Uplift and reactive power payments. Transport Uplift covers the costs of transmission constraints (see 3.14) and most Ancillary Services (see 3.17 onwards), excluding reactive power (see 3.22).

Pool governance

3.37 All traders in the Pool (Pool Members) are obliged to be signatories to the PSA, as are other organisations providing some of the key services to the Electricity Pool. These include the Settlement System Administrator, the Pool Funds Administrator, the Grid Operator and the Ancillary Services Provider. At present, these services are provided by NGC.

3.38 There are 59 Pool Members (as at December 1997), and changes to either the trading arrangements or governance procedures usually require the majority support of Members (generally 65% of all Members weighted by their traded volumes).

¹⁸ USAV payments were described in 3.15

¹⁹ In calculating the volume of electricity for which a supplier must pay, account is taken of the output of any centrally despatched generation connected to the distribution network below the Grid Supply Point.

Significant authority is delegated to the Pool Executive Committee (PEC), comprising elected Pool Member representatives.

- 3.39 Pool Members are bound by the PSA to administer and develop the trading system in a way that balances the interests of actual and potential Members and electricity customers.
- 3.40 The PSA confers certain rights upon the DGES. He has the right to attend all meetings as an observer. He has the right to require Pool Members to examine particular issues and all changes to the trading rules (the Pool Rules) require his approval before they can become effective. Certain changes to the PSA require his prior written approval. Most significantly, Pool Members can, albeit on limited grounds, refer a decision made by Pool Members in General Meeting to the DGES for a binding ruling on whether it should stand or be overturned.
- 3.41 The Chief Executive's Office administers the business of the Electricity Pool. Its work includes facilitating the work of the PEC and its sub-committees, providing secretarial and administrative support, dealing with external relations, and promoting the efficient operation and development of the Electricity Pool.

Developments in the Pool

- 3.42 Since Vesting the Pool has made a number of changes to the trading arrangements and work is progressing on a number of further issues. For example, as a result of the Pool's Longer Term Review (LTR) (see chapter 5), a number of recommendations in the areas of demand-side bidding, transmission services and simplification were made, some of which have subsequently been implemented. Extensive changes have also been made in the context of facilitating the introduction of full supply competition in 1998. From time to time, the DGES has asked the Pool and NGC to review various elements of the arrangements and OFFER has itself carried out three reviews of Pool prices (see Chapter 4 for details).
- 3.43 Some of the changes and initiatives are outlined below. For clarity, the discussion is ordered by issues rather than chronologically since many of the issues have been addressed on several different occasions.
- 3.44 **Bidding:** In 1994, the DGES asked the Pool to consider simplifying the structure of bid prices. The LTR recommended the retention of the existing structure but suggested that the practicability of allocating Uplift costs to those who cause them should be investigated. The LTR also suggested that the Pool should investigate firm bids at the day ahead stage. Neither of these suggestions has been implemented.
- 3.45 **Unconstrained schedule:** Until August 1993, energy and reserve were separately scheduled by GOAL. However the program had increasing difficulties in producing these schedules and frequently an additional program, GOALPOST, had to be run.

This led to a number of spikes in Pool prices and general concerns about the profile of prices. The DGES suggested that the Pool should give serious consideration to discontinuing the use of GOALPOST in setting price. The proposal was accepted by the Pool and implemented in August 1993. The Pool also began to treat reserve as additional demand. The Pool and NGC have jointly undertaken a project to develop a replacement scheduling program for GOAL. It is intended that the new program, SUPERGOAL, will replace GOAL in June 1998.

- 3.46 ***Pool price anomalies:*** A number of Pool price anomalies were caused by inconsistencies in generator bids. On 1 August 1995, the Pool initiated the System Marginal Price Anomaly Reduction Project (SARP). This was designed to alleviate these Pool price anomalies by developing tests to identify potentially anomalous prices, and procedures for checking and amending offer data and rerunning, if necessary, GOAL and the SMP calculation. The project was implemented in February 1996, and the range of events with which SARP can deal was later widened.
- 3.47 ***Generator payments:*** In December 1994, financial incentives were introduced to encourage generators to follow their despatch instructions. Provision was also made for testing the availability of a generating unit which has not been required to run for an extended period and penalising units which failed such a test. In 1995, the DGES asked the Pool to review the Pool Rules to ensure that customers would not bear the costs of undergeneration²⁰. In April 1996, generators accepted that they should bear the costs and work was put in hand to produce a mechanism which would deliver this (the Undergeneration Project). Full implementation is due from 25 February 1998.
- 3.48 ***Capacity Payments:*** In 1991, high and volatile Pool prices prompted an OFFER inquiry which concluded that PowerGen had raised Capacity Payments by declaring plant unavailable and then benefited from the higher payments by re-declaring the plant available. The Pool amended the mechanism for calculating LOLP to prevent this situation reoccurring. The issue of Capacity Payments was raised again in 1994, when the DGES suggested that the Pool should consider the abolition of Capacity Payments. The Pool considered the issue but recommended that the mechanism should be retained for the foreseeable future.
- 3.49 ***Vesting Disappearance Ratios:*** In 1997, the DGES noted that the performance of the advanced gas cooled reactor plant had improved significantly. He asked the Pool to consider the case for the revision of the Vesting Disappearance Ratios of these plant.
- 3.50 ***Losses:*** In his 1989 Annual Report, the DGES first raised concerns about locational signals and the role of losses. He reminded the Pool of his concerns in 1995 and Pool members subsequently agreed to charge both generators and suppliers on a cost reflective basis and drew up a mechanism for so doing. The DGES upheld the

²⁰ A plant is said to undergenerate when its actual output is less than its despatch instruction.

majority decision of Pool Members to adopt this mechanism but this decision is now the subject of a judicial review.

- 3.51 **Constraints:** Until 1 April 1997, the PSP also included transport related costs, primarily the costs of constraints and Ancillary Services. OFFER published a report on constrained-on plant in October 1992, which included a number of suggestions for controlling costs including constraint contracts, incentive schemes and reformulating the security standards which it asked NGC to review. In 1994, the LTR recommended that these costs be removed from the Pool and that NGC manage reactive power, constraints and other costs associated with the transport of electricity outside the Pool. Following a series of incentive schemes started in 1994, which exerted downward pressure on these costs and those now included in Energy Uplift, Pool Members agreed to transfer responsibility for Transport Uplift and reactive power to NGC. The costs of Transport Uplift and reactive power are now covered by an incentive scheme on NGC with effect from 1 April 1997.
- 3.52 **Treatment of interconnectors:** Prior to 1 October 1997, superposition (see 3.23) was not allowed in the treatment of interconnectors.
- 3.53 **Demand-side bidding:** At its inception, no provision for demand-side bidding was included in the Pool. OFFER asked the Pool to consider the possibility of demand-side bidding in 1991. A temporary scheme was introduced in December 1993 that, with some extensions and refinements, is still in place today. The Pool has recently developed a number of enhancements to the present scheme, and these are expected to be implemented later this year. These enhancements include penalties on demand side bidders for failing to self-despatch, an increase in the number of participants, and the input of demand side bidders' availability into the LOLP calculation.
- 3.54 **Pool governance:** In 1991, OFFER supported moves to simplify the Pool Membership conditions. The Pool took steps to address this, particularly in respect of small independent generators and suppliers. In 1997 the PEC invited two customer representatives to sit on the committee in a non-voting capacity.
- 3.55 **Pool information:** In 1990 OFFER asked the PEC to put as much disaggregated information in the public domain as possible. The Pool has worked steadily to achieve this aim, through the Transparency Reporting Implementation Group (TRIG) and by preparing guidance documents on the Pool Rules and particular mechanisms for use by Pool Members and others.

4. EXPERIENCE IN THE POOL TO DATE²¹

Annual Pool prices

4.1 Table 3 shows the evolution of real annual average Pool prices over the eight years since wholesale trading was introduced. For the first four years, the annual average values of both PSP and PPP increased each year. By 1993/94, PPP was 28.8% higher than in 1990/91, and PSP 33.3% higher in real terms. Since then, prices have fallen each year and the average PPP and PSP values for the first nine months of 1997/98 are now only 15.7% and 11.8% higher respectively than their values for the first nine months of 1990/91.

Table 3. Annual Average Pool Prices (October 1997 £/Mwh)

Year	SMP	Capacity Payment	Pool Uplift ⁽¹⁾	PPP	PSP
1990/91	21.51	0.06	1.13	21.57	22.70
1991/92	23.09	1.53	1.91	24.63	26.54
1992/93	25.95	0.19	1.59	26.15	27.73
1993/94	27.25	0.31	2.46	27.56	30.02
1994/95	23.61	3.52	2.61	26.34	28.95
1995/96	21.05	4.74	2.17	25.35	27.52
1996/97	20.95	3.35	1.95	24.59	26.53
1997/98 ⁽²⁾	22.64	0.93	0.41	23.58	23.99
1997 ⁽³⁾	23.62	1.17	0.71	24.79	25.50

Notes:

1. From 1 April 1997, Pool Uplift comprises Energy Uplift and Unscheduled Availability payments. Prior to that date, Pool Uplift also includes Transport Uplift and Reactive Power.
2. Figures for 1997/98 are averages of the first nine months, April to December.
3. Calendar year 1997

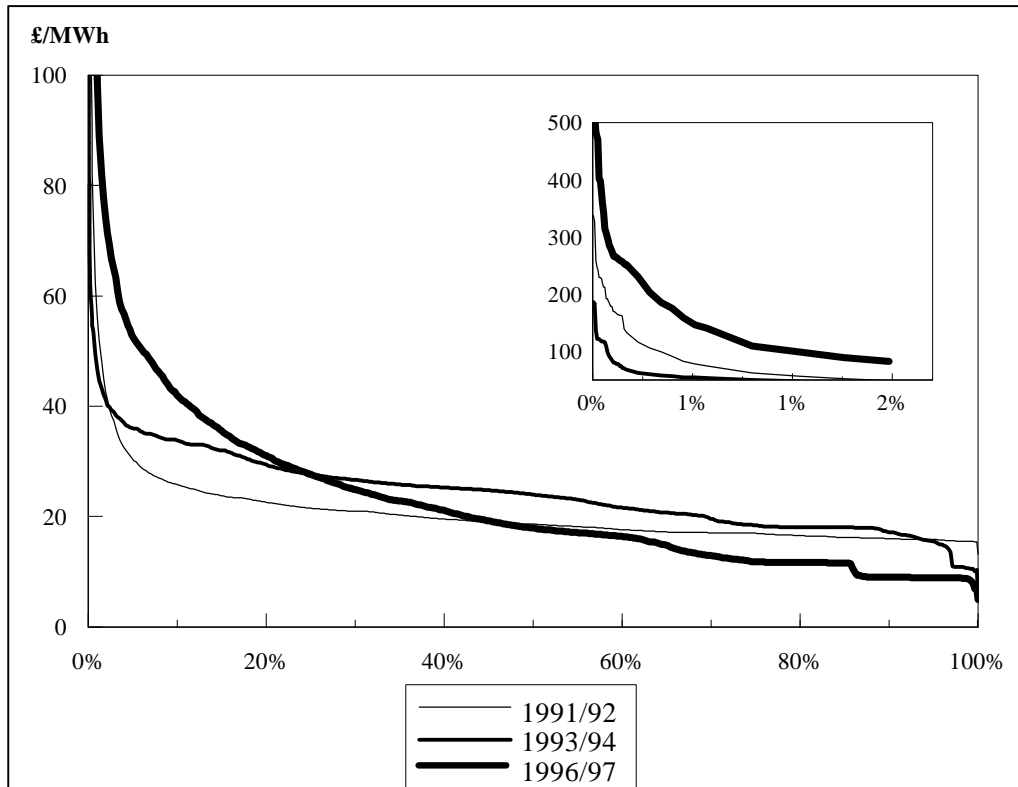
4.2 The profile of prices has also changed over time. Figure 3 compares the PPP duration curves for 1991/92, 1993/94 and 1996/97. A PPP duration curve orders all the Pool prices in a year from highest to lowest and hence can be used to indicate the percentage of half-hours in the year that PPP has exceeded any given value.

4.3 By 1996/97, the differential between the highest and lowest prices in the year had increased compared to the first four years of the Pool, as competition to generate at times of low demand increased (see Chapter 8 for a discussion of

²¹ In this Chapter, all price data are presented in real, October 1997, terms using the Retail Price Index as a deflator.

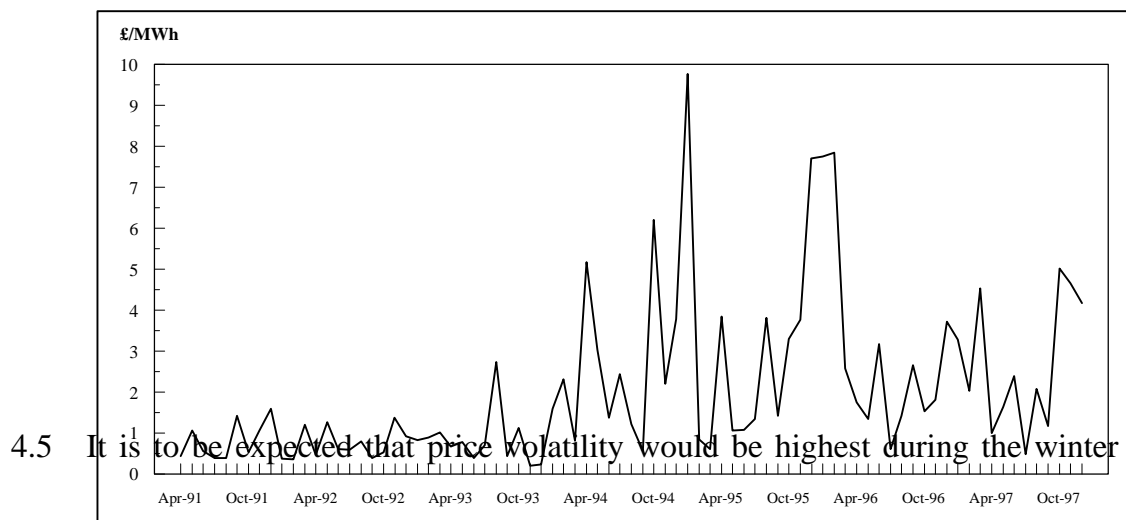
competition in generation). Overnight prices averaged around 10 £/MWh compared to 20-24 £/MWh in 1991/92. Although average overnight prices have increased over the winter months in 1997/98, they remain well below the levels seen in the early years of the Pool.

Figure 3. Annual PPP Duration Curves



4.4 The volatility of prices has also increased over time. Figure 4 shows the standard deviation of the weekly average SMP within each month. A high value indicates significant variations between the weekly values and vice versa.

Figure 4. Weekly SMP Volatility



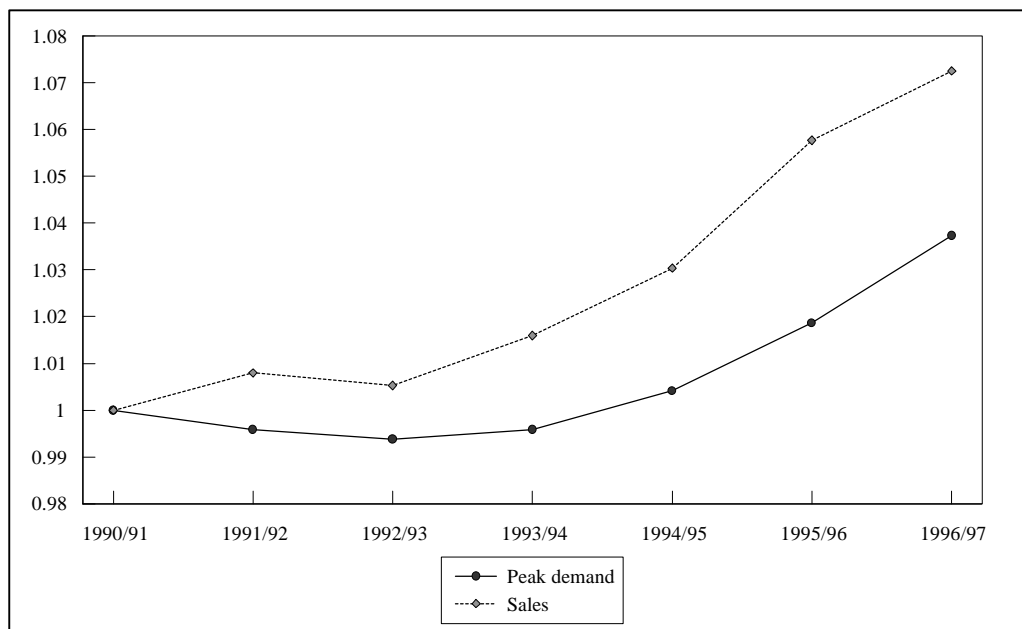
4.5 It is to be expected that price volatility would be highest during the winter

months when temperature variations have a greater impact on demand. The extent of winter volatility might vary significantly from year to year depending on weather conditions. However, there has also been a significant increase in summer volatility since 1994/95.

Supply and demand

- 4.6 Electricity sales and peak demand have grown by 7.3% and 3.7%, respectively (on a weather corrected basis). The main growth in both demand and sales has occurred during the past three years (1994/95 to 1996/97) as the economy has come out of recession, as can be seen in Figure 5.

Figure 5. Changes in Electricity Sales and Peak Demand (Average Cold Spell (ACS) Weather Corrected) 1990/91

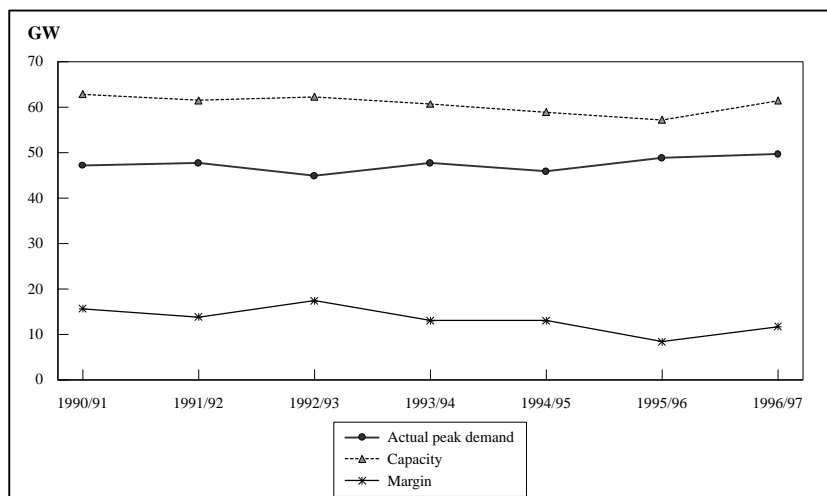


Source: NGC Seven Year Statement

- 4.7 The total of generation capacity on the England and Wales system has remained at around 60 GW a year over the past eight years. 16 GW of new plant has been built over the period, but this has been offset by 13 GW of closures, and the mothballing²² of a further 5 GW (see Chapter 8).
- 4.8 The growth in demand, combined with the static level of capacity has meant that the margin of generating capacity over peak demand, shown in Figure 6, has declined from 33% in 1990/91 to 24% in 1996/97. In this diagram, actual rather than weather corrected peak demand is shown since this is what determines the margin achieved.

²² A mothballed plant is one that has been temporarily closed but could be brought back into operation.

Figure 6. Peak Demand, Capacity and Margin



Source: NGC Seven Year Statement

4.9 Another significant change has been that the number of generating sets has fallen by 35% whilst the total capacity on the system has remained essentially constant. This has occurred because it is predominantly smaller units that have been closed and they have been replaced by larger ones. All other things being equal, reducing the number of units on the system will increase the level of Capacity Payments²³. Since the size of the largest unit on the system has also increased, reserve requirements have grown because the system must be able to withstand the loss of its largest in-feed.

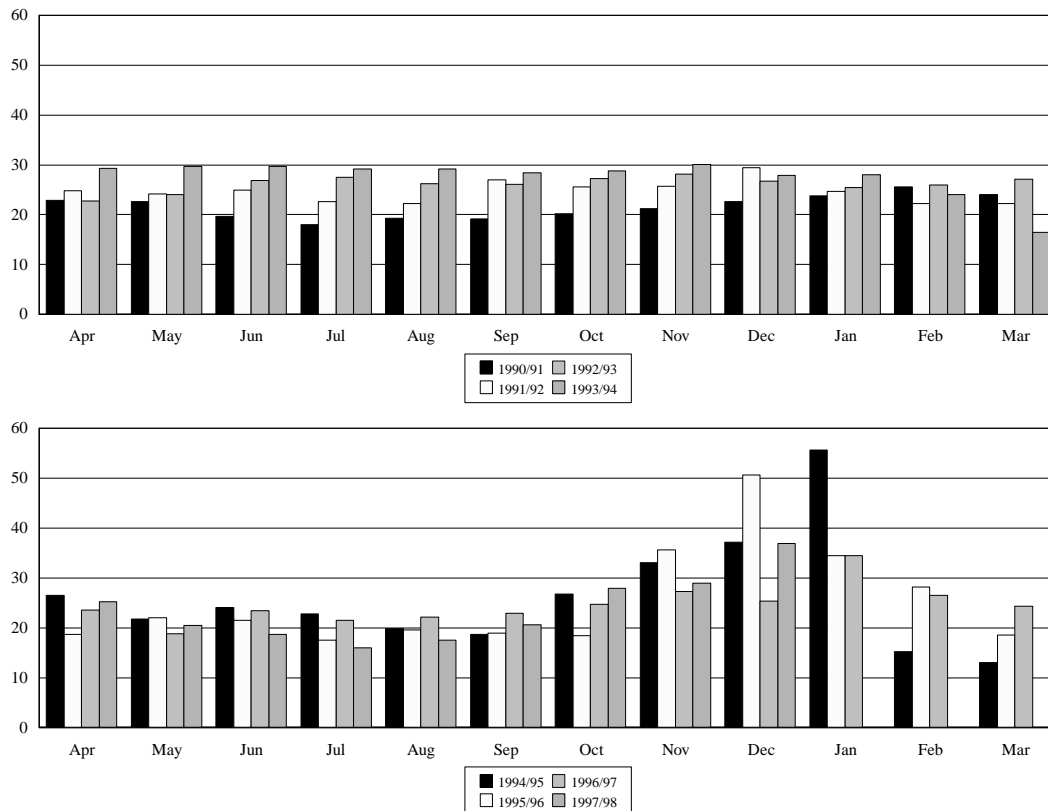
Pool price experiences

4.10 The DGES has investigated the changes in the level of Pool prices, and also the split between the different components, on a number of occasions²⁴. He has considered them both in the context of the operation of the Pool and his consideration of whether or not to refer National Power and PowerGen to the MMC.

²³The central limit theorem in statistics states that the variance of a population decreases as the number of members of the population decreases. In electricity terms, this means that the unreliability of supply increases as the number of units on the system decreases.

²⁴Report on Pool Price Inquiry, December 1991; Report on Gas Turbine Plant, June 1992; Report on Constrained-On Plant, October 1992; Review of Pool Prices, December 1992; Pool Price Statement, July 1993; Decision on a MMC reference, February 1994; Generators Pool Price Undertaking 1994/95, June 1995.

Figure 7. Monthly Pool Purchase Prices (October 1997 £/Mwh)



1990/91

4.11 In 1990/91, prices were low and very flat with monthly average PPP only ranging between 18.0 £/MWh (July) and 25.6 £/MWh (February), see Figure 7. For three half hours, PPP was actually zero. It is generally acknowledged that prices in this year were depressed by the very high level of contract cover that National Power and PowerGen were given at Vesting (see Chapter 7). These contracts provided them with a secure revenue stream which was not related to Pool prices.

1991/92

4.12 PPP in April 1991 was 8% higher than in April 1990 (and 3% higher than in March 1991). This higher level of prices was maintained throughout the year with all three components of Pool prices – SMP, Capacity Payments and Uplift – showing significant increases. SMP levels rose particularly sharply in the early part of the year – prices in the first six months of 1991/92 were 15% higher than in 1990/91, but only 1% higher overall. Over the year, Capacity Payments were 300% higher than in 1990/91 and Uplift 70% higher.

- 4.13 These rises led to the first serious concerns being raised over the functioning of the Pool. Concerns were also raised over the spike in Pool prices on 9 September, when the SMP exceeded 195 £/MWh (160 £/MWh, in money of the day) for three half-hours. In OFFER's Pool Price Inquiry (published December 1991), the DGES concluded that spikes had not constituted a serious and persistent problem and that it was not possible to make an unambiguous judgement about whether prices previously had been too high or low.
- 4.14 However, the rise in Capacity Payments was considered to be a cause for concern and action was taken both by OFFER and the Pool to remedy the situation. The DGES introduces a new licence condition on NP and PG explicitly to prohibit monopolistic or anti-competitive behaviour in relation to the availability of plant and the closure or mothballing of stations (see Chapter 8). The Pool modified the LOLP calculation to neutralise the impact of a bidding policy adopted by PowerGen in September and October that increased prices and volatility²⁵.
- 4.15 Uplift rose because there were increases in both USAV payments, due to the rise in Capacity Payments, and Operational Outturn²⁶, due to constraint costs. The rise in constraint costs led to OFFER investigating constrained-on plant. At the same time, the issue of the remuneration of open cycle gas turbines was addressed in a separate review. Both National Power and PowerGen had indicated that the revenues these plant were receiving was insufficient to cover their costs and that unless new Ancillary Service contracts were forthcoming, some of their plant would be closed. Indeed, PowerGen declared all its gas turbines to be unavailable throughout April 1991.

1992/93

- 4.16 Although prices in April 1992 were comparable to those in April 1991, SMP rose by 22% between April and July 1992 whilst demand fell by 13%. This was primarily due to increases in the incremental and no-load prices of the coal sets belonging to National Power and PowerGen. The profile of prices was also significantly peakier during the period May to August which, in turn, led to a convergence of weekday and weekend prices. Prices were particularly high over the lighting-up peak (21:30 to 23:00). As a result of complaints from the PESs and large customers, OFFER investigated Pool

²⁵ PowerGen followed a policy of declaring plant unavailable at the day-ahead stage and then re-declaring it available on the day. Declaring the plant unavailable increased Capacity Payments, whilst re-declaring the plant available meant that the plant were paid the higher payments. The remedy adopted by the Pool was to change the LOLP calculation so that instead of using declared availabilities, the greater of declared and re-declared availability was used.

²⁶ Operational Outturn comprises constraint costs and Energy Uplift. Until 1 April 1997, all Operational Outturn payments were included in Uplift and hence the Pool Selling Price. From that date, constraint costs have been recovered via Transport Uplift which now forms part of Transmission Services Use of System Charges.

prices again and concluded that National Power and PowerGen together had market power and exercised it in a significant way. However, since the average avoidable costs of the generators were higher than their Pool revenue in 1991/92, OFFER concluded that it was difficult to object to a rise in bids, and hence prices, in 1992/93.

1993/94

- 4.17 Further increases in the bid prices of National Power and PowerGen resulted in a rise in SMP during the first few months of 1993/94. This effect was compounded by scheduling problems that led to an increase in the number of SMP spikes – over half the spikes that occurred in the first three years of the Pool happened during the period April to July 1993. The spikes contributed to a reduction in the differential between day-time and night-time prices and between weekday and weekend prices.
- 4.18 For the six months, April to September, SMP was 14% higher in 1993/94 than in 1992/93. Changes to the treatment of reserve (discussed in Chapter 3) and the scheduling process significantly reduced the Pool spikes and SMP in the second six months of the year fell by 15%.
- 4.19 Uplift costs continued to increase substantially. In 1993/94, Uplift was 55% higher than in 1992/93 and 118% higher than in 1990/91. Constraint costs again accounted for the majority of the increase with Operational Outturn increasing from £235 million to £417 million. Ancillary Services also increased by 24% to £181 million.
- 4.20 OFFER investigated Pool prices for the third time and in this instance, the DGES concluded that the main generators' Pool revenues exceeded their avoidable costs and consequently that the need to cover avoidable costs did not justify a price increase as large as the one that occurred. Following on from this, in February 1994, National Power and PowerGen each undertook to bid into the Pool in such a way that the Pool price would not exceed predetermined levels for the following two years (see Chapter 8).

1994/95

- 4.21 The shape of Pool prices changed profoundly during the two years' of the generators' undertakings. Overnight Table B prices, at times of troughs in demand, fell from an average of 20.28 £/MWh in 1993/94 to 11.05 £/MWh in 1994/95 and 10.06 £/MWh in 1995/96. Furthermore, in contrast to previous years, there was a strong correlation between SMP and demand.
- 4.22 There was an eleven-fold increase in Capacity Payments in 1994/95 compared with 1993/94, with particularly high prices in December 1994 and January 1995. This resulted in the forty-nine highest Pool prices in the first

five years of the Pool occurring in these months. The generation margin was lower than in previous years in part due to an increase in the levels of demand. This, combined with outages at two nuclear stations and, in January, one large coal set, led to the high levels of Capacity Payments.

- 4.23 As a result of the high payments, it appeared likely that the Pool price undertakings would be breached. However, prices in February and March fell significantly, averaging 11.3 £/MWh and 12.1 £/MWh, respectively, as National Power and PowerGen substantially reduced their bids. Consequently, the DGES concluded that the generators had not breached their undertakings.
- 4.24 The high Capacity Payments resulted in high USAV payments but this was partially offset by a 7% fall in Operational Outturn and a 24% fall in Ancillary Service payments. Overall Uplift only rose by 7%. 1994/95 was the first year that an incentive scheme was introduced for Uplift (excluding USAV payments) and the fall in Operational Outturn resulted in NGC gaining the maximum benefit allowed under the scheme.²⁷

1995/96

- 4.25 A similar but more pronounced pattern was seen in 1995/96. For the first six months of the year PSP was 13% lower than in 1994/95 but winter Capacity Payments were 34% higher. In this instance, the high Capacity Payments were again partly due to problems at nuclear stations but demand also rose to record levels. French strikes led to a reduction in EDF's output and, consequently, to the French interconnector being used to import electricity into France. Since the interconnector is normally used to export electricity from France, this effectively increased the generation requirement by 4 GW.
- 4.26 Uplift fell by 17% with Operational Outturn payments falling by 46% and Ancillary Service payments rising by 25%. For the second year running, this enabled NGC to gain the maximum benefits allowed under the Uplift incentive scheme.

1996/97

- 4.27 The major feature of interest in 1996/97 was the high level of summer Capacity Payments. They averaged 3.0 £/MWh between April and September, over 2 £/MWh higher than in any other summer. Capacity Payments over the remainder of the year, October to March, were only 3.7 £/MWh compared to 8.7 £/MWh in 1995/96, and 6.8 £/MWh in 1994/95. Summer Capacity Payments in 1997/98 reverted to the low levels seen in other years.

²⁷ For each component of Uplift included in the scheme, a cost target was set. If the costs were below this target, NGC was allowed to receive a proportion of the savings made.

1997/98

- 4.28 Although the Pool price undertakings are no longer in place, the general shape of prices has remained the same as when they were. Overnight prices remain relatively low and stable with daytime prices substantially higher and quite volatile. For the first nine months of 1997/98, SMP has been 16% higher than in the same months of 1996/97, but Capacity Payments have been 75% lower over the same period, resulting in the Pool Purchase Price rising by 1%. The rise in SMP has been general: overnight as well as daytime prices have risen.

5. TRADING OUTSIDE THE POOL

5.1 Nearly all electricity in England and Wales is required to be traded through the Pool. However, some generation can be traded outside the Pool as described below. A supplier purchasing non-pooled generation avoids paying Pool Uplift and Transmission Services Use of System Charges²⁸.

Exempt Generation

5.2 An exempt generator is a generator who does not require a generation licence, and hence has no licence obligation to join the Pool. Exemption is granted to the operators of power stations which, in general terms, export less than 50 MW of electricity if their capacity is less than 100 MW, or 10 MW if it is greater. Exempt generation is, typically, “embedded”; that is, connected to a REC’s distribution network rather than to NGC’s transmission system. Exempt generators can sell their electricity directly to an authorised supplier (PES or second-tier) or (subject to their obtaining a supply licence, where appropriate) to end users. Accurate data on their numbers and capacity are not available.

Licensed Generation - “Small” Stations

5.3 The principles under “exempt generation” apply equally to the output of those stations of licensed generators which, if viewed in isolation, would not cause the generator to need a licence.

On-site generation

5.4 Before 1993, licensed generators with on-site demand had to sell all their output to the Pool at PPP and then buy back the electricity required to meet on-site demand at PSP. Since 1 April 1993 (following a decision by the Secretary of State), only net electricity flows have to be traded through the Pool. There are currently 10 on-site schemes registered with the Pool.

Spill, top-up and standby

5.5 “Spill” occurs when the output of an embedded generator is greater than the purchasing supplier’s demand or the demand of its on-site customers. Embedded generators need to make arrangements for the sale of such spills either with their host PES or another supplier. At present, if no specific spill contract is signed, the host PES may absorb the spill power free of charge.

²⁸ These items are described in 3.34 and 3.36 respectively.

- 5.6 An embedded generator acting as a second-tier supplier or an on-site generator will have to make provision for top-up and standby supplies to cover supplies at times when its output is less than demand²⁹ or it is not operating at all³⁰. PESs are obliged, under the terms of their PES licences, to offer non-discriminatory top-up and standby terms for all customers within their licenced areas. Alternatively, the embedded generator can purchase such supplies directly from the Pool providing it is a Pool Member.

Consideration of trading outside the Pool

OFFER's 1994 Report

- 5.7 In July 1994, OFFER published a report on trading outside the pool. This report was a response to a request by the Minister for Energy. The DGES examined the possibility of allowing any generator and supplier, wherever situated, to sign a bilateral contract for the physical sale of electricity and to require the Grid Operator to despatch that contract. A key feature of such an arrangement is that contracted output does not need to be bid into the day-ahead market in order to secure despatch.
- 5.8 The report concluded that allowing trading outside the Pool could have potential benefits to those involved, and arrangements could be made to maintain co-ordinated control of the system. However, there was little tangible evidence of the possible gains and the arrangements would be time-consuming and costly. The report further noted that there were several potential detriments to competition and new entry, both from a thinner and less transparent market and from placing new entrants and smaller competitors at a disadvantage in securing rights to despatch. The DGES said that he would be prepared to consider the matter again if: market conditions changed, there was a lack of progress in Pool reforms, more tangible benefits from trading outside the Pool could be identified, or the likely implementation costs could be reduced.

The Pool's Longer Term Review

- 5.9 The Pool has also considered the issue of trading outside the Pool, as part of its Longer Term Review between 1992 and 1994. It concluded that although there were feasible external trading options there would be major difficulties in prioritising access to the transmission network and that this could conflict with the production of the generation merit order. In addition, some Pool Members contended that trading outside the Pool did not achieve anything more than could already be achieved using contracts.

- 5.10 In May 1995, the PEC confirmed that it recognised that trading outside the Pool was

²⁹ Top-up supplies

³⁰ Standby supplies

an issue that might need to be reconsidered at an appropriate time subject to a business case being made. In reviewing the Pool Business Plans for 1996/7 and 1997/8, the PEC concluded that further scoping of trading outside the Pool should not be considered for those periods. The Independent Suppliers recorded their dissatisfaction with this course of action.

- 5.11 The issue subsequently came to OFFER on appeal in March 1996. The DGES decided that the interests of dissenting Pool Members had not been unfairly prejudiced by the failure to allocate funds for scoping trading outside the Pool. The DGES again acknowledged that trading outside the Pool could have potential benefits to those involved. However, the arguments put by the appellants had not introduced any new evidence of likely gains from trading outside the Pool, or of new scope for reducing the costs and detriments of doing so. The DGES emphasised nevertheless that the Pool should not close its mind on the matter, since it was important that Pool arrangements should facilitate the efficient provision of electricity to customers, whether traded inside or outside the Pool. He noted that the case for considering trading outside the Pool would be correspondingly strengthened if the Pool was unable to make significant progress in taking forward issues in a timely and cost-effective manner.

6. THE ELECTRICITY MARKET IN SCOTLAND

Trading arrangements

- 6.1 Scotland has a different set of trading arrangements from those in England and Wales. There is no Pool in which to trade electricity. Instead, ScottishPower and Hydro-Electric³¹ are responsible for the scheduling and despatch of all plant within their licenced areas and the purchase of Ancillary Services.
- 6.2 The Scottish Trading Arrangements Group (STAG), comprising generators and suppliers from England and Wales and Scotland, has been discussing how a market mechanism might be developed. An interim report was produced in May 1997. This described existing Scottish trading arrangements and assessed several proposals for future trading arrangements. However, there was no consensus on any particular option.
- 6.3 ScottishPower currently owns 42% of the generation capacity in Scotland and Hydro-Electric owns 32%. The remaining generation (with a few exceptions, see below) is owned by Scottish Nuclear, a subsidiary of British Energy.
- 6.4 At Vesting a number of contracts relating to generation entitlement were signed between ScottishPower and Hydro-Electric. These were designed to ensure that, in the absence of a Pool, each generator had access to output generated from a variety of fuels. The contracts are:
- The Coal Agreement (expires 2004): This entitles Hydro-Electric to the output of one-sixth of the capacity of ScottishPower's two coal stations (Longannet and Cockerzie). The charges payable include both a fixed capacity charge and a variable energy charge (related to the coal burn, which is not payable if Hydro-Electric burns coal purchased by itself).
 - The Peterhead Agreement (expires 2012): This entitles ScottishPower to 50% of the output of Peterhead (Hydro-Electric's oil/gas fired plant). Furthermore, ScottishPower is obliged to buy between 50% and 70% of the output whilst the station is burning gas produced from the Miller Field. The charges payable include a fixed capacity charge and a variable energy charge.
 - The Hydro Agreement (expires 2039): This obliges ScottishPower to purchase 400 GWh of electricity per annum from Hydro-Electric. The charges payable include a fixed charge plus a fuel charge, which is derived from the average fossil fuel costs incurred by ScottishPower from generation in Scotland.
- 6.5 In addition, the Nuclear Energy Agreement (NEA) was signed between ScottishPower, Hydro-Electric and Scottish Nuclear. The NEA requires Scottish

³¹ ScottishPower and Hydro-Electric are the trademarks of Scottish Power and Scottish Hydro-Electric respectively.

Nuclear to sell all its output to ScottishPower and Hydro-Electric, and for ScottishPower and Hydro-Electric to purchase 74.9% and 25.1% of that output at an agreed price, linked to the Pool price in England and Wales. It expires in 2005.

- 6.6 As discussed in Chapter 3, ScottishPower and Hydro-Electric bid into the Electricity Pool in England and Wales. Their access to the market through the interconnector is governed by the terms of the Use of Interconnector Agreement (Scotland), which the two companies signed with NGC. This expires in 2034. The interconnector is connected to ScottishPower's transmission system but Hydro-Electric has access to it under the terms of the Scottish Interconnector Agreement, agreed between ScottishPower and Hydro-Electric, which is of indefinite duration.

Competition in generation

- 6.7 There is little independent generation in Scotland and so the principal sources of electricity for second-tier suppliers are the generation businesses of ScottishPower and Hydro-Electric. So far, the only independent generation to enter the market since Vesting has been the 27 MW of capacity which has been commissioned under the Scottish Renewables Orders (SRO). To date, a total of 56 contracts representing 190 MW of capacity have been awarded under the SRO. Under the terms of the SRO contracts, the output of each renewable station is contracted exclusively to the Scottish PESs for the duration of the contracts which can last for a maximum of 15 years.
- 6.8 In April 1996, PowerGen announced its intentions to build a 700 MW gas-fired combined cycle gas turbine station (CCGT) at Gartcosh in Lanarkshire. This would enable PowerGen to sell directly as a Second tier Supplier in Scotland, export into England and Wales through the interconnector, or sell to the local PES, in this case ScottishPower. However, consent for the station is currently the subject of a Public Inquiry.
- 6.9 In January 1997, Fife Energy (a consortium of the Bank of Scotland, Energy Investors Funds and Global Energy) announced plans to build a 75MW waste-fuelled Integrated Gasification Combined Cycle (IGCC) at Westfield in Fife. The station is due to be commissioned during 1998. Subsequently, it has applied for permission to increase the capacity of this station to 400 MW.
- 6.10 Also during 1997, ScottishPower announced plans to build an 80MW IGCC coal station at Kincardine and Hydro-Electric received consent to increase the capacity of Peterhead to 2500 MW from 1524 MW.

Competition in supply

- 6.11 As there is no market mechanism in Scotland to facilitate trading, ScottishPower and

Hydro-Electric are required to establish relevant second tier supply arrangements to facilitate the supply of customers by second tier suppliers within their authorised areas.

6.12 The DGES approved the present second tier supply arrangements in April 1991. These are:

- A second tier supplier wishing to supply premises in Scotland is entitled to transfer to the transmission and/or distribution systems in Scotland the electricity required to meet the demands of his customers.
- To acquire this electricity the supplier may have his own generation or contract with one or other of the Scottish companies.
- If the second tier supplier sources the supply from his own generation, spill production will be paid for by the host PES at the SMP prevailing in England and Wales. Similarly, top-up and standby supplies will be provided by the host PES at a Pool related price.
- When the second tier supplier contracts with one of the Scottish companies, they must provide electricity at a price not exceeding the Scottish Wholesale price.

6.13 The Scottish Wholesale price is based upon England and Wales Pool prices. Originally, the Scottish Wholesale price was equal to the PSP. In June 1996, the DGES agreed to change the calculation of this price. For 1997/98, the Scottish Wholesale price is given by the PPP plus the Ancillary Services component of Uplift³². However, from 1 April 1998, a further change to the wholesale price has been agreed, it will be calculated as PSP plus the components of Uplift recovered through NGC's Transmission Services Use of System Charge, less 1%.

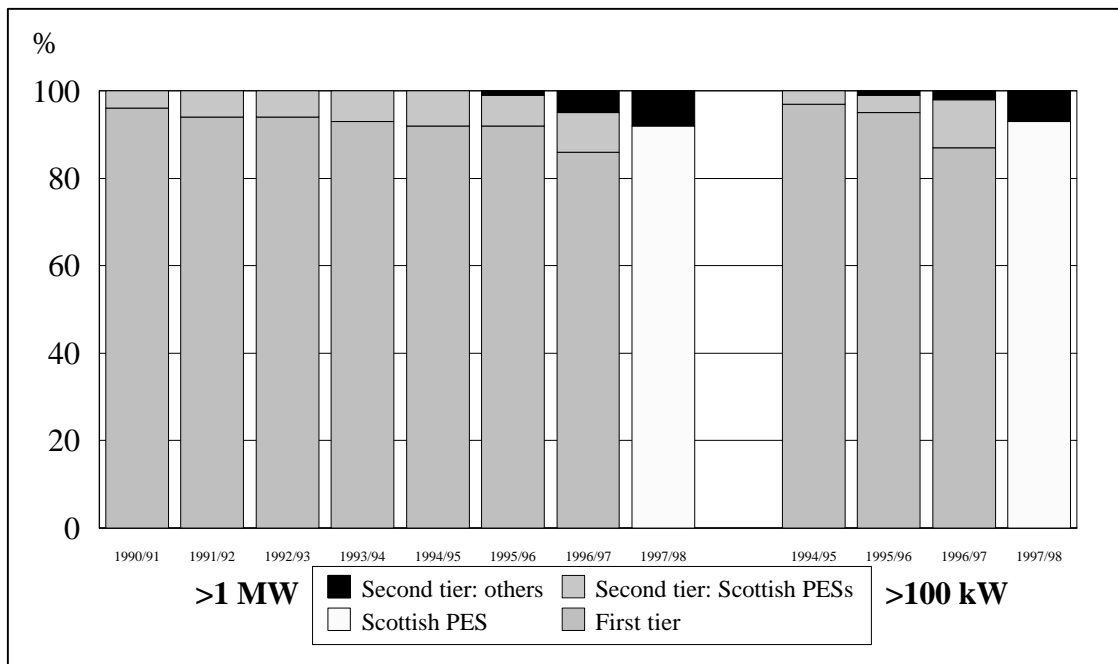
6.14 Bilateral trades between the generation businesses of ScottishPower and Hydro-Electric and second tier suppliers have been at the wholesale price cap approved by the DGES.

6.15 The timetable for supply competition in Scotland has mirrored that in England and Wales. However, the proportion of customers who have contracted with a second-tier supplier in Scotland has been significantly lower than in England and Wales. Furthermore, the majority of customers that have switched supplier, have contracted with the second tier supply business of the other PES, see Figure 8.

6.16 Preliminary estimates for 1997/98 suggest that there has been some increase in second tier activity. In the greater than 1 MW market, companies other than ScottishPower and Hydro-Electric have increased their market share to 8% from 5% in 1996/97. In the 100 kW to 1 MW market, the increase has been to 7% from 2%.

³² This refers to the pre-April 1977 definition of Uplift.

Figure 8. Non-Franchise Market Shares by Output Supplied



Note: 1997/98 figures refer to Scottish PESs' output supplied as both first and second tier suppliers.

7. THE CONTRACTS MARKET

7.1 In many markets, including electricity, exposure to price volatility is a risk. One method widely used to reduce risk exposure is to sign hedging contracts. These, for a given volume of the commodity, replace a variable price with a fixed price (the contract price). The contract price will depend on:

- The expectations of the purchaser and seller with regard to the movement in the underlying commodity price;
- The typical volatility of the commodity price;
- The relative value of the contract to the purchaser and seller;
- The size and length of the contract.

7.2 In the England and Wales electricity market, suppliers are exposed to price risk because they supply most of their customers at a fixed tariff but have to purchase electricity at the variable Pool price. Generators also face price risk because they do not know what price they will be paid for their output, although their fuel costs may be fixed. However, the risks faced by suppliers are generally greater than those faced by generators. Generators can decide not to generate if they consider the Pool price is too low, but only under interruptible contracts can suppliers choose not to supply customers when the Pool price is very high.

Contracts for differences

7.3 A Contract for Differences (CfD) is a financial “over-the-counter” (OTC) contract, i.e. it is negotiated directly between the parties concerned and no broker or screen-based trading system is involved. Generators typically sell CfDs to suppliers. The contract is settled by paying a price equal to the difference between the contract price and the Pool price in each half hour for the contract volume. A CfD can be struck against any component of the Pool price – SMP, PPP, PSP or Capacity Payments – but the majority of contracts are struck against PPP.

7.4 There are two main types of CfD, one-way contracts and two-way contracts. At its simplest, a one-way CfD can be called by the purchaser every time that the Pool price exceeds the contract price. In return, the contract seller is paid an option fee, regardless of whether or not the contract is called. One-way CfDs cap the risks to which the contract purchaser is exposed but enable the purchaser to benefit from low prices. The seller enjoys a guaranteed income, the option fee, but foregoes the potential benefit of high Pool prices.

7.5 Two-way contracts do not merely cap the price paid by the purchaser, they fix it at the contract price. Under a two-way contract, the purchaser makes a difference payment to the contract seller when the contract price is greater than the Pool price and the seller makes a payment to the purchaser when the Pool price is lower than

the contract price. Thus, irrespective of whether the contract price is higher or lower than the Pool price, the net price that the seller receives and the purchaser pays is the contract price.

- 7.6 Both one-way and two-way contracts can contain restrictions on how often the contract can be invoked. Two-way contracts may apply throughout the year or can specify the minimum number of times that the contract has to be called³³. The volume and price in a contract may also vary by time of day, type of day and season.
- 7.7 Similar instruments to CfDs, such as swaps and options, are used in other derivatives markets. However, unlike other OTC markets, such as those in the gas market, there are no generally recognised price reports, so there is little, if any, information on contract volumes and prices. In addition, CfDs are tailored towards a particular customer's requirements rather than of a standard format.

Evolution of the CfD market

- 7.8 At Vesting, the expected output of each of the generators was covered by contracts with the PESs, see Table 4. The contracts were split between those which lasted three years which were dedicated to the franchise market, and those dedicated to the non-franchise market (customers with a maximum demand above 1MW), which lasted one year but could be revoked after three months. Each PES received a share of each contract in proportion to its share of electricity sales.

TABLE 4 RECs PURCHASES OF CONTRACTS FOR DIFFERENCES, 1990/91

Generator	Electricity contracted (TWh)
National Power	124
PowerGen	75
Nuclear Electric	38
Others	21
Total	258

- 7.9 During the period 1990-1996, CfDs were used to secure non-recourse³⁴ financing for new entrants seeking to enter the generation sector. The CfDs formed the end of a contract chain, starting with a gas supply agreement, that defined the costs and revenues of the station. They reduced the project risks to a level at which banks

³³ Suppliers have no incentive to call the contract when the Pool price is less than the contract price but the contract is only of benefit to a generator if has to be called in these circumstances. Thus, specifying a minimum number of times that the contract must be called is one way in which the generator can lock in a margin.

³⁴ The project debt is not guaranteed by the parent companies.

were willing to provide high levels of debt finance (typically in excess of 90% of the project's costs). Without such contracts, it is likely that the pace of entry would have been slower. Eleven of the twelve PESs have signed long term contracts with CCGTs operated by new entrants³⁵, typically lasting for fifteen years. In all instances, the PESs took equity stakes in the projects³⁶. In 1996/97, new entrant contracts covered 32 TWh (11% of the market) at an average contract price of 38.4 £/MWh.

7.10 After the expiry of the franchise Vesting contracts in March 1993, all the RECs signed five-year contracts with National Power and PowerGen covering the period 1993/94 to 1997/98. These CfDs are directly related to the five year contracts between the generators and UK coal suppliers, and include a premium to cover the high coal prices included in the coal contracts. In 1996/97, the total volume of coal contracts was 71.7 TWh with an average contract price of 39.2 £/MWh.

7.11 Apart from the long and medium term contracts described above, PESs also enter into shorter contracts, lasting for one or two years, typically to cover the requirements of their non-franchise customers. Over time, the percentage of the market covered by CfDs has varied. For example, in 1996/97, only 88% of the market was covered by such contracts, compared to 97% in 1990/91, as can be seen from Table 5.

TABLE 5 RECs PURCHASES OF CONTRACTS FOR DIFFERENCES, 1996/97

Generator	Electricity contracted (TWh)
National Power	72
PowerGen	70
Nuclear Electric	36
Magnox Electric	16
New entrants	32
Eastern	11
Others	21
Total	258

Electricity Forward Agreements

7.12 In order to attempt to inject greater liquidity into the market, ease trade and tailor cover in response to market fluctuations such as variations in demand, the Electricity Forwards Agreement (EFA) market was established. An EFA functions like a two

³⁵ Manweb was the exception.

³⁶ NORWEB has subsequently disposed of its equity interests in generation.

way CfD with weekly settlement based on the average Pool price. The main difference between an EFA and a CfD is that an EFA is a standard contract traded through a broker.

7.13 EFAs are traded through the broker initiating transactions by matching potential buyers and sellers anonymously over the telephone. Once all the details of the trade have been agreed (price, quantity, period and time frame) the identities of the two parties are revealed to each other. When the two parties accept each other's name, the EFA is in place. It is important that the identity of the two parties is revealed as, unlike exchange based trading, the credit risk associated with the deal is entirely between the two companies, so each must be satisfied that the counter party is financially sound.

7.14 The EFA time periods are illustrated in Table 6. The week is divided into twelve four-hour blocks. The standard contract is for a 1 MW trade in a single block or a cluster of blocks. PPP is generally used as the reference price.

TABLE 6 EFA TIME PERIODS

Time Period	Weekday	Weekend Day
23.00 – 03.00	WD1	WE1
03.00 – 07.00	WD2	WE2
07.00 – 11.00	WD3	WE3
11.00 – 15.00	WD4	WE4
15.00 – 19.00	WD5	WE5
19.00 – 23.00	WD6	WE6

7.15 Some combinations of blocks have become particularly well-established, for example, the so-called "Load Shape 44". This comprises 20 MW of cover throughout the week plus an additional 20 MW of cover during the three weekday daytime periods (WD3 to WD5).

7.16 Since CfDs are used to hedge the bulk of electricity traded through the Pool, EFAs are predominantly seen as fine tuning instruments. Liquidity in the EFA market has developed, see Table 7. In 1996/7 and so far in 1997/8, the volume of EFA trades has grown significantly. However, the physical number of trades has not grown at the same rate i.e. the average size of trades has increased. Some of the growth in volume may be attributed to the actions of traders who trade on the market purely for financial gain without any underlying physical position to support. Thus, the same block of electricity may be traded several times.

Table 7. EFA Trades Involving RECs

Year	Total EFA Cover (TWh)
1994/5	3.48
1995/6	9.15
1996/7	26.30
1997/8	28.64

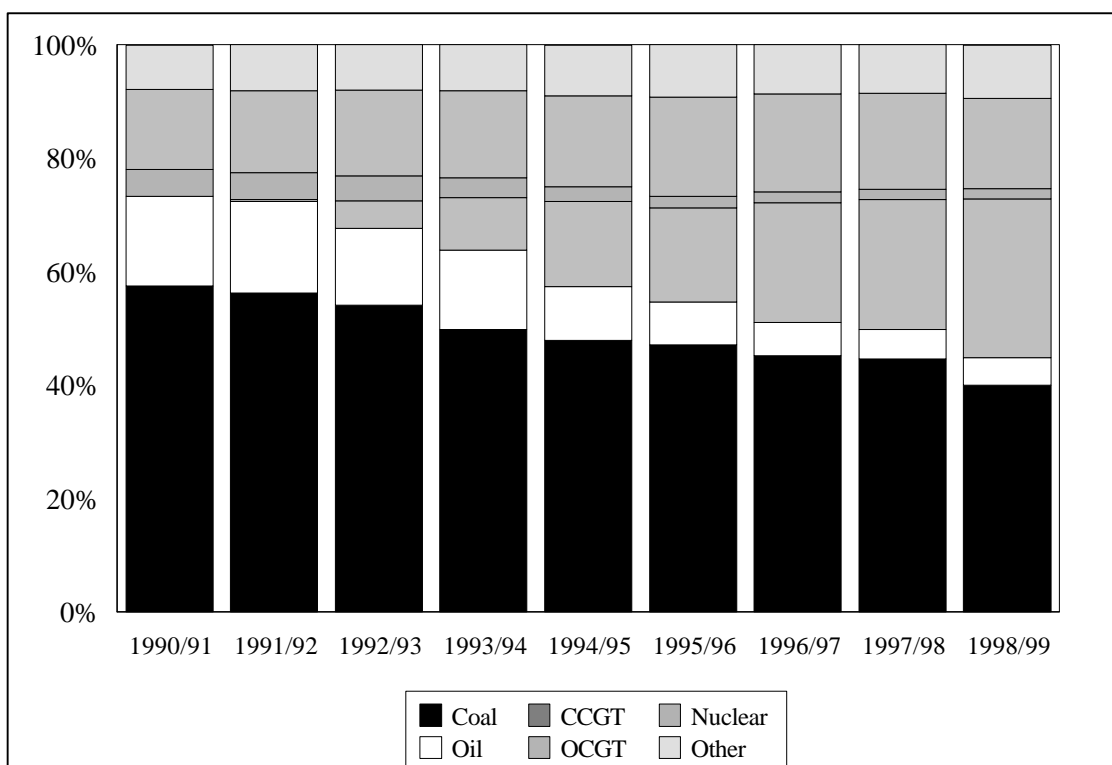
Note: Data for 1997/98 refers to year to date

8. THE DEVELOPMENT OF COMPETITION IN GENERATION

Plant mix

8.1 There has been a significant change in the mix of generation capacity over the past eight years. At Vesting, almost 70% of the total electricity produced was generated by coal-fired plant, and 59% of the installed capacity was coal-fired, see Figures 9 and 10. By 1996/97, the output share of coal-fired plant had reduced to 38%, and its capacity share to 44%.

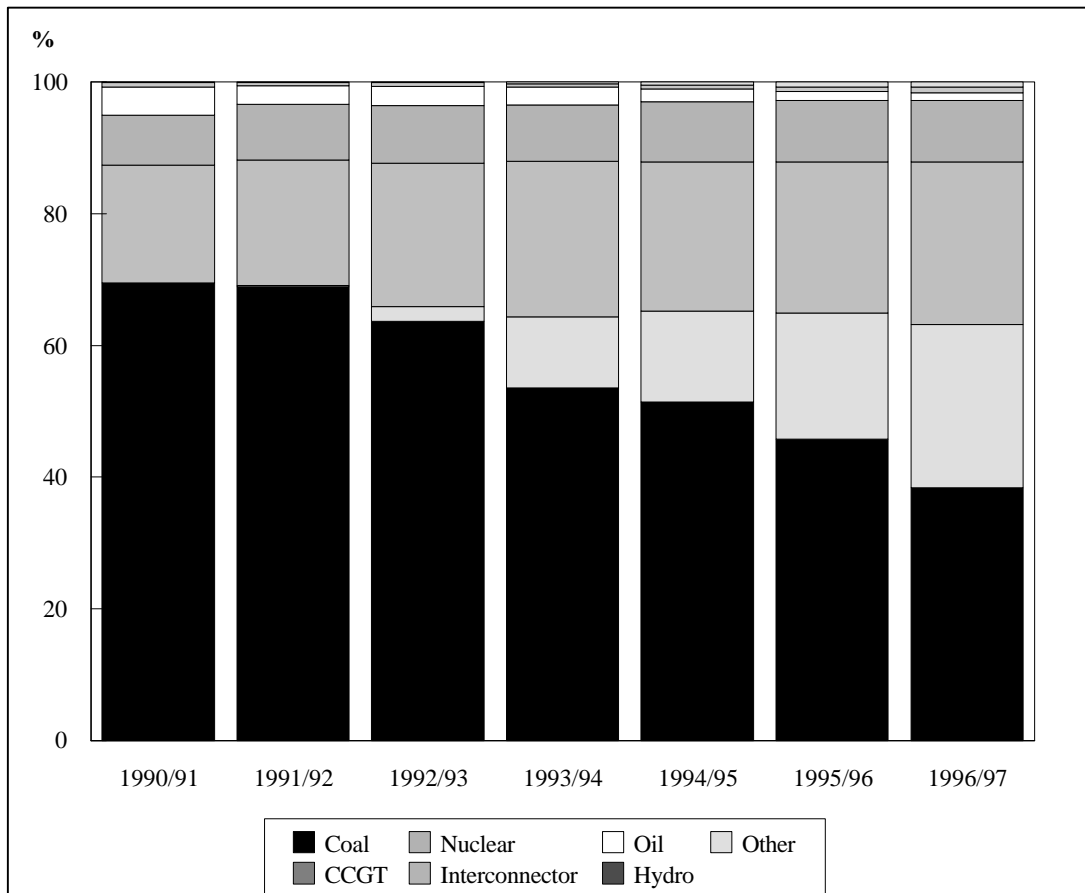
Figure 9. Capacity Share By Fuel Type



Source: NGC Seven Year Statement

Note: Capacities are as at end of financial year indicated.

Figure 10. Output Share by Fuel Type



8.2 The closure, or mothballing, of 9.5 GW of coal-fired generating units and 6.9 GW of oil-fired units has been largely offset by the commissioning of 14.3 GW of CCGTs. No CCGTs were operating in 1990/91 but by 1996/97, they produced one quarter of the total electricity generated. The nuclear stations have also significantly increased their output market share, from 18% in 1990/91 to 25% in 1996/97. This is due partly to improved performance from the existing stations and partly to the commissioning of the 1.2 GW pressurised water reactor at Sizewell B, in 1995.

8.3 Half of the CCGT capacity on the system in 1997/98 (11 out of 20 stations) is owned by new entrants³⁷. Much of their output is covered by long term contracts with PESs (see Chapter 7 for further details). They typically offer zero price bids into the Pool to ensure that they are scheduled. The remaining CCGTs, owned by National Power (4 stations, 22% of CCGT capacity), PowerGen (3 stations, 22% of CCGT capacity) and Eastern (2 stations, 5% of CCGT capacity), also frequently offer low or zero bids because the gas supply contracts for the stations incorporate high take-or-pay levels³⁸.

³⁷ This number excludes two plant, Peterborough and King's Lynn which, although they have separate generation licences, are wholly owned by Eastern. It does, however, include Barking, a station in which Eastern has a 13.5% stake.

³⁸ A contract with a take-or-pay clause imposes an obligation on a generator to pay for a predefined volume of

Market shares

- 8.4 At Vesting, the majority of the generation assets of the CEGB were split between three companies, National Power, PowerGen and Nuclear Electric. Together, they owned over 90% of the total generation capacity³⁹ in England and Wales. Apart from the 3 GW of interconnectors, the only other significant generation capacity was the 2.1 GW of Pumped Storage then owned and operated by the National Grid Company, and since sold (as First Hydro) to Edison Mission Energy in 1995.
- 8.5 The generation market has changed considerably in terms of ownership since 1990. There have been a number of new entrants into the market, the nuclear generator has been split into two separate companies (Magnox Electric and Nuclear Electric), and Eastern has leased divested plant from National Power and PowerGen. Over the same period National Power and PowerGen have closed or mothballed plant so that the total capacity on the system today is very similar to that in 1990.
- 8.6 There are currently 22 companies with centrally despatched generation capacity in England and Wales, of which 12 are new entrants.⁴⁰ The new entrants are owned by a number of different types of company, including REC consortia and international generating companies. Table 8 compares the ownership of capacity in 1990 and in 1998.

Table 8. Capacity by Company

Company	1990		1998	
	GW	%	GW	%
National Power	30.0	47	17.0	27
PowerGen	19.0	30	15.4	25
Eastern	0.0	0	6.7	11
Nuclear Electric	8.7	14	7.3	12
Magnox Electric	0.0	0	3.1	5
New entrants	0.0	0	7.3	12
First Hydro	2.1	3	2.1	3
Interconnectors	2.9	5	3.2	5
Others	0.2	1	.2	1
Total	62.8	100	62.3	100

Note: Nuclear Electric in 1990 relates to the assets of both Nuclear Electric and Magnox Electric. Figures do not add exactly due to rounding.

gas each year whether or not the gas is actually burnt in the power station.

³⁹ Total capacity includes the capacity available through the interconnectors with France and Scotland.

⁴⁰ This number excludes plant wholly owned by Eastern.

8.7 Table 9 compares the share of generation output by company in 1990/91 (the first year after Vesting) with the position in 1996/97. Together, National Power and PowerGen produced 74% of the total electricity generated in 1990/91. By 1996/97, their share had fallen to 46%.

Table 9. Generation Output by Company

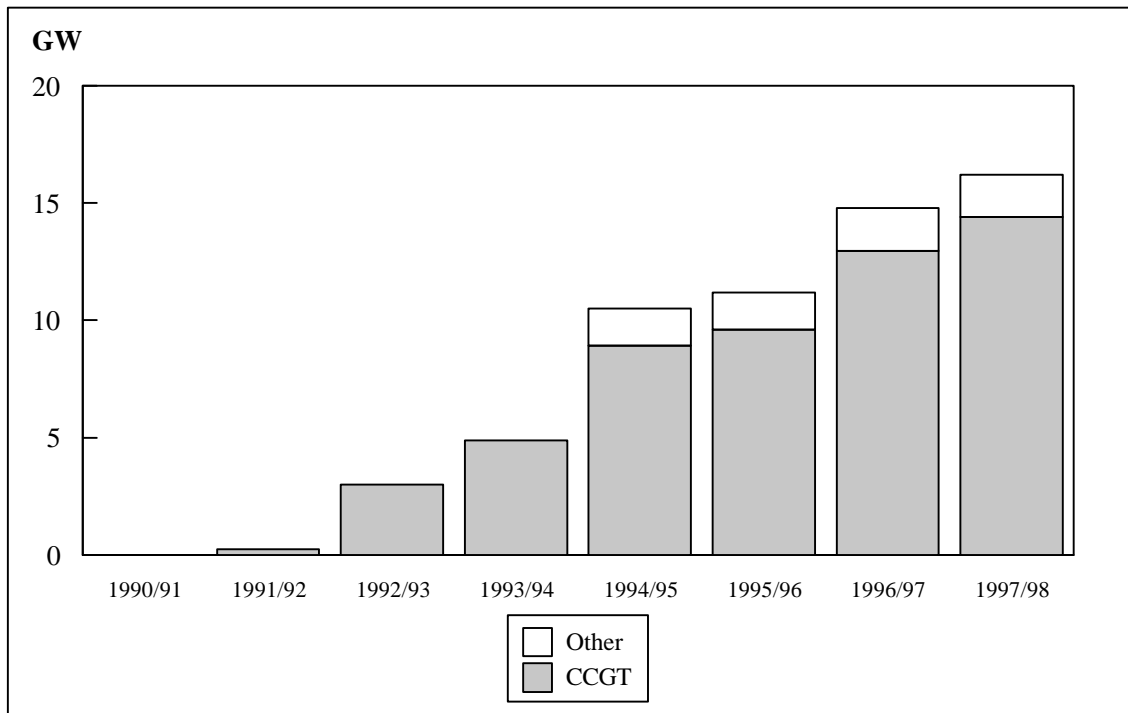
Company	1990/91		1996/97	
	TWh	%	TWh	%
National Power	121.26	45.46	70.17	24.10
PowerGen	75.76	28.40	62.67	21.52
Eastern	0.00	0.00	19.26	6.62
Nuclear Electric	46.51	17.43	50.30	17.28
Magnox Electric	0.00	0.00	20.20	6.94
New entrants	0.00	0.00	37.86	13.00
First Hydro	1.55	0.58	2.18	0.75
Interconnectors	20.32	7.62	27.19	9.34
Others	1.36	0.51	1.31	0.45
Total	266.76	100	291.14	100

8.8 Tables 8 and 9 show that National Power and PowerGen have lost considerable market share in both the capacity and output markets. The new capacity that has entered the market has predominantly operated at high levels of output. This, together with the increase in the output of the nuclear stations has led to increasing competition between plants wishing to operate at high levels of output (known as “baseload”). The only non-baseload new capacity that has been commissioned is the OCGT⁴¹ peaking plant at Indian Queens, although several more plants are under construction which may not operate at baseload. Figure 11 shows the new plant that has entered the market since 1990. In the mid-merit⁴² section of the market the divested plant leased by Eastern from National Power and PowerGen currently provide the main competition to National Power and PowerGen.

⁴¹ OCGT = open cycle gas turbine

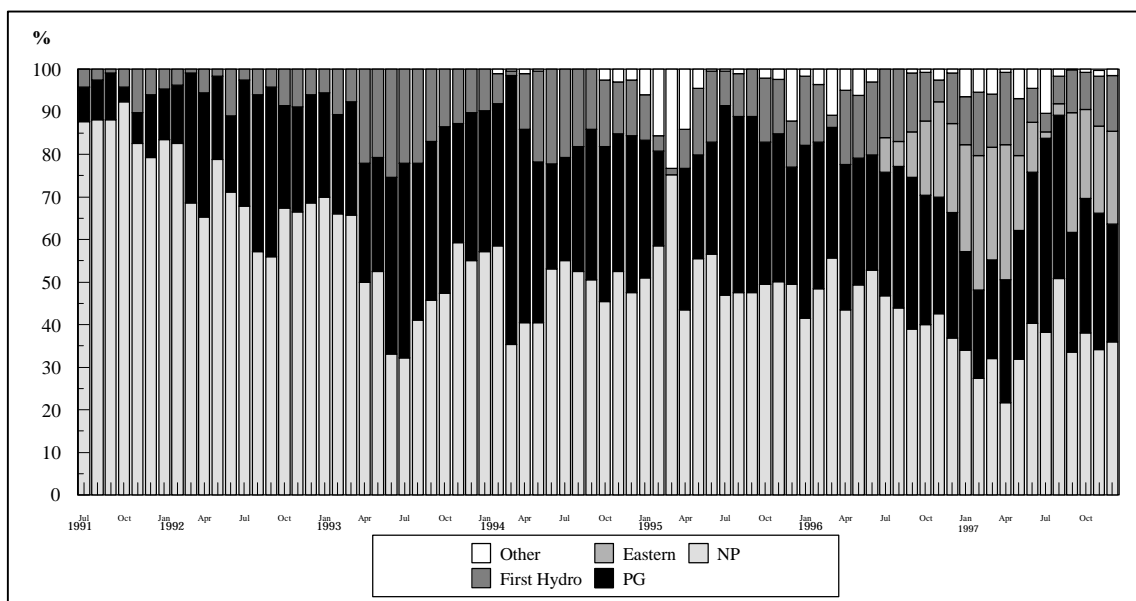
⁴² Mid-merit plant operate at load factors intermediate between baseload plant and peaking plant. The latter are typically taken to operate at load factors of 20% or less.

Figure 11. New Plant Since 1990



8.9 Figure 12 shows, on a monthly basis, the percentage of time that plant owned by National Power, PowerGen and Eastern have set prices. Together, they typically set prices for around 80% of the time. First Hydro generally sets the price (mainly at times of peak demand) for the remaining 10-20% of the time.

Figure 12. Monthly SMP Setting



8.10 Figure 12 shows that whilst National Power and PowerGen have lost over a third of their market share in terms of capacity and output since Vesting, they still set prices for over 65% of the time during calendar year 1997.

Pool price and divestment undertakings from National Power and PowerGen

8.11 In February 1992 the Energy Select Committee recommended that the DGES should take steps to reduce the dominance of National Power and PowerGen and should decide no later than 1995 whether to refer them to the MMC. The DGES announced, in July 1993, that he was bringing forward his decision on an MMC reference.

8.12 In February 1994, the DGES published his decision on an MMC reference. His decision was not to make a reference on the basis that both National Power and PowerGen had agreed to give the following undertakings:

- To each undertake to use all reasonable endeavours to negotiate the sale or disposal of about 4000 MW (National Power) and 2000 MW (PowerGen) of coal-fired or oil-fired generation plant for operation in the England and Wales market within two years.
- To each undertake to bid into the Pool during financial years 1994/95 and 1995/96 in such a way that, under reasonable assumptions of other generators' bids and taking seasonal fluctuations into account, average annual Pool Purchase Price would in normal circumstances reasonably be expected not to exceed 24 £/MWh time weighted and 25.5 £/MWh demand weighted⁴³ (both in October 1993 prices). These figures convert to 27.00 £/MWh and 28.68 £/MWh, respectively, in October 1997 prices.

8.13 The Pool price undertakings were met in both years that they applied.

8.14 In his decision on an MMC reference, the DGES stated that

“the differential between peak and off-peak prices may well need to be greater than at present”.

This view was incorporated in the differential set between the time and demand weighted Pool price caps. Pool prices in 1994/95 and 1995/96 did indeed show a much wider differential in prices, see Table 10, and this peakier profile of prices has been maintained in subsequent years.

⁴³ The demand weighted price is calculated by weighting the price in each period by the demand in that period.

Table 10. Pool Purchase Price (October 1997 £/Mwh)

	Time weighted	Demand weighted	Differential
1990/91	21.57	22.48	0.91
1991/92	24.63	25.58	0.95
1992/93	26.15	26.73	0.58
1993/94	27.56	28.03	0.47
1994/95	26.34	28.95	2.61
1995/96	25.35	28.51	3.16
1996/97	24.59	26.80	2.21
1997/98 ¹	23.58	25.07	1.49
1997 ²	24.79	26.95	2.16

Undertakings

) on Price

Notes: 1. Figures for 1997/98 are for the first nine months, April to December.

2. Calendar year 1997

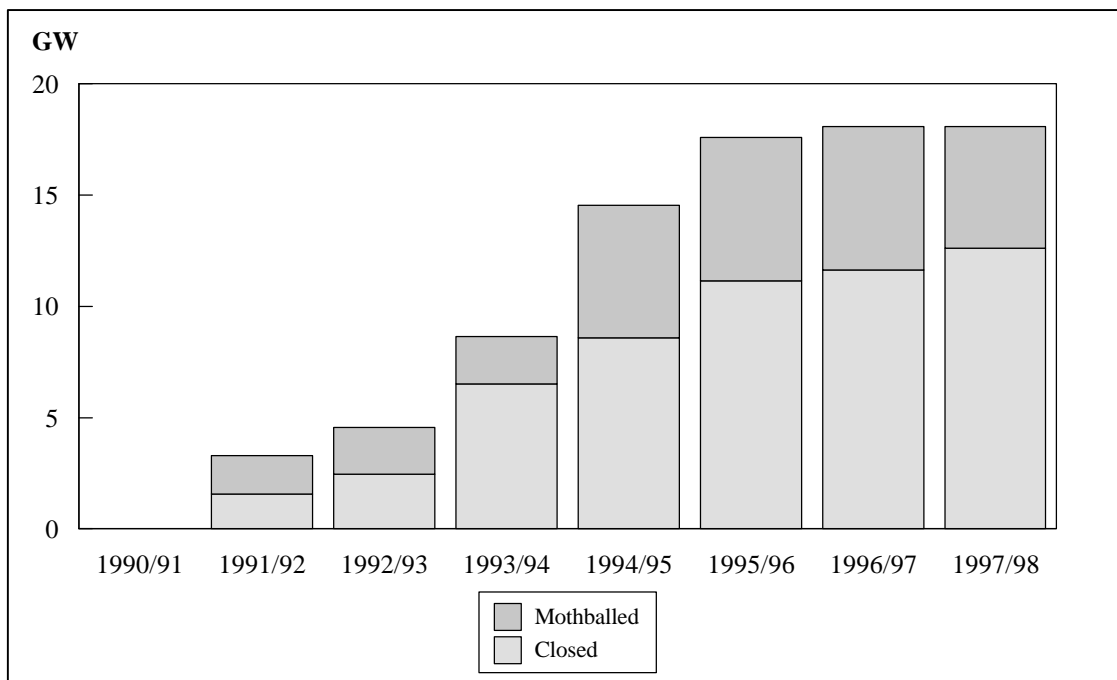
8.15 Consistent with their undertakings to sell or dispose of a total of 6000 MW of coal-fired or oil-fired generation plant, PowerGen announced in September 1995 that it had agreed to lease two stations to Eastern, and National Power announced in April 1996 that it had agreed to lease three stations to Eastern. Eastern commenced bidding the five stations into the Pool in July 1996.

Maintenance and closure programmes

8.16 As a result of the DGES' Pool price investigation in 1991, and in particular the increase in Capacity Payments resulting from plant retirements and lower declarations of plant availability, a new licence condition was agreed with National Power and PowerGen. The condition requires the companies to provide the DGES with a detailed annual forecast of the availability for each of their generating units for the year ahead. At the end of the year, the companies are required to reconcile the actual outturn with the forecast and explain any significant differences. In addition, the condition requires the companies to provide the DGES with the reasons for their decision to close or reduce generating capacity. The DGES may then appoint an independent assessor to report on whether the decisions were reasonable.

8.17 Figure 13 shows the amount of plant that has been mothballed or closed since Vesting. This plant to date has consisted mainly of small and medium sized coal sets, oil fired stations and OCGTs.

Figure 13. Plant Closures Since 1990



Source: NGC Seven Year Statement

Note: Figures are cumulative. Where plant has been mothballed and subsequently closed the capacity has been removed from the mothballed figure.

8.18 In September 1993, National Power and PowerGen announced their first plant closures since the new licence condition was put in place. Following these closure announcements, the DGES appointed an Independent Assessor to examine the whole of National Power and PowerGen's closure programmes. The Assessor concluded that both companies' closure decisions were reasonable.

8.19 In October 1997, the DGES announced the appointment of another Independent Assessor to report to him on the decision of National Power and PowerGen to close generating capacity at three power stations. In his announcement the DGES stated that it was necessary to examine the justification the companies had put forward for their closure and to consider the potential impact on Pool prices

Own Generation limits

8.20 A limit has been placed on each PES's own generation capacity, as shown in Table 11. The DGES can grant consent for a PES to exceed its limit. Own-generation capacities are allocated to PESs in the same proportion as their financial interest in the plant except that when a PES's interest is more than 50%, the entire capacity is allocated to the PES.

Table 11. PES Own-Generation Limits

PES	Limit (MW)	Allocated capacity of plant operating or under construction (MW)	Percentage of limit utilised (%)
Eastern ^(a)	1000	925	93
Midlands	800	686	86
Southern	900	621	69
Northern	500	320	64
SWEB	400	173	43
Yorkshire	800	320	40
SEEBOARD	650	253	39
SWALEC	400	163	41
East Midlands	750	140	19
London ^(b)	700	126	18
NORWEB	750	44	6
Manweb ^(c)	550	3	1
TOTAL	8,200	3,749	46

Notes:

- (a) Excludes the divested plant leased from National Power and PowerGen and the proposed stations at Shotton and Dowlais.
- (b) Excludes the Saltend project being developed by Entergy, the owner of London.
- (c) Manweb is owned by ScottishPower but the Manweb limit excludes ScottishPower's capacity.

8.21 The DGES granted a consent to Eastern allowing it to exceed its own generation limit in respect of the stations it is leasing from National Power and PowerGen. However, the consent restricts Eastern's ability to run the plant at baseload, and does not allow Eastern's supply business to enter into new contracts with the leased plant.

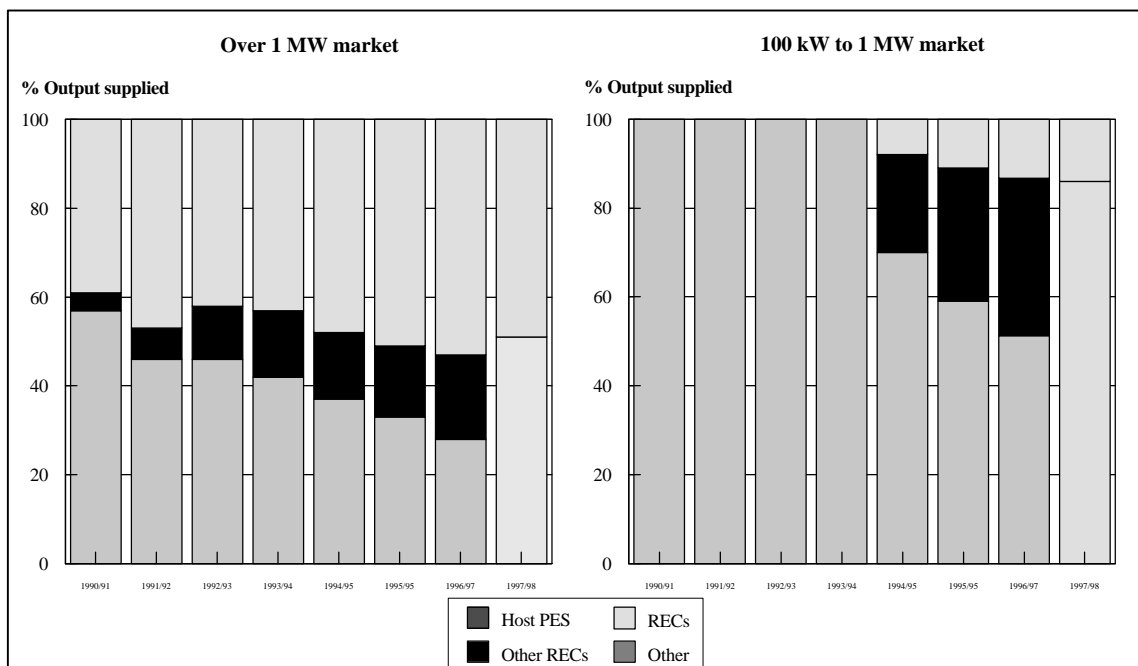
9. THE DEVELOPMENT OF COMPETITION IN SUPPLY

9.1 At Vesting licence conditions provided for the phased introduction of competition in supply. Customers with a maximum demand over 1 MW have been able to choose their electricity supplier since Vesting. Choice was extended to customers with a maximum demand over 100 kW (0.1 MW) from 1 April 1994. From the autumn of 1998, a similar choice will be extended to all electricity customers, including some 26 million households and small businesses.

Market shares

9.2 In England and Wales, there are about 50,000 customers in the competitive market at present, of which approximately 5,000 have a maximum demand over 1 MW. In 1996/97, more than half of the over 1 MW sites (72% by output) and over one third of the over 100kW sites (48% by output) chose a supplier other than their host PES. As Figure 14 shows, there has been a steady growth in the uptake of second-tier supply.

Figure 14. Shares in the Competitive Supply Market



Note: In 1997/98 data refers to RECs acting as first and second tier supplier.

9.3 The “other” category of suppliers comprises National Power, PowerGen, Nuclear Electric, ScottishPower, Hydro-Electric and other independent suppliers, including customers who have chosen to become second tier suppliers and purchase their electricity directly from the Pool. Since Vesting, on average, National Power has supplied 16% by output and PowerGen 20% by output of customers in the over 1 MW market. For example, in 1996/97 their market shares were 17% and 23%,

respectively. However, in the 100 kW to 1 MW market, the aggregate market share of all non-PES suppliers was only 13% in 1996/97.

- 9.4 Table 12 provides an estimated breakdown by company of the market shares achieved in the competitive supply markets in 1996/97 and 1997/98. Three PESs – Eastern, Yorkshire and Southern – have consistently accounted for market shares of over 5% in both segments of the market. In the 100 kW to 1 MW market, this may, in part, reflect that the authorised areas of each of the companies contains a higher than average number of customers in this category. Only three PESs – SWALEC, SWEB and Manweb - have not achieved a 5% market share in either category in at least one of the two years for which data are shown.

Table 12. Estimated Shares In The Competitive Supply Market By Output (%)

Company	> 1 MW market		100 kW – 1 MW market	
	1996/97	1997/98	1996/97	1997/98
National Power	17	13		
PowerGen	23	19		
Nuclear Electric		6		
Eastern	8	14	15	12
Yorkshire	8	7	12	9
London			12	10
Southern	5	7	9	12
Midlands				7
Northern			9	11
East Midlands			6	6
SEEBOARD			6	6
NORWEB	5	5		5
Other PESs	20	18	18	8
Other	14	11	13	14

Notes:

1. The table identifies any company with a market share of 5% or more. The remaining companies market shares are aggregated.
2. The market shares for PESs include first-tier supply.

Extension of competition

- 9.5 Responsibility for delivering the arrangements for domestic supply competition rest with several different parties. The Electricity Pool has responsibility for the trading arrangements to enable suppliers and generators to settle accounts in the Pool. The two Scottish PESs have similar responsibilities for the trading arrangements in

Scotland. These arrangements include a system of standard demand profiles so customers below 100 kW will be able to change supplier without the need to have a half-hourly meter installed. PESs have both individual and joint responsibilities for providing various services and processes to facilitate the competitive market. OFFER has responsibility for promoting competition in supply and protecting customers in respect of prices and quality of supply.

Supply price controls

9.6 Until 1 April 1998, the PES supply licences contain a supply price control that regulates the average price chargeable to franchise customers. During 1998/99 and 1999/2000, the licences will contain a maximum price restraint relating to domestic and small business customers.

9.7 No specific restraints have been placed on PESs contractual arrangements. However, the DGES has said that contractual arrangements would be likely to need further investigation if:

- More than a quarter of a PES's total electricity purchases were contracted to a single major generator under margin-sharing arrangements of more than five years' duration; or
- More than half of a PES's total electricity purchases were contracted to a single major generator under arrangements of any form, excluding contracts signed following an anonymous process or in an auction; or
- A generator's aggregate contract with suppliers of more than three years' duration exceeded 10% of the total generation market in England and Wales.

10. ELECTRICITY AND GAS MARKET INTERACTIONS

10.1 Interactions between the gas and electricity markets are increasingly significant particularly because of the growth of CCGTs since Vesting. Gas market interruptions, for supply or transportation reasons, can affect the supply of fuel to power stations and hence their ability to generate electricity. Furthermore, arbitrage between the gas and electricity markets is now easier following the introduction of daily balancing in the gas market.

Gas fired generation

10.2 Presently, there is over 14 GW of CCGT capacity trading through the Pool, accounting for over 23% of installed capacity in England and Wales and 39% of total electricity generation in the Pool. A further 3 GW is under construction and is expected to be generating by 2000. In 1997/98, gas consumption in power stations is expected to account for around 30% of the total gas use in the UK.

Gas supply interruptions

10.3 Gas contracts with customers, including power stations, are typically either interruptible or firm. An interruptible contract allows the gas supply to be interrupted for up to a specified maximum number of days per year. Interruptions can either be on supply or transportation grounds. Some contracts permit one type of interruption while others permit both.

10.4 A supply interruption occurs when the gas shipper⁴⁴ chooses to sell the gas elsewhere in the market to obtain a higher price or to divert supplies to another customer. A transportation interruption occurs when Transco, which owns and operates the main gas transportation system, interrupts supplies either because of a specific transmission constraint or because the gas supplies are approaching the design capacity of the system due to very high demand levels. Transco's standard interruptible transportation terms give it the right to interrupt supplies for up to 45 days. Power stations with interruptible contracts have had their gas supplies interrupted on a number of occasions in January 1996, November 1996, January 1997 and December 1997.

10.5 The interruption of a power station's gas supply, whether for supply or transportation reasons, will be driven principally by conditions in the gas market rather than those in the electricity market. If a gas-fired power station's supplies are cut off, a generator may be able to choose whether to generate with a substitute fuel, typically

⁴⁴ Gas shippers purchase gas from producers or wholesalers and sell it to suppliers who, in turn, sell it to customers. Gas shippers are responsible for organising the transportation of the gas to the suppliers' customers. Shippers may also act as suppliers.

gasoil. However, some gas-fired power stations do not have the capability to use a back-up fuel. In the case of a supply interruption, the generator may also be able to purchase a replacement gas supply.

Trading arrangements

10.6 The “on the day” markets in electricity and gas are very different. To some extent this reflects the physical differences between the two fuels, but it is also a result of the market mechanisms in the two markets having been developed largely independently of each other. Table 13 summarises the main differences between the price setting mechanisms in the two markets.

Table 13. Summary of Price Setting Mechanism Differences

	Electricity	Gas
Settlement pricing:	marginal	marginal and average
Settlement period:	half-hour	one day
Principle settlement prices calculated:	in advance	retrospectively
Scheduling day start time:	5 a.m.	6 a.m.

10.7 The gas system is not centrally despatched. Instead, shippers are responsible for balancing their own gas inputs to the system with the demand of their customers. The system operator, Transco, monitors the balance of the system throughout the day. If it forecasts that gas pressures will move outside acceptable limits it invokes centralised system balancing measures, principally the flexibility mechanism⁴⁵.

10.8 If the flexibility mechanism is invoked, shippers’ flexibility bids are selected according to price and used to generate settlement prices. The settlement period covers 24 hours starting from 6 a.m. Prices are calculated retrospectively according to the bids selected during the day. Three daily settlement prices are calculated: a volume-weighted average price of the selected bids (System Average Price, SAP), and two marginal prices one for gas purchases by Transco (SMP Buy) and the other for gas sales (SMP Sell). Shippers are only exposed to the settlement prices to the extent that they are out of balance. Small imbalances are cashed out at SAP whilst the balance of large imbalances are cashed out at the appropriate SMP, SMP Buy for under-deliveries and SMP Sell for over-deliveries.

10.9 In the electricity market, generators must submit price and availability bids by 10 a.m. on the day preceding the scheduling day. They can subsequently alter their availability bids, but they cannot change their price bids. Thus, if a plant changes its fuel after it has submitted its bids, it is unable to adjust its bids accordingly. In the

⁴⁵ The flexibility mechanism is a screen-based system in which shippers are able to place bids to buy gas from or sell gas to Transco.

gas market, flexibility bids cannot be changed once posted, but non-selected bids can be withdrawn and replaced with different priced bids at any point in the day.

Arbitrage

10.10 Arbitrage is the process of trading a commodity between two (or more) markets to take advantage of a price differential. In the context of the wholesale gas and electricity markets, the owners of gas-fired generating plant may choose to sell their gas into the gas market rather than burning it to generate electricity. However, the plant may be able to continue generating using a substitute fuel.

10.11 Since the Pool is a day-ahead market, electricity generators know by 16:00 what Pool prices will be for the following day and their unconstrained schedule of production. At this stage, therefore, generators who can arbitrage between the two markets are in a position to calculate their optimal strategy. They can calculate the opportunity cost of not generating and then decide whether to seek to sell their gas through an OTC trade, post a bid in the flexibility mechanism or sell gas through the cash-out mechanism by over-delivering. If the gas is sold, the generator re-declares his availability downwards and foregoes Pool revenues in return for higher revenues from the gas market.

10.12 If the plant has a back-up fuel supply, the generator will also have to decide whether to continue generating using the substitute fuel, typically gasoil. The decision will depend on the level of expected or published Pool prices relative to the cost of generating using the substitute fuel, and the generator's contractual position. Typically, if gas prices are high, Pool prices will also be high so continuing generating will be an attractive option. In making this decision, the generator will also have to take account of emissions constraints. Gasoil produces more sulphur dioxide than natural gas and hence a gas-fired plant may not be able to burn as much substitute fuel as it would otherwise wish to do.

10.13 The demand for both electricity and gas shows strong seasonal and diurnal variations. However, the diurnal variation in gas demand is, to a significant extent, smoothed out by the gas storage available within the gas transmission and distribution networks, known as linepack. Thus gas can be injected into the transmission network in advance of a peak in gas demand. This is in contrast to the electricity system in which generation and demand have to be matched continuously. Consequently, a power station which can arbitrage may be able to help meet both the gas and electricity demand peaks. In principle, it could sell-on its gas early in the day and then switch to generating electricity over the electricity demand peak.

10.14 Power stations that have interruptible contracts are unlikely to be able to benefit from arbitrage since it is likely that their supplies will be interrupted at the times that arbitrage would be profitable. Furthermore, the terms of some supply contracts prohibit the re-sale of gas and hence explicitly prevent arbitrage.

10.15 Full daily balancing was only introduced in the gas market in September 1996.

Consequently, there has been little time for arbitrage to develop and to date there is little evidence to suggest that arbitrage between the two markets is commonplace.

Electricity market considerations

- 10.16 The impact on the electricity market of a generator choosing to sell-on its gas or having its gas supply interrupted will depend on whether the plant continues to generate with a substitute fuel. If it does, there will be no effect on SMP or Capacity Payments on the day. SMP may increase on subsequent days of interruption/arbitrage if the plant increases its bids to reflect the higher costs of the substitute fuel. Capacity Payments will only be affected if the plant is unavailable for seven days or more. This is because these payments are calculated on the basis of the maximum availability of the plant over the preceding seven days. However, temporary Pool rules in force over the winter of 1996/97 allowed plant to reclaim the additional costs of burning back-up fuels under certain circumstances. On the day Uplift may have increased as a result.
- 10.17 Even if the plant chooses to stop generating, in the short term there will be no effect on SMP or Capacity Payments. If the interruption/arbitrage persists, SMP will rise as more expensive capacity will be scheduled to replace the withdrawn plant.
- 10.18 A downwards re-declaration by a plant will generally result in a replacement plant being scheduled and this will increase Energy Uplift. This will increase electricity suppliers purchase costs and may ultimately lead to an increase in the prices paid by customers. However, downwards re-declarations will not always increase Uplift. For example, if the demand forecast happened to be over-estimated, generation would normally have to be constrained-off and payments made accordingly. The withdrawal of gas-fired generation could be a substitute for constraining-off plant. In this case, Energy Uplift would decrease.
- 10.19 The Pool, from 1 November 1997, introduced a temporary penalty mechanism for gas-fired plant which reduce their availability by more than 15% during times when the electricity system is under stress, i.e. when NGC issues a High Priority Notice of Inadequate System Margin (HPNISM). If the Pool price is less than 30 £/MWh, gas generators who reduce their availability have to pay 20 £/MWh for their availability reduction. In parallel with this mechanism, the Pool also introduced a temporary process whereby the Grid Operator can call on demand reduction during periods of HPNISM. Parties providing such demand reduction would be paid for providing the service.
- 10.20 Over the longer term, both Capacity Payments and Ancillary Service payments may be increased as a result of interruptions and arbitrage. Capacity Payments could increase if plant are treated as less reliable in the LOLP calculation as a result of their downwards re-declarations. Ancillary Service payments could rise if NGC decides that a higher level of reserve is required as a result of the lower reliability record of the plant.

10.21 Recent initiatives have resulted in a greater exchange of information between Transco and NGC on the likelihood of gas interruptions

APPENDIX 1 – TIMETABLE

February	Publication of OFFER background papers on (a) present electricity trading arrangements in England and Wales and related issues and (b) electricity trading arrangements in other countries
February 23	Explanatory workshop on issues raised in the background papers
March	Publication of the OFFER working papers on trading arrangements both inside and outside the Pool
March 30	Explanatory workshop on the trading arrangements models
Early April	Publication of third party working papers on electricity trading arrangements
April 14	Explanatory workshop to discuss the third party working papers
15 & 16 April	Two day seminar to consider possible models for electricity trading arrangements both within and outside the Pool
Early June	Publication of interim conclusions
15 & 16 June	Seminar on interim conclusions
July	Publication of final report to Minister on conclusions and recommendations