REVIEWS OF
PUBLIC ELECTRICITY SUPPLIERS
1998 to 2000

PRICE CONTROLS AND COMPETITION

CONSULTATION PAPER

JULY 1998

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CONTENTS

FOREWORD

In February 1998, I published a consultation paper "Reviews of Public Electricity Suppliers 1998 to 2000". This outlined issues that will need to be considered as part of the programme of work and reviews envisaged for the 14 public electricity suppliers (PESs) over the next two years. The programme of work has the following eight main components, which have significant inter-relationships between them:

- distribution price control;
- quality of supply standards;
- competition in supply;
- separation of activities;
- metering and meter reading;
- regulatory accounts;
- prepayment meter customers; and
- Scotland.

In May, I issued a consultation paper on the separation of PES businesses. This set out my initial thinking on future arrangements for separating the present PES activities of distribution, metering and meter reading, and supply; and in Scotland, transmission.

The present consultation paper deals with price controls and competition. It covers the following areas of work:

- distribution and metering price controls;
- quality of supply standards;
- competition and supply price restraints;
- Scottish transmission price controls; and
- prepayment meter customers.

The reviews will cover a wide range of issues, which are described in the following Chapters. These develop the work programmes outlined in the February consultation paper, and reflect also the views of respondents and proposals in the Government's Green Paper on utility regulation. The purpose of this consultation paper is to inform interested parties about the proposed approach to the various reviews, and about the main considerations likely to be relevant, and to seek views on these matters.

Over the next few months, I aim to publish papers on regulatory accounts and on the development of trading arrangements in Scotland. I will also want to meet all the PESs and discuss with them issues raised in the consultation paper on separation of businesses, before publishing a further paper on this subject.

Later in 1998, I intend to publish information derived from the business plans which I am asking each PES to prepare. This will include their projections of distribution operating and capital costs over the period to about 2005. Then I intend to publish a paper on quality of supply issues which will consider the implications for quality of supply of the companies' plans, possibilities for setting new or tighter Standards of Performance on supply quality, and the possible implications for companies' costs and for prices. As the review progresses the intention is also to publish one or more further papers on the issues emerging from the price control reviews. Draft price control proposals will be published in the summer of 1999 for comment by the companies and others, and final proposals in the early autumn.

I should like to hear from all those with an interest in these issues, including customers, their representatives and other interested groups as well as the companies themselves and other suppliers. Views are invited by 25 September 1998 on the matters raised in this paper, including issues to be covered, appropriate approaches, relevant information and any other aspects of interest or concern. These comments should be sent to:

Mr Cemil Altin
Regulation and Business Affairs
OFFER
Hagley House
Hagley Road
Birmingham
B16 8QG

Fax: 0121 456 6361
Telephone: 0121 456 6262

Responses will be published by placing them in the OFFER library.

PROFESSOR S C LITTLECHILD
Director General of Electricity Supply

July 1998

1 INTRODUCTION

1.1 This Chapter explains how the various issues in the paper relate to each other, and sets them in the context of other relevant developments in the industry.

1.2 In the period since the last distribution price control review in 1995, there has been considerable change in the electricity industry. In some important respects, the PESs are a more diverse group today than was the case five years ago.

1.3 There have, for example, been significant changes in ownership. Of the 12 PESs in England and Wales, eight (Eastern, East Midlands, London, Midlands, Northern, SEEBOARD, South Western and Yorkshire) are now owned by US electricity companies; two (NORWEB and SWALEC) by UK-based water companies; and one (Manweb) by ScottishPower. Southern Electric, and the two PESs in Scotland, remain independent. East Midlands has recently been the subject of a take-over bid by PowerGen, and there may be further changes in ownership in the future.

1.4 There have also been significant changes in the way that many of the PESs structure their business, and the range of activities in which they are involved. For example, several PESs have developed very active second tier supply businesses. Eastern now has substantial generation interests, and is in fact the fourth largest generator in England and Wales. Most PESs are now active in the supply of gas as well as electricity. This provides opportunities for joint marketing of the two fuels. Some PESs also have telecommunications licences. On the other hand, most PESs have now withdrawn from appliance retailing, though some such as ScottishPower remain active there. Both NORWEB and SWALEC have merged their customer service operations with the corresponding operations of their parent water company. Hyder (the parent company of SWALEC) has recently begun to merge the operational functions of its water and electricity businesses.

1.5 Against this background, Chapter 2 contains information on the businesses and activities of the PESs, including the main developments since the last price control review. In earlier years there had been some public concern about profits and prices; later there was some concern that PESs were able to increase dividends significantly and finance share buybacks, and about the high prices which bidders have been willing to pay to acquire PESs. Chapter 2 shows that the tighter distribution price controls introduced by OFFER in 1995 and 1996 have led to reductions in costs and profits. Since 1994/95, average distribution charges have fallen by about 25 per cent in real terms, and average electricity prices to domestic customers by about 15 per cent in real terms.

1.6 Chapter 3 considers issues related to the review of the existing distribution price controls which run until the end of March 2000. In responding to the February consultation paper[1] a number of PESs stressed that the analysis of operating costs and capital expenditure requirements should identify relative efficiency, treat companies on

[1] OFFER "Reviews of Public Electricity Suppliers 1998 to 2000 Consultation Paper" February 1998

a consistent basis, and take account of the operating conditions in each area. The Electricity Consumers Committees (ECCs) emphasised the need for a detailed assessment of future capital expenditure requirements. A number of PESs argued against reconsidering distribution business asset valuation as part of the review, arguing it would increase perceptions of risk and so increase the cost of capital. All these issues will be considered as part of the review. The review will also need to consider the form, scope and duration of the control. Those respondents that commented favoured an RPI-X control.

1.7 The distribution price control review will provide the opportunity to consider issues associated with metering and meter reading services. These have hitherto been part of PES distribution businesses. The consultation paper on the separation of PES businesses[2] envisaged competition in the provision of these services, and the separation of metering from distribution. It will be necessary to make separate calculations of the costs of these services, and, depending on the prospects for increasing competition in metering, consider a separate price control on PES charges for metering and related services. In response to the February consultation paper a number of PESs suggested that any price controls placed on metering activities should be set in such a way as to protect PESs from stranded costs. Other respondents stressed the importance of encouraging competition.

1.8 Chapter 4 considers issues relating to the quality of supply delivered by PES distribution networks. An important aspect of the distribution price control review will be to assess what levels of expenditure are required to maintain the PES distribution networks, and to invest in replacing and upgrading them. To do this, it is necessary to take a view about the level of performance of the networks and the extent to which customers might be prepared to pay more for more reliable networks. In responding to the February consultation paper the majority of ECCs highlighted the importance of considering issues relating to quality of supply. PESs suggested that if enhanced quality of supply targets are put in place then any associated capital and operating expenditure should be taken into account in setting the price control.

1.9 Chapter 5 concerns competition in supply. Competition in supply has continued to develop for larger customers, with 63 per cent of over 1 MW customers in England and Wales and 41 per cent of 100 kW to 1 MW customers now taking second tier supply. The proportions in Scotland are smaller at 27 per cent and 18 per cent respectively. The supply market for smaller customers will open to competition over the period from September 1998 to about June 1999.

1.10 There are increasing concerns that the future growth of competition in supply and in metering services may be hindered by the present close association of PES supply and distribution businesses. This gives scope for cross-subsidy, discriminatory treatment and anti-competitive flows of information, which may disadvantage competitors and customers. OFFER's recent consultation paper on separation of PES businesses proposed that steps should be taken to bring about full managerial and operational

[2] OFFER "Reviews of Public Electricity Suppliers 1998 to 2000 Separation of Business Consultation Paper" May 1998

separation of the two businesses. It also proposed greater separation between distribution and metering, including prohibitions on cross-subsidy between them. The Government's Green Paper[3] on utility regulation has proposed that the present PES licence should be replaced by separate licences for distribution and supply. This would open the way for these activities to be in separate subsidiary companies or in separate ownership. The price control reviews will need to take account of the implications of separation of PES activities. They will need for example to consider which costs are appropriately associated with each business.

1.11 The present restraints on PES supply charges apply to domestic and small business customers, and run to March 2000. All these customers will be better protected by competition than by price restraints. However, competition for these customers may take time to develop. Deciding whether and if so how to continue price restraints requires an assessment of the present and prospective development of competition for smaller customers. It also involves considering whether continued price restraints might adversely affect the development of competition. In responding to the February consultation paper a number of ECCs stressed the importance of a detailed assessment of the development of competition. Other respondents argued that there should be no presumption that price restraints will be needed after the year 2000.

1.12 The distribution and supply price control reviews and related work will cover Scotland as well as England and Wales. In addition, it will be necessary to review and reset the price controls on the transmission businesses of the two Scottish PESs. These transmission businesses share some activities with the companies' distribution businesses. The consultation paper on separation of PES businesses argued for further separation of transmission in Scotland, as in England and Wales. The price control reviews will need to consider how shared costs of transmission and distribution should be dealt with. Chapter 6 considers issues relating to the Scottish transmission price controls.

1.13 Particular consideration needs to be given to how best to protect disadvantaged customers, particularly prepayment meter customers. These issues are described in Chapter 7. This will include consideration of the surcharges paid by prepayment customers, the extent to which such surcharges are justified by higher costs associated with prepayment systems, and possibilities for reducing or eliminating the surcharges. These aspects of the distribution and supply reviews are important components of the Action Plan[4] on disadvantaged customers which OFFER and OFGAS have drawn up in response to proposals in the Government's Green Paper on utility regulation. Most respondents to the February consultation paper welcomed the review of arrangements for prepayment meter customers.

[3] DTI "A Fair Deal for Consumers Modernising the Framework for Utility Regulation" CM3898 March 1998
[4] OFFER "The Social Dimension: Action Plan OFFER and OFGAS Proposals" June 1998

2 BACKGROUND

PES Structure

2.1 There are 12 PESs in England and Wales, which are sometimes called Regional Electricity Companies (RECs), and two PESs in Scotland. Each PES carries out two core activities, distribution and supply. Most have interests in generation, carried out as a separate business. PESs may undertake other activities which in general are not regulated by OFFER. Where PESs have been taken over and have become parts of larger groups, licence conditions have been put in place that limit the scope of the other activities carried out by the PES itself. In Scotland, the two PESs have substantial generation and transmission businesses as well as supply and distribution businesses.

2.2 Each PES owns and operates the electricity distribution network in its authorised area. This network transfers power from the transmission system to customers' premises. Distribution is a capital intensive activity. Most of the distribution services provided by PESs, such as use of system, are not subject to competition and distribution charges are subject to price control. However, there is scope for competition in the provision of certain distribution services, such as metering and connections to the network.

2.3 The supply business purchases electricity from generators and traders, pays distribution and transmission use of system charges on the electricity it sells to its customers, and provides customer service functions such as billing and account handling. The supply business is a trading activity rather than capital intensive activity, and a high proportion of its turnover goes toward purchasing generation and paying use of system charges.

Distribution

2.4 In England and Wales the NGC transmission system, operating at 400kV and 275kV, transports electricity from generating stations to PES distribution systems at grid supply points. The initial stage of distribution is generally at 132kV. Towards the centres of demand, transformers are used to reduce distribution voltage in stages. In Scotland the situation is slightly different. There the transmission systems of the Scottish companies operate at 400kV, 275kV and 132kV, and the distribution systems at lower voltages. Most customers are supplied at low voltage (LV), which is defined as a voltage less than 1kV, with domestic customers being supplied at 230V. Business customers are sometimes supplied at high voltage (HV), which is defined as a voltage greater than 1kV.

2.5 The distribution systems consist of overhead lines, cables, switchgear, transformers, control systems and meters to enable the transfer of electricity from the transmission system to customers' premises. While there are many similarities between the distribution systems which PESs operate, there are some significant differences. For example, companies vary in size (in terms of area or the number of customers or the quantities of electricity distributed), in the degree to which their customers are scattered

in rural areas or concentrated in urban areas, in the extent to which they have larger customers who may take supply at higher voltages rather than requiring it to be transformed to a lower voltage, as well as in other ways. The following Table summarises some of the characteristics of the distribution networks, indicating their differences in size and technical character.

TABLE 1: PES DISTRIBUTION NETWORKS - 1996/97

PES	Area sq km	Customers (000s)	Circuit length km	Percentage of circuits underground	Quantity distributed LV (GWh)	Quantity distributed HV (GWh)
Eastern	20,300	3,222	88,686	60	23,069	7,293
East Midlands	16,000	2,300	67,678	64	14,783	10,273
London	665	1,969	29,957	100	16,880	4,236
Manweb	12,200	1,371	44,901	52	9,138	4,251
Midlands	13,300	2,200	63,431	59	14,358	9,938
Northern	14,400	1,442	43,211	60	9,161	3,646
NORWEB	12,500	2,190	59,345	75	14,640	7,774
SEEBOARD	8,200	2,071	44,912	72	14,359	3,001
Southern	16,900	2,622	72,245	60	19,525	6,929
SWALEC	11,800	970	32,135	42	5,973	2,435
South Western	14,400	1,308	47,817	39	9,733	3,226
Yorkshire	10,700	2,060	54,644	71	12,841	8,148
ScottishPower	22,950	1,800	65,218	60	14,573	5,074
Hydro-Electric	54,390	640	44,669	31	6,311	1,304
Average	16,366	1,869	54,204	60	13,239	5,538

2.6 At Vesting, the Government put in place initial price controls on the distribution businesses for a period of five years which typically allowed for increases in distribution charges in real terms. Over the period of these initial controls PESs proved able to cut their costs and the RECs in particular increased their profits significantly. OFFER introduced revised distribution price controls for England and Wales in 1995 and 1996, which required cuts in real terms of 11 to 17 per cent in distribution charges in 1995/96 and further reductions in real terms of between 10 and 13 per cent in 1996/97. Thereafter, distribution charges were required to fall by 3 per cent per year in real terms for the duration of the price control (until March 2000). In Scotland, a revised price control was implemented in 1995 which required an initial real reduction in distribution charges of 0.3 per cent for one company and 2 per cent for the other and further cuts of 2 per cent per year in real terms for both companies for the duration of the price control. As from 1998/99 their licences require all PESs to provide additional services to facilitate competition in supply, and enable them to make additional distribution charges to reflect this. The present price control is set out in Condition 3 of the PES licences for companies in England and Wales and in Schedule 6 of the PES licences for the Scottish companies.

2.7 The price controls place an obligation on PESs to set charges so that regulated distribution revenue does not exceed a maximum level. This maximum level is determined, subject to certain adjustments, by multiplying allowed average revenues per kWh distributed and per customer, which are specified in the price control, by the actual number of kWh distributed and a projection (made when the control was set) of the number of customers. There is a correction factor for under- or over-recovery of revenue in previous years. If actual revenue in any year turns out to be greater than that allowed under the price control (ie an over-recovery), a reduction is made in the following year's allowed revenue. Similarly, allowable revenue in the following year is increased in the event of an under-recovery. Under- and over-recoveries are subject to maximum levels, which are set out in the PES licence.

2.8 At present distribution price control revenue covers most distribution business functions, including metering. Metering itself encompasses a range of activities including meter ownership, meter reading, meter installation and data aggregation. The separation of businesses consultation paper proposes that in future these activities should be separated from other distribution functions.

2.9 There are different distribution use of system (DUOS) charges for different categories of customers, reflecting a range of factors, such as the voltage at which they take supply. Typically the charges for each group of customers have two elements: a fixed standing charge and a unit rate charge. Table 2 shows for each PES the DUOS charges applying on 1 April 1998 to customers on standard domestic tariffs, and the average and total charges for a customer with a typical demand of 3,300 kWh per year. These charges are made by the PES distribution businesses to suppliers, who are at present the PES supply businesses in the case of domestic customers. In future, domestic customers will be able to choose their competitive supplier, as larger customers already can. It is for suppliers to consider how to reflect these use of system charges in their prices to customers.

TABLE 2: DISTRIBUTION USE OF SYSTEM (DUOS) CHARGES FOR DOMESTIC CUSTOMERS (1 APRIL 1998)

PES	DUOS Standing Charge (£ per year)	DUOS Unit Rate (pence per kWh)	Average DUOS Charge (pence per kWh) (1)	Total DUOS Charge (£ per year) (1)
Eastern	14.24	1.37	1.80	59.45
East Midlands	23.00	1.50	2.20	72.50
London	28.80	1.42	2.29	75.66
Manweb	31.06	1.78	2.72	89.80
Midlands	26.50	1.34	2.14	70.81
Northern	18.76	1.91	2.48	81.79
NORWEB	32.60	1.44	2.43	80.12
SEEBOARD	18.47	1.48	2.04	67.31
Southern	26.97	1.40	2.22	73.17
SWALEC	38.69	2.05	3.22	106.34
South Western	28.40	1.88	2.74	90.44
Yorkshire	19.20	1.68	2.26	74.64
ScottishPower	23.58	2.18	2.89	95.52
Hydro-Electric	24.46	1.69	2.43	80.23
Average	25.34	1.65	2.42	79.84

Note:
(1) Calculated assuming an annual consumption of 3300 kWh.

2.10 Customers are concerned not only with price but also with quality of service. PESs are required to meet design standards for their distribution networks as set out in Condition 9 of their licences. In addition there are other standards relating to network design set out in the Distribution Codes. The companies also need to meet Guaranteed and Overall Standards of Performance. Guaranteed Standards set service levels which must be met in each individual case. If a company fails to provide the level of service specified, it must make a fixed payment to the customer concerned. Overall Standards cover areas of service where it is not feasible or appropriate to give individual guarantees, but where it is reasonable for customers in general to expect a certain level of service. These issues are discussed more fully in Chapter 4.

Supply

2.11 Paragraph 2.3 described the main functions of PES supply businesses. The total costs of supplying customers are determined by a range of factors including their demand

profile, location and connection voltage. In broad terms the cost of generation purchases might account for 50 to 70 per cent of the bill, distribution charges 20 to 40 per cent and transmission use of system charges 0 to 10 per cent, with the remaining 5 per cent or so consisting of other supply business costs and the fossil fuel levy. The total bill is also subject to VAT (at a rate of 5 per cent for domestic customers).

2.12 A supply business will offer a range of tariffs to the different groups of customers it serves. For instance, companies will typically offer an "Economy 7" tariff to those customers with suitable metering arrangements to enable them to take advantage of the lower costs of off peak electricity during seven night-time hours. They will also offer a range of tariffs to business customers. Table 3 shows supply business charges on 1 April 1998 to domestic customers on standard and Economy 7 tariffs, and average and total charges for customers with typical demands of 3300 kWh and 6600 kWh per year. These supply business charges include distribution use of system charges, as set out in Table 2 for customers on standard domestic tariffs.

TABLE 3: SUPPLY BUSINESS CHARGES FOR DOMESTIC AND ECONOMY 7 CUSTOMERS (1 APRIL 1998)

PES	Standard Domestic				Domestic Economy 7				
	Standing Charge (£ per year)	Unit Rate (pence per kWh)	Average Charge (pence per kWh) (1)	Total Charge (£ per year) (1)	Standing Charge (£ per year)	Day Unit Rate (pence per kWh)	Night Unit Rate (pence per kWh)	Average Charge (pence per kWh) (2)	Total Charge (£ per year) (2)
Eastern	25.48	6.47	7.24	239	37.96	6.70	2.74	5.12	338
East Midlands	33.72	6.38	7.39	244	50.40	6.58	2.45	5.09	336
London	44.16	6.12	7.45	246	55.84	6.67	2.49	5.24	346
Manweb	46.20	6.68	8.09	267	59.20	7.10	2.56	5.52	364
Midlands	29.68	6.40	7.30	241	42.84	6.95	2.71	5.29	349
Northern	43.72	6.86	8.18	270	54.64	7.19	2.42	5.41	357
NORWEB	34.32	6.41	7.45	246	47.40	6.94	2.46	5.21	344
SEEBOARD	0.00	7.26	7.26	240	0.00	7.74	2.66	4.97	328
Southern	37.56	6.22	7.36	243	48.20	6.93	2.35	5.12	341
SWALEC	44.00	7.26	8.61	284	55.36	7.56	2.89	5.85	386
South Western	34.20	6.88	7.91	261	46.40	7.54	2.67	5.59	369
Yorkshire	40.00	6.14	7.36	243	52.00	6.47	2.49	5.09	336
Scottish Power	40.44	6.75	7.97	263	60.88	7.2	2.99	5.83	385
Hydro-Electric	45.44	6.67	8.06	266	80.96	6.67	3.43	6.14	405
Average	35.64	6.61	7.70	254	49.43	7.02	2.67	5.39	356

Notes:
(1) Standard Domestic is calculated assuming an annual consumption of 3,300 kWh.
(2) Economy 7 is calculated assuming an annual consumption of 3,000 kWh at the day rate and 3,600 kWh at the night rate.

2.13 The Government set the initial supply price controls in 1990. These covered almost all PES supply business customers and provided for almost all costs (such as generation costs, and distribution and transmission charges) to be passed directly through to customers. When the franchise reduced to 100 kW in 1994, OFFER set new controls covering only customers below 100 kW, ie. those who could not take advantage of the competitive market. As from April 1998 OFFER reduced the scope of the control further to cover only designated domestic and small business customers, for whom competition could take time to become established. At the same time, OFFER changed the form of the control to maximum limits on prices for smaller customers, with no provision for automatic pass-through of generation purchase costs and use of system charges.

Financial Performance of the PESs

2.14 The statutory and regulatory accounts of the PESs provide information on the turnover, costs, profitability, assets and liabilities, and cash flows associated with the distribution businesses, the supply businesses, and the PES groups as a whole. The following analyses use the historic cost accounting convention. Information is shown for each financial year from 1990/91, the first year after Vesting, to 1996/97, the last year for which regulatory accounts are presently available. To adjust for inflation all figures are expressed in 1996/97 prices. For Hydro-Electric's distribution business the figures include Hydro Benefit, as discussed in Chapter 6.

Distribution

TABLE 4: AGGREGATE PES DISTRIBUTION BUSINESS PROFIT AND LOSS ACCOUNT - 1996/97 PRICES

PES Total	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97
Turnover £m	4,203	4,626	4,545	4,677	4,773	4,374	4,082
Operating costs £m	(2,774)	(2,702)	(2,653)	(2,790)	(2,706)	(2,642)	(2,327)
Operating profit £m	1,429	1,924	1,892	1,887	2,067	1,732	1,755
Operating profit as % of turnover	34	42	42	40	43	40	43

2.15 Table 4 shows that aggregate PES distribution business turnover generally rose from 1990/91 to 1994/95. This reflected increases in unit sales after Vesting and the allowances for increased revenue under the price controls set at Vesting. Turnover fell significantly in 1995/96 and 1996/97 reflecting the tightening of the distribution price controls. Aggregate operating costs (including depreciation) in the distribution businesses changed little in the first six years of the period, but fell in 1996/97 as the tighter price controls took effect. (Figures shown in Table 15 in Chapter 3 show that operating costs excluding depreciation fell at a faster rate). Aggregate distribution business operating profits, being the difference between turnover and operating costs, were relatively low in 1990/91 because of an under recovery of price control revenue. They increased significantly after 1990/91, were flat for three years, peaked in 1994/95 then fell in 1995/96 and 1996/97. Operating profit was 34 per cent of turnover in 1990/91, and has varied between 40 per cent and 43 per cent in each year since then.

2.16 Table 5 shows the operating profits of each distribution business separately. There is considerable variation between companies since turnover, costs and profits reflect a number of factors including size of network, number and type of customers and quantity of units distributed. There is a significant difference between the experience of RECs and the Scottish PESs. In aggregate, operating profits of the RECs' distribution businesses increased by 41 per cent from 1990/91 to the average level over the period 1991/92 to 1994/95, then fell by 11 per cent to the average level over two years 1995/96 and 1996/97. For ScottishPower's and Hydro-Electric's distribution businesses the corresponding changes were respectively an increase of 10 per cent followed by an increase of one per cent and an increase of 2 per cent followed by a fall of 20 per cent.

TABLE 5: INDIVIDUAL PES DISTRIBUTION BUSINESS OPERATING PROFITS - 1996/97 PRICES

PES	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Eastern	137	201	175	181	209	167	164
East Midlands	122	170	169	185	192	164	131
London	116	180	168	166	144	151	125
Manweb	69	121	112	99	121	80	112
Midlands	121	157	159	154	190	171	149
Northern	85	104	114	106	104	83	72
NORWEB	88	146	153	162	168	43	129
SEEBOARD	77	105	102	110	124	97	146
Southern	140	190	180	179	221	236	200
SWALEC	57	80	76	86	98	85	81
South Western	81	102	94	83	101	79	105
Yorkshire	128	154	151	147	183	169	126
ScottishPower	137	133	166	156	149	155	151
Hydro-Electric	71	80	74	72	64	52	64
Total	1,429	1,924	1,892	1,887	2,067	1,732	1,755

2.17 Table 6 shows the aggregate PES distribution business cash flow statement from 1990/91 to 1996/97. Operating cash flow has moved broadly in line with operating profit (shown in Table 4). The total level of capital expenditure has been maintained at over £1 billion per year, and was somewhat higher in the last four years than in the previous three. Receipts from sales of fixed assets (such as surplus land and buildings) have generally increased, but are only a small proportion (about one per cent) of total operating cash flow. Customer contributions (to the cost of new connections to the network) have fallen from about 20 per cent to about 15 per cent of total capital expenditure. The net cash inflow before financing, which amongst other things provides a return on capital already invested in the business, more than doubled from about £700 million in 1990/91 to about £1400 million in 1994/95 before falling back to about £1100 million in 1996/97. Table 7 shows the net cash inflow before financing for each distribution business separately. As with the operating profits shown in Table 5 there is considerable variation between companies.

TABLE 6: AGGREGATE PES DISTRIBUTION BUSINESS CASH FLOW STATEMENT - 1996/97 PRICES

PES Total	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Operating cash flow	1,656	2,369	2,303	2,347	2,458	2,308	2,271
Capital expenditure	(1,231)	(1,108)	(1,164)	(1,299)	(1,256)	(1,284)	(1,393)
Sales of fixed assets	16	16	16	13	19	21	28
Customer contributions	241	229	222	224	228	213	220
Other investments	0	0	(1)	(2)	(5)	13	0
Net cash inflow before financing	683	1,506	1,376	1,283	1,444	1,270	1,126

TABLE 7: INDIVIDUAL PES DISTRIBUTION BUSINESS NET CASH INFLOW - 1996/97 PRICES

PES	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Eastern	60	167	168	186	188	122	181
East Midlands	19	113	97	106	154	170	88
London	66	158	132	108	100	76	90
Manweb	14	98	76	40	57	86	91
Midlands	35	139	133	124	101	103	88
Northern	25	81	77	91	65	71	48
NORWEB	74	144	112	114	126	32	89
SEEBOARD	75	85	75	66	106	81	80
Southern	105	117	125	95	134	111	104
SWALEC	2	64	38	46	54	68	37
South Western	32	56	53	58	81	70	49
Yorkshire	77	133	129	135	139	145	66
ScottishPower	59	90	107	73	109	101	106
Hydro-Electric	42	60	55	41	30	33	10
Total	683	1,506	1,376	1,283	1,444	1,270	1,126

Supply

2.18 The next four Tables look at the finances of the PES supply businesses. Table 8 shows that aggregate PES supply business turnover and operating costs rose between 1990/91 and 1992/93 then fell to 1996/97. This reflects to a significant extent movements in real electricity prices to final customers, which increased after Vesting and then fell steadily from 1992/93 onwards. Operating profits are a much smaller proportion of turnover than for distribution, typically in the range ½ to 1½ per cent. They are also sensitive to over- and under-recoveries against the price control; the main reason for the relatively low level of profits in the first two years was an under-recovery of price control revenue in 1990/91 and an increase in this under-recovery in 1991/92.

TABLE 8: AGGREGATE PES SUPPLY BUSINESS PROFIT AND LOSS ACCOUNT - 1996/97 PRICES[(1)]

PES Total	**1990/91**	**1991/92**	**1992/93**	**1993/94**	**1994/95**	**1995/96**	**1996/97**
Turnover (£m)	16,608	17,254	17,357	16,908	16,287	15,698	14,961
Operating costs[(1)] (£m)	(16,459)	(17,171)	(17,167)	(16,668)	(16,020)	(15,458)	(14,812)
Operating profit (£m)	149	83	190	240	267	240	149
Operating profit as a % of turnover	0.9	0.5	1.1	1.4	1.6	1.5	1.0

Note:

[(1)] In 1995/96 the PESs in England and Wales sold their shareholdings in NGC. PESs treated the revenue and costs from this sale in different ways in preparing their profit and loss accounts. For consistency all these revenues and costs have been removed from this Table.

2.19 Table 9 shows the operating profits for each of the PES supply businesses separately. Again there is considerable variation both as between companies and in movements over time. The large loss made by Yorkshire in 1996/97 reflects provisions of £125 million made against gas and electricity purchase contracts. Had it not been for this, the aggregate operating profit in 1996/97 would have been £274 million rather than £149 million, and the aggregate operating profit 1.8 per cent of turnover rather than 1.0 per cent in Table 8.

TABLE 9: INDIVIDUAL PES SUPPLY BUSINESS OPERATING PROFITS -1996/97 PRICES

PES	1990/91 (£m)	1991/92 (£m)	1992/93 (£m)	1993/94 (£m)	1994/95 (£m)	1995/96 (£m)	1996/97 (£m)
Eastern	18	(11)	34	34	33	19	27
East Midlands	15	5	29	29	27	26	4
London	12	7	7	7	15	9	7
Manweb	5	(6)	8	30	15	11	20
Midlands	3	9	21	36	27	27	41
Northern	8	5	4	6	26	18	22
NORWEB	14	14	15	17	32	18	46
SEEBOARD	9	5	14	16	17	8	33
Southern	13	4	22	31	14	16	22
SWALEC	9	4	6	7	9	17	18
South Western	2	5	18	28	16	12	7
Yorkshire	17	10	12	15	23	31	(132)
ScottishPower	19	36	1	(17)	2	24	36
Hydro-Electric	8	(2)	(1)	1	12	1	(2)
Total	149	83	190	240	267	240	149

2.20 Table 10 shows the aggregate PES supply business cash flow statement from 1990/91 to 1996/97. Operating cash flows have varied significantly from year to year. Three factors were particularly important in this. First, in England and Wales there was a change at Vesting in the timing of payments made by PESs in respect of electricity purchase costs. The change had a one-off impact on operating cash flow, and is the major cause of the cash outflow in 1990/91. Second, customers made payments in advance in 1993/94 in order to avoid, at least for a time, the impact of the imposition of VAT on domestic electricity bills from April 1994. This is the main reason for the higher operating cash flow in 1993/94 and reduced operating cash flow in subsequent years. Third, PESs in England and Wales received income from the flotation of NGC in 1995/96 and made rebates to customers based on this. Some PESs placed the costs of the customer rebate in the supply business, and as a consequence this reduced operating cash flows.

TABLE 10: AGGREGATE PES SUPPLY BUSINESS CASH FLOW STATEMENT - 1996/97 PRICES

PES Total	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Operating cash flow	(610)	213	542	1,608	(420)	(228)	3
Capital expenditure	(35)	(35)	(32)	(35)	(44)	(46)	(69)
Sales of fixed assets	4	1	4	2	2	2	2
Other investments	0	0	0	0	(1)	2	0
Net cash inflow before financing	(641)	178	513	1,574	(463)	(270)	(64)

2.21 Table 11 shows the net cash inflow before financing for each of the PES supply businesses separately. Again there is considerable variation between them.

TABLE 11: INDIVIDUAL PES SUPPLY BUSINESS NET CASH INFLOW - 1996/97 PRICES

PES	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Eastern	(128)	(19)	50	207	(80)	(172)	(22)
East Midlands	(86)	(3)	65	130	35	(63)	(15)
London	(129)	(9)	65	129	(40)	(84)	(35)
Manweb	(53)	(1)	6	72	(20)	25	41
Midlands	(31)	38	47	144	(28)	22	33
Northern	(51)	4	29	57	(26)	(5)	4
NORWEB	(1)	(14)	90	136	(60)	49	(15)
SEEBOARD	(100)	12	10	161	(59)	24	(23)
Southern	(163)	32	51	174	(69)	(81)	(12)
SWALEC	(16)	13	43	53	(15)	18	(7)
South Western	(32)	16	17	143	(15)	4	(19)
Yorkshire	(17)	6	42	99	(38)	51	(28)
ScottishPower	168	82	(25)	50	(37)	(52)	48
Hydro-Electric	(3)	21	24	21	(11)	(5)	(13)
Total	(641)	178	513	1,574	(463)	(270)	(64)

PES Groups

2.22 The distribution and supply businesses are parts of larger corporate groups. For the majority of the RECs these corporate groups are dominated by distribution and supply activities. However, Eastern has significant interests in generation and the two Scottish PESs have significant interests in both generation and transmission. ScottishPower has also recently acquired Manweb and Southern Water. Paragraph 1.4 explained some of the other activities in which PESs are active and some of the other important variations between PESs.

2.23 The takeovers of 11 out of 12 RECs and the acquisition by ScottishPower of Southern Water has led to some diversity in corporate structures which it is helpful to understand when interpreting the statutory accounts of the PESs. First, the group numbers consolidate information for all those companies owned by the PES, but do not include the results of any companies that now own a PES. Therefore, ScottishPower's results include Manweb and Southern Water. However, following the takeover of NORWEB by North West Water, NORWEB became a subsidiary of United Utilities and so the results of North West Water are not included in the PES group accounts. Similarly, the results of Welsh Water are not included in SWALEC's accounts. Second, as explained more fully below, many takeovers were in part financed by increasing borrowing. This debt is sometimes held in companies that own the PES, in which cases the debt and interest payments will not appear in the PES group accounts, but dividend payments to these other companies will. The parent company can then use the dividends received from the PES to finance its interest payments.

2.24 In the aggregate group profit and loss account, the figures for operating profit incorporate the operating profits of the distribution, supply and other businesses. Table 12 breaks down these aggregate PES operating profits by activity for 1990/91 to 1996/97. Operating profits are derived largely from the distribution business, but in aggregate this proportion is falling. from about 90 per cent of group profits in 1990/91 to about 80 per cent during 1991/92 to 1994/95, to 76 per cent in 1995/96 and to 66 per cent in 1996/97. This relative decline reflects partly the reduction in distribution business profits, partly the reduction and elimination of losses associated with activities such as retailing, and partly the growth in other activities, such as generation and ScottishPower's acquisition of Southern Water. The contribution made by Southern Water to ScottishPower's operating profit was £136 million in 1996/97 (the year of acquisition), which was nearly as large as the £151 million operating profit of ScottishPower's distribution business.

TABLE 12: AGGREGATE PES GROUP OPERATING PROFIT BY DIFFERENT ACTIVITY 1996/97 PRICES

PES Total	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Distribution	1,429	1,924	1,892	1,887	2,067	1,732	1,755
Supply	149	83	190	240	267	240	149
Other	(6)	175	261	282	453	296	748
Total	1,572	2,182	2,343	2,408	2,787	2,268	2,652

2.25 Table 13 shows the aggregate PES group profit and loss account for 1990/91 to 1996/97. In order to explain the dividend and interest payments in this Table (and also in the cash flow statement which is discussed in paragraphs 2.28 to 2.31) it will be helpful to explain the changes that have taken place in the financing and capital structure of the PESs and the factors which have driven these. In privatising the industry the Government established an initial capital structure which included about £3 billion of net debt. The capital restructuring of the RECs took place part way through financial year 1990/91, and their accounts for the first year contain a relatively low level of dividend and interest payments. The substantial and increasing net cash inflows under the initial price controls enabled the PESs to increase dividends significantly in real terms and to reduce debt, which in turn reduced interest payments. By 1993/94 the PESs had repaid debt and generated an aggregate net cash surplus of about £½ billion, although this change also reflected the effect of the prepayments received by PESs before the imposition of VAT on domestic electricity bills in April 1994.

2.26 For the first five years, the RECs were protected from takeover by a golden share held by the Government. As the possibility of takeover approached, and potential bidders began to appraise the PESs, it became apparent that the relatively secure cash flow of the distribution businesses could be used as a basis for much higher levels of borrowing. Higher borrowing would in turn create more efficient capital structures, as debt is in general cheaper and more tax efficient than equity finance. Increased borrowing could provide large amounts of cash which could be used to make special dividends or buy back shares, or to engage in other activities. It could also be used to finance the takeovers; that is, the acquirer of a PES could subsequently increase borrowing in order partially to repay the acquisition costs. As a result of these factors, in 1995/96 and 1996/97 nearly £4 billion in cash was paid out in dividends (including special dividends and dividends to acquiring companies). The increased borrowing led to interest payments in 1996/97 that were about three times the level in 1994/95.

TABLE 13: AGGREGATE PES GROUP PROFIT AND LOSS ACCOUNT - 1996/97 PRICES[1]

PES TOTAL	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
Turnover	18,434	19,302	19,499	19,143	18,887	18,441	18,835
Operating Costs	(16,861)	(17,119)	(17,156)	(16,735)	(16,100)	(16,173)	(16,182)
Operating Profit	1,572	2,182	2,343	2,408	2,787	2,268	2,652
Other Income	166	178	184	197	9	126	57
Profit before interest	1,739	2,360	2,526	2,605	2,796	2,393	2,709
Interest	(180)	(247)	(186)	(128)	(123)	(210)	(374)
Profit before taxation	1,559	2,114	2,341	2,477	2,674	2,184	2,335
Taxation	(397)	(558)	(620)	(649)	(687)	(585)	(696)
Profit for year	1,162	1,556	1,720	1,829	1,990	1,598	1,639
Dividends	(274)	(566)	(626)	(708)	(1,190)	(2,383)	(1,383)
Retained profit	889	990	1,094	1,121	797	(785)	255

Note:

(1) In 1995/96 the PESs in England and Wales sold their shareholdings in NGC. PESs treated the revenue and costs from this sale in different ways in preparing their profit and loss accounts. For consistency all these revenues and costs have been removed from this Table.

2.27 Table 14 shows the aggregate PES group cash flow statement from 1990/91 to 1996/97. The trends shown are similar to those described for the group profit and loss account. Operating cash flow peaked in 1993/94, compared to operating profits which peaked in 1994/95. It was also more erratic than operating profit because of substantial payments in advance by customers in 1993/94, as described above, which affected cashflow but not operating profit. Interest and dividend payments followed broadly the same paths in both statements. Over the last three years the profit and loss account shows a flatter path of taxation than the cash flow statement does. This is because substantial payments of advance corporation tax change the pattern of cash flows, but for most PESs do not affect the profit and loss account.

TABLE 14: AGGREGATE PES GROUP CASH FLOW STATEMENT - 1996/97 PRICES

PES Total	**1990/91 £m**	**1991/92 £m**	**1992/93 £m**	**1993/94 £m**	**1994/95 £m**	**1995/96 £m**	**1996/97 £m**
Operating cash flow	1,193	2,961	3,315	4,451	2,480	2,005	2,775
Capital expenditure	(1,475)	(1,421)	(1,504)	(1,699)	(1,633)	(1,711)	(1,943)
Sales of fixed assets	30	27	30	46	41	123	111
Customer contributions	247	241	239	235	231	230	234
Net interest paid	(180)	(273)	(167)	(102)	(105)	(153)	(295)
Dividends received	42	124	137	145	183	1329	79
Tax paid	(293)	(407)	(564)	(530)	(699)	(869)	(456)
Dividends paid	0	(432)	(569)	(647)	(1,118)	(2,617)	(1,252)
Other investments	(5)	(101)	(359)	(182)	(154)	(229)	(1,132)
Net cash inflow before financing	(441)	719	557	1,717	(773)	(1,890)	(1,878)

2.28 Table 14 shows that, in aggregate, group capital expenditure has generally been increasing over time. This is also true of the distribution businesses, as discussed in the next Chapter. However, the proportion of PES group capital expenditure accounted for by the distribution businesses has fallen over time. Calculations based on the information in Tables 6 and 14 suggest that in 1990/91 distribution made up 83 per cent of the total, falling to around 75 per cent in the next five years and then to 72 per cent in 1996/97. The lower proportion in the last year is mainly due to ScottishPower's acquisition of Southern Water, this contributed about £90 million to group capital expenditure in 1996/97, which is of the same order of magnitude as ScottishPower's annual expenditure in its PES distribution business.

2.29 The 12 RECs owned NGC between 1990/91 and 1995/96. The dividends they received from NGC increased steadily to 1994/95. In 1995/96 they floated NGC, and some of the proceeds are included in the figure of £1.3 billion for dividends received in that year. Part of the proceeds were used to fund a £50 per customer rebate in England and Wales in that year.

2.30 Other investments relate to purchase and sales of fixed asset investments, rather than capital expenditure. The largest figures represent purchases of other companies. For instance, in 1996/97, ScottishPower's acquisition of Southern Water led to a net cash outflow of £1.2 billion at ScottishPower. In the absence of this, the aggregate investments would have been slightly negative (that is, as small net disinvestment), and the aggregate net cash outflow would have been about £0.7 billion rather than £1.9 billion.

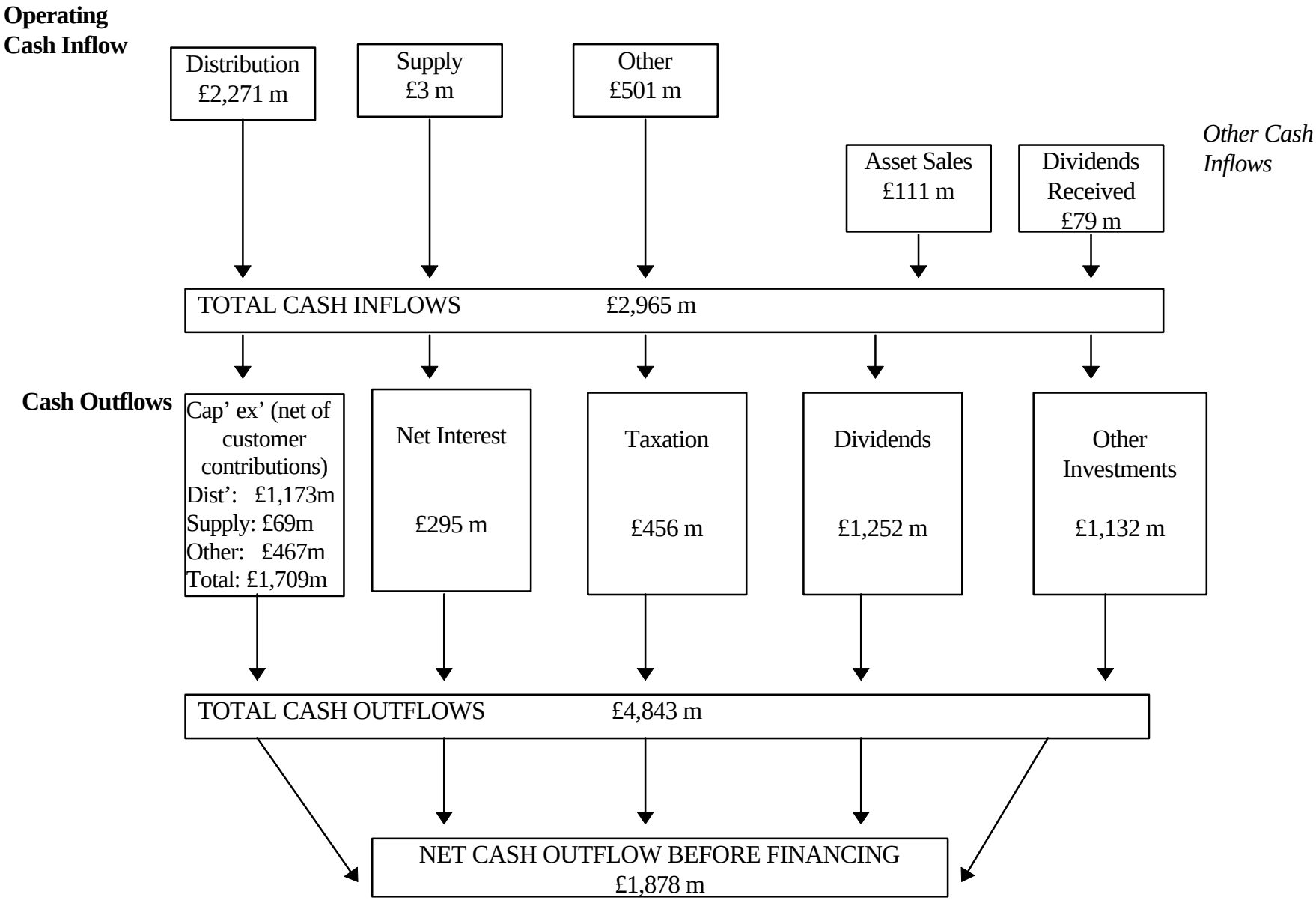
2.31 As discussed earlier the total net cash inflow before financing shows that PESs in general generated surplus cash in the first four years after Vesting. This allowed them to pay off debt. Since 1994/95 increased dividends and other investments have led to a net outflow of cash and debt has increased.

2.32 Figure 1 summarises the information in this Chapter about aggregate PES cash flows in 1996/97. It shows that, in 1996/97, the operating cash flow of the distribution businesses was the main source of cash inflow into the PESs. The main outflows were capital expenditure, particularly in the distribution business, dividends, and other investments (including acquisitions). PES cash outflows exceeded cash inflows by about £1.9 billion, which was financed by increased borrowing.

Summary

2.33 The PESs vary considerably in size and nature, but there are important common features. The aggregate picture in the distribution businesses is one of increasing revenues and profits over the first five years followed by tighter price controls and lower revenues, costs and profits over the next two years. Net operating profit has been around 40 per cent of turnover. Capital expenditure has been maintained at a high level and there has been a high positive net cash flow. The aggregate picture of the supply businesses is one of high but falling turnover and costs; low and variable profits, averaging around one per cent of turnover; and variable net cash flow. PES groups as a whole were initially characterised by increasing cash flow used to increase dividends and reduce borrowing, but more recently have had lower cash flows and have increased borrowings to develop more efficient capital structures, to repay shareholders and finance takeovers.

FIGURE 1: PES GROUP CASHFLOW - 1996/97



3 DISTRIBUTION AND METERING PRICE CONTROLS

Introduction

3.1 The distribution businesses comprise activities which at present are for the large part monopolies. There is scope for competition in metering and the provision of new connections. In some circumstances, for example major new industrial or commercial developments, there is potential for competition between PES distribution systems and private distribution systems. However, there is no direct competition of any significance between PES distribution systems. Regulation of these systems is therefore necessary in order to protect customers with respect both to price and quality of service. The form of the control should stimulate the PESs to achieve efficiency savings, which in due course can be shared with customers. It should also be conducive to competition in supply and other potentially competitive activities.

3.2 The February 1998 consultation paper identified the following issues for consideration as part of the distribution price control review. Many of these issues have been discussed in previous reviews, but in most cases there are new dimensions in the light of experience and the proposals in the Government's Green Paper on utility regulation.

- Whether the RPI-X form of the present control should be maintained, and in particular whether RPI-X should be supplemented by some sort of Error Correction Mechanism.

- What levels of spending on operating and capital costs are required in order to operate and maintain the PES distribution networks, and how far it would be desirable to increase capital expenditure or take other steps to improve quality of supply.

- What rate should assets be remunerated and in particular whether Vesting assets should continue to be valued at flotation value uprated by 15 per cent, and whether 7 per cent remains an appropriate cost of capital.

- How much revenue companies require over the period of the new control and the relevance of present value calculations, financial ratios and other considerations in assessing this.

- How energy efficiency considerations should best be accommodated, and in particular whether numbers of units distributed should continue to have a 50 per cent weighting in determining allowed revenue; whether the incentives on companies to reduce distribution losses should be revised; and whether any other modifications are necessary to take account of any proposals on energy efficiency matters made by the Government following the publication of the Green Paper on utility regulation.

- How to encourage the development of competition in the provision of metering and meter reading services while ensuring that customers' interests are adequately protected in the transition to full competition.

- Whether there is scope for increasing competition in the provision of connections to the distribution systems and how connection assets and charging should be treated under the price control.

The New Control

(i) Form of Control

3.3 The present distribution price control limits average revenue to increase by no more than the rate of inflation as measured by the Retail Price Index (RPI) less a specified level of X. The level of the control was set to reflect anticipated future operating costs and capital expenditure, and to provide an adequate return to shareholders consistent with efficient performance. A price control of this form provides an incentive to efficiency insofar as companies keep the gains from greater efficiency during the period of the price control. Customers benefit from efficiency improvements in two respects, because the price control can be set to reflect both the efficiency improvements shown during the previous price control period as being actually achievable, and the further efficiency savings that might be reasonably expected over the duration of the new price control.

3.4 There are various alternatives to a RPI-X form of control. Under a profit control prices might be adjusted annually in the light of actual expenditure, including a specified return on capital. A sliding scale control might specify that if profits move outside specified limits, prices would have to be adjusted downwards or upwards, for example to share between customers and shareholders the consequences of expected or unexpected movements in cost.

3.5 Previous reviews have concluded that a RPI-X price control has advantages over profit regulation and sliding scale regulation for the main distribution and transmission businesses of licence holders. Both profit and sliding scale price controls could reduce the incentives towards efficiency, pose problems of defining and measuring profit, and could be difficult to enforce. RPI-X regulation has continued to be used by other regulators for network businesses, and the Monopolies and Mergers Commission (MMC) has endorsed its use on a number of occasions. In their responses to the February 1998 consultation paper a number of PESs and ECCs supported the continuation of RPI-X price controls for the distribution business.

3.6 In its Green Paper on utility regulation the Government concluded that RPI-X should continue to be used as the basic system of regulating prices, if this is the system regulators choose in future. It suggested that one approach was to rely exclusively on RPI-X provided that regulators judged that this would be the best deal for customers. An alternative would be to supplement RPI-X by making greater use of Error

Correction Mechanisms (ECMs). These ECMs might adjust for changes in elements of cost over which the company has little control or where the company misled the regulator when the price control was set by providing incomplete or inaccurate information.

3.7 In considering these issues it will be important to ensure that the form of price control does not blunt incentives for efficiency, create unnecessary uncertainty for customers and companies over future price levels, or give rise to a price control which is unduly difficult to enforce. In recent reports on price control references the MMC has looked at the differences between forecast and actual costs, and taken account of these in setting future controls and made adjustments depending on the reasons for these differences. It seems sensible to do something similar in the present review. It will also be necessary to consider the impact of the form of control on the development of competition in supply and its interaction with the structure of charges.

(ii) Duration

3.8 The longer the time for which a price control is set, the greater the incentive companies have to make efficiency savings. However, a longer duration also increases the risk of unexpected circumstances, and the possibility of company performance being significantly different from the assumptions used in setting the price control. It will be necessary to strike a balance between these considerations in setting the revised control, also taking account of the possible impact of any ECM or cost pass-through mechanism. The existing distribution price controls were originally set for a period of five years. More generally, regulators have tended to set monopoly price controls for between four and six years. It seems appropriate that the duration for the revised distribution price controls should fall within this range. Of those respondents to the February 1998 consultation paper who mentioned this issue, two supported a five year duration for the new price control and one a ten year duration.

(iii) Scope

3.9 The present distribution price control covers all charges made by the distribution business except those for certain excluded services and the pass through of transmission charges. There are presently seven categories of excluded revenue. This will increase to eight later this year as certain new distribution services associated with the introduction of competition for domestic customers will also be excluded from the price control. The existing categories are described below.

- Extra High Voltage (EHV) charges apply to those customers connected to a company's distribution system at a voltage of 22kV or above, or directly to a sub-station with a primary voltage of 66kV or above. In the past PESs have argued that EHV customers vary widely in both consumption and load characteristics and are connected at different voltage levels with consequent differences in the assets used to make supply available. For these reasons

EHV customers are generally charged on a customer-specific basis.

- Top-up and standby charges are made to customers who do not use the PES distribution system for the bulk of their electricity needs.

- Non-trading rechargeables are generally related to specific requests made by third parties for a PES to carry out work on its distribution system (for example, moving lines and cables to accommodate the needs of public authorities or developers). The volume of such work tends to vary unpredictably from year to year.

- Prepayment meter distribution business surcharges are related to the extra costs of providing prepayment meters. Issues relating to prepayment meters are discussed in Chapter 7.

- Special metering includes the provision of metering to customers and suppliers in the over 100 kW supply market.

- Other excluded services encompass a variety of minor activities including wheeling, where units are transferred from one distribution system to another.

- Connection charges are levied when a customer first connects to the distribution system or makes a material change in supply requirements, for example by requesting a higher capacity connection. Issues relating to connection charges are discussed in paragraphs 3.90 to 3.95.

3.10 A breakdown of excluded and other revenue is set out in Table 15 (total revenue is slightly more than turnover shown in Table 4 because of the accounting treatment of over recoveries against the price control). In aggregate revenue from excluded services is about one-tenth of the level of price control revenue. Income from connection charges, which are shown separately as they are generally treated as a capital receipt rather than revenue in the regulatory accounts, is equivalent to about 7 per cent of price control revenue.

TABLE 15: EXCLUDED SERVICES REVENUE 1996/97 - PES TOTAL

Excluded Services	**£ million**
EHV Charges	67
Top-up and Standby	18
Non-Trading Rechargeables	102
Prepayment Meters	78
Special Metering	12
Other Excluded Services	41
Total Excluded Services Revenue	318
Price Controlled Revenue	3504
NGC Exit Charges	265
Total Revenue	4087
Connection Charges (capital receipt)	227

3.11 Revenue that is collected for the provision of excluded services does not affect the level of revenue that a company is allowed to recover under the price control. Excluded service charges are controlled in a variety of ways. Revenue derived from some of them, such as EHV and top-up and standby, are subject to the Director General's powers to determine disputes. Other services, such as special metering arrangements, are subject to competitive pressures; and charges for some others, such as non-trading rechargeables, may be subject to independent arbitration The Director General also has powers under the PES licence to issue directions specifying whether particular sources of distribution business revenue should be classified as excluded from the price control.

3.12 Large users have expressed some concerns that EHV charges have not reduced at the same rate as price controlled charges. It will be relevant to explore this issue, and to consider whether the present scope of the price control remains appropriate in the next period.

3.13 The 12 RECs pay transmission connection point exit charges to NGC. The RECs recover these costs through distribution use of system charges and at present they are treated as cost pass-through for the purposes of the distribution price control. Over the longer term there may be scope for RECs to influence these charges, by changing the size or location of these exit points. It will therefore be sensible to consider whether this pass-through treatment remains appropriate in the next period.

Setting The Control

3.14 Setting a price control, whatever its precise form, requires an estimate of the revenue that would be sufficient to finance an efficient business. Therefore, it is necessary to consider the level of operating costs and capital expenditure, over the period of the control and beyond, that an efficient company might need to incur, and the appropriate level of return to shareholders and other providers of capital.

3.15 In 1996/97 distribution business turnover was in aggregate about £4.1 billion, operating costs (excluding depreciation) about £1.9 billion and capital expenditure about £1.4 billion. Operating costs are the largest component of outlays. The revised price control will provide the opportunity to pass on to customers the benefits of the efficiency improvements that the PESs have achieved over the last few years. It will also be necessary to consider the scope for further improvements in the future.

3.16 Capital expenditure is also an important item. Because capital assets may last many years, it is often appropriate to remunerate the expenditure over several price control periods. Consequently, the last control did not simply take the total amount of the projected capital expenditure within the period, and provide for revenues to cover that. Rather, it provided for revenue to cover a proportion of that total and the financing costs of the remainder. By the same token, the control also provided for revenue to pay off or continue financing the outstanding balance of previous spending. Therefore, capital expenditure under the present control has not been financed by customers as it has been incurred, but its magnitude in the price control period and previously is such that it substantially influenced the level of control.

3.17 It will be important to understand the reasons for any difference between actual capital expenditure and the levels projected during the previous review. PESs should have the incentive to seek efficiencies, and not simply to extend, replace or reinforce their distribution networks regardless of need. Customers will benefit from not having to pay in future years for unnecessary expenditure. At the same time, it would be desirable to reduce any incentive on PESs to over-estimate their requirements for capital spending.

3.18 The third important component of outlays includes dividends, tax and interest payments. As explained in Chapter two, the level and structure of these payments has changed significantly over time, partly because of the take-over of many of the PESs by other companies. They are also affected by activities outside the price control. The control will need to protect customers, ensure that the prospective return to shareholders arising from efficient operation of the distribution business is sufficient to sustain the business, and maintain the incentive to pursue greater efficiency in financing as well as in operating and capital expenditure.

3.19 For any set of assumptions on future costs, the appropriate level of allowed revenue can be assessed in a number of ways. In setting previous distribution and transmission controls OFFER has considered present value calculations over the period of the

control and beyond. This approach has been adopted by the MMC. The calculations contained in the MMC's 1995 report on Hydro-Electric[5] are set out at Annex 2.

3.20 In order to assess levels of capital and operating costs, and the balance between these categories of expenditure it will be necessary to take a view on the quality of supply that the distribution businesses should aim to provide for their customers. Issues relating to quality of supply are dealt with in Chapter 4.

3.21 The May 1998 consultation paper on separation of businesses contained proposals that would place new requirements on PESs in terms of separating distribution, metering and supply activities. Any additional costs of making these changes cannot be estimated with confidence at present and may vary between PESs. Any such costs need to be assessed in the context of the potential improvements in management control and efficiency and the scope for increase in shareholder value which might be realised by the possibility of demerging businesses and of potential merger and acquisition activity.

3.22 There may be conflicting evidence and arguments as to the appropriate values to ascribe to all the parameters involved. Any set of calculations can only be indicative. It will be necessary to consider the implications of any present value calculations for the financial position of the distribution businesses. An important element of judgement is involved in assessing the overall reasonableness of the proposed control, and in balancing a variety of relevant considerations, so as to best protect the interests of customers.

3.23 In the last price control review, a variety of calculations and considerations influenced the final proposals. This Chapter describes the central estimates of operating costs, capital expenditure, the cost of capital and the valuation of assets underlying the present price controls. The implications of different assumptions, particularly on operating costs and asset valuation, were also taken into account. The precise positions of companies relative to each other were quite sensitive to the particular assumptions used in the calculations, although a fairly consistent overall pattern tended to emerge. This suggested putting companies in bands or groups in calculating the overall level of the prescribed price reductions. It is for consideration whether a similar approach should be adopted in the present review, and how the present value calculations should take account of the previous banding.

3.24 In setting the distribution price control for Hydro-Electric it may be necessary to take into account a cross-subsidy known as Hydro Benefit. This potential transfer allows the relatively low operating costs of the hydro resources of the generation business to be used to offset higher distribution and transmission charges, which might otherwise be needed as a result of the climatic and geographic characteristics of Hydro-Electric's area. These issues are discussed in more detail in Chapter six.

[5] MMC "Scottish Hydro Electric plc" A report on a reference under section 12 of the Electricity Act 1989, May 1995

Analysis of Costs

3.25 It is conventional and convenient to break down spending between operating and capital costs. It will also be important to consider the relationship between these two categories of expenditure. For instance, investment in information technology and control systems may reduce the costs of operating and maintaining the network. Increased investment in switchgear may increase maintenance but reduce repair costs. Both sorts of spending also influence the quality of supply that distribution businesses can provide. It will be appropriate to retain incentives on companies to operate efficiently in both areas. A number of the respondents to the February 1998 consultation paper emphasised the importance of a thorough analysis of operating and capital costs as part of the distribution price control review.

(i) Operating Costs

3.26 Distribution business operating costs may be influenced by many factors including the geography and topography of the area, the numbers, nature and density of customers, length of circuit, weather, quality standards, and operating practices. The presentation and allocation of costs will also reflect accounting policies. The review will focus on the future cash outlays of the distribution businesses. What components of this can be influenced by the management of the PESs is for consideration.

3.27 An indication of the changes in these costs over time can be obtained by comparing distribution business operating costs (excluding depreciation) in 1992/93, the mid-point of the first price control period, with 1996/97, the latest year for which audited information is presently available. During this time operating costs aggregated over the 14 PESs fell from about £2.3 billion to about £1.9 billion, a reduction of about 18 per cent. The costs for each company are shown in Table 16. There is considerable variation between companies, with reductions in the costs of the RECs of between 0 and 45 per cent but increases in costs for the two Scottish PESs. To some extent this may reflect changes in the allocation of costs between distribution and supply in Scotland.

TABLE 16: DISTRIBUTION BUSINESS OPERATING COSTS (EXCLUDING DEPRECIATION) IN 1996/97 PRICES

PES	1992/93 £m	1996/97 £m
Eastern	250	198
East Midlands	178	169
London	201	175
Manweb	141	115
Midlands	203	163
Northern	133	133
NORWEB	185	162
SEEBOARD	182	99
Southern	232	153
SWALEC	112	86
South Western	139	100
Yorkshire	194	151
ScottishPower	102	128
Hydro-Electric	54	61
Total	2306	1893

3.28 It will be important to understand the changes in distribution business costs in the past and to discuss and challenge the assumptions behind the PESs' assessment of future costs and efficiency as reflected in their business plans. It will also be necessary to consider the implications of the separation of PES businesses, particularly the extent to which costs associated with customer services, marketing and advertising, information technology, and corporate overheads should be funded by the distribution business; and how to separate out costs associated with metering.

3.29 The price control review will build on the appraisal of actual and expected distribution costs undertaken at the last price control review. This previous analysis estimated what cash outlays companies would need to make over the price control period to 2000, assuming they were managed efficiently and that they maintained or improved quality of supply, but taking account of the particular circumstances under which each company had to operate.

3.30 The first stage of the previous review was to examine and compare companies' actual operating costs in 1992/93 in order to try to understand what factors were responsible for driving costs, what allowance would have to be made for different circumstances and to what extent there were initial differences in efficiency between companies. Statistical analysis helped inform this part of the study. The second stage was to assess PES projections of the path of operating costs over the forthcoming period, taking account of possible increases in certain costs but also the potential for overall cost reduction. The scope for potential reductions in operating costs was assessed by

comparison with previous cost reductions made by the PESs and other utility companies, and by considering the advice given by management consultants.

3.31 The PESs' own projections reflected strikingly different assumptions and aspirations as between companies. For example, one company considered that it would be able to reduce operating costs (excluding depreciation) in both the 1990 to 1995 and 1995 to 2000 periods, seven companies projected increases in one period and decreases in another, six companies projected these costs to increase in real terms over the whole ten year period. One company projected a fall of 6 per cent in costs by the year 2000 but another anticipated a rise of 45 per cent. In general, companies said that operating costs would increase as a result of higher business rates, higher costs of insurance and wayleaves, wage increases and severance costs and limited scope for cost reductions without compromising on quality of service. On average, they projected a real increase in operating costs (excluding depreciation) of about 17 per cent from 1992/93 to 1999/2000.

3.32 OFFER's analysis noted these possibilities of costs increases, but suggested that the PESs and other utilities had previously been able to reduce operating costs in real terms and were likely to be able to continue to do so. The price control calculations were based on average real reductions in operating costs of about 4 per cent from 1992/93 to 1999/2000. The information in Table 16 suggests that from 1992/93 to 1996/97 companies were able to reduce their operating costs by about 18 per cent. Whether companies will be able to maintain this rate of cost reduction over the rest of the price control remains to be seen.

3.33 It will be important to understand the reasons for the differences between the PESs' previous projections of costs and actual outturn costs, and the reasons for the differences in the pattern of costs over time and between companies, and to assess the scope for further cost reductions.

3.34 In the present review, the analysis of operating costs will include a variety of methods and techniques. These are likely to include the following:

- an assessment of the factors underlying the movements in costs over the period since the introduction of the existing price control;
- statistical analysis of costs in a base year, to help assess relative efficiency and cost drivers;
- a study of best operating practices to cast light on relative efficiency and the scope for cost reduction in the future;
- consideration of the costs and practices associated with the maintenance of the network given the effect on quality of service and the need to understand the relationship between capital and operating costs;

- consideration of cost attributions, allocations and recharges between the supply, distribution and other activities of the PESs in the light of the consultation paper on separation of businesses;

- an examination and critique of PES forecasts of operating costs over the period of the next price control; and

- an analysis of the differences between and implications of PES accounting policies, particularly with respect to the capitalisation of expenditure, restructuring costs and other provisions and exceptional items.

3.35 OFFER is appointing consultants to assist in analysing operating costs. In the near future PESs will be asked to complete business plan questionnaires. These will include questions relating to past and envisaged future distribution business operating costs and non-operational capital expenditure (such as spending in information technology and transport), methods and amounts of cost allocation and recharges, network capital expenditure forecasts, and the activities and costs associated with metering.

3.36 Assumptions about the future level of operating costs will have a significant impact on the overall level of the next price control. It will be important to consider whether there can be continued reductions in operating costs as achieved over the last few years, consistent with maintaining or improving quality of supply. The proposals in the consultation paper on separation of businesses may have significant implications for the allocation of activities and costs, and will also need to be taken into account in formulating projections of the future level of distribution business costs.

(ii) Capital Expenditure

3.37 A company's capital expenditure programme influences the quality of supply it provides and the amount of revenue it needs and hence the level of the price control, well into the next century. The capital costs of building and extending the distribution network are determined partly by the need to replace existing assets (non-load related capital expenditure) and partly by the need to expand the system to accommodate new customers or to cater for shifts in the geographical pattern of demand and generation (load-related capital expenditure). Management policy also has an influence on capital costs.

3.38 During the 1994 price control PESs provided projections of network capital expenditure (load and non-load related spending) over the period 1995/96 to 1999/2000 totalling about £7.7 billion in 1996/97 prices. However, not all the projected expenditure seemed justifiable and the price control was based on projections of capital expenditure totalling about 90 per cent of this level. Table 16 shows PESs' actual expenditure to date and their recent forecasts of network capital expenditure for the remainder of the present price control period together with the assumptions used to set the price control in 1994. The Table shows that PESs are in aggregate planning to spend about 90 per cent of the amount assumed when the price control was set (or

about 80 per cent of their original forecasts). The two companies forecasting the lowest capital expenditure as a proportion of the 1994 assumptions (Northern and SEEBOARD) indicated at the time of resetting the control in 1995 that they had revised their previous forecasts downwards. Aggregate capital expenditure over the present price control period is forecast to be some 38 per cent higher in real terms than during the previous period.

3.39 OFFER has engaged consultants to examine the companies' investment expenditure during the present price control period and their plans for further investments until the year 2005/2006. The consultants will investigate the reasons for discrepancies between actual and forecast programmes and their relation to the forecast provided by the companies at the time of the last review. The consultants will review the forecasting methods used by the companies and consider the approach used by OFFER in setting the present price control. They will also analyse the relationship between capital and operating expenditure.

TABLE 17: DISTRIBUTION BUSINESS NETWORK CAPITAL EXPENDITURE - 1996/97 PRICES

REC	A Expenditure 1990/91-1994/95 £m	B Assumptions for Price Control 1995/96-1999/00 £m	C Expenditure 1995/96-1996/97 £m	D Recent PES Forecast Expenditure 1997/98-1999/00 £m	E Total Forecast Expenditure E=C+D 1995/96-1999/00 £m	Column E as % of Column B	Column E as % of Column A
Eastern	326	868	230	497	727	84	223
East Midlands	491	555	170	311	481	87	98
London	332	540	189	279	468	87	141
Manweb	299	392	121	215	337	86	113
Midlands	383	513	199	255	454	89	119
Northern	199	374	111	197	308	82	155
NORWEB	314	528	158	352	511	97	163
SEEBOARD	272	505	112	285	397	79	146
Southern	520	726	290	436	726	100	140
SWALEC	273	331	127	193	319	96	117
South Western	282	364	133	215	349	96	124
Yorkshire	264	560	193	357	550	98	209
ScottishPower	391	432	164	248	411	95	105
Hydro-Electric	251	265	112	177	288	109	115
TOTAL	4597	6953	2309	4018	6326		
AVERAGE	328	497	165	287	452	91	138

These totals exclude non-operational capital expenditure (such as spending on information technology and transport) by the distribution business and so cannot be directly compared to the capital expenditure totals shown in Chapter 2.

3.40 In assessing the PESs' capital expenditure forecasts (to be provided for the present review) the consultants will be considering where expenditure may be over generous or unnecessary, or where deferment or reduction in expenditure could be accommodated without affecting the companies' ability to fulfill their licence duties.

3.41 When assessing the companies' non-load related expenditure plans, the consultants will consider the companies' approaches to replacing or refurbishing assets, and in particular how these relate to asset condition and age. They will want to ensure that the planned replacement of assets is neither too soon, involving customers in extra costs, nor too late which could result in a deterioration in network condition and possibly quality of supply. They will seek to establish reasonable levels of load-related expenditure in the price control period in the light of external drivers such as levels of economic activity.

3.42 At the same time the consultants will analyse the companies' investment strategies for making improvements to quality of supply, and the relationship between capital expenditure, operating costs and quality of supply. This analysis will include:

- examining the relationship of quality of supply to the security standards and standards of performance;
- identifying the likely costs and benefits of any changes to standards; and
- examining alternative approaches that could be adopted to achieve an improved network performance.

3.43 Quality of supply issues are considered more fully in Chapter 4.

Financial Issues

3.44 This section describes some of the issues that will be involved in estimating the cost of capital and an appropriate return to shareholders. As discussed earlier, the MMC has used present value calculations when resetting price controls. This involves establishing a regulatory asset base and estimating a return equivalent to the cost of capital on this asset base. As a supporting check on these calculations it will be necessary to consider the implications for the financial position of the distribution businesses.

i) Cost of Capital

3.45 The level of return that is required by the financial markets is called the cost of capital. In setting the previous distribution price controls, OFFER used an estimate of 7 per cent for the real pre-tax cost of capital. The same value was later used in OFFER's price control proposals for NGC's transmission business[6] in 1996, in the MMC's report

[6] OFFER "The Transmission Price Control Review of the National Grid Company Proposals" October 1996.

on the transmission and distribution business of Northern Ireland Electricity (NIE)[7] in March 1997, and in the MMC's report on the transmission and distribution business (Transco) of BG plc[8] in May 1997.

3.46 Table 18 sets out the main elements of the calculations for NGC and NIE. In broad terms, the cost of capital is usually calculated as a weighted average of debt and equity finance, with an allowance for corporation tax. In its report on NIE the MMC estimated the cost of debt finance at between 3.8 and 4.6 per cent and the post-tax cost of equity finance at between 5.6 and 7.5 per cent. The post-tax cost of equity finance was uprated by a tax wedge to allow for corporation tax, giving a pre-tax cost of equity finance in the range 6.7 to 9 per cent. Weighting these two ranges with a ratio for debt to equity finance (in this case 8 per cent debt and 92 per cent equity) gave a weighted average pre-tax cost of capital between 6.5 and 8.7 per cent. In its calculations of price control revenue the MMC used a cost of capital of 7 per cent, an estimate toward the bottom end of this range. OFFER's calculation for NGC yielded a range for the cost of capital of between 5.9 and 7.5 per cent, so 7 per cent was toward the top end of that range.

[7] MMC "Northern Ireland Electricity plc". A report on a reference under Article 15 of the Electricity (Northern Ireland) Order 1992, March 1997.

[8] MMC "BG plc" A report under the Gas Act 1986 on the restriction of prices for gas transportation and storage services, May 1997

TABLE 18: COST OF CAPITAL CALCULATIONS

	OFFER on NGC August 1996		MMC on NIE May 1997	
Component	**Low %**	**High %**	**Low %**	**High %**
Cost of debt				
Risk free rate	3.5	3.8	3.5	3.8
Risk premium for debt	0.4	0.4	0.3	0.8
Cost of debt	3.9	4.2	3.8	4.6
Cost of equity				
Risk free rate	3.5	3.8	3.5	3.8
Risk premium for equity	3.5	4.5	3.5	5.0
Equity beta (1)	0.55	0.75	0.6	0.75
Post-tax cost of equity*	5.4	7.2	5.6	7.55
Taxation adjustment(1)	1.194	1.194	1.194	1.194
Pre-tax cost of equity**	6.5	8.6	6.69	9.01
Weighted average cost of capital				
Percentage of debt finance(2)	24	24	8	8
Pre-tax WACC***	5.9	7.5	6.46	8.66

Notes:

(1) Absolute number not a percentage figure.

(2) The percentage of equity finance is (100-percentage of debt finance).

* The post-tax cost of equity is calculated by multiplying the equity premium by the equity beta and adding to the risk free rate. For example, in the MMC low case (3.5 x 0.6) + 3.5 = 5.6.

** The pre-tax cost of equity is calculated by multiplying the post-tax cost of equity by the taxation adjustment. For example in the MMC low case (5.6 x 1.194) = 6.69.

*** The pre-tax WACC is calculated as a weighted average (according to the level of gearing) of the cost of debt and equity finance. For example, in the MMC low case $\left(6.69 \times \frac{92}{100}\right) + \left(3.8 \times \frac{8}{100}\right) = 6.46$

3.47 Looking at the components in more detail, the cost of debt finance can be thought of as having two parts, a risk-free component and a company-specific risk premium for debt. The risk-free rate can be estimated from the return available on government indexed linked gilts and treasury bills. In its report on NIE, the MMC estimated a range for the risk free rate of between 3.5 and 3.8 per cent. The risk premium for debt will depend on a number of company specific factors, including the gearing (the proportion of financing provided by debt) of the company issuing the debt and its overall financial position. The MMC estimated the debt risk premium for NIE in the range 0.3 to 0.8 per cent, giving a total cost of debt of between 3.8 and 4.6 per cent. The PESs tend to be larger businesses than NIE, which might suggest a lower debt risk premium. Against

this, PESs have a higher level of gearing which might suggest a higher debt risk premium. OFFER assumed a debt risk premium for NGC at 0.4 per cent.

3.48 In its 1997 report on NIE, the MMC used the capital asset pricing model (CAPM) and the dividend growth model (DGM) to estimate the cost of equity finance. CAPM assumes that the cost of equity finance can be derived by adding an estimate of the risk-free rate to an estimate of the appropriate equity risk premium. Estimating the risk-free rate is discussed in paragraph 3.45. In estimating the appropriate equity risk premium two factors are taken into consideration: the equity risk premium for the market as a whole, and the riskiness of the company or investment concerned relative to the market. Using information on historic equity returns and estimates for the risk-free rate the MMC report on NIE concluded that the equity risk premium for the market as a whole lies in the range 3.5 to 5 per cent. A measure of the riskiness of a company relative to the market is the beta coefficient. This indicates the extent to which a company's share price will tend to change in response to changes in the overall level of the market. A beta value of 0.75 would indicate that a share price would be expected to change by 0.75 per cent for every one per cent change in the overall level of the market. In general beta values lie in the range 0.5 to 1.5, with beta values less than one indicating companies with relatively low risk and beta values greater than one indicating companies with relatively high risk. Using daily and weekly historic data on share prices the MMC estimated beta in the range 0.6 to 0.75 for NIE.

3.49 The DGM can be used as a supporting check on the cost of equity finance. This method estimates for the cost of equity finance by adding together the companies dividend yield with an estimate of expected real dividend growth for the company. In its report on NIE the MMC quoted estimates for the gross dividend yield for NIE at around 5 per cent. It indicated that the company's real dividend growth should equal the growth in the economy as a whole, and quoted an estimate of this at between 2.5 and 3 per cent. Adding these two components together suggested a post-tax cost of equity capital at between 7.5 and 8 per cent, which was at the top of the range derived by the MMC using CAPM. Nevertheless, the MMC concluded that the indications given by the DGM did not contradict its other findings on the cost of capital. The gross dividend yield of the groups of companies owning PESs and which are quoted on the London stock exchange is at present typically between 4 and 6 per cent.

3.50 As well as CAPM and the DGM, it may be possible to make use of other methods in making estimates of the cost of equity finance. For instance Arbitrage Pricing Theory (APT) relates the relative return a company should earn to a range of factors, rather than focusing simply on beta, as CAPM does. These factors might include the return on the market as a whole and the level of economic growth as well as more company-specific factors. However, in practice it may be difficult to quantify the impact of such factors and it is unlikely that APT would provide a robust basis for estimating the cost of equity capital.

3.51 As explained in paragraph 3.46 the cost of capital is usually calculated as a weighted

average of the cost of debt and equity finance. The estimates in Table 18 show that the cost of debt finance is cheaper than the cost of equity finance. In these circumstances companies may be able to reduce their average cost of capital by increasing the proportion of debt finance. In addition, as discussed below, debt can be a tax efficient method of finance. However, increasing gearing will tend to increase equity beta values and the risk premium for debt. While the level of debt remains relatively low, the effect of these factors may be small and more than offset by the relatively low overall cost of debt finance. There is some uncertainty as to the precise effects of these various factors and in particular as to the point at which increases in gearing start to cause increases in equity beta values and in the debt risk premium that are sufficiently large to increase rather than reduce the overall cost of capital.

3.52 As well as paying dividends and interest, companies must also finance corporation tax payments. As interest payments are allowable against corporation tax the cost of debt finance does not need to be adjusted upwards to take account of corporation tax. This can make debt a cheaper source of finance than equity and suggests that the high level of gearing associated with some PESs may reduce their overall cost of capital.

3.53 The MMC report on NIE adjusted the cost of equity finance upwards by a tax wedge to take account of corporation tax. In doing so it made a number of simplifying assumptions, including that the company pays corporation tax at the full rate and that all profits are distributed as dividends. It will be necessary to consider whether such simplifying assumptions remain valid for the distribution businesses and whether the allowance for tax in the calculations makes an appropriate contribution to corporation tax, when combined with assumptions relating to asset valuation. It is for consideration whether to assess the individual tax position of each PES, but this may reduce incentives on PESs to deliver efficient capital structures and could be difficult, this suggests a simpler approach involving more general assumptions across all companies.

3.54 Since the last distribution price control review most of the PESs have been taken over. It will not be straightforward to estimate beta values for the distribution business as most of the share price data that is available relates to larger groups of companies, many of which are under US ownership. The control of many PESs by US-owned companies raises the question whether the cost of US debt and equity finance is relevant to setting the distribution price controls. PESs now have different proportions of debt finance, and it is for consideration what proportions to assume, and whether to assume a uniform proportion in calculating the cost of capital for each company.

3.55 There are also a number of other factors to take into account which might indicate that the cost of capital has changed. Recent evidence from the yields on indexed linked gilts suggests that the risk free rate might now be below the 3.5 to 3.8 per cent range used by the MMC in 1997. The downward trend in dividend yields over the last twenty years has continued, perhaps indicating a downward trend in the equity risk premium and so in the cost of equity capital. On the other hand there is evidence that the beta values of some utility companies, particularly the Scottish PESs, have increased. Finally, it may be necessary to take account of changes in the corporation tax regime that have

occurred in the last few years in calculating the taxation adjustment for the cost of equity capital. An important question for the price control review will therefore be whether a 7 per cent real cost of capital remains appropriate for distribution businesses or whether the evidence suggests a different figure.

(ii) Valuation of Assets

3.56 In order to secure continuing access to funds on acceptable terms, a business needs to provide a return on the capital already invested in the business as well as a return on new investment. Previous price control reviews have divided the capital invested in the business into two components; the initial capital as it stood at flotation and the investment made since then.

Valuation of Assets Acquired at Flotation

3.57 Assessing the appropriate value for the initial capital is not straightforward. At the last REC distribution price control review OFFER concluded that it was not necessary to remunerate shareholders on the basis of the replacement value or the current cost book value of the initially acquired assets. Rather, regard should be had to the money actually paid to purchase a company, which was less than the above values. The starting point was the flotation value of each company. Certain adjustments were necessary in order to translate this value of the company as a whole into a value for the distribution business. First, the value of parts of the company other than the distribution business, that is other businesses and the shareholdings in the NGC, were deducted. Second, OFFER also took account of other considerations, particularly changes in the cost of capital, and concluded that it would be appropriate to base the control on a higher value than the flotation value in order to maintain the returns that investors might reasonably have expected at flotation. The August 1994 proposals[9] were based on the adjusted flotation values uprated by 50 per cent.

3.58 In formulating proposals for the Scottish companies, OFFER faced a somewhat different valuation problem, partly because of the extent of vertical integration in these companies and partly because of the different relationship of flotation values to book values of assets. In order to translate the flotation values for the companies as a whole into values for the distribution businesses, it was assumed that investors valued the generation assets of ScottishPower and Hydro-Electric at the same relation to their current cost book value as they did for National Power and PowerGen. By deducting this value from the total value which investors placed on the two Scottish companies, values were derived for the distribution and transmission businesses. Unlike the position in England and Wales these values were close to the current cost book values at flotation. Adjustments were also made for events since flotation. It appeared that the cost of capital was higher than the 6 per cent rate of return assumed by the Government in setting the original price controls. In order to maintain consistency with the initial price control for the Scottish PESs, OFFER considered that the revised price control

[9] OFFER "The Distribution Price Control: Proposals" August 1994

should be based on a lower value for the initial assets than the value obtained at flotation.

3.59 Hydro-Electric rejected the proposals for revised distribution price controls. In accordance with the Electricity Act, the Director General referred the matter to the MMC. One of the issues in this case was whether the flotation value should be adjusted downwards (rather than upwards) to reflect the difference in the cost of capital between the 6 per cent used by the Scottish Office in setting the initial price control and the 7 per cent assumed to be obtaining in 1994. In May 1995 the MMC concluded that "an adjustment of this kind at the present time, based on an assessment of what investors may rightly or wrongly have assumed about the cost of capital at the time of privatisation, does not seem appropriate to us in this analysis" (paragraph 2.50).

3.60 In February 1995, one of the RECs announced a significant change in financial structure, and scope for further cost reductions, in response to the first take-over bid for a PES. In March 1995 OFFER announced an extension of the consultation period relating to the licence modification arising out of the August 1994 proposals. Subsequently, in the light of representations received and new evidence, it announced a further review of the distribution price controls for the 12 RECs. In formulating revised distribution price controls it reconsidered the approach to initial valuation in the light of the 1995 MMC report on Hydro-Electric. OFFER concluded that it was no longer appropriate to make an uprate in flotation values to reflect a reduction in the cost of capital. However, there still remained several potentially relevant arguments for an uprate. First, investors bought shares at flotation with a prospect of rising dividends. Second, shareholders originally valued the PESs at a lower price because of the risks they perceived - for example, resulting from the possible failure of the new electricity trading arrangements, upheaval in world energy markets at the time of the Gulf War or changes in public policy in the United Kingdom. Third, some uprating had in practice been applied by the MMC and other regulators. OFFER also wished to ensure that the incentives to efficiency were maintained, since this would potentially benefit customers as well as shareholders. In the light of these considerations OFFER decided to reduce the uprate on flotation value from 50 per cent to 15 per cent. The calculations of the Vesting asset values for each company at the last price control review are set out in Annex 3.

3.61 In July 1996 the Director General for Electricity Supply in Northern Ireland made proposals for revised price controls on the transmission and distribution business of NIE[10]. He argued that it was not appropriate to make any uprate on the flotation values of NIE's assets. NIE rejected the price control proposals and the matter was referred to the MMC. In March 1997 the MMC concluded

> "an uplift on the close of first-day trading has been adopted in nearly all previous cases where price reviews have been carried out, ranging from 26 per cent in the case of British Gas to single figures for the water and sewerage companies. The exception was the adoption of a negative 3 per cent for the

[10] OFREG "Price Control Reviews for Northern Ireland Electricity plc - DGESs proposals", July 1996

two Scottish electricity companies. The general trend has been downwards. These previous cases might have been taken to constitute a reason for adopting an uplift in the present case on the grounds of regulatory consistency. Taking account of the various considerations which we have set out above, we have adopted an uplift of 7½ per cent for the purpose of this price review" (paragraphs 2.83 and 2.84).

3.62 The MMC also made a recommendation (see below) on the period of time over which the asset valuations should be written off. The Director General for Electricity Supply in Northern Ireland considered that the public interest detriments identified by the MMC could be met by making certain revisions to his previous proposals but that it was not appropriate to accept the MMC's recommendation on uprating the value of NIE's Vesting assets and the period of time over which these valuations are written off. The company applied for a judicial review, contending that the decision was ultra vires Article 17 of the Electricity (Northern Ireland) Order 1992. The Court has recently dismissed the application for judicial review[11], noting that the Director General was at liberty to devise modifications to deal with these adverse effects identified by the MMC provided he had regard to the modifications suggested by the MMC.

3.63 In its May 1997 report on British Gas, the MMC explained that the approach adopted to asset valuation in its 1993 MMC report[12] remained appropriate.

Asset Lives

3.64 A related issue is the period of time over which initial valuations are written off. In setting the last distribution price control OFFER assumed that a proportion of the flotation values associated with each REC's distribution business would be written off on a uniform annual basis, typically over 10 to 15 years, depending on the average age of each REC's assets at Vesting. In its report on NIE the MMC took a more disaggregated approach, attributing the flotation value to various categories of assets, and writing-off each part of the total according to the accounting life of each category of asset. If applied to the RECs, the effect of this latter policy would be to write off the flotation values over a longer period, which in turn would reduce the allowed revenue in the period 2000 to 2005 and increase it beyond 2005. As noted in paragraph 3.60 the Director General for Electricity Supply in Northern Ireland rejected the MMCs recommendations relating to writing off of the lives of initial assets.

Summary

3.65 In resetting the existing distribution price controls it is for consideration whether an uprate on attributed flotation value should be maintained, and if so whether this should be at 15 per cent or at some different level. It is also for consideration whether to use

[11] High Court of Justice in Northern Ireland in "Judgement in the Matter of an Application by Northern Ireland Electricity plc for Judicial Review" June 1998.
[12] MMC "Gas and British Gas plc reports under the Gas and Fair Trading Acts" September 1993.

more precise assumptions about expected lives of Vesting assets. Some PESs have said that the approach to the valuation of distribution assets should remain as in the previous review arguing that to do otherwise could lead to an increase in regulatory risk and a higher cost of capital. It is for consideration how to balance the advantages of consistency with the last distribution price control review, with recent MMC reports and with other regulators. It will also be relevant to consider the impact on the financial position of the companies and the path of prices in the shorter and longer term.

Investment Made Since Flotation

3.66 The present price control was set to finance actual network capital expenditure over the period 1990/91 to 1994/95 and the projected spending for the period 1995/96 to 1999/2000. As in the recent NGC transmission price control it is to be expected that the revised distribution price control will continue to finance only the actual network capital expenditure for the period 1995/96 to 1999/2000, if this is less than projected expenditure. In setting the control consideration will also be given to the reasons for any shortfall in capital expenditure.

3.67 As noted in paragraph 3.6, the Government's recent Green Paper on utility regulation has suggested that consideration be given to establishing an Error Correction Mechanism which might supplement the RPI-X price control. Such a mechanism could apply to capital expenditure and might adjust allowed revenue on a continuing basis depending on the extent of capital expenditure at any time relative to the projections underlying the price control.

3.68 The MMC considered capital expenditure in its June 1996 report on BAA[13]. It reported that a formal relationship between airport charges and investment would be to the detriment of users in the longer term by removing incentives on BAA to seek efficiency in its investment programme in the light of changes in demand or other external factors. It also noted BAA's new arrangements for consultation with airlines on its investment programme. It concluded that there should not be continuing adjustments for capital expenditure but that any evidence of significant unjustified under-investment should be regarded as a factor to be taken into account at the time of the next review.

3.69 The MMC again considered the issue of underspend against capital expenditure projections in its 1997 report on NIE. It concluded that in the case of NIE the scale of the underspend in the first price control period was difficult to ignore and that NIE itself had acknowledged that not all of it had been due to efficiencies. Several projects included in the capital programme for the first five years appeared again in the programme for the forthcoming period. The MMC concluded that it would not be appropriate for all such expenditure to be refinanced under the new price control. It noted that this decision to some extent reflected the absence of output measures (such

[13] MMC "BAA plc A report on the economic regulation of the London airports companies (Heathrow Airport Ltd, Gatwick Airport Ltd and Stansted Airports Ltd)", June 1996.

as interruptions per customer or customer minutes lost) for the period concerned which would have permitted a considered judgement to be made of the justification for the underspend.

3.70 Evaluating the nature and implications of capital expenditure underspend or overspend in any one year is not straightforward. It is important not to overcharge customers but also important to maintain incentives on companies for efficient capital spending, and to look at experience during one price control period when setting a control for the next. It is for consideration whether it is practicable or sensible to commit to an automatic correction or adjustment mechanism for capital expenditure, either on an annual basis or within a given price control period.

Energy Efficiency

3.71 In reaching decisions during the review OFFER must have regard to the Director General's statutory duties which include promoting the efficient use of electricity and also taking into account the effect on the physical environment of activities connected with the supply of electricity. In the last distribution review, OFFER modified the revenue driver of the control so as to remove any artificial incentive to increase sales of electricity; and also strengthened incentives on the PESs to reduce the electrical losses associated with distribution systems. A number of respondents to the February 1998 consultation paper suggested that the distribution price control review would provide an appropriate opportunity to reconsider the incentives on distribution.

(i) Revenue Drivers

3.72 Price controls can be designed so that the permitted level of total revenue varies with changes in volume as well as being indexed to the RPI. Under the original distribution price control, allowed revenue increased in proportion to units distributed. The last distribution price control review concluded that the weight of units distributed in the revenue driver of the price control should be halved, from 100 per cent to 50 per cent. The remaining 50 per cent was fixed by relating it to a predetermined projection of customer numbers. This change was intended to avoid any artificial incentive on the PESs to promote increased sales of electricity. The retention of a weighting for units distributed, albeit at a reduced level, was intended to maintain the normal commercial incentives on companies to seek out and meet the needs of their customers. It would also avoid undue fluctuations in distribution charges per unit as the volume of output varied.

3.73 In its March 1997 report on NIE the MMC recommended a price control revenue driver with a 75 per cent fixed and a 25 per cent unit element. In its May 1997 report on BG the MMC recommended a price control revenue driver with a 50 per cent fixed and 50 per cent unit element.

(ii) Distribution Losses

3.74 Over the four year period leading up to the first price control review, average distribution losses fell from 7.6 per cent to 7 per cent. Concern was expressed that PESs had insufficient incentive to reduce these losses. As part of the last distribution price control proposal the incentives on companies to reduce distribution losses were increased by doubling the proportion of the benefit retained by companies from reducing losses, while allowing most of the gains to continue to be passed on to customers.

3.75 Table 19 sets out the average level of distribution losses for each company since Vesting. It shows that the average level of distribution losses fell to about 6.7 per cent in 1995/96, but then increased to 6.9 per cent in 1996/97 before falling to 6.8 per cent in 1997/98. In the light of this, and given the apparently significant differences between the experiences of individual companies, it will be necessary to review the incentive arrangements for reducing losses. One possibility might be to replace the present incentive mechanisms with a projection of the cost of distribution losses for each year of the price control period and an additional element in the price control to reward companies for reducing the cost of losses below this level or penalise them if the costs exceed it. Another possibility might be to make distribution businesses responsible for purchasing the energy lost in distribution, replacing the present arrangements in the Pool where supply businesses pay for distribution losses.

TABLE 19: DISTRIBUTION LOSSES FOR LV AND HV CUSTOMERS

PESs	1990/91 (%)	1991/92 (%)	1992/93 (%)	1993/94 (%)	1994/95 (%)	1995/96 (%)	1996/97 (%)	1997/98 (%)
Eastern	7.0	7.0	6.8	6.5	6.7	6.9	7.1	7.0
East Midlands	6.6	6.5	6.7	6.8	6.0	6.1	6.1	6.1
London	7.8	7.2	7.0	7.0	7.1	6.7	7.1	6.8
Manweb	9.8	8.1	8.7	8.7	8.1	8.8	8.8	9.0
Midlands	6.2	5.9	5.7	5.5	5.5	5.5	5.6	5.5
Northern	7.5	7.6	6.8	7.2	6.1	6.8	6.9	6.7
NORWEB	7.1	7.1	6.3	6.3	6.4	4.8	5.0	5.7
SEEBOARD	7.9	7.7	7.6	7.5	7.5	7.1	7.6	7.7
Southern	7.1	7.2	7.1	7.0	7.0	7.2	7.2	7.2
SWALEC	8.9	8.4	8.1	7.0	7.0	6.7	8.0	6.9
South Western	8.6	8.5	8.5	8.3	7.3	7.2	7.9	7.3
Yorkshire	6.3	6.3	6.2	6.2	6.5	6.5	6.5	6.5
ScottishPower	8.5	7.2	7.7	8.1	8.0	6.7	7.2	7.2
Hydro-Electric	9.5	8.9	9.0	9.1	9.1	9.0	9.0	9.1
Average	7.6	7.2	7.1	7.0	6.9	6.7	6.9	6.8

Note: The averages are weighted by the number of units distributed.

(iii) Other Issues

3.76 It has been suggested that distribution and supply business should be required to structure their charges in such a way as to give larger customers incentives to improve their power factors and so increase energy efficiency and reduce the overall costs of power distribution.

3.77 As part of the review of supply price restraints OFFER will need to consider whether to continue the energy efficiency Standards of Performance beyond 2000. This is discussed in Chapter 5.

3.78 The review will need also to take into account any changes to the regulatory regime affecting energy efficiency arising from the Governments' proposals in its Green Paper on utility regulation. The Government proposed that Ministers should issue statutory guidance on social and environmental objectives, including energy efficiency objectives, relevant to regulation in each utility sector. Regulators should be placed under a duty to have regard to such guidance. This would require changes in legislation, the timetable for which is not yet clear. The Green Paper also proposed that where Ministers wished to implement social or environmental measures, including energy efficiency measures, which had significant financial implications for consumers or for regulated companies, these should be decided by Government and implemented through new, specific legal provision rather than through guidance to the regulator.

Metering and Related Services

3.79 The present definition of the distribution business includes a range of activities associated with metering and meter reading. The costs of providing these services was taken into account in setting the present price control. It was recognised, however, that with the onset of competition in supply changes might need to be made in this area. Accordingly, the distribution control was set to include two components, one associated with metering related activities and the other related to the other distribution activities.

3.80 The calculation of the metering component was based on the proportion of business costs which the companies attributed to metering activities and on the number of different types of customers with different types of meters. On average, this was equal to around 10 per cent of revenue. These calculations were necessarily broad brush and were not intended to represent the level of costs which should be attributed to a separate metering business.

3.81 Subsequently, the OFFER concluded that PESs should retain a monopoly over metering related services for non-half hourly metered customers until 2000. New licence conditions were introduced on the PESs to require them to make these services available to other suppliers on non-discriminatory terms. The introduction of competition in supply also required certain new services for suppliers. These include data aggregation (calculations made primarily for settlement purposes) and meter point administration (the registration system for suppliers).

3.82 To reflect the costs of providing these new services and the additional costs of adjusting

existing metering arrangements to facilitate competition, a modification was made to the distribution price control. This modification, known as the data management services charge, provided for PESs to make additional charges up to a maximum specified level.

(i) Metering and Separation

3.83 OFFER set out its thinking on the separation of PES businesses in a consultation paper published in May 1998. In summary, the paper confirmed that meter operation, meter reading and data aggregation should be opened to competition from April 2000, whilst meter point administration should remain a monopoly service provided by the distribution business. Whilst competitive metering related services should be treated as supply business activities, additional considerations applied to meter operation and ownership and to meter reading.

3.84 The paper noted that there was likely to be an effective initial monopoly of meter operation and ownership related to the use of the existing metering stock. Responsibility for the existing metering stock should be given to a metering business either in distribution business ownership or provided by a third party and at least initially the charges for this service would need to be regulated.

3.85 The paper concluded that whilst meter reading should be a supply business activity there should also be a meter reading service of last resort. This could be achieved by the distribution business procuring a specified meter reading service to be made available to suppliers at request on a non-discriminatory basis. The service would not be provided from within the distribution business itself, instead the distribution business would invite tenders to carry out the work.

(ii) Implications for Price Controls

3.86 The reform of metering and related activities has significant implications for the distribution price control from 2000.

3.87 First, the transfer of activities from distribution to supply will need to be reflected in the cost projections, attributions and allocations underpinning the distribution price control.

3.88 Second, distribution charging principles will need to be revised to facilitate competition in metering. In particular, any charges for meter provision and operation and for meter reading will need to be separately identified. Suppliers that choose not to use the distribution business metering service should not be charged for it.

3.89 Third, consideration needs to be given to how these arrangements are reflected in price controls. If a price control is judged necessary for metering, one option would be to introduce a separate price control for metering related services provided by the distribution business. An alternative might be to provide for a specific metering term in

the overall distribution price control.

3.90 Fourth, there is a need to consider how, if at all, the price control arrangements relate to the tendering process proposed for meter reading provision. Initially meter reading may not be fully competitive and a satisfactory tendering process may not be completed in time for price control decisions.

3.91 Fifth, whilst any price control arrangements for metering will raise some of the same issues as the distribution price control, it will also be important to consider the implications for competition in metering. Similar considerations arose in the case of the supply price restraint from 1998 to 2000. In that case, the market was being opened to competition but it was recognised that it would take some time for competition to be established. Whilst encouraging efficiency on the part of the supplier, the supply maximum price restraints were designed to encourage competition to develop by leaving scope for competitors to enter. A similar approach might be adopted in the case of metering activities. In particular, consideration will need to be given to the allocation of the initial asset valuation and other costs between the metering business and the remaining distribution business. An important aim will be to facilitate competition in metering and meter reading, and more generally in supply, rather than to restrict, prevent or distort it.

3.92 Sixth, the scope and form of any control will also need to be determined. At present charges for special metering, including half-hourly metering, are excluded from the price control. Other areas of charging might not need to be covered if competition is expected to provide effective protection for users and customers. The form of the control may be influenced by the expected level of activity by competing meter service providers, the extent to which the revenue drivers identified for distribution are appropriate for metering activities, and the potential effect of any control on the extent and development of competition.

Competition In Connections

3.93 Charges for connections to the distribution system are not covered by the present distribution price control. PESs have said it is difficult to forecast the number or scale, and hence the cost, of new connections: in the event of a dispute individual connection charges can be determined by OFFER.

3.94 The last distribution price control review examined the possibility of introducing competition in the provision of connections. As a result, from April 1995, changes were agreed with PESs to allow suitably approved independent contractors to undertake some of the connection work.

3.95 Part of the connection work (called the non-contestable element) still needs to be done by the PES. This includes the design and specification of the new connection, deciding on the point of connection, obtaining consents and wayleaves, removal of existing assets, and inspection and monitoring of competitors' works and final connection and

energisation. The remaining (so-called contestable) elements which include supplying all materials, site preparation and construction of electrical infrastructure between the customers premises and the point of connection, and recording the location of equipment, can be done by a contractor chosen by the customer and approved by the PES.

3.96 Contractor approval can take different forms. Some PESs approve contractors via a nationally recognised evaluation and registration scheme. Other PESs insist on their own approval process.

3.97 Customers have indicated some dissatisfaction with the level of connection charges presently levied by PESs and about the prospects for effective competition. Problems to which they draw attention include an overly bureaucratic, extensive and costly approval system adopted by some PESs and limited scope of contestable work. This presently excludes live line working which effectively removes work associated with provision of connections to streetlighting columns or upgrades to existing connections.

3.98 It might be difficult to devise a price control on connections, because individual connections can vary greatly in cost. Determinations of charges by OFFER impact in the first instance only the relatively small number of cases that are referred. OFFER intends to consult separately on competition in connections in due course.

Issues for Consideration

3.99 Views are invited on any aspect of the distribution and metering price controls, and in particular on:

- the appropriate duration of the control, whether it should continue to be an "RPI-X" control, and whether it should incorporate any form of Error Correction Mechanism;
- whether the scope of the price control should be widened to include revenue from some or all presently excluded services, and what would be the most appropriate treatment of NGC exit charges;
- the assessment of allowed revenue, including the role of present value calculations and the treatment of any underspend or overspend against previous projections of capital expenditure;
- the approach to assessing future levels of operating costs and capital expenditure;
- the approach to asset valuation including the level of any uprate to the value of Vesting assets;
- the appropriate cost of capital and related evidence;

- what approach should be adopted to energy efficiency, the revenue driver and the treatment of distribution losses;

- the most suitable approach to metering activities, including the possibility of establishing a metering price restraint and encouraging competition in metering activities, and tendering for meter reading; and

- the possibilities for increasing competition in connections.

4 QUALITY OF SUPPLY

4.1 Quality of supply relates both to the reliability of supply, which can be measured by the number and duration of supply interruptions, and to the quality of the supply received in terms of the voltage level and the waveform quality. Quality of supply varies from place to place and from time to time. In general customers in urban areas suffer fewer supply interruptions than those in rural areas but there can be wide variations in quality depending on the particular location of customers within the network, and on the weather at different times of year.

Regulation of Quality of Supply

4.2 Several statutory and regulatory factors affect the design, operation and maintenance of networks and influence the quality of supply experienced by customers.

(i) Electricity Supply Regulations

4.3 The Electricity Supply Regulations, which are issued by the Secretary of State, contain basic requirements for supply quality. They place a duty on PESs to ensure a continuous supply except in exceptional circumstances. They define limits of allowed variations about a declared supply voltage of 230V (presently +10 per cent to -6 per cent), and a nominal frequency of 50Hz ($\pm$ 1 per cent). They also contain requirements about the safety and adequacy of networks.

4.4 On 1 January 1995 the Government changed the declared voltage and statutory limits of variation from 240V $\pm$ 6 per cent to 230V +10 per cent to -6 per cent as part of a move to harmonise voltages across the European Union.

(ii) Guaranteed and Overall Standards

4.5 OFFER has set Guaranteed and Overall Standards of Performance for PESs under sections 39 and 40 of the Electricity Act. These Standards - which cover a wide range of key service areas for customers - were first introduced in July 1991, and have been progressively tightened and extended since then. Several of these Standards relate to quality of supply. One of the Guaranteed Standards requires payments to individual customers when a PES does not restore supply within 24 hours of an interruption. Two of the Overall Standards (1a and 1b) require companies to aim to restore supplies to specified minimum percentages of customers within specified periods (respectively 3 and 24 hours) after an interruption. OFFER publishes the companies' performance under the Standards, and PESs are required to inform customers about them.

4.6 During 1997, OFFER consulted on the scope for making improvements in the Standards. Most of the resulting changes, which were implemented on 1 April and 1 July 1998, were in areas other than quality of supply. There were, however, a number of changes in Standards affecting the restoration of supplies following interruption. In particular, as from 1 April, all PESs are required (under Overall Standard 1b) to restore 100 per cent of supplies within 24 hours (previously, ten PESs had a target of 99 per cent); and the targets under Overall Standard 1a, covering the percentage to be restored within 3 hours, now range from 85 to 95 per cent (previously they ranged from 80 to 95 per cent). OFFER indicated that proposals for more wide-ranging changes in Standards covering quality of supply should, in view of their potential cost implications, be considered as part of the present review.

(iii) Licence Requirements

4.7 Each PES licence contains a condition relating to network design and performance reporting. Condition 9 (Condition 7 in Scotland) of the licence requires the companies to design their networks to meet a standard known as Engineering Recommendation P2/5. The Recommendation specifies different levels of security for different sizes of electrical demands, which represent different customer numbers. For example, a 1 MW demand could consist of a few hundred domestic customers or one large industrial customer. In assessing the design of the network, each part of the network is examined, together with the customer demand connected to it, to ensure that the network has adequate security for the size of the demand. For large demands, the network has to be designed to continue to provide electricity to customers after a single fault or failure of network equipment. For groups of customers with demands below 1 MW, supplies can be cut after such a fault or failure and there is only a requirement to restore supplies after repairing the faulty part of the system. These requirements mean that companies need to provide some form of backup arrangement for large demands, usually by having two or more alternative ways to provide supplies from the network. No backup arrangements are needed for demands below 1 MW.

4.8 Recommendation P2/5 was issued in 1978 and was generally used by all electricity boards when constructing their distribution systems. Prior to 1978 extensions to their systems were designed in accordance with earlier, somewhat higher, standards. PESs say that they sometimes apply higher standards of security of supply, where they consider it appropriate, including when a customer requests it. There are other standards relating to other aspects of network design imposed by the Distribution Codes which PESs are obliged by their licences to draw up. OFFER invited views on the continued applicability of existing network standards in the consultation process during the 1994 distribution price control review, and concluded that there was no overriding reason to change them at that time. It is for consideration whether the standards continue to be appropriate.

Present Levels of Quality of Supply

4.9 OFFER monitors the distribution system performance of each PES using information supplied by companies under Condition 9 (Condition 7 in Scotland) relating to network design and performance. The companies' reports are summarised and published annually in a Distribution and Transmission System Performance Report by OFFER. These reports show that, on average, each customer suffers 0.9 interruptions per year and each of these interruptions lasts approximately 90 minutes. There is a wide range of performance between and within companies and from one year to another. Some customers experience no interruptions, or very few, whilst others suffer them frequently.

4.10 OFFER's 1996/97 Customer Service report[14] shows that 167 Guaranteed Standards payments were made by PESs for failure to restore supplies within 24 hours. PESs' performance in restoring supplies within 3 hours (Overall Standard 1a) varied between companies in the range 81 to 95 per cent. The Standard itself ranges from 80 to 95 per cent, depending on the company. Only one company failed to meet its required level of performance under this Standard. PES performance in restoring supplies within 24 hours (Overall Standard 1b) varied between companies in the range 99 to 100 per cent. The required level was either 99 or 100 per cent depending on the company. Again, only one company failed to meet its required level of performance under this Standard.

4.11 In addition to the above measures of quality of supply, OFFER has asked PESs to report annually on steps they are taking to improve quality. The present price control included an element of capital expenditure for quality improvement and required companies to set targets and report on capital expenditure and quality improvements in their own areas.

4.12 Quality of supply reports are asked to focus on those parts of the network, and those customers, which are worst served in terms of quality of supply. The companies are also asked to set themselves targets relating to two measures of network performance, namely security and availability. Companies express their targets in different ways: some define them in terms of an improvement over 1994/95 performance levels; others express them in terms of an improvement over rolling average figures for a number of years; yet others set targets including ranges. Tables 20 and 21 show companies' performance in recent years and include their targets expressed on a common basis in terms of absolute performance in 1999/2000.

[14] OFFER "Report on Customer Services 1996/97"

TABLE 20: SECURITY OF SUPPLY: INTERRUPTIONS PER 100 CUSTOMERS

	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	Company target for 1999/2000
Eastern	76	68	96	59	65	85	89	70
East Midlands	169	82	75	92	96	97	95	87
London	41	47	38	36	40	33	39	30
Manweb	82	74	86	89	70	62	57	50-60
Midlands	170	110	129	125	121	139	148	109
Northern	108	90	87	80	89	90	89	87-92
NORWEB	58	62	57	56	70	61	60	55
SEEBOARD	98	90	139	87	91	83	80	82
Southern	80	81	82	78	75	79	79	70
SWALEC	285	229	195	214	220	223	192	189
South Western	146	129	118	119	124	116	106	87
Yorkshire	158	69	72	71	85	86	93	55
ScottishPower	70	71	83	58	61	65	57	45-55
Hydro-Electric	176	204	135	178	176	193	146	170
Average Customer-weighted	111	88	95	85	88	91	89	77

TABLE 21: AVAILABILITY OF SUPPLY: MINUTES LOST PER CUSTOMER

	1990/91	1991/92	1992/93	993/94	1994/95	1995/96	1996/97	Company target for 1999/2000
Eastern	76	65	91	63	94	85	77	66
East Midlands	1,004	87	87	97	105	95	79	73
London	51	67	53	52	58	54	56	40
Manweb	185	108	129	121	102	88	78	65-75
Midlands	398	118	122	144	128	151	126	86
Northern	246	97	102	102	95	86	82	96
NORWEB	88	75	77	69	70	67	66	64
SEEBOARD	101	86	106	75	83	69	82	60
Southern	104	109	91	74	78	78	67	60
SWALEC	330	325	212	200	212	233	189	191
South Western	185	176	184	167	133	111	103	93
Yorkshire	175	60	59	61	69	62	60	56
ScottishPower	85	76	98	77	70	81	89	55-65
Hydro-Electric	172	270	356	254	233	365	206	210
Average Customer-Weighted	226	102	106	96	97	97	87	75

Customer Attitudes to Quality of Supply

4.13 OFFER gets feedback from customers about supply quality in several ways. These include surveys conducted to seek customer view; complaints received from customers and views from ECCs.

(i) Customer Survey

4.14 In 1997 OFFER commissioned research into the views of customers on a number of topics relevant to regulation of the electricity supply industry including quality of supply. The results from three of the questions were as follows:

In general how satisfied or dissatisfied are you with reliability of your electricity supply?

	%
Totally satisfied	15
Very satisfied	46
Fairly satisfied	35
Neither satisfied nor dissatisfied	2
Totally/Very/Fairly dissatisfied	2

How much extra per year would you be prepared to pay (if anything) to help ensure that there are no power cuts in future?

	%
Nothing	71
Less than £10	12
£11-£25	5
£26-£50	2
£51-£65	<0.5
£76-£100	<0.5
More than £100	<0.5
Don't know	9

Do you think it is fair and reasonable that targets for meeting standards should vary somewhat between companies in different parts of the country because of their own local circumstances?

	%
Yes	56
No	35
Don't Know	9

4.15 Ninety five per cent of those questioned were totally, very or fairly satisfied with their quality of supply. Only one in five customers said that they would be prepared to pay anything extra to ensure that there were no power cuts.

4.16 The survey also asked customers whether some company targets for quality of supply should vary according to local circumstances. A small majority (56 per cent) said this was fair and reasonable, but one in three customers said it was not a good idea.

4.17 These findings appear to indicate that customers are generally satisfied with the quality of supply they receive. They do not suggest that customers are willing to pay significantly more to get better service, and there are mixed feelings about encouraging differential service levels in different parts of the country. However, other evidence discussed below suggests that there are some important aspects of customer dissatisfaction with present quality of service.

(ii) **Complaints**

4.18 About 1500 quality of supply complaints are made to OFFER each year. This does not include complaints which are made direct to companies and resolved by them without being referred to OFFER. Overall the total number of complaints made to OFFER on most topics has fallen significantly since Vesting. However, the number of complaints about quality of supply has remained roughly constant. Such complaints have therefore grown as a proportion of the total number of complaints received by OFFER, from about 7 per cent after Vesting to 22 per cent in 1997.

4.19 The nature of some complaints suggests that customers may be more sensitive to the quality of supply than they were in the past. In part this is related to the way in which customers now make use of their electricity supply. Many customers have appliances which include electronic controls, for example, video recorders and computers; many of these appliances cannot tolerate even brief interruptions in supply. At the same time, PESs are making increased use of automatic equipment to reduce the duration and impact of prolonged outages by interrupting and quickly restoring supplies after faults. In such cases, customers therefore experience short interruptions of a few seconds rather than much longer power cuts. During the operation of such equipment, customer appliances like those mentioned above may lose data or need resetting after power is restored.

(iii) **Views of ECCs**

4.20 ECCs and others have said that customers wish to see improvements in quality of supply. They have made various suggestions: tightening the targets set under existing Standards, for example, by reducing the time required to restore supplies after interruption; extending the circumstances in which Standards would apply, such that payments for supply interruptions should be made irrespective of the severity of the weather; requiring payments for supply interruptions to be made automatically instead

of at the customer's request; and introducing new Standards, for example covering multiple supply interruptions. The Committees have also expressed concern that investment in PES distribution networks has in many cases fallen below the level for which provision was made when the present price control was set.

Performance in Bad Weather

4.21 Customers in the UK receive their electricity through a mixture of overhead and underground networks. Most EHV transmission circuits are carried on large steel pylons. Distribution networks vary in nature; in towns they are usually placed underground using buried cables; in rural areas overhead lines using bare conductors, usually carried on wood poles, are commonplace. Most failures in supply (about 98 per cent of the number of interruptions and minutes lost by customers in a typical year) arise from incidents on distribution networks.

4.22 The disaggregated data now given by companies in their quality of supply reports shows variations of performance between different parts of the same company. These differences often reflect the different underlying performance of underground and overhead networks. Underground networks are typified by low fault rates, which are unaffected by weather, but sometimes with relatively long repair times. On the other hand, overhead networks suffer more frequent outages which are often weather related but restoration times can be short if circuits are not damaged during the fault incident.

4.23 During periods of particularly bad weather, overhead networks can suffer widespread and prolonged interruptions. Two such periods occurred recently, on 24/25 December 1997 and again on 3/4 January 1998, when parts of England and Wales were affected by storms which caused widespread damage to overhead electricity distribution networks. In response to numerous complaints from customers, the Minister for Science, Energy and Industry asked the DGES to carry out an investigation. His subsequent report identified a number of issues for consideration in the price control review.

4.24 The first issue concerns the levels of investment and the standards of supply reliability. Some companies said that, in general, lines built more recently stood up to the storms better than older ones. The report said that, as part of the present review, OFFER would examine the appropriateness of present technical design standards, the progress of companies in replacing or upgrading lines built to earlier design standards, and the costs and benefits of measures which might improve supply reliability such as undergrounding overhead lines. OFFER would also be examining what levels of capital expenditure are consistent with efficient distribution network operation and maintaining levels of system security, including how actual expenditure relates to the levels projected at the last review.

4.25 Secondly, serious shortcomings were found in some PESs' arrangements for communicating with customers during the storms. Companies have a licence

obligation to provide enquiry services, and OFFER accordingly asked them to review their arrangements in the light of the storms. A number of companies have described improvements they have made as a result of their reviews, and OFFER is presently considering their replies.

4.26 Finally, OFFER's investigation revealed considerable variation in practice between companies in the basis on which payments are made to customers in the event of disruption to supply. Some made them under Guaranteed Standards, some on a goodwill ex-gratia basis. The criteria for payments and their amounts also seemed to vary.

Analysing Quality of Supply

4.27 Against the above background of technical, legislative and regulatory factors which influence supply quality, and evidence of customer perceptions of quality, the review will consider whether and to what extent further steps should be taken to improve quality of supply in the forthcoming review period. To facilitate analysis and discussion, attention will initially focus on three main topics: tightening existing Guaranteed and Overall Standards and introducing new Standards where appropriate; undergrounding part of the distribution network; and other company-specific programmes of quality improvement. OFFER will be asking companies to indicate the costs of each of these approaches. In the light of this information, OFFER intends to seek further views in a public consultation. It may also be appropriate to seek more information about customer wishes, including by a further customer survey.

(i) Guaranteed and Overall Standards

4.28 The percentage targets set for restoration of supply within 3 hours under Overall Standard 1a range from 85 to 95 per cent. ECCs have suggested that the targets for all companies should be increased to 95 per cent. It is for consideration whether this or a similar change should be made.

4.29 The Guaranteed Standard covering supply interruptions requires payments when supplies are not restored within 24 hours. ECCs have suggested that the relevant time should be halved to 12 hours. It is for consideration whether the 24 hour period should be reduced and by how much.

4.30 The Guaranteed Standard on supply interruptions requires companies to make payments to customers only in circumstances where severe weather conditions did not impair their ability to restore supplies within 24 hours (the severe weather exemption). It is for consideration whether the exemption should be more tightly defined (for example, by specifying what is meant by severe weather) or removed altogether.

4.31 The Guaranteed Standard on supply interruptions requires companies to make payments to customers only after prior claim by those customers affected. This

provision formed part of the Standard because of the difficulty of identifying precisely which customers are affected by interruptions. It has, however, led to substantially fewer payments than might otherwise have been made. During 1996/97, for example, only 132 customers received payment under this Standard, whereas PESs' returns indicate that over 19,000 supplies were lost for more than 24 hours. A number of PESs have recently indicated that they can now identify affected customers. It is for consideration whether to require automatic payments to customers for breach of the Standard.

4.32 Overall and Guaranteed Standards do not presently cover short losses of supply, which last for less than a minute, but may occur relatively frequently over a period of a few days. Some such losses are caused by equipment which companies have installed to minimise the incidence of longer interruptions. It is for consideration whether to introduce Standards in this area. A Guaranteed Standard could require payments to customers who suffer more than a specified number of short interruptions each year. An Overall Standard could require companies to aim to design and operate their networks so as not to exceed a specified total number of short interruptions each year.

4.33 At present, companies report quality in terms of statistics for the average number and duration of interruptions. They have also set themselves voluntary targets against these parameters. It is for consideration whether to introduce Overall Standards in this area. The levels in these Standards might, for example, be determined on the basis of specific percentage improvements for each company in numbers of interruptions or minutes lost by the end of the next price control period.

4.34 The experience of customers during the supply interruptions last Christmas (see paragraph 4.25 has highlighted the need for improved provision of customer information during supply emergencies. It is for consideration whether to introduce an Overall Standard requiring companies to provide a specified level of response, perhaps defined as the percentage of customer telephone calls to be answered (in person or with a substantive message) within a specified time. This could relate to both normal and exceptional conditions to provide a means of ensuring adequate communications on a day-to-day basis and during emergency conditions such as those experienced in the winter of 1997/98.

(ii) **Undergrounding**

4.35 As explained in the report to the Minister on Christmas and New Year storms, the review will examine the appropriateness of present design standards, companies' progress in replacing or upgrading lines built to earlier design standards, and the costs and benefits of other measures to improve supply reliability such as placing overhead lines underground. This would reduce the exposure of the network to severe weather conditions and also bring environmental benefits by removing the visual impact of overhead lines.

4.36 OFFER asked companies for their views on placing the distribution network underground. The companies said that the wholesale use of underground cables would avoid collective failure during storm conditions so that incidents such as those seen during Christmas and New Year 1997/98 would not reoccur. A further benefit would be that underground cables would not be susceptible to the causes of short term transient interruptions that overhead line networks experience. However, companies described important disadvantages of wholesale undergrounding in rural areas. One example given was that repair time on an underground cable can be 20 hours or longer, compared with 4 to 6 hours for an overhead line. Companies said that, in rural areas, the problem may be compounded as circuit lengths would be longer and cables may be laid across agricultural land resulting in longer fault location times, thereby delaying repair. Some PESs said that repair and maintenance costs would be higher for a completely underground network whilst others took the opposite view.

4.37 Companies said that a large-scale programme of undergrounding would mean considerable expenditure. Estimates given by some companies suggest that undergrounding the whole HV distribution network for England, Scotland and Wales could cost in the region of £9 to 13 billion. Undergrounding the whole LV distribution network, including service cables, could cost in the region of £2.5 to £4.5 billion. This would be largely in addition to a capital expenditure programme, which has been of the order of £4 - 5 billion in each of the last two five year periods.

4.38 As each HV circuit supplies approximately 10 to 100 times more customers than each LV circuit and is just as susceptible to faults, HV circuits influence aggregate quality much more than LV ones. To maximise benefits to customers any large-scale programme of undergrounding might concentrate mainly on the HV network. Such an HV undergrounding programme might be phased over 10 to 20 years, with the financing costs spread over the lifetime of the assets as with the present capital expenditure programme. Phasing the capital expenditure programme in this way would mean that customers' bills would increase only gradually over time. By the time the programme was complete customers' bills might be on average £25 higher per year than they might otherwise have been. There would be significant variations between companies depending, for example, on the present extent of undergrounding and the customer density and geography of each area.

4.39 The present evidence on customers' preferences cited in paragraphs 4.14 - 4.17 above calls into question whether they would wish to pay for such an extensive undergrounding programme. There would also be questions of which customers would gain and which should pay. It is for consideration whether a smaller undergrounding programme would be worthwhile - say focusing on that 10 per cent of the HV (or LV) circuits where undergrounding might yield greatest improvement in quality of service in relation to cost.

(iii) **Company-specific Improvement Programmes**

4.40 Some companies said there were better or more economic ways of improving quality than by uniform changes to Standards or by large scale undergrounding. They suggested company-specific programmes of quality improvement which take account of the perceived needs of customers in each company's area. Such company-specific programmes might include improved standards, targets and other quality improvements. They might originate from each company based on their experience and the views of their customers, ECCs and others.

4.41 The review will consider the extent to which companies have succeeded in meeting their own targets in improving quality; whether this approach is appropriate for the next price control period; whether further targets should be requested or imposed; and if so what the nature of such targets should be. It is for consideration whether to accept further company-specific programmes instead of, or in addition to, the more uniform approaches just mentioned. Companies will be therefore asked to give their views about appropriate levels of service and where improvements are needed and about the costs of achieving this higher level of service, in terms of capital and operating expenditure over the price control period and beyond.

4.42 It would be helpful if PESs were to discuss all three options - improved Standards, undergrounding and company-specific improvement programmes - with their ECCs and other interested parties over the next few months, in order to inform the design and discussion of alternative ways of improving quality of supply.

Linking Revenue to Performance

4.43 It would in principle be possible to link allowed distribution business revenue to achieved performance on quality of supply. The Director General of Water Services has indicated that he is considering such an approach in the water industry.

4.44 This issue was raised in the last distribution price control review. At that time, some companies said that it was a normal feature of a competitive market that a higher quality product would command a higher price. Some consumer groups also argued for a link, though they placed more emphasis on penalising companies whose service standards fell below an acceptable level.

4.45 Other companies drew attention to the difficulties of identifying, measuring and monitoring the relevant aspects of quality of service, of making appropriate allowances for differences in companies' starting positions and areas served, and of putting a value on quality of service. They pointed out that companies had already provided improvements in customer service in response to the standards of service, without an explicit financial inducement.

4.46 OFFER considered this matter very carefully in the last review and explored various possible methods of relating price to quality of service. It concluded that the difficulties and disadvantages of making an explicit link outweighed the potential advantages. It is for consideration whether this conclusion should still hold for the next period.

Issues for Consideration

4.47 Views are invited on any aspect of quality of supply and in particular on:

- the extent to which present levels of quality of supply are appropriate or need modifying; and
- the extent to which it would be in customers' interests to increase capital and operating expenditure to secure a better quality of supply.

4.48 Changes to quality of supply could be introduced by several different routes. Views are invited on all aspects of this and in particular on:

- changes to network design standards;
- tightening existing performance Standards or introducing new targets or Standards;
- reducing or removing the scope for companies to claim severe weather exemptions in applying Standards;
- making payments under Standards automatic instead of paying only those customers who make claims;
- introducing Standards of Performance for communication between companies and customers during supply interruptions, and how these should be formulated;
- undergrounding of overhead networks; and
- whether there should be a link between achieved or reported performance on quality of supply and price control revenue, and if so what form this should take.

5 COMPETITION AND SUPPLY PRICE RESTRAINTS

Introduction

5.1 The initial supply price controls put in place by the Government at Vesting regulated charges to final users of electricity and applied to almost all the customers of the PESs' supply businesses. The subsequent development of supply price controls has reflected the development of competition in supply.

5.2 From Vesting, customers with a maximum demand above 1MW were allowed to choose a competitive supplier. From 1 April 1994 access to competition was extended to customers with a maximum demand above 100 kW. In resetting the supply price controls from April 1994, OFFER took the view that above 100 kW customers would be adequately protected by competition, and that removing price controls from that sector of the market would be conducive to increasing competition. Revised price controls were put in place to protect those customers with a maximum demand below 100 kW, who could not yet take advantage of the competitive market.

5.3 The market was scheduled to be fully open to competition in 1998. In considering what controls should apply from April 1998, OFFER concluded that larger customers under 100 kW would be adequately protected by competition, and that further reducing the scope of price controls would again be beneficial to competition. As a safeguard for smaller customers, for whom competition would be likely to take time to become fully effective, maximum price limits were set in relation to tariffs for domestic and small business customers ("designated customers") for the two years 1998/99 and 1999/2000.

5.4 Customers are best protected by competition. In considering whether price restraints should be continued beyond March 2000, and if so over which set of customers, it will be necessary to take account of the development of competitive activity for different groups of customers. Since competition can be expected to develop over time, it will also be necessary to look ahead, at the prospective state of competition over the next few years. Price restraints can prevent, restrict or distort competition. In considering the interests of customers today, it is important not to undermine the protection of customers interests tomorrow. In doing so, and in making decisions about price restraints, it will be important to take account of the feedback between continued price restraints and competition.

5.5 This approach would be consistent with the Government's proposal in the Green Paper on utility regulation. It proposes to insert a new primary duty requiring utility regulators to exercise their functions in the manner best calculated to protect the interests of consumers, wherever possible and appropriate through promoting effective competition. The Government says that, in defining the interests of consumers, due weight should be given to their longer- and medium-term interests as well as to their immediate or short-term interests.

Development of Competition Above 100 kW

5.6 Competition has developed strongly in those parts of the electricity supply market which are already open. Table 22 and Figure 2 below show the aggregate market shares for first and second tier supply for over 1 MW customers and 100 kW-1 MW customers in England and Wales. The graph and tables show a number of features:

- second tier supply has been more extensive for larger customers than smaller customers. Market shares of second tier suppliers have at all times been higher for over 1 MW customers than for 100 kW-1 MW customers;
- second tier supply developed faster in the 100 kW-1 MW market, which opened later, and is now at a higher level than it was in the 1 MW market after a comparable period of time; and
- market shares of second tier suppliers have steadily increased over time in both markets.

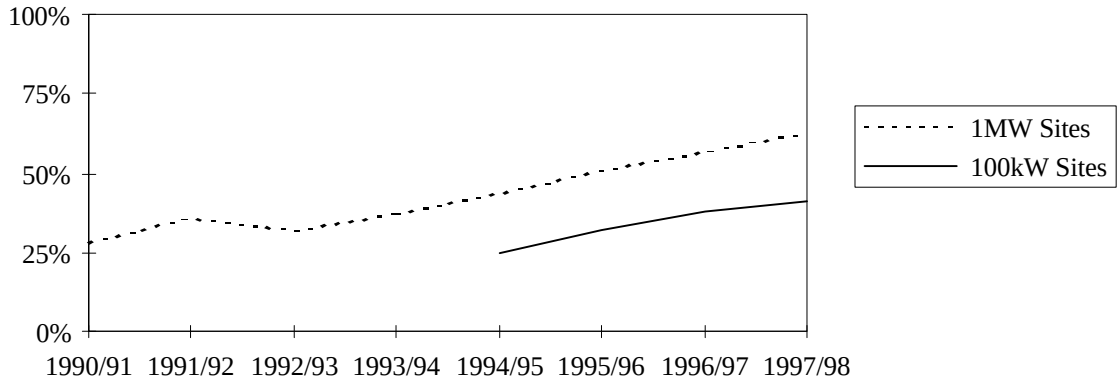
TABLE 22: NON-FRANCHISE MARKET SHARES IN ENGLAND AND WALES - OF SITES SUPPLIED (%)

Over 1 MW Market	**1990/1 %**	**1991/2 %**	**1992/3 %**	**1993/4 %**	**1994/5 %**	**1995/6 %**	**1996/7 %**	**1997/8 %**
First Tier	72	64	68	63	56	49	43	37
REC Second Tier	4	10	12	19	23	26	29	33
All Others	24	26	20	18	21	25	28	30

100 kW-1 MW Market	**1994/5 %**	**1995/6 %**	**1996/97 %**	**1997/8 %**
First Tier	75	68	62	59
REC Second Tier	20	26	31	32
All Others	5	6	7	9

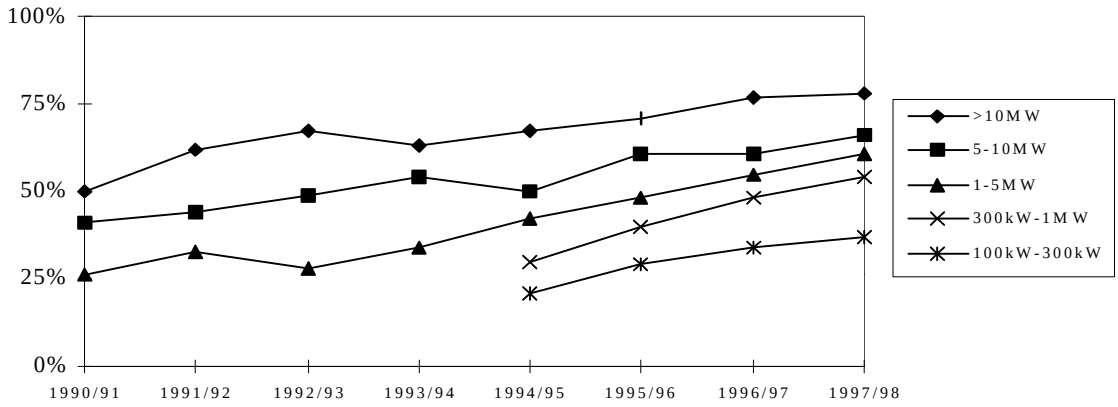
Note: All others includes National Power, PowerGen, Nuclear Electric, Magnox, ScottishPower, Hydro-Electric and independent suppliers.

FIGURE 2: NON-FRANCHISE MARKET SHARES OF SECOND TIER SUPPLIERS IN ENGLAND AND WALES - SITES SUPPLIES (%)



5.7 A more detailed picture is given by OFFER's survey of suppliers, which provides data on the number of sites supplied second tier in sub-groups of customers within the two broad categories. These cover the ranges 100 to 300 kW, 300 kW-1 MW, 1 MW-5 MW, 5 MW-10 MW and over 10 MW as shown in Figure 3.

FIGURE 3: NON-FRANCHISE MARKET SHARES IN ENGLAND AND WALES - SIZE OF SITE SUPPLIED (%)



5.8 In Scotland competition has been introduced on the same timetable as in England and Wales. The same characteristics apply as described in paragraph 5.6. However, as can be seen in Table 23 and Figure 4 below, the extent of second tier supply has been less than in England and Wales. Further, second tier sales continue to be dominated by ScottishPower and Hydro-Electric, with less than 15 per cent of all second tier sales made by other second tier suppliers. Customers, suppliers and others have expressed concern about the development of competition in Scotland.

TABLE 23: NON-FRANCHISE MARKET SHARES IN SCOTLAND - SITES

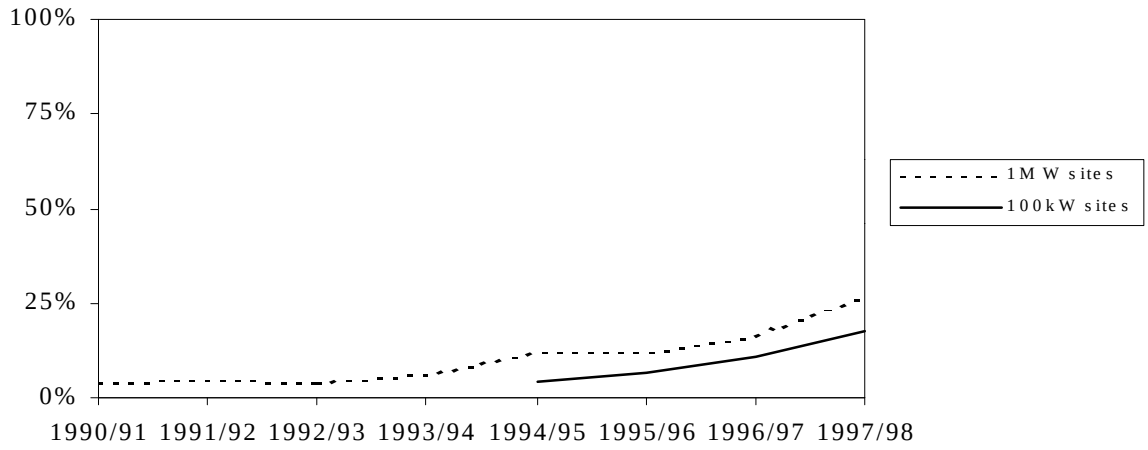
SUPPLIED (%)

Over 1 MW Market	1990/91 %	1991/92 %	1992/93 %	1993/94 %	1994/95 %	1995/96 %	1996/97 %	1997/98 %
First Tier	96	95	96	94	88	88	84	73
Scottish Second Tier	3	3	4	6	12	10	11	13
All Others	1	2	0	0	0	2	5	14

100 kw - 1 MW Market	1994/95 %	1995/96 %	1996/97 %	1997/98 %
First Tier	96	93	89	82
Scottish Second Tier	4	6	9	12
All Others	0	1	2	6

Notes: 1) Scottish Second Tier are sales by ScottishPower and Hydro-Electric in each other's authorised supply areas.
2) All others includes all sales by the RECs, National Power, Nuclear Electric, PowerGen and independent suppliers.
3) 1997/98 figures are estimates.

FIGURE 4: NON-FRANCHISE MARKET SHARES OF SECOND TIER SUPPLIERS IN SCOTLAND - SITES SUPPLIED (%)



Introducing Competition

5.9 The programme for introducing competition in supply below 100 kW envisages that an initial group of PESs will begin to open their markets in September 1998. A second group of PESs are expected to open their markets in October, with the remaining PESs opening their markets by December. In each PES area competition will be introduced in phases over a six month period. The initial phase will include all half hour metered and maximum demand customers plus about 10 per cent of other customers in the area. The second phase includes all non-domestic customers plus about 40 per cent of domestic customers. The final phase will include the remaining 50 per cent or so of domestic customers. This timetable would mean that all PES areas should be fully open to competition by about June 1999.

Experience In Gas

5.10 It will be helpful to consider the implications of developments in the gas market for competition in electricity. The initial phase of domestic gas competition was launched on 29 April 1996, when around 500,000 customers in the South West of England, with an annual consumption of 2,500 therms or less, were able to choose an alternative supplier. Competition in gas supply was extended to 1.5 million customers in Devon, Avon, Kent and Sussex on 10 February 1997; to 2.5 million customers in the North East of England and Scotland on 1 November 1997; and to all other customers between February and May 1998.

5.11 In the domestic gas market there are some 25 licensed suppliers, a number of which are subsidiaries of PESs. Companies with an established reputation in the provision of gas or electricity supply have tended to form the core of new entrants in the gas market.

5.12 By June 1998, new entrants supplied around 25 per cent of the domestic gas market in the South West of England. New entrants acquired a similar share of the market in those areas of the South West and South East of England forming phase two of liberalisation, and did so over a shorter period. There was further evidence of customers switching more rapidly in areas of Scotland and the North East of England, where new entrants obtained around a 20 per cent share of the market within the first eight months after the market was opened there.

5.13 New suppliers have entered the domestic gas market offering substantial price reductions compared to the incumbent. Direct marketing and sales techniques have been used to provide customers with information. These factors have enabled a broad range of customer groups to switch supplier. A study published by OFGAS in March 1998[15] indicates that customer switching has occurred across all socio-economic categories. Customers within higher socio-economic groups are more likely to switch supplier at an earlier stage of liberalisation, and customers from lower socio-economic groups form a larger proportion of switchers at a later stage.

[15] Ofgas "Gas Competition Review: December 1997" A research study conduced by MORI for Ofgas", March 1998

5.14 The circumstances in gas are not directly comparable to those in electricity. In particular, the initial extent of discounts offered by entrants in electricity is likely to be lower than those observed in the gas market to date. Entrants in the electricity market are also faced with the present integration of PES supply and distribution activities, and the PES monopoly over metering services until 2000.

5.15 The development of competition in gas does however indicate that domestic customers are interested in alternative suppliers. It is likely to have raised customer awareness of the scope for choice in electricity also. Several companies are now offering joint electricity and gas contracts effective when the electricity market opens. This may provide customers with further benefits and increase the extent of take up of second tier supply in electricity.

Assessing the Development of Competition

5.16 In responding to the February 1998 consultation paper a number of ECCs stressed the importance of a careful assessment of the development of competition. Other respondents argued that there should be no presumption that price restraints will be required after the year 2000. OFFER will be monitoring closely developments in the market. The key issues for the review will be to assess the development of competition and whether price restraints for some categories of customers remain appropriate.

5.17 In assessing the development of competition it may be relevant to look at, amongst other things:

- the number of competing suppliers and the range of offers on price and other terms;
- the history of entry and exit of suppliers to and from the market;
- any evidence that suppliers base their business decisions and price setting behaviour on the prospects of customer substitution in response to relative price changes;
- actual and prospective changes in suppliers' costs, prices and profit margins;
- how suppliers compete in the market and differentiate themselves to customers (in terms of advertising, the importance of branding and quality of service);
- any evidence on how the price restraints have impacted on competition in different PES areas and for different categories of customers;
- whether there are potential suppliers not presently in the market that would be likely to enter in the event of a change in circumstances, such

as a price increase by the original suppliers or a relaxation in price restraints;

- any evidence of barriers to entry;
- the extent to which customers would incur costs in switching from one supplier to another and the time that customers would need to organise such a shift; and
- the extent to which all the above factors vary between types of customers and PES areas.

5.18 It will also be useful to consider the impact of developments in the gas market and the extent to which the electricity and gas markets have converged.

Revising the Restraints

5.19 The existing maximum price restraints were set for two years until 31 March 2000. When a decision needs to be made about their replacement there will be relatively little experience on which to assess the development of competition. In the event that some regulatory restraint over PESs' prices continues to be necessary after 2000, the following issues will need to be considered, in the context of ensuring that any revised restraints do not have an unduly adverse impact on the development of competition or new entry.

Role of Non-discrimination Provisions

5.20 The PESs are subject to non-discrimination provisions in their licences, which require them not to discriminate unduly in setting prices to their customers or to set predatory or onerous prices. The condition provides for these restrictions to be relaxed as competition is established, and removed when competition is effective. Nevertheless, PESs would continue to be subject to the constraints of general competition law. This will be strengthened in the future when the Competition Bill becomes law, which will introduce general prohibitions on anti-competitive agreements and abuse of dominant position.

5.21 In circumstances where competition is not yet fully effective, the licence provisions prohibiting non-discrimination and onerous pricing provide a valuable protection for customers. It is for consideration whether the enforcement of these provisions, without the application of specific price restraints, would be sufficient to protect customers from April 2000.

Form, Scope and Duration of Price Restraints

5.22 If price restraints remain necessary, it will be important to ensure that their form and scope do not unduly distort the development of competition.

5.23 The present price restraints establish maximum levels for tariffs applying to domestic and small business customers. This form of control provides reassurance to customers that they will be protected and will benefit from the competitive market. It also increases incentives on PESs to purchase efficiently, provides targets for competitors to aim at and avoids the difficulties and potential distortions of cost pass-through controls and associated correction factors in a competitive market. If a price restraint is required in future it seems likely that it will be of a similar form to the present maximum price restraints, in the sense that it will not involve cost pass through.

5.24 The present maximum price restraints cover all domestic customers and small business customers with a demand of less than 12,000 kWh per year. In considering the scope of any future price restraint it will be necessary to consider the actual and prospective development of competition for different groups of customers. For instance, it may be that competition develops faster for small business customers than for domestic customers, or for direct debit customers than for customers who use a different payment method. If this proves to be so, it might suggest that the scope of the new restraint should be restricted to domestic customers, or to particular groups of domestic customers such as those on prepayment meters.

5.25 Given the relatively rapid rate at which competition has developed in the non-franchise market and in the gas market, a short duration for any restraints might be most appropriate, perhaps with an explicit provision to remove or extend them after a short period.

Level and Approach

5.26 There are five main elements of cost to be considered in revising the level of any restraint: generation, transmission, distribution, supply business margin and the Fossil Fuel Levy. The Levy was added to the price restraints rather than included within it, and it may be sensible to continue this.

5.27 Generation costs represent the largest component, and presently comprise two elements: the cost of buying electricity through the Pool and the cost of hedging Pool price risk (for example, through contracts for differences). Since the end of the five-year coal-backed contracts for differences a larger proportion of demand has been covered by short-term purchase contracts. The final outcome of the Government's review of energy sources for power stations will be relevant in assessing generation costs in the future, as will progress in establishing new wholesale electricity trading arrangements, and competition, new entry and potential divestment in the generation market.

5.28 Most charges levied for the use of the transmission and distribution systems are subject to price controls. A new transmission price control in England and Wales is due to take

effect from April 2001. The present distribution price controls will be replaced at the same time as the supply price restraints. As the distribution price control review proceeds, more information will become available on the proposed future level and form of distribution charges.

5.29 The review will consider the present attribution and allocation of operating costs and non-operational capital expenditure between distribution and supply and the appropriate future attribution and allocation of costs between distribution, supply and metering. It will be important to ensure that competition is not restricted by costs properly attributable to potentially competitive activities being allocated to monopoly activities, thereby favouring suppliers who also have distribution activities. The existing supply business margin was set on the basis that PESs could cover certain operating costs and earn a 1½ per cent return on turnover. PESs have argued that such a margin is unduly low, and a disincentive to competition. The review will need to consider this point.

5.30 PESs expressed different views about the method used to set the present price restraints and the resulting relative levels of price restraints as between PESs. Some said that the margins over costs differed significantly, and will result in different prospective price reductions when competition opens. These points will need to be considered in the light of experience.

5.31 The present price restraints sought to ensure that no group of customers would be worse off as a result of competition. A large number of restraints related to the then-existing tariffs of the PESs, with restrictions on changes that could be made and a process for approving such changes. As competition develops this may become burdensome and unnecessary. The need to monitor dominant suppliers will remain but it is for consideration whether the number of price restraints for each PES could be reduced to one or two.

5.32 In setting any price restraints, it will be relevant to consider potential future movements in costs, as discussed. But this is not to say that any remaining price restraints should automatically be moved up or down in parallel with such prospective movements in cost. They could be left at their present level, thereby allowing the benefits of any future cost reductions to come from competition rather than from tighter price restraints. This would promote the growth of competition, and enable the benefits to be passed to customers by rival suppliers.

Supply Business Service Standards

5.33 The Government's Green Paper on utility regulation notes that in competitive markets, a light approach to regulation of service standards may be appropriate, possibly based

on a requirement to publish comparable quality of service performance indicators and

comparable information on prices, in a format agreed with the Regulator.

5.34 OFFER has set Overall and Guaranteed Standards of Performance for the PESs under Sections 39 and 40 of the Electricity Act. Most of these standards relate to activities of PES distribution businesses, but some apply to PES supply businesses. These include standards relating to speed of response to customer queries, to making and keeping appointments, and to ensuring that firm meter readings are obtained. OFFER does not have power to set Standards of Performance for second tier suppliers. However, the amended second-tier licences require licensees to publish reports on performance in a number of important aspects of customer service.

5.35 The review will need to assess, in the light of the development of competition, whether formal Standards of Performance in relation to supply issues continue to be appropriate. This will need to be considered against the background of the proposal in the consultation paper on the separation of businesses that the present distinction between supply businesses and second tier suppliers should end, and that all suppliers should be placed on the same legislative footing. If this proposal is implemented, the Government will need to consider whether powers to set Standards of Performance should be in relation to all suppliers, or only some, or abolished altogether.

5.36 So long as PESs remain dominant suppliers, there could be advantages in the existing Standards being maintained on PESs. These Standards have provided a significant level of protection for customers. However, there would be advantages in the evolution of service levels beyond this being determined by customer choice.

Energy Efficiency Standards of Performance

5.37 Under Section 41 of the Electricity Act OFFER may determine Standards of Performance for PESs on the efficient use of electricity by consumers. Standards were first set for PESs in England and Wales in April 1994 and for the Scottish PESs in April 1995. These ran until March 1998. New Standards have been set to run from April 1998 to March 2000. They require PESs to undertake projects aimed at achieving specified levels of energy savings. The costs of meeting the Standards (about £1 per customer a year) were taken into account in setting the present supply price restraints.

5.38 The Electricity Act makes no provision for Energy Efficiency Standards of Performance for second tier suppliers. Imposing an energy efficiency obligation on PESs, without a similar obligation on second tier suppliers, could distort competition between PESs and second tier suppliers. Since competition for small customers would take time to develop, OFFER concluded that there was a case for continuation of the Standards for a transitional period after 1998, provided that this could be done on a scale that did not unduly distort competition or adversely affect the interests of customers. Schemes under the extended Standards are to focus on customers covered by the supply price restraint, particularly those least likely to benefit from competition initially.

5.39 It is necessary to consider whether Energy Efficiency Standards of Performance on PESs should continue for a further period after 2000. As competition in supply develops, it will become increasingly difficult to set Standards for PESs alone without distorting the market. Even if the Standards applied to all suppliers there could be a possible adverse impact on energy service companies and on competition between electricity and gas.

5.40 As noted earlier the consultation paper on separation of businesses proposes that new legislation to implement the Green Paper proposals should remove the present distinction between PESs and second tier suppliers. If this is implemented the Government will need to consider whether the present power to set the Standards of Performance should relate to all suppliers in future, or just to some, or be withdrawn.

5.41 The Government has proposed in its Green Paper that Ministers should give guidance to regulators on social and environmental objectives. Where Ministers wish to implement measures with significant financial implications for consumers or companies, the Government would seek appropriate new legal provision. It is not yet clear how or when the Government will implement these proposals. They would seem to imply that the Government might at some future date take responsibility for any energy efficiency obligations on electricity licensees.

Issues for Consideration

5.42 Views are invited on any aspect of competition and supply price restraints, and in particular on:

- the appropriate approach to assessing the development of competition and the impact of price restraints;
- the future role of the non-discrimination provisions in protecting customers;
- the appropriate approach if some price restraints seem to be required;
- what criteria might be relevant to a decision on whether or not to continue Energy Efficiency Standards of Performance on PESs.

6 SCOTTISH TRANSMISSION PRICE CONTROLS

Introduction

6.1 The initial Scottish transmission controls were set by the Government at Vesting for a period of 4 years, and then revised by OFFER for a further 5 years from April 1994 until March 1999. In February 1998, OFFER's consultation paper on the Scottish Transmission Price Controls set out the case for deferring the transmission price control review for a year to allow the transmission and distribution price controls to be reviewed together. A subsequent document in March 1998 proposed to extend the existing transmission price controls until March 2000 on the basis of allowing each company the same level of total revenue in real terms in 1999/2000 as is allowed in 1998/99. In April 1998, the Scottish companies accepted this proposal.

6.2 Scottish Hydro-Electric and ScottishPower are vertically integrated companies which generate, transmit, distribute and supply electricity. They own and operate both the transmission system and the distribution system in their areas. Although the companies' transmission and distribution activities are required to be in separate businesses, and are subject to separate price controls, each company has now integrated the management of its transmission and distribution systems under a common "power systems" business.

Financial Performance

6.3 Table 24 shows the turnover, operating cost and HCA operating profit of the transmission businesses of the two Scottish companies since Vesting, taken from the regulatory accounts. Table 25 shows the cash flow statement of the transmission businesses over the same period.

6.4 Schedule 7 of Hydro-Electric's licence allows for a cross-subsidy known as Hydro Benefit from its generation business to its transmission and distribution businesses. In its May 1995 report on Hydro-Electric the MMC suggested that the availability of the cross-subsidy should be retained and it is shown as a separate item in Tables 24 and 25. Hydro Benefit is explained in more detail in paragraphs 6.17 to 6.19.

TABLE 24: TRANSMISSION BUSINESSES PROFIT AND LOSS ACCOUNT IN 1996/97 PRICES

	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
ScottishPower							
Turnover	108	106	119	123	120	119	126
Operating Costs	(37)	(42)	(60)	(55)	(56)	(51)	(49)
Operating Profit	71	64	59	68	64	68	77
Operating Profit as a % of turnover	66	60	50	55	53	57	61
Hydro-Electric							
Turnover	49	35	42	50	46	47	50
Operating Costs	(24)	(28)	(26)	(29)	(28)	(27)	(26)
Operating Profit	25	7	16	21	18	20	24
Operating Profit as a % of turnover	51	20	38	42	39	43	48
Provision for Hydro-Benefit	13	13	13	13	13	0	0
Adjusted Operating Profit	38	20	29	34	31	20	24
Adjusted Operating Profit as a % of turnover	78	57	69	68	67	43	48

Note: Hydro-Electric stopped reporting Hydro Benefit in its regulatory accounts in 1995/96.

TABLE 25: SCOTTISH TRANSMISSION BUSINESSES: CASH FLOW STATEMENT IN 1996/97 PRICES

	1990/91 £m	1991/92 £m	1992/93 £m	1993/94 £m	1994/95 £m	1995/96 £m	1996/97 £m
ScottishPower							
Operating cash flow	70	75	71	72	68	78	87
Interest paid	0	0	(2)	(2)	0	0	0
Capital expenditure	(15)	(42)	(62)	(28)	(12)	(21)	(26)
Receipts from sales	0	0	0	0	0	0	1
Customer contributions	6	11	13	8	1	1	0
Net cash inflow	61	44	20	49	56	58	63
Hydro-Electric							
Operating cash flow	33	11	19	29	28	24	30
Capital expenditure	(22)	(19)	(27)	(29)	(19)	(10)	(12)
Customer contributions	0	0	2	2	0	0	0
Net cash inflow	11	(8)	(6)	2	9	14	18
Hydro-Benefit	13	13	13	13	13	0	0
Adjusted Net Cash Inflow	24	5	7	15	22	14	18

Note: Hydro-Electric stopped reporting Hydro Benefit in its regulatory accounts in 1995/96

6.5 The Tables show a somewhat unsystematic pattern of turnover, operating profit and operating cash flow over time. In part, this reflects the way in which the price controls have related to the number of units transmitted, as explained in paragraph 6.10. There has been a fall in operating costs under the present control. Operating profit as a percentage varied considerably; in the four years 1993/94 to 1996/97 it ranged between 53 and 61 per cent for ScottishPower, with an average of 56 per cent, and between 39 and 48 per cent for Hydro-Electric with an average of 43 per cent (excluding Hydro Benefit).

6.6 Table 25 shows a variable path of capital expenditure by the transmission businesses. However, on average, it was lower over the last three years than over the first four. The combination of increasing operating cash flows and falling capital expenditure has led to a rise in the level of net cash inflow provided by the transmission businesses over the last three years.

Form of the Control

6.7 The transmission price controls limit the total regulated revenues of the transmission businesses. The present maximum allowed revenues are derived by applying a

specified average revenue per unit to a specified projection, made at the time the control was set, of the number of units which would be transmitted. The projection of units included units exported across the interconnector. This projection of units, rather than the number which are actually transmitted, is the revenue driver of the control. (Chapter 3 explained that a similar projection of customer numbers was used in setting the distribution price control.)

6.8 The allowed average revenue per unit is indexed to the percentage change in the RPI minus an X factor, plus a correction factor which allows for any over or under-recovery in the previous year. The one year extension of the control will fix the total regulated revenue of the transmission businesses rather than specify a unit charge and a projected number of units.

6.9 The form of the transmission price control will be for consideration, taking into account the issues discussed in Chapter 3 on the form of the distribution price control. In 1996 OFFER concluded that an RPI-X control continued to be appropriate for NGC's main transmission price control. No arguments have been made by the Scottish companies to adopt a different form of control.

6.10 The present transmission price controls set an X factor of 1 per cent for ScottishPower and 1.5 per cent for Hydro-Electric. There have however been large differences between the year-on-year price movement implied by RPI-X and the actual movement in the average transmission charge per unit from one year to the next. The difference is due partly to the combined effect of over and under recoveries and partly to the differences between the projected quantity of units transmitted, on which the control was based, and the number of units that were actually transmitted. The latter differences mainly reflect the delay to the expected capacity upgrading of the Scotland/England Interconnector as a result of delays in planning permission for the North Yorkshire line. Some uncertainty still exists on the timetable for upgrading this line, and hence on the expected future capacity of the interconnector. The review will consider how far the quantity of units transmitted should be incorporated into the price control formula and the method by which this might be done.

Scope and Duration of the Control

6.11 The present price control does not cover the total revenue of the transmission businesses. The charges for the use of the pre-Vesting capacity on the Scotland/England Interconnector are at present within the price control but are set at zero. Transmission use of system revenue is used to meet the costs associated with the pre-Vesting Interconnector capacity. That is, users of the Scottish transmission system pay for the cost of the pre-Vesting interconnector capacity. ScottishPower says in its charging statement that this is to reflect the economic and security benefits provided by the pre-Vesting Interconnector to all Scottish customers. It will be for consideration whether this remains appropriate.

6.12 The charges for some of the transmission services provided by the Scottish companies are outside of the price control. These excluded charges cover the connection charges for post-Vesting assets, certain charges for EHV customers and some charges associated with the use of the Scotland/England Interconnector including those for the use of post-Vesting capacity. As is the case for distribution connection charges (discussed in Chapter 3) customers have the opportunity to seek a determination from the Director General on the level of any individual connection charge, and this may provide sufficient protection. Consideration will be given, as part of the review, to whether it is still appropriate for these charges to remain outside the price control, and whether there are any charges presently inside the price control that would be more appropriately outside it.

6.13 As regards the duration of the new control, a longer period (say 5 years) may promote more cost savings by the companies than a shorter period would, which would ultimately be to the benefit of consumers. A shorter duration (say 3 years) would reduce the possibility of unanticipated outcomes. OFFER's consultation paper on separation of businesses suggested the advantages of separate ownership of the Scottish transmission businesses. A further paper is planned on trading arrangements in Scotland. Both of these aspects may have implications for the duration of the control.

Setting the Control

6.14 Chapter 3 outlined issues to be considered in the review of distribution price control. For the transmission review, a similar analysis of costs will be required. ScottishPower and Hydro-Electric will be asked to report actual and forecast operating costs and capital expenditure for 1993/94 to 2005/06 and will be asked to explain the variance from their previous forecasts and the assumptions made in setting the present control. The business plans will also help OFFER to analyse the cost drivers of the transmission business and inform conclusions as to the efficiency of the business. They will also assist decisions on the appropriate allocation of costs between the distribution and transmission businesses.

6.15 An important aspect of the transmission price control review will be to assess what levels of expenditure are required to maintain and where necessary upgrade the transmission network. This analysis will consider separately investments to maintain and upgrade interconnector circuits. It will involve assessing the quality of service delivered by the transmission networks. The engineering consultants appointed to advise on the distribution price control review have also been appointed to advise on these aspects of ScottishPower's and Hydro-Electric's capital expenditure plans. The consultants appointed to review the operating cost of the distribution businesses for all 14 PESs will also advise on the scope for efficiency savings in transmission operating costs.

6.16 The present control was set using a 6 per cent real pre-tax cost of capital applied to a calculation of the market value of the transmission businesses at Vesting, uprated for

inflation and new investment. As noted in paragraph 3.56, this market value was close to the CCA value of the assets at that time. The 6 per cent cost of capital was not inconsistent with the MMC report on British Gas in 1993. The MMC had concluded that a cost of capital between 6.5 and 7.5 per cent would represent an appropriate weighted cost of capital for British Gas. Stock market evidence at that time suggested that ScottishPower and Hydro-Electric were perceived by investors as less risky than British Gas, and the transmission business itself was seen as less risky than each company as a whole. OFFER concluded that a cost of capital of around 6 per cent was appropriate. The present review will consider more recent evidence. It will look at price control reviews of other network utilities, including NGC. As described above, the MMC has also considered the case of NIE and Hydro-Electric's distribution business. It will be for consideration whether a 6 per cent return continues to be an appropriate estimate of the cost of capital, and whether the previous basis for asset valuation would continue to be appropriate, taking into account the issues discussed on the distribution price control.

Hydro Benefit

6.17 As noted in paragraph 6.4, Schedule 7 of Hydro-Electric's licence allows for a cross-subsidy known as Hydro Benefit from the generation business to the transmission and distribution businesses. The transfer provides for the relatively low operating costs of the hydro resources of the generating business to be used to offset potentially higher charges to customers in the transmission and distribution businesses, where such higher charges might result from climatic and geographic characteristics of Hydro-Electric's area. At present the maximum amount allowed by the licence condition is £40 million a year in 1990/91 prices uprated annually by inflation.

6.18 In its report on Hydro-Electric in 1995, the MMC applied a hydro benefit of £29.2 million a year (at 1994/95 prices) to the Distribution Business, to make Hydro-Electric's distribution charges comparable to ScottishPower's. The present transmission price control does not make use of the cross-subsidy available, as this was not required to ensure that Hydro-Electric's transmission charges were at a level comparable with those of ScottishPower. The MMC suggested that the availability of the cross-subsidy should be retained in case it became necessary to apply it to transmission in the future.

6.19 The MMC also said that if there was wider restructuring of the Scottish electricity industry the cross subsidy should be continued, with arrangements being put into place for a transfer from the generation business to the transmission business even if it were under separate ownership. The present review will assess the scope for hydro benefit and the extent to which it should be applied to the transmission and distribution businesses.

Structure of Transmission Charges

6.20 The present price control constrains the aggregate level but not the structure of the Scottish companies' transmission charges. The structure of these charges needs to comply with the relevant conditions of the transmission license, such as the non-discrimination obligations, and to be consistent with the transmission licensees' statutory duties to develop and maintain an efficient and economical system of electricity transmission. For Scotland, the statutory duty to facilitate competition in the supply and generation of electricity applies as if the duty were to make the transmission system available to competitors on terms which neither prevent nor restrict such competition.

6.21 Transmission charges fall into three main categories:

- connection charges, to cover the cost of assets providing connections between the transmission system and either generating stations or distribution networks or individual premises;

- use of system charges, to cover the costs of installing, operating and maintaining the transmission systems, other than costs recovered in connection charges; and

- charges or adjustments for transmission losses, calculated by applying a loss adjustment factor to the metered quantity for which use of system charges are payable.

6.22 The broad structure of these charges is common to ScottishPower and Hydro-Electric. However, this structure differs from that of NGC, and there are differences between ScottishPower and Hydro-Electric in the detailed design of these charges.

6.23 The previous review of the transmission price control in Scotland did not, as it did in the case of NGC, consider the charging structure in any detail. Over time, various suggestions have been made for revising the present structure, including by independent generators, suppliers, customers and the companies themselves. The present review will consider whether changes are appropriate.

(i) Connection Charges

6.24 Connection charges consist of:

- an entry charge paid by generators to cover the cost of assets deemed necessary to connect and accept generation onto the transmission system; and

- an exit charge, to cover the cost of assets associated with connections to the distribution network and certain customers with premises directly supplied from the transmission system.

6.25 In addition ScottishPower and Hydro-Electric may make a metering and administration charge to cover the cost of providing and reading meters.

6.26 New connections to the transmission system generally result in additional or different power flows which may create a need for system reinforcement. The companies charging statements provide that where it can be shown that reinforcement is required for the sole benefit of a new connection, the new entrant is charged accordingly. This is potentially important in parts of Hydro-Electric's licensed area where transmission constraints can result in high connection costs for new generation. In January 1998, Hydro-Electric issued a consultation paper on transmission constraints and connection costs which discussed the treatment of reinforcement costs. The review will consider the allocation of connection costs, including reinforcement costs, between new and existing customers. One particular issue for consideration is whether any reinforcement costs required solely by users of the Interconnector should be paid for by those users.

6.27 Hydro-Electric's consultation paper also invited comments on alternative policies for the recovery of generator connection costs. At present, the costs of a new connection are determined from the estimated costs to meet the requirements of a firm connection. An "interruptible" connection, built to a lower level of security, would in general be cheaper than a firm connection. Independent generators have argued for an interruptible connection to be available as an option north of the main transmission constraint in Hydro-Electric's licensed transmission area. The transmission price review will consider this, taking into account comments by users and the possible implications for competition, other users and renewable energy.

6.28 A number of large users and potential competitors have drawn attention to the scope for further competition in connections. In Scotland, a user connecting to the distribution system may opt to appoint a preferred contractor to carry out those parts of the work involved in the connection which are open to competition. That work is referred to as "contestable" work. The transmission pricing review will consider whether a user connecting to the transmission system should also have the option of appointing a contractor to carry out some of the connection work.

6.29 In June 1995, ScottishPower published proposals to rebalance its transmission charges by reducing use of system charges and increasing the connection charges paid by customers. This matter was deferred for consideration as part of the transmission price control review. In view of the subsequent deferment of the price control review this issue will be considered at an early part of the review process.

(ii) Use of System Charges

6.30 Use of system charges relate to the costs of installing, operating and maintaining the transmission systems, other than costs recovered in connection charges. They consist of:

- an infrastructure charge for the provision of firm capacity across the transmission system. The infrastructure generation charge is applied to all connected generation capacity, and the infrastructure demand charge is applied to all connected distribution networks and directly-connected premises with demand; and

- a system service charge to cover the cost of providing a core network having stable voltage and frequency, and which is applied to all chargeable demand.

6.31 The structure of use of system charges in Scotland differs in many respects from NGC's. Hydro-Electric has a Common Tariff Obligation (an obligation not to differentiate prices to tariff customers by location) set out in Part V, Condition 4 of its licence. A comparable licence obligation applies to all suppliers operating Hydro-Electric's area. Whilst recognising these obligations, independent generators say that there may be a case for some geographical differentiation of use of system charges. Following NGC's price control review, its use of system charges are now geographically differentiated so as to reflect, in part, the distance-related costs arising from the prevailing direction of electrical power flows. Neither of the Scottish companies' charges are geographically differentiated at present. Transfers of electricity between the two transmission systems attract generation charges only from the company in whose area the generator is located and demand charges only from the company in whose area the demand is located. It will be for consideration whether there is a case for some differentiation of use of system charges in Scotland and whether use of system charges should be restructured to provide incentives to reduce transmission constraints.

(iii) Transmission Losses

6.32 In Scotland the costs of transmission losses are recovered using a different charging procedure to that used in England and Wales. Under the Scottish transmission licences, each company's charging statements includes a schedule of adjustment factors to be made in respect of transmission losses, in the form of additional supplies required to cover the transmission losses. In England and Wales, the costs of transmission losses are recoverable through the Electricity Pool. At present the Pool recovers these costs by measuring the actual percentage of losses, about 2 per cent at present, and correspondingly adjusting the chargeable demands taken from the Pool. For the future Pool Members have resolved to adopt geographically differentiated transmission loss factors which more closely reflect the costs involved. Their resolution was upheld by the Director General on appeal, but the Director General's decision is now subject to an application for judicial review.

6.33 In Scotland, users have said that the level of losses assumed in the charging formula may be greater than actual losses. Embedded generators have suggested that their charges should reflect any reduction in losses that may arise from their generation activities. The review will consider these points and whether the level of charges for transmission losses and the basis of calculating these charges should be revised. The

review will also consider whether the pricing formula should be restructured to provide the transmission licensees with an incentive to reduce transmission losses.

6.34 ScottishPower has argued that there would be advantages in introducing a separate system service charge. It says that second-tier suppliers, contracting with independent generators and using a contract form to avoid residuals, make no payment for ancillary services provided by the host PES. This will be considered.

Other Issues

6.35 Setting the price control will be taken forward within the wider context of the PES and other reviews presently taking place and in particular taking into account the implications of work on the following issues, which are discussed in turn below:

- the further separation of the transmission business, indicated in the OFFER consultation paper on separation of supply and distribution;
- the costs and operation of the trading arrangements to support 1998;
- the further development of trading arrangements in the light of the Review of Electricity Trading Arrangements in England and Wales;
- the determination on access to the interconnector and any developments arising therefrom; and
- any OFREG decision on the proposal for the electrical interconnector between Northern Ireland and Scotland.

6.36 In the consultation paper on separation of businesses OFFER raised a number of issues for consultation about the structure of the industry in Scotland, in the light of concerns from users, independent generators and second tier suppliers. The paper indicated that there was now greater potential for competition in both generation and supply, but that industry structure and regulatory framework are increasingly perceived as obstacles. It is for consideration whether and how changes in these respects might improve the development of competition in Scotland.

6.37 The consultation paper on the separation of businesses indicated the need to consider changes to licensing arrangements in respect of second tier supply and settlement obligations, as contained in Conditions 23 and 24 of Part V of the composite licences. The changes might involve the transfer of these obligations from the supply to the transmission businesses. Any licence modifications would depend on the outcome of the consultation on the separation of businesses. It would be for consideration whether this would impact on the costs and revenues of the transmission licensees.

6.38 The present trading arrangements have been designed to support the opening of the domestic electricity market in Scotland and have involved a substantial development of new systems and commercial arrangements. Unlike in England and Wales, some of these relate to generator trading arrangements. Recovery of the costs of developing System Data Provision and Generation Registration Services will be considered in the price control review. Any implications of deferring the transmission review by one year will also be considered.

6.39 The present trading arrangements are in place until March 2000. They will be reviewed as part of the process of selecting new arrangements to come into operation after that date, and a consultation paper will be issued later this year. This will take into account the conclusions of the Review of Electricity Arrangements in England and Wales. At present trading is on the basis of bilateral contracts, with system operation undertaken by ScottishPower and Hydro-Electric in their respective areas. It will be for consideration how this might develop further, whether in the form of a trading pool or continuing with bilateral contracts. EC Directive 96/92/EC, which concerns the common rules for the internal market in electricity, could also be relevant.

6.40 ScottishPower's transmission business operates the interconnector between Scotland and England, and owns the Scottish part of it. The interconnector's capacity is shared under contract between ScottishPower and Hydro-Electric. Under the terms of both companies' transmission licences, capacity is required to be made available to other parties on a non-discriminatory basis. A consultation paper on the interconnector will be issued shortly, in response to requests for determinations by certain generators seeking to use the interconnector.

6.41 The proposed interconnector between Scotland and Northern Ireland has received planning consent, and is presently being examined by OFREG. A decision to proceed with the interconnector with Northern Ireland may have implications for the transmission business.

Issues for Consideration

6.42 Views are invited on any aspect of the Scottish transmission price control, and in particular on:

- whether the transmission price control should continue to be an RPI-X control;
- what the relationship there should be between allowed revenue and the quantity of units transmitted;
- what assumptions should be made as to operating costs, capital expenditure, cost of capital and asset valuation;

- whether the charge for the use of the pre-Vesting capacity on the Interconnector should continue to be set at zero;

- whether any of those charges presently outside the price control should be inside and whether there are any other charges inside the control that should be outside;

- the appropriate duration of the price control;

- whether the present structure of connection charges remains appropriate including with respect to

    - the allocation of connection costs, including reinforcement, between new and existing users;

    - the demarcation of connection and use of system assets;

    - the introduction of a non-firm connection option;

    - the scope for allowing users to undertake connection work themselves;

    - the method used to recover the cost of connection including the cost of capital;

    - the balance between connection and use of system charges;

    - geographical differentiation of charges and incentives to reduce transmission constraints; and

    - charges for transmission losses.

7 PREPAYMENT METER CUSTOMERS

Introduction

7.1 Since Vesting there have been reductions in average electricity prices for all groups of customers. Over that period, domestic customers have seen real reductions of about 20 per cent. Domestic and small business customers will be further protected by price restraints during the introduction of competition, until March 2000. Concerns have, however, been expressed - most recently in the Government's Green Paper on utility regulation - about the implications of liberalisation of the electricity market for certain groups of disadvantaged customers, including those on low incomes. In its Green Paper, the Government stated that an aim of the regulatory system should be to ensure efficiency, choice and fairness in the provision of electricity and gas to disadvantaged customers. It asked the gas and electricity regulators to prepare a detailed action plan to meet this aim. The two regulators published their action plan on 25 June 1998.

7.2 Concerns have focused in particular on customers who pay for their energy through prepayment meters (PPMs). The number of electricity customers who pay in this way has increased significantly in the years since Vesting, doubling to some 3.8 million over the eight years to 1998. On average, 15 per cent of domestic electricity customers are now supplied on this basis. The proportion varies by PES, ranging from 9 per cent (Northern) to 23 per cent (ScottishPower). The proportion of domestic gas customers served by pre-payment meter is much lower, at about 5 per cent.

7.3 PPMs are variously chosen by customers to assist in budgeting or to avoid the need for security deposits. They can also be calibrated to recover debt. Data provided by the PESs indicates that the proportion of PPM customers who are repaying debt varies by company, from about 5 per cent in the case of London and Southern, to nearly 30 per cent for Yorkshire and SWALEC.

7.4 PPM customers are typically charged more for their electricity than those paying by other methods. At present this amounts to about £15 per customer per year compared to standard domestic quarterly tariffs, although there are wide variations between companies, ranging from about £9.50 for Midlands to nearly £26 for SWALEC. Hydro-Electric does not make additional charges for PPMs, and offers these customers a discount on unit rate rates to reflect what it sees as the cash flow advantages of prepayments, making its PPM tariff cheaper than its standard domestic quarterly tariff.

7.5 ECCs and other consumer bodies have raised concerns about these higher charges. They note the variations in charges between companies and are not convinced that these reflect the net additional costs. Most argue that the surcharges should be reduced or removed, and that there should be greater incentives on PESs to reduce the relevant costs. They are concerned that the higher costs fall on customers who, to a significant extent, are those least able to meet them.

7.6 The new supply price restraints give PPM customers the same minimum price reductions as corresponding customers on quarterly payment tariffs. They also place efficiency incentives on companies. They are intended to protect PPM customers from unjustified price increases, and allow them to benefit from the competitive market.

7.7 There has been a tendency to equate customers who pay through PPMs with disadvantaged or low income customers. The Green Paper notes, however, that there is no straightforward relationship between the two. Many disadvantaged customers have PPMs. Recent market research for OFFER by MORI indicated that about half PPM customers are "low income" customers (those in receipt of Income Support or Family Credit). The Green Paper notes that nearly half of PPM users are lone parents.

7.8 The MORI research suggested, however, that only about half of low income customers have PPMs, and that the remainder use other methods to pay for their electricity. In addition, half of all PPMs are used by those who are not on "low income" as defined. Many customers - regardless of income level - choose them as a helpful way of budgeting for their consumption of electricity (or in some cases repaying debt). Indeed, the MORI research found that 82 per cent of PPM customers were either totally or very satisfied with PPMs as a payment method, suggesting that they are relatively content with present arrangements.

7.9 The use of particular payment methods, such as prepayment, as a proxy for disadvantage or low income is therefore imprecise. This should be recognised when assessing what further might be done to ensure that disadvantaged and low income customers are not excluded from the benefits of competition.

7.10 Against this background it is important that a number of arrangements are in place: first to ensure that there are incentives for PESs to improve the efficiency and reduce the costs of PPMs, while protecting PPM customers from being overcharged; second to ensure that PPM customers are able to participate in the competitive market; and third to ensure that PPM customers are protected as regards standards of service.

Examination of PPM Costs

7.11 Table 26 shows for each PES the level of additional PPM charges on 1 April 1998 and the total additional charge for a customer with a typical demand of 3300 kWh per year, compared to standard domestic quarterly tariffs.

TABLE 26: PREPAYMENT METER CHARGES FOR DOMESTIC CUSTOMERS (1 APRIL 1998)

PES	Additional Standing Charge £ per year	Unit rate Discount p/kwh	Annual Value of Unit Rate Discount £ (1)	Net Additional PPM Charge £ per year (1)
Eastern	11.96	0.00	0.00	11.96
East Midlands	21.20	0.00	0.00	21.20
London	17.89	0.22	7.26	10.63
Manweb	21.20	0.10	3.30	17.90
Midlands	9.48	0.00	0.00	9.48
Northern	21.88	0.20	6.60	15.28
NORWEB	23.42	0.22	7.26	16.16
SEEBOARD(2)	13.50	0.08	2.64	10.86
Southern	18.00	0.09	2.97	15.03
SWALEC	29.52	0.11	3.63	25.89
South Western	16.00	0.15	4.95	11.05
Yorkshire	23.60	0.00	0.00	23.60
ScottishPower	16.22	0.00	0.00	16.22
Hydro Electric	0.00	0.13	4.40	-4.40
Average	17.42	0.09	3.07	14.35

Notes: 1 Calculated assuming an annual consumption of 3300 kWh.
2 SEEBOARD's PPM surcharge includes a discount of £1 per quarter over the credit standing charge.
3 Fourth column = first column less third column.

7.12 The additional costs which companies claim as justification for these additional charges derive from two sources:

- those incurred by the distribution business in purchasing, installing and maintaining PPMs (reflecting their higher costs, shorter working life and lower reliability); and

- costs falling on the supply business in providing a network of facilities to sell tokens or recharge keys, and in handling small cash payments, offset to some extent by earlier or more secure payments for electricity.

7.13 The last supply price review noted considerable differences in claimed costs between PESs, reflecting differences in metering technology, in the number and type of PPM customers, in the methods of allocating costs, and in the companies' efficiency. It pointed out that, since the level and attribution of many of the costs involved potentially overlap between distribution and supply businesses, a full analysis of the situation would need to await the joint review which is the subject of this consultation.

7.14 OFFER will carry out a full examination of all the costs of PPM services, including the costs of the meters themselves, the infrastructure for accepting payment, and the various costs of billing, meter reading, customer service, maintenance, debt collection and so on. It will compare costs across PESs which have different metering technologies and policies. Questions to consider will include:

- the scope for the development of simpler, more reliable, and lower cost PPMs;
- the benefits to PESs of the earlier receipt of payments and the reduction in their costs of recovering debt;
- the extent of prospects for competition in the provision of PPM services; and
- the scope for alternatives to PPMs.

7.15 The review will consider the treatment of any additional charges with respect to the price controls. At present the PPM surcharges made by the distribution business to the supply business are excluded services and so outside the scope of the distribution price control. It is for consideration whether this should remain the case. Charges by the supply business to PPM customers fall within the scope of the supply price restraint, which as explained above was set to ensure that PPM customers received the same minimum price reductions as other domestic customers. It will be for consideration whether any further supply price restraints should continue to limit charges to PPM customers, and if so what form they should take and at what level the limits might be set.

Competition for PPM Customers

7.16 During 1998 and 1999 competition in the supply of electricity is being introduced across the country for domestic customers. Customers will be able to choose the supplier which offers the best combination of price and quality of service. To enable PPM customers to benefit from competition, special arrangements have been put in place to allow second tier suppliers access to the PPM infrastructure operated by PES supply businesses. In developing arrangements for the further separation of distribution and supply, careful consideration will need to be given to the treatment of PPM infrastructure. Any proposals should seek to protect PPM customers in the short-term without restricting or distorting competition to supply them in the longer term.

7.17 The Government and OFFER are concerned to ensure that all groups of customers have the opportunity to benefit from competition. OFFER has been asked to monitor the impact of competition on different classes of customers. Systems are being put in place to collect relevant information. When this becomes available it may be necessary to consider whether anything further needs to be done to ensure that PPM customers can fully participate in the market.

Service Standards for PPM Customers

7.18 In its consultation paper last October on the scope for improvements in Guaranteed and Overall Standards, OFFER identified a need for measures to strengthen protection for PPM customers. To that end, a new Guaranteed Standard is being introduced requiring PESs to repair PPM faults within 3-4 hours.

7.19 The consultation on Standards and the associated market research by MORI suggested that other areas of PPM services were also of concern to customers. These included access to charging points and to PPM outlets; the speed of repair of faulty charge points; and the speed of replacement of faulty keys (or equivalent for PESs who do not use key-based systems). OFFER therefore asked PESs to draw up their new Codes of Practice on payment methods based on specific targets for these services. The review will assess the scope and need for Standards covering these services.

7.20 The work outlined in this Chapter forms an important component of the action plan covering disadvantaged customers which OFFER has submitted as part of its reply to the Green Paper.

Issues for Consideration

7.21 Views are invited on any aspect of prepayment meter services, including those covered in the action plan, and in particular on

- the scope of the study of the costs of PPM services;
- whether the revenue from distribution business PPM surcharges should continue to be excluded from the distribution price control;
- whether further steps need to be taken to enhance the ability of PPM customers to participate in the competitive market;
- whether supply price restraints should continue to apply to PPM customers; and
- the scope and need for further Standards of Performance covering PPM services.

8 SUMMARY OF RESPONSES TO THE FEBRUARY 1998 CONSULTATION PAPER

8.1 The February 1998 consultation paper described the programme of work and reviews to be undertaken over the next two years in relation to the 14 Public Electricity Suppliers (PESs). This section summarises the responses to the consultation paper on issues related to the reviews of distribution and metering price controls, quality of supply standards, competition and supply price restraints, transmission price controls in Scotland and prepayment meters.

8.2 Forty responses were received from a wide range of interested parties - 14 PESs, 8 Electricity Consumers' Committees (ECCs), and 18 others. A list of respondents is set out in Annex 1.

Views of Public Electricity Suppliers

i) Distribution and Metering Price Controls

8.3 Of those PESs that commented on the form of the price control there was support for continuation of RPI-X as it provides appropriate incentives towards efficiency. One PES suggested that revised price controls could be set for a period of ten years, since investment decisions are based on long-term considerations. Another PES suggested that revised price controls should be set for a period of five years.

8.4 A number of PESs stressed that the analysis of operating and capital costs should identify relative efficiency, treat companies on a consistent basis and take account of the operating conditions within each PES area. Some PESs expressed concern about certain issues being revisited during the price control review. In particular, PESs argued that the approach to the valuation of distribution business assets should not be re-opened. It was suggested that any change to the method could lead to an increase in regulatory risk which would need to be reflected in a higher cost of capital.

8.5 Other issues raised included the need for an explicit recognition of environmental obligations and their impact on the level of costs, whether the funding for the energy efficiency Standards of Performance should be collected through the distribution price control, and the need to review the role of the tariff basket mechanism in the revenue driver of the price control.

8.6 There was a general concern among PESs that if there is a separate price control on metering activities it would be important to assess the potential impact of the level of the control on the development of competition. One PES argued that any price control should incorporate sufficient headroom to allow potential competitors to recover costs and an adequate level of return. It suggested that this would encourage the development of competition. There was also a concern that the present obligation on PESs to provide customers with meters could lead to stranded metering assets when

competition is introduced in 2000. It was argued that any price control should include an allowance to cover the potential costs of stranded assets. A number of PESs also argued that OFFER should review the allowance for data management services to include the recovery of costs not covered by the present arrangements.

ii) Quality of Supply

8.7 There was a general concern that if enhanced quality of supply targets are put in place, any associated capital investment and operating expenditure should be allowed for in setting the price control. A number of PESs argued that OFFER should undertake customer research to assess the appropriate balance between improved quality of supply standards and prices. One PES suggested that OFFER should examine how PESs have performed in terms of total expenditure against the existing quality of supply targets. It also identified a number of areas that revised standards should focus on. These included the overall minutes lost per year, number of interruptions, length of interruptions, provision of information during interruptions, and accuracy of supply voltage. It also argued that an overall quality measure should be developed for PES distribution businesses, based on system reliability and performance against the Guaranteed and Overall Standards of Performance. Another PES suggested that if more uniform quality of supply standards are introduced this may have a significant impact on costs, particularly in PES areas that are significantly different in terms of geography, state of the network and customer density.

iii) Competition and Supply Price Restraints

8.8 Of those PESs that commented most indicated that there should be no presumption that price restraints would be needed after 2000. One PES suggested that it may be appropriate to protect customers through non-discrimination conditions rather than with price restraints. Another expressed the view that price restraints would not be needed unless there was no development of competition in generation. There was also a concern among some PESs that competition in Scotland may not develop to the same extent as in England and Wales. PESs generally argued that if price restraints were extended the coverage should be reduced. One PES argued that if the coverage is restricted to a small group of domestic customers it may be appropriate to set revised price restraints for a period of more than three years. Another PES argued that the method used for establishing the existing maximum price restraints was flawed and that any revised control should be based on a consistent application of purchase cost assumptions across all PESs.

iv) Transmission Price Control in Scotland

8.9 Few PESs commented specifically on the Scottish transmission price controls. One PES commented that it welcomed a thorough review of transmission charges in Scotland. Another PES argued that it will be important to consider the comparators against which operating and capital efficiencies might be assessed.

v) Prepayment Meter Customers

8.10 There was general support for the review of arrangements for PPM customers. One PES suggested that it may be appropriate to place the PPM surcharge within the scope of regulated revenue. It argued that this would provide greater incentives towards efficiency and might lead to lower surcharges. Another PES suggested that the provision of the prepayment infrastructure could be treated as part of the distribution business, rather than as part of the supply business.

Views of Electricity Consumers' Committees

i) Distribution and Metering Price Controls

8.11 Of those ECCs that commented on the form of the control there was support for the continuation of RPI-X price controls. One ECC suggested that revised price controls should be set for a period of five years. Two ECCs expressed concern at the lack of competition in new connections. Another ECC highlighted the importance of distribution losses. It suggested that targets and penalties could be introduced to increase incentives towards energy efficiency. A number of ECCs argued that the price control review should include a rigorous assessment of the appropriate level of distribution business capital expenditure.

8.12 One ECC suggested that OFFER should consider the issues associated with joint meter reading and the possibilities for increased use of remote meter reading technology. Another ECC commented that it would support measures to promote competition in metering as this could lead to an increased level of service and lower costs. One ECC argued that OFFER should ensure that in any revised arrangements relating to metering it is clear where the responsibility for detecting metering interference lies.

ii) Quality of Supply

8.13 The majority of ECCs highlighted the importance of quality of supply. Several ECCs suggested that more detailed targets should be set and that these should be more stringent than the present targets. One ECC suggested that PESs may have little incentive to install underground cables on the distribution network. Another ECC expressed concern about the possible costs of setting more stringent Standards.

iii) Competition and Supply Price Restraints

8.14 Several ECCs commented on the assessment of the development of competition. One welcomed the proposal to monitor the development of competition across all customer groups. Another suggested that the review should include an assessment of the standards of service offered by suppliers. One other ECC expressed the view that price restraints should continue for five years, with the possibility of removal if necessary. It also suggested that the funding of the energy efficiency Standards of Performance

should be continued under revised arrangements. Another ECC suggested that this could be financed through the distribution price control.

iv) Prepayment Meter Customers

8.15 There was general support among the ECCs for the review of arrangements for PPM customers, particularly the proposal to examine all the costs of prepayment services. Two ECCs suggested that the focus of the review should be widened to consider all customers on low incomes rather than solely PPM customers. Two also expressed concern at the possibility of PPMs leading to customers being self-disconnected from their electricity supply.

Views of Other Parties

i) Distribution Price Controls

8.16 One respondent commented that much of the work associated with the price control review would involve looking at the operating costs of the PESs and that there should be complete transparency in this area. Another respondent suggested that the funding for the energy efficiency Standards of Performance should be recovered through the distribution price control. It also commented that the price control review would provide an opportunity to reconsider incentives towards energy efficiency.

8.17 A number of respondents stressed the importance of devising arrangements for metering and meter reading which encourage the development of competition. One respondent said that it is unclear which of the costs associated with metering and data services are covered by the existing distribution price control. Two other respondents said that independent meter operators should be encouraged to enter the market and that an allowance should be made for the difficulty that new entrants may face in competing with incumbent suppliers of metering services. They also argued that in a competitive market it should not be necessary for PESs to continue to be obliged to provide data management services. Another respondent argued that PESs should adopt a consistent approach towards the depreciation of metering assets. It suggested that without this there could be significant differences between PESs in the prices charged for selling or leasing of metering equipment.

ii) Quality of Supply

8.18 One respondent suggested that the focus of the review of quality of supply should be extended to include aspects of customer service such as the provision of bills and other information in alternative formats, compliance with Codes of Practice, and customer satisfaction.

iii) Competition and Supply Price Restraints

8.19 One respondent suggested that important factors in the development of competition are the level of customer awareness and the ease with which customers can change supplier. It also suggested that any barriers to entry into the supply market should be removed. Another indicated that it intends to undertake a regular independent survey of the competitive market. One respondent argued that it will be important to consider whether the competitive market will encourage energy efficiency measures. Another respondent suggested that unless price restraints are absolutely necessary they should not be extended after the year 2000. It argued that price restraints have an adverse impact on the development of competition in the generation market.

iv) Prepayment Meter Customers

8.20 One suggested that the review of arrangements for PPM customers should be more widely defined and should be extended to consider the availability and fairness of supply to all domestic customers. One respondent said that it would be important to analyse all the costs and benefits of PPMs. Another respondent said that OFFER should ensure that prepayment meter services are provided by the PESs on a non-discriminatory basis.

ANNEX 1

LIST OF RESPONDENTS TO FEBRUARY 1998 CONSULTATION PAPER

1 Public Electricity Suppliers

East Midlands Electricity
Eastern Electricity
London Electricity
Manweb
Midlands Electricity
Northern Electric
NORWEB
Scottish Hydro-Electric
ScottishPower
SEEBOARD
Southern Electric
Southern Western Electric
SWALEC
Yorkshire Electricity

2 Electricity Consumers' Committees

East Midlands ECC
Eastern ECC
Midlands ECC
North West ECC
South East ECC
South Wales ECC
South West ECC
Yorkshire ECC

3 Other Respondents

British Gas
CBI
Centre for Utility Consumer Law, University of Hull
Coalfield Communities Campaign - Yorkshire
Consumers Association
Dundee City Council
Electricity Association
Energy Savings Trust
Enron
Findhorn

First Hydro
IVO Energy
Nuclear Electric
Powermet Ltd
Quadrant Consultants
Royal National Institute for the Blind
Scottish Electricity Settlements
Unison Energy

ANNEX 2

THE MMC'S CALCULATION OF HYDRO-ELECTRIC'S DISTRIBUTION PRICE CONTROL

In its report on Hydro-Electric the MMC used present value calculations to estimate the revenues which Hydro-Electric's distribution business would require over the price control period 1995/96 to 1999/2000.

The MMC calculated the present value of cash outlays on operating costs and capital expenditure during the period, plus a value for the opening assets less a value for the closing assets. It then calculated a price control which had the same present value of revenues as the present value of costs. Allowance was made for the fact that some of Hydro-Electric's costs and revenues refer to excluded services and were not part of the price control, and for Hydro-Benefit.

Line 1 of Table 27 sets out the MMC's projections of operating costs net of depreciation. Line 2 sets out projections of network capital expenditure and line 3 projections of non-operational capital expenditure. Line 4 adds these together and line 5 discounts these totals to give present values. Over the five years of the control the present value of these outlays is £457.9 million.

Line 6 notes the opening value in 1995/96 of the assets assumed to be in existence at the beginning of that year, and the present value of the closing balance in 1999/2000 of the assets assumed to be in existence at the end of that year. The opening asset value was derived from the calculations set out in Table 28. The MMC used the same approach to calculate the closing value, with depreciation calculated assuming an asset life of 20 years for those assets existing at Vesting and 40 years for subsequent network capital expenditure. The difference in present values between the 1995/96 and 1999/2000 asset values of £128.2 million represents a return on the value of assets in the period.

Line 7 shows the sum of the present value of the cash outlays plus the present value of the assets in the period, totalling £586.1 million.

TABLE 27: MMC'S CALCULATION OF HYDRO-ELECTRIC'S DISTRIBUTION BUSINESS COSTS (1994/95 PRICES)

	1995/96	1996/97	1997/98	1998/99	1999/2000	TOTAL
1. Operating Costs	60.7	59.5	58.3	57.1	56.0	
2. Network Capital Expenditure	43.5	43.2	43.8	44.1	44.6	
3. Non-Operational Expenditure	6.7	5.6	5.3	5.6	5.0	
4. Total Cash Outflow	110.9	108.3	107.4	106.8	105.6	
5. PV of Cash Outflow	107.2	97.8	90.7	84.3	77.9	457.9
6. PV of Asset Values at 7%	563.0				-434.8	128.2
7.						586.1

TABLE 28: MMC'S CALCULATION OF HYDRO-ELECTRIC'S DISTRIBUTION ASSET BASE (1994/95 PRICES)

	1990/91	1991/92	1992/93	1993/94	1994/95
Opening Value	523.4	534.6	534.4	536.1	545.1
Depreciation	(27.2)	(27.9)	(28.7)	(29.7)	(31.0)
Network Capital Expenditure	38.4	27.7	30.4	38.7	48.9
Closing Value	534.6	534.4	536.1	545.1	563.0

The total of £586.1 million in Table 27 represented the present value of the revenue that the MMC considered HE would need to raise in order to cover its allowable cash outflows and earn a 7 per cent return on its asset value. The MMC calculated that the continuation of the existing price control would raise revenue with a present value of £462.1 million, which fell short of this amount. However there was an additional source of revenue, the Hydro-Benefit, which could be transferred from the generation business to the distribution business in accordance with Schedule 7 of Hydro-Electric's PES licence. In deciding how much Hydro-Benefit should be used to reduce Hydro-Electric's distribution charges the MMC considered it appropriate set distribution charges by reference to the historic relationship between Hydro-Electric's charges and those of ScottishPower. Taking this into account the MMC decided that an appropriate relationship would be established and maintained if Hydro's price control required it to reduce prices by 0.3 per cent in 1995/96 followed by reductions of 2 per cent a year for the next 4 years in line with the RPI-X price controls then applying to ScottishPower and the RECs. The MMC calculated that this would need an annual Hydro-Benefit of £29.2 million. Table 29 shows the MMC's projections of distribution business revenue, including its assumption of £29.2 million per year in Hydro-Benefit. The present value of revenue and Hydro-Benefit is £586.1 million, which is equal to the present value of costs and return on assets shown in Table 27.

TABLE 29: MMC'S PROJECTIONS OF HYDRO-ELECTRIC'S DISTRIBUTION BUSINESS REVENUE (1994/95 PRICES)

	1995/96	1996/97	1997/98	1998/99	1999/2000	TOTAL
Regulated Revenue	105.2	104.6	103.8	102.9	102.1	
Unregulated Revenue	5.5	5.3	5.1	5.0	4.8	
Hydro-Benefit	29.2	29.2	29.2	29.2	29.2	
Total	139.9	139.0	138.1	137.2	136.2	
PV of Revenue at 7%	135.2	125.6	116.6	108.2	100.4	586.1

ANNEX 3

THE VALUE OF THE CAPITAL OF THE DISTRIBUTION BUSINESSES AT FLOTATION

The last distribution price control review included calculations of the value of capital invested in the distribution business. In making these calculations the value of capital invested was split into two components, the initial capital as it stood at flotation and the investment made since then. Chapter 3 explains the broad approach to these issues. This annex sets out the calculations made at the time of the last distribution price control review of the value of the initial capital at flotation.

As explained in Chapter 3 the approach to valuing the initial capital involved calculating an initial market value for each PES and adjusting this in order to translate it to a value for the distribution business. The initial market value for each PES was calculated by adding a value of its net debt to a value of its equity. The process differed slightly as between the RECs and the two Scottish PESs.

The value of each REC's net debt was estimated by taking the nominal value of debt shown in the REC privatisation prospectus (issued in November 1990) and adjusting it to a market value to reflect differences between the market rate of interest in 1990 and the rate of interest necessary to service the debt. This was converted to a net figure by adjusting for the short term cash position shown in the prospectus. Similar calculations were made for the Scottish PESs, based on the privatisation prospectus issued in May 1991. The value of net debt for each of the PESs is set out in Table 30.

TABLE 30: VALUE OF PESs' DEBT

	Nominal Value of Debt in Prospectus £m	Market Value of Debt £m	Subtract Short-Term Cash £m	Net Debt £m
Eastern	263	269	(29)	298
East Midlands	127	124	(42)	166
London	310	303	185	118
Manweb	63	68	(52)	120
Midlands	120	117	(34)	151
Northern	164	163	65	98
NORWEB	153	167	(39)	206
SEEBOARD	125	128	(2)	130
Southern	295	286	84	202
SWALEC	25	25	(11)	36
South Western	80	89	(45)	134
Yorkshire	189	186	32	154
TOTAL REC	1914	1925	112	1913
ScottishPower	394	426	(110)	316
Hydro Electric	232	257	3	254

The value of equity for each REC was calculated from the market value of its shares. The market price for each REC was initially quoted on a partly paid basis. This needed to be adjusted to take account of the future payments due on the shares. The cost (discounted at 10 per cent) of future instalments, payable on the shares in October 1991 and September 1992, was added to the share price at the close of business on the first day's trading (in December 1990). This adjusted market price was multiplied by the total number of shares to derive the market value for each REC's equity. Similar calculations were made for the Scottish PESs, based on a first day share price in June 1991 and further instalments payable in May 1992 and April 1993. These calculations are shown in Table 31.

TABLE 31: PESs' MARKET CAPITALISATION

	First Day Share Price £	**Value of Future Instalments £**	**Total £**	**No. of Shares million**	**Market Capitalisation £m**
Eastern	1.480	1.237	2.717	269.9	733
East Midlands	1.505	1.237	2.742	218.1	598
London	1.420	1.237	2.657	218.1	579
Manweb	1.660	1.237	2.897	118.7	344
Midlands	1.440	1.237	2.677	209.4	561
Northern	1.425	1.237	2.662	123.1	328
NORWEB	1.520	1.237	2.757	172.7	476
SEEBOARD	1.420	1.237	2.657	127.4	338
Southern	1.500	1.237	2.737	269.9	739
SWALEC	1.640	1.237	2.877	101.5	292
South Western	1.500	1.237	2.737	123.1	337
Yorkshire	1.595	1.237	2.832	207.3	587
TOTAL					5,911
ScottishPower	1.150	1.233	2.383	814.8	1942
Hydro-Electric	1.220	1.233	2.453	383.4	941

Table 32 adds together the values net debt and equity for each PES, as derived from Tables 30 and 31.

TABLE 32: VALUE OF NET DEBT PLUS EQUITY

	Value of Net Debt £m	Value of Equity £m	Initial Market Value £m
Eastern	298	733	1031
East Midlands	166	598	764
London	118	579	697
Manweb	120	344	464
Midlands	151	561	712
Northern	98	328	426
NORWEB	206	476	682
SEEBOARD	130	338	468
Southern	202	739	942
SWALEC	36	292	328
South Western	134	337	470
Yorkshire	154	587	741
TOTAL REC	1813	5911	7724
ScottishPower	316	1942	2258
Hydro-Electric	254	941	1195

In order to derive a value for each REC distribution business, it was necessary to adjust the initial market value of each REC for the value of its other businesses and its shareholdings in NGC. For the purpose of setting the price control it was assumed that the RECs' other business activities had a zero value. OFFER considered a number of approaches to splitting the initial market value of the REC between the distribution business and the REC's shareholding in NGC. Tables 33 and 34 show two such approaches.

In Table 33 the split is made for each REC according to the ratio of its distribution business CCA net asset values to its share of NGC's CCA shareholder funds. A number of RECs criticised this approach because it implied different implicit value for a share in NGC from one company to another. For example, a 1 per cent shareholding by London would be valued at £218 ÷ 10.5 = £20.8 million, whereas a 1 per cent shareholding by Southern would be valued at £318m ÷ 11 = £28.9 million. Table 34 shows a modification of this approach in which the aggregate value of the REC shareholdings in NGC and the aggregate value of their distribution businesses are calculated in proportion to the aggregate CCA values of the two sets of businesses. The resulting aggregate value are consistent with the aggregate values calculated in Table 33. Each REC's shares in NGC is then valued on a consistent basis by multiplying the proportion of each REC's shareholdings in NGC by the value of NGC's shareholders funds. The value for each REC's distribution business is then derived by subtracting the value of its NGC shareholding from its initial market value.

TABLE 33: HYPOTHECATION OF INITIAL MARKET VALUES ON THE BASIS

OF CCA ASSET VALUES

	Share-holdings in NGC % (1)	NGC CCA net assets allocated by share holdings £m (2) =(1) x 4363	Distribution CCA net assets £m (3)	Initial Market Value £m (4)	Value of holdings in NGC £m (5)	Value of distribution £m (6)
Eastern	12.5	545	1246	1031	314	717
East Midlands	8.4	367	920	764	218	546
London	10.5	458	1008	697	218	480
Manweb	5.5	240	627	464	128	336
Midlands	9.2	401	964	712	209	503
Northern	6.5	284	572	425	141	284
NORWEB	8.2	358	823	682	207	475
SEEBOARD	7.3	319	631	468	157	311
Southern	11.0	480	941	941	318	623
SWALEC	5.4	236	415	328	119	209
South Western	6.3	275	687	470	134	336
Yorkshire	9.2	401	851	741	238	503
TOTAL REC	100	4363	9685	7724	2400	5323

Notes

(1) Percentage shareholdings in NGC as shown in the REC privatisation prospectus.

(2) NGC's CCA shareholder funds as at 31 March 1991 (£4363 million) allocated to each REC according to the proportion of its shareholdings in NGC. For example, Eastern owned 12.5 per cent of NGC's shares and so hypothecating NGC's asset value on this basis gives 0.125*4363= £545 million.

(3) Distribution business CCA net asset values at 31 March 1991.

(4) Initial market values from Table 32.

(5) Value of each REC's holdings in NGC calculated as the proportion of its hypothecated NGC CCA shareholder funds (see note 2) to the total of its hypothecated NGC CCA shareholder funds distribution business net CCA assets (see note 3), multiplied by its initial market value. For example, Eastern 545/(545 + 1246) x 1031 = £314 million

(6) Value of each RECs distribution business calculated as the proportion of its distribution business CCA net assets (see note 3) to the total of its hypothecated NGC CCA shareholder funds (see note 2) and distribution business CCA net assets, multiplied by its initial market value. For example, Eastern 1246/(545 + 1246) x 1031 = £717 million.

TABLE 34: HYPOTHECATION OF INITIAL MARKET VALUES WITH EQUAL

VALUES FOR SHARES IN NGC

REC	Initial Market Value £m (1)	Share-holdings in NGC % (2)	Value of NGC holdings £m (3)	Value of distribution £m (4)
Eastern	1031	12.5	300	731
East Midlands	764	8.4	202	562
London	697	10.5	252	446
Manweb	464	5.5	132	332
Midlands	712	9.2	221	491
Northern	425	6.5	156	269
NORWEB	682	8.2	197	485
SEEBOARD	468	7.3	175	293
Southern	941	11.0	264	677
SWALEC	328	5.4	130	198
South Western	470	6.3	151	319
Yorkshire	741	9.2	221	520
TOTAL	7724	100.0	2400	5323

Notes

(1) Initial market values from Table 32.

(2) Shareholdings in NGC as shown in the REC privatisation prospectus

(3) Values for holdings in NGC based on the value for the RECs total shareholdings in NGC (£2400 million) as derived in Table 33 apportioned between the RECs according to their percentage shareholdings in NGC. For example, the value of Eastern's holding in NGC was calculated as 0.125*2400=£300 million.

(4) Value of distribution calculated by subtracting the value for holdings in NGC from the initial market values. For example, the value of Eastern's distribution business was calculated as £1031 million minus £300 million giving £731 million

As explained in Chapter 3, the flotation values of the distribution businesses were then uprated by 15 per cent. The first column of Table 34 shows the range of values for the distribution businesses as calculated in Tables 32 and 33. The second column shows these uprates and the third column the total uprated values.

TABLE 35: UPRATE OF REC FLOTATION VALUE

REC	Value of Distribution £m (1)	Plus 15% uprate	Total £m
Eastern	717-731	108-110	825-841
East Midlands	546-562	82-84	628-646
London	446-480	67-72	513-552
Manweb	332-336	50	382-386
Midlands	491-503	74-75	565-578
Northern	269-284	40-43	309-327
NORWEB	475-485	71-73	546-558
SEEBOARD	293-311	44-47	337-358
Southern	623-677	93-102	716-779
SWALEC	198-209	30-31	228-240
South Western	319-336	48-50	367-386
Yorkshire	503-520	75-78	578-598

Notes
(1) The range derives from the values shown in Tables 33 and 34 for the value of the distribution business.

The circumstances of the privatisation of the two Scottish PESs were somewhat different to those pertaining at the time of the privatisation of the RECs. Investors in ScottishPower and Hydro-Electric purchased companies with substantial assets in generation and transmission as well as distribution. It was therefore more difficult to assess a value for the distribution businesses alone.

In valuing generation assets it was assumed that investors valued the generation assets of ScottishPower and Hydro-Electric at the same relation to their CCA book values as they did for National Power and PowerGen. By deducting these values from the total value which investors placed on the two Scottish companies values were derived for distribution close to their CCA net book values. Scottish Power's distribution business CCA net book value at 30 March 1990 was £1186 million, Hydro-Electric's was £464 million.

The September 1994 price control proposals explained a further adjustment to these values. At flotation analysts and others reported that the initial distribution price controls in Scotland were set on the basis of a 6 per cent return on the CCA book value of distribution assets at the time. However, if the cost of capital for the distribution businesses of the Scottish companies is taken to be 7 per cent, as it was estimated to be, rather than 6 per cent as the Government had reportedly assumed, then this implied that investors placed a lower value on the investment than the CCA book value. Accordingly, a value lower than CCA net book value should be used in order to be consistent with the reported basis of the initial control.

However, as explained in Chapter 3 the MMC rejected this argument and adopted a value for the distribution business of Hydro-Electric consistent with its CCA net book value.

The numbers set out in Table 35 for the RECs and the numbers for the Scottish companies described above, formed the basis for the valuation of the flotation assets of the PESs distribution businesses. In the case of the RECs the implications for the level of price control allowed revenue for the range of flotation values as set out above was considered. In making the present value calculations of allowed revenue described in Chapter 3 and Annex 2 a number of further adjustments were made to these values. First, they were adjusted upwards by the change in the RPI to take account of inflation. Second, it was assumed that a proportion of the flotation values would be written off on a uniform annual basis, depending on the average age of that PES's assets at Vesting.