March 2000

The Transmission Price Control Review of the National Grid Company from 2001

Initial Thoughts Consultation Document

Executive summary

This document follows Ofgem's December 1999 "The transmission price control review of the National Grid Company from 2001: Initial Consultation Document". Ofgem intends to publish initial proposals for NGC's price control in June 2000.

This document sets out Ofgem's initial thoughts on the form and structure of NGC's price control from April 2001. Respondents to the December document broadly supported the continued use of an RPI-X control, the lengthening of duration of the control to five years, and the inclusion of some form of revenue driver. Accordingly, Ofgem is minded to lengthen the duration of the control, and include a revenue driver based on the volume of electricity transmitted.

Ofgem has commissioned two firms of consultants, Arthur Andersen and PB Power, to undertake studies of NGC's operating and capital expenditure respectively. This document sets out some initial results from their studies and discusses the approach which Ofgem intends to use in determining NGC's revenue allowance for the period of the next price control.

Ofgem has studied the development of Energis, NGC's telecoms associate, and considered what impact, if any, this should have on NGC's regulatory asset value (RAV). Ofgem believes that it would be inappropriate and inconsistent to alter NGC's RAV in this respect. However, Ofgem proposes to review the rental paid by Energis to NGC which could have an impact on transmission prices.

In determining a range for the cost of capital for NGC, Ofgem will base its conclusions on its modelling of financial forecasts for an efficient transmission company, alongside analysis using the capital asset pricing model and the dividend growth model. Ofgem's approach for NGC is consistent with the approach adopted for the final proposals for the distribution price control reviews in December 1999. While Ofgem is aware that any results from the models used must be treated with caution, it has nevertheless estimated a preliminary range of 4.4-6.5% for NGC's cost of capital. Ofgem has built a financial model of NGC to ensure that its draft proposals, to be published in June, do not jeopardise NGC's ability to fund its licensed activities.

TABLE OF CONTENTS

Foreword

Ofgem is reviewing the price control on the transmission business of the National Grid Company plc (NGC). This consultation paper sets out Ofgem's initial thoughts on that review following the submission of the business plan questionnaire (BPQ) by NGC and the first phases of Ofgem's efficiency and capital expenditure studies. Ofgem is conducting a separate consultation on NGC's incentives under NETA and will release a consultation document in April 2000. A consultation document on NGC's access arrangements will be published in May 2000. Throughout this review, Ofgem will be guided by its statutory duties, set out in Appendix One.

NGC's price control is intended to allow NGC to finance those costs attributable to, and efficiently incurred in the operation of, its transmission business. Other costs are covered by separate incentive schemes, known as the transmission services incentives arrangements. These arrangements were the subject of a separate consultation document, "NGC's System Operator Incentives, Transmission Access and Losses under NETA", published in December 1999. A further consultation document on these arrangements will be produced in April 2000. These two areas of work are closely interrelated.

The remainder of this document is structured as follows:

- Chapter 1: describes the licensed activities of NGC's business;
- Chapter 2: discusses the form, structure and duration of the next control; the inclusion of a revenue driver; the interaction with NETA and the system operator incentives and Ofgem's responsibilities on energy efficiency and the environment;
- Chapter 3: discusses NGC's operating costs, including NGC's and Ofgem's forecasts at the last price control review and the outturn and the efficiency study of NGC that Arthur Andersen are conducting;
- Chapter 4: discusses NGC's capital expenditure, both load related and non-load related; how this may be reconciled with forecasts made at the last price control review; and how Ofgem will ensure that NGC is

allowed sufficient capital expenditure to enable an efficient company to fulfil NGC's obligations under its licence and the Act;

- Chapter 5: discusses how the incentives on NGC might be improved including how to incentivise NGC to maintain high service quality;

- Chapter 6: discusses the methodology for determining NGC's cost of capital; its regulatory value; and Ofgem's approach to financial modelling;

- Appendix One includes a summary of Ofgem's and NGC's duties relevant to this price control review;

- Appendix Two includes a summary of responses to the initial consultation document (published in December 1999);

- Appendix Three includes a summary of NGC's business plan questionnaire response. This summary has not been edited by Ofgem, and reflects NGC's views, rather than those of Ofgem;

- Appendix Four includes a diagram of the structure of National Grid Group, provided to Ofgem in July 1999; and

- Appendix Five includes a summary of recent determinations of the cost of capital by Ofgem and other regulators.

Rationale

The operations of NGC are central to the operation of the electricity supply industry in England and Wales. Its quality of service affects almost all users of the system. This price control review is required given NGC's position as a monopoly provider of electricity transmission services in England and Wales. This review will strengthen the incentives on NGC to improve its efficiency, leading to lower costs and lower prices for customers.

Transmission charges account for about 5% of an average domestic customer's electricity bills. In 1998/99 (the last year for which NGC produced audited financial data), NGC's RPI-X revenue, the primary subject of this review, was approximately £850 million. A price control remains necessary for NGC's operation as a monopoly and can serve NGC's position as a monopoly. This review needs to be completed in time to allow NGC to set new charges from April 2001, when the present price control expires. The direct costs to Ofgem in conducting the review are expected to be £0.75 million (including a provision of £0.5 million for consultancy services).

Responses

Ofgem welcomes comments from all interested parties on the matters raised in this paper by 10 May 2000. Should you have any questions, Justin Coombs on (020) 7932 1605, Bill Hetherington on (020) 7932 5878 or Peter John on (020) 7932 5941 will be pleased to help. We would ask respondents to ensure that Ofgem receives replies by the deadline. Written replies should be sent to:

Mr Peter John

Regulation and Financial Affairs Division

Office of Gas and Electricity Markets

Stockley House

130 Wilton Road

London SW1V 1LQ

E-mail: peter.john@ofgem.gov.uk

Fax: (020) 7932 1675

Electronic replies should be sent as an MS-Word document or else in the main text of the e-mail message. Ofgem would prefer that responses were provided in a form that can be placed in the Ofgem library in London. Please mark your comments clearly if you consider that they must be regarded as confidential.

Ofgem
March 2000

1. Price control review of the National Grid Company (NGC)

Structure and role of National Grid Group (NGG) and NGC

1.1 NGC is a wholly owned subsidiary of National Grid Holdings, which in turn is a subsidiary of NGG. The structures of NGG and NGC are shown in Appendix Four. NGC owns and operates the network of high-voltage transmission lines and associated equipment in England and Wales ("the National Grid"). It enables the bulk transfer of electricity from power stations and the Scottish and French interconnectors to the distribution systems of the regional electricity companies (RECs). A few very large customers are directly connected to the National Grid.

1.2 NGC's transmission business plays several roles in the electricity system in England and Wales. In addition to enabling bulk transfers of power, it contributes to the efficiency and security of supplies. The output of any particular power station may be affected by, for example, mechanical breakdown or planned maintenance or safety checks. The National Grid enables supplies to customers to be maintained from other stations. Without a transmission system providing equivalent security of supply there would need to be other arrangements, such as greater reserves of generating capacity.

1.3 The transmission system also facilitates competition between generating companies and stations. The Electricity Act 1989 contains an obligation on the Director General of Electricity Supply (DGES) to promote such competition. In addition, NGC's licence contains an obligation that it shall not, in the setting of use-of-system charges, restrict, distort or prevent competition in the generation, transmission, supply or distribution of electricity. This obligation compliments the existence of a wholesale mechanism for the purchase and sale of electricity. At present, this mechanism is the Electricity Pool of England and Wales (the Pool). However, the electricity industry trading arrangements are under review by Ofgem and the Department of Trade and Industry (DTI), and it is proposed that New Electricity Trading Arrangements (NETA) will be introduced in Autumn

2000. The ways in which that review will interact with the price control review are discussed in Chapter 2 below.

1.4 The customers of the transmission system include the companies that hold generation or supply licences in England and Wales and the small number of large users of electricity who take supplies direct from the grid. These users include those who wish to accept or deliver electricity into other connected transmission systems, such as the transmission systems in Scotland.

NGC's revenues

1.5 NGC's electricity transmission business has three principal sources of revenue, of which two are regulated by Ofgem, and one is arranged with suppliers through the Pool. This section describes each of these three sources of revenues.

1.6 The first concerns the bulk transfer of power for which NGC levies separate charges for connection to the transmission system and for the use of the system. Charges for connections made since 30 March 1990 (post-Vesting connections) are calculated with reference to the particular costs of making that connection, while charges for connections made prior to 30 March 1990 (pre-Vesting connections) relate to the connection assets existing at Vesting. Generators and suppliers pay transmission network use-of-system (TNUoS) charges for use of the transmission system. TNUoS transmission charges for generation are calculated by reference to the capacity of individual generating stations, and for suppliers are generally recovered on the basis of demand averaged over three peak half-hours.

1.7 Secondly, suppliers must also pay Transmission Services Use-of-System (TSUoS) charges. These charges include the costs of reactive power and the additional generation costs that result from constraints in the transmission system (collectively known as 'Transmission Services Uplift'). These costs are initially paid for by NGC in the Pool and recovered by NGC (after the application of incentives schemes) through NGC's TSUoS charges. TSUoS charges also cover the costs of ancillary services.

1.8 Thirdly, NGC incurs costs from transmission losses and from providing for errors in demand forecasts or generators failing to provide projected levels of output. Losses are paid for by suppliers through the Pool. NGC has an incentive scheme negotiated with Pool members to manage the cost of losses. The costs of providing for demand forecast errors and generator shortfalls are known as 'Energy Uplift' and are recovered from suppliers subject to a further incentive scheme arranged through the Pool.

1.9 This price control review process addresses the first of these three revenue streams: the price control covers TNUoS and pre-Vesting connection charges. NGC's TSUoS charges and their associated incentive schemes are being reviewed separately. Throughout this review process, however, Ofgem must consider the interactions between the TSUoS incentives schemes and the price controlled revenue, to ensure consistency of approach.

Objectives of the price control review process

1.10 The objectives of this price control review process are:

(i) to ensure that NGC can finance its licensed activities, given efficiency and economy on NGC's part;

(ii) to enable quality of service to be maintained and appropriate new investment to be financed;

(iii) to ensure that the prices charged to NGC's customers are no higher than necessary to fulfil objectives (i) and (ii); and

(iv) to provide incentives to ensure that NGC maintains an appropriate balance between the quality of its services, efficient capital investment, efficient operating expenditure and efficient financial management.

1.11 In setting the next price control, Ofgem will need to consider the effects of future developments during its duration, including:

- **New Electricity Trading Arrangements (NETA)**: the introduction of NETA, which will significantly affect the way in which NGC discharges its functions, is scheduled for 31 October 2000;

- **Review of the structure of use of system charges**: Ofgem is planning to review the way in which NGC's use of system charges are collected following the introduction of NETA;

- **Division of system operator and transmission asset owner functions**: in future NGC's electricity transmission business may be divided between these functions; and

- **Developments in transmission and in ancillary services**: there may be technical changes in these areas over the period of the next price control.

1.12 NGC's customers, suppliers and generators, must recover their charges from final consumers. Because NGC monopolises high-voltage transmission in England and Wales, it is important for customers that NGC is as efficient as possible in reducing its costs. Table 1.1 shows the levels of operating expenditure, depreciation and the return on capital in NGC's RPI-X revenue in 1998/99.

Table 1.1: Transmission business RPI-X-controlled costs and revenues (1998/99)

1999/00 prices	1998/99 (£m)	Share of transmission revenues (%)
Current cost depreciation	294	32
Operating expenditure	320	35
Return on capital	235	25
Total RPI-X revenue	**849**	**92**
Post-1990 connections	76	8
TOTAL	**925**	**100**

Source: NGC submissions to Ofgem

1.13 On average NGC's RPI-X controlled revenue represents 5 per cent of final electricity prices to consumers. A 25 per cent difference in operating expenditure over one year could change final electricity prices to consumers by about 0.4 per cent. NGC's return on capital for the present price control was set assuming a 7 per cent cost of capital. A variation of 1 percentage point in this cost of capital would affect allowed revenue by around £40 million, leading to a variation in prices to consumers of about 0.2 per cent.

1.14 Ofgem considers that the performance of regulated companies in delivering certain outputs should determine the revenue that they may raise, and hence the return that they can offer shareholders. During the distribution price control reviews, Ofgem relied heavily on benchmarking each company. Benchmarking is much more difficult in the case of NGC, since NGC is the only electricity transmission company in England and Wales, and the validity of any comparison with transmission companies outside England and Wales will be limited by many factors, including differences in legal and regulatory regimes and in the economical and physical structure of the electricity industry. Ofgem will explore the potential for such comparisons but take account of these factors before drawing conclusions.

1.15 It may be possible to benchmark NGC with other network utilities within the UK, including the electricity distribution companies, the Scottish electricity transmission businesses, Transco, Railtrack and the water and sewerage companies, taking account of the differences between NGC and these businesses.

1.16 Ofgem considers that customers should not be affected by corporate factors outside the licensed activities of a regulated company. In particular, they should not be expected to bear the costs of any other part of a group, such as Energis (NGG's telecoms associate) in the case of NGG. By the same token, customers should not expect to benefit from factors arising outside the licensed activities. However, in the case of a national monopoly such as NGC it can be argued that, since the customers of the transmission business have financed construction of the towers used by Energis to carry its fibre-optic cables, customers should also share in the profits NGC earns from its shareholding in Energis. This issue is explored further in Chapter 3 below.

1.17 In order to improve regulatory transparency, Ofgem intends to construct a financial ringfence around the licensed activities of NGC similar to those which exist around the public electricity suppliers (PESs) and Transco. This ringfence will strengthen the legal and regulatory protection of NGC's assets and impose a clearer division between the assets and personnel associated with the licensed activities and the rest of the group. Ofgem's model for regulatory ringfences is outlined in "Electricity Distribution Licences: Initial Proposals on Standard

Conditions for the financial ‘Ringfence’”, published in December 1999. Ofgem will set out its proposals for applying a financial ringfence to NGC in its initial proposals document in June.

2. Form of control

RPI-X regulation

2.1 In order to protect consumers from the possible abuse of market power by a national monopoly such as NGC's transmission business, NGC is subject to controls on the prices which it can charge and the quality of service which it must provide.

2.2 Around 92 per cent of the revenue of NGC's transmission business is regulated by an RPI-X control (see table 1.1 above), under which allowed revenue is set every few years from a forecast of the volume of electricity transmitted and the costs required to transmit it. Allowed revenue declines each year in real terms by a factor (the 'X' factor) which represents the scope for efficiency improvements estimated by the regulator. In addition, at each price control review, the regulator may make an adjustment to prices ("the P_0 cut") to allow for the regulated company's under- or over-performance in its cost reductions.

2.3 RPI-X regulation has been the most widespread form of revenue regulation for network utilities in the UK since the privatisations of the 1980s. The government's recent review of utility regulation supported the continued application of RPI-X controls, where regulators thought this to be the most appropriate approach. It also encouraged regulators to consider greater use of error correction mechanisms alongside RPI-X regulation – for example to deal with windfall events. All of the respondents to the December consultation document supported the continuation of RPI-X controls in some form for this part of NGC's revenue.

Enhancing the application of RPI-X regulation

2.4 RPI-X regulation provides strong incentives to reduce costs during the period of a price control. The benefits from these cost reductions can be shared with customers at the next price control review. In addition, RPI-X regulation has provided clear and transparent targets for regulated companies.

2.5 However, there are areas in which the present application of RPI-X regulation could be improved. It has been argued that the periodic negotiation with the regulator has become unduly important. The perceived ability of the regulated company to influence the outcome of the review process in favour of its shareholders may have resulted in the company devoting a disproportionate amount of management time to dealing with the regulator, rather than to improving the business.

2.6 There also appears to be greater incentive to reduce operating expenditure than to reduce capital expenditure. At the price control review, the regulator calculates the value of the regulatory asset base at the start of the control by adding the capital expenditure (and subtracting the depreciation) efficiently incurred during the previous price control period and allowing a return on this at the cost of capital. Thus the regulated company may be allowed a return on capital expenditure, but not on operating expenditure.

2.7 Ofgem is investigating further developments, which might be made to the existing system of regulation to overcome these shortcomings without losing the benefits of RPI-X regulation. Ofgem is investigating the requirements on PESs to provide information and how the incentives on regulated companies may best be arranged to fulfil the Director's statutory responsibilities. Progress of this information and incentives project was set out "Letter to the Chief Executives of the PES Distribution Businesses – Information and Incentives Project", published by Ofgem in March 2000. While the focus of the Information and Incentives Project is on the PESs, its conclusions may have implications for NGC. The measurement of NGC's performance is discussed further in Section 5.

Revenue driver

2.8 In setting NGC's present price control, OFFER regulated NGC's total revenue, rather than revenue per unit of electricity transmitted, thereby removing any artificial incentive on NGC to boost peak demand for electricity, and also removing any disincentive on NGC to co-operate with load management initiatives. In the initial consultation document, Ofgem raised the issue of whether a "revenue driver" should be incorporated into the price control. Most of the respondents who commented favoured such a step, though there appeared to be no clear consensus on which revenue driver was appropriate.

2.9 Ofgem considers that the incorporation of a revenue driver could improve the incentives on NGC. The RPI-X controls on Transco[1]'s gas transportation business and the PES distribution businesses are structured so that 50 per cent of the revenue is fixed, while 50 per cent is dependent on the volume of energy transported or distributed. Ofgem considers that the incorporation of a revenue driver could strengthen incentives on NGC and would be in accordance with its policy of regulatory consistency. Given that NGC's costs are largely fixed, the incorporation of a revenue driver based on volume would be inappropriate and would discourage energy efficiency. A revenue driver would also need to be consistent with NGC's system operator incentives and avoid creating perverse incentives on NGC. The incorporation of a revenue driver and the incentives on NGC are discussed further in Section 5.

Division between transmission asset owner (TO) and system operator (SO) functions

2.10 With the introduction of NETA, NGC's roles as SO and TO will be more clearly defined. The TO will own the transmission assets, ensure their maintenance and undertake longer-term development of and investment in the transmission system. The SO function will cover all the short-term operational activities required to keep the system balanced and operating within safe limits. NGC's response to the business plan questionnaire (BPQ) summarised in Appendix Two, provided both a transmission business 'as is' case (without a TO/SO split) and a TO only case going forward from 2001. Neither case took account of the impact on NGC of the new trading arrangements.

2.11 The SO and TO functions will not be separately licensed in the near future and there will continue to be strong interactions between the SO and TO functions. While a single company is carrying out both roles, it will be important to ensure the interactions between them are fully considered so as to ensure that the overall costs of operating, maintaining and developing the transmission system are minimised.

[1] In Transco's case, volumes do not vary in direct proportion to revenue due to the existence of a 'deadband'. Two levels of volume are set, between which allowed revenue is constant. If volumes of energy transported are outside these limits, allowed revenue varies proportionately with volume.

Scope of the RPI-X price control and the SO incentive schemes

2.12 In December 1999, Ofgem issued a consultation document, which discussed the role of and incentives on NGC under NETA[2]. In this document, Ofgem set out the role of NGC under NETA including discussing how NGC might procure and utilise balancing services and the form, scope and duration of the incentives schemes on NGC. Under the present arrangements, NGC is incentivised through a series of sliding scale schemes for transmission services (including constraint costs and most ancillary services), reactive power, energy uplift, and losses (see Section 1 above). It is proposed that these schemes will be replaced by a single SO incentive scheme. Ofgem's initial view is that the SO incentive scheme introduced for NETA should be a single scheme covering both the energy and system balancing costs incurred by NGC in operating the system. It should continue to be of a sliding scale or profit sharing form with incentivised costs being based on a target volume of services and a reference price emerging from forward markets. This approach should allow NGC as SO to take appropriate balancing actions looking across all its activities.

2.13 In "NGC's System Operator Incentives, Transmission Access and Losses under NETA", published in December 1999, Ofgem argued that appropriate locational signals for participants and NGC need to be introduced. By April 2001, Ofgem intends to introduce a new transmission access and pricing regime based around a market in firm access rights. This market will allow participants to discover the value of transmission access at different locations and enable NGC to resolve the majority of transmission constraints outside the energy market. Through the revised transmission access and pricing arrangements, participants will be given both short-term signals of the value of generation and demand at different locations and long-term investment signals.

2.14 Ofgem will be issuing a further consultation on NGC's incentives under NETA in April 2000. This document will also discuss the role of NGC under NETA and the initial treatment of losses. Also in April 2000, Ofgem will publish a further consultation on the development of a new Connection and Use of System Code for NGC's transmission system.

---

[2] *NGC System Operator Incentives, Transmission Access and Losses under NETA: A Consultation Document, December 1999.*

2.15 In May 2000, Ofgem will be publishing a further consultation on new transmission access and pricing arrangements under NETA. This document will also consider the long term options for procuring Balancing Services and the role of NGC as SO, the form, scope and duration of an enduring SO incentive scheme and the long term treatment of transmission losses.

2.16 The RPI-X control will continue to apply to all NGC's TO costs. The SO costs of operating and balancing the system will be incentivised through the single SO incentive scheme designed to ensure that overall costs, not just the individual cost elements, are at an efficient level. In the first instance, the SO operating expenditure will continue to be financed through RPI-X controlled revenues but will be clearly identified when setting the RPI-X control.

2.17 Ofgem will keep under review during the price control period whether there is merit in moving the SO operating expenditure into an overall SO incentive scheme. If this were to be implemented, Ofgem would expect the overall revenue entitlement to remain fixed. Ofgem will be considering NGC's proposals on the division between SO and TO functions and its allocation of operating expenditure before issuing its initial proposals for NGC's price control in June 2000.

Table 2.1: NGC's initial breakdown of opex costs between the SO and TO:

TO	£m	SO	£m
Network Services	79.8	**System Management**	37.8
Project Management	19.2	**Internal costs of procuring ancillary services** **(formerly NGC internal costs of ASB)**	5.3
Engineering and Technology	256.9	**Market development** **(formerly internal NGC TSS costs within Commerical and System Strategy Unit)**	1.0
Commercial and System Strategy	11.4	**UK Support/Central functions**	7.9
UK Support/Central functions	63.5		
Total	**430.8**	**Total**	**52.0**

2.18 Ofgem will not take account of the impact of NETA on NGC's costs when setting the price control. However, Ofgem believes that NGC's revenues should be adjusted to reflect this impact to the extent that any additional costs are appropriate and efficiently incurred. This will be achieved through appropriate adjustments to NGC's SO incentive arrangements.

Impact of NETA on NGC's costs

2.19 NGC has provided Ofgem with business planning information based on its role before the introduction of NETA. It may be that NETA will impact NGC's operating costs in its SO role, so that its costs will be different either higher or lower. In some areas NGC may face new or higher costs, but in other areas it costs may be lower or avoided completely.

Connection and Use of System Code

2.20 As part of the NETA programme, the Master Connection and Use of System Agreement (MCUSA) will be replaced with a new Connection and Use of System Code (CUSC). Although the NETA power will be used to implement CUSC, in order to ensure that the central NETA programme is not affected by the development of CUSC, implementation will take place after December 2000. CUSC will contain many of the provisions of the present MCUSA with more flexible governance procedures, codification of generic aspects of supplemental agreements, and clearer dispute resolution procedures. Ofgem has recently published a consultation document outlining the structure, governance arrangements and form of CUSC.

Duration of the control

2.21 Regulators in the UK have tended to set monopoly price controls for between three and five years. NGC's last price control lasted for four years (1997-2001). Respondents to the December initial consultation document generally supported lengthening the control to five years.

2.22 A longer price control will give greater incentives to NGC to make efficiency savings, since it may retain the benefits over a longer period. However, a longer duration also increases the risk of unexpected circumstances and the possibility of company performance being significantly different from the projections and assumptions used in setting the price control. One respondent to the December document commented that it might be desirable to set the form of the control for five years and revisit the parameters of the control halfway through the duration, given the present uncertainties of NGC's role. Ofgem considers, however, that this would create unnecessary regulatory uncertainty and that the present provisions for revision of the price control in NGC's licence are adequate.

2.23 Ofgem is presently minded to increase the duration of NGC's price control from four to five years. This would be consistent with the duration of the price controls for BT, Transco and the distribution businesses of the PESs.

Energy efficiency and the environment

2.24 A high level of electricity lost in transmission impacts the environment, since - if losses are higher - a given level of demand requires greater generation, producing more emissions. Since 1997 NGC has been incentivised through its system operator incentives to minimise transmission losses. Ofgem published a consultation document in December 1999[3] which discussed future incentives for NGC to reduce losses.

2.25 Ofgem considers that an RPI-X control gives NGC strong incentives to reduce capital expenditure. Capital expenditure can impact the environment, if it involves the construction on towers in areas of ascetic value, for example. Accordingly, providing incentives for NGC to reduce capital expenditure to the minimum required to provide the necessary quality of supply to transmission customers lessens the environmental impact of the transmission system.

2.26 There has been public concern over the impact of transmission lines, particularly in areas of attractive scenery. Undergrounding transmission circuits costs at least ten times as much as the installation of overhead transmission circuits. Ofgem considers that in circumstances such as a change in legislation requiring additional undergrounding, it may be necessary to adjust NGC's price control to allow NGC to pass through extra costs to consumers if the additional costs are likely to have a severe impact on NGC's ability to finance its licensed activities.

2.27 In the present price control, NGC's revenues are not linked to transmission volumes. One reason for the lack of such a link was because OFFER concluded

[3] NGC System Operator Incentives, Transmission Access and Losses under NETA: A Consultation Document

that such a link might discourage NGC from cooperating with load management initiatives. Ofgem believes that this concern needs to be balanced against the comments in response to the December consultation document which favoured introducing a link between NGC's revenues and its output performance.

Issues for consideration

2.28 Ofgem seeks views on:

- whether an RPI-X control is appropriate for the regulation of the revenue which finances NGC's transmission business;
- whether Ofgem has correctly identified the weaknesses in the application of the RPI-X regimes and how these weaknesses may best be addressed within the statutory framework;
- whether a revenue driver should be incorporated;
- whether Ofgem has correctly identified and treated the impact of the proposed changes under NETA on the next price control;
- where the boundary between the RPI-X regulated revenue and the revenue regulated by the incentives mechanism should lie; and
- whether five years is an appropriate duration for the control.

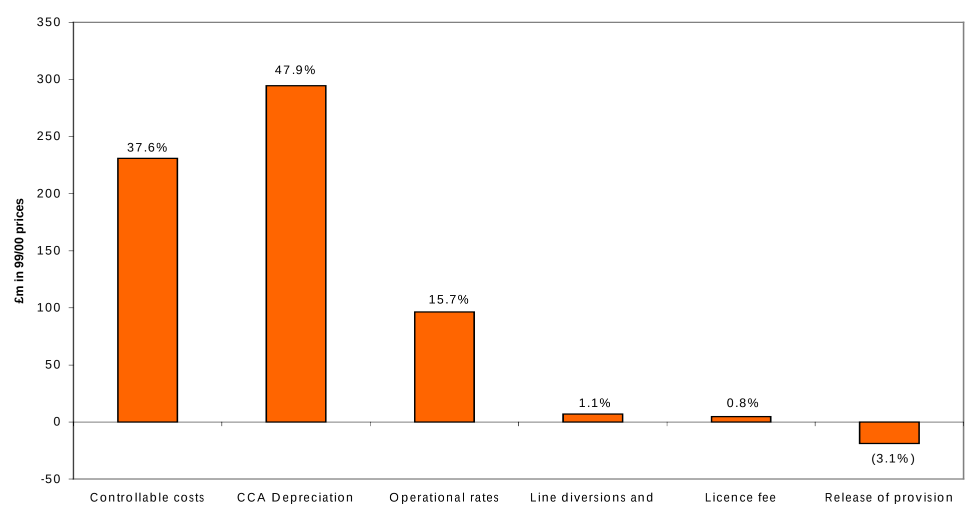
3. Operating costs

Introduction

3.1 Transmission business spending is broken down into capital and operating expenditure. Capital expenditure covers spending on assets whose benefits can be expected to last for several years, such as substations or overhead lines. Operating costs cover the day-to-day costs of running the transmission network, such as repairs and maintenance, some staff salaries or business rates. In the calculations underlying the present price control, NGC was given an allowance for operating costs excluding depreciation, which declined from £365 million in 1997/98 to £330 million in 2000/01 (in 1995/96 prices). Throughout the period of the present price control, this made up around 40-45 per cent of NGC's allowed revenue. Therefore, the allowance for operating costs is likely to have a significant impact on the overall level of price control revenue.

3.2 Figure 3.1 shows a breakdown of NGC's operating costs. Depreciation, NGC's licence fee, line diversions, 'one-offs' and business rates are assumed to be outside NGC's control, leaving 36 per cent of operating expenditure classified as "controllable operating costs".

Figure 3.1: Breakdown of NGC's operating costs, 1998/99 (Total £614m)[4]



[4] All figures in this section are given in 1999/00 prices, except where otherwise indicated

3.3 Depreciation is not calculated within the operating expenditure allowance used to set the price control. The treatment of depreciation is discussed in section 6 below. Controllable operating costs cover 65 per cent of operating expenditures excluding depreciation.

3.4 Ofgem has appointed Arthur Andersen as its consultants to assist with the analysis of operating costs. NGC has completed a business plan questionnaire (BPQ) providing detailed information on its operating costs since 1996/97 and projections to 2005/06. Ofgem's consultants are in the process of analysing the operating cost projections. As the review progresses, further details of their analysis will be published.

3.5 Controllable operating costs, around £230 million in 1998/99, include:

- staff costs (salary, non-salary and agency costs but excluding capitalised salaries) including redundancy, severance and relocation costs;
- materials and subcontractor costs;
- consultancy and legal costs;
- travel and subsistence costs;
- computing and information systems costs;
- rents and buildings;
- communications;
- insurance;
- property;
- car leasing; and
- electricity.

3.6 This section discusses:

- NGC's previous forecasting record on operating expenditure and the outturn since 1996/97 and NGC's forecasts to 2005/06;
- NGC's capitalisation policy;
- NGC's policy on allocations and recharges;
- NGC's charges to Energis; and
- Ofgem's efficiency study of NGC.

Operating cost projections and outturn

3.7 Figure 3.2 shows NGC's transmission business operating expenditure during the last and the present price controls. Table 3.1 calculates NGC's outperformance in operating expenditure against its and OFFER's projections at the last price control review. These indicate the extent to which NGC has underestimated the scope for reductions in operating expenditure. NGC argues that operating costs in 1998/99 are lower by £15 million because of a one-off factor, the release of a 'significant provision' of £15.3 million, relating to a revision of accounting estimates of provisions resulting from the implementation of FRS12 which Ofgem is presently investigating.

3.8 It should be noted that companies regulated under RPI-X price control are incentivised to outperform cost projections made at each price control review.

Figure 3.2: NGC's projected and actual operating expenditure (excluding depreciation and rates) over the present price control review period

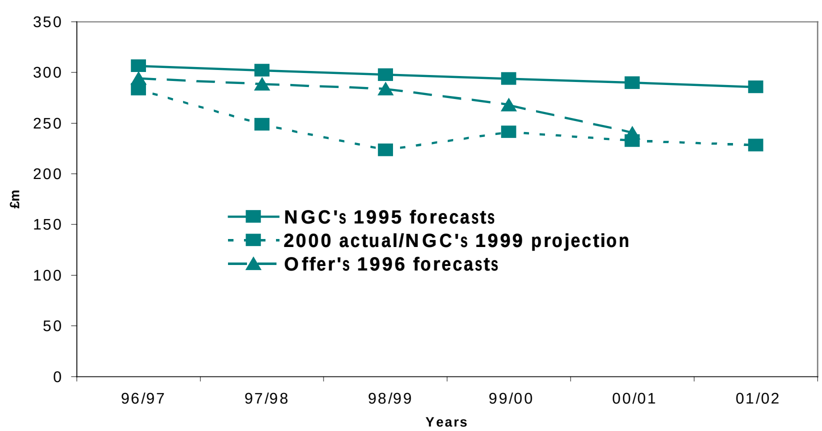


Table 3.1: NGC's operating costs outperformance (actual and present forecasts) compared to forecasts

	1996/97	1997/98	1998/99	1999/00	2000/01
Actual vs NGC's 1995 forecasts (£m)	23.2	53.4	74.3	52.5	57.3
% outperformance	8.2%	21.5%	33.2%	21.7%	24.6%
Actual vs OFFER's 1996 forecasts (£m)	10.8	39.9	60.4	26.6	7.9
% outperformance	3.8%	16.1%	27.0%	11.0%	3.4%

N.B. Percentage outperformance is absolute outperformance as a percentage of outturn
Changes in NGC's organisational structure since 1995 have made direct comparisons difficult; this table shows NGC's suggested comparisons
The figures for 1998/99 include the release of a provision of £15.2 million relating to a revision of accounting estimates of provisions resulting from the implementation of FRS12

3.9 However, regulated companies also have a greater incentive to outperform forecasts made at a price control review at the beginning of the review than at the end. Accordingly, by the end of the present price control review period, NGC forecasts that its operating costs will be in line with OFFER's 1996 forecasts.

Capitalisation policy

3.10 As discussed in Section 2 above, under the RPI-X methodology there may be an expectation amongst regulated companies that capital expenditure will be included in the regulatory asset base and allowed a rate of return, while operating expenditure will simply be charged to consumers in the year in which it is incurred. This apparent asymmetry of incentives on regulated companies may lead to the reclassification of some costs as capital expenditure, when these costs would more appropriately be designated as operating expenditure.

3.11 The three main areas of operating expenditure which are capitalised, or have associated capital expenditure, are:

- staff costs relating to capital projects;
- IT/computer costs, particularly those related to asset management; and
- materials and subcontractor costs.

3.12 NGC considers its capitalisation policy to be conservative. This policy, set out in NGC's Financial Controls manual, has been amended to increase the de minimis limit for expensing through the profit and loss statement from £1000 to £2000.

3.13 Arthur Andersen and PB Power, Ofgem's engineering consultants, will be investigating the implementation of NGC's capitalisation policies to advise Ofgem whether these are appropriate, and whether any items have been inappropriately capitalised.

Allocations and recharges

3.14 Up to 1999/00, NGC's support activities were performed by its 'Corporate Functions' operating unit which sat outside the transmission business. The unit was composed of:

- Information Systems group: this unit provide IT Support to NGC's UK businesses; and
- UK Audit, UK Regulation, Company Secretaries, Corporate Affairs, Finance and Human Resources.

3.15 Until 1999/00, NGC allocated corporate overhead costs to the licensed transmission business using three approaches:

- **directly attributable costs**: all costs directly attributable to the transmission business (£26.6 million in 1998/99) are allocated to it. This includes the transmission licence fee, IT costs and some human resource costs;
- **group costs**: costs incurred for the benefit of the whole group (£2.3 million allocated to the transmission business in 1998/99) are allocated among business units according to the proportion of operating profits which that business unit generates. These include the costs of the group annual report, the share register and the annual general shareholders' meeting; and

- **prime user costs**: the remaining central costs (£28.2 million allocated to the transmission business in 1998/99) are allocated entirely to the transmission business as the prime user in incurring these costs.

3.16 From 2000/01 onwards, NGC has changed the way in which its corporate costs are allocated between businesses as part of a group reorganisation following the acquisition of the American electricity company, NEES. Following this reorganisation, UK Information Systems will fall within the transmission business. NGC has informed Ofgem's consultants that UK Information Systems will be available provide services to other non-transmission businesses at market rates and anticipates that approximately 20 per cent of the costs will be charged out to other non-transmission business units. Ofgem is presently considering whether or not this is appropriate.

3.17 After the reorganisation, NGC will allocate costs of the remaining support activities (UK Support Functions and Central Functions) initially on the basis of time, as the main cost driver. Group costs will be allocated subsequently on the basis of four metrics (turnover, operating profit, historic cost net assets and headcount). This is likely to result in the allocation of approximately 70 per cent of the UK Support Functions and Central Functions costs on aggregate to NGC's transmission business in each year. Ofgem's consultants are presently considering the key cost drivers of central costs and how to take account of the group reorganisation both in determining appropriate cost allocations and in projecting forward the reduction in central cost allocations to the end of the next price control review period.

3.18 Ofgem considers that the customers of NGC's price regulated activities should not pay inappropriately high charges for services provided from outside the regulated business. Similarly, NGC's price regulated business should not be paid for services provided to companies outside the regulated business at inappropriately low rates. This would give those businesses a competitive advantage. Such cross-subsidies are prohibited by Condition 5 of NGC's licence, and accordingly, Ofgem is investigating NGC's policy on charging for such services.

3.19 NGC presently charges for services provided by the transmission business to other business units at market rates (UK Information Systems and Network Services) or at cost (UK Support Functions). Services provided by NGC's Property and Leasing (cars) businesses to the licensed transmission business are charged at market rates, and the services of Central Functions are charged at cost. Ofgem's consultants are presently investigating whether NGC's recharges are appropriate and whether its recharges at market rates are realistic and in line with industry benchmarks.

Energis

3.20 In March 1993, NGG set up a telecommunications subsidiary, Energis Communications Limited (Energis). Over 4,000 kilometres of fibre-optic cable has been installed on NGC's transmission network. Energis holds a public telecommunications operator's licence which enables it to offer certain communication services in competition with other telecommunications operators. NGG floated Energis in December 1997, and has since further reduced its stake.

3.21 When Offer set the present NGC price control, it estimated the value of NGC's then 100% shareholding in Energis at £250 million for the purpose of adjusting the regulatory value of NGC's transmission business. Ofgem needs to consider whether it would be appropriate to adjust NGC's regulatory value to take account of the increase in Energis's valuation when setting the new price control. Ofgem has concluded that these unanticipated gains should be retained by shareholders. There is no reason to believe that £250 million was not an appropriate value at that time. NGG's shareholders incurred the risk that its stake in Energis might fall in value and should therefore benefit from any gain. It would be inappropriate for customers to be exposed to any loss as a consequence of such ventures. It would also be inconsistent with Ofgem's treatment of the Market/Asset Ratio of the PES distribution companies.

3.22 However, Ofgem takes the view that it may be appropriate to take account of Energis's use of the transmission network for its fibre optic cables by calculating a market-based rental fee for access to the network and to deduct this from the allowable revenue. Such a fee was set as part of the 1996 price review and deducted from transmission revenues (as part of excluded services) in setting the allowed revenues for the 1997/98 to 2000/01 period. The rental fee in 2000/01 is forecast to be £3.7 million. Ofgem is presently looking at how best to calculate this fee for the period from April 2001 and how much of it should be deducted from allowable revenues. One method is to use the market rate to calculate the fee which Energis would have to pay for the provision of equivalent access by unrelated providers.

3.23 In setting NGC's price control Ofgem proposes to follow the approach described above. Ofgem will be consulting separately in April 2000 on the regulatory issues raised by new ventures which use energy companies' regulated network assets.

Efficiency study

3.24 Ofgem's consultants on the efficiency study have:

- made preliminary adjustments to NGC's operating costs in the areas described above;
- begun to assess the level of operating costs achievable by NGC through the application of efficient operating practices;
- considered the level of the charges on Energis for the use of NGC's equipment; and
- liaised with Ofgem's engineering consultants (PB Power) to ensure that the split between NGC's capital and operating expenditure is sensible.

3.25 So far, the consultants have provided comments on the BPQ, analysed the completed questionnaire, visited NGC to clarify areas of uncertainty, gathered further information and asked further written questions. They are at present working on a draft report relating to efficiency over the period of the present price control which will be sent to NGC for comment in due course.

3.26 Further details of this analysis will be published after NGC has had an opportunity to comment, and any appropriate amendments have been made. In addition to their work on costs in the base year, Ofgem's consultants have also been asked to consider the factors influencing cost levels in the future and to make a projection of the efficient level of operating costs between the base year 1998/99 and 2005/06. Projections of NGC's transmission business operating costs for the period after 2001 will be published in the draft proposals, scheduled for publication at the end of June 2000.

Issues for consideration

3.27 Ofgem seeks views on:

- whether Ofgem has correctly identified the primary components of NGC's operating expenditure;
- how Ofgem should reduce NGC's ability to make excess profits by over-predicting operating expenditure and give NGC an incentive to find savings in operating expenditure at the end of a price control period;
- whether NGC's policies on capitalisation, allocations and recharges and Energis charges are appropriate.

4. Capital expenditure

Capital expenditure

4.1 In setting the present price control, OFFER allowed a capital expenditure of £845 million over the four years rising from £211 million in 1997/98 to £233 million in 2000/01. This section considers capital expenditure in the period of the present price control, NGC's forecasting methodologies for the future period and the overall capital expenditure forecasts in the future period.

4.2 In order to relate capital expenditure to its drivers, NGC classifies its expenditure into seven categories:

- customer connections;
- transmission network capacity;
- defence and security;
- safety;
- transmission network reliability;
- environment; and
- other.

4.3 Capital expenditure on an electricity transmission system can be classified as either 'load related expenditure' (LRE), if it can be influenced by the amount and location of generation and demand on the system, or 'non load related expenditure' (NLRE) from other factors such as asset replacement. NGC indicates that the first three categories above are associated with LRE and the last four with NLRE. In assessing the need to make capital investments, NGC says that a wide range of issues are considered which can result in one project being impacted by a number of different drivers and possibly result in the appropriate allocation of expenditure to both LRE and NLRE categories.

4.4 Ofgem is examining NGC's capital expenditure during the present price control period and assessing the appropriate level for capital expenditure during the next price control period. Comparisons of actual expenditure against forecasts made at the time of the last review may provide an insight into forecasting accuracy and investment practices.

4.5 NGC's completed BPQ contains forecasts of capital expenditure to 2005/06. In making these forecasts, NGC has made assumptions about future developments and have used modelling techniques to assess both the most likely level of spend and the probable range of expenditure around this level. Ofgem will consider the assumptions used in such modelling, and the modelling techniques, as part of the forward expenditure review. Engineering consultants PB Power have been engaged to assist Ofgem in this review.

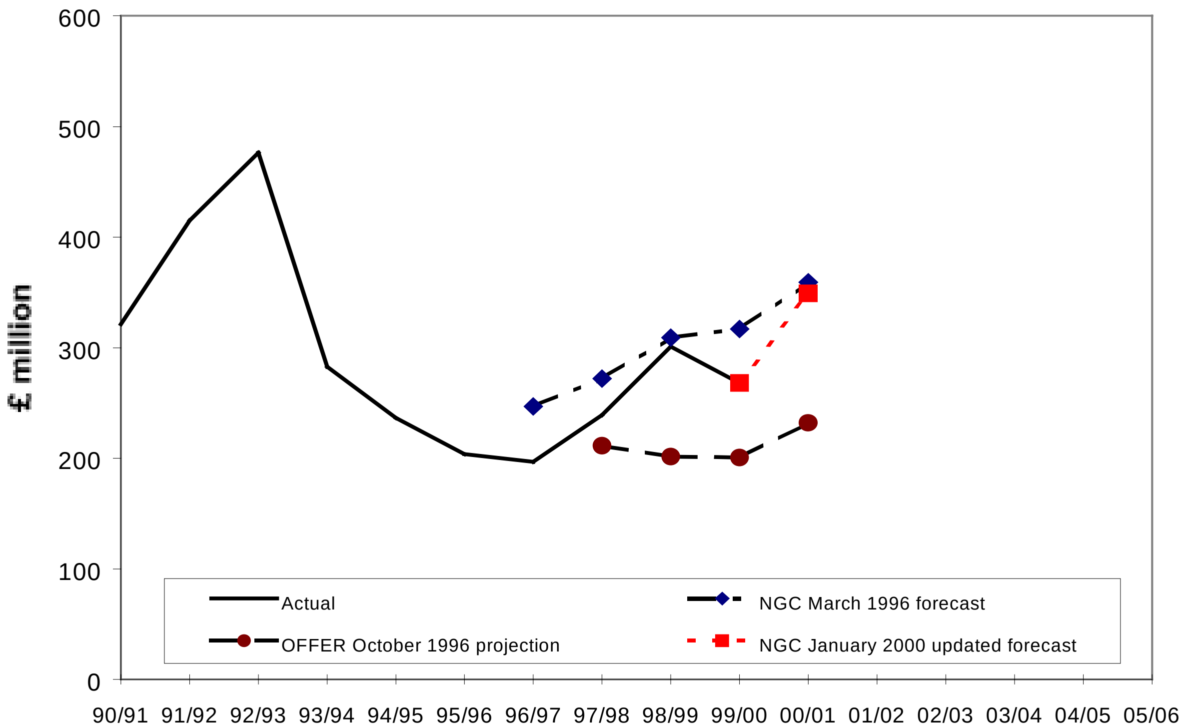
Expenditure in the Present Price Control Period 1997/98 to 2000/01

4.6 In March 1996 NGC submitted a capital expenditure business plan forecast covering the period of the present price control (1997-2001) ('the NGC March 1996 forecast'). Additionally, this plan took account of divestment of certain National Power and PowerGen power stations. OFFER made projections which were set out in the October 1996 price control proposals ('OFFER 1996 projections').

4.7 These projections are shown in Figure 4.1. Also shown are outturn expenditure with updated forecasts for the remainder of the review period ('the NGC January 2000 updated forecast').

4.8 NGC's outturn expenditure has been lower than the NGC March 1996 forecast and higher than the OFFER 1996 projections. NGC's updated forecast for 1999/2000 and 2000/01 is also lower than its March 1996 forecast and higher than OFFER's 1996 projection. In total, present forecasts indicate that NGC will spend over £300 million more than OFFER's projection over the four year period, but less than its own March 1996 forecast. However, a considerable part of this expenditure is forecast to occur in the final year of the present period.

Figure 4.1: NGC's gross annual capital expenditure (98/99 £m)



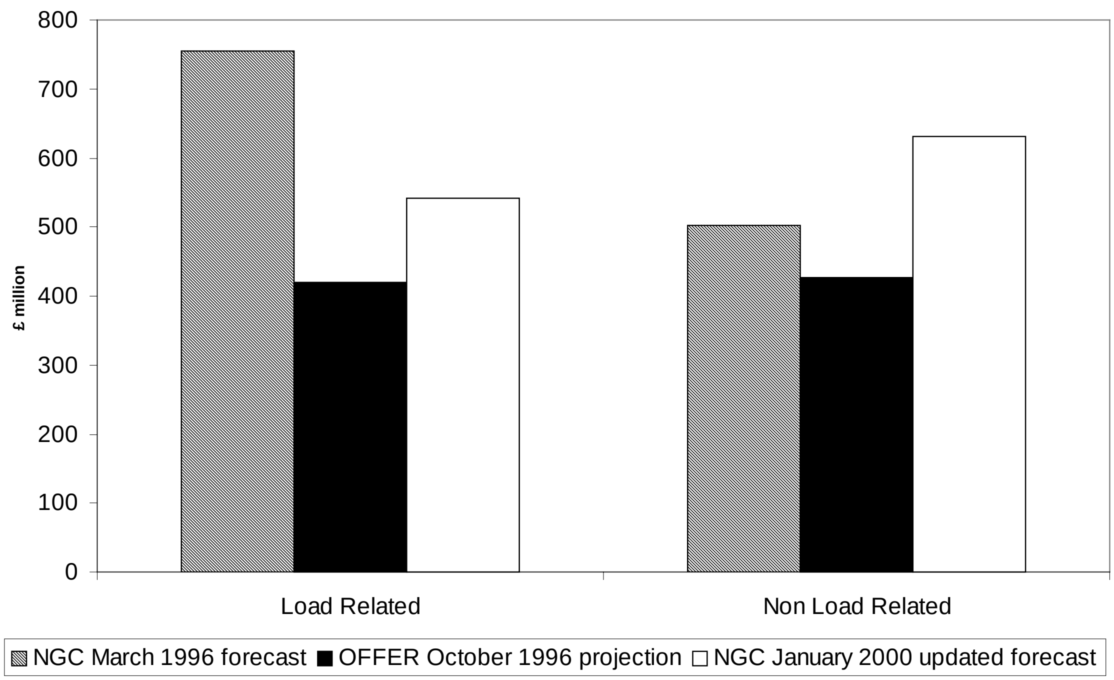
4.9 Figure 4.2 shows the comparison of NGC's March 1996 forecast, OFFER's 1996 projection and NGC's January 2000 updated forecast for both LRE and NLRE. NGC has submitted an explanation for the differences between the outturn and forecast expenditure for the present price control in its business plan submission.

4.10 In the case of LRE:

- NGC states that assumptions on generation connections and closures did not match its 1996 forecasts owing to life extension of nuclear plant, the divestment of coal fired plant and the restricted consents policy on CCGT. However, Ofgem notes that while the amount of new generation expected to connect during the period is greater than initially forecast, NGC's associated expenditure is roughly in line with its March 1996 forecast; and

♦ in comparison, infrastructure expenditure, that is uprating the main transmission system excluding new connections, has fallen by nearly £70 million against NGC's forecast.

Figure 4.2: Forecast, allowed and outturn capital expenditure, 1997/98 to 2000/01



4.11 In addition:

♦ new supply point expenditure is expected to be about £20m below forecasts; and

♦ NGC says that a further delay in obtaining consents for the North Yorkshire Line has delayed £14m of expenditure this period. However, as sections of this line must now be undergrounded, the overall project cost has risen.

4.12 NGC ascribes the increase in NLRE to a combination of the following factors:

♦ an increase in the rate of replacement of obsolete and increasingly unreliable control systems;

♦ the power system control and protection telecommunications provider has changed from BT to Energis, with an associated capital cost;

- ♦ increased remedial work on older underground cables and increased expenditure on statutory environmental obligations. However, in the replacement of overhead lines, expenditure has decreased owing to improved information through condition assessment leading to deferring remedial work.

4.13 Increased capital expenditure will add to the regulatory asset base and may give an indication of likely future expenditure needs. Where savings against forecast expenditure have been made, they may be due to efficiency gains from NGC's initiatives, windfall gains from events outside NGC's control or mistaken forecasts. Ofgem considers that NGC should have an incentive to pursue efficiency, but may wish to deal differently with gains from poor forecasting or from windfall events outside NGC's control. In reviewing past expenditure, Ofgem will pay particular attention to allowances for major projects such as the North Yorkshire Line, given that allowances have been made for this significant project in the two previous price control reviews. Also, NGC has made significant expenditure on equipment to facilitate the use of Energis as a service provider. NGC says this is to maintain the reliable operation of its telecommunications infrastructure. Understanding the technical and commercial factors that led to this decision and the benefits to NGC in reducing operating costs will be important, particularly as NGC has financial interests in Energis.

NGC's Expenditure Forecasting Methods

4.14 NGC uses different techniques to model LRE and NLRE forecasts for the forthcoming price control period. In order to assess NGC's forecasts for future capital expenditure, Ofgem's engineering consultants will examine the modelling techniques employed.

Load Related Modelling

4.15 NGC describes load related forecasting as a combination of a deterministic 'best view' and a probabilistic expenditure analysis. According to NGC, the probabilistic forecast provides a range of likely outcomes based on the same drivers and assumptions as their 'best view', with both using market intelligence and customer knowledge.

4.16 Key assumptions in NGC's load-related forecasts are:

- growth in peak demand remains at 0.5 per cent per annum, as observed over the last ten years;
- a steady level of commissioning of new generation projects, consistent with the average level since 1990;
- closure of existing generation so giving a plant margin that continues at present levels;
- demand load factor increasing by about 2 per cent over the period; and
- the growth in peak demand and demand load factor take account of overall energy efficiency improvements each year.

4.17 The probabilistic forecast is also based on these drivers and assumptions but takes into account uncertainties, particularly in the generation market. Instead of giving a single view, as with the best view approach, a range of outcomes is observed. The uncertainty inherent in the assumptions has led to the development of probabilistic planning techniques to support NGC's best view of future investment requirements.

Non Load Related Modelling

4.18 The largest category of NLRE is transmission network reliability, which is mainly asset replacement. According to NGC, expenditure forecasts are based on generic asset lives with the decision on whether an asset should be replaced based on condition assessment. This will defer the replacement of some assets beyond their expected lives, whilst some assets found in a poorer condition will be replaced earlier. NGC has told Ofgem that it is its policy to replace assets before they exhibit an unacceptable risk of failing in service, since failure in service will compromise network reliability in the short term and may lead to a situation where system access is driven by fault outages, with reduced opportunities for planned system development and asset replacement outages.

4.19 According to NGC its views on asset lives have continued to develop and comparisons show asset lives are consistent with, if not longer than, those in international companies. The technical asset lives are based on engineering judgements derived from operating experience, condition monitoring and an understanding of deterioration processes.

4.20 Safety and environment categories of NLRE are not modelled in the same manner as asset replacement by NGC. Safety is the largest of these categories. NGC says safety related investments are generally modelled in a similar manner to asset replacement, but are classified as safety schemes where a particular failure mechanism may result in an unacceptable risk to staff or the general public. Some of the assets that fall into the first two of these are specific families or types of asset. From information provided by NGC to Ofgem there does not appear to be a clear distinction between some expenditure in this category and the category of transmission network reliability. In the case of environmental expenditure, NGC says this is expenditure to meet legislative requirements and reduce risk to the environment through pollution prevention and addressing public concerns.

Expenditure in the Future Price Control Period from 2001/02

4.21 Ofgem and its consultants will examine NGC's forecasts to ensure that NGC is able to fulfil its statutory and licence obligations and to maintain its assets without incurring excess capital costs. Overall, NGC's forecast of expenditure for the period from 2001/02 ('the NGC 2001 forecast') is higher than that of the present period. Table 4.1 show comparisons of the present period and NGC 2001 forecasts, normalised to average annual figures to aid comparison.

Table 4.1: NGC's actual and forecast expenditure (£ million)

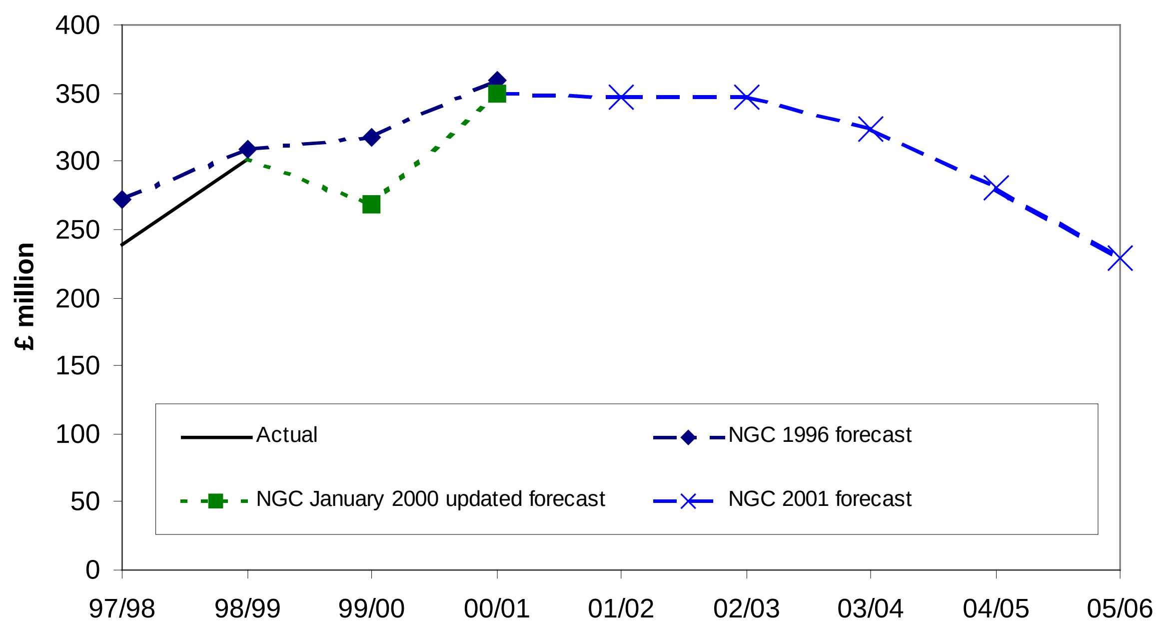
	Load Related		Non Load Related		Capital contrib-utions	Total (net of customer contributions)	
	Total	Annual Average	Total	Annual Average		Total	Annual Average
NGC 2001 forecast	752	150	799	160	11	1543	309
Actual and NGC 2000 updated forecast	552	138	644	161	39	1157	289
Increase	200	12 9%	155	-1 0%	-28 -71%	386	20 7%

NB NGC 2001 forecast total expenditure does not sum from the parts due to rounding.

4.22 NGC's forecast is the deterministic best view but supported by the probabilistic analysis which NGC says shows its best view is robust against a range of generation and demand assumptions. Ofgem's engineering consultants will examine NGC's forecasts for the period of the next price control. For LRE, the study will consider the expenditure drivers and the individual projects that make up the forecast. An important part of this will be the assumptions used by NGC that influence the best view and the probabilistic techniques. The 2001 forecast for NLRE remains at a level consistent with the forecast for the last year of the present period. However, the analysis of LRE in the present period shows a considerable increase in expenditure in the final year. Ofgem's consultants will consider:

- whether the levels of expenditure which NGC forecasts for the last two years of the present period are likely to occur and whether they are appropriate; and
- whether this level of expenditure is appropriate in the next period.

Figure 4.3: Total capital expenditure (98/99 prices)



4.23 Figure 4.3 shows that NGC's forecast expenditure for the five year period from 2001/02 continues at the level forecast for the last year in the present period, around £350 million, before falling by 33 per cent to £233 million in 2005/06. However, the forecast for the final year of the present period is significantly greater than in earlier years in the period. NGC has indicated that their 2000/01 forecast includes expenditure associated with the North Yorkshire Line, which is still subject to meeting certain conditions before work can commence. Also, from 2001/02 NGC forecasts include expenditure on a London Infrastructure scheme. Any slippage in the expenditure will tend to smooth the profile of the expenditure. In last year's review of distribution price controls, Ofgem noted that companies tended to delay expenditure until the end of the period thereby minimising their financial costs. Any year-on-year discretion NGC have over expenditure may be expected to affect the expenditure profile in a similar way.

Issues for consideration

4.24 Ofgem seeks views on:

- whether NGC's expenditure in the present period has been at an appropriate level;
- whether the level that NGC has proposed will enable NGC to fulfil its obligations under its licence and the Act; and
- whether NGC's forecasts are appropriate.

5. Performance and output measures

5.1 It was argued in Section 2 above that it would be desirable to improve NGC's incentives by linking its allowed revenues to its output performance.

5.2 The outputs on which these incentives might operate should pass the following tests, namely that they:

- matter to customers, whether they be the direct customers of NGC (such as generators, distributors and large customers who are directly connected to NGC's system and companies that use NGC's system), or final consumers of electricity;
- are, to some extent at least, within NGC's control; and
- are not subject to separate regulation or incentives. For instance, transmission losses are separately incentivised through an arrangement with the Electricity Pool under the existing trading arrangements and will be subject to a separate incentive scheme, following the introduction of NETA and therefore do not fall to be considered in the context of the price control.

5.3 Excluding services covered by the existing Transmission Services Schemes (TSS) and the Pool-based incentive schemes which will be covered by NGC's SO incentive schemes following the introduction of NETA, the principal outputs delivered by NGC which matter to customers would appear to be NGC's ability:

- to provide firm entry and exit capacity to and from the transmission system, particularly at times of peak demand;
- to minimise the number and duration of incidents causing loss of supply to customers (and to minimise the load lost as a result);
- to restrict voltage excursions; and
- to restrict frequency excursions.

5.4 In considering how to incentivise these outputs, it will be necessary to ensure that the incentives do not conflict with the incentives created elsewhere in NGC's regulation, either:

- presently, as in the existing transmission services schemes; or
- in future, as in the likely incentives to be created following the introduction of NETA (these are described in more detail below).

5.5 Nor should the incentives conflict with Ofgem's other broader policies, such as its environmental policies (as discussed above in section 2).

5.6 The majority of respondents to the December consultation paper who commented on the issue, favoured the reintroduction of output-based incentives on NGC. After careful consideration of the possible environmental impact, Ofgem is inclined to introduce a link between NGC's revenues and its delivery of outputs, such as those mentioned in 5.3 above.

5.7 In considering the output measures in greater detail, it may be helpful to consider each in the context of the relationships between three different aspects of NGC's business, namely:

- its respective functions as transmission asset owner (TO) and as system operator (SO);
- its price controlled business and those regulated activities not directly subject to price control. At present, this distinction does not exactly mirror the TO/SO split; and
- those activities which are subject to price control today but which are likely to be incentivised differently within the life of the next price control period (e.g. following the introduction of NETA).

5.8 The output measures fall naturally to be considered in two groups: demand-related (capacity provision and supply interruptions); and system-related (voltage and frequency control).

Demand-related

5.9 Ofgem believes that meeting demand at grid exit and entry points is the transmission operator's primary function. Throughput (load) is also important and it is therefore appropriate to ensure that NGC, as TO, avoids supply interruptions. There seems little need for any additional incentivisation with respect to load. Table 5.1 sets out NGC's five year track record in terms of incidents and load lost as a result.

Table 5.1: NGC system performance (loss of supply and unsupplied energy)

	94/95	95/96	96/97	97/98	98/99
Loss of supply incidents	8	5	14	14	5
Unsupplied energy (Gwh)	10	34	6	31	7

5.10 At present, demand and load are price controlled functions but NGC is not presently subject to any explicit incentive within the price control period.

5.11 With the introduction of NETA, Ofgem believes that it will be necessary to reform NGC's existing arrangements for access to NGC's transmission system. Existing transmission access rights are to a large extent defined through the Pooling and Settlement Agreement (PSA). The PSA defines users' contractual rights to compensation in the event of a transmission constraint. Ofgem has set out its initial view that the new access arrangements should be based on auctions of firm rights for NGC's entry and exit capacity (or 'access rights'). These auctions will be designed to ensure orderly trading in firm capacity and will establish a clear signal to NGC as to the value of access rights at the various entry and exit points designated for auction.

5.12 Ofgem expects to publish a separate consultation document before the end of April detailing its proposals for the reform of NGC's transmission access arrangements. In relation to the present price control process, some of the key issues are likely to include:

- the timetable for introducing the new regime;
- the impact of the regime on NGC's revenues;
- the impact of the regime on use of system charging;

- the distribution of any surplus arising from the auctions;
- the funding of any loss arising from the auctions; and
- the implications of NGC's inability to meet capacity demands once auctioned, and the impact of this on customer prices.

5.13 It will be seen from the above that the auction regime will need to address both the provision of capacity and the treatment of service interruptions. It is proposed to introduce capacity auctions for access rights from April 2001 (the date from which the new price control arrangements will take effect). It is therefore Ofgem's present intention to set a price control which assumes that capacity auctions will be effective from that date.

5.14 In that case, it is arguable that there would be no further need for any residual price control incentive towards demand and load outputs. Indeed, the experience of introducing capacity auctions in gas suggests that a price control incentive may conflict with the incentives provided by the auction regime. Certainly it would seem unnecessary to provide NGC with a double incentive to add capacity to the system. With a very high level of fixed cost in the remaining TO business, a straightforward revenue cap may be appropriate. This might also be felt to be the most appropriate way to remunerate assets, the vast majority of which were constructed when the regulations did not seek to value capacity differentially at different entry and exit points.

5.15 If, however, capacity auctions cannot be certain of being introduced from April 2001, it may be appropriate to seek to maximise NGC's overall provision of capacity (and to minimise interruptions to supply) within the scope of the new price control.

5.16 Under either scenario, it will be necessary to consider the impact of the present developments in the price regulation of the PES distribution businesses. PESs presently have performance targets with respect to customer minutes lost on their systems. In a document published in March 2000[5], Ofgem has raised the

[5] "Information and incentives project: defining output measures and incentive regimes for PES distribution businesses, Update" March 2000

question whether these targets ought to be affected by storms or faults on the NGC system.

5.17 If PESs are put at risk due to such faults on the National Grid, it will be appropriate to consider how this should affect NGC's revenues, either under the price control or as part of the capacity auctions regime.

System operation

5.18 Voltage and frequency excursions are relatively rare events but with potentially severe impacts on the system and customers. Table 5.2 sets out the recent incidence of each type of excursion.

Table 5.2: NGC system performance (voltage and frequency excursions)

	94/95	95/96	96/97	97/98	98/99
Voltage Excursions	0	0	0	2	0
Frequency Excursions	0	5	0	0	0

5.19 Limits for such excursions are statutory and are defined in the Electricity Supply Regulations. As such, it is for debate whether any additional incentives on NGC to maintain or improve its performance against these measures are appropriate.

5.20 These are clearly functions of NGC as the system operator (SO) and, while the costs of meeting these requirements are incentivised, NGC's performance against these measures is outside the present TSS arrangements. Ofgem generally regards statutory matters (such as safety) as transcending price controls. As with demand-related performance incentives, it is for consideration how best, if at all, these matters should be subject to incentivisation.

Issues for consideration

5.21 Ofgem invites views on:

- ♦ whether NGC's revenues should vary with the volume of output it supplies and, if they should, how the level of output should be measured and the proportion of revenues that should be determined by the volume of output; and

♦ whether NGC's revenues should also vary according to its performance in meeting certain output measures and, if it should, whether the performance measures described in this chapter are appropriate; what alternative measures might be adopted; and the extent to which its revenue should be exposed to variations in these measures.

6. Financial issues

Introduction

6.1 The December 1999 consultation document set out a framework for the analysis and assessment of financial issues for NGC's price control review. This involves establishing an asset base and estimating a return equivalent to the cost of capital for that asset base. Other regulators and the Competition Commission (formerly the Monopolies and Mergers Commission) have consistently adopted similar approaches in setting price controls. It is also necessary to consider both the actual financial position of NGC, and Ofgem's duty to ensure the proper financing of NGC's licensed activities by reference to forward looking projections of its financial indicators based on an efficient and economic operation of its licensed activities.

6.2 This chapter calculates a range for NGC's cost of capital and deals with issues relating to asset valuation. It then discusses Ofgem's approach to the financial modelling of NGC.

Cost of capital

6.3 The level of return required by the financial markets to provide capital to a company is called the cost of capital. The cost of capital is usually calculated as a weighted average of the cost of debt and of equity finance. As well as providing a return on debt and equity, companies must also finance corporation tax payments. The cost of capital can be adjusted to provide an allowance for corporation tax.

6.4 In its final proposals for the review of the PES distribution businesses and the Scottish transmission businesses, published in December 1999, Ofgem estimated a cost of capital for those businesses of 6.5 per cent (see Table 6.1). This estimate was accepted by both Scottish transmission companies and all 14 PESs. Recent determinations by other UK regulators of the cost of capital for the network utilities which they regulate and of the MMC's determinations on Cellnet and Vodafone are shown in Appendix Five. Ofgem considers that, in line with its policy of regulatory consistency, there may be a case for using the same cost of capital for NGC. However, Ofgem considers that there may be factors specific to NGC which make a different cost of capital appropriate. It is also clearly appropriate to take into account any changes in financing costs since those reviews were completed. Accordingly, Ofgem has used the methodology applied at the PES distribution business price control review to calculate a value for NGC's cost of capital. It is also clearly appropriate to take into account any changes in the components of the cost capital since the PES reviews. This subsection discusses each component of the capital asset pricing model (CAPM) and the dividend growth model (DGM) in turn. Ofgem considers that the estimates for the cost of capital derived from CAPM have shown considerable volatility in recent years, and that many of the components of CAPM, particularly the equity risk premium and the equity beta, are not directly observable. Accordingly, Ofgem considers that it should use financial modelling to ensure that its estimate for the cost of capital does not jeopardise the financing of NGC's licensed activities. Ofgem's approach to financial modelling is discussed at the end of this section.

Table 6.1: Calculation of the cost of capital for final proposals for the PES distribution business price control reviews (December 1999)

Component	Central case
Cost of debt	
Risk free rate	2.5%
Debt risk premium	1.4%
Adjustment for long-term debt	0.4%
Cost of debt	4.3%
Cost of equity	
Risk free rate	2.5%
Equity risk premium	3.5%
Equity beta	1.0
Post-tax cost of equity	6.0%
Taxation adjustment factor	1.429
Pre-tax cost of equity	8.6%
Weighted average cost of capital	
Gearing	50%
Pre-tax WACC	6.5%

6.5 Companies can be financed by both debt and equity. The proportion of debt to debt plus equity is referred to as gearing. In calculating an average cost of capital it is necessary to make an assumption about gearing. Gearing also influences the cost of both debt and equity finance. It will be appropriate to assume that companies have reasonably efficient levels of gearing to encourage financial efficiency and to protect the interests of consumers.

Gearing

6.6 Debt finance is usually cheaper than equity finance. There are two main reasons for this:

- debt holders have a prior claim on the distribution of a company's income ahead of equity holders and so face lower risk; and
- debt can be a tax efficient form of finance.

6.7 In these circumstances, companies may be able to reduce their weighted average cost of capital (WACC) by increasing the proportion of debt finance. However, increasing gearing will tend to put some upward pressure on the underlying cost of both debt and equity finance. At higher levels of gearing a company may no longer be able to access debt finance at a reasonable cost. If these relatively high levels of gearing are reached, then the advantages of debt in terms of tax management are likely to be more than offset by the higher levels of debt premia. At such levels, investors are likely to seek higher returns on equity. This suggests that there is some notional level, or more likely a range, of gearing at which the WACC is minimised. This range will reflect an efficient capital structure.

6.8 Ofgem's 1999 review of the PES distribution and Scottish transmission businesses used an estimate of such an efficient level of gearing, rather than the entity's own gearing, on the grounds that:

- management had had the opportunity to influence the financing structures supporting each business in the period since Vesting; and
- the actual gearing in the relevant groups was seldom incurred at the level of the regulated business.

6.9 The Competition Commission, however, has tended to base its calculations of the cost of capital on the actual rather than the efficient level of gearing. This approach was also adopted by OFFER in the 1996 price control review of NGC's transmission business. Ofgem considers that NGC has also had the opportunity to influence its financing structure. Since its demerger from the RECs in 1995, NGC's (i.e. excluding other components of NGG, such as Energis) balance sheet gearing has increased significantly from 36 per cent in 1996/97 to 63 per cent in 1998/99.

6.10 Ofgem considers that the 'market' gearing of its UK electricity transmission business, measured as net debt divided by the regulatory asset value, is a better measure of the indebtedness of NGC's transmission business, as balance sheet gearing relies on concepts which appear to work less well when considering businesses with long asset lives. This measure of 'market' gearing has increased over the same period from 24 per cent to 43 per cent between 1996/97 and 1998/99. In order to calculate the net debt of the regulated transmission business, Ofgem has assumed that it is the same as the net debt of NGC as a whole, as around 94 per cent of the capital employed in NGC is employed in the transmission business rather than in the Settlements, Interconnectors or Ancillary Services businesses, according to NGC's 1998/99 regulatory accounts. The significant change in the level of gearing since the last price control review appears to demonstrate that NGC's management has had sufficient time to influence the level of NGC's gearing. Ofgem considers, therefore, that it would be appropriate to move from an actual level of gearing to an efficient level of gearing in calculating the cost of capital for NGC's transmission business.

6.11 In determining the efficient level of gearing, it will be necessary to consider the impact of increasing gearing on the cost and availability of debt and equity finance, and to focus on the position of the electricity transmission business within NGC rather than the position of NGG. Ofgem assumed an efficient level of market gearing of 50 per cent for the PES distribution businesses, on the basis of discussions with rating agencies and financial institutions. Among other factors, this level of gearing took into account the impact on a PES's business profile of participation in the competitive supply market. Ofgem is using financial modelling to assess the effects of an increase in market gearing on NGC's credit ratings. The preliminary indications from this analysis, discussed further in the subsection on financial modelling at the end of this section, indicate that NGC's transmission business could sustain market gearing in the range of 60-70 per cent while maintaining financial ratios consistent with a solid investment grade credit rating.

6.12 Specialist credit rating agencies assign rating grades to individual debt issues by assessing the degree of credit risk. These ratings are regularly reviewed. Those rating categories which represent the lowest risk are classified as investment grade, indicating suitability for a wide range of investors. Ratings representing higher risk are classified as speculative, indicating suitability only for limited types of investor. In consequence, there is a marked difference in the ease of access to and cost of debt finance for speculative grade borrowers.

6.13 As mentioned in Section 1 above, Ofgem has modified the licences of every PES in England and Wales so as to require each PES to maintain an investment grade credit rating on its debt. The Scottish PESs have agreed to accept similar modifications at an appropriate time. This condition is calculated to secure that each PES manages its affairs so as to maintain access to a wide range of sources of finance, readily and at reasonable cost. Ofgem intends to modify NGC's licence in the same way and will publish proposals to do so with its draft proposals on NGC's price control review in June.

6.14 The two main credit rating agencies are Moody's and Standard and Poor's, their minimum investment grade categories being Baa3 and BBB- respectively. NGC presently has a 'split' credit rating of AA+ from Standard and Poor's, and Aa3 from Moody's, effectively two 'notches' lower, with Aa3 being six 'notches' above Baa3. Moody's confirmed NGC's credit rating in March 2000 despite the increase in NGC's debt following the purchase of NEES. Though its credit ratings reflect a range of factors, they suggest that NGC has substantial scope for increasing its gearing, without jeopardising its ability to fund its licensed activities. In so doing, Ofgem does not necessarily constrain the debt issuer to reduce its credit rating to this level: Ofgem is simply making a judgement about an efficient level for NGC's gearing.

6.15 In an October 1997 report on various utility companies, Warburgs suggested that gearing levels of about 50-60 per cent would be consistent with an efficient capital structure for companies owning distribution businesses. In January 2000, Warburgs revised this figure to 45-50 per cent for European utilities. A survey of institutional investors conducted by Credit Lyonnais Securities Europe (CLSE) in October 1998 indicated that an average gearing level of between 50 and 60 per cent would be the maximum acceptable level for the water and sewerage companies commensurate with maintaining an investment grade credit rating for debt.

6.16 In its October 1998 consultation paper 'Prospects for Prices' OFWAT assumed a level of gearing of between 50 and 60 percent for water companies. In its December 1998 document on the financial framework for the review of Railtrack's access charges, ORR has assumed a level of gearing between 40 and 50 per cent. Ofgem assumed an efficient level of gearing of 50 per cent in its modelling both for BGT's and for the PESs' price control reviews.

Cost of debt

6.17 The cost of debt finance can be thought of as having two components – a risk-free component and a company-specific risk premium. In addition, Ofgem allowed a premium for long-term, fixed-rate ('embedded') debt taken out when yields were higher in the 1999 PES distribution business price control reviews.

Risk-free rate

6.18 Although the real risk-free rate is not directly observable, it is possible to derive an estimate from the return available on UK government index-linked gilts (ILGs) and treasury bills. Ofgem and other regulators have consistently used ILGs to estimate the real risk-free rate. Since early 1997, redemption yields on ILGs with a maturity of greater than five years have fallen from around 3.5 per cent to 1.9 per cent. At the last PES distribution reviews, Ofgem assumed a value for the risk free rate of 2.5 per cent. It is for consideration whether a different risk free rate is appropriate for NGC.

6.19 In its December 1998 report on Cellnet and Vodafone, the MMC estimated a range for the real risk free rate of between 3.5 and 3.8 per cent. In deriving this range, the MMC took account of both recent and longer-term historical evidence. The MMC argued that "focusing too narrowly on the present spot rate would run the risk of setting an inappropriate cost of capital, if, as history suggests is likely, real interest rates rise from their present low level" (Appendix

5.6 paragraph 7). It is also noted that this range was consistent with that used by the MMC in previous reports following regulatory inquiries, notably the MMC's 1997 report on NIE.

6.20 In its March 1999 paper, OFWAT stated that "highly liquid and well analysed financial markets provide the most efficient and best informed view of the trend of future interest rates and stock prices". In its November 1999 final determination of water and sewerage charges, it estimated the risk-free rate at 2.5 to 3.0 per cent. ORR has estimated the real risk-free rate from the present rate of redemption yields on ILGs at 2.25 to 3.0 per cent in December 1999.

6.21 Since the MMC's report on Cellnet and Vodafone, the yield on ILGs has remained well below historical levels, suggesting that these lower yields are not simply a feature of short-term market conditions. It is nevertheless important to bear in mind the argument made by the MMC suggesting that it would be inappropriate to focus too narrowly on the present average spot rate of 1.9 per cent. In addition, there has been some concern over distortions in the long-term ILG market which may have reduced the yield on long-term ILGs. The average redemption yield on ILGs with maturities greater than five years over the two years to December has been 2.3 per cent and the average over the last three years 2.7 per cent.

6.22 After reviewing all the available evidence, Ofgem considers 2.0 to 2.75 per cent to be an appropriate range for the risk-free rate for the purposes of determining NGC's cost of capital. Though this is above the average present yield on ILGs with a maturity of greater than five years (1.9 per cent), it is consistent with the three year average of the yield on such bonds. The upper end of this range is consistent with the range used in the initial proposals for the PES distribution business price control review. The lower end of the range is lower than that adopted for the PES distribution business price control review final proposals, since the yield on ILGs has declined since those proposals were published in December last year.

Debt risk premium

6.23 The debt risk premium reflects the additional return required by the providers of debt finance to hold specific corporate rather than Government debt and can be estimated as a premium over the real risk-free rate. It will depend on a number of company specific factors including the company's level of gearing and its overall financial position, the size and liquidity of the debt issue and its maturity, and wider economic factors. These factors are assessed by credit rating agencies. In the December 1999 final proposals for the PES distribution business price control reviews, Ofgem estimated a debt risk premium of 1.4 per cent. As the debt risk premium depends on company specific factors, Ofgem has examined whether a different debt risk premium is appropriate for NGC.

6.24 As discussed above, NGC's debt presently commands a relatively high credit rating of AA+/Aa3. In deciding on the appropriate debt risk premium for NGC, it is for consideration whether Ofgem should use the present credit rating on NGC's debt issues, or the rating for debt consistent with an efficient capital structure (which Ofgem considers is consistent with an investment grade rating of A/BBB). As explained in the previous section, it will be appropriate to assume that NGC's debt maintains its investment grade status, since this ensures access to capital markets on relatively easy terms.

6.25 At present, spreads of Baa3/BBB- rated utility bonds (the lowest investment grade) over the comparable gilt are around 150 basis points, equivalent to a debt premium of 1.5 per cent. As with the risk free rate, it may be appropriate to note that the average over the last five years for this figure has been 1.0-1.5 per cent. The debt premium on NGC's present debt, rated AA+/Aa3, is around 90 basis points for its 2006 issue, rising to 150 basis points for its 2024 issue, giving an estimate for NGC's debt premium of between 0.9 and 1.5 per cent, or an average of 1.2 per cent. Ofgem's view, based on present market conditions and on discussions with analysts, is that a reasonable range for the debt risk premium for an A or BBB rated nationwide electricity transmission business in the UK is 1.0-1.4 per cent. This is consistent with the debt risk premium adopted by Ofgem for the PES distribution businesses price control review in the December 1999 final proposals.

Embedded debt premium

6.26 Over the period of the present transmission price control, the average real yield on longer term ILGs has declined, from around 3.4 per cent for the period from

December 1995 to August 1998 to around 1.9 per cent for the period August 1998 January 2000. Average yield spreads for longer term investment grade corporate bonds compared to the relevant benchmark gilts have widened from around 0.8 percentage points in the earlier period to around 1.8 percentage points in the later period. These trends indicate that the future cost of debt to NGC may be lower than the actual cost of its historical debt.

6.27 In its review of the PES distribution price controls, Ofgem made an explicit allowance of 0.4 percentage points for the higher real interest cost of historical or 'embedded' debt, compared to present rates. This was based on a stylised assumption that, to alter its capital structure so as to bring it into line with Ofgem's 50% efficient gearing assumption, a PES would typically have increased its borrowings over the period of the preceding price control and that a proportion of these borrowings would have been on a long-term, fixed rate basis. It is for consideration whether a similar allowance should be made in the present review of NGC's transmission price control.

6.28 Taking 2.0 to 2.5 per cent as the estimate of the real risk free rate and a debt premium of 1.0 to 1.4 per cent, as set out in paragraphs 6.22 and 6.25 above, gives an estimate of the present nominal cost of debt to NGC of 5.5 to 6.4 per cent (assuming future inflation averages 2.5 per cent). These figures may be compared to the coupons on NGC's outstanding fixed rate debt, which average 6.6 per cent. This suggests that NGC's embedded debt is not significantly more expensive than the estimated present cost of new debt, indicating that no additional allowance might be necessary.

6.29 NGC's market gearing (defined as net debt/regulatory asset value) was 24 per cent at the time of its flotation in 1995. To bring its capital structure into line with Ofgem's present view of the efficient level of gearing, as set out in paragraph 6.10 above, would have required NGC to increase its borrowings by some £1.8 billion over the subsequent period, compared to an actual increase of around £750 million in the period to March 31, 1999. If it is assumed that £1.8 billion of additional borrowings had been taken out during this period, that two-thirds of it had been fixed rate, and that the average coupon was 6.4-6.9 per cent (as the average risk free rate was 3.1 per cent, the average risk premium was 1.3 per cent, and inflation averaged 2-2.5 per cent), the average coupon on notional outstanding debt would become 6.5-6.8 per cent. The higher end of this range is significantly above Ofgem's estimate of the current nominal cost of debt to NGC calculated in the preceding paragraph, suggesting that it might be appropriate to make an allowance of up to 0.4 percentage points, in line with the treatment of embedded debt in the PES distribution reviews. Ofgem has used an embedded debt premium of between 0-0.4 per cent for its cost of capital calculations.

6.30 In principle, the allowance for embedded debt should apply to NGC's existing capital only, not to new capital raised by NGC. If it applied to new capital this would distort at the margin NGC's incentives to undertake additional capital projects, by remunerating them by more than the costs it would incur to finance to these projects. Over time the fixed-interest loans, which lead to the inclusion of the present embedded debt allowance, will mature and be replaced by new debt.

6.31 Taking these considerations together suggests an estimate for the real cost of debt to NGC of between 3 and 4.55 per cent.

Cost of equity finance

6.32 Respondents to the December consultation paper supported the use of the CAPM to estimate the cost of equity capital with the DGM used to provide a supporting check on the results provided by CAPM. There was no support for the use of other methods to estimate the cost of equity finance such as the Arbitrage Pricing Theory.

6.33 The CAPM derives an estimate for the cost of equity finance by adding an estimate of the real risk-free rate to an estimate of the appropriate equity risk premium (ERP). Estimating the real risk-free rate is discussed in the section on the cost of debt finance.

Equity risk premium

6.34 In estimating the cost of equity, three factors are taken into consideration: the risk free rate; the ERP for the market as a whole; and the riskiness of the company relative to the market. In its review of the PES distribution and Scottish transmission businesses Ofgem estimated a central value of 3.5 per cent for the equity risk premium for the market as a whole. Ofgem considers that the same value may be appropriate for NGC. The appropriate method of estimating the ERP for the market as a whole has been the subject of considerable debate. This has mainly focused on whether the ERP should be based on observing historic returns, surveying investors' expectations or combining estimates of dividend yields with real dividend growth.

6.35 In its report on Cellnet and Vodafone, the MMC concluded that the most reliable estimate of the expected future ERP would be based on averages of historic returns. The MMC suggested that over shorter periods of time both the real risk free rate and equity premia exhibit significant volatility. The MMC estimated that real equity returns have averaged between 7.0 and 8.3 per cent. Together with its estimated range for the real risk free rate of 3.5 to 3.8 per cent, the MMC's implied range for the ERP was 3.2 to 4.8 per cent. Taking this into account, the MMC concluded that a range of between 3.5 and 5.0 per cent would be appropriate for the ERP, consistent with the ranges used in previous MMC reports.

6.36 In their recent determinations on the cost of capital, both OFWAT and ORR indicated that they estimated the ERP by reference to present expectations rather than historic information. In its November 1999 paper, OFWAT used a range of between 2.75 and 3.75 per cent, while the range used by ORR in its December 1999 final determination of Railtrack's track access charges was between 3 and 4 per cent.

6.37 The survey of institutional investors published by CLSE in October 1998 suggested that, after adjusting for inflation, the ERP is in the range 2.7 to 4.5 per cent. In its September 1998 report on electricity companies, Merrill Lynch noted that some fund managers have started to use estimates of the ERP as low as 2 to 3 per cent. In a November 1998 report on the water sector, Commerzbank quoted an equity risk premium for the market of about 3 per cent. In an October 1997 report on the cost of capital, SBC Warburgs used 3.5 per cent as an estimate of the ERP. The Millenium Book, published in January 2000 by ABN Amro and the London Business School, surveyed the rate of return to equities and bonds since 1900 and indicated that the equity risk premium has been 1.7 per cent over the past decade.

6.38 Based on the available evidence, a range of between 3.25 and 3.75 per cent for the ERP appears appropriate. This takes account of present City and investor expectations, and is consistent with that used in Ofgem's final proposals on the distribution and Scottish transmission price control reviews.

Beta coefficient

6.39 An indication of the systematic riskiness of a company relative to the market over an historic period is given by the Beta coefficient. This aims to predict the extent to which a company's share price would tend to change in response to changes in the level of the overall market, and seeks to measure a company's non-diversifiable risk relative to equities generally. In the December 1999 final proposals for the PES distribution and Scottish transmission price control reviews, Ofgem assumed an equity beta of 1.0, derived from an asset beta of 0.5. While there are likely to be important reasons for considering that the asset beta for an efficient electricity distribution business and an efficient electricity transmission business are similar, there may be reasons why they should be different, particularly if the values are being estimated at different times.

6.40 Ofgem considers that NGC's electricity transmission business is characterised by very little risk. Electricity transmission, like distribution, is presently considered to be a natural monopoly, meaning that there is no risk for NGC of losing market share under present trading arrangements. The regional nature of the PESs' distribution businesses or the Scottish transmission businesses may make them vulnerable to a change in the level of economic activity within one region, but NGC is a national business. While an investor may, in theory, "hedge" the additional risk arising from the regional nature of a PES distribution business by buying a portfolio of shares in each REC, such diversification may be costly. Moreover, an investor cannot buy shares in each REC at present as all are now part of wider groups carrying on a diverse range of activities. In addition, NGC's electricity transmission business has greater revenues and a larger asset base than the PESs's distribution businesses. Accordingly, Ofgem's preliminary view is that NGC's transmission business may be able to sustain considerably higher gearing than the 50 per cent which Ofgem assumed as an efficient level in the distribution price control reviews, without prejudicing the investment grade credit rating of its debt. The calculations set out later in this chapter are based on an assumption of 60-70 per cent gearing.

6.41 Beta estimates are usually based on historic data; the London Business School, for example, publishes beta values estimated on monthly observations over a five-year period. It is debatable whether such estimates accurately reflect the markets forward-looking expectations of risk. Nevertheless, it is worthwhile to consider the information that is available on beta estimates for NGG.

6.42 The main difficulty in using the observed beta for NGG's shares to calculate a beta for NGC's electricity transmission business is that there are a number of other components to NGG (including its overseas businesses, its remaining stake in Energis and its interconnector business) and there is no reason to suppose that the hypothetical beta for NGC's electricity transmission business is the same as that for NGG's other businesses. Ofgem considers that there are three possible methods for deriving an estimate for NGC's equity beta:

- **beta decomposition**: Ofgem has attempted to obtain an estimate for NGC's equity beta by eliminating the effects of Energis;
- **comparator companies**: Ofgem has calculated the implied asset betas for comparator companies using the series calculated by the London Business School; and
- **regulatory precedents**: Ofgem has examined other Regulators' determinations of the equity betas for the network utilities which they regulate.

Beta decomposition

6.43 NGG's beta can be expressed, in terms of the betas of NGG's businesses, as:

$$\beta_{NGG} = w_{NGC}\beta_{NGC} + w_{En}\beta_{En} + \ldots$$

Where βi is the Beta of business i and wi is the weighting given to the beta factors for each of NGG's businesses (NGC, and NGC's holdings in Energis are the largest by far). As Energis's beta is greater than NGG's, it seems probable that NGC will have a lower beta than NGG. The choice of how to weight the businesses is problematic. Use of market capitalisation results in an extremely low beta for NGC, because of the extremely high market capitalisation of NGG's holdings in Energis. Use of profit to weight the betas, on the other hand, results in a beta for NGC the same as the beta for NGG, as Energis does not make profits. After careful consideration, Ofgem has decided to use weightings based on turnover. Ofgem has attempted to split NGG's equity beta into an Energis and a non-Energis component in Table 6.2, using the above formula:

Table 6.2: Disaggregation of NGG's beta

	NGG	Energis	Non-Energis NGG
Revenue (£m98/99)	1568.3	263.4	1304.9
Weighting	1	0.17	0.83
Equity beta	0.56	1.25	0.42

Comparator companies

6.44 Relevant comparators for NGC include Railtrack, the water and sewerage businesses, the PESs, and BG Group plc. Table 6.3 lists the equity and asset betas for selected network utilities in May 1999 and January 2000. NGG's equity beta was 0.56 in January 2000. For the reasons given above, it is reasonable to suppose (as shown in table 6.2) that the beta for NGC's electricity transmission business is lower than that for the group as a whole, and also that the beta of the electricity transmission business is lower than that for the RECs or the Scottish companies. It should be remembered that, in all cases, the regulated entity differs from the entity whose share price is observable. However, the present betas appear to be unusually low by historical standards and it may be that this reflects exceptional factors, such as the market's present preference for high-technology stocks over low-risk companies such as utilities.

Table 6.3: The equity and asset betas and gearing for selected comparator companies of NGC

Company	Gearing (D/D+E) %	Equity Beta (May 1999)	Asset Beta (May 1999)	Equity Beta (Jan 2000)	Asset Beta (Jan 2000)
Scottish & Southern	49	-	-	0.70	0.36
ScottishPower	18	0.91	0.74	0.65	0.53
United Utilities	29	0.72	0.51	0.63	0.45
Hyder	33	0.64	0.43	0.50	0.34
Anglian Water	31	0.66	0.45	0.46	0.32
Thames Water	23	0.67	0.52	0.35	0.27
BG plc	23	0.56	0.43	0.62	0.48
Railtrack	54	0.67	0.31	0.56	0.26

Notes:
Gearing calculated as average net debt (derived from latest Annual Reports over the last five years) divided by the value of equity plus net debt.
The value of equity betas are based on five year averages calculated by LBS Risk Measurement Service (January-March 2000).
The asset beta is calculated using the following adjustment: $\beta_{ASSET} = (1\text{-}g)*\beta_{EQUITY}$.

6.45 All the utilities in the table above have asset betas of between 0.25 and 0.55. It would seem reasonable to assume that NGC's asset beta is at the lower end of this range, between 0.3 and 0.4, because:

- a national electricity transmission monopoly would appear to be less exposed to a local downturn in one region than a regional electricity or water distribution company, though it is arguable that this additional risk may be 'diversifiable', and hence should not be counted in the estimate for an asset beta, where only 'non-diversifiable' risk is counted;

- the regional electricity companies have signifcant competitive supply businesses, which exposes them to greater, non-diversifiable risk, hence raising their asset betas; and

- NGC does not incur the risks from having a large programme of capital expenditure to complete in the next two decades, unlike Railtrack or the water and sewerage companies.

6.46 Given Ofgem's assumption of 60-70 per cent gearing, this translates to an equity beta of 1.0, consistent with that used for the final proposals at the PES and Scottish transmission price control reviews. The higher gearing which Ofgem is assuming for NGC offsets the lower risk of NGC's transmission business relative to a PES distribution business.

Regulatory precedent

6.47 OFWAT in its determination of the cost of capital for the water and sewerage companies in December 1999 used an equity beta of 0.9-1.0. ORR used a beta of 1.0 to 1.1 for Railtrack. Ofgem used an asset beta of 0.5, giving an equity beta of 1.0, for the PES price control reviews.

Conclusion

6.48 While there is clearly a wide divergence of possible values for NGC's equity beta, an equity beta of 1.0 seems appropriate for NGC. This takes into account the relatively high level of gearing which Ofgem is assuming and the lower level of risk in its business compared to the PESs. This is higher than NGG's five-year average equity beta as at January 2000 of 0.56, and may mean that the range which Ofgem has derived for NGC's cost of capital is relatively generous.

Adjusting for taxation

6.49 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.

6.50 In its report on Cellnet and Vodafone, the MMC adjusted the cost of equity finance upwards by a tax wedge to take account of corporation tax payments. In calculating the tax wedge, the MMC assumed that the companies would pay the mainstream rate of corporation tax of 30 per cent, giving a multiplier of 1/(1-0.3) or 1.429. Ofgem used this approach in its final proposals for the distribution price control reviews (published in December 1999). It is for consideration whether this approach produces an appropriate amount of cash to meet the corporation tax liabilities associated with NGC's transmission business.

WACC

6.51 Table 6.4 shows a calculation of a 4.4 to 6.5 per cent range for the pre-tax cost of capital using the assumptions discussed in this chapter.

Dividend growth model (DGM)

6.52 The DGM can be used as a supporting check on the results provided by CAPM. This method estimates the cost of equity finance by adding together a company's dividend yield and an estimate of its expected dividend growth. NGC's dividend yield cannot be directly observed (though NGG's may be), and future dividend growth is uncertain. Accordingly, the application of the DGM depends on the choice of other indicators as proxies for dividend yield and growth.

Table 6.4: NGC's weighted average pre-tax cost of capital

Component	**Low case**	**High case**
Cost of debt		
Risk free rate	2	2.75
Debt risk premium	1	1.4
Adjustment for long-term debt	0	0.4
Cost of debt	3	4.55
Cost of equity		
Risk free rate	2	2.75
Equity risk premium	3.25	3.75
Asset beta	0.3	0.4
Equity beta	1.0	1.0
Post-tax cost of equity	5.3	6.5
Taxation adjustment	1.429	1.429
Pre-tax cost of equity	7.5	9.3
Weighted average cost of capital		
Gearing	0.7	0.6
Pre-tax WACC	4.4	6.5

6.53 The DGM can produce significantly different estimates for the post-tax cost of equity given different input parameters. Ofgem has used two such sets of parameters:

- the dividend yield of the market as a whole as a proxy for dividend yield and the growth of the economy for dividend growth; and
- the average dividend yield of comparator companies for the dividend yield and the growth of electricity demand for dividend growth.

6.54 Over the last three years the dividend yield on the FTSE 100 share index has averaged around 2.5 to 3 per cent. Assuming real dividend growth tends to move in line with the overall growth of the economy suggests a range of 2 to 3 per cent. This suggests a range for the overall cost of equity of between 4.5 and 6 per cent.

6.55 Ofgem has calculated the average dividend yield, weighted by market capitalisation, for a number of comparator companies (see Table 6.5), of around 4.75 per cent. Making the assumption, as NGC does in the BPQ, that electricity demand in the UK will grow by 0.5 per cent each year, and therefore that NGC's dividends will grow by 0.5 per cent over the long run, suggests a value for the cost of equity of 5.25 per cent, consistent with the estimate derived using the first methodology.

Table 6.5: Calculation of weighted average of dividend yields of comparator companies

Company	**Yield Q1 2000**	**Market cap (£m)**
Railtrack	2.6	5311
NGG	2.8	6993
NGG less Energis	7.1	2768
Powergen	5.6	2891
ScottishPower	5.2	8782
Scottish and Southern	5.3	4243
BG	2.2	14024
Anglian Water	5.3	1538
Hyder	13.9	447
Severn Trent	7.1	2098
Thames Water	5.7	2715
United Utilities	6.9	3539
Weighted average	**4.74**	

Source: LBS Risk Measurement Service January-March 2000

6.56 These estimates for the post-tax cost of equity are consistent with estimates of 5.3 per cent to 6.6 per cent from CAPM. Ofgem has used a wider range of input variables for CAPM, giving a wider range for the cost of equity. The mid-point for the range derived from CAPM is 5.95 per cent, rather higher than the estimate derived from the DGM (5.25 per cent).

Regulatory asset base

6.57 In order to secure continuing access to funds on acceptable terms, an enterprise needs to provide a return on the capital invested in its business. In the last NGC price control review, the capital invested in NGC's business was considered in two parts: the initial capital at flotation and investment made since flotation.

6.58 Table 6.6 shows the regulatory asset value of NGC between 1990 and the end of the previous price control.

Table 6.6: NGC's regulatory asset valuation 1990/91-1996/97 (1995/96 £m)

	90/91	91/92	92/93	93/94	94/95	95/96	96/97
Opening value	3710.0	3780.2	3905.8	4079.8	4140.6	4100.2	4057.1
FCM deprecation	-185.2	-191.9	-199.8	-209.2	-215.9	-220.3	-224.7
Capital expenditure	255.7	317.4	373.9	269.9	175.6	177.2	192.5
Closing value	3780.2	3905.8	4079.8	4140.6	4100.2	4057.1	4024.8

Valuation of assets at flotation

6.59 When the initial price control was set in 1990, while NGC was still under public ownership, its assets were valued on a present cost basis. In setting NGC's price control in 1992, OFFER did not commit to any particular asset valuation methodology. At the second NGC price control review, OFFER calculated NGC's regulatory value using two methods: an approach based on the 1990 valuation of the RECs, as used in the 1995 Distribution price control review and an approach based on the 1995 valuation of NGC on its demerger from the RECs. The OFFER paper concluded that both methods gave a similar valuation for NGC of around £4.15 billion excluding a valuation for Energis of £250 million.

6.60 Ofgem considers that, as with the distribution price control reviews, to revisit the methodology for valuing NGC's regulatory asset base would increase investors' perceptions of uncertainty, thereby raising the cost of capital. As explained in section 3, similar considerations apply to the valuation of Energis. Ofgem considers that the methodology used to assign a regulatory value to NGC's assets should be consistent with that adopted in the last price control review of NGC.

Investment made since flotation

6.61 The present price control of NGC's transmission business was set in order to finance network capital expenditure between the first year after Vesting in 1990/1 and the end of the present price control in 2000/01. The next price control will be set in order to finance NGC's past network capital expenditure between 1990/91 and 2000/01 and an efficient level for its projected capital expenditure to the end of the next price control period in 2005/06, assuming a five-year duration for the next control. Ofgem considers that in making an allowance for the return on NGC's capital expenditure in the present price control period, the actual level of expenditure (provided that this level was efficient) should be financed, rather than the level projected at the last price control review.

6.62 In order to calculate an efficient level for projected capital expenditure to the end of the next price control period, Ofgem's engineering consultants (PB Power) are analysing the methods used by NGC for forecasting. They are also analysing the relationship between capital and operating expenditure and are working closely with the consultants examining operating expenditure.

Asset lives

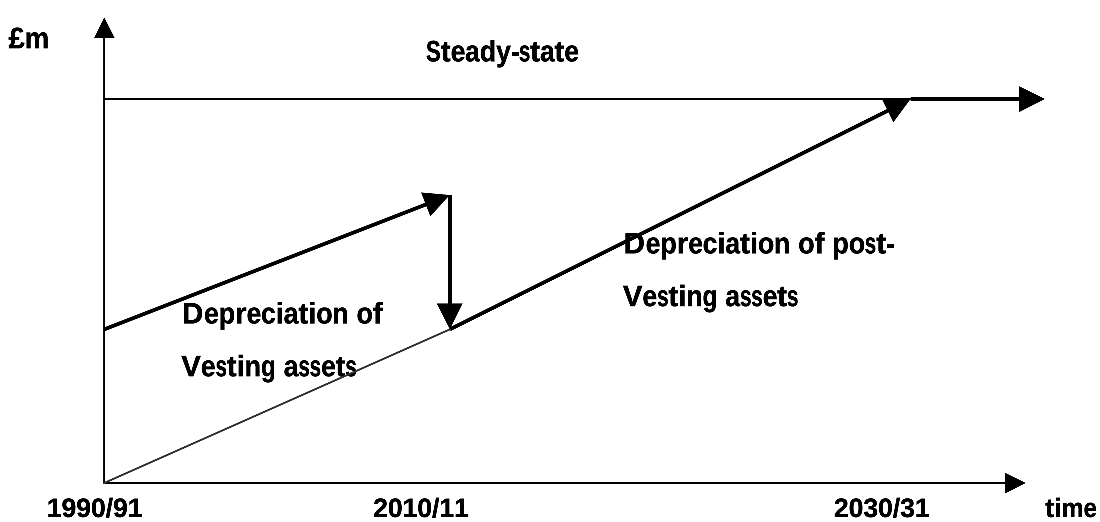
6.63 The depreciation charge for NGC's assets is calculated based on an assumption of an average asset life of 20 years for those assets existing at Vesting, and 40 years for those purchased subsequently. This approach was similar to that adopted by the RECs' distribution businesses, which assumed an asset life of 10 to 15 years for assets existing at Vesting, 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.

6.64 In deciding on the approach to asset lives for the next price control, it is important to bear in mind the impact of any assumptions on the financial position of NGC over the period of the proposed price control and beyond. Figure 6.1 shows a stylised representation of the allowance for depreciation in the calculation of price control allowed revenue over the period 1998/99 to 2029/30. The graph shows a sharp fall in depreciation in the period after 2010 followed by increasing allowances in the longer term.

6.65 The fall in depreciation after the year 2010 is caused by the writing down of Vesting assets on a straight line basis over 20 years. The associated depreciation allowances would be exhausted by 2010, causing a sharp fall in the total depreciation allowances (depreciation on Vesting assets plus depreciation on post-Vesting capital expenditure) at the same time. Nevertheless, the depreciation on post-Vesting assets gradually increases, until depreciation and capital expenditure allowances are in steady state, probably sometime after the year 2030.

6.66 The extent to which this issue causes difficulties in the future will depend on a number of factors, including future trends in operating costs and capital expenditure. In terms of regulatory stability, there may be advantages in consistency with the assumptions made at the last review, and any change will only be considered if there are advantages for customers. There may be benefits from consistency with the PESs where all PESs were adjusted in the next price control period. However, Ofgem considers that, as this issue will have no impact on the next price control, it would be preferable to defer a decision on how to deal with this issue until the next price control review.

Figure 6.1: Depreciation profile using present assumptions on asset lives



Financial modeling

6.67 In the light of Ofgem's duty to secure that NGC is able to finance its licensed activities, Ofgem will consider what sort of supporting checks would be appropriate on the financial position and viability of the licence holder.

6.68 The transmission price control applies only to some of NGC's business activities. This might suggest confining any supporting checks on financial viability to the transmission business. On the other hand, the licence holder is NGC and, since NGC is part of a larger group, licence conditions are to be put in place to limit the scope of the other activities carried out by NGC itself, and to create a financial ringfence around NGC to protect it against financial pressures which might arise from developments in the wider group.

6.69 In order to judge NGC's revenue requirements, and to assess the best way of strengthening incentives on NGC to reduce costs and promote efficiency, it is necessary to assess how much revenue NGC requires to cover its operating costs, capital expenditure and financing costs. Ofgem has constructed a financial model, which will incorporate Ofgem's projections of the efficient level of costs to give an appropriate level of revenue for NGC. This model will be audited before Ofgem publishes its initial and final proposals.

6.70 In assessing financial viability, it is important to consider what sort of tests are most appropriate. In its 1997 report on PacifiCorp and the Energy Group, the MMC indicated that "it would be essential for Eastern Electricity to have access to requisite finance on acceptable terms. This can be ensured by the maintenance of an investment grade credit rating for the debt of the company" (paragraph 2.72). This is consistent with the approach adopted by OFFER in establishing the financial ringfencing provisions and in the approach to the cost of capital discussed earlier in this chapter. In the light of this, it appears reasonable to focus checks for financial viability on the ability of NGC to maintain an investment grade credit rating for its debt. This approach is consistent with the approach which Ofgem adopted in the 1999 review of the distribution price controls.

6.71 Both Moody's and Standard & Poor's stress the importance in determining credit ratings of qualitative factors such as overall management strategy and perceptions of the regulatory environment, as well as of quantitative assessments based on financial modelling. Nevertheless, both agencies have published guidance on the financial analysis they undertake, both generally and specifically in respect of electric utilities. The overall approach is to examine earnings, cash flow and capital structure in relation to debt service obligations, working capital needs and capital expenditure requirements. This analysis is carried out using both historical results and future projections. Particular emphasis is placed on analysis of real stocks and flows (levels of debt, cash and cash flow), in view of the difficulty of comparing reported earnings and balance sheet data between companies operating under different regulatory regimes and following different accounting conventions. Therefore parameters such as the coverage of fixed financial charges by cash flow and the ratio of free cash flow to total debt are considered more relevant and reliable than earnings coverage or balance sheet gearing.

6.72 Measures of financial protection, as revealed by such analysis, are considered in the context of the utility's business profile. A company with a strong business profile may have less financial protection than a company with a weaker business profile yet achieve a similar credit rating (and vice versa). A transmission business faces limited business risk and is thus able to sustain lower interest coverage and higher gearing compared, for example, to generation or supply which operate in a more competitive environment with greater cash flow volatility. In its December 1999 final proposals on the distribution price control review, Ofgem, following discussions with City institutions, rating agencies and investors, set out the indicators in Table 6.7 which it had applied in assessing the impact of the proposed revisions to the distribution price controls:

Table 6.7: Ofgem's financial indicators for PESs

Indicator	Level	NGC (98/99)
EBIT interest coverage	Min 1.5 x	5.6 x
EBITDA interest coverage	Min 2.25 x	6.8 x
FFO interest coverage	Min 2 x	6.4 x
FFO to total debt	Min 12%	30.8%
Balance sheet gearing (D/D + E)	Max 70%	61.7%

6.73 In assessing the potential reaction of credit rating agencies to changes in the NGC's financial position over the period of the revised price control, Ofgem will pay close attention to the above ratios. It is for consideration whether, given the low risk of NGC's transmission business compared to the distribution businesses of the PESs, NGC would be able to sustain an investment grade credit rating with lower levels of coverage than are indicated by the figures applicable to PESs set out in table 6.7 above. Nevertheless, it will be important to ensure that NGC's credit rating remains comfortably within the investment grade category throughout the period of the revised price control.

6.74 Where the averages for these ratios over the period of the revised price control indicate a financial position broadly consistent with the above ratios, and in the absence of any evidence that a severe deterioration will occur after the end of the period, it would be reasonable to assume that the revised control will not threaten NGC's ability to sustain an investment grade credit rating for its debt.

Issues for consideration

6.75 Ofgem seeks views on:

- whether Ofgem's methodology for assessing NGC's cost of capital is appropriate;
- whether Ofgem has correctly estimated each component within the capital asset pricing model (CAPM) (risk-free rate, debt risk premium, equity risk premium, company specific beta, taxation wedge and optimal gearing);
- whether a premium for long-term, fixed rate ('embedded') debt taken out at higher interest rates should be adopted;
- whether an efficient capital structure should be assumed or NGC's actual gearing should be calculated for the purposes of assessing NGC's cost of capital;
- whether Ofgem's methodology for rolling forward the regulatory asset base is appropriate; and

- whether Ofgem's approch to financial modelling is suitable for the calculation of NGC's financial requirements.

Appendix 1 Ofgem’s and NGC’s statutory duties

1.1 Section 3 of the Electricity Act 1989 sets out the duties of the Director General of Electricity Supply (DGES) in the performance of his functions. In particular, Ofgem will exercise the DGES’s functions in a way that is best calculated: to secure that all reasonable demands for electricity are satisfied and that licence holders can finance their authorised activities; to promote competition in the generation and supply of electricity; to protect customers' interests with respect to prices charged and quality of electricity supply services; and to promote efficiency and economy by NGC (and other licence holders). Ofgem will also have regard to the effect on the physical environment, for example an increase in pollution, of activities connected with transmission, generation and supply of electricity, protect the public from dangers arising from the generation, transmission or supply of electricity, and take into account in particular the interests of consumers in rural areas.

1.2 A bill is before Parliament to modernise the framework for utility regulation. If this legislation is enacted before final proposals for NGC’s price control are published, Ofgem will need to have regard to any changes to the DGES’s or NGC’s duties. It is also expected that the enactment of the bill will result in the introduction of New Electricity Trading Arrangements (NETA) that will involve changes to the NGC transmission licence, proposals for which have already been published by Ofgem.

1.3 Section 6 of the Electricity Act 1989 (‘the Act’) regulates NGC’s electricity transmission business. Section 9 of the Act requires the holder of a transmission licence to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition in the supply and generation of electricity. In addition, the licence conditions at present include the following (although it is envisaged that these may change as a consequence of NETA):

- **Condition 2**: prohibits NGC from purchasing electricity for general supply to third parties;

- **Condition 3**: requires NGC to produce separate accounts for the separate regulated businesses (Transmission, Settlements, Interconnectors and Ancillary Services);

- **Condition 4**: restricts the revenues that NGC can recover from its transmission business;

- **Condition 5**: prohibits the separate regulated businesses from giving or receiving a cross subsidy to or from a related undertaking of the licensee or any authorised electricity operator that owns shares in the licensee or licensee related undertaking or affiliate;

- **Condition 6**: requires NGC to purchase ancillary services from the most economical sources within the licence and statutory constraints;

- **Condition 10**: sets out the basis for charging for connections and the use of the system and requirements for transparency;

- **Condition 11**: relates to charges for use of interconnectors;

- **Condition 12**: relates to NGC's transmission system security standards and quality of service;

- **Condition 14**: requires NGC to establish a forum in order to consult with its employees on employees' health and safety issues; and

- **Condition 16**: requires NGC to obtain the DGES's approval before disposing of or relinquishing operational control over any relevant asset forming part of the NGC transmission system or any interconnector.

Appendix 2 Responses to initial consultation document

Subject	Comments
Ancillary services	Removal of licence condition to purchase ancillary services economically must be subject to satisfactory market arrangements being in place. Ofgem has issued no consultation yet. Ancillary services business should be incorporated into SO function. There is an expectation that the obligation on generators to offer to provide particular ancillary services will be removed. No reasoning given by Ofgem as to why present arrangements for separation of ASB will no longer be necessary under NETA. Ofgem should continue to consider separating the ancillary service business; making a decision now is premature. Market-based mechanisms for all ancillary services. No need for ancillary services business in its present form under NETA. However, activities of ASB should be transparent. Ancillary services should remain outside SO and TO and be treated as any other demand or generation bid or source.
Charges	The generator/supplier split should be revisited. Charges should be allocated in the most economically efficient manner and kept to the minimum required to maintain a reliable network. Connection charges should be derived from clear principles. Users should be able to own their own connection assets. In capacity auctions, NGC should have an incentive to minimise the value of rights denied. Boundary between connection and use of system assets uncertain. Review of charges welcome. Transmission rights should be based on cost-reflective and transparent prices rather than on auctions. Review should focus on the total of revenues required to finance activities rather than on addressing capacity auctions. Auctions should be used to provide locational signals in relation to transmission access. Separate charging for connections/use of system an area for debate. Will need to be discussed in the light of changes to existing TNUoS charges. Present structure of charges appropriate. Present regulation of connection charges appropriate.

Subject	Comments
Connections	Connectees should own connection assets, which could be removed from the price control. Separate controls on connections and use of system to facilitate competition in the provision of connections. Shallow connections should be key definition.
Consistency	NGC control should also consider Transco, PESs and Information and Incentives project. Ofgem should analyse other Regulators' recent price control reviews. Transmission regime should be consistent with distribution, except for SO.
Cost of capital	Ofgem should use efficient level of gearing. Estimate of risk-free rate should be 2.7-3.5 per cent. Beta should be 0.55-0.75, lower than PESs. Debt premium should be around 0.4 per cent. A suitable cost of capital should be 5.4 per cent-7.5 per cent. Cost of capital should not be influenced by debt raised by Energis in February 1999. NGC less risky than distribution businesses. Particular circumstances driving yields on current government debt also a matter for consideration in determining risk-free rate. It is arguable that Ofgem's method for estimating the risk-free rate is inconsistent with its method for estimating the equity risk premium. Longer term averages appropriate. Mid-point of MMC's range for equity risk premium is 4.2 per cent. Should be consistent with PESs.
Determining allowed revenues	Ofgem should publish a summary of BPQ and consultants' reports.

Subject	Comments
Duration	5 years most appropriate, with provision for shortening to 2 years if it is in customers' best interests. Decision should be delayed until need for separate controls is clear. In principle, 5 year control welcome. 4 years. 5 years. 5 years. Balance to be struck between stronger incentives for efficiency and risk of getting initial price control parameters wrong. 5 years for TO, SO much shorter (perhaps annual). 5 years. 5 years for TO. Support lengthening of period of reviews which would set framework for regulation. Scope for mid-term reviews to redefine detail on which price control is set. 4-5 years for TO. Form of SO control 4-5 years. Parameters of SO control could be revised more frequently. Ofgem should move towards longer price controls as regulation matures. Scottish price controls have been set for five years despite the review of Scottish trading arrangements. For NGC, flexibility should be maintained for the effects of new trading arrangements on the price control. 5 years probably right, though after annual performance monitoring, much longer duration may be possible. 5 years reasonable. 5 years. 5 years.

Subject	Comments
Energis	NGC should be required to publish a tariff for Energis charges. Ofgem should assess what charges NGC should collect from Energis if it was totally independent. Value to Energis of NGC's assets should be calculated. Inappropriate for work on Energis's equipment to affect the operation of the transmission system. Costs of providing, maintaining and managing overhead lines should be apportioned between electricity and telecomms users, including central costs. Oftel should be consulted. Amount Energis is actually charged has no relevance. Ofgem should increase the transparency in the setting of Energis charges by NGC and consider requiring the complete divestment of NGC's shareholding. Ofgem should consider the valuation of Energis and its effect on the RAB and the split between customers and shareholders of revenue from Energis. Any constraints caused by Energis should be paid for through a transparent mechanism. Revenue from charges for Energis should be divided between shareholders and customers, as in a competitive market. Any constraints caused by Energis should be paid for through a transparent mechanism. Energis charges should reflect costs incurred from another service provider. Energis charges should be at a commercial rate as if to a third party. Rental charges deducted pound for pound from RPI-X revenue. This provides no incentive for development of services using licensed assets. Energis should pay part of the costs of TO assets. Revenue derived should reduce NGC's TNUoS charges Unregulated income should be allowed for in the regulated revenues. Energis's charges should be transparent. Energis should be paying NGC a rent for the use of the network which reflects its present profitability. Ofgem should decide appropriate levels for charges. Full separation and transparency necessary.

Subject	Comments
Form of control	Supports RPI-X as long as this continues to deliver benefits to customers. Asset base should be subject to variation with actual use. Regulatory regime should provide modest incentives for NGC to maintain an economic system. RPI-X best suited to TO, incentives to SO. Support Ofgem's agenda to improve RPI-X. Extending control to 5 years will add to NGC efficiency incentives but could reduce the accuracy of projections, unless a mechanism was introduced, which would allow the control to be revisited. Principles should include efficient capex, efficient opex, quality of supply and efficient financial management. Support benchmarking and present 50/50 split of revenues (forecast/actual revenue). Support effective capex monitoring, if consistent with incentives mechanisms. Should be a single SO scheme. RPI-X most appropriate. Incentive schemes should reinforce price control. Benchmarking with other transmission businesses in Scotland and abroad. NGC's expenditure and performance should be monitored continuously through a more formalised framework. A tougher ringfence should be introduced. Support RPI-X for TO, incentives for SO. Supports RPI-X, but auction evaluations should feed through into price control. Should be separate price controls for TO and other functions. RPI-X for TO, incentives for SO. Support increased reliance on output measures and making use, where possible, of benchmarking. Support more ongoing monitoring of expenditure. Recovering capex in the year it was incurred would increase the incentive on NGC to reduce capex, but would increase volatility. RPI-X. Support the concept of increased reliance on an output-based price control. Targets for key measures should be agreed for next price control period and revenues and performance linked. Benchmarking should be used where possible. Ofgem should be able to get the initial price control parameters 'right', so the risk of 'excess profits' due to 'underspend' is minimised. Connections split anomalous. All connections should be governed by long-term contracts outside the price control. Support revenue driver. TO price control should reveal whether incremental investment in D system is more efficient than transmission system investment. Customers should not be penalised for stranded assets directly, though NGC's rate of return should perhaps reflect this risk. RPI-X for TO, incentives for SO. Revenue driver should be incorporated, as with Transco and distribution. RPI-X for TO (possibly including performance measures), incentives schemes determined separately for SO. Present price control should focus on those parts of NGC which will be unaffected by NETA. Any simple revenue driver will involve a degree of approximation. NGC welcomes Ofgem's intention to utilise appropriate benchmarking.

Subject	Comments
Form of control (cont)	P_0 gives rise to crises and distortions, and should be avoided. RPI-X for TO, incentives for SO. Support RPI-X controls and benchmarking NGC. Control should last for five years. TSUoS, Losses and Energy Uplift can be separated from TNUoS and connections. Support SRMC-reflective auctions. Costs of constraints should be recovered through the auctions. Losses should be allocated zonally. Revenue should continue to be price-regulated and recovered from demand and generation on a locational basis. Pre-Vesting connections should be removed from the price control and treated as post-Vesting connections. NGC should be obliged to facilitate competition in the provision of connection assets. Departure of a shared user should not result in remaining part paying more than he would have as sole user throughout. Separate price controls for TO and SO not necessary. RPI-X methodology has delivered large cost reductions, which can be shared with consumers. The penalties and rewards agreed during the distribution reviews were arbitrary and unscientific. In line with the Scottish controls, no revenue driver should be imposed. The present split between price control and incentives is satisfactory, subject to comments on TO/SO. Contribution to balancing services by static compensators should be recognised in price control. Support RPI-X. May be a case for refining the system to deal with distortions. Benchmarking of limited use in a transmission price control review. Structure of present control reduces uncertainty for NGC and transmission system users. Revenue from auctions should not be a means of recovering a return on the transmission asset owner's investment. It is not certain that such revenue would be sufficient to allow NGC to finance its activities. Support RPI-X. Asset valuation should be consistent with PESs. RPI-X most appropriate for TO. Present approach to revenue drivers appropriate.

Subject	Comments
Incentives	RPI-X control similar to an incentive scheme. Separate incentives schemes and RPI-X revenue can co-exist provided they are compatible with each other. Transmission incentive schemes and price control should be concurrent, with a break after two years in the incentive schemes. Danger that incentives schemes are sustained as source of income for monopolist activities. NETA will affect incentive schemes more than price control. Appropriate incentives should be set for both SO and TO. Incentives should encourage lowest cost solutions to meeting its targets. Schemes have been successful. Any review of incentives should be consistent with the Information and Incentives Project. The key focus should be on building on existing incentives to concentrate on key areas of NGC's output. Support incentives to improve efficiency and maintain high levels of service quality. Should not conflict with RPI-X control or create perverse incentives. South West should not be penalised from any reform. SO incentives should be separate and facilitate innovation and competition and be subject to frequent reviews. Business incentives should be reasonably separated to prevent conflicts of interest. Incentives should be transparent. Zonal charging for losses appropriate. Any surplus should either be subject to a sharing mechanism or be required to be invested in the network.
Interconnectors	Scotland and France should open markets.

Subject	Comments
NETA	Clear statement of Ofgem's policy on costs required. Long-term costs of the TO should be at an efficient level for the required future capacity. Price control must determine level of revenue required and present over- and under-recovery arrangements should continue. Some NETA interaction with price control. Much uncertainty on NETA. Essential that the functions of NGC are unbundled in their licence. NETA will change NGC's role, in the interaction between the despatch of energy under the balancing mechanism and the services presently provided by NGC under ASB agreements. Future arrangements uncertain. NETA should not significantly affect TO's revenue. Introduction of tradeable access rights and marginal charging for losses could have major affect on way in which TO revenue is recovered. Ofgem has identified interactions between NGC PCR and NETA. NETA should not significantly impact level of revenue to be collected over next 5 years. Introduction of tradable access rights and marginal charging for losses could impact recovery of NGC's allowed revenues. Ofgem's proposed model seems practical. Not in consumers' interests for NGC's costs to be underwritten. Cost recovery of NETA systems should be from signatories to the BSC. At the moment, it appears that NETA will affect incentives schemes rather than price control (unless auctions for access are introduced), but it is not possible to comment in detail until the arrangements are more certain. Efficiently incurred costs for systems should be recoverable. Consultants should determine which costs are efficient. No relevant aspects of NETA identified, besides those in consultation paper. Important that Ofgem identifies areas where interaction takes place. Transmission network access arrangements unnecessarily complicated and unlikely to deliver benefits. Might undermine other NETA changes.
Operating expenditure	There seems to be scope for further reductions in opex. Staff costs seen as changeable. No consideration given to re-employment of redundant workers as consultants, and whether this is economic. NGC is experiencing difficulties in recruitment and retention.
Reactive power	If unified market for reactive power is adopted, it would result in removal of operating costs and assets from the RAB. Income for reactive compensation assets should be recovered from the reactive power market.

Subject	Comments
TO/SO	Review should also cover SO functions. BPQ and Andersens should obtain SO costs. SO function should perhaps be incentivised. Precise partitions between SO and TO to avoid double-accounting. Services should be unbundled, but the cost to the industry as a whole should be taken account of. SO/TO split should happen eventually, with separate price controls. Model outlined by Ofgem reasonable starting position. Tendering scenario only viable if TO and SO truly separated. TO output should be based on efficient use of capital, and SO output on efficient use of opex. Ofgem should develop scenarios based on separate controls and a combined control, and decide between them according to which gives NGC better incentive to serve its customers. If there is a division of responsibilities between TO and SO, there should be separate controls. TO/SO should be split or synergy savings sought and passed to customers Three distinct functions: 1) TAO, 2) Transmission System Operator, 3) Total System Operator, such as operating the balancing mechanism. Would support model of TO/SO. Transmission asset ownership not necessarily a monopoly (like airports). Ofgem should define a model with clear separation of TO and SO and consult. SO should contract services levels and investments from TO. Support clear definition of roles. Should be separate price controls for each. NGC's business primary monopoly undertaking. Scope for competition in TO and SO. SO might be required to commission transmission investment from TO. Shortening gate closure will allow more competition. Future controls should not stifle competition. Support separate controls and accounts if separate ownership not possible. SO should be made independent of asset holders. SO's responsibilities might be contracted out to a third party after five years. NGC's dual role constitutes a conflict of interest. SO should initially operate behind Chinese walls, but subsequently develop as a stand-alone operation. Consultants should commence work on division without delay. SO may warrant higher profitability than TO. SO should have the option to purchase services elsewhere or to invest in its own assets or use existing assets more efficiently. SO's responsibilities should include balancing, managing of constraints, losses and ancillary services. Both activities should remain under transmission licence. SO role includes: present costs of SO function; internal costs of procuring ancillary services; internal costs relating to balancing services; and increased costs of SO in NETA world. Integration of TO and SO has delivered substantial benefits.

Subject	Comments
TO/SO	Disaggregation should be avoided and separate controls not imposed, unless these result solely in separate ccounts. Static compensators removed from TO control; remunerated instead if successfully bid into SO's ancillary services procurement process. SO and TO do not need to be in separate ownership, but a clear definition of roles is required. Proposed split in consultation has some merit. SO should be incentivised correctly. Proposed model of SO/TO interaction would have a large impact on price control. In Scotland, pressure to separate TO/SO has been to split them from Scottish companies' generation. No similar pressure in England and Wales. Supports separate controls, provided a) clear definition of each activity and b) clear benefit to customers. Should be revisited when issues are clearer. Clear definition required of SO and TO functions. Separate controls for energy balancing and system balancing. Role of SO should be to procure, not provide, transmission services. Costs centrally incurred by SO should be recovered from all market participants. Transmission access pricing arrangements at a very early stage. No competition in TO or SO role likely in short term. Transmission services could be procured by SO. Separate licences unnecessary.

In addition to the above, there were three confidential responses.

Appendix 3 Summary of NGC's reply to the Business Plan Questionnaire

Price Control Review 2000
NGC's Response to the Ofgem Business Plan Questionnaire
Summary

Introduction

1. This document summarises the detailed narratives on operating costs and capital expenditure provided to Ofgem by National Grid as part of the Business Plan Questionnaire (BPQ) in January 2000. It also provides summary financial tables on operating costs and capital expenditure during the period 1996/7 to 2005/06.

2. As agreed with Ofgem, this summary has been drafted exclusive of any incremental costs, which National Grid may incur as a result of the implementation of the New Electricity Trading Arrangements. This is also the basis on which the main BPQ was prepared for Ofgem.

3. This summary sets out:

- the duties and obligations which National Grid must meet and the cost drivers these obligations place on us
- our contribution to the electricity market
- our operating expenditure performance since 1990, and our projected performance to 2005/06
- our capital investment performance (actual and projected) for the period 1996/97 to 2005/06.

Duties and Obligations

4. The National Grid Company plc holds the only Transmission Licence in England and Wales and as such we are required, by the Electricity Act and by that Licence, to carry out various duties and fulfil various obligations. These duties provide the cost drivers for the transmission business. The key cost drivers are set out below:

- the operation, maintenance and replacement of the physical plant, equipment and substations which comprise the transmission system, the volume and range of those assets and their geographical spread from Cornwall to Cumbria

- externally driven changes to the transmission system; the number of new generator openings and closings and the effect these have on power flows and the consequent impacts for operational management and maintenance/construction access to the system

- the security standards set out in our licence which dictate the level of availability and reliability demanded by our customers and hence the investment we have to make in the system

- our obligation to facilitate competition in the generation and supply of electricity; this involves making offers for connection to and use of the system to tight timescales, at whatever location the customer specifies, and reviewing our connection and use of system terms on a regular basis

- our obligation to develop and operate the system for the purpose of restricting, and where possible reducing, the costs arising from the operation of the system; our transmission services activity which seeks to reduce these costs for suppliers of electricity to the end customer

- environmental and health and safety requirements; characterised by the pressure imposed on network operators like ourselves from tightening legislation in these areas

- many of our installations are of national strategic importance and classified as Economic Key Points

5. We explain in the sections below how our operating expenditure and capital investment are driven by our duties and obligations, and the benefits we have provided to the customer in discharging these duties since 1990.

NGC's Role

6. As background, we set out the broad context within which we have operated since the creation of National Grid ten years ago and look forward to anticipated developments in the forthcoming price review period.

7. The National Grid transmission system comprises over 7,000km of 400kV and 275kV overhead lines with some 22,000 towers, approximately 650km of underground cable, some 300 substations and a national control centre. It is one of the most heavily loaded systems in the world and its integrated nature and geographically small size, combined with its limited interconnections to other systems, (presently only those in Scotland and France) make its management more electrically complex than others around the world with comparable demand.

8. We have two complimentary and interdependent roles relating to the ownership and operation of the transmission system:

   - The first is the management of the physical network; maintaining our assets and constructing new assets where that is necessary to meet the needs of customers and to allow the bulk transfer of power.

   - The second is the role of system operator; matching second by second, the available generation to the demand in the market to ensure continuity of supply, with two key measures of quality being the maintenance of frequency and voltage.

9. The fact that the Great Britain system is an island system, with limited interconnection to continental Europe, means that frequency control must be maintained within the GB system. As the operator of by far the largest of the three interconnected British systems, National Grid has the principal responsibility for managing frequency control by buying services through its Ancillary Services Business. These services are mainly provided by generators, but National Grid has successfully broadened the market by encouraging an increasing number of demand side participants to provide such services. This contrasts with the two Scottish transmission companies which source their share of the requirements for these services internally from within their vertically integrated companies.

10. Condition 12 of the Transmission Licence recognises our interlinked roles and sets out the security standards to which the system has to be developed and operated. In a recent review the vast majority of our customers confirmed the need for these standards, which give them comfort that the quality and security of their supply will be maintained. Ofgem has agreed with this conclusion.

Summary of Past Performance

11. Since 1990 the rapid growth of competition in England and Wales has resulted in the challenge of an unprecedented growth of customers applying to connect new generating stations to our system. Year on year we have seen a consistent level of new generator connections, with some 22GW (predominantly Combined Cycle Gas Turbine stations) connecting to the system over the last ten years. This amounts to over one third of the total capacity connected to our system and has displaced older plant, with some 15GW of notified closures (predominantly coal) and 5GW of plant mothballed since 1990. On the basis of applications already made to us and subject to government policy on consents, we expect to see this level of new connection and closures continuing. This plant turnover will continue to produce further changes in the variability and patterns of the flow of electricity across the network which National Grid must manage effectively.

12. To provide this level of connection and ensure that the overall system is reinforced and able to meet our licence standards against the changing generation and demand patterns, we have managed a substantial capital programme amounting to some £1,620m (at 1999/00 price levels) in the period 1990-1999. We have used a variety of innovative approaches to help meet the challenges competition has brought in the form of this unprecedented change to generation siting and power flows. Given the obvious difficulties associated with building new lines, (visual impact, increased public awareness on the environment) we have focused on seeking ways to work our existing assets harder. This has been supplemented by the installation of new technology such as reactive compensation equipment and quad boosters, which has changed both the type and size of assets installed on the system.

13. The age profile of our assets, with the concentration of assets around the age of 30-35 years, means that a carefully managed long term asset replacement programme is absolutely essential to ensure phased replacement to maintain network performance. This has resulted in investments of some £1,380m (at 1999/00 price levels) since 1990.

14. By the end of the financial year 1999/00 we will have reduced our controllable costs by 48 per cent in real terms since 1990/91, from £433m to around £224m. These savings, and the consequent benefits to customers, have been achieved by a series of management actions to achieve the most efficient and cost effective means of delivering a transmission system that is reliable and secure over the medium and long term. Benchmarking studies with other electricity companies have shown us consistently to be a “best performer” in terms of maintenance cost and service levels.

15. Controllable costs now constitute less than half our total costs, the balance being made up of costs over which we have limited opportunity to exert management influence. These controllable costs primarily cover:

- Repairs and maintenance of the physical transmission assets spread throughout England and Wales, including ensuring the on-going strong technical performance of the network

- Second by second operation of the transmission system from a single control centre

- Dealing with new connections, capital planning and system design

- Environmental obligations
- Information systems to facilitate each aspect of our operations

Customer Benefits

16. Over the last ten years we have continually broken our own records for system availability year on year, improving system availability at the time of winter peak demand, from 97 per cent in 1990/91 to 99 per cent in 1998/99, whilst average system availability has increased from 92 per cent to 96 per cent over the same period.

17. Overall our achievements in providing an efficient, cost effective, reliable and secure transmission system have been delivered against a background of a real reduction in our revenues of some 30 per cent between 1990/91 and 1998/99, from £1200m to £840m. This has enabled us to contribute to the 22 per cent real reduction in the average customer bill that has been seen between 1993/94 and 1998/99. The transmission element of that bill has reduced by some 41 per cent, and now represents just 3.9 per cent of the final bill.

18. Primarily as part of our role as system operator, in the second half of 1994/95, we introduced an initiative to control uplift costs, which has had a significant impact on wholesale prices to suppliers. By 1993/94 uplift (the difference between Pool selling price and Pool purchase price which is passed directly on to suppliers and their customers) had risen from £344.3m in 1990/91 to £694.9m in 1993/94 (1999/00 prices). While some of these costs were outside our control we believed that with a focused management strategy we would be able to lower a number of costs, such as those relating to transmission constraints and the costs of providing response and reserve. The result was the Uplift Management Incentive Scheme (later the Transmission Services Scheme) which delivered significant benefits for electricity suppliers through lower wholesale prices. The initiatives we introduced, for example greater focus on outage co-ordination across planning and operational timescales, have enabled us to achieve a total saving of £400m against annual targets over the past 5 years. The savings against the headline figure of uplift in 1994/95 amount to more than £1,000m.

Implications of NETA

19. Looking to the future our revenue and cost assumptions have been derived on a methodology consistent with that used at the last Price Review. We have also adopted the assumption that the transmission business will be split between a Transmission Owner (TO) and System Operator (SO) from April 2001. Whilst discussions are taking place with Ofgem on the precise nature of the TO/SO split, we have assumed that the costs of those parts of the current RPI-X regulated business associated with our system operator role will in future be regulated via the incentive arrangements introduced from April 2001. This approach enables the main price control review settlement to focus on our TO role which will be broadly unaffected by NETA.

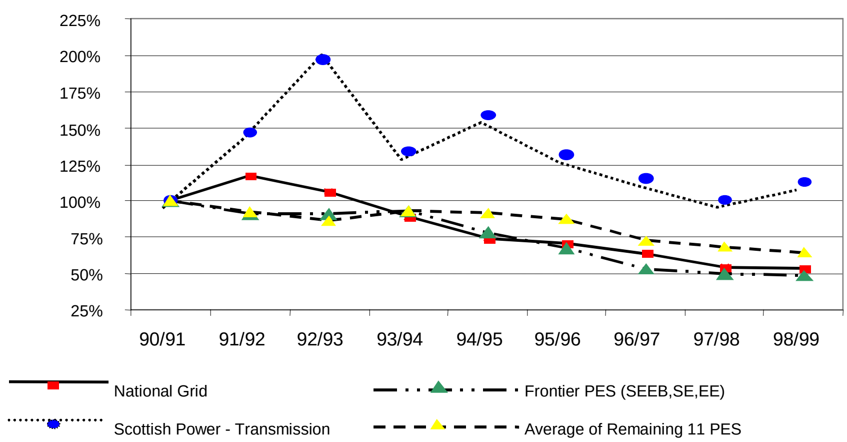
20. As described above, the BPQ has been prepared exclusive of NETA, and therefore the costs which we are incurring both in respect of NETA implementation, and in respect of ongoing operations after implementation, are not included in our financial projections at this time. Discussions on these costs and the mechanism to recover them are taking place with Ofgem, which will result in our submitting an adjustment to certain BPQ financial data in the near future.

Operating Expenditure Summary

Performance 1990/91 to 1999/00

21. Since 1990, National Grid has reduced controllable costs by 48 per cent in real terms. This performance compares favourably with the performance of Public Electricity distributors in Great Britain, including those considered to be on the efficiency frontier in the recent distribution review, and with the performance of Scottish Power (Transmission). The graph below sets out our performance against these companies.

Controllable Costs Index (1990/91=100)



[Source of information: published regulatory accounts and documentation from the PES Distribution and Scottish Transmission Price Control Review. No Scottish Hydro comparison is included because full information on the breakdown of total costs was not publicly available.]

22. This performance has been delivered through a series of management initiatives, which have sought to achieve the most efficient and cost effective means of delivering a transmission system which will be reliable and secure over the medium to long term. This performance should also be seen in the context of our operating environment set out above, one which has seen pressures to increase operating expenditure, in particular:

- 22GW of new generation connected to the system, representing one third of the total capacity connected to the system

- increases in the amount of plant and equipment to be maintained and operated on the network of around £1,500 million since 1990/91, equivalent to a growth of some 12 per cent in our asset base

- the installation of a broader range of assets, including more sophisticated equipment, which has required a wider range of skills to manage and maintain those assets.

- increased complexity in the operation of the system.

Performance 1996/97 to 1999/00

23. Since the start of the current price control period, we have reduced controllable costs by 19 per cent in real terms by a range of management actions including:

- leading the world in system operation management such that the transmission system is now controlled from a single, national management unit, rather than via a central control centre augmented by regional centres

- de-manning our substations to a point where almost all of our sites are controlled remotely from that national control centre

- introducing a range of organisational changes which have reduced our maintenance centres to four and our construction centres to two

- reducing payroll costs by 24 per cent in real terms and progressive changes in remuneration, managing pay to be in line with the market, with increased emphasis on enhancing productivity and all awards being based on individual or team performance.

Projected Performance 1999/00 to 2005/06

24. Traditionally, Ofgem has adopted a definition of controllable costs as total costs, less depreciation and operational rates. A background of substantial cost reductions, progressively reduces the proportion of costs over which management has control. Two additional factors further reduce the level of costs over which we will have management control going forward as transmission owner.

25. Some £36m of operating costs are associated with the SO function. Given our assumptions in responding to the BPQ, these have been excluded from controllable costs on the basis that they will be picked up via the post NETA incentive arrangements from April 2001. In addition, a further £29m of TO costs are subject to limited further management control in that they are externally driven or already directly linked to market rates.

26. The combined effect of these adjustments is to leave the TO with a genuinely controllable cost base of some £160m in 1999/00.

27. Given the current nature of our controllable costs, our salaries position and our benchmarking results, we aim to reduce TO controllable costs by a further £21m, or by 13 per cent in real terms, in the period to 2005/06. This equates to an average reduction in our genuinely controllable costs of 2.4 per cent per annum. This will be achieved through:

- further outsourcing and procurement efficiencies

- completing the demanning of substations programme

- more condition monitoring to optimise maintenance work

- further information systems rationalisation

- reductions in corporate and support function costs

Information on operating costs is provided in the attached tables.

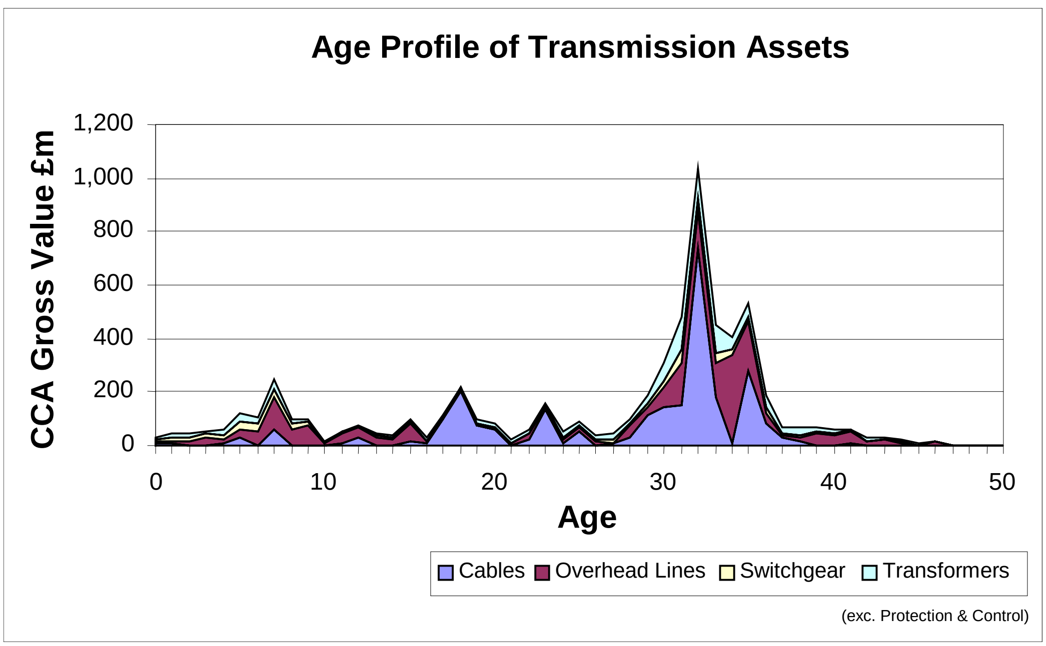
Capital Expenditure Summary

28. The two main drivers for our capital investment are the connection activity of our customers and the reliability of our network. Capital investment is carried out in accordance with the security standards defined in our Transmission Licence. Whilst the drivers for load related and non load related capital expenditure are distinct, the two activities are addressed together to ensure efficiency in development and replacement investment decisions.

29. In planning investment, there has been no fundamental change to our policies since the last regulatory review and we continue to invest to provide new customer connections, network reinforcement and asset replacement. This expenditure ensures that over the medium to long term appropriate levels of transmission capacity and network reliability are maintained, environmental obligations are met, and the health and safety of both staff and the general public are ensured.

30. Our investment in new infrastructure is driven by the level and location of generation openings and closures together with demand growth. Whilst the level of generation construction activity in the current review period has been influenced by the application of the restricted consent policy adopted by the Government, we continue to see a high level of applications for new connections. Between 1990 – 1995 and 1995 – 2000, generator openings have taken place at a rate of around 11 GW in each of these five year periods. We anticipate generator openings to remain at this rate in the medium term. We have also assumed that combined heat and power schemes will be developed in line with Government targets.

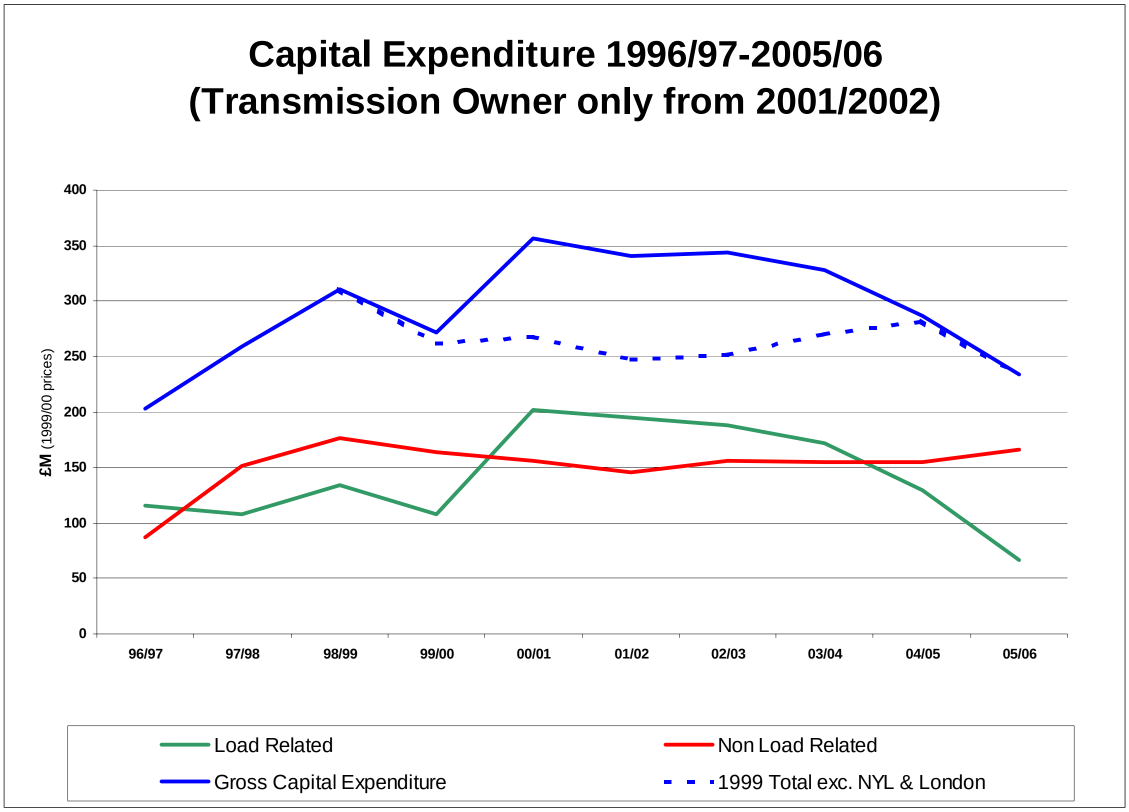
31. The reliability of our network is determined by the age and condition of our transmission assets, which are maintained to provide quality and security of supply to our customers. The age profile of our asset base is summarised in the chart below. The concentration of assets around the age of 30 to 35 years highlights the need for a carefully managed asset replacement programme, enabling the phased replacement of the ageing asset population. This is essential to maintain high availability of the system while providing access for both new construction, asset replacement and maintenance.



32. We continue to review the anticipated life of all our plant taking into account improved understanding, from our R&D programmes, of equipment failures and their associated

impact on asset lives. This informs our condition based replacement policy through forensic examination of failures and retired equipment, coupled with fault and defect information gathered through daily operations. Individual asset replacement candidates are selected on the basis of asset life information subject to specific condition assessment.

33. The current review period has seen increased emphasis upon environmental and public acceptance issues surrounding our operations (i.e. our licence to operate in society) driven by good practice, legislation and increased public awareness. It is expected that this trend will continue. Capital expenditure for the periods 1996/97-2000/01 and 2001/02-2005/06 is summarised in the attached table and the chart below. The forecast £1,532m for the TO for the latter period incorporates a capital efficiency factor which ranges from 7 per cent to 15 per cent across the period and results from improvements through the design of the system and the procurement of assets which we install on the system.



34. The increase in total expenditure between the two five year periods is largely attributable to the important London Infrastructure scheme, which includes the cost of a long cable installed in a purpose built tunnel and to delays to construction of the North Yorkshire Line. Excluding these two large schemes, the capital projections show an underlying average £110m per annum for load related and £160m per annum for non-load related as illustrated in the above chart.

Transmission Base Case Capital Expenditure

All prices in £m (1999/00)	Actual Expenditure			Forecast Expenditure						
	96/97	**97/98**	**98/99**	**99/00**	**00/01**	**01/02**	**02/03**	**03/04**	**04/05**	**05/06**
Load Related	116	108	134	108	202	195	188	172	130	67
Non Load Related	87	151	177	164	156	160	169	160	158	169
Gross Capital Expenditure	203	259	311	272	357	355	357	333	289	237
Capital Contributions	-6	-20	-10	-4	-5	0	0	-3	-7	-1
Total Capital Expenditure	**197**	**239**	**301**	**268**	**353**	**355**	**357**	**330**	**282**	**236**

Notes:
As at: 10/03/2000
All numbers are **net** of capital efficiencies.
Includes expenditure attributable to corporate restructuring.

Transmission Owner Capital Expenditure

All prices in £m (1999/00)	*Forecast Expenditure*				
	01/02	**02/03**	**03/04**	**04/05**	**05/06**
Load Related	195	188	172	130	67
Non Load Related	145	156	155	155	166
Gross Capital Expenditure	340	344	328	286	234
Capital Contributions	0	0	-3	-7	-1
Total Capital Expenditure	**340**	**344**	**325**	**279**	**233**

Notes:
As at: 10/03/2000
All numbers are **net** of capital efficiencies.
Includes expenditure attributable to corporate restructuring.

Transmission Base Case HCA Operating Costs
99/00 Prices

Base Case Table 1.1

EXCLUDING NETA RELATED COSTS

Description	Actual 1996/97 £m	Actual 1997/98 £m	Actual 1998/99 £m	Forecast 1999/00 £m	Forecast 2000/01 £m	Forecast 2001/02 £m	Forecast 2002/03 £m	Forecast 2003/04 £m	Forecast 2004/05 £m	Forecast 2005/06 £m
Payroll costs	113.1	80.4	77.0	73.7	*84.5	85.6	82.5	83.5	82.7	82.1
Insurance	21.4	7.5	7.0	6.5	5.7	5.6	5.5	5.4	5.3	5.1
Material and subcontractor costs	44.0	48.3	37.8	33.2	30.5	29.4	30.1	29.1	29.7	27.3
Other non-payroll costs	98.2	101.4	109.1	110.8	*97.3	96.5	94.4	90.5	88.9	88.6
Controllable Operating Costs	**276.7**	**237.5**	**230.9**	**224.3**	**218.0**	**217.1**	**212.5**	**208.5**	**206.6**	**203.2**
Depreciation	113.7	111.5	113.3	134.3	147.0	153.6	154.6	159.3	161.9	164.4
Rates	97.9	96.4	96.4	97.8	96.2	95.8	93.2	88.5	88.3	90.3
Excluded Services and Other Non-Controllable Costs	6.6	11.1	-7.3	17.1	14.7	11.2	7.6	6.5	4.6	5.5
Transmission Base Case HCA Operating Costs	**494.9**	**456.6**	**433.3**	**473.5**	**475.9**	**477.7**	**467.9**	**462.8**	**461.3**	**463.4**

NOTES. 1. This table includes System Operator costs, on a without NETA basis.

2. *The apparent increase in payroll costs is fully offset by a reduction in 'Other non-payroll costs'. This change in accounting presentation arises following a reorganisation within NGG.

3. This excludes the cost of externally procured services in respect of Transmission Services.

Transmission Owner HCA Operating Costs
99/00 Prices

TO Table 1.1

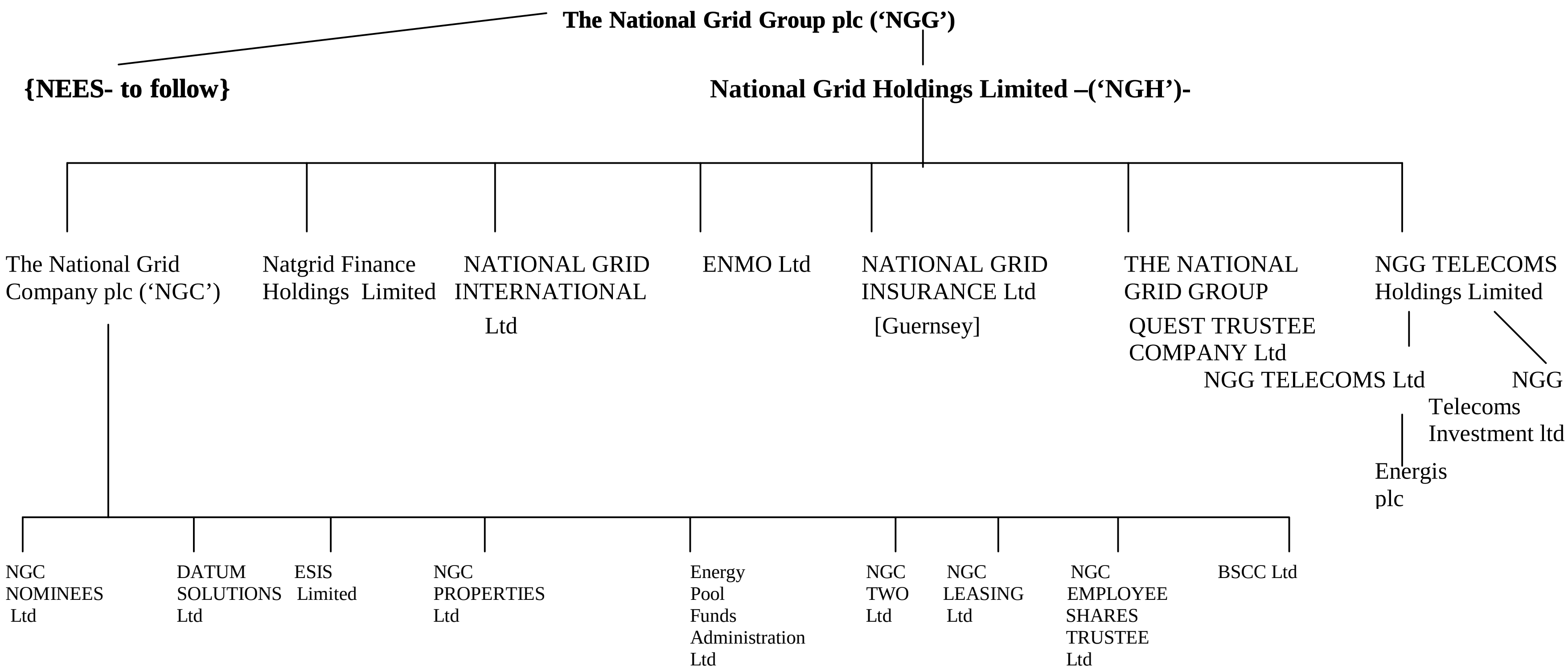
EXCLUDING NETA RELATED COSTS

Description						**2001/02 £m**	**2002/03 £m**	**2003/04 £m**	**2004/05 £m**	**2005/06 £m**
Payroll costs						67.6	64.2	64.6	64.3	63.4
Insurance						4.6	4.5	4.4	4.4	4.3
Material and subcontractor costs						27.9	28.6	27.6	29.0	26.5
Other non-payroll costs						81.0	79.8	76.5	73.9	73.5
Controllable Operating Costs						**181.2**	**177.1**	**173.1**	**171.6**	**167.7**
Depreciation						143.5	144.8	149.5	153.3	155.6
Rates						94.8	92.2	87.6	87.4	89.4
Excluded Services and Other Non-Controllable Costs						11.2	7.6	6.5	4.6	5.5
Transmission Owner HCA Operating Costs						**430.7**	**421.7**	**416.7**	**416.9**	**418.1**

Appendix 4 Structure of National Grid Group

January 2 2000

THE NGG GROUP OF COMPANIES



Appendix 5 Recent estimates of cost of capital

Cost of capital calculations

	PES draft proposals (low)	PES draft proposals (high)	PES final proposals	Ofwat 12/99	ORR 12/98	ORR 12/99	MMC 12/98 (real)	MMC 12/98 (nominal)
Cost of debt								
Risk free rate	2.25	2.75	2.5	2.5-3.0	2.25-3.0	2.25-3.0	3.5-3.8	6.5-6.8
Debt risk premium	1.4	1.4	1.4	1.5-2.0	1.0-1.5	1.2-1.5	0.7-1.0	0.7-1.0
Adjustment for long term debt	0.45	0.3	0.4					
Cost of debt	4.1	4.45	4.3	2.8-3.5	3.25-4.5	3.5-4.5	4.2-4.8	7.2-7.8
Cost of equity								
Risk free rate	2.25	2.75	2.5	2.5-3.0	2.25-3.0	2.25-3.0	3.5-3.8	6.5-6.8
Equity risk premium	3.25	3.75	3.5	3.0-4.0	3.0-4.0	3.25-3.75	3.5-5	3.5-5.0
Asset beta	0.5	0.5	0.5					
Equity beta	1.0	1.0	1.00	0.9-1.0	0.75-0.85	1.1-1.3	1.27	1.27
Post-tax cost of equity	5.5	6.5	6				7.95-10.15	10.94-13.15
Taxation adjustment	1.429	1.429	1.429	1.429	1.429	1.429	1.429	1.429
Pre-tax cost of equity	7.9	9.3	8.6			5.8-7.9	11.36-14.5	10.94-13.15
WACC								
Gearing	0.5	0.5	0.5	0.45-0.55	0.4-0.5	0.5	0.091	0.091
Pre-tax WACC	6.0	6.9	6.5	4.25-5.25	5.0-6.0	5.9-7.9	10.71-13.62	14.87-17.79

NB Ofwat's WACC is post-tax rather than pre-tax, MMC's calculations in the Cellnet and Vodafone case in nominal rather than real terms. Ofgem has adjusted these using an inflation assumption of 3.0%