Transmission investment and renewable generation

Consultation document

October 2003

Summary

In the Government's Energy White Paper, one of the key goals for energy policy is to tackle the threat of climate change by reducing greenhouse gas emissions. As part of this policy, the Government is committed to stimulating growth in renewable energy sources. The Government aims for renewables to provide 10% of UK electricity supplies by 2010 with the aspiration that this rises to 20% by 2020. The Government has put in place a range of policy measures to support this aim. The Government estimates that by 2010 these measures will provide the renewables industry with support worth £1bn a year financed by energy customers and tax payers.

Many of the sites currently being considered for developing renewable generation (particularly wind), and in light of problems with planning permission, are geographically remote and often some distance from the existing electricity transmission system and the majority of customers. The expected growth in renewable generation may, therefore, require significant additional investment to extend the existing network and increase capacity. It is important that any investment is efficient as customers ultimately pay these costs.

In Great Britain, there are three electricity transmission network operators ("TOs"): The National Grid Company ("NGC") in England and Wales and Scottish Hydro Electric Transmission Limited ("SHETL") and SP Transmission Limited ("SPTL") in Scotland. Ofgem regulates these companies' transmission revenues and charges because transmission is a natural monopoly. Every five years Ofgem sets a price control that fixes their allowed revenue based on forecasts of efficient costs, their investment requirements and an allowed rate of return on their assets. Ofgem also regulates the structure of their charges. The structure of charges determines how the companies recover their allowed revenue from different customers.

The price control provides the companies with strong efficiency incentives. The companies can earn additional profits by delivering the outputs agreed at lower levels of costs than the level assumed by Ofgem when setting the control. This benefits customers as these efficiency savings are passed through to customers at subsequent price controls when revenues are reset. The price control also protects customers from price increases. If costs are higher than forecast in setting the control, the companies cannot simply raise charges.

At the time that the last price controls were set, neither the companies nor Ofgem anticipated significant new investment to accommodate renewable generation. If the companies undertake significant infrastructure investment to accommodate new renewable capacity during the present price control period there would, at present, be no adequate mechanism by which they could recover the funding of this investment before the start of the next price control period. The companies are, however, obliged to offer terms to[1] all generators including renewables, wishing to connect to and use their systems.

NGC's current price control expires in March 2006 whilst SHETL's and SPTL's current price controls end in March 2005. The estimated infrastructure expenditure to accommodate renewables for the three TOs in 2004/05 is £21m compared to the estimated capital expenditure over the same period of £277m. In 2005/06 NGC's estimated capital expenditure is £222m compared with the estimated additional expenditure of £60m to accommodate renewables. Ofgem has proposed that the Scottish price controls should be rolled over for another year so that they end at the same time as NGC's price control. This is in recognition of the intention to implement GB wide trading arrangements from April 2005 and the consequent interactions between the positions of the Scottish TOs and NGC, as prospective GB System Operator. If the price controls for the Scottish TOs are rolled forward a year, the total estimated capital expenditure for all three TOs in 2005/06 is likely to be about £265m compared with an estimated £164m of additional expenditure in infrastructure investment for renewables, resulting in a significant funding gap.

Additional transmission investment and renewable generation could have an impact on the level and distribution of transmission charges for existing and new transmission users. This is because NGC's transmission charges are set annually to reflect the costs of providing the transmission system at different locations. These costs vary depending on the balance of generation and demand at different points on the system. With the planned implementation of British Electricity Trading and Transmission Arrangements (BETTA) from 1 April 2005, these arrangements are being consulted upon to be extended to cover all GB transmission charges.

Ofgem therefore believes that it is appropriate to consult on whether the existing price controls should be adjusted to provide funding for any additional investment required to accommodate new renewable generation sources. If no adjustment is made, delays may

[1] Conditions C7D and D8B of the Electricity Transmission Licence: Standard Conditions

occur in new renewable generation gaining access to the transmission system. Such delays and associated uncertainty would raise costs, harm customers and risk frustrating Government policy.

Price controls are not intended to shield regulated companies from the normal range of business uncertainties. Ofgem therefore does not normally consider making significant adjustments to price controls once they have been set. If companies believe that Ofgem will re-open price controls once they have been set then this could significantly reduce the incentives to outperform during the existing control and future controls. If, for example, Ofgem agreed to re-set a price control where capital expenditure was greater than forecast due to cost overruns then companies would have less incentive to manage costs effectively. Customers would, over time, face higher bills as a result. However, when circumstances change in a way that was unforeseen when the price control was set, Ofgem will carefully consider whether there is an argument for reflecting such changes by reopening the price control or via an Income Adjusting Event. Such changes could in principle be positive or negative. If Ofgem decides that it is necessary to make adjustments to the current price controls we will seek to ensure that any adjustment mechanism maintains strong incentives on the companies to invest efficiently.

Ofgem has identified three possible approaches to the issues raised by the prospect of significant additional transmission investment to meet the demands of renewable generators and has highlighted some of the potential advantages and disadvantages of each:

- rely on existing mechanisms i.e. do nothing until the next price control review;
- re-open all three price controls; or
- add an adjustment mechanism to the existing controls to deal with renewable expenditure.

Ofgem would welcome views on the merits of the three different approaches outlined in this document. If respondents believe that it is appropriate to adjust the existing price controls, Ofgem would welcome views on how we could continue to ensure that the companies have strong incentives to invest efficiently. Given the potential impact of additional investment on charges for existing users, Ofgem would encourage both generators and customers of the transmission network to respond to this consultation.

Ofgem will publish a more detailed consultation in November 2003 having carefully considered the responses to this consultation. The November 2003 consultation will include a regulatory impact assessment. If appropriate, this will be followed in early 2004 by a statutory licence modification consultation under Section 11(2) of the Electricity Act 1989. Assuming the TOs agree to the proposed licence modifications, they will take effect from April 2004.

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1. Introduction

The issue

1.1. One of the key planks of Government energy policy is to deal with the threat of climate change by taking action to reduce greenhouse gas emissions. As part of this policy, the Government is committed to stimulating the growth in renewable energy. As set out in the recent Energy White Paper, the aim is for renewables to provide 10% of UK electricity in 2010 with a further aspiration to double this share by 2020.

1.2. Achievement of these targets is likely to involve changes in the geographical distribution of generating capacity as the best sites for many renewable technologies are likely to be located in electrically remote locations because of resource availability. For example, there seems set to be a substantial increase in windfarm capacity in Scotland, particularly given the devolved administration's more challenging targets on renewable delivery.[2] If the targeted levels of renewable generation are to be delivered to the market, appropriate infrastructure will need to be put in place and this is likely to entail significant extensions requiring significant additional investment in the transmission network.

Background

1.3. There are three electricity transmission network operators in Great Britain each holding a transmission licence. The transmission network operators are responsible for investing in and maintaining the transmission assets and making these available to users of the transmission system.

1.4. These transmission asset owner (TO) costs are regulated via a RPI-X type price control. Under this approach, Ofgem sets the allowed revenue for each of the transmission licensees every five years. The allowed revenue is based on

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[2] The Scottish Executive has committed to a target of 17-18% of electricity to be provided by renewables in 2010 compared to the current level of around 11% (the exact value depends on rainfall levels).

forecasts of efficient capital and operating expenditure and financing costs over the period.

1.5. The price control provides strong incentives on the transmission licensees to improve efficiency. The transmission licensees can earn additional profits by delivering the outputs agreed at lower levels of costs than the level assumed by Ofgem when setting the control. This benefits customers as these efficiency savings are passed through to customers at subsequent price controls when revenues are reset. The price control also protects customers from price increases. If costs are higher than forecast in setting the control, the transmission licensee is unable to raise charges.

1.6. In June 2003, the Department of Trade and Industry ("DTI") published the final report of the Transmission Issues Working Group ("TIWG").[3] The TIWG consisted of representatives from the DTI, the devolved administrations, Ofgem, the three GB TOs - NGC, SPTL and SHETL - and a number of consultants. The TIWG's remit was to look at the implications for the GB electricity transmission network of the Government's renewables targets, particularly in relation to large scale renewable development. The group concluded that substantial levels of investment, of the order of £81m would need to be made before the next price controls to accommodate large scale renewable investment in Scotland or offshore in England and Wales.

1.7. Since the TIWG study, the TOs[4] have continued to estimate the levels of investment in the transmission network necessary to provide access to different levels of renewable generation based on a number of scenarios considered by the TIWG. Since the TIWG report was published, the Scottish TOs have received a number of new requests for access from renewable generators. The best information available at this time therefore confirms the general thrust of the conclusions of the TIWG study. It has also highlighted the fact that at least part of the required investment will need to be undertaken during the present price control periods of the TOs, which expire from March 2005.

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[3] 'The Transmissions Issues Working Group, Final Report', DTI, June 2003 available on the DTI Energy website.

[4] The term "TO" is used throughout this document in the sense that it will apply once BETTA is implemented, namely as the owner but not the operator of a transmission network. At present, SPTL and SHETL combine the roles of system operator and TO and their price controls cover both activities. NGC's price control, on the other hand, has already been split into system operator and TO elements.

Rationale for this document

1.8. The levels of renewable generation that now seem likely were not anticipated by the TOs when presenting their investment forecasts to Ofgem when the price controls were set. Ofgem did not, therefore, make any allowance to finance this investment when setting the current price controls. The current price controls do not have in place adequate mechanisms for adjusting the allowed revenues of the TOs in such a situation. Ofgem is, therefore, consulting on how to deal with this issue.

1.9. If the Scottish TOs were to undertake substantial infrastructure investment to accommodate new renewable capacity during the present price control period, there would, at present, be no mechanism by which they could recover these funding of this investment before the start of the next price control period. The TOs are, however, obliged under their transmission licences to offer terms to all persons applying for connection to and use of their systems. Ofgem also has a statutory duty to have regard to the need to secure that transmission licensees can finance efficiently incurred expenditure.

1.10. The companies could apply to Ofgem to recover funding costs for any additional investment over and above the levels assumed when the price control was set. However, this approach runs contrary to Ofgem's current thinking on cost recovery under network monopoly price controls. The allowed revenues for each of the transmission licensees is based on forecasts of efficient capital and operating expenditure and financing costs over five years to give the companies strong incentives to be efficient. They can earn additional returns over and above their allowed revenues by delivering the outputs agreed at a lower level of costs than the level assumed by Ofgem when setting the control. Any move to funding actual levels of capital expenditure as they are incurred risks undermining this efficiency incentive and could see inefficient levels of investment by companies who could simply pass the costs through to customers.

1.11. If the issue of recovering the costs of investing in the transmission network to accommodate renewables is not addressed, the risk is that the transmission companies may not invest as quickly as they otherwise might which could frustrate government targets for renewables.

1.12. In recognition of this position, Ofgem issued "letters of comfort" to the Scottish TOs in April 2003 indicating that reasonable relevant costs that they incur before 31 March 2005 associated with the work required in preparation for the connection and use of system of renewable generation may be considered for cost recovery. These letters did not, however, specify a cost recovery mechanism.

1.13. There is an adjustment mechanism in NGC's transmission licence which allows its allowed revenues to vary if there are unforeseen changes in generation or interconnector connections during its current price control period. Although a substantial increase in renewables capacity in Scotland is anticipated, which will tend to increase flows south, no formal request for an interconnector upgrade has been made. Moreover, it is likely that even if an interconnector upgrade is not required, NGC will have to undertake reinforcement work as a result of changes in the type and disposition of generation in Scotland.. The adjustment mechanism cannot be used by NGC in these circumstances, despite the fact that it expects to have to undertake significant investments.

1.14. Ofgem considers, therefore, that there it may be appropriate to introduce new mechanisms to enable adjustments to be made to the allowed revenues of TOs to accommodate the infrastructure investments required to support increased renewable generation. This consultation is the start of a process that Ofgem intends could lead to modifications to the licences of the three GB TOs by April 2004, in time for the start of the new charging year. It presents information on the cost estimates produced by the TOs and invites views on these estimates and ideas on how best to approach the task of allowing appropriate revenue increases to the TOs to fund infrastructure expansions for renewable generation under the current price controls.

Consultation

1.15. Ofgem's aim is to put in place arrangements that are designed to improve the existing signals and incentives on transmission companies to invest in additional entry capacity in an efficient and timely manner to ensure that the arrangements for transmission investment would facilitate significant new entry in renewables generation, consistent with Government policy whilst maintaining strong incentives on the transmission companies to invest efficiently.

1.16. Ofgem has identified three possible alternatives for dealing with the recovery of costs associated with infrastructure investment to accommodate renewable capacity. They are:

- rely on existing mechanisms ie do nothing until the next price control review,
- re-open all three price controls, or
- add an additional mechanism to the existing controls to deal with renewable expenditure.

1.17. Each of these options is discussed further in Section 4.

1.18. Ofgem would welcome views on:

- the appropriate principles to apply in considering how to tackle the issue of the recovery of costs associated with infrastructure investment to accommodate renewable capacity;
- the TOs' investment forecasts and the assumptions underpinning them;
- potential approaches to adjusting the TOs' allowed revenues during the current price controls to allow funding of this investment.

Related issues

Duration of the TO price controls

1.19. The price controls for the Scottish TOs are currently scheduled to run until March 2005. However, NGC's TO price control runs for a further year (to March 2006). Transco's TO price control for the gas transportation system ends in March 2007. In recognition of the intention to implement GB wide trading arrangements from April 2005 and the consequent interactions between the positions of the Scottish TOs and NGC, as prospective GB System Operator (SO), Ofgem proposed in June 2003[5] that the Scottish price controls should be rolled over for another year so that the control period ends in March 2006, at the

[5] 'Developing network monopoly price controls, Initial conclusions', June 2003, Ofgem 54/03

same time as NGC's price controls end. Ofgem further consulted on whether all five price controls (the two Scottish TO price controls, NGC's two price controls and Transco's price control) should be set simultaneously by rolling over the price controls for the Scottish companies and NGC until March 2007.

1.20. If either of these extension proposals is adopted, it will serve to heighten the need to introduce a mechanism to enable the allowed revenues of the Scottish TOs and NGC to be adjusted to take account of requests for access from renewable generation.

Developing network monopoly price controls

Distribution price controls

1.21. Ofgem has been working with industry and other interested parties to review the way in which network monopoly price controls work and to identify any potential improvements both in general terms and specifically for the forthcoming price control review of the electricity distribution companies and, in June 2003, Ofgem published its initial conclusions[5]. A particular consideration for the distribution price controls is the expected but uncertain increase in distributed generation.

1.22. As part of the review process, Ofgem commissioned consultants to consider how such uncertainty on costs could be incorporated into the regulatory mechanism. This culminated in a report[6], published in March 2003. Ofgem considers that the report is likely also to be relevant when considering the next price controls for the GB TOs but it does not directly address the issues covered by this consultation.

Developments in the gas market

1.23. Developments in the gas market could provide some guidance on how to deal with the issue of recovering efficiently incurred expenditure to accommodate renewables.

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[6] 'Developing network monopoly price controls: Workstream A, Regulatory mechanisms for dealing with uncertainty, A final report prepared for Ofgem', Frontier Economics, March 2003.

1.24. Ofgem has put in place price control and system operator (SO) incentive arrangements for Transco for the period 2002 – 2007 with effect from 1 April 2002[7]. Under these arrangements, Transco's price control for its NTS is split between its transmission asset owner (TO) and its SO functions. In respect of NTS entry capacity, Transco is funded under its TO function to provide specified TO baseline output measures of entry capacity at each existing entry terminal to its NTS. Under its Gas Transporter's (GT) licence, Transco must offer for sale SO baseline output measures, which it does through a series of long-term and shorter-term entry capacity auctions. The SO baseline output measures are set at 90 per cent of the TO baseline output measures at each terminal.

1.25. The first auction for long-term entry capacity rights to Transco's NTS was held in January 2003, under arrangements specified in Transco's network code.

1.26. Transco's GT licence includes an entry capacity investment incentive scheme which, for a defined period, potentially allows it to earn a relatively high rate of return between 5.25% and 12.25% on obligated incremental entry capacity offered for sale above its SO baseline output measures. This incentive is designed to encourage Transco to respond to changes in the levels and locations of demand for entry capacity to its NTS.

1.27. Transco is only allowed to earn a relatively high rate of return on investment in incremental entry capacity above its SO baseline output measures if it has received strong signals from the entry capacity rights auctions that this incremental capacity is needed. Transco recovers the costs of the incremental capacity and its allowed rate of return through sales of the incremental capacity. To the extent that the amount of revenue Transco recovers falls outside either its cap or collar, the difference is channelled back or recovered from shippers through Transco's SO commodity charge.

Offshore windfarms

1.28. In July 2003, the DTI launched the second round of tenders for offshore wind farms in the Thames estuary, Greater Wash and the North West. The DTI considers that up to 6 GW of offshore windfarms could be built as a result of this

[7] 'Review of Transco's price control from 2002 – Final proposals', Ofgem, September 2001.

tender. Whilst these windfarms are unlikely to be built until after the end of the current price controls, they will require further expansion of the transmission infrastructure.

1.29. In addition, the DTI has decided that the owners of cables linking offshore windfarms to the main transmission and distribution networks may require a transmission licence, although the details of the conditions to be imposed in these licences have not yet been decided. Nonetheless, the issue of how the costs of offshore cables are recovered is another element in the wide ranging interactions between the Government's renewable targets and policy and Ofgem's regulation of network monopoly businesses.

Transmission charging under BETTA

1.30. BETTA is a joint Ofgem/DTI initiative to reform wholesale electricity trading and transmission arrangements to promote the creation of a single competitive wholesale market across GB and to introduce a single set of arrangements for connection to and use of any transmission system in GB, using the arrangements in England and Wales as a basis for consultation.

1.31. BETTA would create the role of a single GB system operator. The GB system operator would be responsible for a number of GB-wide transmission-related activities associated with the operation of the transmission system in timescales close to real time. The GB system operator would also be responsible for contracting with users wishing to connect to and use the GB transmission system, on the basis of GB-wide charging methodologies. The Government has indicated that it is minded to appoint NGC as GB system operator when the necessary legislative powers are made available.

1.32. On 17th June 2003 the Government reaffirmed its intention to bring forward legislation to implement BETTA by April 2005 at the latest. Ofgem/DTI has subsequently published a consultation on transmission charging arrangements under BETTA.[8] This paper sets out Ofgem/DTI's proposals on the licence obligations that would prescribe how the GB system operator develops its charging methodologies. The key proposal is to base these licence obligations

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[8] 'Transmission charging and the GB wholesale electricity market', Ofgem, August 2003

on those that are currently in place for NGC. The consultation paper also includes a separate DTI consultation on transmission charging and the Government's targets for renewables. Ofgem/DTI intend to publish a conclusions document on these issues in November 2003.

1.33. NGC, in its capacity of designate GB system operator, is expected to initiate its process of consultation on GB charging methodologies to apply from commencement of BETTA in December 2003. The basis of consultation is anticipated to be the methodologies approved for England and Wales at that time, applied to GB.

Outline of this document

1.34. Chapter 2 discusses the regulatory framework for funding the transmission network businesses. Chapter 3 discusses the transmission companies' estimates of the required investment to accommodate renewable capacity. Finally, Chapter 4 looks at possible ways forward and invites views on the issues raised in this document.

Way forward and timetable

1.35. Having carefully considered respondents' views, Ofgem will be publishing a more detailed consultation in November 2003, which will include a regulatory impact assessment. The timing of subsequent developments will depend on the approach to be adopted. If a simple approach is appropriate, Ofgem would seek to publish the statutory licence modification consultation under Section 11(2) of the Electricity Act 1989, in early 2004. Assuming that the TOs agree to the proposed licence modifications, they will take effect from April 2004. However, should a more sophisticated approach be appropriate, development of the relevant licence modifications will be needed, which may not be complete by April 2004.

Views invited

1.36. Views are invited in response to the issues raised in this document. Responses should be submitted in writing by 17 November 2003.

1.37. Responses should be addressed to:

Tracey Hunt

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1.38. Electronic responses may be sent to: tracey.hunt@ofgem.gov.uk

1.39. Respondents are free to mark their replies as confidential although Ofgem would prefer, as far as possible, to be able to place responses to this paper in the Ofgem library. Unless clearly marked 'confidential', responses will be published by placing them in the Ofgem library and on the Ofgem website.

1.40. If you wish to discuss any aspect of this document, please contact any of the following people who will be pleased to help:

- Sonia Brown – telephone number: 020 7901 7412, fax number: 020 7901 7452, email: sonia.brown@ofgem.gov.uk; or

- Richard Ford – telephone number: 020 7901 7411, fax number: 020 7901 7452, email: richard.ford@ofgem.gov.uk; or

- Una Oligbo – telephone number: 020 7901 7051, fax number: 020 7901 7452, email: una.oligbo@ofgem.gov.uk.

2. Background

The regulatory framework for the network business

2.1. Ofgem has a duty to protect the interests of customers, through the promotion of competition, which includes the effective regulation of network monopolies. Ofgem's powers are provided under the Electricity Act 1989 as amended by the Utilities Act 2000. Ofgem's duties include promoting efficiency and economy on the part of persons authorised to transmit, distribute or supply energy and in carrying out this function Ofgem is obliged to have regard to the effect on the environment.

2.2. The Electricity Act and the Utilities Act also provide the framework for the licensing to enable the generation, transmission, supply and distribution of electricity. Under section 9(2) of the Electricity Act 1989, holders of transmission licences are obliged 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.

2.3. NGC is the sole possessor of a transmission licence in England and Wales whilst SPTL and SHETL hold transmission licences in Scotland. The transmission licences set restrictions on the revenues that the transmission businesses are allowed to earn.

Price controls and allowed revenues

2.4. All three transmission licensees in Great Britain are subject to price controls set by Ofgem that limit their revenues from their transmission businesses. This is because the transmission businesses are natural monopolies.

2.5. Under the price control, Ofgem sets the TOs' allowed revenue (usually for a period of five years) for the transmission business based on the regulatory value (the TOs' asset base at the start of the price control period), forecasts of efficient levels of capital and operating expenditure necessary to maintain the existing network and the investment necessary to develop the network. Ofgem also sets the TOs' allowed cost of capital. The cost of capital determines the allowed revenue necessary to finance the existing asset base and any capital expenditure over the price control period.

2.6. The TO submits forward looking forecasts of its capital and operating expenditure over the price control period based on expected developments on the network and forecast generation connections, disconnections and demand growth. Ofgem reviews these plans and, following public consultation and discussion with the companies, publishes final proposals. These final proposals set out Ofgem's views on the revenues required by the company to finance efficient levels of capital and operating expenditure for the next five years.

2.7. Ofgem requires the consent of the company when setting its price control. Ofgem can refer the matter to the Competition Commission if the company does not consent with Ofgem's proposals. Once Ofgem's final proposals have been accepted (or after the Competition Commission appeal), the company's licence is modified and restrictions on the allowed revenue are placed in the company's licence.

Incentives under the price control

2.8. The price control provides strong incentives on the TO to improve efficiency. The TO can earn additional profits by delivering the outputs agreed at lower levels of costs than the level assumed by Ofgem when setting the control. This benefits customers as these efficiency savings are passed through to customers at subsequent price controls when revenues are reset. The price control also protects customers from price increases. If costs are higher than forecast in setting the control, the TO is unable to raise charges

2.9. If the TOs' investment exceeds the level of investment assumed when setting the price control, then the TOs allowed revenues will not fund the investment during the period of the control. The TO can, however, ask Ofgem to include the additional investment when setting the regulatory value at the start of the next price control. Consistent with Ofgem's statutory duties, Ofgem will include any capital expenditure that has been efficiently incurred when setting the regulatory value at subsequent price controls.

The existing TO price controls

The Scottish Company controls

2.10. The current price controls for the two Scottish TOs apply from1 April 2000 to 31 March 2005. The price control calculations are given in Appendix 1. The price regulated activities of the Scottish transmission businesses are:

- a 'core' transmission activity, which is the primary owner of transmission assets other than the interconnector assets;
- a system operator activity concerned with real time despatch of generation power stations and operation of the transmission network and interconnector;
- a pre-vesting interconnector activity, comprising the ownership and operation of capacity in existence at vesting.

2.11. There is no automatic adjustment mechanism to the Scottish TOs allowed revenues in the event of unforeseen changes to the costs of the TO regulated activities. This has the advantage of providing strong incentives on the TOs to improve efficiency. However, the TOs can ask Ofgem to include the additional investment when setting the regulatory value at the start of the next price control.

NGC's price control

2.12. NGC's current price control applies from 1 April 2001 to 31 March 2006. The price control calculations are given in Appendix 1. NGC's current price control contains a mechanism that allows its price controlled revenues to vary (based on an investment cost of £23/kW of additional capacity) if the capacity of generation or interconnectors connecting to its transmission system exceeds or falls short of that assumed when the price control was set.

Cost recovery

2.13. The three TOs currently recover their allowed revenues through connection and use of system charges levied on generators, suppliers and customers.

2.14. The TOs are required, under their transmission licence, to prepare statements describing the methodology that they will adopt in calculating use of system[9] and connection charges[10] respectively. These methodology statements have to be approved by Ofgem and the TOs' charges have to conform to its methodology statements.

2.15. The TOs are also obliged to offer terms to any authorised electricity operator requesting use of its system and to any market participant seeking access to its transmission system[11] . There is a role for the Authority to resolve disputes if there is a failure to agree terms in respect of a new agreement or changes to an existing agreement[12]. The TOs are required to ensure that their use of system and connection charges are non-discriminatory, and, in respect of use of system charges, do not restrict, prevent or distort competition in generation, supply, transmission or distribution[13].

2.16. As far as connection charges are concerned, the TOs are required to ensure that charges for connections made after 30 March 1990 ("post-Vesting") are set at a level that enables them to recover an appropriate proportion of the costs incurred and a reasonable rate of return on the capital represented by those costs, and to ensure that charges for connections made before 30 March 1990 ("pre-Vesting") are set, as far as practicable, on the same basis.

2.17. NGC is also obliged to keep its charging methodologies for connection and use of system under constant review, and where appropriate to bring forward proposals for change where such change will in its view result in better meeting the relevant objectives for the respective methodologies. The relevant objectives for both the use of system and connection charging methodologies are[14] that:

- compliance with the relevant methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

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9 Standard licence conditions (SLC) C7 and D8.
10 SLC C7B and D8.
11 SLC C7D and D8B
12 SLC C7E and D8C.
13 SLC C7C and D8A.
14 Standard Licence Condition C7A.5 and C7B.11

- compliance with the relevant methodology results in charges which reflect, as far as is reasonable practicable, the costs incurred by NGC in its transmission business; and

- so far as is consistent with the objectives listed above, the relevant methodology, as far as is reasonably practicable, properly takes account of the developments in NGC's transmission business.

In addition, the connection charging methodology has the relevant objective of:

- in so far as consistent with the above listed objectives, facilitating competition in the carrying out of works for connection to NGC's transmission system.

2.18. If NGC considers that the relevant objectives would be better met by changing the relevant charging methodology, it is required to consult with Connection and Use of System Code (CUSC) users on its proposed changes.[15] Having consulted, it has to provide Ofgem with details of its proposed changes (including any amendments made as a result of the consultation), respondents' views, how the proposed changes better facilitate the relevant objectives and a timetable for implementing the proposed changes.[16]

2.19. If Ofgem does not veto NGC's proposals within 28 days[17] of receiving NGC's report, then NGC has to implement the changes that it has proposed.

2.20. Unless Ofgem consents to a shorter period, NGC is required to give 150 days notice of any proposals to change its use of system charges, together with a reasonable assessment of the effect of its proposals on the charges[18].

2.21. The Scottish TOs may also periodically revise the charging statements and are obliged to make any necessary revisions to the charging statements at least once every year in order that the information set out in the statements shall continue to be accurate in all material respects. The Scottish TOs are required to send a

[15] SLC C7A.3(a) and C7B.9(a)
[16] Whilst this is the typical procedure for changing a methodology, Ofgem can, if it deems it necessary, consent to the waiving of some, or all, of these requirements and direct that NGC shall comply with such other requirements that the Authority may specify.
[17] SLC C7A.4
[18] SLC C7.5(a)

notice to the Authority setting out the licensee's proposals to amend the use of system charging statement, not less than 5 months prior to the date on which it proposes to amend its use of system charges.

2.22. The charging mechanisms for all three TOs are discussed in turn below.

NGC's charges

2.23. NGC recovers its allowed revenues set at the time of its price control through use of system charges and charges for pre-vesting connections.

Use of system charges

2.24. NGC levies two separate types of charges for use of system. It levies Transmission Network Use of System (TNUoS) charges, which cover the costs of providing and maintaining transmission assets, and Balancing Services Use of System ("BSUoS") charges, which cover the costs of maintaining a balanced system in real time. This consultation is concerned only with the recovery of infrastructure investment costs, and BSUoS charges are not considered further in this document.

2.25. NGC's TNUoS charges vary by location and depend on whether a party is a net exporter (i.e. putting energy on to the system) or a net importer (i.e. taking energy off the system) at times of peak demand. Parties pay generation TNUoS charges on the basis of their highest Transmission Entry Capacity (TEC), while the demand TNUoS charge is levied on the basis of demand take over peak periods.

2.26. All generators, including those connected to distribution systems, are potentially liable for TNUoS charges. Following a change to its charging methodology, from 1 April 2003 all distributed generators capable of exporting no more than 100MW are exempt from generation TNUoS charges. Prior to this embedded generation of less than 100MW would have been liable for generation TNUoS charges if it participated in the Pool or, under NETA, the Balancing Mechanism.

2.27. NGC's TNUoS charges are levied on a zonal basis and can be considered to have two elements. First, there is a charge to reflect the long-run incremental cost of a change in generation or demand at a particular node on the network.

Second, there is a charge to reflect the overall cost of providing a secure network. This second element is used to ensure that NGC is able to recover its total allowed revenue, as set in its price control. The tariff for each zone is published in NGC's Statement of Use of System Charges.

Connection charges

2.28. Connection charges enable NGC to recover, with a reasonable rate of return, the costs involved in providing the assets which afford connection of a user to the transmission system. Pre-Vesting connection charges, unlike post-Vesting connection charges, are regulated through the price control.

2.29. NGC's connection charging methodology is based on a 'shallow connection' approach where transmission system reinforcement costs that result from new connections are recovered through use of system charges.

2.30. NGC levies site-specific connection charges for assets installed solely for the use of a single user or a specified group of users. For example, a user connecting directly to NGC's transmission system will pay charges for all NGC owned substation assets at its point of connection. In the small number of instances where a user is connected to NGC's system at a voltage less than 275kV, the connection charge reflects the cost of all NGC assets up to and including assets at the first transmission voltage (i.e. 275 or 400kV) substation.

2.31. In NGC's transmission area the scope of connection charges does not generally include spur circuits. The exception to this rule is where the spur is only required to connect generation or in the case of multiple spurs, which serve to connect both generation and demand, and where not all these circuits are required by security standards to serve Distribution Network Operator ("DNO") demand. In these cases, the more costly circuits are classed as connection for charging purposes. This type of connection is referred to as a Generation Only Spur. As well as paying for the connection at the local substation a user (or users) located on a Generation Only Spur will pay connection charges for the spur circuitry and an appropriate share of the switchgear at the system end of the spur.

2.32. NGC's connection charges pursuant to its current methodology comprise:

- a depreciation charge over the appropriate depreciation period (based on the Gross Asset Value ("GAV") of the relevant assets, net of any capital contribution paid by the customer)

- a return on the undepreciated value (Net Asset Value, or "NAV") of the relevant assets, taking account of any capital contributions paid by the customer, and

- charges relating to the ongoing operation and maintenance of the assets (based on annual average costs and expressed as a percentage of the GAV).

2.33. The GAV represents the initial total costs of an asset and comprises construction, engineering and financing costs. The GAV is rolled forward on an annual basis by either the Modern Equivalent Asset ("MEA") value method, whereby the GAV is indexed with reference to the prevailing price level for an asset which performs the same function as the original asset, or using the Retail Price Index ("RPI").

2.34. The standard terms for a connection differ depending on whether the connection assets were constructed pre or post-Vesting. For pre-Vesting assets the revaluation between Vesting and 1996/97 was done on an MEA basis and subsequently by the RPI. Pre-Vesting assets are depreciated on a straight-line basis over 40 years and a rate of return of 6% is used. The standard terms for post-Vesting connections involve RPI indexation. However, post-Vesting connections have more options including MEA revaluation combined with a 7.5% rate of return.

2.35. In addition to basic annual connection charges users may pay NGC for other specific costs related to their connection. These include one-off charges such as for relocating or diverting existing transmission lines, land charges necessary where NGC purchases land to facilitate a connection, application fees, consent costs and rental site costs incurred when NGC owns a site embedded within a distribution network. A full breakdown of other charges is available in NGC's Statement of Connection Charging Methodology[19].

Scottish Power Transmission Limited's charges

2.36. SPTL's use of system charges comprise system service charges levied on demand and infrastructure charges levied on both generation and demand. System service charges reflect the costs of providing a core network having stable voltage and frequency. Infrastructure charges reflect the costs of providing firm transfer capacity between transmission entry and exit points. SPTL's use of system charges also recover some of the costs associated with the Scotland-England interconnector.

2.37. Distribution-connected generators are also potentially liable for SPTL's infrastructure charge and entry connection charges on the proportion of their output that SPTL determines is using the transmission system. Generators who are contracted to sell electricity under the terms of the Scottish Renewables Obligation ('SRO generators') are currently exempt from SP Transmission's use of system charges.

2.38. Infrastructure charges for generators depend on generation capacity, and infrastructure demand and system service charges are dependent on demand at times of system peak. System peak is characterised as the three half-hour periods of peak demand separated by at least ten days in the period between November and February. Neither infrastructure charges nor the system service charge vary by location within SPTL's area.

2.39. There are agreed charging arrangements between SPTL and SHETL for contractual flows between their two transmission areas. Such trades attract infrastructure generation charges from the company in whose transmission area the generation is located, and infrastructure demand and system service charges from the company in whose transmission area the demand is located. This position contrasts with contractual flows between Scotland and England, where demand and generation charges are levied at the border for exiting and entering the respective transmission systems.

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[19] NGC's Statement of Connection Charging Methodology is available on its website at:

SHETL's charges

2.40. SHETL's use of system charging structure is broadly similar to that of SPTL. It levies infrastructure charges on generation and demand, and a system service charge on demand. The key difference is that SHETL levies an entry charge (as defined in SHETL's transmission use of system charging statement) on generators connected to its system after 1 April 2002.

2.41. The entry charge shares reinforcement costs caused by new generation amongst all new generator connections[20]. Generators connected to SHETL's transmission system before April 2002, who were consequently subject to 'deep' connection charges, are not liable to pay the entry charge. Further, the entry charge does not apply to networks designed for single 132kV operation or to the island networks as the demand on the transmission system is secured by lower voltage interconnections or the use of standby generation.

2.42. Generators connected to the distribution system are liable for transmission use of system charges if their authorised capacity exceeds the minimum demand on the bulk supply point through which they are connected to the transmission system. Generators who are contracted to sell electricity under the terms of the SRO ('SRO generators') are currently exempt from SHETL's use of system charges.

2.43. In common with SPTL, SHETL's charges are calculated on the basis of generation capacity and demand at system peak.

BETTA

2.44. Under the BETTA proposals, it is envisaged that the Scottish TOs would still be responsible for operating their respective transmission businesses but a single GB system operator that is independent of generation and supply interests would be required to carry out specified transmission related functions necessary to facilitate effective competition in generation and supply.

2.45. The proposals are also for a common GB transmission charging regime and common terms throughout GB for connection to and use of the transmission

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www.nationalgrid.com/uk/indinfo/charging/pdfs/CCM_Apr_03_(I3R1).pdf

[20] Although there is no equivalent to SHETL's Entry Charge in NGC's and SPTL's areas, they apply a shallow

system (reflecting in part the incorporation of the Scotland-England interconnector into the GB transmission system). It is proposed that the GB system operator is responsible for developing and implementing a new GB transmission charging regime, which would be based on the arrangements in England and Wales with the extension of locationally varying use of system charges throughout GB.

charging policy.

3. Required investment

TIWG investment forecasts

3.1. The Government's target that 10% of electricity supplies within the UK should be generated from renewable sources by 2010 could require up to 10GW of additional renewable generation capacity.

3.2. To provide an indication of the sums that might be involved, the TIWG report concluded on the costs of reinforcement associated with the provision of access to 2 GW, 4 GW and 6 GW of additional renewable capacity in Scotland (half in SHETL's area and half in SPTL's area). These three cases, referred to as Stages 1 to 3, were used to estimate required infrastructure investment for each of the TOs. Under the Stage 1 (2 GW) case, it was concluded that the required investment costs would be £190m for SHETL, £160m for SPTL and £170m for NGC. The report also suggested that construction of the reinforced system would take between three and five years so that, even were the TOs to consider that such a level of investment needed to be undertaken immediately, the bulk of the expenditure might be expected to occur in the next price control period i.e. beyond the timescales considered in this document.

3.3. The report also identified the costs associated with network development that would accommodate up to 6GW of wind generation in England and Wales and 2GW in Scotland by 2010 which could be as high as £1,125m.

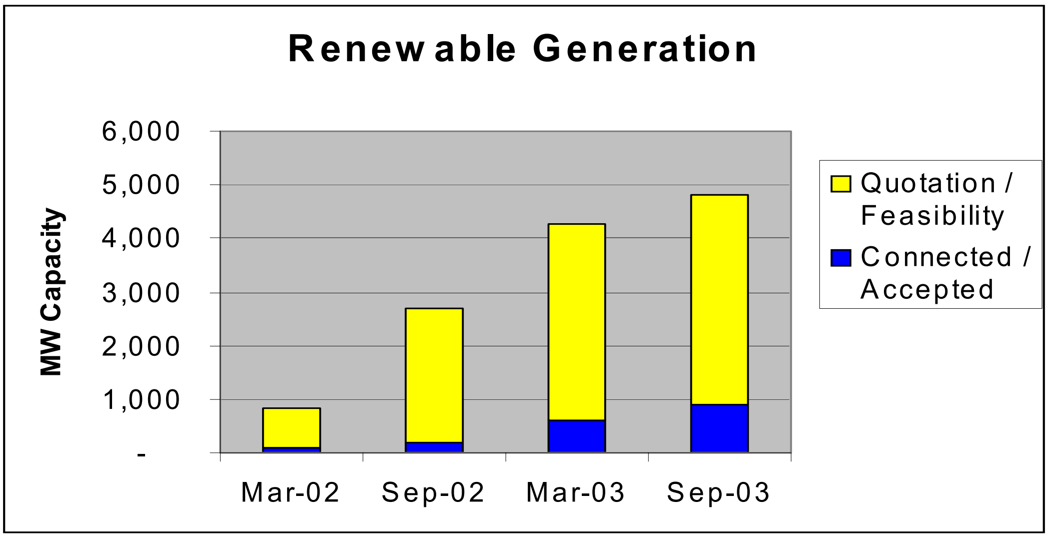
Further developments

3.4. All three transmission companies have provided further information to Ofgem on the potential costs of network reinforcement to accommodate renewable generation projects. The revised forecasts are based on higher levels of committed renewable generation since the TIWG report was published.

SHETL

3.5. There has been considerable renewables activity in the SHETL area since the analysis presented in the TIWG report was undertaken. As Figure 3.1 shows, SHETL is now dealing with some 4500MW of renewable generation access requests, of which 900 MW is either firmly accepted, under construction or already connected.

Figure 3.1: Connection requests in SHETL's area



Source: SHETL

3.6. This level of activity has led SHETL to conclude that a significant programme of investment will be necessary. The level of renewable projects that are connected, under construction or committed is already nearly equal to the total amount envisaged under the Stage 1 case.

3.7. SHETL has forecast that the investment required to provide access for 2GW would be £190m. SHETL estimate that one third of the investment, some £60m will be required by March 2006 and the remaining two thirds by March 2007.[21]

3.8. The extent to which further upgrades will be required will depend on how many and which renewable projects go ahead. For example, there are proposals for projects in the far north of Scotland on the islands which would require significant investment – in the TIWG report, the three TOs estimated that providing access for 1GW in the Western Isles would cost around £250m. However, it is likely that the bulk of the costs of any infrastructure upgrades associated with projects at the connection feasibility stage would take place after the end of SHETL's current price control (even if it were extended to March 2007).

[21] As discussed in Chapter 1, Ofgem has proposed extending the price controls of SHETL and SPTL to March 2006 and consulted on whether they should be further extended to March 2007.

SPTL

3.9. SPTL's analysis has also concentrated upon providing sufficient infrastructure to cope with the Stage 1 case but also considers the upgrades required in the south west of Scotland, which formed part of the Stage 2 (4 GW) case.

3.10. SPTL estimates that a total of £159m of additional investment would allow for:

- Increased transfers from SHETL's area (as a result of 1 GW of renewable capacity being commissioned)
- Increased exports from Scotland to England
- Flows resulting from the renewables projects on the Mull of Kintyre for which connection agreements have already been sought, and
- The potential for 1.6 GW of renewable generation potential in the south west of Scotland that has been identified by the Scottish Executive.

3.11. Not all of this investment would be required during SPTL's current price control period but SPTL estimates that £50m of investment would be required by March 2006 and a further £51m by March 2007.

NGC

3.12. NGC has also concentrated upon analysing the Stage 1 Case, which, from its perspective, relates to the need to accommodate an additional 2GW of exports from Scotland to England & Wales. It considers that this would require a four year programme of investments, with costs in the region of £250m, of which £55m-£75m would be required by March 2006. These figures are higher than those identified in the TIWG report as a result of changes to the committed generation background arising from the considerable renewable activity in the north west of England.

Impact on transmission charges

3.13. As discussed in section 2, the TOs recover expenditure on infrastructure investment by Transmission Network Use of System (TNUoS) charges in England

and Wales and by infrastructure charges in Scotland. Expenditure on infrastructure investment to accommodate new renewable capacity will also be recovered through these charges. This may affect both the level and the distribution of the charges across the charging zones not just for renewable generators but all transmission system users. Ofgem will be asking the TOs to model the potential impact of this expenditure on TNUoS and infrastructure charges, which we intend to publish in the next paper.

Summary

3.14. As outlined above, the companies have estimated what they consider (allowing for reasonable assumptions on the volume and location of new generation) to be a reasonable level of capital expenditure in the years 2004/5, 2005/6, and 2006/7. These costs are summarised in the Table 3.1.

Table 3.1: Estimated infrastructure expenditure related to renewables over the next 3 years

Company	**Year**		
	2004/5	**2005/6**	**2006/7**
SHETL		£60m	£65m
SPTL	£6m	£44m	£51m
NGC	£15m	£60m	£95m
Total	£21m	£164m	£211m

Source: NGC, SPTL, SHETL

3.15. These figures suggest that a total of £81m could be invested in advance of the next price control periods. This figure rises to £185m if a decision is taken to extend by one year the existing price controls for the Scottish transmission businesses.

3.16. To put these figures in context we can compare the estimated infrastructure expenditure to accommodate renewables with the estimated capital expenditure for the three TOs in 2004/05 which are £21m and £277m respectively. In 2005/06 NGC's estimated capital expenditure is £222m compared with the estimated additional expenditure of £60m to accommodate renewables. If the price controls for the Scottish TOs are rolled forward for a year this funding gap would widen significantly. The total estimated capital expenditure for all three TOs in 2005/06 is likely to be about £265m compared with an estimated £164m of additional expenditure in infrastructure investment for renewables.

4. Issues for consultation

4.1. Ofgem's aim is to put in place arrangements that are designed to improve the existing signals and incentives on transmission companies to invest in additional entry capacity in an efficient and timely manner to ensure that the arrangements for transmission investment would facilitate significant new entry in renewables generation, consistent with Government policy whilst maintaining strong incentives on the transmission companies to invest efficiently.

4.2. Ofgem has, at this stage, identified three broad categories of possible ways forward, which are:

- rely on existing mechanisms i.e. do nothing until the next price control review,
- re-open all three price controls, or
- add an additional mechanism to the existing controls to deal with renewable expenditure.

4.3. Each of these options is discussed briefly below. Ofgem has highlighted some of the potential advantages and disadvantages of the three approaches.

Rely on existing mechanisms

4.4. Having regard to its statutory duties, Ofgem does not consider that the first option (do nothing) would be appropriate. The Scottish TOs are required by their licences to offer terms for access but their connection charging methodologies are generally 'shallow' in that connection charges cover only the costs directly associated with connecting a generator to the transmission system and not the wider grid reinforcement costs. Thus, doing nothing would require the Scottish TOs to reinforce their systems without any immediate prospect of being able to recover those costs unless they charged new renewable generators for the full system reinforcement costs. Ofgem considers that a general change to charging new renewable generators the full reinforcement costs i.e. reintroducing deep connection charges would be a retrograde step and would also be likely to stifle the development of new renewable generation. It would be feasible to take the unforeseen expenditure into account at the next price review in the value of the revised regulatory asset base and additional depreciation allowances. However, given the scale of investment relative to that allowed in setting the price control and the potential funding gap, it is Ofgem's preliminary view that it would be appropriate to provide funding. Without funding the TOs may not invest as quickly as they otherwise might and it could raise the cost of capital if investors saw this precedent as increasing the risk inherent in transmission companies.

4.5. It is important to note that one of the incentives of the price controls is to encourage efficient development of the transmission systems. However, the uncertainty associated with the funding of the currently anticipated level of renewable generation could impact adversely on the incentives of transmission companies, which would not be in the interests of consumers.

Re-open the price controls

4.6. Under this option, the projections of efficient investments by the TOs would be reassessed and their allowed revenues adjusted in the light of new information on likely requests for access by renewable generators. Ofgem's initial view is that re-opening the price controls shortly before the start of the normal price control reviews would entail significant costs and an undue amount of time, be disproportionate to the issue involved, increase regulatory uncertainty and be incompatible with the BETTA timetable. Another disadvantage is that this may not adequately address the problem as forecast expenditure may be too high or low. It would not provide particularly strong enhanced incentives to invest efficiently or in a timely manner.

4.7. Ofgem is therefore minded to explore ways in which additional revenues can be allowed to the TOs without reopening the main price controls.

4.8. For the longer term, Ofgem will continue to consult on how uncertainty in costs should be addressed as part of the process of setting the next set of electricity distribution and transmission price controls.

Add an additional mechanism

4.9. There are a broad range of additional mechanisms that could be considered. These range from 'quick fix' solutions to more sophisticated approaches that seek to encompass some of the longer term objectives for price control regulation. For example, a 'quick fix' solution might be to make a simple engineering based estimate of the returns and depreciation associated with renewable related investment and then to include an additional revenue allowance to cover this. A more sophisticated approach, but one that would take longer to develop and implement, might involve providing the TOs with greater flexibility and incentives to meet the needs of their customers whilst at the same time strengthening the regulation on quality of service. Greater flexibility might be achieved, for instance, by introducing a mechanism that spans more than one price control period, such as Transco's NTS entry capacity investment incentive discussed in 1.23 – 1.27. Whilst a simple approach could be introduced in time for the start of the next charging year (April 2004), it is unlikely that a more sophisticated approach could be implemented to this timescale.

4.10. Such mechanisms could exist alongside other potential amendments to the price control mechanisms. For example, an obligation might be introduced on either new generation licensees or the existing transmission licensees in Scotland such that any agreement for connection and use of system in the SPTL or SHETL area is accompanied by a related request for an increase to the capacity of the Scottish interconnectors.

4.11. A more complicated mechanism is likely to take more time to develop and this could hold up investment. A simple adjustment mechanism would have some positive incentive advantages and make sure the investment takes place but efficient investment incentives may not be as strong as with a more complicated mechanism. Ofgem's initial view is therefore that it may be appropriate to do something relatively simple for the next couple of years and then develop a more enduring solution that has better signals and incentives from next price control.

Summary and views invited

4.12. At this stage, Ofgem has no firm views on the most appropriate way forward and would welcome respondents' views on all the issues raised in this document. In particular, Ofgem would welcome views on:

- ♦ the appropriate principles and objectives to apply in considering how to tackle the issue of the recovery of costs associated with infrastructure investment to accommodate renewable capacity;
- ♦ the TOs' investment forecasts and the assumptions underpinning them;
- ♦ potential approaches to adjusting the TOs' allowed revenues during the current price controls to allow funding of this investment. In particular:
    - which of the three generic approaches outlined above respondents consider to be most appropriate and why;
    - if an additional mechanism is to be introduced, whether it is more appropriate to go for a "quick fix" or a sophisticated mechanism, particularly given the different timescales likely to be involved in the two approaches; and
    - any other mechanisms that respondents consider might be appropriate.

Appendix 1 Price control calculations

Scottish Power Transmission Ltd

In 1997/98 prices

Asset value - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Opening asset value	559.1	539.3	518.3	496.9	484.8	
Depreciation	-42.1	-42.6	-43.2	-43.7	-44.5	-216.0
Net network capex	22.3	21.6	21.7	31.7	31.1	128.4
Closing asset values	539.3	518.3	496.9	484.8	471.4	

Costs - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Return	35.7	34.4	33.0	31.9	31.1	166.0
Depreciation	42.1	42.6	43.2	43.7	44.5	216.0
Operating costs	35.1	33.6	33.1	32.8	32.5	167.1
Total costs	112.9	110.6	109.3	108.4	108.1	549.3
PV of total costs	108.3	99.7	92.5	86.2	80.7	467.3

Revenue - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Price controlled revenue	104.4	104.4	104.4	104.4	104.4	521.9
Excluded revenue	4.6	4.6	4.6	4.6	4.6	22.9
Total revenue	109	109	109	109	109	544.8
PV of total revenue	105.1	98.7	92.6	87	82.1	467.3

X = 0

Cost of capital = 6.5%

Scottish Hydro Electric Transmission Ltd

In 1997/98 prices

Asset value - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Opening asset value	222.1	223.4	224.1	224.0	222.9	
Depreciation	-11.4	-11.7	-12.0	-12.2	-12.4	-59.8
Net network capex	12.7	12.5	11.8	11.1	11.9	60.0
Closing asset values	223.4	224.1	224.0	222.9	222.3	

Costs - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Return	14.5	14.5	14.6	14.5	14.5	72.6
Depreciation	11.4	11.7	12.0	12.2	12.4	59.8
Operating costs	20.0	19.5	19.2	19.1	19.0	96.7
Total costs	45.9	45.8	45.7	45.8	45.9	229.1
PV of total costs	44.1	41.2	38.7	36.4	34.2	194.6

Revenue - £M	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Price controlled revenue	45.3	45.3	45.3	45.3	45.3	226.4
Excluded revenue	0.1	0.1	0.1	0.1	0.1	0.5
Total revenue	45.4	45.4	45.4	45.4	45.4	226.9
PV of total revenue	44	41.3	38.8	36.4	34.2	194.6

X = 0

Cost of capital = 6.5%

NGC

In 2000 prices

Asset value - £M	2001/02	2002/03	2003/04	2004/05	2005/06	Total
Opening asset value	4517	4522	4509	4470	4398	
Depreciation	-285	-292	-299	-306	-312	-1493
Net network capex	290	279	260	234	222	1285
Closing asset values	4522.0	4509.0	4470.0	4398.0	4308.0	

Costs - £M	2001/02	2002/03	2003/04	2004/05	2005/06	Total
Controllable operating costs	187	175	166	162	158	849
Operating costs	290	276	262	254	260	1342
Depreciation allowance	285	292	299	306	312	1493
Return	282	282	281	277	272	1395
Total	858	850	842	837	843	4230
PV of total costs	832	776	723	677	642	3651

Revenue - £M	2001/02	2002/03	2003/04	2004/05	2005/06	Total
Price controlled revenue	758	747	736	724	714	3678
Excluded revenue	100	105	109	116	121	550
Total revenue	858	852	844	840	835	4229
PV of total revenue	833	778	725	680	635	3651

X = 1.5

Cost of capital = 6.25%