Transmission price control review

Second consultation

December 2005 277/05

Summary

This document (the Second Consultation) is the second of six consultation documents Ofgem plans to publish as part of the Transmission Price Control Review (TPCR). The first TPCR consultation document (the Initial Consultation), published in July, summarised the current price control arrangements, and identified the objectives for this review and the key issues to be addressed. The primary purpose of this Second Consultation document is to seek views on a number of important policy issues.

This series of consultation documents will conclude with publication of final proposals for new price controls for National Grid Electricity Transmission plc (NGET), SP Transmission Limited (SPTL) and Scottish Hydro-Electric Transmission Limited (SHETL), and National Grid Gas plc in its capacity as licensed gas transporter responsible for the National Transmission system[1]. Final proposals will be published by December 2006. If the companies accept Ofgem's proposals, then the new price controls will take effect on 1 April 2007.

The transmission systems in gas and electricity are the onshore networks of high voltage lines and cables and high pressure pipes that enable gas and electricity to be transported from producers to consumers. The annual revenues of the transmission networks amount to some £1.5bn for electricity transmission, and in excess of £0.4bn for gas transmission. Regulated asset values amount to some £6bn for electricity, and £2.5bn for gas. Transmission networks play a key role in facilitating the competitive electricity and gas markets in Great Britain, and timely investment in the networks is essential to ensure their efficient operation.

Following the extension of the existing price controls for the electricity transmission licensees, this review represents the first opportunity for Ofgem to consider new price controls for all electricity and gas transmission companies at the same time. This will allow us to consider common issues facing electricity and gas transmission and will assist the Authority in fulfilling its objectives and duties, in particular its principal duty to protect the interests of current and future consumers.

[1] Referred to in this document as "National Grid NTS", to differentiate from National Grid Gas plc in its capacity as a licensed gas transporter with responsibility for certain gas distribution networks.

There have been a number of changes in the external environment since the current transmission price controls were set and there is significant uncertainty concerning the future development of the networks. This uncertainty arises, in particular, from:

- changing patterns of gas supply resulting from the decline of UK gas production and its replacement by imports;
- changes in the electricity generation mix, particularly relating to the development of renewable generation; and
- environmental factors.

Against this background, a key focus for the review will be to develop the incentives for investment in gas and electricity infrastructure, ensuring they are best able to promote efficient and timely investment and allocate risk appropriately. At present, the approaches to new investment in gas and electricity transmission under the current price controls are very different.

The approach to gas investment was designed to be more responsive to the requirements of users of the network, with mechanisms to allow them to signal their demand for capacity and incentives on National Grid NTS to respond with investment where appropriate. This approach has been successful in avoiding unnecessary investment, and in allowing investment relating to new entry points to the system which were not under consideration at the time of the last review. However, experience with this approach has also raised questions about both its complexity and effectiveness.

In the case of electricity, the current price control arrangements are less flexible and were unable to respond to the increased demand for capacity from renewable generators. As a result, a separate set of price control arrangements was introduced, ahead of the price control review, to allow funding for new investment in transmission to connect renewable generation in Scotland. The use of separate price control arrangements relating to individual investment projects generally dilutes the incentives on transmission companies to manage their investments within an overall price control allowance, and can expose consumers to the risk of stranded assets and possibly also delayed investment.

This review will consider potential improvements to the incentives for investment in electricity and gas transmission. A key issue will be whether to move towards incentives for electricity transmission similar to those applying for gas, or alternatively to

retain an approach based on the existing mechanisms, recognising that this may require further recourse to separate funding arrangements for some individual investment projects. To this end, the Second Consultation document identifies a number of options for incentive design in gas and electricity.

This Second Consultation document also considers a number of financial issues arising in the review and presents:

- summaries of, and commentary on, the responses to the Initial Consultation; and
- summarised historic cost information provided to Ofgem by the transmission companies.

Ofgem would welcome responses on all the issues raised in this document, and in particular on the relative merits of the options for incentive design set out in Chapters 7 and 8. Responses should be sent to TPCR.responses@ofgem.gov.uk, or in hardcopy to Robert Hull (Director, Transmission) no later than 30 January 2006.

The third Ofgem consultation document will be in March 2006, and will provide Ofgem's view on its preferred package of incentive design in gas and electricity. It will also provide an initial view on the efficiency or otherwise of the companies' historic expenditure and a description of the forecast cost information provided by the companies.

Table of contents

1. Introduction

1.1. This is the second consultation document (the Second Consultation) in the Transmission Price Control Review (TPCR). The consultation process will culminate with the publication, by November or December 2006 for implementation in April 2007, of final proposals for the price controls of National Grid Electricity Transmission plc (NGET), SP Transmission Limited (SPTL), Scottish Hydro-Electric Transmission Limited (SHETL) and National Grid Gas plc, in its capacity as the licensed gas transporter responsible for the system of high pressure gas pipelines in Great Britain (the "national transmission system")[2].

1.2. The scale of the activities being reviewed as part of the TPCR can be illustrated with reference to the current price controls and the allowances provided for within those price controls.

Table 1: Summary of current price controls (£million, all in 2004/05 prices)

			Based on:		
	Period	**Total Allowed revenues**	**Opening Regulatory Value**	**Capital expenditure**	**Operating costs**
NG NTS	2002/03 to 2006/07	**2,385**	2,360	889	1,110
NGET[3]	2001/02 to 2005/06	**4,163**	5,112	1,453[4]	1,519
SPTL					
Original	2000/01 to 2004/05	**618**	662	152	198
Extension[5]	2005/06 to 2006/07	**325**	754	169	64
SHETL					
Original	2000/01 to 2004/05	**268**	263	71	115
Extension[6]	2005/06 to 2006/07	**103**	277	43	21

[2] References in this document to "National Grid NTS" are references to National Grid Gas plc in its capacity as the licensed gas transporter with responsibility for the national transmission system. This is to differentiate National Grid Gas plc in this capacity from National Grid Gas plc in its capacity as the licensed gas transporter with responsibility for certain gas distribution networks.
[3] Excluding all SO costs and including efficiently incurred costs in the delivery of NETA (as per NGC's Transmission asset owner Final Proposals, September 2000, Table A6.2)
[4] This is before any adjustment for the impact of the generation revenue driver. It is currently anticipated that the effect of the revenue driver will be to reduce capital expenditure allowance by around £60m over the period.
[5] These figures include BETTA adjustments.
[6] These figures include BETTA adjustments.

1.3. In addition, the current price controls provide allowances for system operation activities, undertaken by NGET in electricity and National Grid NTS in gas. For electricity the target cost under the system operator incentive scheme was £415 million for 2004/05. For gas the target costs under the various system operator incentive schemes are £124 million in 2004/05.

1.4. Further background material can be found on the companies on the TPCR website7.

Purpose and structure of this document

1.5. The primary purpose of the Second Consultation is to identify and seek views on policy options for determining the appropriate form and scope of the new price controls.

1.6. The document also summarises responses to Ofgem's first consultation document on the TPCR (the "Initial Consultation"[8]) which was published in July 2005, and sets out Ofgem's views on the issues, and in some instances raises specific issues where further consideration is required and views would be particularly welcomed. Discussion of certain issues makes reference to material provided in appendices to the Second Consultation. The appendices should be viewed as being of equal importance to the material covered in the main body of this document.

1.7. Finally, the document provides an opportunity for Ofgem to update interested parties on how it plans to run the consultation process. Hopefully, this will enable parties to plan when and how they engage with the process most effectively.

[7] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr
[8] Transmission Price Control Review – Initial Consultation, Ofgem, July 2005

Responding to this document

1.8. If you wish to respond to this document, then please submit your response no later than 30 January 2006 to:

Robert Hull
Director, Transmission
Office of Gas and Electricity Markets (Ofgem)
9 Millbank
London
SW1P 3GE
Tel: 020 7901 7050

1.9. Responses can also be sent by email to TPCR.responses@ofgem.gov.uk and should be clearly marked as 'Response to Second Consultation'.

1.10. All responses, except those marked confidential, will be published on the Ofgem website[9] and held electronically in the Ofgem Research and Information Centre. Ofgem would encourage respondents to confine any confidential material in their responses to appendices. It would be helpful if responses were submitted electronically.

1.11. If you wish to discuss any aspect of this document, please contact Colin Sausman (colin.sausman@ofgem.gov.uk, 020 7901 7339).

[9] www.ofgem.gov.uk

2. Timetable and consultation process

2.1. This chapter provides an update on events that have occurred since the Initial Consultation was published, and sets out a revised document schedule. It also set out plans for consultation workshops.

Events since the Initial Consultation

2.2. The key developments since the Initial Consultation are as follows:

- Historic Business Plan Questionnaire (HBPQ[10]) sent to companies;
- HBPQ completed and returned;
- Forward Business Plan Questionnaire (FBPQ[11]) sent to companies; and
- the October Workshop on gas incentive design issues was held.

2.3. The following documents have been or will shortly be placed on the TPCR section of the Ofgem website[12] for reference:

- blank HBPQ and FBPQ forms; and
- slide presentations from the October Workshop on gas incentives by Ofgem, National Grid and Exxon/Mobil, plus a summary note of the discussion.

2.4. In addition to the events listed above Ofgem has met bilaterally with the transmission companies and, upon request, with other stakeholders. We have also given presentations to publicise the TPCR at a number of conferences and industry events.

[10] The Historic Business Plan Questionnaire is a detailed questionnaire covering how and why costs (of different types) have been incurred by the companies in the past.
[11] The Forward Business Plan Questionnaire is a detailed questionnaire covering how and why costs (of different types) might be incurred by the companies in the future.
[12] www.ofgem.gov.uk /ofgem/work/index.jsp?section=/areasofwork/transpcr

Revised consultation document plan

2.5. The Initial Consultation set out a planned schedule of consultation documents, and noted that further consultation documents, open letters and other methods of consultation (eg workshops) would be added as appropriate.

2.6. The Initial Consultation anticipated the need for a further document in March 2006. Ofgem has concluded that this is indeed appropriate. The revised document schedule is therefore:

- **Initial Consultation**: July 2005
- **Second Consultation**: December 2005
- **Third Consultation** March 2006
- **Initial Proposals**: June 2006
- **Updated Proposals**: September 2006
- **Final Proposals**: December 2006

2.7. The additional document, the Third Consultation, will act as a stepping stone between this document and Initial Proposals in June 2006. It will aim to conclude on the key price control design issues – and other issues, such as the approach to pensions, which need early resolution – ahead of the quantification of the proposed price control design at Initial Proposals stage in June.

Workshops and workgroups

2.8. Ofgem considers that workshops have an important role to play in the TPCR consultation process. Ofgem also considers that for certain areas of work there is a role for workgroups involving a representative group of relevant stakeholders. Ofgem plans to host two workshops and to convene one workgroup between now and the publication of the Third Consultation in March.

- workshop on electricity incentive issues (16 February);

- workshop on offtake arrangements (24 February); and
- workgroup on gas offtake.

2.9. Additionally, Ofgem anticipates hosting a second workshop on gas incentive issues in April or May 2006, and a seminar on the Initial Proposals in June or July 2006. Further information on these events will be provided in the Third Consultation.

2.10. Details on the gas offtake and electricity incentives workshops are provided in chapters 7 and 8 respectively. If you wish to attend any of these workshops then please send an email to Jennifer.Swan@ofgem.gov.uk indicating clearly which workshop you are interested in. The workshops will be held at Ofgem's offices in London.

Use of impact assessments

2.11. Ofgem is committed to ensuring that the policies it develops and implements are properly assessed and developed in the context of a well informed consultation process.

2.12. In the context of this TPCR, Ofgem considers that it is important that, in areas where a range of policy options exist, consideration is given to the impact of the different options as part of the assessment process. Consultation with interested parties who might be well placed to comment on the impact of different options is a key element of this process. It also relies on an appropriate degree of quantification of the different options – and for the exercise to be done at an early enough stage to inform the decision making process. To this end, chapters 7 and 8 below provide opportunity for respondents to comment on the potential impact of different options.

2.13. Additionally, Ofgem has a statutory duty to undertake an impact assessment (IA) or publish reasons why it considers an IA to be unnecessary before implementing proposals which it considers to be important for the purposes of section 5A of the Utilities Act 2000.

2.14. There is a question of whether, and at what stage, an IA is presented for the price control proposals as a whole. The approach under DPCR4 was to

publish a preliminary IA at the Initial Consultation stage, and publish a final IA with Final Proposals. Some industry participants have suggested that more information should have been published at interim stages, while others noted that the final IA was worthwhile insofar as it provided a useful alternative means of presenting information.

2.15. Ofgem is considering whether, in light of the experience of previous price control reviews, it is appropriate to adopt a different approach to IAs in the context of this TPCR and the Gas Distribution Price Control Review (GDPCR) that is currently ongoing. It should be noted that Ofgem has already committed to undertaking an IA in respect of gas offtake reforms. The recently published initial consultation document on the GDPCR consulted on this issue. The relevant extract of that consultation is provided in Appendix 1. If you wish to comment, Ofgem would welcome views.

Legal framework

2.16. The TPCR is being undertaken in the context of the Authority's legal duties and obligations. A document which describes these duties in the context of the TPCR will shortly be placed for reference on the TPCR website.

3. Framework, context and objectives

3.1. The Initial Consultation set the scene for the TPCR by presenting background material on:

- the framework for the undertaking the TPCR;
- the context for the TPCR; and
- objectives that Ofgem considered should be pursued in undertaking the TPCR.

3.2. This chapter sets out what respondents had to say on these issues, and how Ofgem's views have evolved in the light of respondents' views.

Framework

3.3. The Initial Consultation described the framework for the TPCR. It noted the intention to reflect the principles and approaches developed through its Developing Network Monopoly Price Controls project[13], to seek to ensure consistent treatment of common issues, and to seek to apply consistent principles where issues are different, with reference in particular to the recent electricity Distribution Price Control Review (DPCR4). Ofgem also stated its intention to seek to apply best practice in terms of ensuring a transparent and inclusive consultation process.

Context

The Initial Consultation

3.4. The Initial Consultation set the scene for the TPCR by:

- describing the external factors which Ofgem considered to be relevant to the review;
- outlining the nature of the costs incurred by transmission companies; and

[13] Developing Network Monopoly Price Controls: Initial Conclusions, Ofgem, June 2003, 54/03

- describing the range of mechanisms that are used (or could be used) to create a set of financial incentives for each of the companies.

3.5. The external factors cited in the Initial Consultation as having particular relevance to this TPCR were as follows:

- the significant actual and anticipated increase in distributed and renewable generation;
- the impact of carbon emissions trading and other environmental legislation;
- the prospect of major changes in gas flows on the network resulting from Great Britain becoming a net importer of gas;
- increased proportions of electricity demand being met by gas fired power stations supplied by the gas transmission network;
- the sale in 2005 of four gas distribution networks by National Grid;
- the merger in 2002 between National Grid plc and the Lattice Group plc, the owners, respectively, of what are now called National Grid Electricity Transmission plc and National Grid Gas plc;
- the introduction of NETA in 2001 and BETTA in 2005.

3.6. The outline of the nature of transmission costs summarised the level of costs involved – around £2.8 billion of capital expenditure and £3.2 billion of operating costs over the current price control period. It highlighted the issues that would need to be addressed, and analytical approaches that would be adopted, in assessing these and future costs, and introduced a number of related financial issues for consideration.

3.7. The scene setting for the design of financial incentives in the Initial Consultation described why incentive regulation is important in protecting the interests of consumers, and described the wide range of models of incentive design that could be adopted. Ofgem invited views in particular on:

- whether the standard model of a five year control with RPI indexation is still appropriate;
- how, if at all, the standard RPI-X form of control should be supplemented with other types of incentive scheme;
- the role of 'rolling incentives' (ie incentive schemes where any efficiency saving relative to forecast cost is retained for a fixed period of time); and
- whether the incentives to reduce costs should be strengthened or weakened, and what particular activities undertaken by the transmission companies Ofgem should focus on.

Respondents' views

3.8. There were a number of responses to the Initial Consultation relating to the issues described above. Some of the more detailed issues relating to the form of the price controls, and the associated responses, are covered in Chapter 5 below. This section summarises the higher-level responses.

External factors

3.9. National Grid noted the relevance of the external factors listed above, and also noted a number of other factors including legislative change, demand growth, nuclear generation, and competition among network companies for scarce resources. SHETL noted the possible impact of charges levied by BT in respect of telecoms services as being an additional external factor with relevance to transmission company costs.

3.10. One respondent noted that reviewing all transmission price controls at the same time would help identify relevant external factors.

3.11. Three respondents stressed the need – including under statute - for Ofgem to recognise environmental considerations, and in particular the impact of transmission on the visual environment in rural areas, in the TPCR.

3.12. One respondent noted that the development of offshore wind generation would require a co-ordinated approach to grid development to ensure that

network capacity is provided in a timely manner.

Form of price control

3.13. All the transmission companies expressed views in support of the next price control being more flexible. There were various initial views on how this should be done. National Grid supported automatic adjustment mechanisms where possible, while SHETL supported further application by Ofgem of the approach adopted as part of the Transmission Investment for Renewable Generation (TIRG) project[14].

3.14. Two network users also cited uncertainty over future connection activity as needing to be reflected in the price controls, although one of these respondents stressed the need to avoid over-stating the degree of uncertainty. The other respondent stressed the undesirability of re-opening price controls if they are found to be too inflexible.

3.15. One respondent noted that the core price controls in electricity were broadly robust, but that the operational incentives might need further development. The respondent also stressed the need for the price control to avoid providing perverse incentives in respect of where network users should locate.

Ofgem's views

3.16. Ofgem welcomes the comments on the external factors cited in the Initial Consultation, including suggestions for additional factors that need consideration. It is important for Ofgem to develop its proposals in the appropriate context, using all available and relevant information and being aware of all relevant external factors.

3.17. Ofgem would also note that since the publication of the Initial Consultation the Government has announced an energy review. Ofgem will monitor any interactions between the energy review and the TPCR as the scope and direction of the review develops.

[14] Transmission Investment for Renewable Generation – Final Proposals, Ofgem, December 2004, 288/04

3.18. The comments provided by respondents confirm Ofgem's initial view that the flexibility of the price control in the light of external events is an important consideration for this review, and suggest that the ability of the current arrangements to address such uncertainty in a manner consistent with the interests of consumers needs to be improved.

3.19. As a number of the respondents to the Initial Consultation noted, re-opening price controls can reduce incentives on companies to operate and invest efficiently. It can also be inconsistent with better regulation as it is likely to involve a greater degree of intrusion by Ofgem into the day-to-day management of the transmission companies than might otherwise be the case.

Objectives

Initial Consultation

3.20. The Initial Consultation set out Ofgem's proposed objectives for the TPCR. The objectives were as follows:

- **Protect the interests of consumers**: To develop a set of proposals which protect the interests of gas and electricity consumers, recognising that current and future consumers have interests in high quality transmission networks supporting a high standard of security of supply, delivered at efficient cost;

- **Promote social and environmental objectives**: To develop a set of proposals consistent with the Authority's wider statutory duties, reflecting the direct impacts that the transmission systems have on the environment, as well as the role the transmission systems play in facilitating broader social and environmental objectives;

- **Reward focused and timely investment**: To reward transmission licensees for responding dynamically to changing circumstances to develop their networks in an economic, efficient and co-ordinated manner (having regard to best practice in respect of asset stewardship and safety), and thereby facilitate effective competition between

electricity generators and suppliers, and between gas shippers;

- **Allocate risk appropriately**: To ensure that risk is shared appropriately between licensees, customers and other users of the system; for instance to ensure that licensees bear an appropriate share of the risk of under-performance under the price controls in relation to, for example, the costs of buying back capacity rights if investment by a licensee is not focused and timely.

3.21. Additionally, the Initial Consultation noted that Ofgem itself will seek to ensure during the TPCR that its actions are consistent with:

- **Transparency**: The objective and transparent assessment of issues, seeking where possible to ensure Ofgem's approach to particular policy issues is clarified at an early stage (and is not subsequently revisited);

- **Inclusiveness**: Providing information to all stakeholders in a focused and easy to understand form, such that all parties can play a full and active role in the price control review; and

- **Accessibility**: Making Ofgem's project team for the price control review visible and accessible to all stakeholders.

Respondents' views

3.22. One transmission licensee and one network user noted that the objectives should be extended to make explicit reference to the need to enable licensees to finance their activities. Another licensee stressed the need to reflect more directly the principles of best regulatory practice.

3.23. Two network users noted that the objectives should include objectives to ensure transparency and to aim to make the arrangements – particularly in respect of gas – less complex. Another network user noted that consistency between gas and electricity should only be promoted if there are demonstrable benefits.

3.24. One respondent commented that the objectives should make explicit reference to the Government's targets for renewable generation. Two

respondents noted that the one of the prime objectives for the review should be to promote social and environmental objectives.

Ofgem's views

3.25. The objectives for the review must be consistent with the Authority's legal duties and obligations. The intention behind the objectives listed in the Initial Consultation was to encapsulate the main elements of these duties in the context of the TPCR.

3.26. Ofgem considers that the objectives above continue to be broadly appropriate for the TPCR, but the wording has been refined to make explicit reference to the requirement that the Authority have regard to the need to ensure that licensees can finance their licensed and statutory obligations, and to the principles that appear to the Authority to represent best regulatory practice. The revised objectives are set out in Appendix 2.

3.27. Ofgem is particularly keen to do what it can to ensure that the objectives in respect of best regulatory practice, and the specific issues of transparency, inclusiveness and accessibility, are met through the TPCR consultation process. Ofgem has already taken a number of steps in this regard, including:

- publishing and working to a forward work plan;
- hosting and presenting at the October 2005 workshop on gas incentive issues;
- the publication in summary form of 'raw' historic cost information as provided to Ofgem by each of the transmission companies – Appendices 3 to 5 of this document;
- the commissioning by Ofgem of a report from National Grid summarising its performance under the various incentives schemes over the current price control period, a copy of which can be found on the TPCR website;
- a number of presentations to industry meetings and conferences to increase awareness of the TPCR; and

- active engagement with interested parties through bilateral meetings.

3.28. Ofgem intends to develop these approaches further during the course of the TPCR and, in the next six months, will be focusing in particular on:

- the scope for further workshops and meetings;
- accessibility to, and engagement with, stakeholders through bilateral meetings and attendance at (and presentations to) relevant groups and;
- the development of the section of the Ofgem website dedicated to TPCR[15].

[15] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr

4. Cost Assessment

4.1. The Initial Consultation set out, and invited views on, Ofgem's proposed approach to assessing historic and forecast levels of capital expenditure and operating costs, and to the issue of future cost reporting.

4.2. This chapter summarises responses to these aspects of the Initial Consultation, sets out Ofgem's views on the issues raised, and highlights any new or more detailed issues that have emerged since the Initial Consultation. This chapter also provides an update on how Ofgem's approach is being implemented.

4.3. Since the publication of the Initial Consultation, Ofgem has sent each company a Historical Business Plan Questionnaire (HBPQ) – and the completed forms have been returned to Ofgem. These questionnaires include detailed questions on how each company has incurred costs over the current price control period. A summary of the information provided is set out for each company in Appendices 3 to 5.

4.4. The data presented in these appendices is raw information provided by the companies, supplemented by a commentary on the raw information also provided by the companies. For the avoidance of doubt, it includes no comments, checks or judgements by Ofgem in respect of factual accuracy or completeness.

Capital expenditure

The Initial Consultation

4.5. Capital expenditure relates to investment in long-lived assets, such as gas pipelines or electricity transmission circuits and, in the case of energy networks, can be categorised as:

- **Load related**: the installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand; and
- **Non-load related**: the replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need

to be replaced on safety or environmental grounds.

4.6. The Initial Consultation identified a number of specific issues for the TPCR in respect of the assessment of future capital expenditure requirements, namely:

- uncertainty over changing gas flow patterns;
- uncertainty over renewable and distributed electricity generation growth; and
- the potential volume of replacement capital expenditure in electricity.

4.7. The Initial Consultation also described the framework that Ofgem intended to adopt in determining how capital expenditure allowances should be set. The framework involved the following steps:

- reviewing past capital expenditure;
- projecting forward base case capital expenditure; and
- quantifying the impact of variations from the base case.

4.8. The Initial Consultation noted the interactions between how these allowances might be set, and the form of the price control. The form of the price control is the subject of the next two chapters.

Respondents' views

4.9. On the methods and models for assessing capital expenditure, the transmission licensees suggested that detailed assessment should be carried out, either in addition to, or instead of, top-down approaches. Referring specifically to non-load related capital expenditure, some of them agreed that there was a need for Ofgem to scrutinise this area of spend. They argued that the price control should promote efficient investment with a long-term view, and not just encourage deferrals.

4.10. The growth in renewable and distributed generation was recognised by a number of respondents as an important issue that needed to be addressed in the price control, due to the scale of its impact on capital expenditure and the significant uncertainty therein. They suggested that Ofgem's

assessment of relevant transmission capital expenditure requirements could be based on the best available information at the time of the review including the Government's targets and the projects proposed by the licensees, with the revenue allowance incorporating an appropriate mixture of revenue drivers and interim determinations. Some respondents also argued that due consideration should be given to the landscape impact of all new developments.

4.11. More specifically, the model of assessment and allowance adopted for TIRG was considered by the electricity transmission licensees as appropriate for certain circumstances, such as individual projects with a clear driver. However, one electricity transmission licensee also identified perceived limitations of the TIRG model, such as a lack of transparency and sensitivity to assumptions.

4.12. One licensee pointed out that whilst the TIRG approach partially dealt with major deep infrastructure reinforcement, consideration should also be given to the requirement for a considerable increase in local network infrastructure, which had been brought into the price control since the adoption of the "plugs" connection charging methodology.

4.13. A licensee also pointed out that it would be important to consider the increase in costs in the short to medium term due to the impact on supplier and contractor resources of the growth in transmission network infrastructure expenditure in the UK and world-wide.

Ofgem's views

4.14. Ofgem agrees that in the TPCR there is a clear need for detailed examination of specific areas of capital expenditure. However, it believes that there is still merit in and need for some top-down assessment, for example to identify major drivers for investment and to establish the relationship between such drivers and the level of investment.

4.15. On non-load related capital expenditure, mostly driven by asset replacement, Ofgem intends to carry out analyses in more depth and more focused than those carried out in previous price control reviews. This is necessary given

the significant increase in asset replacement indicated by some of the licensees. Ofgem notes that a related area of its current work is the BSI-PAS 55 certification[16]. As explained in a recent open letter[17], the certification will help establish a greater clarity regarding the asset management policy and process that underpin the investment decisions. As it is developed, it is envisaged to enhance, but not replace, Ofgem's analysis of asset management techniques.

4.16. With regard to capital expenditure relating to the growth in renewable and distributed generation, a key concern for Ofgem will be whether network investment is timely and efficient, and based on a clear need for transmission capacity. Recognising that the transmission licensees have more direct and detailed knowledge of the likely development of such generation in their areas, Ofgem believes that the starting point of assessment will be the proposals from the licensees. Our examination will focus on the robustness of assumptions underlying such proposals, areas of major uncertainty, and the potential impact of such uncertainty on capital expenditure.

4.17. Ofgem has reservations about using the approach adopted under TIRG as part of the main price control on an enduring basis. TIRG should, in Ofgem's view, be considered as a pragmatic one-off adjustment to deal with a particular set of circumstances. Ofgem does not necessarily view it as an enduring model of incentive regulation. The issues of how the price control might be designed to address the issues that led to the need for TIRG are discussed further in chapters 5 and 8.

4.18. In assessing capital expenditure relating to renewable generation, there are a number of specific issues that need to be taken into consideration:

- the current review of the treatment of renewable generation in SQSS (Security and Quality of Supply Standards). Clearly the conclusion of this review may impact on the level of transmission capacity required, and given that this review may not be concluded in the next few months,

[16] BSI-PAS 55 is a certification scheme (in some cases through self-certification) demonstrating the attainment of certain minimum standards in asset management.
[17] "Refocusing Ofgem's ARM 2002 Survey to BSI-PAS 55 Certification", Ofgem, 24 November 2005

the assessment will initially look at an appropriate range of values for such factors and identify sensitivities;

- the impact of the "plugs" connection charging methodology on the local network reinforcement, as has been raised by one licensee. The concern was that the charging methodology could, in effect, result in more transmission being built than was previously deemed to be economic and efficient, eg by requiring a double circuit when previously a single circuit was provided (and paid for). This might appear to be an unintended consequence of the charging methodology, and the issue should be addressed. The charging methodology should clearly not act as a barrier to efficiency. Ofgem will shortly write to NGET to request that it reviews this aspect of its charging methodology. In any event, Ofgem will seek to determine allowances for capital expenditure on the basis that an efficient design, compliant with the SQSS, is not constrained by the charging arrangements.

4.19. Since receiving information submitted by the licensees in response to the Historical Business Plan Questionnaires, Ofgem has commenced work on assessing the efficiency of the actual capital expenditure carried out so far. Apart from evaluating demonstrable capital efficiency in the past (such as that arising from an improved trade-off between capex and opex, or technical innovations), the assessment will also examine what reasonable measures the licensees have taken to avoid stranded assets.

4.20. The issues discussed above consider the basic question of how capital expenditure allowances should be determined in order to deliver a network which is fit for purpose, ie basic compliance with standards. There are two issues that need to be considered additionally:

- **Network flexibility**: The basic requirements of planning standards relate to whether transmission networks are fit for purpose given prevailing usage. However, consumers also have an interest in how the networks would be able to cope with changing patterns of network usage, and how much excess capacity should be allowed for in setting the basic capital expenditure allowances. This is a particularly important consideration in this TPCR because of uncertainty over future demands

to be placed on the transmission networks, eg as a consequence of changing patterns of gas flows (as the UK moves to being a net importer of gas), and changing patterns of electricity generation.

In part this requires a consideration of the capital expenditure implications (and probability) of alternative network usage scenarios – an issue which will be analysed by Ofgem in developing its proposals. It also requires a consideration of how the balance should be struck between 'core' allowances and allowances which are set through adjustment mechanisms (eg revenue drivers) to address changing demands for network usage. On the one hand, zero or small allowances for flexibility might minimise the risk of consumers paying for investment which proves to be unnecessary. On the other hand, flexibility might be valuable to consumers; eg if it reduces the risk of short term constraints (and potential price spikes) in the event of changes in network flows. The roles of revenue drivers (and 'baselines') are discussed in chapters 5 to 8.

- **Investment to support efficient system operation**: In the short term, the system operator will manage the network in the context of the existing network as given. However, in the longer term there could be a role for more efficient system operation (eg by reducing constraint costs) through investment in the network over and above what is strictly required to meeting planning standards. Under NGET's current price control there is an allowance for such expenditure as part of its balancing services revenue restriction, or 'SO incentives'. The TPCR will need to consider how such an allowance might be re-set, and how costs and revenues might be treated for SPTL and SHETL in the event that efficient investment to support system operation is required on the SPTL and/or SHETL network. These issues are discussed in more detail in chapter 8.

Operating costs

The Initial Consultation

4.21. Operating costs relate to the day-to-day activities of running the transmission businesses. Controllable operating costs, the main focus of the TPCR, can be broken down into two categories;

- **direct or field activities**: these include inspection, maintenance and repair of network assets. These activities are an integral part of asset management and therefore have a direct relationship with asset replacement, and
- **support functions and overheads**: eg finance, HR, IT and corporate costs.

4.22. The Initial Consultation identified a number of specific factors affecting the TPCR in the context of operating costs, including:

- understanding historic performance against a background of significant corporate restructuring eg the merger of National Grid plc and the Lattice Group plc and the changing roles of the three electricity transmission licensees following BETTA reform;
- the methodology for assessing the efficient level of operating costs and, in particular, the extent to which comparative analysis could be used; and
- understanding the allocation and attribution of costs given that all four licensed businesses are parts of larger corporate groups.

Respondents' views

4.23. On the subject of comparative analysis some respondents said that such analysis should be undertaken on a functional or activity basis. Other respondents highlighted possible difficulties with benchmarking the transmission companies. One licensee noted that costs would have to be adjusted for issues such as capitalisation policies and allocation of shared costs before any comparisons could be made. Another respondent referred to the electricity distribution price control review and stressed the importance of ensuring that the categorisation of costs and drivers was consistent. The same respondent said any benchmarking of

transmission activities against distribution companies should be treated with caution.

4.24. All of the transmission licensees said that it would be important for the assessment of costs to recognise cost drivers specific to each transmission network eg geographic factors, the condition of the asset base, etc. One of the licensees believed that the focus should be on the interaction between operating costs and capital expenditure, in particular the trade off between refurbishment and asset replacement.

4.25. One respondent referred specifically to the corporate restructuring of National Grid. That respondent said that it would expect consumers to benefit from significant savings in operating costs due to the merger and the sale, by National Grid, of some of its gas distribution networks.

Ofgem's views

4.26. Ofgem agrees that any comparative analysis should be undertaken with great care and should ensure as far as possible that any comparisons are made using a consistent set of costs. Overall Ofgem intends to use a package of approaches, including functional benchmarking, top down analysis and bottom up assessments, with each assessment being employed as a cross check against the others.

4.27. Ofgem recognises that some areas of operating costs (eg maintenance, inspections and refurbishment) have a key interaction with asset replacement. Therefore the assessment of these costs will be linked to the work discussed above on asset management.

4.28. Following the licensees' responses to the Historical Business Plan Questionnaires, Ofgem has begun work on assessing historic operating expenditure incurred since the last price control reviews. Consultants have been appointed by Ofgem to provide advice in certain areas and undertake particular areas of cost analysis.

4.29. The Initial Consultation highlighted the potential benefits in respect of future regulation – and the setting of future price controls – of collecting more detailed and consistent information on cost performance on a routine basis. Formal cost-reporting requirements were developed as part of DPCR4 and have now been

implemented for the electricity distribution companies.

4.30. The Initial Consultation set out Ofgem's view that similar arrangements should be put in place as part of the TPCR – and views were invited.

Respondents' views

4.31. All respondents who commented on this issue thought that annual cost reporting requirements would be beneficial. Many thought the arrangements that were in place for the electricity distribution companies served as a good precedent. Two of the licensees stressed that any reporting requirements should be proportionate to the regulatory benefit.

Ofgem's views

4.32. As stated in the Initial Consultation Ofgem believes annual cost reporting requirements can have significant benefits for future price control reviews. Work on the cost reporting framework is expected to begin in summer 2006. Ofgem is keen to ensure that the approach adopted is proportionate, in the context of better regulation, relative to the potential benefits to consumers of Ofgem having access to better quality information when it undertakes price control reviews in the future.

Historic cost information

4.33. As described above, since the Initial Consultation Ofgem has issued Historic and Forecast BPQs to the companies – and the HBPQs have been returned by the companies.

4.34. A summary of some key data from the HBPQs is provided for each company in appendices 3 to 5 to this document. It should be noted that the data presented is raw data as provided by the companies, and the commentary has been provided by the companies. It is provided to help inform the debate – and to place some of the issues in context.

Other issues

Environmental considerations

4.35. A number of the Authority's duties require it to consider the environment and/or environmental matters. These duties include:

- the duty to have regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity, and with the conveyance of gas through pipelines;
- the duty to carry out certain of its functions in the manner which, amongst other things, is best calculated to (a) secure a diverse and viable long-term energy supply; and (b) contribute to the achievement of sustainable development;
- the duty to have regard, when carrying out certain functions, to any social and environmental guidance issued by the Secretary of State;
- the duty to carry out and publish an assessment of the likely impact of implementing a proposal which is important within the meaning of section 5A of the Utilities Act 2000 or to publish reasons for not doing so. A proposal is important if it would be likely to have a significant effect on the environment. An assessment under this section about any important proposal must include an assessment of the likely effects on the environment of implementing the proposal.

4.36. Ofgem will take account of these, together with the Authority's other duties in developing its proposals under the TPCR. In particular, Ofgem will seek to identify certain areas where assessment of environmental costs and benefits might be particularly relevant to decisions under the TPCR. Examples might include:

- understanding and making appropriate allowances for the costs of the transmission companies complying with existing and anticipated legal obligations which are designed to protect the environment;
- understanding the impact of network investment plans (eg by increasing the voltage of certain transmission circuits) on the volumes of transmission

losses;

- analysing the environmental impact of policy options to ensure that transmission companies respond in a timely manner to changing demands for network capacity, eg in the context of new renewable generators; and

- understanding the scope for quantifying the costs and environmental benefits of different forms of transmission investment, eg overhead line assets as compared to underground cables, and having regard to any such quantification in determining allowances consistent with efficient behaviour by the transmission companies.

4.37. A more detailed discussion of these issues is provided in Appendix 6. Ofgem will seek to undertake analysis as a means of ensuring that decisions by the Authority in the light of all of its statutory duties are well informed. In some instances in the past, where the evidence is robust and relates to specific focused measures, this type of analysis has resulted in the commitment of additional funds on behalf of consumers.

Views invited

4.38. Ofgem welcomes views on any of the issues raised in this chapter, and in particular in respect of the following questions:

- How should cost assessment take account of potential changes to SQSS – and in the absence of certainty as to when and how such changes might be implemented, what should Ofgem assume in estimating efficient future costs?

- How should Ofgem assess the need for additional capital expenditure allowances to provide flexibility in the availability of network capacity in advance of firm demands for capacity by network users? What, if any, reasons might there be for consumers placing a higher (or lower) value on such network flexibility over the next price control period as compared to the current (or past) price control periods?

- How should allowances be set for investment to support efficient system operation, and how, in the case of electricity transmission, should

interactions between NGET and SPTL and SHETL be managed in this context?

- What areas, including those cited above and those discussed in Appendix 6, should the Authority focus on in the context of its environmental duties, in terms of analysis to support future decisions as part of the TPCR? What specific measures should be developed and implemented in respect of any such individual areas?

5. Form and structure of price controls

5.1. The Initial Consultation raised a number of issues associated with how the price controls should be designed to ensure appropriate remuneration for the companies and to provide strong incentives to respond pro-actively and efficiently to the needs of network users and the interests of consumers. This chapter groups together these issues under the heading 'form and structure of price controls'.

5.2. The chapter is structured as follows:

- an outline of each element of the form and structure of the price controls to be addressed; and
- under each element, a summary of relevant responses to the Initial Consultation followed by a section setting out Ofgem's views.

5.3. It concludes with an explanation of the framework Ofgem has developed to identify policy options for the form of the price controls. The options developed under this framework are discussed further in Chapter 7 for gas and Chapter 8 for electricity.

Issues to be addressed

5.4. The form and structure of price control encompasses a wide range of issues, particularly at this stage of the review when a large number of design issues are still open. However, it should also be noted that a number of these issues are, to some extent, generic – and have been considered as part of Ofgem's Developing Network Monopoly Price Controls project in 2003, and through application in DPCR4. Ofgem's approach to the TPCR will seek to achieve consistency and continuity with this early work where relevant and appropriate.

5.5. The Initial Consultation set out the different ways in which a price control could be constructed, starting from the basic RPI-X model and considering refinements and alternatives to this approach. The following list of factors provides, in Ofgem's view, a comprehensive list of the issues to be covered:

- the role of RPI-X;
- the use of revenue drivers;
- the role of re-openers;
- duration of controls;
- scope of controls;
- the role of sliding scale incentives;
- the role of 'roller' incentives and 'information quality' incentives;
- the role of performance indicators and output measures;
- allowances for specific items, eg business rates, licence fees; and
- mechanisms for under or over-recovery.

5.6. These factors are discussed in turn below, where relevant drawing on responses to the Initial Consultation.

RPI-X

5.7. The Initial Consultation described the basic RPI-X model of regulation which is generally reviewed every five years and is applied to some extent to each of the four transmission companies. The Initial Consultation invited views on whether the standard model of a five year control and RPI indexation continued to be appropriate and whether there were any activities within the current scope which could be price regulated differently, eg any scope for deregulation.

Respondents' views

5.8. Eight respondents commented on the enduring applicability of price controls based on the RPI-X model. Six of these expressed support for the model as the basis for the forthcoming price control review, noting its successes in reducing costs to date, although several respondents noted the need for appropriate revenue drivers and supplemental additions to the basic model to appropriately incentivise performance, while others stated a preference for rolling incentives.

One respondent considered that RPI is not the appropriate index to deal with pressures on construction costs.

Ofgem's views

5.9. Ofgem remains of the view that the basic RPI-X model should continue to form the foundation of price control regulation in respect of regulated network monopoly businesses.

5.10. However, Ofgem recognises that there is scope for the basic model to be enhanced in certain areas; e.g. in respect of how responsive the revenue allowances are to future events. Such refinements should be explored fully, and should be adopted if they are appropriate and proportionate to the prevailing circumstances. A feature of transmission which should be recognised in this context, and in particular when comparing it to distribution, is that transmission investment can involve very large ('lumpy') individual investment schemes.

5.11. Ofgem also notes the potential significance of asset replacement costs during the next price control period and the limited scope for incentives other than those provided through the basic RPI-X model for such costs. Specifically, while load-related expenditure can make use of revenue drivers and other adjustment mechanisms, non-load-related expenditure is generally not amenable to such mechanisms.

Revenue drivers

5.12. The Initial Consultation noted that the RPI-X model could be supplemented with 'revenue drivers', ie automatic mechanisms for revenues to adjust to future events. It noted that these adjustments could retain the benefits of strong incentives under the basic RPI-X in circumstances where future events (and therefore the costs of the licensee) are uncertain. The Initial Consultation also noted that the appropriate values of revenue drivers could be difficult to set in practice – with the risk of being unduly harsh or generous to the companies.

5.13. The Initial Consultation cited the entry capacity incentive scheme in gas and the adjustment to NGET's revenues linked to volumes of connected electricity generation as examples of revenue driver mechanisms.

Respondents' views

5.14. A number of respondents highlighted the uncertainties regarding the changing pattern of generation connections during the price control period. Four respondents' considered that, to the extent that changes during a price control can be forecast with a degree of certainty, revenue drivers to adjust price controls to changing circumstances are appropriate. However, one respondent noted that avoiding unnecessary complexity in any revenue drivers was of great importance. Two respondents stated that the existing NGET revenue driver is too blunt an instrument for determining increments in allowed revenue and dealing with uncertainty.

Ofgem's views

5.15. There is, in Ofgem's view, a strong case for a continuing and enhanced role for revenue drivers as part of the next price control for all transmission companies. Such arrangements will require detailed assessment and development. The first stage in this process is the discussion of options set out in chapters 6 to 8 below.

Re-openers

5.16. The Initial Consultation noted that in some instances price controls may need to be re-opened prior to their scheduled end date, to accommodate unanticipated developments. The recent re-opener under TIRG in response to the rapid growth of renewable generation was noted as one such example.

Respondents' views

5.17. A majority of respondents supported the use of revenue drivers as opposed to re-opening the price control. However, two respondents noted that there was a degree of uncertainty associated with developments during the price control period and it could therefore be necessary for the price control to be re-opened in light of exceptional events.

5.18. Three respondents commented on the practicality of using the assessment framework developed under TIRG as part of the price control review. One respondent considered that the mechanism was appropriate where there were individual projects with specific triggers but questioned its usefulness in assessing

non load related capex. Another supported the mechanism but considered that it lacked transparency and was dependent on the assumptions used. The third respondent considered that the TIRG mechanism could be developed in order to assess funding requirements on a licensee specific basis.

Ofgem's views

5.19. Ofgem considers that, in principle, price control re-openers should be avoided if possible. The re-setting of parameters within a price control period generally reduces the incentive properties of the price controls – and, therefore, would not normally be the best way to protect the interests of consumers. Ofgem is therefore minded, in the context of uncertainty over volumes of activity, to seek to adopt automatic adjustment mechanisms where practicable, and in a manner which as far as possible retains the incentive properties of ex ante regulation.

5.20. However, there will remain under any price control design (other than pure cost pass-through) a risk of unanticipated events rendering the incumbent arrangements unsustainable. Ofgem must be alert to such possibilities, but should plan to minimise the extent to which such events necessarily trigger price control re-openers.

Duration of control

5.21. The Initial Consultation described how the current price controls were all set for five years in the first instance, although three of the four price controls have been (or are being) extended for additional years – as a means of aligning the full reviews for all four companies.

Respondents' views

5.22. The four respondents who commented all supported a five year price control period. One of these respondents considered that this was due to the current uncertainties in energy markets while another considered that no persuasive evidence for moving away from a five year control had been provided.

Ofgem's views

5.23. Ofgem is of the view that a wholesale review of the price control arrangements

should continue to be undertaken every five years. This would appear to represent a reasonable balance between creating incentives and ensuring that efficiencies are shared, in a reasonable timescale, with consumers.

5.24. Ofgem notes however that certain aspects of the price control regime (eg 'rolling incentives') represent refinements to the standard 5-year RPI-X form of control which affect when the efficiency of particular cost elements are reviewed by Ofgem. Rolling incentives are discussed further below.

Scope of control

5.25. The Initial Consultation described the issues that would be considered through the review, and sought views on which areas Ofgem should focus on. It also sought views on whether any activities should be subject to different forms of price regulation than was currently the case, eg through deregulation.

Respondents' views

5.26. A number of respondents stressed the need for Ofgem to focus on investment needs in this review. One respondent noted the need to examine economies of scope resulting from common ownership (in the context of NGET and National Grid NTS). Another respondent noted the need to examine economies of scale in system operation pursuant to BETTA and the extension of NGET's system operation role to cover GB.

5.27. One respondent noted that an area of focus should be to examine the scope for reducing complexity, while another respondent commented that there should be a thorough review of the various sliding scale incentives and output measures. One respondent stated that they saw limited scope for de-regulation.

5.28. One respondent sought clarity on whether the TPCR encompassed the current system operation incentives.

Ofgem's views

5.29. Ofgem welcomes the input in respect of particular areas of concern and interest for particular parties, while noting that all the areas mentioned are within the scope of the review and will be examined.

5.30. In respect of system operation incentives, Ofgem can confirm that the TPCR will include proposals to update all aspects of the revenue restrictions of NGET, National Grid NTS, SPTL and SHETL – and will therefore include proposals in respect of the activities that currently form the basis of the system operation incentives schemes.

5.31. Chapters 7 and 8 below include a discussion of some of the issues associated with the design of incentives for activities which are covered currently by the SO incentives schemes; eg the costs incurred by National Grid NTS and NGET in buying back capacity rights which cannot be accommodated physically on the network. The remaining issues will be consulted on in subsequent documents, and will form part of the package of proposals to be set out in June 2006 and finalised by December 2006.

Sliding scale incentives

5.32. The Initial Consultation described how a number of activities currently undertaken by transmission companies, and in particular NGET and National Grid NTS in their capacities as system operators, are covered by sliding scale incentive schemes.

Respondents' views

5.33. Six respondents made comments regarding sliding scale incentives. One considered that incentives should focus on the delivery of efficient investment, rather than simply targeting cost reduction. However, another considered that given rises in operating costs are likely, it is important to strengthen incentives for cost reduction.

5.34. One respondent considered that historically targets within sliding scale incentive schemes have not been sufficiently taxing and stated that it was appropriate to provide an appropriate balance of risk and reward between the service provider and system users; advocating the setting of more stretching targets, particularly to reflect the benefits which should accrue from NGET being the GBSO. A further respondent also noted that sliding scale incentives had tended to produce maximum upside for NGET and advocated the use of lower sharing factors.

5.35. A number of respondents noted that the success of sliding scale incentives was

determined by the quality of the underlying model, highlighting the need for transparency. One respondent considered that the incentive framework needed to change in order for further benefits to be realised.

Ofgem's views

5.36. Ofgem considers that sliding scale incentive schemes have been adopted successfully in the past and will continue to have a role to play in the future. They represent an effective and transparent method of determining revenues for activities where underlying costs are uncertain.

5.37. Ofgem will consider as part of the TPCR whether the range of different incentive schemes continues to be appropriate, and will in particular explore whether there is scope for consolidation.

5.38. Ofgem notes the comments in respect of the level of performance of NGET and National Grid NTS under its various incentive schemes – and notes concerns raised with Ofgem in meetings about the availability of information. It is important that, to the extent appropriate, relevant information is made available to interested parties in an accessible way. To facilitate this Ofgem has requested that National Grid compile a report on performance against its various incentive schemes. This report has been published today on the TPCR website[18].

'Information quality' and 'rolling' incentives

5.39. The Initial Consultation highlighted two refinements to the form of price control implemented as part of DPCR: the information quality (referred to in DPCR4 as the 'sliding scale') incentive, and the 'rolling' incentive in respect of future capital expenditure.

5.40. The information quality incentive was structured such that a company would have less scope to retain efficiency savings if it receives more generous capital expenditure allowances (relative to Ofgem's own forecasts of efficient costs).

5.41. The rolling incentive sought to reduce the extent to which the strength of incentives for efficiency can vary across the duration of the price control period

[18] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr

(eg with reduced incentives to cut costs when the next price review is imminent) by providing for efficiency savings to be retained for five years regardless of when during the price control period the efficiency saving was realised.

5.42. The Initial Consultation noted that certain elements of the current transmission arrangements (ie gas entry) already embodied an element of 'rolling' incentive – and sought views on the application of rolling incentives more generally as part of the TPCR.

Respondents' views

5.43. The majority of respondents who commented supported the introduction of some form of rolling incentives, with three considering that they should apply for a five year period. Respondents suggested that rolling incentives could alleviate the diminished incentives for efficiency towards the end of price control periods. One respondent considered that the design of any rolling incentive should be careful not to cause distortions between operating costs and capital expenditure decisions while another suggested that they could remove the temptation to allocate expenditure such that it maximises returns under various incentive regimes. Several respondents endorsed the use of benchmarking in setting incentives.

5.44. The two respondents which commented on information quality incentives considered that any mechanism should be geared towards a licensee's forecast, such that a company has incentives to meet its own forecast rather than Ofgem's forecast.

Ofgem's views

5.45. Ofgem recognises the role for rolling incentives if they can be designed to operate in the interests of consumers. The principle of seeking to adopt rolling incentive mechanisms was established as part of Ofgem's Developing Network Monopoly Price Controls project, and the framework has been applied in the context of the electricity distribution companies through the introduction of a rolling incentive for capital expenditure.

5.46. Ofgem will consider how best to apply this framework in the context of the TPCR. There are particular features of transmission that will need to be addressed

in designing a rolling incentive under the TPCR. These include the relatively lumpy nature of transmission investment and the smaller number of companies to compare. The small number of companies might make a rolling incentive mechanism for operating costs easier to design, but also means that there is less scope for comparative analysis to establish an efficient set of baseline allowances.

5.47. The smaller number of companies being examined in the TPCR relative to the DPCR also raises issues in the context of an information quality incentive. Arguably, an information quality incentive is a useful supplement to a method based on comparative analysis – as in the case of DPCR4 – but is arguably less useful where the primary source of analysis used in establishing efficient costs is company-specific analysis. Further, in transmission the total amount of investment can be comprised of a smaller number of very high cost investment schemes – which in turn might have significant influence over the results of an information quality incentive.

Performance indicators

5.48. The Initial Consultation described the role of performance indicators in the current price controls, including NGET's reliability incentive, and invited views on how such issues should be addressed as part of the TPCR.

Respondents' views

5.49. Three respondents commented on performance indicators. One respondent considered that the price control review provided an opportunity to replace the existing electricity transmission network reliability incentive with an incentive at distribution level. Another endorsed the use of incentives which are aligned with consumers' requirements, noting their support for the performance incentives introduced with DPCR4. The other considered that performance indicators should include environmental quality.

Ofgem's views

5.50. Ofgem considers that there is a role for performance indicators within the framework of the price control, and the most appropriate form of such indicators should be developed through further consultation.

5.51. Ofgem notes that one form of performance indicator – network capacity made available to users – is an integral part of the current arrangements in gas. The issue of capacity baselines and how they could be set is discussed in detail in chapter 7.

5.52. With regard to other forms of performance indicator, Ofgem recognises that the current electricity transmission reliability incentive was introduced as an interim measure and that the TPCR provides an opportunity to examine more comprehensively the appropriate manner in which the outputs might be defined, reported on, and, if appropriate, linked to financial incentives. These issues are discussed in more detail in chapter 8.

5.53. Ofgem would also welcome views, in the context of environmental considerations discussed in Chapter 4, on whether there is a role for additional reporting on (or financial incentives linked to) performance by the transmission licensee that might be considered to have a particularly significant impact on the environment.

Allowances for specific items

5.54. The Initial Consultation noted that a number of specific items are allowed for explicitly under the current price control, through various forms of cost pass through. These include such items as business rates.

Respondents' views

5.55. There were no responses to the Initial Consultation relating to this issue.

Ofgem's views

5.56. In developing its proposals Ofgem will keep under review the scope of cost items which should be subject to individual treatment, including cost pass through, and will plan to identify and discuss the appropriate treatment of such items in the Third Consultation in March 2006. To the extent that the companies exercise any degree of control over the level of such costs, Ofgem will be keen to ensure that the overall levels of costs reflect efficient behaviour by the companies.

Mechanisms for under or over- recovery

5.57. Whatever the choices of price control design, there will in all likelihood be the possibility of a licensee under or over-recovering against the allowed revenues in any given year. The form of price control therefore needs to allow for an adjustment to correct for this.

5.58. Ofgem considers that the standard mechanism for dealing with such adjustments should be adopted under the TPCR. This places obligations on each licensee to seek to minimise the extent of under or over-recovery, and sets out mechanistic rules to adjust the allowed revenues in subsequent years through the use of appropriate interest rates. This approach is, in Ofgem's view, robust and transparent.

Views invited

5.59. Ofgem welcomes views on any of the issues raised in this chapter, and in particular in respect of the following questions:

- How can Ofgem minimise the adverse consequences of price control re-openers if they prove to be unavoidable – even in the context of more sophisticated mechanisms for adjusting revenues automatically within the price control period?
- How should the information on NGET's and National Grid NTS's performance under their current SO incentives, as set out in the report compiled by National Grid, be interpreted by Ofgem in developing an appropriate regulatory regime for these activities from 1 April 2007 onwards?
- How might the differences between transmission and distribution, discussed above, influence the design of information quality and rolling incentives as part of the TPCR?
- How might any additional reporting arrangements (or financial incentives) in respect of environmental impacts be framed, and are such arrangements an appropriate element of the overall regulatory regime given the wider legal framework within which the transmission licensees operate?

6. Price control design options – framework

6.1. The discussion in Chapter 5 highlights the wide range of approaches that could be taken in seeking to ensure that the form and structure of the price controls are appropriate for the particular circumstances in which they are designed to operate.

6.2. The role of transmission is to ensure that energy can be transferred in bulk from where it is produced to where it is consumed. The users of the transmission system are therefore the electricity and gas distribution companies (who then distribute the gas and electricity to end consumers) and a small number of very large consumers who are connected directly to the transmission systems. A key challenge in facilitating the development of efficient transmission systems is the mechanisms whereby the (aggregated) needs for transmission capacity from network users are communicated to the transmission companies, and how the transmission companies are rewarded for responding to these demands.

6.3. This chapter sets out a framework for developing the design of the transmission price controls focusing on how the transmission companies respond to the needs of their customers, and how this in turns relates to protecting the interests of gas and electricity consumers.

Protecting the interests of consumers

6.4. A main purpose of the price control review process, linked to Ofgem's primary statutory duty, is to ensure that the revenues that the transmission companies can earn are structured in a manner consistent with protecting the interests of consumers. In respect of funding the provision of capacity on the network to transmission users, there are a number of important areas in which the design of the price control can have significant leverage in this regard in the light of the external environment in which this next price control might be expected to operate. These include:

- **Risk of insufficient investment**: Too little investment (or investment incurred too late) carries significant risks for consumers. At the extreme, transmission constraints could potentially place strains on security of supply. However, a

less dramatic – but very important – risk is that network constraints create unnecessary delays to new market entry, and result in higher prices to consumers. Focused and timely investment is therefore critical to the interests of consumers;

- **Risk of unnecessary investment**: Too much investment (or investment incurred too early) can also carry significant risks to consumers. Transmission assets are long-lived and expensive assets with associated environmental costs; eg in terms of visual amenity. The price control should be structured such that the risk of unnecessary investment being made is minimised.

  This is a particular issue for this TPCR because of the future uncertainty, in both gas and electricity, over the demands of network users, eg as a result of shifts to imported gas (and the increasing role of LNG terminals and interconnectors) and changes in the patterns of electricity generation (eg as a consequence of the anticipated growth of distributed and renewable generation). If investment could be more focused, for instance by being based on better quality information on future network demands, then the risk to consumers would be reduced. A 5% reduction on capital expenditure allowances would have been worth around £150m to consumers over the course of the current transmission price controls;

- **Allocating risk between different stakeholders**: The process of transmission companies meeting the changing needs of network users in a competitive market raises the issue of who bears the risk of costs being higher than anticipated. The price control design is the key determinant in how these risks are shared between all stakeholders. A design which results in high levels of risk being borne by consumers might not be optimal given that most consumers have no means of managing such risks – and might not therefore be in the interests of consumers.

6.5. There are many different price control designs that could be adopted to address these issues. It is Ofgem's current view that the preferred option(s) for the form of price control design will meet a range of objectives (related to, and expanding on, the TPCR objectives set out in Appendix 2), including the following:

- **Compliance with applicable legal requirements.** Such as those within the

Gas Act, the Electricity Act and relevant European law;

- **Efficient network development and system operation.** Transmission companies should have incentives to respond to changing demands for capacity by network users, including optimising the use of existing capacity. In addition, demands for capacity should be backed by appropriate and proportionate long term firm financial commitments by network users, particularly given the long term nature of the underlying investment. This should lead to stranded asset risks being minimised;

- **Preventing undue discrimination.** The transmission licensees are prohibited by statute and/or their licences from discriminating between certain persons and/or classes of persons. Nonetheless, there are advantages – in terms at least of the transparency of the licensees' compliance with these non-discrimination requirements – to designing a price control which prevents or limits to an appropriate and practicable extent the scope for undue discrimination between users and/or categories of users;

- **Promotion of competition.** The arrangements should, to an appropriate extent, promote competition between industry participants (eg electricity suppliers, gas suppliers, gas shippers, and between GDNs and gas shippers in the context of accessing NTS offtake capacity and offtake flexibility);

- **Appropriate allocation of risk.** Risk should be allocated appropriately between transmission companies, network users, and consumers, and the returns available to transmission companies should be appropriate to the risks they face;

- **Preservation of security of supply.** The framework proposed should allow transmission companies to make investment and operational decisions which are consistent with security of supply requirements;

- **Simplicity and transparency.** The package of incentives should form a consistent and coherent whole, recognising interactions between different types of incentives, and should be implemented, to the extent appropriate and practicable, in a simple and transparent manner;

- **Stability.** The price control package for transmission companies should be

designed with the intention for it not to be re-opened before the next scheduled review date;

- **Minimise implementation costs.** The arrangements should not impose disproportionately high implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on consumers; and

- **Clear and appropriate accountability and responsibility**. The arrangements should ensure an appropriate balance between Ofgem and the transmission companies in terms of accountability and responsibility, based on clearly defined obligations and, where possible, ensuring minimal ongoing regulatory intervention and involvement, consistent with the principles of better regulation.

Framework for options

6.6. Given the wide range of possible designs it is useful to seek to identify groups of options. Ofgem considers that, at a high level, options for price control design can be considered on a spectrum based on the cumulative effect of the following factors:

- the extent to which the revenue allowances are dynamic, ie contingent on future events;

- the extent to which dynamic revenues are linked to financial commitments by network users; and

- the manner in which risks (of costs being higher than anticipated, in particular) are allocated between stakeholders, including the share of risk which is borne by the transmission company itself.

6.7. This spectrum of options can be grouped into three broad categories:

- '**Traditional price control**': a pure revenue cap which is static (ie has no links between revenues and future events) supported by access arrangements which require no (or limited) firm financial commitment by users – with risk being shared, through the level at which the revenue cap is set, between the

transmission company and consumers. This approach is heavily reliant on periodic forecasts of efficient investment costs;

- '**User commitment models**': a regulated revenue stream where allowances for additional investment are contingent on commitments by network users, and where there are explicit risk-sharing arrangements defined as part of the package of incentives. The current gas entry arrangements are an example of such a model;

- '**De-regulated revenues**': a 'merchant' regime, where revenues, access arrangements and allocation of risks are negotiated bilaterally between the network company and network users – possibly within a broad framework of regulation for network access through a 'light touch' licensing regime. The regulatory framework would not include price control licence conditions, but would rely on more general licence and other legal obligations, eg compliance with competition law. The current treatment of certain interconnectors is an example of this regime.

6.8. Ofgem's current view is that options based on user commitment should be the focus of this TPCR, while also seeking to ensure an appropriate allocation of risk between network users, transmission companies and consumers. De-regulation of revenues is not considered to be in the interests of consumers in respect of the provision of core transmission networks, given the lack of competitive pressures in undertaking these activities (and hence the need for extensive regulatory safeguards through conditions of the respective licences) and the significant market power that would prevail, and could potentially be abused, in the absence of price controls.

6.9. Similarly, the risks for consumers associated with the design of the price controls highlighted at the start of this chapter indicate the potential difficulties of adopting a traditional price control approach given the external context for this TPCR, and in particular the uncertainty over the nature of future demands for network capacity. To illustrate, at the time of the last gas transmission price control there was significant uncertainty over whether there would be additional capacity required at the St Fergus entry terminal. A traditional price control approach would have required Ofgem to set revenue allowances on the basis of a forecast. The alternative approach adopted as part of that price control, where allowances

were more closely linked to actual demands for capacity, protected consumers from a significant risk of overinvestment. Such considerations are even more relevant to this current price control review, given the significant uncertainties in both gas and electricity.

6.10. The principle of user commitment has therefore been developed through the options for consultation in Chapters 7 and 8. As noted in Chapter 2 above, Ofgem intends to publish preferred options for the form and structure of price controls to apply to the transmission companies from 1 April 2007 in the third TPCR consultation document in March 2006.

The role of charging within the framework

6.11. The framework outlined above does not consider explicitly the structure of transmission charges or the interaction of charging mechanisms with the price control. In principle, Ofgem's approach is that charges should reflect the costs that users impose on the network. Consideration of the current arrangements, however, illustrates different approaches in gas as opposed to electricity in providing network users with signals as to the costs of using the networks at different points. The TPCR represents an opportunity to examine these differences, and implement greater consistency to the extent appropriate.

6.12. There are two broad models in use currently:

- A model in which the charging methodology is separate from the price control, eg electricity transmission, where NGET has licence obligations to establish a methodology meeting certain prescribed objectives and approved by the Authority, and to keep that methodology under review at all times and propose modifications where appropriate; and

- A model in which aspects of charging are linked (whether formally or through 'custom and practice') to parameters set as part of a price control, eg reserve prices in gas entry auctions.

6.13. The locational cost parameters specified in the price control in the context of gas entry (ie UCAs[19]) perform two separate functions at the same time. First, they are used by National Grid NTS as the basis for setting reserve prices in entry capacity auctions. Second, they are used as part of the calculation of incremental revenues associated with the release of incremental capacity by National Grid NTS, ie they are an entry-point specific revenue driver.

6.14. It should be noted that while there is no formal requirement for reserve prices to be linked to UCAs, this is how the arrangements have been applied in practice by National Grid NTS and this approach has been broadly supported – in the context of this price control period – by Ofgem. However, the TPCR represents an appropriate point to review the practical implications of this link between the price control and charging arrangements. Ofgem is considering whether the approach adopted in electricity, ie of charging being formally and practically separated from the price control, should be adopted in the context of gas. This does not mean that cost reflective locational revenue drivers could not form part of the gas price control design. It simply means that the value of the revenue drivers would not necessarily be held equal to the level of the reserve price or charge.

6.15. The advantages and disadvantages of such a separation in the context of gas transmission (recognising that such separation already exists in the context of electricity transmission) are considered below. On balance, it is Ofgem's current view that there is merit in seeking to separate, both formally and operationally, the roles of charging methodologies and revenue drivers.

Advantages

- **Separation would enable reserve prices to be updated more frequently**: This could be important in ensuring that charges and reserve prices are more dynamically cost reflective rather than being reset to be cost-reflective at the start of each price control, ie once every five years;

[19] Unit Cost Allowances (UCAs) are parameters set in the price control, and which form the basis of the calculation to determine how much additional revenue National Grid NTS earns if it releases incremental capacity. A UCA is set for each entry point (and for new entry points as and when they are established).

- **Clearer lines of accountability**: Arguably, the practical operation of the current arrangements as they have evolved in the context of gas could be viewed as blurring the responsibility for setting and updating gas transmission charges, which formally rests with the National Grid NTS under the terms of its licence, but in which Ofgem plays a significant and detailed role in practice. This contrasts with electricity transmission, where NGET is responsible for developing its charging methodology and setting (and re-setting) tariffs pursuant to it, and where the Authority's role is limited to a right of veto over the initial proposed methodology and any subsequent proposed methodology changes;

- **Transparency**: Establishing a formal methodology for setting, and amending, reserve prices will arguably increase transparency, when compared to the current regime in which the reserve prices were, in effect, set by Ofgem in the context of a price control review and have remained unchanged since the start of the current price control period. The benefits are, however, dependent on the quality of information that might be made available by National Grid NTS in support of its methodology – including access to the underlying network model and modelling assumptions.

Disadvantages

- **Need for alternative revenue drivers**: If the UCAs (Unit Cost Allowances - which form currently the basis for the reserve prices in the auctions) as set in the price control are properly assessed and cost reflective, they could be the best basis for a revenue driver, so that separating UCAs (as the basis for reserve prices) and revenue drivers could result in less accurate revenue drivers; and

- **Certainty**: Cost-reflective charges change over time and these changes, while entirely appropriate, mean that future charges are less certain over a price control period than charges which are, in effect, fixed ex ante for five years. However, a process of updating charges only once every five years is likely to involve greater uncertainty for users in the period approaching when they are to be re-set – because the potential changes could be relatively large if there have been significant changes in locational costs over the five year

period.

Implementation issues

6.16. Subject to further analysis of the underlying legal framework, the adoption of this approach in gas could require National Grid NTS to consult on, and then submit to the Authority for approval, a modified charging methodology. Reserve prices calculated pursuant to the methodology would be updated periodically, as is the case with other types of charge currently.

6.17. For this approach to be adopted, given the timescales involved, it would be necessary for National Grid NTS to undertake some preparatory work in advance of the Third Consultation in March 2006. This work should, in Ofgem's view, involve the development of a new network model to underpin the required changes to the methodology, given its potentially expanded scope and application to set and amend reserve prices and charges on an ongoing basis for (existing and newly established) offtake and entry points. The current network model is not as transparent and readily available as, arguably, it could be – and is recognised as being inappropriate for the identification of investment costs associated with large changes in the demand for capacity at particular points.

6.18. To this end, Ofgem wrote to National Grid NTS on 2nd December. The letter was published on the Ofgem website, and a copy has been placed on the TPCR website for reference[20]. In Ofgem's view, if the refined methodology approach were to be adopted, then it should be used both for gas entry and offtake points, and for small as well as large flow increments. The model (populated and regularly updated) should be made publicly available.

Views invited

6.19. Ofgem would welcome views on any of the issues discussed in this chapter, and would particularly welcome views on:

- Whether respondents agree that Ofgem's focus on 'user commitment' options is appropriate, or whether they consider that there are other

[20] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/transpcr

traditional price control options (or de-regulated revenue options) that might better meet Ofgem's objectives for the TPCR, particularly in the context of the Authority's statutory and other legal duties?

- What is the appropriate allocation of investment risk between network users (both generally and at specific locations), transmission companies, and consumers, during the different phases of investment development, e.g. planning and design, construction, and operation?

- Whether it is appropriate to seek to separate, both formally and operationally, the issue of how charging and reserve prices are set at gas entry from the issue of how incremental revenues are determined under the price control?

7. Incentives options - gas

Introduction

7.1. This chapter considers options for price control design in the context of gas transmission entry and offtake.

7.2. The options identified for gas offtake include models of price control design which require associated changes to the underlying arrangements under which network users book and pay for network access. The options discussed for gas entry are, in contrast, broadly consistent with the current access and charging arrangements.

7.3. The options have been chosen as being consistent in Ofgem's view with the objectives for incentive design outlined in chapter 6 above – and are informed by experience of the current arrangements in gas entry and gas offtake.

7.4. In addition to the detailed issues of incentive design discussed below, the TPCR represents an opportunity to review certain detailed aspects of the access arrangements more generally – given the interactions between these arrangements and the price control. In particular, Ofgem would like to highlight the following as issues needing more detailed consideration in due course:

- the circumstances, eg in pricing capacity in the very short term, in which it might be appropriate for reserve prices to be set at zero, and
- the obligations in place on National Grid NTS to hold back a proportion of capacity for release in the shorter-term, eg month ahead.

Context

7.5. This section:

- sets out how entry capacity and off-take options described in this chapter have been constructed, and identifies a number of related issues; and
- discusses issues that have arisen in the operation of the current gas entry regime that might inform assessment of the advantages and disadvantages of

the different options which are described in this chapter.

Constructing the options

Revenue drivers and baselines

7.6. The purpose of the price control review for National Grid NTS is to provide sufficient remuneration for National Grid NTS to meet its obligations and to provide appropriate financial incentives for it to do so efficiently. It is therefore contingent on how those obligations are defined. A common (either implicit or explicit) and useful demarcation is between (a) obligations to provide a 'baseline' level of outputs and (b) obligations to provide 'incremental' output over and above the baseline.

7.7. The price control could be designed to remunerate National Grid NTS for baseline and incremental provision under a single revenue allowance. However, because the need for incremental outputs is generally more uncertain at the time the price control is set, there is some value in considering separate remuneration arrangements for baseline and incremental capacity.

7.8. A package which provides National Grid NTS with an additional revenue stream to provide incremental outputs, if they prove to be needed, is a revenue driver, ie an automatic mechanism for revenues to adjust in response to future events. The key output in the context of gas entry and gas offtake is capacity. The most obvious revenue driver in this context is therefore some form of unit revenue which is then applied to the volume of additional capacity actually provided.

7.9. A revenue driver can be structured in many different ways. At a high level the dimensions are:

- whether the unit revenue allowance is a single global average, or a number of different locational or zonal allowances;
- whether the unit revenue allowance is fixed at the start of the price control period, or whether it changes during the price control period; and
- at what point the revenue allowance is re-based to actual rather than forecast unit costs (implicit in the unit revenue allowance), ie whether the revenue

driver is intended to set revenues for a fixed period of time, eg five years under a rolling incentive, or whether the revenue driver is intended to provide a revenue stream for the period until the next price control review.

7.10. The price control design must also specify the circumstances in which the revenue driver is activated, ie what defines an output as being incremental. There are two elements to this question:

- how is the baseline set; and
- what, if anything, needs to happen to trigger an obligation on National Grid NTS to provide incremental capacity.

7.11. The first point itself encompasses two questions. First, how is the baseline specified? For example, is it stated as series of nodal values, relating to individual entry points, or as a smaller number of more aggregated values? Second, what is the technical basis upon which the number, however specified, is calculated? The first question is discussed in detail below. The second question will be addressed in detail in the Third Consultation in March 2006. Appendix 7 sets out the different technical approaches that might be adopted.

7.12. The second point mentioned above links directly to how capacity is booked by shippers, Gas Distribution Networks (GDNs) and Transmission Connected Customers (TCCs). If capacity demands can be met within baseline outputs (and revenue allowances) then incremental capacity is not required and should not be funded. Conversely, if there is demand for capacity over and above baseline, then there should be a mechanism for network users to indicate this need – and for National Grid NTS to be funded to deliver it in a timely and efficient manner.

Capacity booking arrangements and buy back incentives

7.13. There are two broad, potentially complementary, frameworks under which capacity could be provided to a network:

- Users tell National Grid NTS what capacity they will need, by location and by year, and National Grid NTS plan the network on the basis of these forecasts (and all other relevant information); and/or
- Users buy, or make a firm financial commitment towards, what they think

they will need in advance, and National Grid NTS plan the network on the basis of these advance bookings (and all other relevant information).

7.14. Under either approach there is then a question of what happens if there is insufficient capacity to meet demand, ie how do users see the effects of constraints? Under the second framework, where users have bought a forward capacity rights, the standard approach is for National Grid NTS to have to buy back those rights if they cannot be accommodated physically on the network. Such buy-back costs are another cost which needs to be allowed for in the revenue restriction.

7.15. Finally, there is the question, in the context of any model involving the purchase of forward capacity rights, of the method of purchase. There are two broad models:

- An auction, with any rationing of available capacity rights done on criteria linked to the value of individual bids; or
- Purchase at administered tariffs, with any rationing of available capacity rights done on the basis of some other criteria (eg date of connection).

7.16. Auctions are currently used at gas entry, while administered tariffs are used at gas offtake, and in the context of electricity transmission.

Issues under the current entry arrangements

7.17. The current gas entry arrangements are based on auctions for long term and short term capacity. A baseline level of capacity was set at the start of the current price control for each entry point, with associated baseline allowances for capital expenditure. If bids in the auctions reveal demand for capacity in excess of the baseline, then in the short term the available capacity is rationed by price, and in the longer term a test is applied to determine whether additional capacity should be released.

7.18. The test for additional capacity is based on the value of the bids for capacity relative to the assumed cost of providing the additional capacity. The assumed cost is linked to unit cost parameters (UCAs) set at the start of the price control. If the test is met and incremental capacity is released, then National Grid NTS is

entitled to an additional revenue stream based on auction bids, with a maximum return of 12.5% on the assumed investment cost and a minimum return of 5.25% on the assumed investment cost, for a rolling five year period.

7.19. If a new entry point is established, then the price control licence condition is modified to establish a new unit cost parameter for the new entry point. Once this is established, auctions are run for the new entry point. The baseline for new entry points is set at zero.

7.20. Since the implementation of the entry arrangements in April 2002 a number of issues have arisen that might inform how baselines and revenue drivers are set going forward:

- **Capital expenditure allowances for the current price control period seem generous, with the benefit of hindsight, due to importance of new entry points**: The allowances under the last price control anticipated significant expansion of NTS capacity at existing entry points, which has not materialised in practice (as evidenced by bidding in the auctions). Network expansion has been driven by the creation of new entry points, such as Milford Haven. Information provided to Ofgem by National Grid NTS in its HBPQ indicates that its cumulative capital expenditure over the first three years of the current price control was around 50% of the cumulative price control allowances over the same three year period. While this does not give the full picture over the complete duration of the control, it might indicate that allowances for capital expenditure would appear to have been, with the benefit of hindsight, generous. Arguably, the development of new entry points to the gas network may be a continuing feature over the short to medium term, as the UK shifts to a different pattern of gas supply based on imports and large-scale storage. However, this might not be the case if import capacities are increased at existing entry points;

- **Information from long-term auctions**: Bidding in the auctions has resulted in the release of relatively little incremental capacity at existing entry points – and in significant incremental capacity being released at new entry points. The need, perceived by some shippers (as indicated in correspondence with Ofgem), for additional capacity at some existing entry points has not been backed by bids in the auctions sufficient to trigger the release of incremental

capacity. However, it should be noted that the auctions have provided valuable information to the extent that, for example, they have signalled that no investment has been required at St Fergus, contrary to some forecasts at the time of the last price control;

- **Revenue under-recovery through entry auctions:** As a consequence of shippers buying significant capacity short term (ie on the day) often at zero cost in clearing auctions, the revenues recovered through the auctions are lower than required to meet allowed revenues. The short-fall is recovered through the TO commodity charge. Costs are smeared across all shippers on a non-locational basis – and therefore might be expected to be passed on to consumers. While under-recovery per se might not be a material problem if it reflects the appropriate short-run cost of capacity, it could be a problem if it is based on an artificial assumption about the extent to which the network is unconstrained;

- **Rate of return for National Grid NTS for delivery of incremental capacity which is lower than the assumed cost of capital:** National Grid NTS uses a hurdle test to determine whether incremental investment should be released. Long term bids need to cover a minimum of 50% of the assumed cost of providing the incremental capacity. Shippers at new entry points have adopted (rational) bidding strategies which are designed to meet the test (and no more). Such strategies combined with the parameters of the incentive design result in National Grid NTS earning a return up to one percentage point lower than its assumed cost of capital of 6.25%;

- **'Sterilised' capacity:** The current arrangements set baselines for each existing entry point and assume baselines at new entry points are zero. National Grid NTS is obliged to offer in the entry auctions the whole of the baseline capacity at existing entry points, irrespective of whether it is expected to be used or not. Consequently, this capacity is deemed to be unavailable for other entry points (including new entry points) even if it represents existing physical system capacity which could accommodate the new entry point and re-allocating this capacity to the new entry point could be the most economic and efficient solution. There is, therefore, a risk that if baselines are too high at specific existing entry points, and the incentives on

National Grid NTS are not appropriately designed, then this capacity can be sterilised. It can also artificially inflate the cost signal for new entrants;

- **The network is assumed to be less constrained than it is:** The current levels of baselines are, in total, significantly higher than the forecast peak (1 in 20) demand, which National Grid NTS is obliged to plan its network to meet. While there might be a degree of spare capacity on the network the current baseline levels assume that this is around 20 to 25% - which arguably does not reflect (nor is it necessarily intended to reflect) the physical reality. To the extent that capacity is 'over-sold' relative to physical capability, this could result in higher buy-back costs. Significant emphasis is therefore placed on the structure of the buy-back incentive and the competitiveness of the buy-back market;

- **Buy-back costs**: The market in buying back rights that cannot be accommodated physically on the network has proven to be relatively illiquid. If prices are not competitively determined, ie do not reflect opportunity cost of the party returning the rights to National Grid NTS, then the trade-offs by National Grid NTS between investing and being exposed to buy-back risk might not be efficient;

- **Structure of buy-back incentive**: The current regime combines buy back risk associated with day-to-day system operation with buy back risk associated with construction of large new entry points. Arguably, these costs are different in nature and should be treated differently (including in how the costs are charged back to network users), eg by enabling more focused and flexible risk-sharing arrangements for new entry points – and by supporting and encouraging the appropriate management of risk by stakeholders. This might be particularly important in the context of the next price control period where changes to the pattern of gas flows – and therefore the need for new entry terminals – might be further in evidence;

- **Planning processes and investment lead times**: There are a number of factors evident over recent years to suggest that the process for obtaining planning and other consents is taking longer than historically experienced. For instance a 12 month data gathering requirement is often required for the environmental impact assessment and the potential issue of compulsory

purchase orders can also be time consuming. This can affect the relevant timescale in which capacity rights should be made available and could significantly affect the scale of buy back risks if compensating adjustments are not made. However, any such adjustments must not dilute the extent to which National Grid NTS acts efficiently where it can influence planning timescales.

Entry incentive options

7.21. As outlined at Ofgem's October gas incentives workshop, Ofgem is considering three broad entry incentive options covering the approach to baselines and the revenue driver for the next price control period (ie April 2007-2012). All of these options are, in Ofgem's view, potentially compatible with the objectives set out in chapter 6 and practicable within the broad framework of the current arrangements.

7.22. Ofgem has not excluded consideration of alternative options involving more fundamental change to the underlying framework under which network users procure capacity and would welcome views on such options. However, alternative approaches would need to be consistent with the framework described in chapter 6 and it would be necessary to demonstrate why fundamental change was necessary now, after only a limited amount of experience of the existing regime, bearing in mind the possible adverse impact on perceptions of regulatory consistency.

7.23. The rest of this section therefore focuses on the options set out at the October workshop. The assumptions underpinning those options, which are consistent with the 'user commitment' framework described in chapter 6 above, are that:

- Network users are given the opportunity periodically to buy entry rights of varying durations;
- The price paid for the rights is determined by an auction, with a reserve price set for each location ahead of each auction;
- The entry rights bought are financially firm, and are defined by time and location;

- Rights are not transferable between locations.

7.24. The broad options for the revenue restriction relate to the questions of how baseline capacities (ie volumes of capacity which National Grid NTS is obliged to make available in return for its base allowed revenues) are set, and how revenues drivers are structured. Four options are discussed below. It should however be recognised that there are many potential variants of each option.

- **Option E1**: entry point specific baselines with an entry point specific revenue driver;
- **Option E2**: zonal baselines and revenue drivers;
- **Option E3**: a single baseline capacity for the network as a whole with more aggregated revenue driver(s)
- **Option E4**: no ex ante baseline specified by Ofgem (National Grid NTS specifies baselines ahead of each auction) with either an entry point specific or a more aggregated revenue driver.

7.25. The detail of each option is set out below. Each option is described and considered in terms of (a) advantages and (b) disadvantages.

7.26. It is Ofgem's intention to assess, in an appropriate and proportionate manner, the costs and benefits of each of the options relative to the status quo. Responses to this consultation document will inform that assessment. A preferred option based on quantitative and qualitative analysis will be included in the March consultation document.

Option E1: entry point specific baselines with an entry point specific revenue driver (either as in the status quo or a refinement of the status quo)

7.27. Under this approach the baselines would be set ex ante by Ofgem for each existing entry point for the duration of the price control. The values could be set using some form of extrapolation of existing baselines, or could be based on a new method, eg based on demand for capacity as revealed through long-term and monthly auctions uplifted in some way to reflect any spare capacity on the network over and above stated demand.

7.28. Ofgem would determine separate revenue drivers for incremental capacity at each entry point. For price control purposes these revenue drivers would be set (possibly index-linked) for the duration of the price control.

7.29. The issue of whether these fixed values should also be used as the locational reserve prices or charges for the duration of the price control is discussed in chapter 6. Arguably, reserve prices and charges should be capable of changing more frequently to ensure ongoing cost-reflective signals for network users.

Advantages

7.30. Option E1 would:

- be more consistent with current arrangements compared to all other options;
- be clear on the detail of what baseline capacity National Grid NTS is required to make available at each point on the network in return for its base revenue allowances; and
- potentially result in more cost reflective revenue drivers when compared to aggregated (ie averaged) revenue drivers. The approach could also be refined to link the value of the revenue drivers in some manner to a relevant cost index, eg steel prices.

Disadvantages

7.31. But Option E1 would:

- be inflexible to changing demands for (and availability of) capacity at specific points on the network with consequential risk of sterilised capacity;
- run the risk of inappropriately high (or low) baselines – relative to demand for and availability of physical capacity – being locked in, with the result that shippers may have artificially reduced incentives to signal demand for capacity in the long term auctions, or be subject to artificial constraints on the volume of capacity that could be made available by National Grid NTS;
- run the risk, if baselines were set too low, of National Grid NTS being remunerated through the revenue driver for capacity which already exists;

and

- require high levels of Ofgem involvement ex ante, both in relation to baselines and revenue drivers with limited accountability on the part of National Grid NTS.

Option E2: zonal baselines and revenue drivers

7.32. Under this approach the baselines would still be set ex ante by Ofgem, but would be set collectively for zones, with each zone being a group of entry points. If entry point specific baselines were to be set (eg ahead of each auction), then this would be done by National Grid NTS in a manner consistent with the aggregate zonal baselines.

7.33. Ofgem would determine separate revenue drivers for incremental capacity for each zone. For price control purposes these revenue drivers would be set fixed (possibly index-linked) for the duration of the price control.

7.34. For the avoidance of doubt, this option assumes that the entry capacity product will continue to be entry point specific, eg capacity bought for Easington will not confer a right to use capacity at any other entry point, even those entry points which might be in the same zone as Easington for the purposes of setting baselines.

Advantages

7.35. Option E2 would:

- be more consistent with current arrangements compared to options E3 and E4;
- be clear, on a zonal basis, on the detail of what baseline capacity National Grid NTS is required to make available in return for its base revenue allowances; and
- make use of revenue drivers which reflect locational differences in costs between zones.

Disadvantages

7.36. But Option E2 would:

- be inflexible to changing demands for (and availability of) capacity between zones, with the consequential risk of sterilised capacity;
- require difficult judgements on how zone boundaries should be set, and how any new entry points should be allocated to the existing zones, especially given that zones would probably be set for a five year period;
- run the risk of inappropriately high (or low) zonal baselines – relative to demand for and availability of physical capacity – being locked in, with the result that shippers may have artificially reduced incentives to signal demand for capacity in the long term auctions, or being subject to artificial constraints on the volume of capacity that could be made available by National Grid NTS;
- run the risk, if zonal baselines were set too low, of National Grid NTS being remunerated through the revenue drivers for capacity which already exists; and
- continue with relatively high levels of Ofgem involvement ex ante, both in relation to baselines and revenue drivers with the risk of limited accountability for National Grid NTS.

Option E3: Network wide baseline with a global/locational revenue driver

7.37. In contrast to options which involve Ofgem setting baselines for specific locations (either individual entry points or groups of entry points), an alternative option is to remove Ofgem's role in prescribing how capacity should be made available at particular points on the network.

7.38. Under this approach Ofgem would determine ex ante a baseline for the network as a whole for the duration of the price control period. The distribution of the network-wide baseline between individual points (or groups of points) on the network would be a matter for National Grid NTS, possibly subject to some additional regulatory safeguards.

7.39. As with entry point specific baselines the level of such a baseline could be determined in a number of ways and could be set to be flat (ie the same for each of the five years of the price control period) or incorporate some degree of growth. The network wide baseline could provide a measure of the existing level of network capacity/capability, with additional capacity in excess of this baseline level being remunerated through the revenue driver.

7.40. A simple global driver could be developed based on a standard unit revenue allowance for each unit of incremental (ie in excess of baseline) capacity. The units of incremental capacity, under a more sophisticated variant, could be weighted by size of increment and distance (along the pipeline routes) to a central reference point. More complex revenue drivers could be developed by including weightings for a number of additional variables such as type of terrain, material costs, minimising environmental impact etc.

7.41. Ofgem would expect to determine such a revenue driver (including the weights to be applied to reflect different factors) on an ex ante basis for the whole price control period. This revenue driver would apply to all incremental capacity, irrespective of whether it was at an existing or a new entry point.

Advantages

7.42. Option E3 would:

- be more flexible than E1 and E2 to changing demands across the network;
- afford more accountability (within the context of an obligation to provide a certain level of capacity in aggregate) to National Grid NTS as to the detail of how capacity is allocated to specific entry points;
- optimise the use of existing capacity which could eliminate – or reduce, in the context of a zonal approach the risk of sterilised capacity; and
- provide stronger incentives for shippers to reveal their demands for longer term capacity to ensure that the capacity is not allocated elsewhere by National Grid NTS.

Disadvantages

7.43. But Option E3 would:

- increase National Grid NTS discretion in relation to the allocation of capacity (noting that the baseline would not reflect physical reality, given that capacity cannot be shifted in an unconstrained manner between all entry points) with a risk that such discretion (absent other safeguards) would not be exercised in the interests of consumers;
- potentially involve regulatory involvement to address National Grid NTS discretion, such as placing additional obligations on National Grid NTS to establish a capacity allocation methodology and network model and an obligation to maximise use of existing capacity (and thereby minimise the need to provide additional funding for incremental capacity); and
- potentially involve Ofgem to a greater extent in dispute resolution in the event that a user challenges how National Grid NTS has allocated baseline capacity.

Option E4: no ex ante baseline specified by Ofgem (National Grid NTS specifies baselines ahead of each auction) with either an entry point specific or a more aggregated revenue driver

7.44. Under this approach, there would be a formal requirement for National Grid NTS to release all physically available entry capacity at any point in time, but Ofgem would not explicitly specify volumes of capacity to be released (in aggregate, or at any particular location at any particular point in time).

7.45. The revenue driver could be either entry point specific or global as discussed in the previous options. However, by definition, the revenue driver would need some reference point against which to operate.

Advantages

7.46. Option E4 would:

- increase flexibility to changing demands across the network;

- place more accountability on National Grid NTS as to the detail of how capacity is allocated to specific entry points;
- have the potential to optimise the use of existing capacity, because of the absence of external constraints on the volumes of capacity that must be made available by National Grid NTS;
- significantly reduce, if not eliminate, the risk of sterilised capacity;
- require less ex ante Ofgem involvement with increased National Grid NTS accountability; and
- increase incentives on shippers to procure capacity in short- and long-term auctions to be certain that the capacity is not allocated elsewhere by National Grid NTS.

Disadvantages

7.47. But Option E4 would:

- involve significant exercise of discretion by National Grid NTS to determine the total amount of available capacity and how it should be allocated between different points on the network. That being the case, and if information asymmetries between Ofgem and National Grid NTS are significant, it could be difficult for Ofgem to determine whether relevant licence and/or statutory obligations of the licensee are being met; and
- mean that it would be difficult to define incremental capacity without defining baseline capacity. This could raise issues with respect to remuneration of incremental capacity and existing capacity.

Assessment of the entry options

7.48. The discussion above identifies advantages and disadvantages with all four options. An assessment of which option (including variants of the options discussed above) is preferable overall will depend on how the relevant criteria are determined, how the options are characterised in respect of each criterion, and how each criterion is weighted.

7.49. Attached as Appendix 9 is a list of potential criteria that could be adopted in assessing the options, based on the objectives set out in Chapter 6 above and the issues identified through the operation of the current arrangements.

7.50. Respondents are encouraged to comment on how these (and other variant) options might score against these criteria, using the template provided in Appendix 8. These views, together with further analysis to be undertaken by Ofgem, will inform the proposals to be set out in the Third Consultation in March 2006.

Gas offtake

7.51. This section sets out how National Grid NTS's revenue restriction might be structured in respect of providing capacity to take gas off the NTS. This issue – and the associated issues of how users book, and are charged for, offtake capacity – is particularly important in the context of the sale by National Grid NTS, on 1 June this year, of four of its GDNs. GDNs and TCCs such as power stations and gas storage facilities are the main customers of National Grid NTS in its provision of offtake capacity.

7.52. In the following section, Ofgem considers the gas offtake regime and the background underlying the development of the enduring offtake arrangements. A number of options are then set out for the development of these arrangements through the TPCR process.

Background

7.53. As part of its January 2005 decision to give conditional consent to the sale of four GDNs, the Authority concluded that the continued development of the "enduring" offtake arrangements[21] was necessary to protect the interests of consumers in a divested industry structure.[22]

7.54. Prior to the sale, it was envisaged that an "enduring" regime for NTS offtake arrangements would be implemented in September 2005 to apply to capacity

[21] As described in: *National Grid Transco – Potential sale of gas distribution network businesses – Final Impact Assessment,* Ofgem, November 2004

[22] *National Grid Transco – Sale of gas distribution networks: Transco plc applications to dispose of four gas*

released from 1 October 2008 onwards[23]. With this in mind an "interim" regime was implemented, on 1 June 2005, to apply to capacity released up to and including 30 September 2008 and Ofgem issued, in February 2005, its "Initial Thoughts" on the framework for the enduring regime (the 'February Initial Thoughts')[24].

7.55. In June 2005, the Authority decided to delay until September 2007 the implementation of the enduring offtake arrangements for the release of NTS offtake rights from 1 October 2010[25]. The intention was, amongst other things, to allow the further consideration of potential interactions with the NTS entry capacity regime as part of the TPCR process. However, the Authority noted the continued importance of implementing the proposed reforms.

7.56. In the light of this decision to delay, Ofgem is currently:

- implementing "transitional" incentives to apply to capacity booked in the period from 1 October 2008 to 30 September 2010[26] [27]; and
- considering a number of high level options for the development of the enduring regime, in the context of possible options at gas entry and for electricity transmission, rather than progressing the incentive proposals outlined in the Initial Thoughts document at this stage.

7.57. It is proposed that the details of the regime should be finalised by December 2006, consistent with the TPCR timetable to allow interactions with the price control determination to be taken into account, and be consistent with the

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distribution networks, Authority decision, February 2005.
[23]Cconsistent with typical investment lead times of three years.
[24] *National Grid Transco – Potential sale of gas distribution network businesses: Initial thoughts on enduring incentive schemes supporting the offtake arrangements*, Ofgem, February 2005, 31/05. Responses to this consultation have been attached to this document on the Ofgem web-site: www.ofgem.gov.uk.
[25] 151/05 - Enduring offtake arrangements, 24 June 2005, Ofgem
[26] *Final proposals on transitional incentive schemes and formal licence consultation under section 23 of the Gas Act 1986 and paragraph 3(a) of Standard Special Condition A2*, Ofgem, November 2005.
[27] In its Final Proposals consultation on transitional incentives, Ofgem stated that it did not propose to specify NTS incentives for the transitional period at this time as it considered that the potential benefits of considering the most appropriate scope and form of NTS incentives at the time of the TPCR outweighed the potential costs resulting from a lack of certainty regarding the cost-recovery and treatment of investment for the transitional period. Ofgem stated that this would enable incentives to be set following the operation of the interim incentives. This would provide the opportunity for incentives to be set in the context of wider price control agreement and enable Ofgem to consider more fully all interactions between entry and offtake.

timetable for gas entry and electricity incentives. This should also allow affected parties sufficient time to plan for the forthcoming arrangements and make procedural and systems changes as necessary.

Options for enduring offtake

7.58. Ofgem considers that there are two broad options for the enduring offtake arrangements and ultimately the price control design:

- **Status quo** (as defined by the transitional offtake arrangements); and
- **Long term user commitment models**

7.59. In the remainder of this section, Ofgem considers both the status quo and long term user commitment models in the light of the objectives set out in Chapter 6. This includes consideration of associated potential reforms to the nature of the products being made available to shippers, GDNs and TCCs, such as the introduction of a flat capacity product and a flex capacity product. Ofgem discusses the potential advantages and disadvantages of each approach and considers potential variations on the long term user commitment model.

Status quo

7.60. The status quo in this case is defined to be the arrangements and associated incentives that are proposed to be in place in relation to capacity released between 1 October 2008 and 30 September 2010 (the "transitional" arrangements)[28]. It should be noted that the transitional arrangements are currently in the form of proposals, and that nothing in this document fetters the discretion of the Authority in making any decision in the context of these proposals.

7.61. Under the status quo, baselines would be specified in order to determine the outputs associated with the National Grid NTS revenue allowance and allow remuneration of additional outputs provided above such baseline levels. Incremental investment above baseline would be funded by allowing the pass-

[28] See *Final proposals on transitional incentive schemes and formal licence consultation under section 23 of the Gas Act 1986 and paragraph 3(a) of Standard Special Condition A2,* Ofgem, November 2005.

through of depreciation and financing costs associated with incremental firm offtake capacity, calculated according to a defined methodology, and subject to Authority approval.

7.62. Only GDNs would be required to make requests for capacity at the three year ahead stage. TCC shippers, in contrast, would effectively be guaranteed "grandfathered" rights without the need to commit to buy in the long term. Furthermore, where capacity requests made by GDNs or on behalf of TCCs were judged, by National Grid NTS, to trigger additional investment, the GDN would be required to enter into an Advance Reservation of Capacity Agreement (ARCA) with National Grid NTS. The terms of this agreement would be a result of bilateral negotiations between National Grid NTS and the relevant connectee. Ofgem would have an important role in settling any disputes that might arise on the terms of the ARCAs.

7.63. TCC shippers would (unlike the GDNs) continue to purchase a combined "NTS offtake capacity" product rather than separate products for NTS offtake flat capacity and NTS offtake flexibility capacity. Furthermore, NTS interruptible status would continue to be available to TCCs on request, with no notice period required.

Advantages

7.64. The status quo:

- represents minimum change, with low implementation costs;
- provides a degree of certainty and stability for existing industry participants; and
- is administratively simple for incumbent TCC shippers to the extent that existing capacity rights can be rolled over from year to year.

Disadvantages

7.65. However, as Ofgem has identified previously the status quo suffers from a number of weaknesses:

- the current framework places only weak incentives upon National Grid NTS

to provide capacity in a timely and efficient basis;

- given that TCC shippers do not have to signal their intention to continue use of the network beyond 12 months but have, in effect, an open-ended right to use offtake capacity, the existing framework might be viewed as one which could facilitate:
  - discrimination between GDNs and TCC shippers;
  - discrimination between new and existing users to the extent that, where investment is necessary, new users are required to enter into ARCAs to enable them to access the NTS; and
  - inefficient investment decisions due to a lack of investment signals from existing users.
- TCC shippers would continue to purchase a combined capacity product, whilst GDNs would purchase two products: flat and flexible capacity. This difference, particularly if the prices of these products diverge, might give rise to concerns that the existing framework could potentially facilitate discrimination between users or classes of user;
- the current framework only provides weak financial incentives for National Grid NTS to optimise the trade-off between investment and interruption, which may result in additional costs being incurred by customers;
- the requirement for connecting parties, or those that require additional network capacity, to enter into ARCAs reduces the transparency of the arrangements and gives National Grid NTS a degree of discretion. This could result in significant involvement by Ofgem in the settlement of disputes over the terms of the ARCAs; and
- there is no competition for capacity across substitutable nodes, and as such, capacity may not be made available to those that value it the most during periods of constraint on the network[29].

[29] However, "buddying" gives users the opportunity to link a firm site with an interruptible site such that, in the event of a decision to interrupt the interruptible site, the firm site could, instead, reduce its demand.

Long term user commitment models for offtake

7.66. This section sets out a number of options for long term user commitment models which could be adopted for offtake. They outline the manner in which baselines could be set and the nature of the product that would be offered to GDNs and TCC shippers. These are key elements in determining how the price control will operate.

7.67. Ofgem's current assumption is that the overall framework within which these models would operate would have the following characteristics:

- a consistent framework of access products made available on a non-discriminatory basis between all classes of network users (which Ofgem currently anticipates would involve some separation of access products, eg a 'flat' offtake capacity product and a 'flow flexibility' capacity offtake capacity product);
- financially firm access products of various fixed durations, including over timescales in excess of estimated investment lead times, which would be available at a regulated price;
- mechanisms that provide for the efficient allocation (and pricing) of access products in the event that the supply of such products is insufficient to meet demand for such products; and
- interruption being managed through the buying back of rights, if necessary, in the short term or pursuant to longer term contracting (which might, for example, provide National Grid NTS with an option to buy-back at specified rates).

7.68. It should be noted that models consistent with these characteristics are likely to require consequential changes to the underlying commercial and access arrangements to operate as intended. Any such changes would need detailed development through the relevant governance processes, including the UNC.

7.69. It is Ofgem's current view that the objectives set out in chapter 6 for a price control and associated set of access arrangements cannot be met without such

consequential changes.

7.70. It is Ofgem's intention to assess the cost and benefit implications of each of the long term user commitment models (including the relevant access arrangements) relative to the status quo. Responses to this consultation document will inform that assessment. However, in addition, Ofgem proposes to undertake a survey in January on costs associated with each option as a means of further informing the impact assessment process. Initial findings will be published in March 2006 in the context of Ofgem identifying a preferred option for further development and assessment.

Baselines and product definition

7.71. As discussed earlier in this chapter, the design of revenue drivers requires a demarcation between outputs that are required to be delivered in return for a base level of funding, and outputs that are incremental to this, and therefore require additional funding. A related question is what trigger is used to oblige National Grid NTS to deliver incremental outputs.

7.72. This section considers high-level options for long term user commitment models defined in relation to two parameters:

- the approach to setting baselines
- the definition of the product to which the baselines apply, ie is National Grid NTS required to provide nodal or zonal rights to take gas off the network.

7.73. The long term user commitment models considered in this section are as follows:

- Option Ex2: A model consistent with the February Initial Thoughts document ie a nodal model with a substitution incentive;
- Option Ex3: Nodal product with zonal baselines;
- Option Ex3A: Nodal product with global/ network wide baselines; and
- Option Ex4: Zonal product with zonal baselines.

7.74. Each of these models is summarised in Table 2 below relative to the status quo.

Table 2:

	Status Quo	**Long term user commitment models**			
	Option Ex1	Option Ex2	Option Ex3	Option Ex3A	Option Ex4
Baseline	(LDZ)	Nodal	Zonal	Global/ network wide	Zonal
Product definition	Nodal	Nodal	Nodal	Nodal	Zonal
Substitution	×	✓	×	×	×

7.75. However, Ofgem would note that one potential, more wide-ranging, option would be to consider a 'no baseline' model where there would be no formal requirement to make available a specified (either global or local) volume of capacity. National Grid NTS would simply be obliged to make available all physical capacity at any point in time. As with the equivalent option presented for entry, it is noted that some form of reference point would be needed for revenue purposes to which a revenue driver could be applied.

Advantages of long term user commitment models

7.76. Long term user commitment models would:

- reduce the potential for undue discrimination between NTS users by ensuring that all categories of users are subject to equivalent access arrangements (including the products available to them), as both GDNs and TCC shippers would be able to make requests for capacity at the three year ahead stage through long term allocation mechanisms;
- provide National Grid NTS with improved investment signals and hence reduce the risk of stranded assets and promote security of supply on the NTS as, by booking longer term, market participants will be able to obtain capacity at a regulated price and therefore avoid the risk of paying a higher price in short term capacity allocations in the event of capacity constraints;
- promote competition between market participants with regards to optimising

capacity booking decisions;

- by creating a separate product for NTS offtake flexibility, allow GDNs and TCC shippers to make appropriate trade-offs between NTS offtake flexibility, alternative forms of diurnal storage, and interruption (or a decision not to offtake gas on the part of the TCC shippers);
- improve the ability of National Grid NTS to optimise the trade-off between investment and adoption of a more flexible framework for NTS interruptions; and
- increase transparency and reduce the likelihood of disputes requiring Ofgem resolution by eliminating the use of bespoke contracting.

Disadvantages of long term user commitment models

7.77. The implementation of long term user commitment models would:

- involve, at least initially, greater complexity and increased implementation costs for NTS users and, in particular, TCC shippers as in their case this would involve a shift away from the status quo.

Option Ex2

7.78. Option Ex2 is, at a high level, consistent with the model outlined in the February Initial Thoughts document on enduring incentive schemes supporting the offtake arrangements.

7.79. Option Ex2 is assumed to embody the key characteristics of a long term user commitment model as outlined above (as are Options Ex3, Ex3A and Ex4). However, what differentiates Option Ex2 from the other long term user commitment models is that:

- the two separate offtake capacity products (NTS offtake flat capacity and NTS offtake flow flexibility) would be available to both GDNs and TCC shippers on an offtake point specific (ie nodal) basis;
- baselines would also be determined for each node; and
- a substitution incentive would encourage National Grid NTS to exploit fully

any potential to substitute NTS offtake rights between offtake points to satisfy demand before undertaking any investment (resulting in a potential resetting of nodal baselines).

Advantages

7.80. Option Ex2 would:

- allow National Grid NTS to make efficient investment decisions, with a resulting positive impact upon security of supply, as specification of a nodal product would result in long term user signals received by National Grid NTS specific to each offtake point;
- maximise the use of the existing network and reduce the potential for discrimination between existing users and new entrants through the implementation of a substitution incentive on the NTS allowing substitution across all nodes; and
- encourage NTS users to purchase capacity in the longer term, thereby improving the investment signals to National Grid NTS and promoting more competitive behaviour amongst NTS users, as the scope for substitution between nodes (and hence the variation of nodal baselines) would mean that the availability of capacity at a particular node within investment lead times would be less certain[30].

Disadvantages

7.81. However, Option Ex2 would also have a number of disadvantages:

- the determination of nodal baselines would require significant Ofgem involvement ex ante; and
- the implementation of a substitution incentive involves a number of potential risks and issues:

[30] Indeed, this model could be developed to overlay exchange rates to facilitate trading between participants.

- a substantial financial incentive may be needed to discourage National Grid NTS from undertaking investment instead of substitution between nodes[31];

- to the extent that the nodal baselines determined are inaccurate and National Grid NTS therefore substitutes between nodes, the substitution incentive will reward National Grid NTS, but impose a cost upon customers in addition to the funding already in place for providing baseline capacity under the price control; and

- the model would require information from National Grid NTS to establish the baselines, and to establish the parameters of a substitution incentive. In this context, information asymmetries may create difficulties with respect to the accurate determination of nodal baselines; and

- even though a substitution incentive would be in place, the determination of nodal baselines may reduce the incidence of long-term signals as, relative to a model with zonal baselines which is discussed further below, it could be viewed as providing some information regarding the possible availability of capacity at a nodal level.

Option Ex3 / Ex3A

7.82. Option Ex3 introduces zonal baselines and option Ex3A takes the special case of a single network-wide zone. The main difference between these options and Option Ex2 is that, rather than defining nodal baselines and super-imposing a substitution incentive, zonal baselines would be determined that would require National Grid NTS to make a quantity of capacity available across a specified number of offtake points. Under this model, National Grid NTS would choose how to allocate the baseline capacity amongst the offtake points in that zone.

[31] In its response to the February Initial Thoughts consultation, National Grid NTS stated that the proposed incentive, whereby it would retain 50% of the auction revenue received for incremental capacity for one year would not provide a significantly strong incentive to choose substitution over investment as it would only provide a small incentive for National Grid Gas to invest in the new technology or systems required.

7.83. Under Option Ex3A, it is assumed that a single, global baseline would be applied where National Grid NTS would be required to make available that volume of capacity to all users of the network in aggregate.

Advantages

7.84. Option Ex3 / Ex3A would:

- allow National Grid NTS to make efficient investment decisions, with a resulting positive impact upon security of supply, as specification of a nodal product would result in long term user signals received by National Grid NTS specific to each offtake point;
- afford more accountability to National Grid NTS (as the party best placed to understand and manage its network) regarding the detail of how capacity is allocated to specific offtake points, by applying more aggregated baselines;
- encourage NTS users to purchase capacity in the longer term, thereby improving the investment signals to National Grid NTS and promoting more competitive behaviour amongst NTS users, as the specification of baselines at a zonal level would mean that the availability of capacity at a particular node within investment lead times would be less certain[32]; and
- be simpler than Option Ex2 as it would not require the determination of baselines for each capacity product at each offtake point and the super-imposition of a substitution incentive.

7.85. The more aggregated the baselines, the fewer are the restrictions placed upon National Grid NTS with respect to how capacity is allocated. As such, a global baseline would allow National Grid NTS to optimise capacity across all offtake points and provide encouragement for NTS users to bid long term. Indeed, under a 'no baseline' approach, there would be even greater National Grid NTS discretion (and less ex ante Ofgem involvement) and hence even greater incentives to procure capacity long-term.

[32] Indeed, this model could be developed to overlay exchange rates to facilitate trading between participants.

Disadvantages

7.86. However, Option Ex3 / Ex3A would also have a number of disadvantages:

- whilst the determination of zonal baselines would allow the substitution of capacity within zones, there is limited scope for substitution between zones. Furthermore, Ofgem will be required to exercise discretion in determining the zones;

- benefits of not imposing constraints upon the allocation of capacity need to be weighed against the risks that National Grid NTS, if provided with greater discretion, may exercise such discretion in a manner inconsistent with the interests of consumers; and

- steps to limit or remove scope for any inappropriate exercise of discretion by National Grid NTS will add a degree of complexity to the overall regime. For example, additional licence obligations may be needed to ensure that there is transparency such that market participants can understand how National Grid NTS is exercising its discretion. Furthermore, the determination of larger zones, whilst reducing ex-ante Ofgem intervention, may increase the potential for Ofgem involvement ex-post in resolving disputes.

7.87. Imposition of a global baseline, or at the extreme, no baseline at all, would increase National Grid NTS discretion, and therefore increase the risks that such discretion may be exercised in a manner which is inconsistent the interests of consumers. In order to mitigate such risks, the regime may need to become more complex and the potential for ex post Ofgem involvement for example through licence enforcement may increase. It should also be noted that in these circumstances information asymmetries between National Grid NTS and Ofgem could be acute (which would make enforcement action difficult) and could require increases in Ofgem resources to monitor closely National Grid NTS's conduct.

Option Ex4

7.88. The main difference between Option Ex4 and Option Ex3 is that, in addition to the baseline, the capacity products would also be defined on a zonal basis such

that a user holding a zonal offtake right would be able to offtake gas at any offtake point within that zone and such zonal offtake rights could be traded with other users within that zone, on a one to one basis.

7.89. Many of the advantages and disadvantages of Option Ex4 are the same as those under Option Ex3. As such, we focus upon the advantages and disadvantages relative to an Option Ex3 approach below.

Advantages

7.90. Option Ex4 would (compared to Option Ex3 / Ex3A) by defining the capacity products on a zonal basis such that the holder of a zonal offtake right would be able to offtake gas at any offtake point within that zone:

- facilitate the bilateral trading of zonal offtake rights within the relevant zone, encouraging competition and therefore allocations of capacity amongst market participants.

Disadvantages

7.91. However, Option Ex4 would also have a number of disadvantages:

- defining the relevant capacity products on a zonal basis would reduce the accuracy of the investment signals received by National Grid NTS and may therefore lead to inefficient investment, indeed, the larger the zones assumed, the more diluted the investment signals;

- to the extent that physical substitution cannot occur on a one to one basis, National Grid NTS may need to buy back capacity at a potential cost to customers;

- the inability of National Grid NTS to be able to determine the specific offtake point at which capacity for which rights are held will be taken off the network would create issues where there are offtake point specific capacity constraints and could create security of supply issues. For example, it may be necessary for National Grid NTS to buy-back significant volumes of zonal capacity in order to have certainty that the constraint at that offtake point had been addressed. In order to avoid such perverse outcomes, (a) additional obligations and incentives may be needed adding a degree of

complexity or (b) reliance would need to be placed upon shipper and GDN licence obligations not to prejudice the safe, economic and efficient balancing of the NTS.

Assessment of the offtake options

7.92. The discussion above identifies advantages and disadvantages with all three options. An assessment of which option (including variants of the options discussed above) is preferable overall will depend on: how the relevant criteria are determined, how the options are characterised in respect of each criterion, and how each criterion is weighted.

7.93. Attached as Appendix 9 is a list of potential criteria – common to entry and offtake - that could be adopted in assessing the options. These are based on the objectives set out in Chapter 6 above and the issues identified through the operation of the current arrangements.

7.94. Respondents are encouraged to comment on how these (and other variant) options might score against these criteria, using the template provided in Appendix 9. These views, together with further analysis to be undertaken by Ofgem, will inform the proposals to be set out in the Third Consultation in March 2006.

Revenue drivers

7.95. Completion of the options for offtake requires the identification of appropriate revenue drivers. The options for revenue driver design are, in broad terms, the same as discussed above in the context of entry options. Specifically:

- **Offtake-point specific revenue drivers**: eg a unit revenue allowance linked to the volume of incremental capacity at each off-take point;
- **Zonal revenue drivers**: eg a unit revenue allowance linked to the volume of incremental capacity for each grouping of off-take points;
- **Global revenue drivers**: eg a single unit revenue allowance for all units of incremental capacity release– possibly weighted to reflect locational factors such as distance from a central reference point.

7.96. Additionally, in determining the appropriate price control to apply from 1 April 2007, Ofgem must determine the form of revenue driver which should apply under the transitional arrangements. The first release of incremental capacity pursuant to enduring offtake arrangements is not likely to be before October 2010, ie three and a half years into the next price control period.

7.97. In the Third TPCR consultation document in March 2006, Ofgem will develop revenue driver proposals for enduring offtake, and will indicate whether and how revenue drivers might be applied prior to the implementation of enduring arrangements.

Buy-back costs and incentives

7.98. The current revenue restriction differentiates for the purpose of setting allowed revenues, between costs associated with system operation activities, such as gas balancing and buy-back, and costs associated with transmission owner activities, ie providing and maintaining the physical network.

7.99. This section focuses on one particular area of system operation costs, which interacts strongly with the design of the price control in respect of transmission owner activities, ie buy-back costs. The wider issues associated with setting incentives for system operator activities, and the associated timetable for the TPCR, are discussed in the next section.

7.100. The options discussed above are based around the concept of incremental capacity being made available to network users in advance of it necessarily being available physically. If National Grid NTS, for whatever reason, is unable to deliver capacity rights physically, then a cost will be incurred by National Grid NTS in the first instance to buy back those rights.

7.101. In some instances buying back capacity rights will be efficient (eg if there is a short term constraint which would be disproportionately expensive to resolve through long term investment). In others, the incidence of buy-back costs might be influenced by factors which are only partially under the control of National Grid NTS (eg the risk that necessary investment is delayed due to delays in obtaining necessary planning consents). In such circumstances a buy-back incentive scheme which is appropriate for a short term constraint may have effects that are disproportionate. The design of a set of incentives for buy-back costs needs to recognise such considerations and ensure that risk is allocated appropriately between shippers, National Grid NTS and consumers.

7.102. This section therefore, considers two broad approaches for the development of the buy back incentive, which might apply both to entry and offtake, although it should be noted that the actual parameters of any schemes might differ between entry and offtake:

- **Approach 1**: retain the current structure of buy back incentive but amend the incentive parameters (eg to include allowances for offtake buy-back costs); or

- **Approach 2**: develop a different incentive structure, eg by providing for more bespoke contractual arrangements in circumstances where buy-back costs and risks might be particularly significant and uncertain.

Approach 1: retain the current buy back incentive but amend the incentive parameters

7.103. Under this option, the current structure of the buy back incentive would be retained, ie with a target level of costs, a cap, collar and sharing factor. However, the cap, collar and sharing factor might need to be changed to achieve an appropriate allocation of risk.

7.104. It may be appropriate to consider a locational component to the buy back incentive which would target a certain proportion of capacity neutrality charges to shippers at the constrained entry point. This could provide an incentive for shippers at a constrained entry point to compete to sell capacity in order to reduce their exposure to buy back costs which would reduce the risk of full buy

back costs being passed on to consumers.

7.105. The duration of the scheme(s) would also need to be considered. One variant is for the parameters to be set with an intention to review after, say, two years. An alternative would be to fix the parameters for the duration of the price control period.

7.106. Currently, connecting pipelines that are to be built by National Grid NTS are not covered by the buy back mechanism until the Aggregate System Entry Point (ASEP). Once the ASEP has been connected, connecting pipelines do fall within the scope of the buy back mechanism. However, it may be appropriate to include connecting pipelines in the buy back incentive going forward on the same basis as network reinforcement more generally.

7.107. It may also be appropriate to develop separate buy back incentive arrangements for operational constraints and incremental investment to take account of the different levels of risk that market participants may be exposed to. For example, it may be appropriate to expose National Grid NTS to more risk for operational constraints than for incremental investment, since delays to incremental investment may be due to a protracted planning consents processes which would be out of National Grid NTS's control.

Advantages

- Requires minimal changes to the current arrangements.

Disadvantages

- The current incentive format may pass the risk of unexpectedly high buy-back costs to National Grid NTS and consumers. Once the collar on National Grid NTS losses is met these costs would be borne by consumers alone;
- Shippers have no incentive to manage buy back risk;
- The parameters might be set inappropriately due to limitation on available information or unanticipated future events.

Approach 2: develop different structures for buy-back incentive to apply in

different contexts

7.108. An alternative approach would be to tailor the buy-back incentive arrangements differently for different contexts. For example, the standard form of incentive might apply to 'core' operational buy-back risk in the context of the existing network, while alternative more bespoke arrangements might apply in the context of new entry points (and the associated planning and construction risk).

7.109. This approach could include a non linear incentive which is linked to buy back volumes. For example National Grid NTS could be less exposed to low volumes of buy back costs and more exposed to high volumes. Also, shippers could be exposed to high volumes of buy back costs through a locational element to the capacity neutrality charge. A non linear incentive could also include an overall cap on buy back costs which would reduce consumers' exposure to buy back costs.

7.110. More flexible contractual arrangements which specified the scope, timescales and costs of an investment could also be facilitated under this option. For example a contract could enable a shipper or developer to fund National Grid NTS's preliminary work to reduce the investment lead time. Also shippers and National Grid NTS could agree to deliver investment at a relatively high cost but in a short timescale or at relatively low cost with longer timescales.

7.111. Contracts could also be utilised to enable shippers to agree a cap on buy back costs if National Grid NTS is unable to deliver the investment within the agreed timeline and in exchange the shipper may negotiate reduced exposure to the buy back incentive. Ofgem would need to consider how any contractually agreed arrangements may impact on the buy back incentive.

Advantages

- More bespoke arrangements in certain circumstances (eg where there is significant planning or construction risk) might result in more appropriate risk sharing – and might promote more efficient management of risk;
- Greater scope for flexibility through contractual arrangements;
- Shippers could be incentivised to manage buy back risk through contracts

which included terms for capping buy back costs/ reducing a specific shippers exposure to buy back costs in the event of late delivery of investment.

Disadvantages

- Some of the options may lead to greater complexity;
- Use of bilateral contracts may lead to less transparency.

Wider system operation costs and incentives

7.112. The current revenue restriction for National Grid NTS encompasses a number of individual incentive schemes for particular aspects of system operation activities. National Grid NTS's performance under each of these schemes is summarised in a report compiled by National Grid NTS and published today on the TPCR website.

7.113. The current set of NTS System Operator Incentives encompass six external cost schemes, three of which are, in terms of the scope of activities, discussed above:

- Entry Capacity Incentive;
- Entry Capacity Buy-Back;
- Offtake Capacity Incentive; and
- Offtake Capacity Buy-Back (introduced in June 2005).

7.114. The three other external costs schemes are:

- System Reserve – Gas Cost;
- System Reserve – System Balancing; and
- Residual Gas Balancing.

7.115. The revised revenue restriction to be put in place for National Grid NTS will need to address how revenues are to be set for these activities. Ofgem will bring forward more detailed proposals for consultation

on these issues in the Third Consultation in March 2006.

7.116. Ofgem considers that the broad structure of these incentives is appropriate to be applied going forward – although clearly there is detailed analysis to be undertaken to set the scheme parameters. There are also a number of higher level issues that will need to be considered in developing more proposals, for example:

- Should the durations of the schemes be aligned to the duration of the main price control?
- Are three separate schemes appropriate, or is there scope to consolidate under a smaller number of schemes?
- What can operation of the current arrangements tell us about how the schemes might be refined, eg in terms of how risk is shared between consumers, shippers and National Grid NTS?

Views invited

7.117. Ofgem welcomes views on the issues raised in this chapter, and seeks responses on the following detailed questions in particular:

Revenue drivers for entry and offtake

(a) Should the revenue driver be nodal, zonal/locational or global? What are the advantages and disadvantages of these different options – and to what extent do these advantages and disadvantages differ between entry and offtake? If a zonal approach is preferred, then how might zones be defined?

(b) What are the key cost drivers of incremental capacity – and how might these vary between entry and offtake? How should these be quantified?

(c) Should revenue drivers be fixed for the price control period or should they be adjusted during the price control period?

Entry capacity baselines

(d) Should the baseline be a measure of capacity and if so, should it reflect the level of existing capacity or the level of anticipated capacity?

(e) For revenue restriction purposes should the baseline be set 'flat' for the five years of the price control period or should it incorporate growth (or decline)?

(f) Should the baseline be set on an entry point specific, zonal or network wide basis or should no ex ante baseline be defined? What are the advantages and disadvantages of the different options?

Approaches to offtake reform

(g) Do you believe that Ofgem's proposals for a long term user commitment model are appropriate?

(h) Are there any alternative models, including those which could be characterised as variants of the status quo, that would meet the defined objectives?

Offtake product definition and baselines

(i) Which of the options described for product definition and baseline determination do you believe is most appropriate?

(j) Are there any alternative models that would meet the defined objectives? Eg a nodal model without the substitution incentive or a "no baseline" option?

(k) Should the baselines be fixed for the five year period, or increase over time?

(l) What method of determination of baseline levels (as discussed in Appendix 7) is most appropriate for the determination of the level of offtake baselines?

Offtake access arrangements and incentives

(m) What threshold should trigger the release of incremental offtake capacity eg a percentage of the deemed cost of providing the incremental capacity, a fixed number of years of commitment or another approach?

(n) How should National Grid NTS be incentivised to release incremental capacity as soon as possible, and should the limit on release be set as a fixed period, for example, three years, or linked to a fixed interval once the relevant planning consents have been obtained?

Transitional offtake incentives and revenue drivers

(o) To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period represent a continuation of the current "interim" NTS incentives, including the 15 day interruption incentive on the NTS?

(p) To what extent should incentives and revenue drivers for National Grid NTS in relation to capacity for the transitional period be consistent with the enduring NTS incentives that will be determined?

Buy back incentives for entry and offtake

(q) Would it be appropriate to treat buy backs from operational constraints differently compared with buy-backs resulting from delayed investment for incremental capacity? If so, should there be two different buy-back mechanisms and what would the advantages and disadvantages be? How could we distinguish between the two types of constraints?

(r) Should the existing buy back incentive be refined to ensure an appropriate allocation and management of risk or should a different type of buy back incentive be considered, and if so, what form might this take?

(s) Should delay to incremental investment due to connecting pipelines be included in the buy back incentive?

(t) How should risks be allocated between shippers, National Grid Gas and consumers?

(u) Would it be desirable for the regulatory regime to enable more flexible

contractual arrangements between shippers and National Grid Gas (for example in relation to construction scope)? How might this achieved? What would the advantages and disadvantages be, especially how might this impact on consumers?

Interactions between entry and offtake options[33]

(v) What are the main interactions between entry and offtake, and how does this affect the approach to baselines, revenue drivers and buy-back mechanisms?

(w) Should the same approach to baselines and the revenue driver be adopted for entry and offtake? What would be the advantages and disadvantages of doing so?

(x) Should there be one buy-back incentive covering both entry and offtake?

[33] A discussion of some of the potential interactions between entry and offtake is set out in Appendix 8.

8. Incentive options - electricity

Introduction

8.1. This chapter considers some of the more detailed issues associated with designing an appropriate package of incentives for each of the three electricity transmission licensees.

8.2. The appropriate incentive design needs to recognise the different roles of each licensee and in particular the differences between NGET in its capacity as Great Britain System Operator (GBSO) and SPTL and SHETL in their capacities as Transmission Owners (TO).

8.3. This chapter sets out a number of options for how the revenue restrictions of the three electricity transmission licensees might be refined and developed – in the light of how the current arrangements have performed under prevailing circumstances, and might be expected to perform under future circumstances. In doing so, the chapter considers the following:

- How might revenue drivers be defined?
- What conditions might trigger the revenue driver(s)?
- What types of output measures might be used to (a) give greater visibility to what is being provided for any given level of allowed revenue, and/or (b) provide direct financial incentives in respect of system performance?

8.4. The options in the chapter have been developed having regard to the aspects of incentive design principles which are common to both electricity and gas, and also the extent to which the starting points (represented by the current arrangements) differ. Ofgem is keen to apply relevant principles consistently, but recognises that this does not mean that identical arrangements across gas and electricity would necessarily be appropriate. The objective is to identify options which are focused, proportionate and practicable given the issues to be addressed and given the respective starting points.

8.5. The chapter does, however, identify options which would require changes to

documents other than the revenue restriction licence conditions to be implemented fully. In particular, there are a range of options which link the trigger for additional revenue allowances to the presence of sustained demand for additional capacity from network users.

8.6. 'User commitment' models are the basis of the gas entry arrangements currently. Further the re-opening of the current electricity price controls as part of TIRG was, to some extent, informed by evidence on the extent of user commitment. Application of user commitment models more systematically in electricity might require consequential changes to the Connection and Use of System Code (CUSC) and charging methodologies, for example.

8.7. The detail of any such code changes would need to be progressed through the appropriate governance procedures under the relevant codes or documents.

Background

8.8. The current revenue restrictions for the three electricity transmission licensees are, in broad terms, standard RPI-X forms of control.

8.9. Additionally, NGET has a second part to its revenue restriction covering the costs of balancing services – which is a sliding scale incentive with a cap on the total profits and a collar on total losses under the scheme around a target level of costs. The parameters of the scheme have been re-set periodically during the current price control period, and will be re-set again prior to the implementation of the TPCR final proposals (of which these arrangements will form a part) for one year with effect from 1 April 2006.

8.10. NGET also has a financial incentive linked to system reliability as measured by the amount of energy lost due to unplanned outages. Similar reliability schemes, based on the number of unplanned outage events, are currently being proposed for SPTL and SHETL to take effect on 1 January 2006.

Issues identified with the current arrangements

8.11. The operation of the current price controls has revealed two key issues with incentive design:

- inflexibility of revenue allowances to unanticipated events; and
- absence of links between demands for future network capacity and revenue allowances – given that capacity at certain points on the network is significantly constrained.

8.12. First, the issue of inflexibility. The price controls make only limited use of revenue drivers. NGET has a revenue driver linked to changes in the total amount of generation connected to its network while SPTL and SHETL have no revenue drivers.

8.13. This, in part, explains why the revenue restrictions needed to be effectively re-opened by Ofgem to provide additional funds to invest in the networks in order to facilitate the (unanticipated at the time of the last price control) growth in renewable generation. As a number of the respondents to the Initial Consultation noted, re-opening price controls is less than ideal. Such exercises tend to dilute the incentive properties of the price control, and can introduce a higher degree of intrusion by Ofgem into the day-to-day management of the transmission companies.

8.14. Second, the absence of links between demand for future network capacity and revenue allowances. In circumstances where the electricity transmission network is constrained, the question of how NGET is remunerated for making additional capacity available is clearly important to the operation of the market, and to consumers. These circumstances exist currently in Scotland and northern England – and might be expected to endure in the context of future shifts in the generation mix, eg pursuant to any growth of off-shore renewable generation.

8.15. The method of linking revenues to demand for network capacity is an area where there are interactions between the structure of the price control and the arrangements under which network users – current and future - obtain access to the network. The options discussed below necessarily focus on the design of the revenue restriction. However, they also highlight where changes to the access arrangements might be required to enable a particular price control design to operate as intended if it were implemented. Ofgem is keen to highlight these interactions at this relatively early stage in the process to ensure that interested

parties can understand the impact of various options in the correct context.

Options

8.16. The discussion below is structured in two sections. The first section sets out options which might be considered to be broadly consistent with the prevailing framework under which parties obtain access to the network – 'status quo' options. The second section considers options which would require changes to the access (and charging) arrangements to provide for the forward purchase of access rights of a fixed duration for current and prospective network users – 'user commitment' options.

8.17. The criteria against which the options should be assessed – which, in Ofgem's view, are common across gas and electricity - are set out in chapter 6. There are a number of specific questions associated with these objectives that might inform the development of the proposals, including:

- How can the information available to NGET in respect of demand for network capacity by current and prospective network users be improved?
- How can the rewards available to the electricity transmission companies be focused on the timely delivery of priority investment?
- What should determine the volume of access rights to be released by NGET in the short term – and how should such short term rights be priced or rationed if there are constraints?
- Can the method through which rights are released to the market be improved given potential competing demands for scarce capacity?

8.18. It should be noted that all of the options discussed focus on how revenues might flex in response to changes in the amount of electricity being put on to or taken off the network. This can only address changes in load-related expenditure. The issue of non-load-related expenditure, ie investing to retain the capability of the network irrespective of changes in loads, is discussed at the end of the chapter in the context of system performance indicators.

Status quo options

(i) Pure status quo

8.19. The most obvious status quo option is the pure status quo, ie retain the current form of controls. This would involve a revenue driver based on total connected generation for NGET, and no revenue drivers for SPTL and SHETL.

8.20. Implementation of this option would require Ofgem to analyse the average (efficient) cost of accommodating incremental generation on the network. The value of the revenue driver would be re-set in the light of this analysis – as would the reference level of connected generation capacity against which changes would be measured – but the form of control would be otherwise unchanged.

8.21. The parameters would be set with the expectation of not being changed for the duration of the price control. The incentive for the licensees would therefore be to accommodate additional generation (or demand) at an average cost less than the assumed average cost implicit in the value of the revenue driver.

Advantages

- This option involves minimal change, and could therefore have some perceived benefits in the context of regulatory certainty.

Disadvantages

- The option has not coped particularly well with the changing demands for network capacity over the past price control period – in the sense that re-openers have been required;
- The design does not address the issue of how incentives might be linked more closely to meeting competing demands for network capacity, which in turn could be an important component in ensuring non-discriminatory access to the network;
- It only adjusts revenues for a limited set of cost drivers, ie amount of generation connected – and on a non-locational basis, and so may be prone to error;

- It only adopts revenue drivers for one of the three licensees – while the need to re-open the price controls under TIRG affected all three licensees.

(ii) Refinements to status quo

8.22. The second class of 'status quo' model involves the continued use of high-level revenue drivers, but extended to include separate revenue drivers for England & Wales, the south of Scotland and the north of Scotland. There would, under this model, be a revenue adjustment linked to changes in connected generation for each of the three areas.

8.23. A variant of this model would introduce revenue drivers for each of the three TO areas linked to changes in demand, in addition to revenue drivers linked to changes to connected generation.

8.24. Implementation of this option would require Ofgem to analyse the average (efficient) cost of accommodating incremental generation in each licensee's area. The value of the revenue driver would be set in the light of this analysis – as would the reference level of connected generation capacity against which changes would be measured. The variant of this model outlined above would require similar parameters to be set for the efficient cost of accommodating additional demand.

8.25. The parameters would be set with the expectation of not being changed for the duration of the price control. The incentive for the licensees would therefore be to accommodate additional generation at an average cost less than the assumed average cost for each licensee's transmission area implicit in the values of the revenue drivers.

8.26. The revenue drivers for SPTL and SHETL would need to be set recognising that the total cost of connecting generation (or demand) in their respective areas might involve works in more than one transmission area, ie the level of the revenue driver for SPTL or SHETL might need to be set at a level different to the analogous revenue driver for NGET.

Advantages

- Revenues will flex with volumes of activity in a more sophisticated manner

than currently – reducing likelihood of the need to subsequently re-open the price controls;

Disadvantages

- The design does not address the issue of how incentives might be linked more closely to meeting competing demands for network capacity, which in turn could be an important component in ensuring non-discriminatory access to the network;
- Only adjusts revenues for a limited set of cost drivers, eg does not allow for variations in costs between locations within a transmission licensee's area.

(iii) Locational revenue drivers

8.27. The third class of option involves the use of more sophisticated locational revenue drivers. There are two particular variants which are worth highlighting.

- Zonal revenue drivers linked to volumes of connected generation (and, potentially, demand);
- Boundary flow models.

8.28. Implementation of the first variant would require Ofgem to analyse the average (efficient) cost of accommodating incremental generation in each zone of the network. The value of the revenue drivers would be set in the light of this analysis – as would the reference level of connected generation capacity against which changes would be measured. The model could be extended to set revenue drivers for additional demand in each zone.

8.29. The boundary flow option would require the identification of key system boundaries and an estimate of the cost of accommodating additional flows across each boundary.

8.30. The parameters would be set with the expectation of not being changed for the duration of the price control. The incentive for the licensees would therefore be to accommodate additional generation (or demand) at an average cost less than the assumed average cost for each zone implicit in the value of the revenue

drivers.

8.31. The revenue drivers for SPTL and SHETL may need to be set recognising that the total cost of connecting generation in their respective areas might involve works in more than one transmission area, ie the level of the revenue driver for SPTL or SHETL might need to be set at a different level to the analogous revenue driver for NGET.

Advantages

- Revenues will flex with volumes of activity in a significantly more sophisticated manner than currently – further reducing the likelihood of the need to subsequently re-open the price controls;
- The boundary flow model would, in effect, net off the effect of incremental demand and generation behind a boundary – which is arguably a more appropriate method of characterising underlying cost drivers.

Disadvantages

- The design does not address the issue of how incentives might be linked more closely to meeting competing demands for network capacity, which in turn could be an important component in ensuring non-discriminatory access to the network;
- While reflecting a larger number of cost drivers, it also excludes some potentially important factors influencing costs, eg whether the new generation being connected is close to the prevailing network, and whether accommodating the additional loads involves significant non-standard works, eg underground or sub-sea cable.

User commitment options

8.32. The options described above all fail to address the issue of how financial incentives might be linked more closely to meeting competing demands for network capacity. Implicit in the current arrangements is a set of access arrangements based on 'first-come-first-served'. This means that existing network users have first claim on existing network capacity.

8.33. In circumstances where network capacity is relatively unconstrained this is not a material problem. However, in circumstances where there are, in some areas, competing demands for available capacity then it is appropriate for Ofgem to consider how the price control could or should create incentives for the transmission licensees to deal with such competing claims – as means of ensuring that access to the transmission networks is non-discriminatory.

8.34. An alternative to the current arrangements, which might be expected to address more appropriately the issues raised by shortages of capacity in particular areas of the network, would be to establish a user commitment model which would:

- establish what level of capacity the network should be deemed to be capable of delivering (ie set baselines – either in aggregate or in respect of each area of the network);
- require all users – current and prospective - to state what profile of capacity they want in the future; and
- oblige NGET to make available additional (or 'incremental' capacity) where competing claims cannot be met within the 'baseline' and where there is sustained demand for additional capacity; and
- link the revenue driver(s) to the provision by NGET of incremental capacity.

8.35. Such a model would be consistent with the user commitment framework discussed in chapter 6, and the models for gas entry and offtake discussed in Chapter 7. It should, however, be noted that Ofgem does not consider it necessary for the detail of the arrangements to be the same in gas and electricity.

8.36. For instance, the revenue drivers itself could be any one of the generic types discussed in the preceding chapter. The current gas entry arrangements use a nodal revenue driver – but alternatives could be used (and might indeed be proposed for gas entry in the future). Similarly, while the gas entry arrangements use auctions as the mechanism for network users to book capacity and signal the value of user commitment, this is not core to the user commitment model. Other approaches based may be more appropriate in the particular circumstances of electricity transmission. An appropriate starting point in developing the detail of such a model would be to seek to identify a model which meets the objectives

while keeping the scope of change to wider arrangements (eg access and charging) to a minimum.

8.37. While the framework of user commitment is relatively simple and intuitive, there are a number of detailed questions that would need to be addressed to apply this type of arrangement in the context of electricity transmission. These include:

- **How should the baseline capacities be set?**

  An option for generation capacities would be to sum the Transmission Entry Capacity (TEC) values of all generators with TEC – grouped into zones – and make an upward adjustment to the extent that further capacity could be accommodated in a particular zone without triggering significant additional works.

- **What is the mechanism whereby users (current and prospective) commit their profile of demand for network capacity – and are there any alternative mechanisms which deliver similar effects?**

  An option would be to establish windows (eg annually for long term and monthly for short term bookings) under which generators state what profile of capacity they require for the forthcoming period. The purpose of these arrangements would be to improve the information available to NGET on future network requirements – which in turn could inform the volume of rights available for release to the market. A key factor here will be the timing of closure or reduced operation of existing generation plant. The detailed analysis of options would need to consider whether this information could be generated through alternative routes – eg payments to generators to provide such information.

- **What would the network user be committing to?**

  The commitment could be, in effect, to pay use of system charges. A detail which would need to be developed – and would appear to be an issue for NGET's charging methodology – would be whether the commitment was to pay a use of system charge fixed ex ante, or to pay use of system charges whatever they happened to be in any given year when capacity was booked. The methodology could, in theory, afford users choice over fixed or variable charges.

- **What would trigger the release of incremental capacity?**

  When demand for capacity out-stripped available capacity there would be a test to establish whether incremental capacity should be released. One simple model would be to trigger the obligation for NGET to release additional capacity when it was backed by, say, ten years worth of commitment to pay use of system charges. An alternative model – consistent with the current arrangements in gas entry – would be to link the trigger to the point at which a set proportion (50% in the context of gas entry) of the deemed cost of providing the incremental capacity was covered by commitments to pay use of system charges.

- **When would incremental capacity be released?**

  A simple model would be to oblige NGET to release the incremental capacity as soon as possible, and not more than, say, three years after the trigger test had been met. An alternative model would be to link the release date to, say, two years after relevant planning consents had been obtained.

- **How would scarce capacity be allocated in the short term?**

  If there is an excess of demand for capacity over available capacity in the short term (ie before the point at which additional capacity can be released), then one model would be for available capacity to be allocated first to those parties who had already booked it (in previous booking 'windows'), with parties who had not booked it previously being rationed. An alternative model would be to ration all parties, irrespective of whether

they had bought the rights previously or not. Rationing could be based on non-economic criteria (eg pro-rating) or based on economic criteria (eg willingness to pay) – with the adopted approach needing to be consistent with requirements to ensure non-discrimination.

An alternative approach could be not to ration the volume of rights released in the short term, but to seek to price short term rights appropriately. Arguably, this would be consistent with long term rights (ie consistent with investment timescales) being unconstrained. It does, however, raise complex issue of how charges for short-term rights might be established, given that the underlying cost drivers might be specific to particular locations and highly sensitive to local network conditions at any particular point in time.

- **What would happen if allocated capacity (either under the baseline, or as a consequence of incremental capacity being released) could not be delivered physically at any point?**

  A simple model would deem that once capacity is booked, then it is financially firm. The right would need to be bought back by NGET if it could not be delivered – as is currently the case in respect of TEC.

  What would happen if a user did not book rights?

- A simple model would deem that a user without booked rights has no right to use the network, ie has zero TEC in current parlance. An alternative model might be that all connected parties have non-firm rights to use the network as a default. Intermediate models might provide users with non-firm rights for a transitional period.

Advantages

- Can deliver all the benefits of the 'status quo' options discussed above;

- Creates incentives for NGET to prioritise the provision of additional capacity – and to consider trade-offs between investment and buy-back costs - when capacity is scarce based on economic criteria, eg willingness to pay rather than non-economic criteria such as date of application;

- Places current and prospective network users on a more level footing in respect of claims of future available capacity – hence could be viewed as more consistent with requirements to be non-discriminatory;

- Greater consistency, in principles and approach, between electricity and gas.

Disadvantages

- Involves amendments to documents and codes in addition to the revenue restriction, which would need to be co-ordinated in approach and timing;

- A number of detailed design issues to address – with potential risk of complexity (even with options that might be characterised as 'minimal change') and unintended consequences;

- Could result in a more complicated revenue restriction – eg because there is a greater potential role for buy-back costs for NGET, which in turns needs an appropriate framework of incentive regulation around it.

February Workshop on Electricity Incentives

8.38. Ofgem is proposing to host a public workshop on the issues raised in this chapter. The purpose of the workshop will be to present Ofgem's further thinking in the light of consultation responses – and to facilitate a discussion on possible options for implementation.

8.39. Ofgem is keen to facilitate options which meet the objectives set out for reform while keeping consequential changes to a minimum – both in the context of 'status quo' options and 'user commitment' options. Ofgem would particularly welcome input to the February workshop from parties willing to present 'straw men' options for discussion in the context of user commitment options.

8.40. If you wish to attend the workshop, or wish to present at the workshop then please contact Jennifer Swan on Jennifer.Swan@ofgem.gov.uk marking your email 'Electricity Incentives Workshop'.

System performance and reliability

8.41. The discussion above considers the question of how the revenue restrictions should be structured to be flexible to change. This section considers the question of what should be expected of the networks in return for the funding provided through the revenue restrictions.

8.42. System performance and reliability can be characterised in a number of ways. One important measure of system performance is the availability of network capacity to users. However, it is not the only measure that has relevance to users, or to the interests of consumers. They might also be expected to be interested in system reliability and availability, because for example:

- Unreliable networks can result in losses of supply to end consumers;
- The predictable availability of capacity can impact on the market in wholesale electricity, which in turn can influence market prices; and
- Short term problems with reliability and availability, while manageable by the system operator through balancing market actions, can be costly to consumers.

8.43. In addition, there is a general point relating to transparency. The revenue restriction will afford the companies with revenue streams to undertake their licensed activities. It is important that sufficient information is available to Ofgem and more widely to assess whether the companies are undertaking those activities appropriately and efficiently. Measures of system performance can provide such additional transparency and accountability. The lack of appropriate levels of information runs the risk of companies delivering (and being rewarded for) 'artificial' efficiency savings by simply reducing the quality of the services they are providing.

8.44. There are a number of statutory and licence obligations already in place on the companies relating to the quality of system performance and reliability. For example:

- Duties under the Electricity Act to operate an efficient, economic and co-ordinated network, and to ensure that all reasonable demands for

electricity are met;

- Licence obligations to comply with Security and Quality of Supply Standards (SQSS) in planning and operating their networks.

8.45. In addition, the companies are obliged to submit a report to Ofgem each year documenting system performance, and reporting on any exceptional events. A copy of the report submitted by NGET for 2004/05 is on the TPCR website[34].

8.46. This framework, on the whole, makes limited use of implicit financial incentives. The current system operator incentive scheme addresses whether and how NGET's revenues are reduced if balancing costs are higher than expected, eg as a consequence of system availability and performance being below par. Systematic failure to comply with SQSS would constitute a breach of licence, and could attract a financial penalty. Further, the damage to a company's reputation in respect of poor system performance has a value.

8.47. In 2004 the framework was augmented for NGET with the introduction of a more direct financial incentive linked for system reliability, as measured by the volume of energy lost. Similar schemes have been developed for SPTL and SHETL and proposals to modify the licences of SPTL and SHETL have recently been issued.

8.48. These reliability incentives are intended to be interim measures pending a more comprehensive review as part of the TPCR. If the reliability incentives were to be modified following this more comprehensive review, then there are a number of possible approaches. For example:

- a wider basket of output measures than reliability might be used; eg other output measures, such as an assessment against the requirement to comply with SQSS, or the number and scale of unplanned outages, might be incorporated into the framework;

- a 'penalties only' scheme might be adopted; and

- more stringent reporting requirements might be introduced.

[34] www.ofgem.gov.uk

8.49. The issue of measuring and, where appropriate, setting incentives relating to a wider range of output measures is particularly relevant to the setting of allowances for non-load-related capital expenditure. NGET has indicated that it anticipates large scale asset replacement during the next price control period. The purpose of such investment would, presumably, be to maintain or improve the performance and reliability of the prevailing transmission network in England and Wales. However, system reliability and availability is also significantly influenced by operating expenditure, eg maintenance and analysis of data on asset quality and reliability, and the associated planning and implementation of asset maintenance.

8.50. It would appear appropriate for Ofgem to explore how such investment and operating expenditure might be linked to more detailed reporting of intermediate and final system performance outputs, or to refined incentive measures.

8.51. One particular facet of system performance is the extent to which the licensees are making use of technological innovation. As part of the electricity DPCR4 Ofgem consulted on and implemented an Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ) as transitional measures intended to be in place until distributed generation (and the associated active management of distribution networks) was 'business as usual'.

8.52. Ofgem noted that the context for these measures was a view that the main price control mechanisms operated effectively with the majority of investment situations, including in respect of the advancement of network development – but that transitional measures might be appropriate where DNOs were operating outside their 'core' business, and given the slow rate of technological change historically adopted by DNOs.

8.53. The context for transmission is different in this regard, in that transmission networks have necessarily always been actively managed and rate of technological change has been more rapid. It is Ofgem's initial view that there is not a corresponding need for a RPZ type scheme in transmission. Ofgem will, however, consider as part of TPCR whether further measures are appropriate.

System operation costs

8.54. The current revenue restriction for NGET has two parts. The first part deals with transmission owner activities, ie the provision of transmission assets. The second part deals with system operation costs. The discussion above focuses on how a revised price control might be set for transmission owner activities. The final set of proposals put forward by Ofgem will also include activities which are currently covered by the second part of the revenue restriction. Ofgem will bring forward more detailed proposals for consultation on these issues in the Third Consultation in March.

8.55. Ofgem considers that the broad structure of these incentives is appropriate to be applied going forward – although clearly there is detailed analysis to be undertaken to set the scheme parameters. There are also a number of higher level issues that will need to be considered in developing more proposals, for example:

- should the durations of the schemes be aligned to duration of the main price control?
- how should the issue of capital allowances to support system operation be addressed, including in the context of possible interactions between NGET as system operator, and SHETL and SPTL as transmission owners?
- should costs currently deemed to be internal SO costs continue to be treated differently to other internal costs, which are regulated through the main RPI-X form of control?

Views invited

8.56. Ofgem welcomes views on any of the issues raised in this chapter, and in particular in respect of the following questions:

- Has Ofgem focused on the appropriate issues to be addressed in the light of operation of the current price controls?
- Is it appropriate to develop more sophisticated revenue drivers under a 'status quo' option – and if so, what designs of revenue driver might be

considered to be most appropriate and worthy of further detailed analysis and quantification?

- What are the advantages and disadvantages of user commitment models, as characterised above, in the context of electricity transmission?

- What do respondents consider to be the most appropriate answers to the detailed design questions highlighted above for user commitment models? Are there any further questions that should be added to the list?

- What is the appropriate means of managing a process to develop user commitment model options given the interactions with the revenue restriction, Connection and Use of System Code (CUSC), charging methodologies and other codes and documents? What role should Ofgem adopt in this process? What role should NGET take, given its role of GB System Operator and its obligations in respect of charging methodologies?

- What are the advantages and disadvantages of more extensive system reliability and performance reporting – and how might such metrics be linked to financial incentives?

9. Financial issues

Introduction

9.1. This chapter discusses and updates Ofgem's approach to financial issues for TPCR. In developing its policies in this area, the Authority will be guided by its duties, including the duty to have regard to the need to secure that the transmission licensees are able to finance the activities which are the subject of statutory and licence obligations imposed on them. Ofgem will also aim to provide appropriate incentives for companies to make efficiency savings and, to the extent appropriate, allow customers to share in those benefits in due course.

9.2. The July 2005 TPCR Initial Consultation introduced Ofgem's approach, and invited views on the following financial issues:

- the financing of the transmission licensees' businesses;
- the cost of capital and tax;
- establishing the Regulatory Asset Value (RAV);
- financial ring-fencing; and
- pensions.

9.3. In response, a representative for consumers felt that the benefits accrued by owners/operators should be shared across consumers and shareholders in an equitable manner including, for example, windfall gains extracted from the sale of assets, and that the Authority must not lose sight of its primary objective which is in essence to protect the interests of consumers.

9.4. This chapter summarises further responses to these issues, sets out Ofgem's further views and, where appropriate, requests further views from respondents. The following additional issues are also raised:

- financial modelling;
- gearing;

- regulatory depreciation of electricity transmission assets; and
- financial reporting.

Financing

9.5. Both the Authority and licence holders have obligations with respect to the financing of companies. In setting price controls, Ofgem seeks to ensure that:

- an efficient company should be able to earn a return on its RAV that is at least equal to the expected cost of capital; and
- companies should be able to raise finance from the capital markets readily and on reasonable terms.

9.6. In previous price control reviews (for example, DPCR4) Ofgem has examined whether the price control proposals were consistent with the ability of a licence holder to maintain a satisfactory level and trend of key financial indicators consistent with a credit rating that is comfortably within the investment grade category. It is for consideration whether this remains the most appropriate approach. In forming a view on how to assess financing of companies, Ofgem will have regard to the findings of the joint Ofgem/Ofwat study on financing networks[35]. An initial report is expected to be published in early 2006.

9.7. An important part of the approach to considering the financing of companies for price control purposes will be to consider the timing of cash flows expected to be generated under the revised price controls in relation to the timing of investment, having regard to the proposed regulatory treatment of expenditure (i.e. the extent to which expenditure is funded under the price control as it is incurred, or added to the RAV and funded over time).

9.8. Electricity and gas transmission are capital intensive activities. In the case of electricity transmission, many assets are around 40 years old and replacement demands are expected to increase. This could require substantial amounts of debt or equity funding particularly in forthcoming reviews. However, each price

[35] The study was commissioned following publication of 'The Drivers and Public Policy Consequences of Increased Gearing: A Report by the Department of Trade and Industry and HM Treasury, DTI, October 2004'

review covers only a small part of the lifecycle of transmission assets. Over this lifecycle there may be long periods when asset replacement expenditure will be either above or below average. Ofgem would welcome views on alternative approaches for the financing of such a profile of asset replacement expenditure..

Financial modelling

9.9. Ofgem will use a financial model to help assess the financial impact of the new price controls on companies and to determine allowed revenue. The financial model will take the outputs from the cost assessments (opex, repex and capex) and model the financial impact of these on the companies by calculating the impact on key financial indicators. Ofgem is developing a financial model and will have discussions with the transmission companies and other relevant parties about financial modelling issues during the course of the review. The financial model will be revised as the policies underlying the price control become clearer.

9.10. It is important as part of a price control that information asymmetry is reduced to a minimum by having a transparent process. In Ofgem's view, the transparency of the price control process would be assisted by publication of a full, populated financial model for each licensee. In accordance with good regulatory practice Ofgem is considering to publish the full, populated financial model.

9.11. Ofgem intends to publish a draft of the financial model in July 2006, to take account of policy development between now and then. If you wish to be provided with a copy of the draft model please send an email with the subject "Financial Model" to Paul.ODonovan@Ofgem.gov.uk. Also, Ofgem will hold a workshop on the financial model if interested parties would find it useful. Please indicate whether you think such a workshop would be useful and whether you would like to attend such a workshop.

The Cost of Capital

9.12. The cost of capital is the return required by the financial markets – both debt and equity – to provide capital to a company. It is a significant issue in a price control and it needs to be set at a level that is consistent with the licensee being able to earn an appropriate return from the efficient conduct of its licensed activities.

9.13. Regulators have tended to make an allowance for the efficient financing costs that a company will incur by estimating a return on the value of the capital employed in the business (i.e. the RAV) equal to its expected cost of capital. As part of this price control Ofgem will consider the main factors affecting cost of capital and the issues surrounding the required calculations.

9.14. Traditionally, the cost of capital of an entity has been described as the Weighted Average Cost of Capital (WACC) which is the weighted average of the *expected* cost of equity and the *expected* cost of debt. The three main components of the cost of capital are (i) the expected cost of equity; (ii) the expected cost of debt; and (iii) the gearing assumption. The cost of capital should be considered in a risk-return framework and as part of the overall regulatory framework within which monopoly companies operate.

9.15. The July 2005 TPCR Initial Consultation set out Ofgem's view that the framework used in DPCR4 appeared to be appropriate for the transmission price control review; in particular, the use of a post-tax cost of capital and a separate allowance for tax. It invited comments on this approach and on whether the cost of capital for a transmission business should be different to that of a distribution business.

Respondents' views

9.16. The transmission licence holders took the view that Ofgem should use the post tax method and the general approach adopted in DPCR4. A distribution company added that the rate should be set to incentivise investment and enable adequate financing without resort to high gearing.

9.17. In respect of potential differences in the cost of capital between transmission and

distribution, an industry association thought that only offshore investment might affect this whereas the transmission companies all thought a rate higher than in distribution was appropriate. A supply business considered the cost of capital should be reviewed particularly in respect of gearing and recent market based valuations of energy utilities.

Ofgem's views

9.18. Ofgem expects to build on the approach to cost of capital adopted as part of DPCR4, and will consider differences between the cost of capital for transmission and distribution businesses. In its final proposals for the NGET Price Control extension[36], Ofgem indicated its intention to carry out during 2006 a detailed study on the relevant theory and data for cost of capital estimation. The primary purpose of this study will be to inform Ofgem's consideration of the cost of capital to be allowed in TPCR although it will also be taken into consideration in the GDPCR. Over the next few months, Ofgem would welcome empirical, as well as academic, evidence with respect to the inputs to the cost of capital, and the methods used in its estimation, from interested parties.

Tax

9.19. In the July 2005 TPCR Initial Consultation, Ofgem indicated an intention to move to a post tax approach and consider the expected tax position of each company as part of its financial modelling. The main reasons for this are:

- the change to the tax treatment of asset replacement expenditure, which may result in company's tax liabilities increasing, at least in the short to medium term, relative to historical levels;
- consistency with other aspects of the regulatory framework (e.g. in providing benefits to consumers if costs are reduced, albeit after a delay) - a company specific tax approach would include passing to consumers the benefits of lower tax costs after a period of time; and
- to reduce the incentives to increase gearing.

Ofgem's views

9.20. Ofgem continues to take the view that the approach adopted in DPCR4 for setting tax allowances is appropriate for the transmission review. In this approach, the tax allowance should be based on the position of the licensed entity as if it was taxed on a standalone basis (disregarding group relief). Tax projections should be based on the company's actual gearing, or on the level of gearing assumed in assessing the cost of capital if that is higher. However, in relation to debt guaranteed by the licensee, the question arises whether the licensee should retain the tax benefits of any interest payable on this debt.

9.21. In DPCR4 an ex-ante approach was adopted (with an ex-post adjustment for outturn variances in gearing and interest expense, compared to the price control assumptions, where relevant) which incentivises the companies to manage their tax position in an efficient way. This reflected the traditional approach to cost efficiencies, which incentivises companies to make savings that may then be passed on to customers after a period of time. Ofgem would welcome views on whether this approach remains appropriate.

9.22. If an ex-ante approach to the assessment of tax is used, Ofgem will need to obtain information from the companies on their historical tax charges, their estimate of future tax charges, their opening capital allowance balances, and the expected tax treatment of future capital and operating expenditure. Ofgem may also take account of any expected future changes in the corporation tax rate and/or the tax treatment of particular types of expenditure (e.g. allowances for energy efficient expenditure).

Gearing

9.23. In order to estimate the weighted average cost of capital, Ofgem has to make an assumption about gearing. In the July consultation document, Ofgem stated that, for its cost of capital estimation, it intends to use a level of gearing that is consistent with companies maintaining a credit rating that is comfortably within

[36] Extending National Grid Electricity Transmission Ltd's Transmission Owner Price Control for 2006/7 – Final Proposals, Ofgem, November 2005, 253/05

the investment grade category. This is consistent with the approach used in other recent price control reviews.

9.24. Recent trends indicate that market appetite for risk has evolved and the level of gearing that is consistent with a credit rating comfortably within investment grade may now be higher than was the case when the present control was set. Ofgem will need to have regard to this evidence as part of its cost of capital study.

9.25. Views are invited on whether Ofgem should adopt a common assumed level of gearing for all transmission companies (i.e. large and small, for gas and electricity), or whether company-specific gearing assumptions should be adopted. Views are also invited on the level of gearing that may be appropriate.

Establishing Regulatory Asset Values

9.26. The July 2005 TPCR Initial Consultation asked for views on the principles that should be applied in establishing opening RAVs, in particular in respect of capital expenditure incurred in excess of past capex allowances and also of changes to the policies and procedures adopted by licensees in accounting for such expenditure.

Respondents' views

9.27. The transmission and distribution companies who replied all stated that efficiently incurred capex should be included in the RAV at the earliest available opportunity. One suggested that the future cessation of regulatory depreciation on pre vesting assets should be smoothed as it had been for the electricity distribution companies in DPCR3 and DPCR4. A supplier thought that where a company had chosen to disregard the previous allowance they should not receive any return until the next period.

Ofgem's views

9.28. The treatment of capital expenditure in excess of past allowances set for the current price control will be informed by Ofgem's assessment of the efficiency of that expenditure. In the context of the sale of four of National Grid Gas's gas

distribution networks (GDNs), Ofgem published an open letter[37] setting out the principles it intended to apply in assessing past capital expenditure in excess of allowances. This was further considered in the December 2005 Gas Distribution Initial Consultation[38]. Views are invited upon whether these principles should also apply for transmission.

9.29. With regard to accounting changes, Ofgem will undertake detailed examination and verification of the accounting treatment of all costs, which can vary substantially (as was the case among the electricity distribution companies). Consequently, transmission companies have been asked to identify in their submissions the extent to which they have capitalised the salaries and related overheads of their own staff associated with capital expenditure projects together with any interest during the course of construction directly incurred.

9.30. Ofgem intends that the RAV for each transmission company should be rolled forward from the relevant base on which the previous price control for the companies was calculated. The RAV, which will not include capitalised interest, will be used to set the revenue allowances for 2007/08 onwards.

Regulatory depreciation of pre-vesting assets

9.31. The TPCR will consider the appropriate treatment of regulatory depreciation relating to pre-vesting electricity transmission assets. The electricity transmission companies were given asset depreciation lives of 20 or 22 years at vesting (being about half the then total asset life). If the current approach continues, the regulatory depreciation included in regulated income in respect of pre-vesting assets would cease in 2010 or 2012 and, all other things being equal, the income and profit before tax will reduce correspondingly.

9.32. In electricity distribution, to avoid the large reduction in income arising from the cessation of regulatory depreciation on pre vesting assets the life of post vesting assets was shortened, for the purposes of calculating regulatory depreciation, and smoothed in a neutral net present value (NPV) manner.

[37] Open letter on Gas Distribution Price Controls, Ofgem, 16 March 2004
[38] Gas distribution price control review – Initial consultation, Ofgem, December 2005, 259/05

9.33. Ofgem would welcome comments on the appropriate depreciation treatment of the remaining pre-vesting RAV of electricity transmission companies.

Financial ring-fence

9.34. As stated in the July 2005 TPCR Initial Consultation, Ofgem intends to make the necessary changes to the licences of the electricity transmission companies to bring it up to date with Ofgem's latest thinking in this regard so that the approach for transmission will conform with the approach already adopted or currently being consulted on for electricity and, gas distribution.

The treatment of pension costs

9.35. This section, together with Appendix 10, highlights specific areas for consideration by Ofgem for the TPCR. Ofgem's approach to the treatment of pension costs was developed in Developing Network Monopoly Price Controls which published Initial Conclusions in June 2003 and was further developed in DPCR4. The July 2005 TPCR Initial Consultation indicated Ofgem's intention to follow a similar approach in TPCR, taking account also of the approach proposed for dealing with pension cost issues arising from the unbundling of National Grid Gas's GDNs indicated in the pension position paper published on the 2 August 2004.

Respondents' views

9.36. There were two respondents on this to the July 2005 TPCR Initial Consultation. One requested a clear audit trail over the mini reviews in respect of pensions allowances and the other thought all the deficit arising other than from Early Retirement Deficiency Contributions (ERDCs) should be allowed.

Ofgem's views

9.37. As stated above, Ofgem's approach to pensions will build on the work carried out as part of the June 2003 Developing Network Monopoly Price Controls document, GDN sales, and DPCR4.

9.38. However, pensions law is changing as a result of the introduction of the Pensions

Act 2004 and regulations made thereunder. The Pensions Regulator was established by the Pensions Act 2004. In addition, guidance covering issues such as how pension schemes should be valued and over what period of time deficits should be funded, is anticipated. Ofgem will consider the effect of these changes during the course of the consultation and would like to hear the views of respondents in relation to how they think these changes could affect the price control.

9.39. The key pensions issues for TPCR relate to:

- the impact of corporate restructuring by the transmission companies,
- the allocation of pension costs between price controlled and non price controlled activities,
- the treatment of over/under provision, and
- the treatment of early retirement deficiency costs.

9.40. Of particular note will be the National Grid NTS scheme because of both its size relative to those for the electricity transmission schemes, and the extent of past corporate restructuring that has taken place since vesting in 1986.

9.41. For National Grid NTS there is a crucial link between TPCR and GDPCR due to part of the arrangements associated with GDN sales, (see para 9.45).

9.42. Following GDN sales, Transco, the owner of the NTS and those gas distribution businesses not sold, was renamed National Grid Gas (NGG). NGG is an associated employer of the Lattice Group Pension Scheme (the "LGPS"). Lattice Group plc, an intermediate holding company of NGG, is the principal employer of this scheme. Following a series of corporate restructurings, substantially all past and present employees of Transco (now NGG) and its predecessors are members of the LGPS.

9.43. Broadly, the LGPS comprises five classes of member, namely:

1. Active members currently employed by NGG (NGG active members);

2. Active members currently employed by other Lattice Group companies

(non-NGG active members);

3. Pensioners and deferred pensioners and associated dependants whose employment was within the range of activities presently conducted by NGG (non-active members);

4. Pensioners and deferred pensioners and associated dependants whose employment was not within the range of activities presently conducted by NGG – largely supply business activities now conducted by Centrica (legacy non-active members); and

5. Pensioners and deferred pensioners whose employment related to the former conduct of gas distribution businesses no longer owned by NGG.

9.44. In the current price control, pension costs incurred by NGG are allocated between the National Grid NTS and the GDNs as part of total employment costs. The basis of allocation relates to the costs of staff employed in each business. The present price controls make allowance for the estimated efficient level of employment costs (including pension costs) that were expected to arise in each business during the period of the control. In separating the GDNs price control, this allowance for employment costs was allocated to GDNs and National Grid NTS on a broadly similar basis.

9.45. Ofgem's 2004 GDN sales position paper on pensions made it clear that it expected :-

1. that liability for pension benefits relating to future service of active members whose employment is transferred to the independent GDNs will be assumed by the new employer[39];

2. all other liabilities would remain with the LGPS; and

3. National Grid NTS would recover the costs of meeting liabilities that relate to pensioners and deferred pensioners whose employment related to the

[39] In some cases, liability in respect of past service benefits of such active members may also be assumed by the new employer, where the relevant member so elects, in which case an appropriate proportion of the assets of the LGPS will be transferred to the new employer's pension scheme.

former conduct of gas distribution businesses through a specific NTS charge to customers.

9.46. Subject to Ofgem's established framework of principles governing the treatment of pension costs for price control purposes, customers of National Grid NTS will therefore pay in their charges for the costs incurred by NGG in meeting its obligations in respect of pension benefits to which certain non active gas distribution pension scheme members are (or will become) entitled. Views are invited on the factors to be considered in determining these charges.

9.47. Under Ofgem's pensions principles, allowance is made only for costs properly attributable to the relevant price controlled business. As such, no allowance will be made for the costs of meeting liabilities to members of the LGPS which relate to service performed in connection with activities outside the regulated gas transportation businesses. This would include the activities transferred to Centrica. Similar considerations apply to NGET's liabilities in respect of its membership of the Electricity Supply Pension Scheme.

9.48. Appendix 10 of this document discusses treatments of pension costs, including the following adjustments to ensure that the cost allowances:

- do not include costs that are properly attributable to activities that do (or did) not form part of the price controlled business, to avoid cross-subsidies;
- appropriately reflect differences (if any) between the allowances made in setting previous price controls and the actual employer contributions made to pension funds in the same periods, to prevent over- or under-provision;
- do not include early retirement deficiency costs arising from redundancy and re-organisation which have not already been matched by additional employer contributions; and
- do not include excess costs arising from a material failure of stewardship.

Views are invited from respondents on these issues.

Reporting Requirements

9.49. Chapter 4 of this document sets out Ofgem's initial views on the development of

cost reporting approaches. It is essential that Ofgem should be able to rely on information provided by the companies. The regulatory accounts of these licensees currently vary considerably in terms of both content and completeness, particularly in respect of the cash flow and balance sheet information in respect of debt and taxation.

9.50. It is important that the information supplied by licensees is in a consistent form, and has been audited for accounting compliance. Ofgem's view is that to inform future price controls, each licence holder should produce a detailed regulatory reporting pack each year of disaggregated data for each business in accordance with regulatory reporting guidelines to be developed for this purpose.

9.51. In order to ensure both transparency and accountability, the regulatory pack for each of these businesses reconciles appropriate regulatory and statutory financial statements. The reporting pack of a licence holder should include data for any business it may undertake (e.g. Transmission Owner, System Operator, Interconnector, Distribution, and Unregulated) on a basis and in a format consistent with the relevant price control including RAV, and detailed opex and capex tables. Views are invited on this approach.

Views invited

9.52. Views are invited on the issues raised in this Chapter and in particular on:

- whether the level and trend of key financial indicators consistent with a credit rating that is comfortably within investment grade provides the most appropriate approach to assessing the ability of the licensee to finance its regulated business;
- the financing of the asset replacement cycle;
- whether an ex-ante approach to setting tax allowances (with an ex-post adjustment for gearing and interest expense where relevant) is still appropriate;
- gearing issues, including:
    - whether a common assumed level of gearing should be adopted for

transmission companies, or

- whether company-specific gearing assumptions should be adopted, and
- what levels of gearing may be appropriate,

- the principles that should apply for assessing the past capital expenditure in excess of allowances;
- the cessation of pre-vesting regulatory depreciation for electricity transmission companies;
- pensions issues, including:
  - the calculation of charges in respect of pensions and deferred pensions attributable to GDNs;
  - the valuation and funding of pension schemes under new pensions regulation arrangements;
  - the allocation between price-controlled and non-price-controlled activities;
  - the options in relation to the treatment of over/under funding;
  - the treatment of early retirement deficiency costs;
- a more detailed regulatory reporting requirement in accordance with regulatory reporting guidelines.

9.53. In addition, over the next few months, Ofgem would welcome empirical, as well as academic, evidence with respect to the inputs to and methods for the estimation of cost of capital from interested parties.

9.54. Finally, Ofgem will hold a workshop on the financial model in July 2006 if interested parties would find it useful. If you would find this useful and wish to attend this workshop please send an email with the words "Financial Model" in the subject line to Paul.ODonovan@Ofgem.gov.uk expressing such an interest.

10. Next steps

10.1. The TPCR document schedule following this Second Consultation is set out below:

- **Third Consultation** March 2006
- **Initial Proposals**: June 2006
- **Updated Proposals**: September 2006
- **Final Proposals**: December 2006

10.2. The Third Consultation document will act as a stepping stone between this document and Initial Proposals in June 2006. It will aim to conclude on the key price control design issues – and other issues, such as the approach to pensions, which need early resolution – ahead of the quantification of the proposed price control design at Initial Proposals stage in June.

Workshops and workgroups

10.3. Ofgem considers that workshops have an important role to play in the TPCR consultation process. Ofgem also considers that for certain areas of work there is a role for workgroups involving a representative group of relevant stakeholders. Ofgem plans to host two workshops and to convene one workgroup between now and the publication of the Third Consultation in March.

- workshop on electricity incentive issues (16 February); and
- workshop on gas offtake (24 February).

10.4. Additionally, Ofgem anticipates hosting a second workshop on gas incentive issues in April or May 2006, and a seminar on the Initial Proposals in June or July 2006 and a workshop on financial modelling. Further information on these events will be provided in the Third Consultation.

10.5. Details on the gas offtake workshop and the electricity incentives workshop are provided in chapters 7 and 8 respectively. If you wish to attend any of these

workshops then please send an email to Jennifer.swan@ofgem.gov.uk indicating clearly which workshop you are interested in. The workshops will be held at Ofgem's offices in London.

Appendix 1 Consultation on Impact Assessment Approach

1.1 As mentioned in paragraph 2.15 of chapter 2, this appendix sets out the relevant text from the recent consultation undertaken as part of the gas distribution price control review consultation (GDPCR) on Ofgem's approach to impact assessments in the context of price control reviews.

1.2 The purpose of this appendix is to ensure that all interested parties have an opportunity to comment on this issue either by responding to this consultation or by responding to the GDPCR document referred to above. It is Ofgem's intention, following consultation, to adopt the same approach to impact assessments in both the TPCR and the GDPCR.

Use of impact assessments

The Authority is required to carry out an impact assessment (IA) or publish reasons why it considers an IA to be unnecessary before implementing its proposals:

- *whenever it proposes to do anything for the purposes of, or in connection with, the carrying out of any function exercisable by it under or by virtue of Part 1 of either the Electricity Act or the Gas Act; and*
- *where it appears to it that the proposal is 'important'.*[40]

These criteria suggest that GDPCR qualifies as a project for which it is necessary to carry out an IA or publish reasons why an IA is unnecessary.

During DPCR4, Ofgem published a preliminary IA on the overall price control package in the initial consultation document,[41] *and then published a final overall IA at the same time as the Final Proposals.*[42] *Some industry participants have suggested that further draft versions of the overall IA should have been published during the decision making process rather than at the end of the process.*

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[40] Section 5A Utilities Act 2000.
[41] Electricity Distribution Price Control Review, Initial consultation 68/03, Appendix 1.
[42] Electricity Distribution Price Control Review, Impact Assessment, November 2004 265b/04. Ofgem also produced IAs on the incentive scheme for distributed generation, the innovation funding incentive and

However, Ofgem also received feedback that the final IA was worthwhile insofar as it provided a useful alternative means of presenting information.

During the water price control review, Ofwat published a table which described the options available for various price control policy issues and considered costs and benefits.[43] *The table did not consider issues such as distributional and environmental impacts etc. This approach has the advantage of being more simply integrated into the price control process, however it does not cover the same range of issues as a formal IA.*

Ofgem is considering whether, in light of the experience of previous reviews, it is appropriate to update its approach to the use of IAs as part of price control reviews. For instance, Ofgem could either:

A. *prepare an IA for the overall price control that includes (either as part of the main IA or as separate documents) any important new initiatives which emerge during the course of the review. In this case Ofgem could publish updated drafts of the IA during the consultation process; or*

B. *carry out formal IAs for all important new initiatives that are proposed as a part of the price control review, and on specific issues where it appears that an IA may be of benefit.*[44] *This may include, for instance, an IA in relation to any proposed service quality incentive mechanism. However, under this option Ofgem would decline to carry out a formal IA on the overall price control review itself for the following reasons:*

   - *the review is a continuation of an existing policy rather than the introduction of a new policy;*

   - *in setting allowed revenues, the options are not really meaningful as Ofgem will always seek to set an allowance that reflects efficient costs rather than an allowance that is higher or lower than efficient costs;*

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registered power zones, and metering and quality of service.
[43] Ofwat, *Setting water and sewerage price limits for 2005-10: Framework and approach*, 27 March 2003.
[44] These IAs would include consideration of the environmental and distributional impact of the proposed initiative.

- *the benefits of price control regulation are well established,*[45] *and in this case the 'do nothing' option would clearly not protect the interests of customers;*

- *any consideration of alternative options to price control regulation would constitute a major initiative affecting other Ofgem projects (and indeed other regulators) and it would not be appropriate to consider such options in the context of gas distribution alone; and*

- *an IA on the overall price control review would have the potential to increase the workload of Ofgem and industry without commensurate benefit.*

In the case of Option B Ofgem would publish appendices which set out, in table format, the various policy options under consideration and their respective costs and benefits (quantified where appropriate).

1.3 *Ofgem seeks the views on the use of IAs as part of the price control process, including whether Option A, Option B or a different option should be adopted.*

[45] For example, see National Audit Office, *Pipes and Wires*, April 2002.

Appendix 2 Revised TPCR objectives

2.1 Ofgem has revised the objectives for the TPCR in the light of respondents' view. It should also be noted that more specific objectives for price control and incentive design are set out in Chapter 6 above. The revised objectives are set out below.

- **Protect the interests of consumers**: To develop a set of proposals which protect the interests of gas and electricity consumers, recognising that current and future consumers have interests in high quality transmission networks operated by companies who can finance their activities to support a high standard of security of supply, delivered at efficient cost;

- **Promote social and environmental objectives**: To develop a set of proposals consistent with the Authority's wider statutory duties, paying due regard to the direct impacts that the transmission systems have on the environment, as well as the role the transmission systems play in facilitating broader social and environmental objectives.

- **Reward focused and timely investment**: To reward transmission licensees for responding dynamically to changing circumstances to develop their networks in an economic, efficient and co-ordinated manner (having regard to best practice in respect of asset stewardship and safety), and thereby facilitate effective competition between electricity generators and suppliers, and between gas shippers;

- **Allocate risk appropriately**: To ensure that risk is shared appropriately between licensees, customers and other users of the system.

2.2 Additionally, the Ofgem itself will seek to ensure during the TPCR that its actions are consistent with the principles of best regulatory practice, including:

- **Transparency and simplicity**: The objective and transparent assessment of issues, seeking where possible to ensure Ofgem's approach to particular policy issues is clarified at an early stage (and is not subsequently revisited) and delivering a set out proposals which are unambiguous and simple to understand, operate and monitor – with a level of complexity for the licensed companies and for network users proportionate to the objectives

the proposals are seeking to meet;

- **Inclusiveness**: Providing information to all stakeholders in a focused and easy to understand form, such that all parties can play a full and active role in the price control review; and

- **Accessibility**: Making Ofgem's project team for the price control review visible and accessible to all stakeholders.

Appendix 3 Summary data – National Grid

3.1 This appendix sets out historic data for NG provided to Ofgem by NG through the HBPQ and other sources. The data are presented in their raw form without any checks or adjustments by Ofgem. All prices are 2004/05.

3.2 Ofgem has also requested the companies to provide a narrative to support the raw data. Again, the substance of the commentary is presented in its raw form without any Ofgem commentary or editing. It is presented to help inform debate.

NG commentary

National Grid Electricity Transmission TO Opex

3.3 NGET has reduced Efficient Cash Operating Costs (ECOC) from £225m in 2001/2 to £189m in 2004/5. This profile of ECOC in the period includes the impact of significant investment in one-off opex (mainly severance and property offtake costs) across the period that has enabled underlying opex to be reduced.

3.4 NGET's reductions in operating costs have been achieved through a series of restructuring initiatives and the merger between National Grid Group and Lattice. The principal cost reduction initiatives have involved the closure of National Grid's regional management structures, the centralisation of support service activities and the integration of Gas and Electricity Transmission management and ex-Transco and ex-NGC support service operations.

3.5 These reductions have been offset by the impact of increasing cost drivers in respect of the age and condition of our network that are increasing workload, and also because of shifts in external input costs most notably in respect of insurance costs.

National Grid Electricity Capex

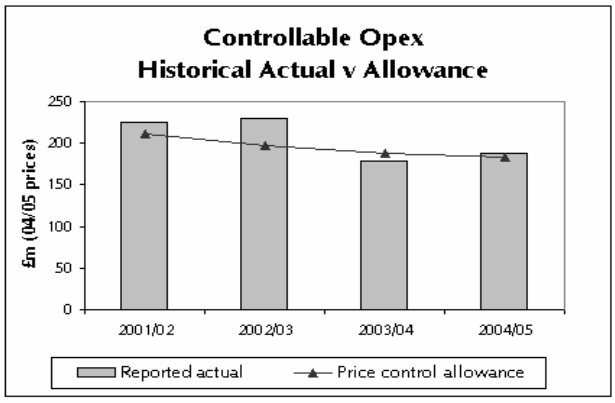
3.6 NGET has invested £1,388m in its network over the four years of the current price control, some £186m more than Ofgem assumed when the price control was set in order to deliver its licence obligations.

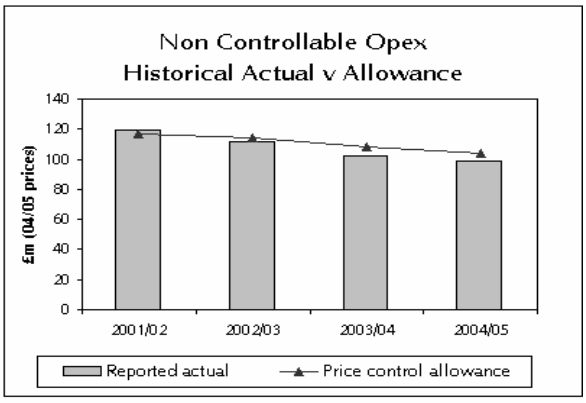
3.7 A large proportion of this increased expenditure has been incurred in response to

the requirements of NGET's customers. Load related expenditure has been £134m above price control levels principally due to a significantly higher level of DNO and Network Rail offtake connection requests, higher demand on the Transmission network and a greater proportion of generation based in the North than anticipated at the last price control. This has been partially offset by a reduced level of investment to connect new generation projects.

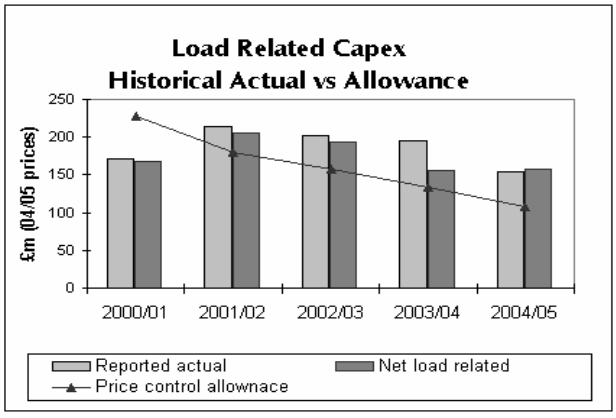
3.8 The remainder of the increase has been driven by the need to replace assets in order to maintain the high level of reliability, safety and environmental performance of the transmission network. Non-load expenditure has been £52m above price control levels, with expenditure principally driven by the need to replace overhead lines, driven by compelling condition information.

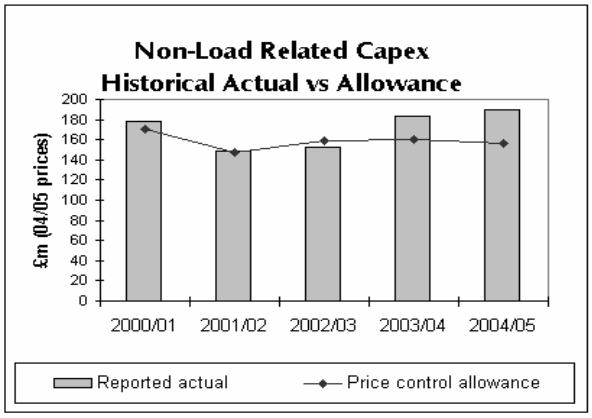
Operating Costs	Previous	Present Price Control			
		2001/02	2002/03	2003/04	2004/05
		£m	£m	£m	£m
Reported actuals					
Controllable		225.3	229.0	178.4	188.5
Non Controllable		119.5	111.4	102.2	98.6
Price control allowance					
Controllable		211.5	197.9	187.8	183.2
Non Controllable		116.5	114.2	108.6	104.1





Capital Expenditure	Previous	Present Price Control			
	2000/01	2001/02	2002/03	2003/04	2004/05
Reported actuals	£m	£m	£m	£m	£m
Load Related	170.9	213.7	201.9	194.6	153.7
Customer Contributions	-2.5	-8.4	-8.4	-38.8	4.1
Load Related net of customer contributions	168.5	205.3	193.4	155.8	157.7
Non Load Related	177.6	149.2	152.5	183.8	190.2
Total Capex Net of Customer Contributions	346.1	354.4	345.9	339.6	347.9
Price control allowance					
Load Related	228.5	180.2	157.4	133.9	107.2
Non Load Related	170.8	148.0	158.5	160.0	156.8
Total Capex	399.3	328.2	316.0	293.9	264.0





System Statistics	Previous	Present Price Control			
	2000/01	2001/02	2002/03	2003/04	2004/05
Resources					
RAV (£m 2004/05 prices)	5044	5084	5101	5096	5145
Total transmission circuit length (km)	14505	14507	14507	14704	14644
Total substation numbers (#)	433	436	439	442	445
Outputs					
Measured system maximum demand (GW)	51.4	51.9	54.8	53.5	53.8
Directly Connected Generation (GW)	59.8	60.1	58.9	59.1	59.7
Units transmitted to Grid Supply Points (TWh)	299.3	300.1	304.2	308.8	310.4
System utilisation based on ACS intact flow (MW.km)		5733163	5273946	5809321	5776008
Performance					
Number of Transmission system incidents (#)	3	11	12	10	11
Unsupplied energy (MWh)	526	473	215	900	888
System availability (%)	95.8	95.4	95.8	95.3	95.3
System unplanned unavailability (%)	0.26	0.35	0.29	0.49	0.47

National Grid Gas Transmission Operating Expenditure

3.9 The gas TO has reduced controllable costs from £63m in 2002/3 to £60m in 2004/5. Cost reductions have been achieved in a similar manner to that described for NGET, however these have been offset by significant increases in insurance costs and increased maintenance costs on compressors as utilisation has increased to provide more entry capacity in response to market signals.

3.10 Actual expenditure has been significantly below Ofgem's allowances at the last price control. This has been primarily due to an over allocation of costs to the Transmission Owner (offset within the National Grid Gas control by an under allocation to the distribution business) at the last price control.

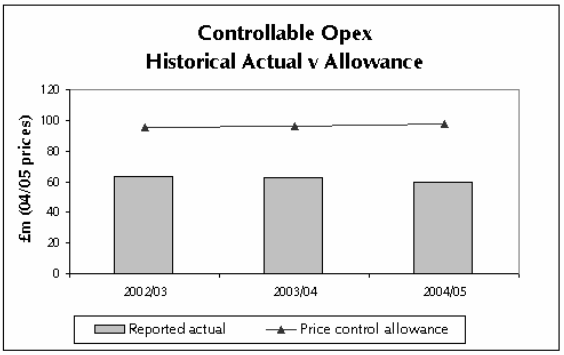
National Grid Gas Capital Expenditure

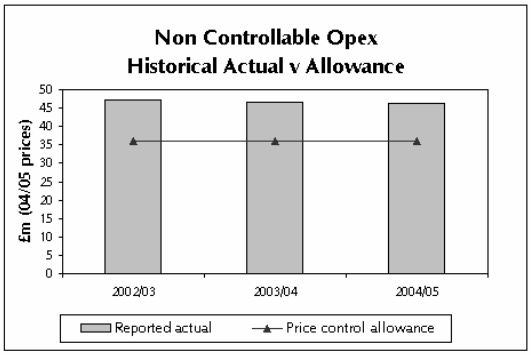
3.11 The Gas Transmission Operator has invested £369m in the gas network over the first three years of the current control to 2004/5, some £348m less than Ofgem allowed. Investment has been lower than Ofgem assumed principally due to lower investment than forecast to facilitate increased summer flexibility capacity and in compressor emissions reduction equipment.

3.12 The change in summer flexibility capex followed the introduction of capacity auctions in 2002 which provided a market test for the need for investment. As patterns of supply have changed significantly since the start of the Price Control, the auction signals did not indicate a need for the forecast investment. Where investment has been carried out, this has enabled National Grid NTS to provide sufficient capacity at the entry points providing gas supplies to the UK.

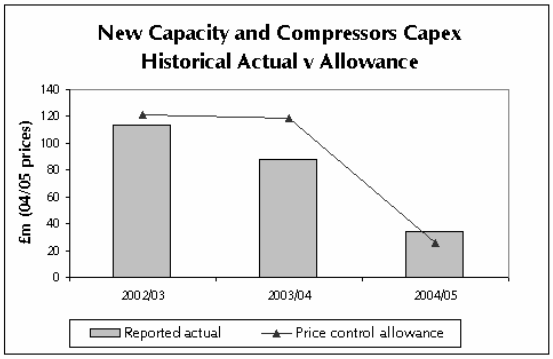
3.13 The compressor emissions reduction equipment has been deferred to the end of the period. This expenditure has been deferred to allow the legislation driving this expenditure to become more clearly defined. In addition, the emissions from compressors are driven by the pattern of supply and demand – by deferring investment to the end of the period, NGET will ensure that the benefit of investment is maximised by investing at those sites with the highest usage, thereby having the greatest impact on emissions.

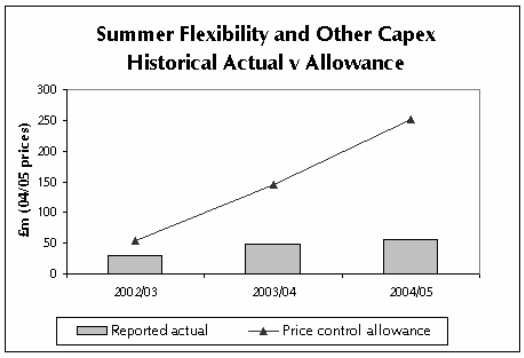
Operating Costs	Present Price Control 2002/03 £m	2003/04 £m	2004/05 £m
Reported actuals			
Controllable	63.4	62.7	59.6
Non Controllable	47.3	46.6	46.4
Price control allowance			
Controllable	95.5	96.5	97.8
Non Controllable	36.1	36.1	36.1





Capital Expenditure	Present Price Control 2002/03 £m	2003/04 £m	2004/05 £m
Reported actuals			
New Capacity and Compressors	113.3	87.7	34.0
Summer Flexibility and Other	29.2	48.5	55.8
Price control allowance			
New Capacity and Compressors	121.6	118.2	25.4
Summer Flexibility and Other	54.2	144.8	252.0





System Statistics	Present Price Control 2002/03	2003/04	2004/05
Resources			
Year end RAV (£m 2004/05 prices)	2384	2435	2443
Total NTS length (km)	6723	6824	6877
Total installed compressor power (MW)	1114	1141	1181
Outputs			
NTS Entry Point Actuals:Maximum Peak Day Winter (GWh/day)	4810	4539	4416
NTS Entry Point Actuals:Maximum Peak Day Summer (GWh/day)	4057	4296	4227
NTS & DN Demand Actuals:Peak Day (GWh/day)	4692	4948	4933
Performance			
Compressor use (run hours)	142045	146858	134090
Compressor fuel gas (tonnes)	517828	537537	378333

Appendix 4 Summary data – SPTL

4.1 This appendix sets out historic data for SPTL as provided to Ofgem by SPTL through the HBPQ and other sources. The data is presented in their raw form without any checks or adjustments by Ofgem. All prices are 2004/05.

4.2 Ofgem has also requested the companies to provide a narrative to support the raw data. Again, the substance of the commentary is presented in its raw form without any Ofgem commentary or editing. It is presented to help inform debate.

SPTL commentary

Capital Expenditure

4.3 Under particularly challenging circumstances, including delays due to the foot and mouth outbreak, SPTL efficiently delivered its capital investment programme over the TPCR3 period. Non-related investment was in line with allowance. Load-related investment was above allowance for two reasons: to address the closure of Chapelcross Power Station and to provide infrastructure for new generator connections that could not have been anticipated when the price control was agreed.

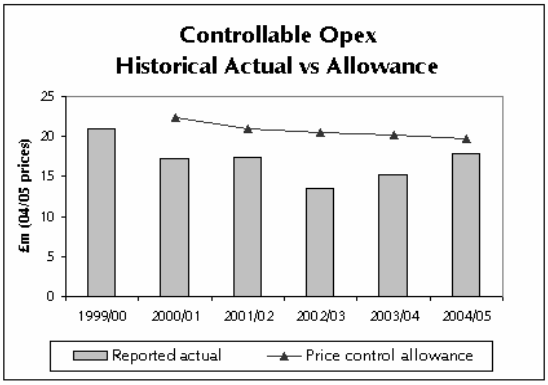
Operating Expenditure

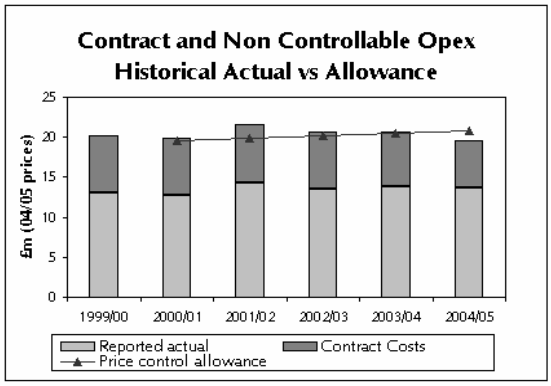
4.4 SPTL's asset management model and strong commercial focus are demonstrated by the outperformance of our controllable operating cost allowance. It should be noted that rigorous cost control and efficiency savings have been offset by increases in external costs and the potential for further savings will be extremely limited.

Technical notes on the data

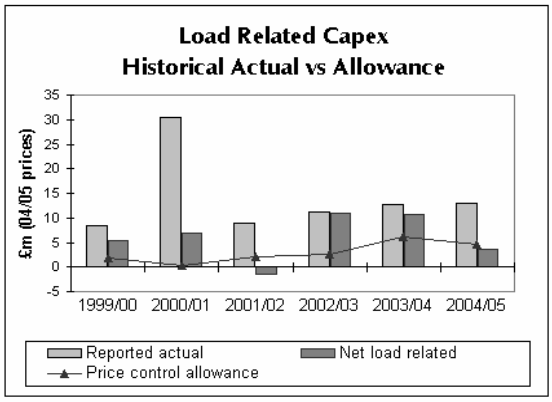
4.5 Historical network data necessary to derive MW/km data from 1999/00 to 2003/04 is not available. Operating costs do not include post vesting interconnector costs, but these will be included in forecast costs from April 2005.

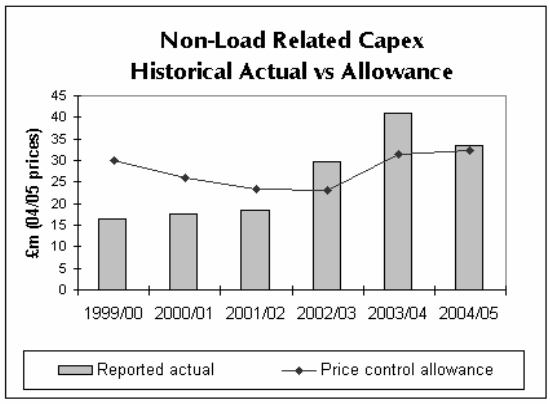
Operating Costs	Previous 1999/00 £m	Present Price Control 2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m
Reported actuals						
Controllable	20.9	17.2	17.4	13.5	15.3	17.9
Interconnector Contract costs	7.2	7.1	7.3	7.2	6.9	6.0
Non Controllable	13.0	12.7	14.3	13.5	13.8	13.6
Price control allowance						
Controllable		22.4	21.0	20.5	20.1	19.8
Interconnector Contract costs		7.3	7.3	7.3	7.3	7.3
Non Controllable		12.2	12.6	12.9	13.2	13.5
Contract Costs and non controllable		19.5	19.9	20.3	20.5	20.9





Capital Expenditure	Previous 1999/00	Present Price Control 2000/01	2001/02	2002/03	2003/04	2004/05
Reported actuals	£m	£m	£m	£m	£m	£m
Load Related	8.5	30.4	8.9	11.3	12.8	13.0
Customer contributions	-3.2	-23.3	-10.2	-0.2	-2.1	-9.4
Load Related Net of customer Contributions	5.3	7.0	-1.4	11.1	10.8	3.6
Non Load Related	16.3	17.7	18.5	29.7	40.9	33.6
Total Capex Net of Customer Contributions	21.6	24.7	17.2	40.8	51.7	37.2
Price control allowance						
Load Related	1.8	0.4	2.1	2.6	6.2	4.5
Non Load Related	30.1	26.1	23.5	23.1	31.4	32.3
Total Capex	31.9	26.4	25.6	25.7	37.6	36.8





System Statistics	Previous 1999/00	Present Price Control 2000/01	2001/02	2002/03	2003/04	2004/05
Resources						
Year end RAV (£m 2004/05 prices)	652	627	593	583	583	739
Total transmission circuit length (km)	4011	3998	4057	4056	4043	4018
Total substation numbers (#)	118	118	119	120	121	119
Outputs						
Measured system maximum demand (GW)	4.3	4.4	4.2	4.3	4.2	4.1
Directly Connected Generation (GW)	6.7	6.9	6.9	6.7	6.7	6.7
Units transmitted to Grid Supply Points (TWh)	24.4	24.2	23.8	23.4	23.0	23.2
System utilisation based on ACS intact flow (MW.km)						565414
Performance						
Number of Transmission system incidents (#)	10	12	13	8	9	5
Unsupplied energy (MWh)	275	829	179	160	202	102
System availability (%)	97.1	96.1	96.5	97.0	96.7	97.0
System unplanned unavailability (%)	0.35	0.49	0.92	0.60	0.40	0.17

Appendix 5 Summary Data – SHETL

5.1 This appendix sets out historic data for SHETL as provided to Ofgem by SHETL through the HBPQ and other sources. The data are presented in their raw form without any checks or adjustments by Ofgem. All prices are 2004/05

5.2 Ofgem has also requested the companies to provide a narrative to support the raw data. Again, the substance of the commentary is presented in its raw form without any Ofgem commentary or editing. It is presented to help inform debate.

SHETL commentary

Capital Expenditure

5.3 Over the period of TPCR3 SHETL has seen two significant changes to its original plans.

- Generation led expenditure has increased markedly
- Following a review of asset management strategy we have been able to reduce asset replacement volumes and expenditure.

5.4 Increased expenditure on generation-led schemes included Errochty/Fiddes Quad Boosters (£3.5M), Sloy/Inverary 3rd 132kV circuit (£1.1M) and Carradale Grid Transformer (£1M)

5.5 SHETL embarked on a review of its Asset Management Policy during the early stages of TPCR3. This resulted in savings being made across a number of areas and in a number of specific projects as noted below.

- Procurement continues to be an area of considerable saving for us with an estimated £3M saved over the whole 5 year review period.
- Innovation by our System Planners also continues to bring benefit with for example £0.75M saved at Keith substation where an original estimate of 3 transformers to be changed was able to be reduced to two units.
- In order to address anticipated P2/5 issues on Skye & Western Isles we had originally planned a line upgrade and two SVCs. However uncertainty over

load growth and generation penetration lead us to believe we should manage the situation in the short term by existing means and defer this Capex until the situation becomes more clear. This saved approximately £9M.

- We have reviewed how we condition assess both our plant and overhead lines. This has resulted in a number of transformer and circuit breaker changes being deferred and a number of overhead line rewires being re-scoped and done on a more targeted basis. For example we saved £1.4M on the Shin/Mybster reconductoring and £1.04M on Killin/Lochay.

Operating Expenditure

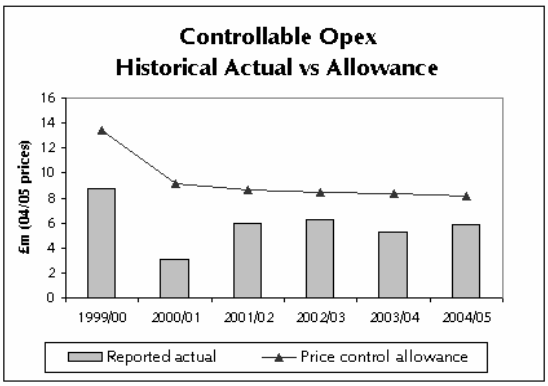
5.6 Prior to 2001/02 and business separation SHETL did not exist as a separate legal entity as it formed part of Scottish Hydro Electric Plc. The Regulatory Accounts in 2000/01 and before were prepared using different ledger structures and processes. This makes direct comparison of 2000/01 and subsequent years difficult.

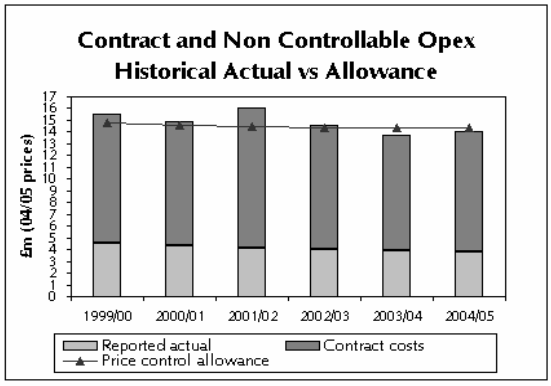
5.7 SHETL's Operating costs during TPCR3 have consistently been lower than the TPCR Opex allowance. This has primarily been due to efficiencies and synergy benefits derived from the merger of Scottish Hydro Electric and Southern Electric. SHETL benefited from the economies of scale, adoption of best practice and headcount reductions arising from the merger. The full merger benefits have now been achieved and the underlying cost base is increasing following the introduction of BETTA and the increase in activity associated with investment in renewable generation in SHETL's territory.

Technical notes on the data

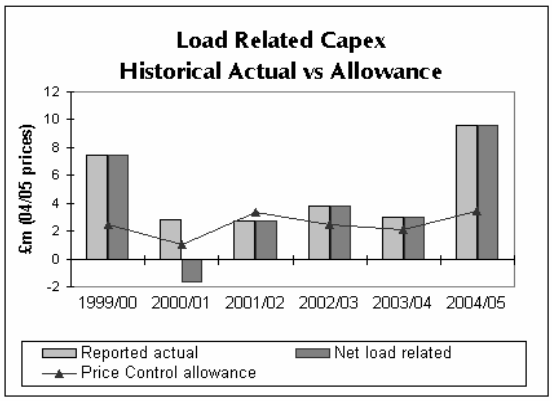
5.8 Prior to 2001/02 SHETL did not exist as a separate legal entity and therefore direct comparisons of the first 2 years with later years is difficult. Operating costs do not include post vesting inter connector costs, but these will be included in forecast costs from April
2005.

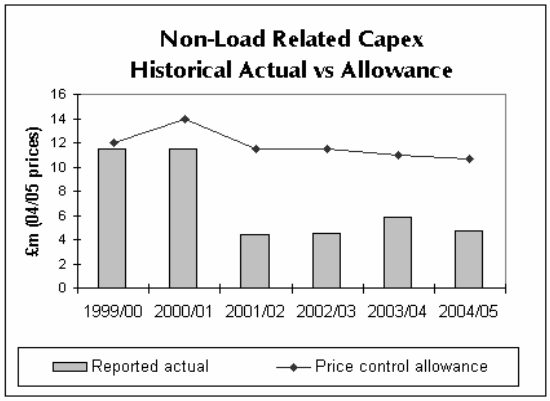
Operating costs	Previous 1999/00 £m	Present Price Control 2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m
Reported actuals						
Controllable	8.7	3.1	6.0	6.3	5.3	5.9
Interconnector Contract Costs	11.0	10.7	11.9	10.5	9.8	10.2
Non Controllable	4.5	4.3	4.1	4.0	3.9	3.8
Price control allowance						
Controllable	13.4	9.1	8.7	8.4	8.3	8.2
Interconnector Contract Costs	10.5	10.5	10.5	10.5	10.5	10.5
Non Controllable	4.3	4.0	3.9	3.8	3.8	3.8
Contract costs and non controllable	14.8	14.6	14.4	14.3	14.3	14.3





Capital Expenditure	Previous 1999/00	Present Price Control 2000/01	2001/02	2002/03	2003/04	2004/05
Reported actuals	£m	£m	£m	£m	£m	£m
Load Related	7.5	2.8	2.8	3.8	3.0	9.6
Customer contributions	0.0	-4.4	0.0	0.0	0.0	0.0
Load Related Net of customer contributions	7.5	-1.6	2.8	3.8	3.0	9.6
Non Load Related	11.5	11.5	4.5	4.5	5.9	4.8
Total Capex Net of Customer Contributions	19.0	9.9	7.2	8.3	8.9	14.4
Price control allowance						
Load Related Allowance	2.5	1.1	3.3	2.5	2.1	3.4
Non Load Related Allowance	12.0	14.0	11.5	11.5	11.0	10.7
Total Capex	14.5	15.0	14.8	14.0	13.2	14.1





System Statistics	Previous 1999/00	Present Price Control 2000/01	2001/02	2002/03	2003/04	2004/05
Resources						
Year end RAV (£m 2004/05 prices)	254	250	243	238	232	269
Total transmission circuit length (km)	4887	4912	4912	4912	4912	4912
Total substation numbers (#)	89	89	89	89	89	89
Outputs						
Measured system maximum demand (GW)	1.6	1.7	1.7	1.7	1.7	1.7
Directly Connected Generation (GW)	2.4	2.4	2.4	2.4	2.4	2.4
Units transmitted to Grid Supply Points (TWh)	8.2	8.6	8.6	8.7	8.8	8.3
System utilisation based on ACS intact flow (MW.km)						594273
Performance						
Number of Transmission system incidents (#)	8	5	5	6	8	12
Unsupplied energy (MWh)	19	49	47	40	227	129
System availability (%)	97.0	98.1	98.7	97.9	97.6	97.8
System unplanned unavailability (%)	1.6	0.9	2.6	1.1	2.3	2.6

Appendix 6 Potential areas of analysis in respect of environmental considerations

6.1 This appendix sets out a number of potential areas where further detailed analysis could be undertaken to understand more fully the environmental implications of particular patterns of expenditure by the companies. This list is not intended to be exhaustive, nor is it intended to represent Ofgem's current view on what areas should be analysed in detail. Its purpose is to inform the consultation process at this stage.

6.2 Analysis undertaken in any of these areas (and in any other areas which are identified subsequently) will inform Ofgem's decisions on the package of proposals brought forward at the end of the TPCR, in the light of the full range and hierarchy of the Authority's statutory and other legal duties.

Investment in transmission and generation:

- How is transmission investment facilitating the expansion of renewable generation?
- How might changes in locational patterns of generation affect the volume of transmission losses?
- How might changes in locational patterns of generation and the associated need for transmission reinforcement impact on the environment in general, and on visual amenity in particular?
- What are the relative costs and benefits (both financial, and in terms of operational efficiency) of different forms of transmission investment which might be considered to have a lower visual impact on the landscape (eg underground cables, low visual impact substation designs, noise reduction measures)? How, if at all, can consumers (or other relevant stakeholders) express their willingness to pay? In the absence of direct mechanisms, how might the value to consumers of any such additional costs be estimated?
- How might the generation market be affected by the EU Emissions Trading

Scheme (EU ETS) and other policy initiative (such as the Large Combustion Plant Directive), and how might this impact on the need for transmission investment? What different scenarios should be analysed?

- How should demand forecasts be adjusted to reflect the success or otherwise of measures designed to promote energy efficiency? What specific factors might be expected to be most significant in reducing demand for energy – and thereby influencing the need for transmission capacity?

Emissions from the transmission system

- What are the current levels of emissions associated with the operation of the gas and electricity transmission systems?
- What are the costs and benefits of reducing emissions from the transmission systems (eg in respect of SF_6 leakage from transformers and switchgear, methane from the gas transmission network, NOx and CO2 from compressor stations)?
- What is the interaction between these costs and benefits and the EU ETS?
- Are additional reporting requirements appropriate in respect of emissions from the transmission system, and if so, then what form should the reporting take? Should levels of emissions be included as a performance indicator with associated financial incentives attached to performance?
- What is the current legacy of contaminated sites related to the operation of the gas and electricity transmission system? What additional measures, if any, should be introduced to affect how the transmission companies deal with any such issues?

Operational efficiency and costing issues

- How does efficient system operation impact on environmental considerations, such as transmission losses?
- How should any costs or revenues for the transmission licensees under EU

ETS be treated for the purposes of setting the transmission price controls?

Environmental Reporting

- What should the formal reporting arrangements be for transmission companies in respect of the impact of their actions on the environment?
- What specific measures should form part of any revised reporting arrangements?

Appendix 7 Approaches to setting baseline levels of capacity

7.1 There are at least five main ways to define the level of baseline capacity, including:

- theoretical maximum physical capacity approach (as adopted at the last National Grid Gas price control review);
- practical maximum physical capacity approach (based on flow scenarios);
- the capacity requirements based on assessments of existing and/or future demands on the network as proxied by 1 in 20 demand scenario(s);
- the capacity requirements based on assessments of existing and/or future demands on the network as proxied by auction signals; or
- a combination of the third and fourth approach.

7.2 These approaches might be used to set either nodal baseline levels or a zonal or network wide baseline.

7.3 Determination of baselines will need careful consideration from a TO funding perspective to ensure that customers do not pay twice for the same investment and hence it is important that the approach to determining baselines is sufficiently robust. The specific characteristics and merits of the five main approaches are discussed in turn below.

(a) Theoretical maximum physical capacity approach

7.4 This approach can be characterised as the maximum amount of gas that can be taken through a particular entry or offtake point by reducing supplies at other nodes in order to balance the network.

Advantages

7.5 The main advantages of this method are that it is the simplest, relatively mechanistic and more objective method compared with the other methods. Also, it results in a comparatively high baseline, which gives shippers a high degree of certainty without any obligation on their part.

Disadvantages

7.6 The problem with this methodology is that the maximum physical capacity at each node is dependent upon the level of flows at other nodes and hence, this approach overstates the level of actual capacity. This could have the following implications:

- combined with a nodal determination of baselines and the wider auction arrangements at gas entry, this approach can lead to baseline capacity remaining unused at certain nodes but not being made available for use at new nodes ie sterilised capacity;
- the higher the baseline, the greater the TO revenue allowance could be expected to be and the smaller the emphasis on the revenue driver; and
- it could also be argued that high baselines create a degree of certainty amongst market participants regarding the availability of capacity and could therefore discourage bidding in the long-term auctions resulting in weaker signals for investment planning purposes.

7.7 One of the key issues with this approach is that baselines will be set at levels which are arguably unrealistically high from an operational point of view. At the last price control, this issue was in part addressed by scaling back. The actual entry baseline for policy purposes (SO baseline) was set at 90% of the theoretical baseline (TO baseline). However, as some of the problems which have emerged since the last price control review indicate, it is difficult and arguably, quite arbitrary, to determine an appropriate scaling factor given that capacity changes by location and over time.

(b) Practical maximum physical capacity approach

7.8 An alternative approach would be to estimate the volume of maximum capacity available at each node on the network, according to a range of plausible flow scenarios whilst taking into account interactions with flows elsewhere on the network.

7.9 This approach has not been used for setting entry capacity baselines but is considered for setting offtake capacity baselines. For offtake purposes, it is anticipated that demand could increase to these baseline levels without significant investment or buybacks, unless there were major changes from the forecasts in terms of the location of demand growth. The starting point for such analysis at offtake could be based on 1 in 20 supply and demand assumptions. For example, demand could be increased until a constraint is triggered that would require offtake investment. There might be a sequencing issue, depending on the assumptions used and the way in which the modelling is undertaken, with respect to this method especially if it were to be used on the entry side. Analysis provided by National Grid NTS earlier in the year stated an expectation that practical maximum physical capacities at offtake would, with the exception of the South West quadrant, be in excess of 2005/6 1 in 20 firm levels (by an average of 12%), equating to demand numbers that may be seen in 2013/14.

Advantages

7.10 A potential advantage of this approach is that, as interactions with other nodes are taken into account, baselines are set at a more realistic level compared with a theoretical maximum physical approach. As such, issues discussed above in relation to sterilised capacity, the impact upon long term auction signals and the potential need for capacity buy backs would be lesser in scale depending on how accurate the underlying modelling assumptions turn out to be.

7.11 Furthermore, a practical maximum physical approach could form a realistic base case against which to measure incremental investment if the underlying assumptions are sufficiently robust.

Disadvantages

7.12 However, there are a number of disadvantages to this approach. Firstly, available

physical network capacity is a dynamic concept. The physical capacity at a certain node depends on a number of factors which are difficult to forecast such as flows at other nodes, the magnitude and distribution of supply and demand, the use of linepack and the installation of new pipelines or compressors within the network and hence will change both during the gas year and from year to year. Therefore if baselines were to be set ex ante for each of the five years of the price control period on a nodal basis, there will be a considerable risk that at least several of these baselines would be fixed at inappropriately high or low levels as the assumptions that were applied will, quite naturally, differ from the out-turn.

7.13 This is especially an issue when baselines are set on a nodal basis. In a situation with declining terminals this approach could still result in inefficiently high baselines (potentially resulting in sterilised capacity) unless the scale and timing of the decline is fully anticipated. Similarly, at offtake, high baselines in the event of mothballed plant could potentially result in sterilised capacity.

7.14 Secondly, the robustness of this approach is dependent on the scenarios and assumptions which have been used.

7.15 Thirdly, on the entry side, assumptions will have to be made with respect to substitution of supply. For example, this might involve having to convert a demand scenario to a supply scenario. This involves a considerable degree of judgment with respect to who would flow, how much and when. This is especially an issue going forward, with greater uncertainty about gas flows and increased reliance on import terminals, interconnectors and storage sites. Assumptions would have to be made about how demand is to be met, ie through the interconnectors/import terminals and storage sites, who would contribute how much and who would flow when and for how long.

7.16 Fourthly, there may be implementation issues in applying this methodology to entry.

7.17 Finally, any approach which relies on medium to long term forecasts is likely to either overestimate or underestimate actual levels of capacity given the lack of robustness of such forecasts. If the level of physical capacity is underestimated it could result in not all existing capacity being released, which could have distortionary effects on competition. If the level of physical capacity is

overestimated it could result in higher buy-back costs, with part of these costs being borne by consumers.

(c) The capacity requirements based on assessments of existing and/or future demands on the network as proxied by 1 in 20 demand scenarios

7.18 It would be possible to set baselines on planning standards, eg 1 in 20 peak day flows. This would involve using 1 in 20 data as, for example, consulted on and published in Transporting Britain's Energy. Either 1 in 20 flows for each node for each of the five years of the price control could be used (resulting in changing baselines on a year by year basis) or data for year 1 only could be used resulting in flat baselines. Alternatively, the average over the five years could be used. Rather than setting nodal baselines, this data could also be used to set a system wide baseline.

Advantages

7.19 A potential advantage of this approach is that baselines are set at a more realistic level compared with a theoretical maximum physical approach.

7.20 The key advantage is that National Grid NTS has an obligation to meet 1 in 20 demand and hence it might provide a realistic base case against which to measure incremental investment. The 1 in 20 demand obligation could be characterised as the minimum required to be delivered by National Grid NTS.

Disadvantages

7.21 There are a number of problems with this approach. Firstly, available physical network capacity is a dynamic concept. The physical capacity at a certain node depends on flows at other nodes, the magnitude and distribution of supply and demand, the use of linepack and the installation of new pipelines or compressors within the network and hence will change both during the gas year and from year to year. As a result, a fixed baseline at a specific node, even if only fixed for one year, will never truly reflect the actual available physical capacity at all times. Thus if baselines are to be set ex ante for each of the five years of the price control period on a nodal basis, there will be a considerable risk that at least several of

these baselines would be fixed at inappropriately high or low levels.

7.22 Secondly, on the entry side, assumptions will have to be made with respect to substitution of supply. For example, this might involve having to convert a 1 in 20 demand scenario to a 1 in 20 supply scenario. This involves a considerable degree of judgment with respect to who would flow, how much and when and hence if Ofgem was to carry this out Ofgem might be accused of picking winners and losers. This is especially an issue going forward, with greater uncertainty about gas flows and increased reliance on import terminals, interconnectors and storage sites. Assumptions would have to be made how demand is to be met, ie through the interconnectors/import terminals and storage sites, who would contribute how much and who would flow when and for how long.

7.23 Thirdly, if baselines are to be set on nodal basis, this approach could still result in inefficiently high baselines at declining entry terminals and/or inefficiently high baselines in the event of mothballed plant at offtake, potentially resulting in sterilised capacity.

7.24 Fourthly, if TO revenue allowance is directly linked to baselines, and baselines are set on the 1 in 20 forecast for year 1 of TPCR, this approach might allow National Grid Gas insufficient revenue to meet its 1 in 20 obligation for the full duration of the price control period especially in situations where 1 in 20 demand is expected to increase during the next price control period. However, this might be addressed by including an appropriate revenue driver and/or specific revenue allowance.

7.25 Fifthly, at certain points on the network maximum available capacity might exceed 1 in 20 and hence at these points this approach might underestimate the actual capacity of the network.

7.26 Finally, this approach is very reliant on medium to long-term forecasts, with all the inherent problems attached to forecasts. If the level of physical capacity is underestimated it could result in not all existing capacity being released, which could have distortionary effects on competition. If the level of physical capacity is overestimated it could result in higher buy-back costs, with part of these costs being borne by consumers.

(d) Capacity required to meet existing/future demands on the network as proxied by auction signals

7.27 Another option would be to set baselines to reflect existing/future demands on the network as proxied by auction signals.

7.28 Nodal or system wide baselines could be set to reflect auction signals from both the monthly and long-term auctions. For year 1 of the next price control both monthly and long-term entry capacity auction signals will be available, but from year 2 onwards only long-term auction signals would be available at the time when this price control is set. Alternatively it would be possible to use all auction signals (including on the day) for say year 3 of the current price control (April 2002 – April 2007).

Advantages

7.29 The advantage of using available auction data for the next price control period (ie forward looking data), is that rather than setting baselines using historical information this approach would determine baselines on a forward looking basis. Arguably, this is more relevant from a network users' perspective as it recognises that demands on the network are dynamic. These approaches would utilise existing market information and arguably reflect what the customers of the network require it to do. Alternatively it would be possible to use historical data. Although it could be argued that actual gas flows are a better measure of existing demand than auction signals, especially if demand is expected to increase during the next few years, actual flows might not be a very good indicator of future demand.

7.30 In both cases, these approaches are transparent and do not involve arbitrary decisions. However, in the second approach (using historical data) some degree of flexibility (slack) is built in. The latter would result in slightly higher baselines (possibly in excess of 1 in 20 at certain parts of the network) given that shippers might buy capacity on the day at zero price to increase their commercial flexibility. In the former approach (using forward looking data, ie auction signals for the next price control period) resulting baselines would be more in line with a tight network assumption and might be below the forecast 1 in 20 demand, especially if only based on long-term auction signals for year 2-5 of the next price

control.

Disadvantages

7.31 Current auction signals for the five year price control period would be insufficient to accurately reflect forecast demand. For year 1 of the price control a combination of monthly auction data as well as long-term auction data could be used, but for the remaining years only long-term auction data will be available when setting the baselines. In both cases, the data would underestimate future demand as the data would suggest baselines significantly below 1 in 20. Also, baselines would not be flat but would actually be declining due to increasing sparseness of auction signals in the latter years of the price control. For a number of entry points no auction data would be available which would suggest zero baselines. This would raise a number of implementation issues.

7.32 In order to determine offtake baselines, the use of entry auction signals would involve a considerable degree of judgment when balancing the network. Hence, there might be a number of implementation issues.

(e) A combination of the capacity required to meet 1 in 20 forecast and existing auction signals to determine baselines

7.33 Another approach for setting baselines would be to use auction data to the maximum extent possible but augment this by 1 in 20 forecast data. For example,

- **using existing auction signals as a starting point for each of the five years of the price control period**. If these signals are insufficient to meet the anticipated 1 in 20 demand the auction signals could be scaled up. Scaling up might be based on a judgment about how demand would be met or through using a more mechanical approach to scaling, for example proportional to existing gas flows;

- **use the lower of the 1 in 20 demand forecast and auction signals.** In most cases, especially for year 2-5 of the price control period this would result in very low baselines given the limited nature of current auction signals. Very low baselines are likely to significantly underestimate both the existing physical capacity of the network as well as the future level of

demand for capacity and hence raise implementation issues with respect of the revenue driver; and

- **use the higher of the 1 in 20 demand forecast and auction signals.** This approach could result in a larger network than necessary to meet 1 in 20 demand if all auction signals are used (eg say auction signals from year 3 of the current price control which includes on-the-day auction bids). Shippers are likely to value a degree of flexibility, though at present it is not clear what shippers would be willing to pay to increase their flexibility given that under the current regime additional entry capacity rights can be purchased at zero or very low price at a significant number of entry points.

Advantages

7.34 Given the shortcomings to the use of planning data, especially over medium to long-term horizons, this approach would ensure best use of all available information by using both auction information and planning data. It could be used to either set entry point specific baselines or a system wide baseline. It might also be possible to use this approach for determining offtake baselines.

7.35 It would also reduce the reliance on forecast data (eg 1 in 20 forecasts) by giving (maximum) weight to auction data and it might provide a reasonable proxy for existing capacity. In addition, it would reduce the buy-back risk faced by National Grid NTS and consumers.

Disadvantages

7.36 However, this approach might underestimate actual physical capacity at declining terminals. Also, if used to set entry point specific baselines by using year 3 data of the current price control or year 1 data of the next price control, it might still result in sterilised capacity at declining terminals. This would not be an issue if a network wide baseline were to be adopted.

7.37 One issue with this approach would be how to use 1 in 20 figures to scale up auction signals. Given that at some entry points there might be no long-term auction signals, proportional scaling might be difficult. Therefore, especially in these cases, this would involve a degree of judgment.

7.38 Although it might be possible to use a similar approach for determining offtake baselines, there might be a number of implementation issues. Especially when considering that the aggregate entry capacity is likely to be in excess of aggregate offtake capacity given network flexibility.

Appendix 8 Interactions between entry and off-take options

8.1 This appendix explains in more detail where there might be interactions between offtake and entry, affecting how baselines and revenue drivers might be set – and how charging arrangements and overall revenue recovery might be structured.

8.2 The concepts of entry and offtake are commercial rather than technical concepts. In practice, the technical considerations relate to a network accommodating patterns of flows, and the possibility of investment requirements if those flow patterns change. Whether it is driven by 'entry' or 'offtake' is not well defined at the margin, and might not be particularly relevant from an engineering perspective.

8.3 As a result it is necessary to consider whether the use of entry and offtake as concepts result in unintended consequences when dealing with the physics of the network. Building a greater understanding of the interactions between entry and offtake was one of the reasons cited in deciding to delay the implementation of enduring off-take arrangements.

8.4 Arguably, a distinction can be made between revenue implications and implications for network capacity as a result of entry-offtake interactions. Under the current arrangements National Grid NTS is expected to recover 50 per cent of its revenue through entry and 50 per cent from offtake. Hence, depending on how the TO allowance and revenue driver are determined there could potentially be a shortfall either on entry or offtake. On entry the shortfall would be recovered through the TO commodity charge, however, this would currently not apply to a shortfall on offtake.

8.5 From a regulatory perspective, the primary interaction is that an expansion of the capacity of the network at, for example, entry can result in an 'externality', ie an enhancement of available capacity at offtake at some points on the network. This relationship works both ways. However, in practice whether this is indeed the case will depend on a number of factors. For example, if a power station was to be built near a large import terminal, the entry capacity at that terminal would increase (ie a positive externality of building the power station). However, the

entry capacity of the network would only increase if the power station is operating when shippers at that entry terminal need it to operate. If the power station is not operating when needed from the entry point's shippers' perspective, the entry capacity at that entry point would not increase compared with the existing network without the power station.

8.6 The same applies to a large power station. In spite of its size, it might still not be appropriate to rely on it to operate during all high demand periods and hence, it can't be used to create firm entry capacity. For example, if spark spread was low it would be unlikely to operate (or switch fuel to condensate), eg during a high gas demand period. Hence the interaction between entry and offtake capacity and whether this would result in higher entry capacity is dependent on operational characteristics.

8.7 Similarly, offtake capacity might increase due to a commercial storage site being positioned near an offtake point. However, the offtake capacity would become dependent on the commercial storage site being able to flow when needed. Smaller storage sites are unlikely to be able to flow all days during the winter, and hence it might not be appropriate to argue that their existence would result in a permanent increase in offtake capacity.

8.8 Nevertheless, there might be some instances when the interactions are more permanent, for example in the case of very large import terminals or very large storage sites. In these situations, one approach is therefore to require National Grid NTS to consider whether any offtake/entry baselines should be increased (free of charge, in effect) if they are beneficially affected by investment for a new (or significantly expanded) entry/offtake point. This could be done through a period one-off adjustment to baselines. The process would be more transparent if it were referable to a publicly available network k model.

8.9 Such an approach would recognise that networks are dynamic and inter-related, and that if baselines are fixed at a particular point it is unlikely to be long before the relationship between the baseline and the physical capacity of the network at that point diverges. It may be possible to develop 'exchange rates' between different entry points on the network (ie nodes or zones) which would convert capacity at one point in entry capacity to another point. And similarly, it may be possible to develop exchange rates for offtake. If a robust system of exchange rates

could be developed then this might address the sterilised capacity issue. However, this is not necessarily straightforward – the general point is that exchange rates might need to change quite frequently to continue to allocate resources efficiently is relevant to this debate. This might imply a high degree of complexity if this type of mechanism is to be made to work.

8.10 One further area, which will require careful consideration as part of any changes proposed will be the impact of such proposals upon storage sites or interconnectors which are both entry and offtake points.

Appendix 9 Option assessment criteria

9.1 The table below sets out a list of criteria against which an option for incentive design (including the options discussed explicitly in chapter 7 and 8) might be assessed.

Table 7.1: Potential assessment criteria

Criterion	Score (see key)
Promoting efficient network development and system operation	
Optimising use of existing network	
Encourage long-run investment signals	
Providing accurate locational signals	
Preventing or limiting the scope for undue discrimination	
Promoting competition	
Ensuring transparency and simplicity	
Appropriate accountability for National Grid NTS	
Appropriate degree of ex ante involvement by Ofgem	
Appropriate degree of ex post involvement by Ofgem	
Minimise implementation costs	
Preservation of security of supply	

Key

✓✓	yes
✓	yes, but to a lesser extent than other options discussed
-	little or no impact
✗✗	no
✗	no, but to a lesser extent than other options presented

9.2 Ofgem would encourage parties to comment on possible options, including those

discussed explicitly in chapter 7, variants of those options, and other options not explicitly covered using the key outlined above (and adding supporting text where appropriate) – together with a description of the option or options being considered, including references to the options discussed in Chapter 7.

Appendix 10 Assessment of Pension Costs

10.1 In order to calculate pension costs for which allowance is to be made in setting future network price controls, Ofgem has developed a framework of principles that can be applied in setting network price controls in all cases. The principles were described in Appendix 1 of the July 2005 Initial Consultation document. Ofgem intends that this framework be used to determine an explicit allowance for pension costs. For the purposes of setting price controls, total operating costs (including employment costs) will continue to be benchmarked to determine an efficient level. This will maintain the incentive on companies to manage their employment costs, including ongoing pension costs, efficiently.

10.2 The allowance for pension costs at each price control review will be based on the cash funding rate recommended by the most recent full actuarial valuation then available for each company's scheme, adjusted for the items referred to below. Provided that valuations are based on reasonable assumptions, in line with prevailing best actuarial practice, Ofgem does not intend to challenge them.

10.3 Typically, actuarial valuations of pension funds are carried out triennially. In contrast, price controls are typically set for periods of five years. Accordingly, it is possible that funding rates may change during the period of a price control. The preferred method for dealing with such changes is to "log up" the cumulative effect and pass the impact through to consumers when setting the price control at the next following review.

10.4 It is recognised, however, that, in exceptional circumstances, an adverse change in the required funding rate may cause significant financial difficulties unless an immediate adjustment is made. In these cases, Ofgem will review the position and consider whether an interim adjustment would be justified. The additional complexities of defining an automatic pass-through do not appear to bring additional benefits.

10.5 To a greater or lesser extent, many if not most network monopolies rely on contractors for the provision of services necessary for the proper discharge of their duties in relation to the price controlled business. Employment costs typically represent a substantial proportion of the overall cost of providing such services. Where the contractor is an affiliate or related undertaking of the licensee, Ofgem

will generally require evidence of the underlying costs incurred by the contractor, and treat these in the same way as costs incurred directly by the licensee for the purposes of determining price controls. This applies equally to pension costs.

10.6 Adjustments are likely to be needed to ensure that the allowance for pension costs is consistent with the guidelines set out in July 2003. For example, adjustments will be necessary to ensure that the costs for which allowance is made :

- do not include costs that are properly attributable to activities that do (or did) not form part of the price controlled business, to avoid cross-subsidies;
- appropriately reflect differences (if any) between the allowances made in setting previous price controls and the actual employer contributions made to pension funds in the same periods, to prevent over- or under-provision;
- do not include early retirement deficiency costs arising from redundancy and re-organisation which have not already been matched by additional employer contributions; and
- do not include excess costs arising from a material failure of stewardship.

These are discussed in turn below.

10.7 Ofgem will continue to take a proportionate and pragmatic approach to the application of these principles, having regard to the quality of data available and the extent of analysis required. This may be of particular significance in the case of NGG, in view of the extent of corporate restructuring that has occurred since privatisation.

Allocation between price-controlled and non-price-controlled activities

10.8 The principles require that regulated network price controls allow for pension costs relating to the regulated network business only and not to any other. In considering the practical application of this principle, it may be useful to consider separately the allocation of scheme liabilities and assets, and to distinguish between different categories of scheme members – active members who are still employed by the group and pensioners and deferred pensioners who have left.

10.9 It will then be necessary to divide each category of liability into two classes: those

that relate to the regulated network business, and the remainder. At DPCR4 a pragmatic approach was taken based on a generic assumption. In principle. Ofgem considers that a more accurate approach should be taken, where practicable and proportionate. Ofgem will consider the most appropriate approach to take in TPCR.

10.10 To determine the surplus or deficit attributable to the regulated network business, it will also be necessary to allocate pension fund assets to the same categories of scheme member. In DPCR4, Ofgem considered allocation in proportion to the allocation of liabilities to be the most appropriate way to do this. It is intended to follow the same approach in TPCR.

Over or under provision

10.11 The principles require that, where actual employer contributions have been more or less than the allowance made in the preceding price control, the allowance in the succeeding price control should reflect, as nearly as practicable, the position that would have existed had contributions exactly matched the allowance. Where there was an explicit allowance for pension costs in the preceding price control (as for the last National Grid NTS price review, for example), this provides the benchmark. In other cases where the pension component of allowances was not explicit (as in the case of the other previous transmission price controls), it would be necessary to make an assumption as to what was implicitly allowed on a case by case basis.

10.12 In DPCR4 Ofgem considered three options:

- assume companies were allowed, in each price control period, an allowance equal to the same percentage of total actual salary costs incurred in the period as the accounting charge for pension costs in the base year for the relevant price control review bore to total actual salary costs in that year (as shown in the BPQs submitted by companies);

- assume each company was allowed, in each price control period, an amount equal to the contributions actually made by that company in the same period (i.e. no adjustment would be made to the future funding rate). This option would have differential impacts on companies according to the

level of their actual contributions and will thus potentially be inequitable; or

- assume each company was allowed, in each price control period, an amount equal to the average level of contributions actually made in the same period by all companies. This option would enable companies whose actual contributions were above the average to recover the excess (and vice versa), which could be held to provide a more equitable approach, with the same aggregate effect on consumers as assuming allowances equal to the contributions actually made.

Ofgem will consider which of these and other options is most appropriate for TPCR.

10.13 To the extent that actual contributions in any period fall short of or exceeded the assumed contribution, the amount of the shortfall or excess needs to be rolled forward to the date of the actuarial valuation on which the future price control allowance is based. Ofgem considers this should be done by assuming a total return in line with the ex post returns typically earned by pension funds in the relevant period(s). For this purpose, it would seem appropriate to use the median returns for comparable UK pension funds (for example, those published by The WM Company).

10.14 In setting the future price control, the allowance for pension costs would be set to reflect the position that would have arisen had contributions in the preceding period equalled the level assumed in setting the price control for that period. This would require addition of the rolled forward amount of any excess contributions and deduction of the amount of any shortfall to/from the value of the scheme assets assumed by the actuarial valuation, and re-projecting future costs accordingly taking account of investment returns. This will have the result of logging up or down variances resulting from changes in contribution rates occurring between price control reviews. To avoid double counting, this amendment will need to be carried through to subsequent reviews.

10.15 In DPCR4, it proved impracticable to derive a reasonable assumption regarding the amount of implicit allowances for pension costs included in any previous price control. Moreover, the available evidence indicated significant variation between

companies in the level and timing of contributions actually made. In light of this, Ofgem determined in that context not to apply the over-/under-funding principle in respect of periods prior to 1 April 2004**.** Different considerations may apply in the case of the transmission businesses.

Early retirement deficiency costs (ERDC's)

10.16 The principles set out in the July 2005 document require an adjustment to be made to the allowances for future price controls to exclude the impact of early retirement deficiency costs resulting from redundancy and re-organisation which have been offset by use of surpluses, rather than being funded by increased contributions. This provides for consistent treatment with other restructuring and rationalisation costs. For this purpose, it will be necessary to roll forward the amounts of unfunded early retirement deficiency costs arising in each year of a previous price control period using the method described in paragraphs 9.13 and 9.14 above.

10.17 In relation to TPCR (and the forthcoming gas distribution reviews), the principle suggests this adjustment should be carried back to the relevant privatisation date (being 1986 for Gas and 1990 for Electricity). It is for consideration how far this would be proportionate. However, application of this principle from any point in time other than privatisation could have differential effects between companies, without clear justification. Ofgem is not convinced that a different approach is needed, but will consider any constructive proposals put forward in response to this consultation.

10.18 Previously companies have argued that the way in which early retirement deficiency costs were to be treated at future price controls had not been clear prior to the publication of Ofgem's principles, and that they should therefore be able to recover the associated pension costs in full from consumers. They have also argued that consumers are benefiting from the reduction in overall employment costs that have been achieved. In DPCR4 Ofgem stated that ERDC's would be a matter for shareholders from 1 April 2004.

10.19 In DPCR4, Ofgem allowed DNOs to recover a substantial proportion of deficit repair costs associated with unfunded ERDCs, in part in recognition of these arguments but also because of the unequal incidence effects that were expected to

result from the decision not to apply the over-/under-funding principle to prior periods (as discussed in paragraph 9.16 above). To a degree, these two decisions were expected to have off-setting effects in their impact on price control allowances.

10.20 It is for consideration whether a similar approach would be appropriate in TPCR. This will depend on the facts relating to each company and may, therefore, lead to different approaches in different cases.

Stewardship

10.21 In seeking to establish whether there are any excess costs arising from material failure of stewardship (e.g. recklessness, negligence, fraud, breach of fiduciary duty), Ofgem intends to compare companies according to the scale of any increase in funding rate recommended by periodic actuarial valuations. If in any case there is one or more marked outlier, Ofgem will investigate, and if this reveals evidence that a material breach of stewardship has contributed to the increase in funding required, Ofgem expects to adjust the recommended funding rate for the purposes of setting the next price control so as to bring it into line with the average.