Transmission Price Control Review 2007-2012: Third Consultation - Supplementary Appendices

Document Type: Appendices

Ref: 51B/06

Date of Publication: 30 March 2006

Overview:

This document contains the appendices for the Transmission Price Control Review's Third Consultation. It follows on from the themes set out in the earlier consultation documents published in the Initial Consultation (July 2005) and Second Consultation (December 2005).

We set out our preferred options for the design of the price controls that will be put in place for 1 April 2007 and clarify our policy position on a number of financial issues. This document also sets out our views on the case for access reforms in electricity and gas transmission.

Contact name and details: Robert Hull, Director - Transmission

Tel: 020 7901 7050

Email: robert.hull@ofgem.gov.uk

Team: Colin Green, Senior Manager - Delivery Assurance, tel: 020 7901 7143 or email: colin.green@ofgem.gov.uk

Deadline for Response: 28 April 2006 to tpcr.responses@ofgem.gov.uk

Target Audience: Transmission licensees, Gas transporters and other interested parties

Ofgem, 9 Millbank, London SW1P 3GE
www.ofgem.gov.uk

Context

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.

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
- changes in wider energy policy, including environmental factors.

Against this background, the objectives of 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.

Associated Documents

- TPCR 2007-2012: Third Consultation (Ref 51/06)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)

Table of Contents

Appendix 5 – Responses to TPCR Second Consultation

Introduction

1.1. This appendix summarises the responses received to questions posed in the Second Consultation published in December 2005, together with our views.

1.2. Please note that this is not intended to be a comprehensive compilation of all points raised by respondents – the content of every non-confidential response is available on our website. If respondents are unsure about how their views are reflected in the document, please contact us for further details.

Responses to Chapter 2 - Timetable & consultation process

Introduction

1.3. In Chapter 2 of the Second Consultation we set out our approach to the consultation process and the associated timetable - and discussed the use of Impact Assessments (IAs). No explicit consultation questions were asked, but six respondents commented on issues covered in the chapter.

Views of transmission licensees

1.4. NG and SP commented on the issues raised in Chapter 2, highlighting the following points on timetable and process:

- The timetable for March looked challenging, with detailed policy issues to consider and resolve;
- Development of revenue driver options which are independent of potential changes to access arrangements looks sensible - and a separation of charging issues and price control design will create flexibility; and
- The benefits of preparing elements of an IA at early stages in the process was highlighted, and doing IAs for each significant element of policy development would facilitate this.

Views of other respondents

1.5. Five parties other than the transmission licensees made comments relating to process and timetable, and more general aspects of how the review was being undertaken, with key summarised points being:

- Concern was raised about the potential interactions between what was being developed as part of the price control, and wider aspects of the commercial regime - highlighting the need for co-ordination;

- Concern was also raised in respect of the potential complexity of some of the proposals, in the context of the available timetable;

- There was support for the publication of a forward timetable, and for the use of workshops and seminars as part of the process - and highlighted the need for transparency and quantification of impacts throughout the review;

- Highlighted the need to consider the proposals more widely in the context of European energy, and encouraged Ofgem to engage with the European Commission and with regulators in other member states in developing its proposals;

- Potential shortages in the supply of skilled labour was highlighted as a key issue for the transmission licensees going forward, and addressing this issue in a structured, strategic way (possibly through the use of specific incentive measures) should be a priority for the review. The need for efficient retention and recruitment of staff should be recognised - as should the currently tight contractor market;

- Support for recognition of the need for Ofgem to develop proposals consistent with its environmental duties; and

- It was also suggested that it would be useful for Ofgem to publish a preliminary IA at the Third Consultation stage - and the need to undertake an IA on gas offtake reform was highlighted specifically.

Ofgem's views

1.6. We would like to make the following observations in respect of the comments made by respondents:

- The main reason why we published our timetable (which we are keen to adhere to) is to provide transparency and facilitate a structured consultation process which is easy for stakeholders to engage in. This is a wider Ofgem objective, as evidenced by our new document format aimed at making our documents more easily accessible. We agree the seminars and workshops play an important supplementary role in the consultation process, and have made active use of them to date - and will continue to do so over the remainder of the review;

- We are aware of the range of possible interactions between the price control review and the wider commercial arrangements, and have taken steps since the Second Consultation to facilitate a structured debate on the available options, through the establishment of industry working groups. Our current view is that this has been a constructive process, and will help in managing any change in a coordinated manner;

- One of the reasons we have focused on identifying options in a systematic way, through industry workgroups, is to ensure that there is clarity on what particular issue each option might address and why. We think this is important in avoiding the risk of unnecessary complexity. However, the level of complexity needs to be commensurate with the issue being addressed;

- We must ensure that the proposals we develop are consistent with our statutory duties, which includes ensuring compliance with EU Directives and other European law. We will be publishing shortly a paper on the legal framework for the TPCR on our website;

- The points raised about staffing and resources are noted, and the detail of how the licensees resource their ongoing work is being reviewed as part of our cost assessment work. We consider that the licensees themselves are best placed to identify their needs in the short, medium and long term - and to highlight any systematic issues that need longer term solutions; and

- We recognise the value in assessing the impacts of different policy options, and are keen to apply this to the significant policy areas. The work is ongoing on gas offtake and in other areas - and we will provide updated information in June. The IA process will deliver most value when the options to be compared are well documented and defined. A key part of our current work in the context of electricity access issues (through the ARODG industry workgroup) - and in the ongoing policy work on revenue drivers - is to develop and document, in a systematic way, the range of options. We think this will provide a solid foundation for further IA work.

Responses to Chapter 3 - Framework, context & objectives

Introduction

1.7. In Chapter 3 of the Second Consultation we set out the context and framework for the review, and restated our objectives for the review in the light of consultation responses to our Initial Consultation. No explicit consultation questions were asked, but ten respondents commented on issues covered in the chapter.

Views of transmission licensees

1.8. NG and SSE commented on the issues raised in Chapter 3, making the following points:

- The standard RPI-X form of control continues to be appropriate;

- Form of control and treatment of pensions will be key elements of the Final Proposals;

- Supported the amendments made to Ofgem's objectives for the TPCR in the light of consultation responses to the Initial Consultation; and

- Pleased that Ofgem recognise the key role of transmission networks in facilitating competition, and the importance in the context of timely investment - assessing whether any policy option will potentially lead to underinvestment is a key criterion.

Views of other respondents

1.9. Eight parties other than the transmission licensees made comments on context, framework and objectives for the TPCR, with key summarised points being:

- Support for revised objectives, particularly in being explicit about the duty on Ofgem to ensure that the licensees can finance their activities - and in stressing the primary importance of the interests of customers;

- Support for seeking to consider the impacts of the review into the medium term, i.e. beyond the period of the review;

- Stressed that there are problems to be addressed in both the current gas and the electricity arrangements. They are too inflexible, and do not support strategic investment;

- Right to recognise changes in market structure are potential drivers for investment and the need to consider environmental factors in the TPCR - and highlight the potential for the Energy Review to influence what networks need to do going forward. The role of potential new interconnectors is an additional source of uncertainty, which was not highlighted by Ofgem;

- Need thorough investigation of capex plans as part of review, given large projects being covered - and need more transparent cost reporting, particularly in respect of SO costs;

- Network investment (and the need to deliver sustainable networks) will be a key factor in a period of changes for UK energy markets - and it is vital that the regulatory regime recognises this. Work on cost of capital is a key part of this, and welcome the proposed work; and

- Concern that some of the options put forward are too complex, in particular in the context of transmission access (and gas offtake in particular) - need to apply simple solutions where they are effective. Continued support for 5-year RPI-X framework.

Ofgem's views

1.10. We would like to make the following observations in respect of the comments made by respondents:

- We acknowledge the broad support for the (re-stated) objectives for the TPCR;

- The key theme of uncertainty, and the need to ensure that the transmission licensees are incentivised to respond flexibly to changing needs for investment, is a clear message from the consultation responses. This theme is reflected in practice in a number of our proposals, e.g. the use of revenue drivers;

- We agree that the investment plans raised by the licensees need detailed assessment, and this work is being progressed through our cost assessment work-stream - with findings to be reported in June at the Initial Proposals stage; and

- We agree that options should not be unnecessarily complex - nor should simple, but ineffective (relative to the issue being addressed) options be proposed. The reasons for detailed industry involvement through workgroups to identify the range of options on access is demonstrating how are seeking to reduce these risks.

Responses to Chapter 4 - Cost assessment

Introduction

1.11. Chapter 4 of the Second Consultation invited views on a range of issues associated with Ofgem's proposed approach to assessing historic and forecast levels of capital expenditure and operating costs, and to the issue of future cost reporting. It also invited views on a number of environmental issues. The three transmission licensees, and 24 other parties, including one confidential response, commented on the issues raised. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this heading):

- ➔ 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?

Views of the transmission licensees

1.1. The three transmission licensees commented on the issues raised in this chapter. We have summarised the points raised by one or more of the transmission licensees as follows:

- The assessment of efficient costs should be based on cost-benefit analyses and detailed statistical modelling using the best information available. One respondent suggested that changes in investment costs resulting from potential revisions to the SQSS should be allowed for, e.g. as an income adjusting event;
- Network flexibility has value in improving efficiency and security of supply, and helping to reduce emissions by accommodating more outputs from renewable generation. The baseline for TO should take into account a realistic range of potential variations of flows on the network, e.g. by statistical modelling approaches;
- There was some support for the model of GBSO being incentivised to coordinate and pay relevant TOs to carry out investments. Some respondents raised issues regarding practicality of this model, including the interaction between TO and SO revenues, and associated changes to codes and methodologies. One respondent suggested an alternative model which would leave the responsibility to carry out such investment directly on TOs and remunerate them directly;
- In its assessment of efficient investment and operation, clear responsibility for environmental considerations should be made by Ofgem, and a consistent regulatory framework should be developed. Consideration also needs to be given to mechanisms that would recognise environmental and operational investments of longer term duration than 5 years; and
- Consideration should be given to the issues created by the ageing transmission network from an environmental perspective both in terms of remediation of noise pollution and in terms of visual amenity. In recent years, increased public resistance to the installation of transmission assets means that the least cost solution may no longer be acceptable to the planning authorities.

Views of other respondents

1.12. Twenty-four parties other than the transmission licensees commented on one or more of the issues raised in this chapter. We have summarised the points raised as follows:

- Changes in investment costs resulting from potential revisions to the SQSS should be allowed for by price control re-openers;

- System flexibility should be limited to the scenarios covered in the TBE process and limited to a 2-3 year planning horizon in line with the normal timescale for development of incremental transmission capacity. Some respondents believed that Ofgem could allow NGG increased ability to commit capex to respond to shippers' requirements for flexibility. However, some others suggested that flexibility needed would rarely exceed available capacity and that therefore there was no need for additional capex allowances to provide flexibility;

- On treatment of investment for system operational efficiency, one respondent suggested an alternative model of incentivising the TOs by exposing them to system operation costs;

- Emphasis should be given to the importance of giving consideration in the transmission licensees' investment plans to their effects on the environment, and in particular National Parks;

- Ofgem should give explicit reference to its duties under the National Parks and Access to the Countryside Act 1949, as amended by the Environment Act 1995 when listing its environmental duties;

- Willingness to pay surveys provide a useful indication of the value consumers place on the landscape, or to remove or reduce any perceived impact on visual amenity, and were used in DPCR. Such an approach should be used for TPCR;

- Support should be given for incentives that drive quality enhancement that benefit the public without incurring additional costs;

- There is a need to consider longer term issues in the price control, and specifically whether policy should be changed to consider undersea cabling as a more viable method of preventing environmental impacts from transmission investment; and

- The capex baseline and supporting mechanisms need to be transparent and the PC mechanism should be sufficiently flexible to allow for re-opening of the price control, but only in extreme events, such as TIRG. Potential savings derived from the sale of the gas distribution networks have not been mentioned in the TPCR consultation process.

Ofgem's views

1.13. We would like to make the following observations in the light of the points raised by respondents on the questions cited at paragraph 1.11:

- Ofgem will rely on cost-benefit analyses to assess economically efficient transmission investment for wind generation. The Third Consultation will consult on key parameters to be used in the cost-benefit analysis. So long as the cost-benefit analyses are robust, Ofgem does not believe that any potential changes of the SQSS in themselves should result in a materially different level of efficient investment. However, in the event that SQSS minimum requirements are higher

than justifiable by consideration of economic efficiency, then there may be a need to consider derogation from SQSS;

- The costs of additional capex and the potential value of providing network flexibility need to be carefully balanced. The level of flexibility already existing in the networks is also a relevant factor to be considered in the assessment of future capex required;

- On investments to support system operational efficiency, the GBSO is best placed under the current division of TO and SO licence duties to coordinate the trade-off between system operation costs and network investment costs across the whole GB electricity transmission system. Therefore the logical solution is to incorporate the remuneration for investment directly within GBSO's incentives and to allow it to contract with the Scottish TOs to deliver the required investment. However, Ofgem agrees that the mechanism adopted should take account of practical issues and be proportionate with the materiality of the costs. These will be further explored with interested parties in the process of developing the appropriate arrangements;

- Ofgem recognises that the requirements of environmental legislation will have had an effect on the transmission licensees' investment plans. Our views are that it is up to the licensees to provide details of their investment plans under the TPCR, and to highlight any specific environmental investment that has or is intended to take place. Ofgem, as part of its cost assessment exercise will consider the appropriateness of these allowances, and will provide views prior to issuing Final Proposals. Ofgem will also consider the longer term environmental issues associated with the TOs' investment plans, in keeping with its social and environmental obligations, and will develop proposals with this in mind;

- As mentioned in the Second Consultation, one of our objectives for the TPCR is to promote social and environmental objectives. This will involve developing a set of proposals consistent with the Authority's 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. Whilst we recognise the importance of our environmental duties, we do not exhaustively list any of them for the purposes of our TPCR consultation documents as it appears unnecessary;

- In considering the proposals for the TPCR, we will seek to identify certain areas where assessment of environmental costs and benefits might be particularly relevant to decisions under the TPCR. We have stated that we intend to assess the implications of the licensees' investment plans from an environmental perspective. Ofgem also recognises that there is some evidence to suggest that consumers would be willing to support increases in their bills to preserve the landscape. Under the TPCR we will consider a range of mechanisms by which to better understand the environmental impacts of the investment plans, and where issues arise, ways to address them;

- We consider that there is an ongoing role to incentivise quality of service and reliability of the transmission system. As part of the TPCR, we intend to explore options for the existing reliability incentives placed on the transmission licensees;

- As mentioned in the Second Consultation, we will give consideration to the costs and benefits of exploring alternative routes to traditional overhead wiring, including undersea cabling, in subsequent documents; and

- We agree that whatever mechanisms are used for the capex baseline, and any revenue driver should be transparent and verifiable. We also agree that for the most part automatic adjustments are more efficient than re-opening the price control, but we also feel that in the case of unforeseen and extreme costs, re-opening may be appropriate. Ofgem considers that some consideration of the DN sales project has been made in terms of effects on overheads, but recognises that the majority of the issues pertain most closely to the Gas Distribution Price Control Review (GDPCR)..

Responses to Chapter 5 - Form & structure of price controls

Introduction

1.14. Chapter 5 of the Second Consultation invited views on a range of issues associated with the form and structure of the transmission price controls to apply from April 2007. The three transmission licensees, and six other parties commented on the issues raised. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this heading):

- ➔ 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?

Views of the transmission licensees

1.15. The three transmission licensees commented on at least some of the issues raised in this chapter. We have summarised the points raised by one or more of the transmission licensees as follows:

- Best way to minimise risk (and material impact) of price control re-openers is to use automatic adjustment mechanisms (which, in principle, is supported subject to further development of detail) - but a residual risk of the need to re-open due to material and unforeseen cost pressures is likely to remain. However, re-openers should be exceptional events;

- Options to explore for automatic adjustment mechanisms should include TIRG-type mechanisms - with trigger points, and methods of adjustment defined up front as far as possible. This option could also include a rolling incentive element;

- SO incentives schemes have promoted innovation and delivered benefits to consumers - and note factors going forward (and evident in 2005/06) which might be expected to push up the external costs of system operation;

- Mixed views on rolling incentive mechanisms. NG do not support, due to perceived likelihood of inaccurate revenue allowances (even with automatic adjustment mechanisms) in context of large, lumpy nature of transmission investment. SP and SSE see a role for rolling incentives;

- Need to be aware of existing levels of environmental impact reporting (and avoid unnecessary duplication) - but recognise possibility of some areas where additional reporting might be appropriate; and

- Ofgem need be careful to avoid unintended interactions between the TO and SO price controls, gives the separate roles of TOs and the GBSO. Clarity on responsibilities and revenue allowances is needed.

Views of other respondents

1.16. Six parties other than the transmission licensees commented on one or more of the issues raised in this chapter. We can summarise the points raised as follows:

- Need to understand (and focus on) the impact on consumers, also need to understand the potential (or past) costs to consumers of stranded assets;

- Support continuing role for RPI-X regulation as the basis for the price control design with refinements at the margin;

- There should be a role for automatic adjustment mechanisms in the context of significant uncertainty on future developments, and in the light of the potential adverse effects of price control re-openers (e.g. dilution of incentives) - but need to recognise that re-openers for certain large, unanticipated costs increases (e.g. as a result of new legislation) might be inevitable. Also, revenue drivers and potential re-openers should not be substitutes for robust, detailed analysis of efficient costs;

- Efficiency savings on SO costs should be shared appropriately with consumers - and these need to include estimates of efficiency savings resulting from the merger between NGT and Transco, and should be informed by past behaviour under previous schemes. SO incentives need to be aligned with incentives created through TO price controls, particularly in the context of balancing short term constraint costs against long term investment costs;

- Information published by NG on past performance under SO incentives was useful, but further detail in some areas would be useful too. Support for greater transparency in reporting more generally (including in respect of environmental impacts);

- Visual amenity impacts, particularly in National Parks, should be factored in to the design of the form of control, and consideration should be give to providing additional allowances to invest in ways which reduce the impact on visual amenity and noise pollution. Investment to facilitate the growth in renewables and the attainment of Government targets is a key consideration for the price review - recognising that transmission investment will be important to allow projects to connect to the network; and

- Support for rolling incentives (possibly with sharper incentives attached), while noting the need to consider carefully how they might be applied to capex and opex; scepticism over the value of DPCR-type sliding scale incentives - which should certainly not be a substitute for detailed analysis of company forecasts. Performance incentives can be important in shaping company behaviour, but they need to be well designed with clear and meaningful output measures.

Ofgem's views

1.17. We would like to make the following observations on progressing our thinking in the light of the points raised by respondents on the questions cited at paragraph 1.14:

- We note the broad support for the standard RPI-X framework continuing to have a significant role to play in regulating the transmission licensees going forward;

- We note the broad, but qualified, support for automatic revenue adjustment mechanisms as a sensible means of setting allowances in the context of uncertainty over future needs - and accept the need for further detailed work to illustrate and assess how they would work in practice. This will be a key part of our next document. While we accept that TIRG-type mechanisms could be one form of (semi) automatic revenue adjustment, we have reservations about the incentive properties of such arrangements relative to alternatives;

- We note the comments about the need to allow for the possibility of re-openers, even with automatic adjustment mechanisms in place - and will take forward work before the next document to assess what the scope is, and how it might be handled. This will include options which specify some (but not all) aspects of a re-opener mechanism in advance;

- We do not share the scepticism expressed by some respondents on the limited value of a 'sliding scale' mechanisms - and therefore think it an avenue still worth exploring. The informational advantage that the licensees have over Ofgem is a material issue, and we need to explore all available tools;

- We recognise that there are challenges in designing incentives which work effectively across the interface between SO and TO, and this needs to be addressed in developing our package of proposals. The details are still, at this stage in the process, under development;

- In principle we think that measures which seek to create a consistent strength of incentive over time (such as rolling incentives) are appropriate - but the detailed design needs to be worked through. We are not persuaded at this stage that transmission is substantially different to distribution in terms of the potential applicability of rolling incentives; and

- We will have regard to environmental factors, as we are required to do, in developing our proposals, and we have initiated a plan of work to understand and quantify some of the impacts that are particularly relevant to transmission. This includes examining environmental reporting by the licensees, and work to establish how potential environmental impacts (such as visual amenity) might be quantified and factored in.

Responses to Chapter 6 - Price control design options: framework

Introduction

1.18. Chapter 6 of the Second Consultation invited views on a range of issues associated with price control design options. The three transmission licensees, and nine other parties commented on the issues raised. We invited views on the following specific questions (and invited comments on any other issues that parties wished to raise under this heading):

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

Views of the transmission licensees

1.19. The three transmission licensees commented on at least some of the issues raised in this chapter. We have summarised the points raised by one or more of the transmission licensees as follows:

- All three licensees expressed a degree of support for the possibility of user commitment models (UCM), but raised a number of questions and reservations about how it would work in practice. These included:
  - how, exactly, are revenues linked to user commitment;
  - whether incremental revenues are determined solely by user commitment (which NG did not support), or whether other factors are relevant;
  - whether user commitment would be required from all users or just new users, and whether it would apply at entry and exit, or just entry;
  - potential risk that barriers to competition could be created if user commitment is too significant;

- Alternative ways in which revenue could be linked to user commitment (or other trigger mechanisms related to demonstrated need for capacity, e.g. TIRG-type assessments) were highlighted;

- A key principle in allocating risk should be whether the party exposed to a risk can manage it or not - and that the regime should recognise that transmission licensees cannot manage all risks related to network investment (which might have particular relevance to buy-back arrangements and default delivery timescales) - and should reward transmission licensees accordingly for the risks they face. It was noted that user commitment could affect how risk is allocated across different parties; and

- Support for greater separation between charging arrangements and the design of the revenue restriction, with greater flexibility and transparency being cited as important reasons.

Views of other respondents

1.20. Nine parties other than the transmission licensees commented on one or more of the issues raised in this chapter. We can summarise the points raised as follows:

- Emphasise the need to consider whether and how UCM (and potential changes in the allocation of risk) would benefit consumers;

- Gas and electricity arrangements should not necessarily be the same - given that there are significant underlying differences;

- Qualified support from most respondents for user commitment models, but need more detail on how it would work in practice (and transparency/quantification on what the costs and benefits would be) and how it would relate to existing arrangements for planning network investment (supplement or complement?). Concerns expressed about cost/benefit in particular in the context of gas offtake;

- Concerns raised by some respondents that UCMs would shift risk inappropriately to network users - and that this would impact on competition;

- Focus on UCM is outdated and greater emphasis should be placed on strategic network investment as a means of meeting the Government's energy objectives;

- General recognition that some form of risk sharing is appropriate, and some support expressed for the existing 50% NPV test in gas entry. Also noted that transmission licensees are best placed to manage many of the risks associated with transmission investment, and they should be appropriately remunerated for this. Also noted that different users might have different abilities to manage risk themselves; and

- Mixed views on greater separation of charging arrangements in gas entry. Support from some respondents (but recognise need for appropriate regulatory safeguards to ensure stability), but also concern that reforms in this regard might create charging uncertainty, and might have unintended consequences (including in terms of incentives to bid in the long term auctions). Ensuring non-discrimination between classes of new user was highlighted be a key consideration.

Ofgem's views

1.21. We would like to make the following observations in the light of the points raised by respondents on the questions cited at paragraph 1.18:

- We recognise that there are a multitude of possible models of user commitment that could be adopted in the context of transmission, including the current arrangements. We have taken steps since the publication of the Second Consultation to engage actively with stakeholders to develop the range of possible models - to help understand, specifically, what the issues are with the current arrangements and how they might be addressed. We have established, and chair, the Access Reform Options Development Group (ARODG) and the Enduring Offtake Working Group (EOWG). We fully accept that the models in gas and in electricity do not need to be the same, but they should adopt common principles where there are common issues;

- We do not agree with the view that user commitment models are outdated, and greater emphasis should be placed on 'strategic' investment. There is a significant risk to consumers that too much investment is undertaken under such a regime, or that it is directed 'strategically' in the wrong place (or at the wrong technology). It would also appear to reduce the incentives on network users to demonstrate where they need capacity - and hence could potentially exacerbate rather than alleviate capacity scarcity. Further, it could be argued that 'strategic'

investment (i.e. investment before an explicit demonstrated need) is more uncertain in the context of obtaining planning consents;

- We remain of the view that it is important to explore whether the allocation of risk under the current arrangements could be improved upon. In some circumstances, e.g. in gas entry, it could be argued that too much risk is borne by consumers, while in electricity there could potentially be scope for consumers bearing more risk during construction as a means of addressing potential barriers to competition. It therefore seems appropriate to continue to purse policy options which might change this balance of risk, and do so in a manner which compares and contrasts underlying principles in gas and electricity. The proposals set out in this document on gas entry buyback are informed by these types of consideration; and

- While we note concerns about pricing uncertainty if gas entry charges are set on a more dynamic basis, we also think it is important not to lose sight of the important role of cost-reflective relative prices in influencing locational decisions. The basis upon which charges are set needs to be transparent and robust, but this is not inconsistent with models where prices are more dynamic. While the process of change might potentially create incentives to bid (or not) before the changes are implemented, there are also significant potential distortions in keeping reserve prices fixed where they no longer adequately reflect costs.

Responses to Chapter 7 - Incentives options: gas

Introduction

1.22. Specific responses to Chapter 7 of the Second Consultation were received from seventeen respondents including National Grid Transmission (in its role as operator of the National gas Transmission System (NTS), hereafter referred to as National Grid Gas NTS (NGG NTS)), SSE[1], a GDN respondent, energywatch and thirteen network users including gas shippers (GB and Irish), producers and producer representatives. None of these responses were confidential.

1.23. The questions posed in the Second Consultation were broadly grouped into the following categories:

- Revenue drivers for entry and offtake
- Baselines for entry and offtake
- Offtake access arrangements and enduring reform
- Entry and offtake incentives

Revenue drivers for entry and offtake

[1] SSE's response did not distinguish in which capacity, out of its many functions, it was providing comments.

➔ (a) Should the revenue drivers 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?

Views of NGG NTS

1.24. NGG NTS commented on the issues raised in this chapter. We have summarised the points raised as follows:

- Revenue drivers should be viewed as "down payments" for necessary investments and that revenues should be adjusted at the next price control to ensure that the company is "left whole". Fixing these for five years would not distinguish between variations in capital expenditure due to inefficiency and variations due to "unanticipated requirements to spend"; and

- Revenue drivers would have to be linked to some other elements, such as cost per km, rather than just to the existence of a user commitment.

Views of other respondents

The key points raised by parties other than NGG NTS regarding these questions are summarised as follows:

- Respondent's views were varied on the question of the scope (nodal, zonal or national) of revenue drivers. Some respondents argued that nodal drivers allowed for a more cost reflective setting of drivers and some argued that a national approach would be simple and transparent; and

- Some respondents expressed the view that distance and steel price were key cost drivers for investments. Respondents expressed the view that revenue drivers should be allowed to vary during the price control to reflect cost changes.

Ofgem's views

1.25. We would like to make the following observations on progressing our thinking in the light of the points raised by respondents to the questions cited at paragraph 1.23:

- We consider it is not appropriate to treat revenue drivers as down payments on future income streams, as such an approach would dilute the incentive properties of such revenue drivers;

- We understand the argument that it may be appropriate for revenue drivers to contain elements relating to steel prices and distance from network and will be exploring these possibilities as part of our work on the appropriate levels of revenue drivers. If we were to be convinced that NGG NTS should not bear this risk it would be necessary for consumers to bear it. However we are keen that, to retain the incentive properties of the regulatory approach, apart from adjustments to revenue drivers that can be specified ex ante like these there should be no variation of revenue drivers during the price control period; and

- Our preferred approach is to implement a system of revenue drivers based on a nodal approach for existing and known new nodes so utilising the maximum available information. At entry, our initial view is that this should be combined with an automatic system for "small" new nodes so giving some of the flexibility and transparency available from global or zonal products.

Baselines for entry and exit

➔ (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?

➔ (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?

Views of NGG NTS

- NGG NTS wanted Ofgem to be clear whether it (NGG NTS) is obliged to make investments to meet the "1 in 20" obligation and how it would be remunerated for these;

- In its response, NGG NTS stated that it is crucial to consider both the obligations and remuneration of NG in parallel to ensure that they are aligned. NGG NTS particularly emphasised the need for clarity on obligations to invest (including the 1 in 20 obligation on gas) and the remuneration of incremental investment; and

- NGG NTS stated that it fundamentally disagreed with the theoretical maximum physical capacity approach (max phys), as setting baselines in excess of physical capacity can remove incentives for users to signal true needs in any long-term booking process and hence lead to a situation where the network operator cannot respond in timely manner to any shorter term signals for additional capacity; and NGG NTS considered that offtake baselines should be consistent with the physical capability of the system taking into account interactions between various nodes and that baselines should be set to match funding provided in the TO allowance.

Views of other respondents

The key points raised by parties other than NGG NTS regarding these questions are summarised as follows:

- Many of the respondents who expressed a preference indicated a desire to maintain the status quo interpretation of entry baselines as giving an obligation to NGG NTS to release capacity. Respondents' views varied on whether baselines should include growth other than that related to user commitment. Some respondents favoured a fixed approach with others arguing that baselines should vary for anticipated planned investment;

- One network user also expressed concern that in zonal or national models (or by implication no baselines) it was unclear how NGG NTS would allocate capacity on a transparent and equitable basis; and

- Two shippers who expressed a preference indicated that continuing with theoretical max phys approaches for baseline definition is desirable as this approach is simple and objective.

Ofgem's views

1.26. We make the following observations on progressing our thinking in the light of the points raised by respondents under this section of Chapter 7 of the Second consultation:

- It is our initial view that, within a user commitment framework, it would only be appropriate for additional NTS capacity to be provided if NTS users have signalled that such capacity would be of value to them. In particular, in the case of GDNs, it is our view that NTS exit capacity built for GDNs should be consistent with the GDNs' assessment of their NTS exit capacity requirements given their 1 in 20 obligation. As a result there would be greater clarity of responsibility between NTS users and NGG NTS. As the causality for investment would be unambiguous, users would be incentivised to provide long term investment signals;

- We appreciate the desire of some parts of the industry for stability and the maintenance of the status quo. We are keen to minimise the impact of the changes to the price control on network users. However in addition to price control changes, we are also considering reform of access regimes and this is discussed below;

- We consider that under our preferred approach a key factor in the allocation of capacity between entry points by NGG NTS will be the existence of a published (populated) network model and the charging methodologies. We note that work is already taking place under the gas GTCMF that will inform these; and

- We agree with NGG NTS that offtake baselines should be set consistent with the physical capability of the system taking into account interactions between various nodes and that baselines should be set to match funding provided in the TO allowance. We do not believe that a theoretical maximum physical capacity approach is appropriate as this may lead to significant buyback exposure for NGG NTS and customers or over-investment.

Offtake access arrangements and enduring 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?

➔ (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?

Views of NGG NTS

1.27. NGG NTS commented on all of the questions posed with regard to offtake access arrangements and enduring reform. We have summarised the points raised as follows:

- Reform should focus on those elements of the existing regime that require change, rather than implementing the model developed as part of GDN sales, including common capacity booking process for all NTS users and clarity of level of commitment required by those users requesting incremental capacity. As there is limited competition at offtake points, the complexity associated with longer term application and allocation processes based upon the Gas Entry model might not be warranted;

- There may be simpler ways of obtaining sufficient user commitment to avoid the risk of stranded investment, such as requiring all users to indicate their

incremental capacity requirements (with associated financial commitment) and also indicating any reduction in capacity requirements a certain number of years ahead of delivery;

- The threshold to trigger the release of incremental offtake capacity should be set having due regard to the apportionment of risk between key stakeholders (eg, ensuring investment cost is borne by users rather than the wider community who receive no benefit from such specific investment); and

- Incentives for delivery should focus on activities within the control of NGG NTS. It would be appropriate for the release of capacity to be linked to a fixed period once all relevant planning consents have been granted but that it may be appropriate to have different time periods to release depending on the type and complexity of the project to be delivered.

Views of other respondents

1.28. 16 other parties other than NGG NTS commented on one or more of the issues raised in this chapter. We have summarised the key points raised as follows:

- Mixed views regarding the appropriateness of UCMs, with the most contentious issue being the length of such a commitment;

- Concern that a mismatch between a user's requirements for offtake capacity and the (relatively shorter) period of shipper contracts made user commitment difficult to implement in practice;

- Concerns that enduring reform may not be appropriate at bi-directional points and interconnectors, with some respondents stating that parties at these offtake points should be treated differently to other users (eg, because they use different NTS services or have different requirements, that different users have different planning horizons or that different users face different consequences in the event of failure to secure capacity);

- Concern that the models presented in the Second Consultation were not sufficiently well defined for them to be able to assess such options fully, and a desire to develop the proposals further to gain a better understanding of how the whole measures may work as a package, allowing a more meaningful assessment (including a consideration of the trade offs between each of the defined objectives of reform);

- Concern at the application of a framework of arrangements akin to those implemented at entry for gas offtake on grounds of complexity, and the proposal of an alternative (simpler) approach in which any user commitment required to secure incremental capacity from the NTS is secured through an ARCA type arrangement (with appropriate cost pass-through arrangements for GDNs);

- Some concern that moving away from the status quo may involve greater cost and complexity, may impact competition and that reform may place a resource

burden on industry (due to the need to consider alternative options for reform, and the associated tight timescales); and

- Delivery of investment 'as soon as possible' may not always be appropriate. Instead, different approaches may be appropriate at different offtake points, consistent with the needs of the connectee and the project being undertaken. Once a firm delivery date has been set, there should be strong incentives to deliver to this date (and associated penalties for failure).

Ofgem's views

1.29. We would like to make the following observations, in light of views made by NGG NTS and respondents under this section of Chapter 7 of the Second consultation:

- We continue to believe that user commitment is an appropriate basis for investment decisions, and that additional NTS capacity should only be provided if NTS users have signalled that such capacity would be of value. We welcome the role that NGG NTS and shippers have played within the Enduring Offtake Working Group (EOWG) to facilitate discussions of the potential framework for access reform. Our initial views on the appropriate framework for reform (as detailed in Appendix 12) have taken full consideration of both respondents' views in relation to the Second Consultation and discussions of the EOWG, including the "strawmen" presented by EOWG attendees;

- We have also had discussions with other parties (such as the CER, Ofreg and other parties downstream of the Moffat interconnector) to understand their concerns in more detail. The proposals outlined in this consultation have taken into account industry demands for reduced complexity. We also note that the EOWG will continue to run until June, and we propose addressing more detailed concerns raised by respondents in this working group;

- We encourage views on the framework proposed in this consultation which retains the ability for TCCs to reserve capacity directly where new or increased capacity is required. We also agree that NGG NTS should be incentivised to deliver capacity on a timely basis, or early when this is of value to users;

- We recognise different NTS users have different characteristics, however where a user is obtaining or receiving a service from the NTS, the identity of that user should have no bearing on the costs associated with the NTS providing that service. We therefore continue to believe a common framework should be developed for all NTS users, but with sufficient flexibility to allow users to tailor their capacity requests to their individual circumstances. However, we do not believe that it is appropriate for different products to apply to different classes of users where such products fundamentally represent the same underlying NTS service, namely the provision of NTS offtake capacity;

- We agree that the threshold chosen that triggers the release of incremental capacity should be consistent with a level that may be viewed as suggesting that any such investment is efficiently incurred. We also consider it is important that

users understand the nature of this trigger ex ante, to be able to make efficient signals for the unconstrained release of capacity;

- We agree that early delivery of investment is only desirable when this is of value to the connectee and is achievable at an appropriate cost. We note that certain types of project (eg, those that lead to releases of large increments of capacity) may be subject to specific risks of delay that are beyond NGG NTS's control (e.g. delays resulting from the requirement to obtain environmental consents). We therefore consider there may be merit in allowing a certain degree of flexibility in the determination of investment lead times for such projects;

- We consider that it may be appropriate to allow parties to agree with NGG NTS to vary the standard terms for buyback in some circumstances, as well as potentially agreeing to vary the associated incremental capacity delivery date; and

- We believe that risks should be borne by those parties best placed to manage such risks so that appropriate mitigating actions may be taken to reduce the overall risk faced by customers. We do not believe that it would be appropriate for the generality of customers to bear the costs of planning risks incurred by TCCs as it is the TCCs that are responsible for making the siting decision.

Entry and offtake incentives

Transitional offtake incentives:

➔ (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" NGG NTS incentives, including the 15 day interruption incentive on the NTS? and

➔ (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 NGG NTS incentives that will be determined?

Buyback incentives:

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

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

➔ (s) Should delay to incremental investment due to connecting pipelines be included in the buyback 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 be achieved? What would the advantages and disadvantages be, especially how might this impact on consumers?

Interactions between entry and offtake:

➔ (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 buyback incentive covering both entry and offtakes?

Views of NGG NTS

1.30. Key points raised by NGG NTS in relation to entry and offtake incentives can be summarised as follows:

Transitional offtake incentives:

- That it is difficult to assess whether incentives and revenue drivers for the transitional period should either be a continuation of the current interim incentives or whether they should be consistent with enduring incentives; and
- That it would be necessary to ensure that the form of the incentives in the transitional period include a revenue driver to provide additional revenue to fund investment made for providing capacity above the agreed baseline level.

Buyback incentives:

- That the two types of buyback have qualitatively and quantitatively different risks so separate buyback mechanisms should be developed to take account of this and that it would be possible to distinguish between the two types of constraint;
- That there should be either more appropriate compensation where there are fixed timescales for providing incremental capacity or that the timing of capacity provision could be subject to consenting delays that are beyond the control of the transmission company;
- That it is inappropriate for a user, in a monopoly position, to set a buyback price that is well in excess of the initial price it paid for the capacity and for those costs

to be smeared to all shippers and that an administered buyback price or liquidated damages may be more appropriate for delays to new investment; and

- That the decision on whether there should be one buyback incentive for entry and offtake would depend on whether the risks are the same.

Interactions between entry and offtake:

- That the main interactions between entry and offtake concern the setting of the levels for baselines, and the amount of remuneration that is provided by the relevant revenue drivers and that baselines and revenue drivers should be determined such that any investment needed to support requirements for extra capacity on NTS should be remunerated on a consistent basis between entry and exit.

Views of other respondents

1.31. Key points raised by other respondents in relation to entry and offtake incentives can be summarised as follows:

Transitional offtake incentives:

- That the transitional arrangements are essentially a roll forward of the existing regime for capacity booking and holding and that it was therefore appropriate to extend this approach and roll forward the existing incentive arrangements as a default; and

- Should proposals emerge that are consistent with the enduring regime, when this is finalised, it would be sensible to introduce the relevant elements at an earlier stage.

Buyback incentives:

- Broad agreement that, in principle, it may be appropriate to separate the buyback arrangements for operational constraints and incremental capacity;

- That it may be difficult to distinguish between the two types of constraints although one respondent commented that it should be straight forward to identify buybacks related to delays to investment as it would be specific to capacity that does not exist. Another queried whether investment in new entry points should be treated differently to investment at an existing entry point;

- That the benefits of separating the buyback incentive should be assessed against the complexity involved in the separation, although another respondent considered that any such complexity would be minor;

- That the proposals represented a transfer of risk away from NGG NTS to consumers; and

- Some support for a combined buyback incentive either now or in the future.

Interactions between entry and offtake:

- That the interaction between entry and offtake is complex, depending on a range of varied factors including the design of the network and configuration of supply and demand;

- That, in general, at a high level, there may be an argument for establishing a common and complimentary framework across both entry and offtake, for example, by adopting the same approach at entry and exit to the setting of baselines and revenue drivers; and

- That the clearest interaction between entry and offtake will be at bi-directional points (eg, storage facilities), although similar issues would also arise where offtake points are close to entry points.

Ofgem's views

1.32. We would like to make the following observations in the light of the points raised by respondents under this section of Chapter 7 of the Second consultation:

Transitional offtake incentives:

- We agree that the transitional arrangements should not restrict the development of new arrangements; and

- We also agree that, in the main, the interim incentives should be rolled forward into the transitional period. However, we have considered the applicability of some of the interim incentives to the transitional period and looked at what aspects of the enduring regime should be implemented on a consistent basis across the entire duration of the next price control period. We agree that where certain elements of the enduring regime are compatible with the transitional arrangements, consideration should be given to introducing these elements in advance of the implementation of the enduring regime - one such area being the application of revenue drivers.

Buyback incentives:

- We note respondents' support for separating the buyback incentive in principle;

- With regards to the respondent's views on differentiating between investment in new and existing infrastructure, under our preferred approach NGG NTS would be required to buyback capacity for delays to either type of investment and consequently we do not consider it necessary to differentiate between them;

- We note that the benefits of separating the buyback incentive should be considered in the context of greater complexity. It is likely that the level of complexity from these arrangements will be clearer as the arrangements are developed. This would be considered in the impact assessment as part of the assessment of changes to the gas entry regime;

- We consider that it may be appropriate to allow parties to agree with NGG NTS to vary the standard terms for buyback in some circumstances, as well as potentially agreeing to vary the associated incremental capacity delivery date;

- We consider that the preferred approach enables an appropriate sharing of risk between NGG NTS, connectees and customers; and

- We will further consider whether the buy-back incentives for entry and offtake should be combined, once the arrangements proposed at entry and exit have been developed in greater detail.

Interactions between entry and offtake:

- We agree that care will need to be taken in determining both the definition of baselines and revenue drivers across the exit and entry regimes in order to ensure both that customers do not remunerate the same investment twice, and that NGG NTS receives sufficient revenues to fund the investments concerned if implemented efficiently;

- That any reforms that are introduced recognise the potential for interaction between regimes in an appropriate manner;

- That it may be appropriate for the basis of revenue drivers across entry and exit to be similar in nature, and note that the determination of revenue drivers will be the subject of further consideration and analysis over the coming months;

- That there is a close correlation between the provision of entry and offtake capacity and that care needs to be taken to ensure that the relevant incentive regimes produce efficient outcomes in this regard; and

- We recognise that entry and offtake interactions are of particular relevance to bi-directional sites, and will seek to ensure that clarity regarding these interactions is provided as the arrangements are developed further.

Responses to Chapter 8 - Incentives options: electricity

Introduction

1.33. Chapter 8 of the Second Consultation invited respondents' views on electricity incentive design and access issues. The three transmission licensees and 7 other parties commented on the issues raised. We invited views on the following specific

questions (and invited comments on any other issues that parties wished to raise under this heading):

- ➔ Whether Ofgem had focused on the appropriate issues to be addressed in the light of the operation of the current price controls?
- ➔ Whether it is 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 the most appropriate and worthy of further detailed analysis and quantification?
- ➔ What are the advantages and disadvantages of user commitment models in the context of electricity transmission?
- ➔ What respondents consider to be the appropriate answers to the detailed design questions posed in the Second Consultation and whether any other questions 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 and other document?
- ➔ What role Ofgem should adopt in the process and what role should NGET take given its role as GBSO and obligations in respect of charging methodologies?, and
- ➔ What are the advantages and disadvantages of more extensive system reliability and performance reporting - and how might such metrics be linked to financial incentives?

Views of the transmission licensees

1.34. The three transmission licensees commented on at least some of the issues raised in this chapter. We have summarised the points raised by one or more of the transmission licensees as follows:

- The best way to minimise risk (and material impact) of price control re-openers is to use automatic adjustment mechanisms (which, in principle, is supported subject to further development of detail) - but a residual risk of the need to re-open due to material and unforeseen cost pressures is likely to remain. However, re-openers should be exceptional events. In designing appropriate revenue drivers, mechanisms to apportion costs between TOs and between the SO and TOs will be paramount;
- Revenue drivers should provide a down payment which will be 'trued up' at the subsequent price control review;
- User commitment models may be able to improve the quality of information about the generation and demand background, improving investment decisions; particularly if commitment was made by all users. It may also rationalise the demand for connections in congested sections of the network. However, it will be

important to consider the interaction of user commitment with licensees' other obligations; and

- The existing transmission network reliability incentive scheme is aligned with the interests of consumers. Any more onerous scheme, and particularly a penalties only mechanism, would be opposed. While there may be a role for a wider basket of measures to be used, it is important for any scheme not to increase complexity.

Views of other respondents

1.35. Seven parties other than the transmission licensees commented on one or more of the issues raised in this chapter. We have summarised the points raised as follows:

- While the limitations of the current TPCR, particularly the inflexibility of revenue allowances, have been accurately reflected, there is not a case for wholesale change to address these issues. Any change must be focussed and proportionate and impact assessments should be used to demonstrate this;

- It is important to address the differing treatment of transmission licensees that exists under the current price control arrangements and apply any revenue driver consistently;

- The possible interaction between revenue drivers and user commitment based reform to access arrangements must be acknowledged. In order to ensure that the price control is not dependent on changes to access reform beyond Ofgem's gift, it would be appropriate to separate these two pieces of work;

- There may be benefits in terms of increased information and efficient investment from user commitment models. However, it is necessary to fully consider implementation costs and to note the parallels of capacity auctions in gas;

- There is a case for considering the existing levels of final sums liabilities, which may be creating barriers to entry and the extent to which non-firm products could be introduced to the market place;

- Existing governance forums may not allow a focussed across the piece discussion of the complete range of access related issues. Therefore there is a need for Ofgem to convene a working group to discuss these issues; and

- In terms of system reliability, licensees should be incentivised to deliver what customers value.

Ofgem's views

1.36. We would like to make the following observations in the light of the points raised by respondents on the questions cited at paragraph 1.33:

- In particular, given the uncertainty over future needs for transmission capacity, there would appear to be significant potential benefits in automatic adjustment mechanisms which adapt to changing circumstances (including growth in new renewable generation) while retaining the incentive properties;

- We consider that revenue drivers are capable of adjusting allowed revenues such that licensees are able to finance their activities, and are provided with incentives to outperform costs, while ensuring that consumers do not fund investments at the price control which are not undertaken. We consider that a locational revenue driver, based on changes in generation and demand, may be most likely to reflect the differing costs of accommodating changes in the pattern of demand or generation;

- We are conscious of the need to fully assess any potential revenue driver option. We also note that, were the revenue driver to provide a down-payment to licensees, risk would be significantly reduced for the licensees, and the incentives to operate efficiently would be diluted;

- The package of incentives across all three electricity transmission licensees needs to form a coherent whole in rewarding efficiency, recognising the different roles of the GBSO and TOs and the interactions;

- It is appropriate to consider, as part of the transmission price control review, whether the existing mechanisms for allocating transmission capacity are promoting efficient investment, facilitating competition and ultimately working in the best interests of consumers;

- We accept that it will be necessary to fully consider any possible changes to existing arrangements and the likely costs of implementing these. As such, we created the Access Reform Options Development Group (ARODG) to discuss these issues in detail and will issue a development group report in April. However, we note that any changes to industry codes will need to be proposed by the industry; and

- It is appropriate for reliability incentives on licensees to be consistent with the outputs valued by customers which are within the licensee's control. As such, we are also considering the measures used in assessing any scheme as well as the existing report requirements as well as refinements to the existing scheme to apply from April 2007.

Responses to Chapter 9 - Financial issues

Introduction

1.37. Chapter 9 of the Second Consultation invited views on a range of financial issues. Responses were received from the three transmission licensees, the trustees of the National Grid pension schemes, a representative union and four network

users. We invited views on the following specific questions (and invited comments on any other financial issues that parties wished to raise in this area):

- ➔ 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 including over 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.
- ➔ Whether a common assumed level of gearing should be adopted for transmission licensees, or whether company-specific gearing assumptions should be adopted.
- ➔ The principles that should apply for assessing the past capital expenditure in excess of allowances.
- ➔ The treatment of the cessation of pre-vesting regulatory depreciation for electricity transmission licensees.
- ➔ The appropriate calculation of charges in respect of pensions and deferred pensions attributable to GDNs.
- ➔ The methods for valuation and funding of pension schemes under new pensions regulation arrangements.
- ➔ The allocation of pension costs between price-controlled and non-price-controlled activities.
- ➔ Views on the options in relation to the treatment of over/under funding on pensions.
- ➔ Views on the treatment of early retirement deficiency cost for pensions.
- ➔ Other comments on pensions issues.
- ➔ Views on a more detailed regulatory reporting requirement in accordance with regulatory reporting guidelines.
- ➔ Other comments on financial issues.

Views of the transmission licensees

1.38. The transmission licensees commented on all the questions and one was extensive in its views on pensions. These views have been summarised below:

- The licensees agreed with using investment grade ratios on a stand alone basis for debt but the cost of capital should be high enough to attract equity investment and enable a more efficient company to earn an excess return with

gearing remaining at the current level. They also agreed with Ofgem setting company specific tax allowances and allowing all efficiently incurred past capital expenditure. They considered advancing post vesting depreciation to meet the cash drop on pre vesting depreciation as in DPCR was appropriate. They were also generally supportive of the use of regulatory reporting packs; and

- On pension costs the licensees favoured a full allowance for both new costs from pension legislation and the recovery of existing deficits rather than following any previously stated principles. They also thought the actions of the trustees were not a matter for action on the company by the regulator.

Views of other respondents

1.39. The representative union and pension trustees commented on pensions. The distribution companies and a supplier also commented on more general financing issues. In summary, on pensions the union and trustees favoured pass through whilst the supplier thought the reverse. On other issues the distribution companies favoured approaches already used for themselves, and the supplier thought that the reduction in risk implicit in the approaches on a number of issues should be reflected in a lower cost of capital.

Ofgem's views

1.40. We would like to make the following observations in the light of the points raised by respondents on the questions cited at paragraph 1.37:

- On financial ratios no change in approach is proposed. On gearing it is noted that the recent relative deregulation of utilities in the United States has resulted in a significant increase in the ratio of Debt to Fixed Assets to 95% across all of one agency “A” rated US utilities. Within the UK new entrants have been able to achieve debt funding for 75% off acquisition costs at a premium to Regulatory Asset Value by paying a fee to a debt guarantor. These actions in the debt market may indicate a market preference towards the thin equity model common in the 19th century for utilities. An independent assessment of the cost of capital is underway that in conjunction with the views obtained from the joint discussion paper on financing networks will help inform our views in this area;

- On tax no change in approach is proposed. However it is understood that expenditure on replacing existing assets which is expensed to the Profit and Loss account will continue to obtain immediate tax relief. With the choice between obtaining this under UK GAAP or not doing it under IFRS in subsidiary accounts effectively at the licensees discretion, an approach incentivising them to minimize their statutory tax charge to the benefit of consumers can be considered;

- On the cessation of regulatory income from pre vesting depreciation a number of alternative views are under consideration but this topic cannot be considered separately from the wider issue of financial stability; and

- On pensions it is intended that a consistent framework across electricity and gas networks for efficiently incurred pension costs including deficits will be applied. This will recognise requirements that flow from the Pensions Act 2004 but given the differences in approach on pension matters it is unlikely to result in the full pass through of all pension costs for all licensees. This issue will be covered in more detail in the Initial Proposals.

Appendix 6 – Responses to TPCR Open Letter on capex projections

Introduction

1.1. This appendix highlights the significant points raised by respondents to the Open Letter published in February 2006, together with our views.

1.2. Please note that this is not intended to be a comprehensive compilation of all points raised by respondents – the content of every non-confidential response is available on our website. If respondents are unsure about how their views are reflected in the document, please contact us for further details.

Responses to Open Letter

1.3. The Open Letter invited views on a range of issues associated with the capital expenditure (capex) projections provided by the transmission licensees. Two transmission licensees, and seven other parties, including two confidential responses, commented on the issues raised. We invited views on the following specific questions:

- ➔ What factors should be taken into account in the TPCR given the potential scale and uncertainty of forecast capex?
- ➔ What other factors, or alternative approaches, should Ofgem take into account in designing the incentive framework to ensure that transmission licensees finance their capital investment plans in a timely and efficient manner, and serving the interests of consumers?
- ➔ How might we address the issue of fully depreciated pre-Vesting assets to ensure that they are replaced according to need rather than to replace the lost value?

Views of the transmission licensees

1.2. Two transmission licensees commented on the issues raised in the Open Letter. We have summarised the points raised by the transmission licensees as follows:

- In addition to specific customer requirements and replacing existing assets, a significant part of the load related capex is to accommodate changing patterns of generation;
- Allowance for non-load related capex can be set ex-ante and be supplemented by a sliding scale and/or a roller mechanism. For load related capex, ex-ante allowance can be made for investments associated with local infrastructure & pre-construction work for infrastructure. The construction costs of major infrastructure investment, however, depend on the outturn of the particular

combination of generation. The allowance can use a trigger mechanism linked with user commitment, with ex-ante parameters and flexible time profile to avoid the need to re-open the price control;

- User commitment should be a key element in driving load-related capex, but using it as the only trigger may lead to untimely investment; and

- The full depreciation of pre-vesting assets in a few years only affects the financeability issue, which can be dealt with by measures such as appropriate profiling of future revenues. However, it is not clear how this issue is relevant to the assessment of the need for asset replacement, which is only based on asset condition.

Views of other respondents

1.3. Seven parties other than the transmission licensees commented on one or more of the issues raised in the Open Letter. We have summarised the points raised as follows:

- A couple of respondents expressed their surprise at the scale of capex proposed. However, they pointed out that more information is required on transmission licensees' proposals to enable more objective comments. Another respondent supported in principle the highest additional investment indicated by the transmission licensees, and considered that the potential increase in customers' bills not unreasonable pay for supply security;

- The significant increase in capex proposed by the transmission licensees represents a significant challenge for all the stakeholders including contractors, equipment manufacturers and other utilities. The competition, nationally and globally, for resources such as contractors and capital raises the issue of the availability and price of these resources. It would be reasonable to question how the capex programme can be delivered within the context of the current capacity existing within the ESI in the UK. It is crucial that agreements on future levels for future capex provides an environment in which network companies can make long term investment decisions;

- Ofgem's primary objective should be to protect the interests of consumers to ensure that transmission investment is efficient, cost effective, timely and provides secure supplies of energy. It should avoid the licensees making windfall gains or losses due to circumstances beyond their control. Where Ofgem and its consultants can assess the robustness of cost drivers and costs, a rolling incentive mechanism is appropriate. A specific factor to be taken into account is the introduction of new technology, e.g. to maximise the use of existing assets or to seek more environmentally acceptable solutions;

- Given the considerable uncertainty regarding generation and network architecture, it is vital that the regulatory framework is flexible and takes into account the long term nature of the investment. It should be aligned with the output of the government's energy review. At the same time, regulatory certainty

is important. For example, Ofgem needs to be clear about how efficiency of past investment is reviewed;

- To deal with the uncertainty in the need for network capacity, it is important for users to signal their requirements for network capacity in an effective manner, e.g. financial commitment by new connections. The current "first come first served" approach needs to be reformed. New solutions should be simple and transparent. Models other than long term commitment should also be considered, and that the risk on network users should be taken into account; and

- On the issue of pre-Vesting assets, the replacement should meet tests of efficiency and cost-effectiveness.

Changes in Ofgem's views

1.4. Most of the points raised above are covered by views expressed in responses to the relevant chapters of the Second Consultation. They are taken into account in further development of our thoughts throughout the Third Consultation document. On points specific to the Open Letter, we make the following observations:

- We acknowledge the need for more information to be made available as part of our consultation in order to allow informed and objective comments. We endeavour to adopt a number of approaches including publishing more information within, or in parallel with, our consultation documents and organising open seminars to facilitate more detailed discussion with the transmission licensees on their capex proposals;

- In the development of network access arrangements we continue to bear in mind the need to balance the risk between the network users and the network companies; and

- It is agreed that the issue of the cessation of regulatory depreciation on pre-vesting assets is purely one of financial stability. It should not affect the actual replacement of these assets which should be based on condition and system security requirements.

Appendix 7 – Responses to informal consultation events

Introduction

1.1. Since publication of the Second Consultation, we have undertaken a range of informal consultation events, held in order to raise awareness and obtain views from attendees on a range of the issues being addressed in the course of the price control process.

1.2. These consultation events have included:

- a workshop on electricity incentives;
- a seminar on enduring gas offtake reform;
- three meetings of the Access Reform Options Development Group for electricity transmission; and
- six meetings of the Enduring Offtake Working Group for gas transmission.

1.3. All of the presentations delivered in the course of these consultation exercises have been placed on the Ofgem website for reference at the following location:

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

Informal consultation events

1.4. A short summary of the informal consultation events is outlined below. The minutes of all EOWG and ARODG meetings are available on the Ofgem website, at the above website address.

Workshop on electricity incentives

1.5. This workshop was held on 16 February 2006, and was open to all industry participants. At the workshop, we presented our current proposals on price control design, and also set out our initial views on a range of issues associated with current access arrangements. Two industry participants (NGET and E.On) also provided their thoughts on elements of the access arrangements.

Seminar on enduring gas offtake reform

1.6. We held an open industry seminar on enduring gas offtake reform on 24 February 2006. At this seminar we presented our latest thoughts on the application of user commitment models to gas offtake, the most appropriate methodology to apply in setting baselines, revenue drivers and NGG NTS buyback incentives. NGG NTS also presented a range of proposals relating to capacity allocation mechanisms and the definition of offtake capacity products (including the flexibility product).

Access Reform Options Development Group (ARODG) for electricity transmission

1.7. The first ARODG meeting was held on 8 March 2006, at which significant progress was made in developing strawmen options for electricity transmission access reform. This group will continue to meet weekly, and be used to develop thinking on alternative approaches to access reform.

Enduring Offtake Working Group (EOWG) for gas transmission

1.8. Six EOWG meetings have been held since the initial meeting on 4 January. The group has discussed a wide range of issues relating to enduring offtake reform, including the further development the "offtake flexibility" product, more detailed proposals concerning capacity allocation mechanisms and how user commitment could work in practice. The group has also had constructive discussions relating to two "strawmen" proposals of enduring offtake reform (presented by NGG NTS and Scotia Gas Networks).

Appendix 8 – Details of respondents

Introduction

1.1. During the last four months, we have conducted two formal consultations for TPCR:

1. TPCR Second Consultation - published in December 2005 (29 responses received, including 2 confidential)
2. TPCR Open Letter on capex projections - published in February 2006 (9 responses received, including 2 confidential)

1.2. This appendix lists the 27 non-confidential respondents to the TPCR Second Consultation, by industry group, and includes a brief description of respondents' business interests. Note that business interests are assumed to be based in Great Britain, unless otherwise stated. The seven non-confidential respondents to the TPCR Open Letter on capex projections are indicated below by an asterisk (*).

Transmission Licensees

- *National Grid Transmission – also has business interests in gas distribution & shipping as well as the US energy industry.
- *Scottish & Southern Energy plc – also has business interests in electricity generation, distribution & supply, and gas shipping & supply.
- SP Transmission & Distribution – member of the ScottishPower Group which has business interests in electricity generation & supply, and gas shipping & supply.

Distribution Licensees

- National Grid Distribution – see National Grid Transmission (above).

Generators / Producers

- Association of Electricity Producers – represents electricity generators.
- British Energy Group plc – owns 8 nuclear power stations, a coal plant, and four small embedded gas generator sites. Also has business interests in electricity supply and gas shipping.
- *EDF Energy plc – has business interests in operating power stations, electricity distribution & supply, and gas shipping & supply.
- *Warwick Energy Ltd – has interests in gas storage, shipping & supply, and electricity generation.

Other Network Users

- Bord Gais Networks (on behalf of Bord Gais Eireann) – BGE has interests in gas transmission, distribution, shipping & supply.

- British Gas (on behalf of Centrica plc companies using the networks but excluding Centrica Storage Ltd) – has business interests in gas shipping & supply, and electricity generation & supply.
- Central Networks plc – has business interests in electricity distribution.
- Egdon Resources plc – has business interests in oil & gas exploration & production, and gas storage.
- E.ON UK plc – has business interests in electricity generation, distribution & supply, and gas shipping & supply.
- ExxonMobil International Ltd (on behalf of ExxonMobil Gas Marketing Europe Ltd – gas shipper) – parent company (ExxonMobil Corporation) is a multinational petroleum and petrochemical company.
- Mulberry Capital Limited (on behalf of Canatxx Gas Storage Limited & Canatxx LNG Limited) – provides financial project advisory services.
- RWE Npower (on behalf of RWE Trading GmbH, gas shipper & supplier) – also has business interests in electricity generation & supply, and gas shipping & supply.
- Shell Gas Direct Ltd – has business interests in gas shipping & supply, and electricity supply.
- *Statoil (UK) Ltd – has business interests in gas shipping & supply.
- Viridian Energy Ltd – has business interests in electricity generation, transmission, distribution & supply in Northern Ireland.

Other Industry Stakeholders

- *Chemical Industries Association – the trade and employers' association for the chemical industry.
- Council for National Parks – charity which aims to protect and enhance national parks in England and Wales.
- *energywatch – gas & electricity watchdog.
- Institution of Gas Engineers & Managers – independent professional body for the gas industry.
- Prospect – trade union for professional engineers.
- Revolt – representative group.
- Siemens Power Transmission & Distribution (on behalf of supplier of services to transmission network) – provides technical consulting services; parent company (Siemens) has business interests in the power, transportation, information & communication, medical, lighting, finance, R&D industries globally.
- Trustees of Lattice Group Pension Scheme
- Trustee to NGET Group of Electricity Supply Pension Scheme

Appendix 9 – Environmental considerations

Introduction

1.1. 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; and
- the duty to carry out and publish an assessment of the likely impact of implementing proposals 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, amongst other things, it would be likely to have a significant effect on the environment. An assessment under this section about any important proposals must include an assessment of the likely effects on the environment of implementing the proposal.

1.2. As mentioned in the Second Consultation, Ofgem will take account of these, together with the Authority's other duties in developing its proposals under the TPCR.

Areas of work in progress

1.3. Ofgem has embarked upon a work programme to understand more fully the environmental implications of particular patterns of expenditure by the transmission licensees, and the options for dealing with the GB Queue. The first stage of the work programme is largely an information gathering process.

1.4. At a high level, the main environmental elements that have been identified so far in the TPCR work programme are:

- consideration of mechanisms by which to improve the current status of the GB Queue[2], in which large volumes of generators, particularly renewable generators, are facing long delays to connect;
- seeking to understand the impact of network investment plans on the environment and making appropriate allowances for the costs faced by transmission licensees in complying with existing and anticipated legal obligations designed to protect the environment;

[2] See 'Options for user commitment' for more details.

- seeking to understand the scope for quantifying costs and environmental benefits of different forms of transmission investment, e.g. overhead line assets as compared to underground cabling;
- seeking to understand the impact of network investment plans on the volumes of transmission losses;
- consideration of the impact on network investment plans of emissions requirements for gas turbine compressors on the NTS;
- seeking to understand the emergent changing pattern of supply in Great Britain and the impact of this on the NTS with regard to future compressor use; and
- developing a consistent approach to impact assessment.

1.5. The above areas can be further distilled into three main areas, as set out below.

Access arrangements

1.6. In the Second Consultation, and subsequent seminars and development group meetings, we have highlighted a number of potential issues with the current access arrangement for the electricity transmission network. We have drawn attention to potential ways in which the current arrangements might create barriers to entry, and might result in a lack of information for the transmission licensees in planning investment on their network.

1.7. Measures which address barriers to entry and improve information available to the transmission licensees to plan their networks might well have environmental impacts. There is currently in excess of 10GW of capacity seeking connection to the transmission network, particularly in the North of England and Scotland (the GB Queue). The GB Queue is comprised mainly of renewable plant and removing barriers to entry in terms of grid connections could increase the speed at which viable new renewable projects can connect to the network.

1.8. We are playing an active role in developing the options for potential change through an industry work group, the ARODG, which Ofgem chairs. Any changes would require changes to codes being brought forward by the industry. Any proposals for change will, at some point, require Ofgem approval. In considering options for approval we will have regard to the environmental impacts, and might choose to undertake specific impact assessments. For more information on ARODG, please see Appendix 7.

Price control allowances

1.9. Currently our cost assessment teams are analysing the Historic and Future Business Plan Questionnaires (HBPQ and FBPQ) submitted by the four TOs, which detail their capex and opex plans for the present and forthcoming price controls. This process, whilst focussing on the cost submissions, will also take into consideration the project-specific implications directly related to environmental issues, such as visual amenity.

1.10. To inform this process, a report has been commissioned from environmental economic consultants, EFTEC, which will focus on:

- current/recent research on the value of visual amenity in the context of electricity and gas transmission;
- characterisation/classification and relative valuation of landscape types in GB;
- consideration of willingness to pay surveys;
- feasibility of developing general transferable tools that could be used in price controls, and an indication of the form these might take;
- any preliminary evidence regarding the order of magnitude of value as compared to the cost of undergrounding or re-routing of transmission lines;
- the feasibility of deriving threshold values for undergrounding based on the cost of undergrounding/re-routing;
- net environmental values, such as trade off of visual amenity against the potential for leakage, interruptions etc; and
- existing work on the relative value of alternative transmission tower designs.

1.11. In commissioning this report, Ofgem expects to be able to better assess the environmental effects of the TOs' capex and opex plans going forward, and identify issues that may need further exploration and impact assessment.

1.12. In analysing potential options for undergrounding or re-routing sections of reinforcement to the electricity and gas transmission systems, Ofgem will consider the effects on transmission losses which result from lengthening or shortening the overall length of transmission lines and revisions to line voltage. From a gas perspective, Ofgem will assess the impacts caused by potential revisions to system reinforcement and changes to compressor usage in the context of shrinkage.

Environmental Impact Assessment for the Price Control

1.13. Following feedback on the Distribution Price Control Review (DPCR) and the Gas Distribution Price Control Review (GDPCR), it is Ofgem's intention to adopt the same approach to impact assessments in the TPCR. In line with Ofgem's commitment to full impact assessments of all significant proposals, the key consultation and decision documents for the TPCR will include analysis of the environmental impact of the review[3]. The analysis is likely to include:

- implications of measures included for government environmental targets;
- the impact of the licensees capex and opex plans with regard to visual amenity; and
- the impact of price changes on demand for electricity and gas and hence emissions.

1.14. The results of this analysis will be incorporated into forthcoming TPCR documents. This will be updated as proposals are developed in the light of responses received through the usual consultation process.

[3] We are obliged to do this under section 5A, Utilities Act 2000.

Appendix 10 – Gas entry modelling results

Questions

Question A10.1: What preliminary conclusions should we draw from the initial gas entry modelling results reported in this appendix, particularly in light of the preferred option for gas entry incentives presented in the main document?

Question A10.2: What options for further modelling work (if any) should we pursue, and which ones should we prioritise?

Introduction

1.1. In order to set the gas entry revenue drivers and trigger levels[4] proposed in the main document, it is necessary to undertake modelling of the gas transmission network.

1.2. Since the Second Consultation was published, we have asked NGG to undertake two pieces of modelling work, namely:

- modelling network capability (ie, what the network can provide without additional investment, in order to develop trigger levels), and
- modelling revenue drivers (this analysis also informs trigger levels).

1.3. The adopted modelling approaches are described in more detail below. We explain the modelling request that was issued to NGG, report the modelling output we received from NGG, and make some initial observations about the modelling output. We also consider options for further modelling work.

1.4. We have not yet reached a firm view on how to use these modelling results for incentive design from April 2007. We invite views on the conclusions that we should draw from the results presented here, as well as on the options for future modelling.

1.5. The modelling output has not been checked by us and is reported as received. It does not represent our view on the level of any revenue drivers or trigger levels in NGG's future price control.

Caveats

1.6. These results are initial results provided by NGG in draft form at this stage, to aid discussion. The work being undertaken by NGG is ongoing, and a consolidated

[4] Trigger levels refer to the level of capacity at which a revenue driver would be activated.

finalised set of analysis will be provided to Ofgem by 14 April. The results in the final report might vary from the working draft data provided to date.

1.7. Ofgem will publish the finalised information also, and will consider how best to facilitate discussion on the results more widely. This might involve convening an industry workshop to discuss the results with NGG. We will also be undertaking our own quality assurance work on the analysis provided by NGG, and will report the findings of this work if appropriate.

Modelling network capability

Modelling request

1.8. The aim of the first piece of modelling work was to derive estimates of the amounts of capacity that could be provided at entry points without triggering additional investment, starting from an initial gas entry (and offtake) flow scenario. Under the preferred option for gas entry set out in the main document, the amount of capacity available at an entry point could inform the setting of trigger levels for nodal revenue drivers. However, an important caveat to this work is that the analysis was undertaken on an entry point by entry point basis (or zone by zone basis, see below), and that it would be misleading to suggest that the network is capable of accommodating all of amounts of capacity at individual entry points (or zones) simultaneously. The overall purpose of the modelling work was nevertheless to determine the physical capability of the transmission network.

1.9. We asked NGG to derive estimates both for individual entry points (or "nodes") and for "zones", in order to inform policy development on the nodal and zonal options set out in the Second Consultation. Zones are collections of nodes within a certain geographical area that have a relatively high degree of substitutability between them.[5]

1.10. We asked NGG to derive results for two consecutive years: 2007/08 and 2008/09. These years were chosen in order to keep the amount of network modelling that was required to a reasonable limit and to reflect that any additional capacity should be associated with user commitment. They were also chosen because forecast data for later years (eg, 2009/10 and beyond) is likely to be relatively less robust than for earlier years.

Balanced network

1.11. The modelling approach starts from a balanced network, ie a physical network on which initial gas entry flows (or "baseflows") meet assumed demand. It then adds progressively larger increments to entry baseflows, while adjusting flows

[5] Nodes are considered more substitutable when an incremental flow at one node, accompanied by an offsetting flow at another node, triggers less trigger network reinforcement. With 100 percent substitutability, no network reinforcement is triggered as there is a lot of interaction between the nodes. With zero substitutability, both the incremental flow and the offsetting flow could cause network reinforcement, as there is no interaction between the nodes.

elsewhere to maintain network balance, until a particular increment size triggers network reinforcement. This approach can be used for nodes as well as for zones.

1.12. The balanced network was assumed to consist of the physical network in place in 2007/08 and in 2008/09. It also incorporates the following initial gas flow scenarios, both taken from NGG's latest Ten Year Statement (TYS):[6]

- demand (or gas offtake) side: "1 in 20" winter peak day gas offtake flows, and
- supply (or gas entry) side: "Auctions+" supply scenario gas entry flows.[7]

1.13. These scenarios specify one possible combination of peak day entry and offtake flows across the network. On the demand side, 1 in 20 peak demand flows were chosen because they largely determine capacity needs on the network. On the supply side, the Auctions+ scenario was chosen because it is arguably the most objective of the three supply scenarios in the TYS since it incorporates firm auction signals from network users.[8] However, shippers are not required to flow the same amounts of gas as they book capacity for in long term auctions, so in practice flows can differ from auction signals.

Adding nodal and zonal increments

1.14. To estimate nodal amounts of capacity that could be provided without triggering additional investment, NGG was asked to gradually increase the initial baseflow at each entry point in turn, until a particular increment size triggered network reinforcement.

1.15. To estimate zonal amounts of capacity that could be provided without triggering additional investment, NGG applied a pro-rata increase to all nodal baseflows in each zone, again until a particular increment size triggered network reinforcement. The choice of zones was left to NGG, and NGG informed us prior to undertaking the core modelling work what the approach would be (see below).

Keeping the network in balance

1.16. While incremental flows are added as described above, the system must be kept in balance (ie, the amount of gas going in at entry points must approximately be equal to what comes out at offtake points). We asked NGG to keep the network in balance using two alternative approaches:

- "load absorption", whereby as the entry flow is increased, demand is scaled up, *pro-rata*, across all offtake points, and

[6] National Grid (December 2005), Gas Transportation Ten Year Statement 2005, available on National Grid's website at http://www.nationalgrid.com/uk/Gas/TYS/

[7] For 2008/09, the balanced network also incorporates the Isle of Grain auction signal from the November 2005 long term system entry capacity (LTSEC) auction.

[8] In the Auctions+ scenario, the long term system entry capacity or "LTSEC auction results (through to Dec 2004) have been "used as a guide in projecting the supply profile across the entry points, with individual terminal and storage flows constrained by the respective obligated capacity levels where necessary" (TYS, p45). The other two supply scenarios in the TYS are "Transit UK" and "Global LNG".

- a combination of "load absorption" and "supply substitution", whereby for 50 per cent of the increment at any entry point, demand is scaled up, *pro-rata*, across all offtake points, and for the other 50 per cent of the increment, supply is scaled down, *pro-rata*, across all *other* entry points.

Summary of requested output

1.17. Our modelling request as set out above was for four sets of outputs on free increments at both a nodal and zonal level:

- 2007/08, load absorption
- 2007/08, 50 per cent load absorption / 50 per cent supply substitution
- 2008/09, load absorption, and
- 2008/09, 50 per cent load absorption / 50 per cent supply substitution.

Modelling output

1.18. NGG used its Graphical Falcon network model to derive the modelling results,[9] and referred to the amounts by which can nodal or zonal capacities can be increased above baseflows without triggering additional investment as "free increments". It produced four tables of results, corresponding to the four sets of outputs listed above. The key data on baseflows, free increments, and "total flows" (ie, baseflows plus free increments") are reproduced below. As noted before, the results reflect raw data provided by NGG and we have not checked them for accuracy.

1.19. NGG also reported the investments that were triggered for each node (or zone) by going just "beyond" the resulting free increments, but for simplicity these investments are not reported in the tables below. NGG classified most of the investment that was triggered as "exit investment" and noted that such investment can largely be considered a modelling artefact because of the chosen network balancing approach (ie, load absorption).

1.20. For the zonal work, NGG defined six zones on the basis of engineering judgement about the degree of substitutability between individual nodes: South East zone, Easington Area, Northern Triangle, West UK, South West UK, and North West Corridor. It also defined a "superzone", namely the East Coast, consisting of the South East zone, the Easington area, and Theddlethorpe, and reported results for this superzone. The nodes within each zone are set out in the table below.

[9] Graphical Falcon is a computer model of the UK gas transmission network that is used by NGG to model network flows and consider the impact of the addition of different network assets.

Table A10.1: Nodal make-up of zones

South East Zone	**Easington Area**	**Northern Triangle**
Bacton	Easington	St. Fergus
Isle of Grain	Hatfield Moor	Teesside
	Aldborough (Garton)	Barrow
	Hornsea	Glenmavis LNG
West UK	**South West UK**	**North West Corridor**
Milford Haven	Humbly Grove	Point of Ayr (Burton Point)
Dynevor Arms LNG	Avonmouth LNG	Hole House Farm
		Cheshire
		Partington LNG
East Coast (Superzone)		
Bacton		
Isle of Grain		
Easington		
Hatfield Moor		
Aldborough (Garton)		
Hornsea		
Theddlethorpe		

Source: NGG

1.21. For some of the zones (Easington Area and North West Corridor), initial baseflows at some individual entry points within the zone were zero. Applying a *pro-rata* increase across the zone would have left the baseflows at these entry points at zero. NGG therefore adopted an alternative approach, which involved assuming a small, non-zero initial baseflow at these entry points, before estimating the free increment.

1.22. Free increments have also been estimated for the four LNG network support (constrained LNG) points, and results are reported in the bottom part of each table. NGG has confirmed that for the LNG network support points, it has aimed to keep initial baseflows as low as possible (given network balancing constraints).

Table A10.2: Estimated free increments in 2007/08 with Auctions+ supply scenario, using load absorption

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	98	3	101
Bacton	161	7	168
Isle of Grain	20	5	25
Milford Haven	60	0	60
St. Fergus	106	61	167
Teesside	24	45	69
Barrow	25	29	54
Theddlethorpe	25	10	35
Point of Ayr (Burton Point)	2	17	19
Hole House Farm	2	16	18
Humbly Grove	7	12	19
Hatfield Moor	0	20	20
Aldborough (Garton)	0	15	15
Cheshire	3	23	26
Hornsea	0	30	30
LNG used in network			
Glenmavis	9	15	24
Partington	16	70	86
Dynevor Arms	0	0	0
Avonmouth	3	7	10
Zone			
South East Zone	181	9	190
Easington Area	99	2	101
Northern Triangle	164	92	256
West UK	60	0	60
South West UK	11	13	24
North West Corridor	23	22	45
Superzone			
East Coast	306	5	311

Source: NGG

Table A10.3: Estimated free increments in 2007/08 with Auctions+ supply scenario, using 50 per cent load absorption and 50 per cent supply substitution

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	98	3	101
Bacton	161	12	173
Isle of Grain	20	5	25
Milford Haven	60	0	60
St. Fergus	106	61	167
Teesside	24	44	68
Barrow	25	28	53
Theddlethorpe	25	10	35
Point of Ayr (Burton Point)	2	19	21
Hole House Farm	2	15	17
Humbly Grove	7	16	23
Hatfield Moor	0	35	35
Aldborough (Garton)	0	18	18
Cheshire	3	22	25
Hornsea	0	34	34
LNG used in network			
Glenmavis	9	16	25
Partington	16	66	82
Dynevor Arms	0	0	0
Avonmouth	3	9	12
Zone			
South East Zone	181	9	190
Easington Area	99	6	105
Northern Triangle	164	90	254
West UK	60	0	60
South West UK	11	15	26
North West Corridor	23	22	45
Superzone			
East Coast	306	5	311

Source: NGG

Table A10.4: Estimated free increments in 2008/09 with Auctions+ supply scenario, using load absorption

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	100	26	126
Bacton	166	20	186
Isle of Grain	42	21	63
Milford Haven	88	0	88
St. Fergus	98	73	172
Teesside	27	53	80
Barrow	22	52	74
Theddlethorpe	24	39	63
Point of Ayr (Burton Point)	2	30	32
Hole House Farm	2	29	31
Humbly Grove	7	20	27
Hatfield Moor	0	25	25
Aldborough (Garton)	0	25	25
Cheshire	0	81	81
Hornsea	0	30	30
LNG used in network			
Glenmavis	0	26	26
Partington	0	83	83
Dynevor Arms	0	0	0
Avonmouth	1	12	13
Zone			
South East Zone	207	21	228
Easington Area	99	48	147
Northern Triangle	148	119	267
West UK	88	0	88
South West UK	9	16	25
North West Corridor	10	90	100
Superzone			
East Coast	331	52	383

Source: NGG

Table A10.5: Estimated free increments in 2008/09 with Auctions+ supply scenario, using 50 per cent load absorption and 50 per cent supply substitution

	Baseflow (mscm/d)	Free increment (mscm/d)	Total flow (mscm/d)
ASEP			
Easington	100	31	131
Bacton	166	20	186
Isle of Grain	42	21	63
Milford Haven	88	0	88
St. Fergus	98	76	174
Teesside	27	53	80
Barrow	22	50	72
Theddlethorpe	24	29	53
Point of Ayr (Burton Point)	2	30	32
Hole House Farm	2	27	29
Humbly Grove	7	20	27
Hatfield Moor	0	25	25
Aldborough (Garton)	0	25	25
Cheshire	0	81	81
Hornsea	0	30	30
LNG used in network			
Glenmavis	0	26	26
Partington	0	95	95
Dynevor Arms	0	0	0
Avonmouth	1	13	14
Zone			
South East Zone	207	19	226
Easington Area	99	47	146
Northern Triangle	148	115	263
West UK	88	0	88
South West UK	9	16	25
North West Corridor	10	88	98
Superzone			
East Coast	331	48	379

Source: NGG

Preliminary observations

1.23. This section sets out some preliminary observations on the analysis carried out by NGG on modelling network capability. These are initial thoughts and further work is required before we can draw any firm conclusions on the basis of the analysis that has been undertaken so far.

1.24. Various factual observations can be made from the tables:

- Nodal free increments: All entry points (except Milford Haven and Dynevor Arms) have positive, non-zero free increments throughout. In other words, starting from the assumed Auctions+ gas entry baseflows, there nearly always appears to exist some spare capacity to accommodate further flows, when considering that individual entry point in isolation. However, this does not mean that the network could accommodate all nodal free increments simultaneously (in fact, it cannot).
- Zonal and superzonal free increments: Again, all zones (except West UK) have positive, non-zero free increments throughout. In other words, starting from the assumed Auctions+ gas entry baseflows, there nearly always appears to exist some spare capacity to accommodate further flows within the zone, when considering the individual zone in isolation. However, as for nodal free increments, this does not mean that the network could accommodate all zonal free increments simultaneously.
- Estimates of free increments vary extensively between entry points and years. They tend to be particularly high either at those nodes where the initial entry baseflows in the Auctions+ supply scenario are relatively low (eg compared to current Ofgem baselines) or at some gas storage sites including LNG network support sites.
- Total flows and free increments are, on average, significantly higher in 2008/09 than they are in 2007/08. Total flows are about 26 to 29 per cent higher in 2008/09 (depending on the network balancing approach). NGG has indicated that one possible contributory factor is that the new Transpennine pipeline is included in the balanced network for 2008/09, and that the remainder of the increase in 2008/09 is provided by the other investments it is planning to deliver for that year.
- Comparing results between full and part load absorption, there does not appear to be a clear pattern in whether free increments (or total flows) are higher or lower under either approach. (On average, total flows are 1 to 3 per cent higher under part load absorption than under full load absorption.)

1.25. We have also undertaken some initial analysis, comparing NGG's total flows with the baselines currently in NGG's Gas Transporter (GT) licence and comparing nodal versus zonal results. The initial findings are as follows:

- With a few exceptions, the total flows estimated by NGG (for 2007/08 and 2008/09) generally appear to be higher than the baselines in the GT licence (for

2006/07).[10] On average, NGG's total flows are 15 to 17 per cent higher in 2007/08, and 46 to 47 per cent higher in 2008/09.[11] However, strictly speaking, the comparison is not like-for-like, as the years are different and the approach by which baselines have been estimated is different, so it should be treated with care. Also, it is important to note (again) that the transmission network cannot accommodate all of the total flows across individual entry points simultaneously.

- The main exceptions include Theddlethorpe (both years) and Barrow (2007/08).
- For all zones, the zonal total flow is less than or equal to the sum of the corresponding nodal total flows. This is because under the zonal pro-rata approach explained above, the network is likely to run into a constraint well before the point at which all nodal free increments can be accommodated. There are no clear patterns discernable across zones with respect to the relationships between zonal total flows and corresponding sums of nodal total flows (the former are either equal to, somewhat lower or significantly lower than the latter).
- Similarly, the superzonal total flows (including an implied one for "non-East Coast") are either less than or equal to the sum of the corresponding zonal total flows, and hence, by implication, the sums of corresponding nodal total flows.

1.26. These findings suggest that any estimates of nodal trigger levels could vary significantly from one year to the next. If we were to set nodal trigger levels equal to nodal "total flows" derived by NGG, the combined set of nodal trigger levels will overestimate total network capability (as the network cannot accommodate all free increments implicit in the total flow figures simultaneously). Similarly, if we were to set nodal trigger levels equal to "baseflows", the combined set of nodal trigger levels will underestimate total network capability. Total network capability is likely to lie somewhere between these two extremes. Nodal and zonal approaches appear to lead to quite different estimates of free increments and possible implied trigger levels. The zonal analysis suggests a narrower range for total network capability than the nodal analysis. There does not appear to be a clear relationship between the two approaches (eg, with zonal total flows consistently being, say, 20 per cent lower than corresponding nodal total flows) that applies uniformly across the gas transmission network.

Modelling revenue drivers

Modelling request

1.27. The aim of the second piece of modelling work was to derive estimates of revenue drivers, ie the costs of providing additional network capacity for different flow increments as well as the points at which additional capacity might be needed (the trigger levels). Under the preferred option for gas entry set out in the main consultation, we would aim to estimate nodal (rather than zonal or global) revenue drivers and we would have to specify the trigger level at which they would start

[10] This result may appear counterintuitive, as Ofgem's baselines at the last price control review were set using the "theoretical may phys" approach, while the modelling approach adopted for this exercise was closer to the "practical may phys" approach. The latter tends to produce lower estimates of baselines than the former. See Appendix 7 of the Second Consultation.

[11] These percentage comparisons exclude Milford Haven, Barton Stacey and Garton for which initial NTS SO baselines are zero as they are new entry points.

applying. We asked NGG to derive estimates of incremental revenues for individual nodes only.

1.28. We asked NGG to derive results for one year, namely 2008/09. This year was chosen to keep the required network modelling work to a reasonable limit. It was also chosen to ensure that some key network investments that are due to come on-stream in 2008/09, and for which clear user commitment signals have already been provided (eg, the 950 GWh/d signal for Milford Haven), were included in the analysis.

Balanced network

1.29. The adopted modelling approach involves specifying a balanced network, and subsequently adding entry flow increments of 25, 100, 500 and 1,000 GWh/d to each entry point in turn. The final step involves working out the incremental costs of each flow increment.

1.30. The balanced network was assumed to consist of the physical network in place in 2008/09. It also incorporates the following initial gas flow scenarios, both taken from NGG's latest Ten year Statement (TYS):[12]

- demand (or gas offtake) side: "1 in 20" winter peak day offtake flows for 2008/09, and
- supply (or gas entry) side: gas entry flows under each of the three supply scenarios for 2008/09, ie Auctions+, Transit UK and Global LNG.[13]

1.31. In other words, NGG was asked to estimate the costs associated with four different incremental flows at each entry point, in 2008/09, for each of three supply scenarios. Each of the three supply scenarios, taken in combination with the chosen demand scenario, provides a balanced network. On the demand side, 1 in 20 peak demand flows were chosen because they largely determine capacity needs on the network. On the supply side, three different scenarios were chosen as the cost estimates associated with different flow increments are likely to be highly dependent on the initial make-up of entry baseflows. The aim was to develop a range of plausible incremental revenue functions given different input assumptions. We also asked NGG, as a sensitivity, to model a "minimum LNG" scenario, whereby LNG import terminals are turned down as low as possible whilst still satisfying demand.[14]

Keeping the network in balance

[12] National Grid (December 2005), Gas Transportation Ten Year Statement 2005.
[13] The Transit UK supply scenario assumes "an aggressive, phased build-up of imports from Norway and LNG" and "assumes that international LNG players decide to use the UK as a 'gateway to Europe'". The Global LNG supply scenario assumes "a situation where the majority of the LNG potentially destined for the UK is shipped to alternative markets as a result of stronger gas prices outside of the UK" so that "to meet the supply shortfall the UK receives relatively high volumes from Norway and, to a lesser extent, from the Continent". (TYS, p44)
[14] NG noted in discussions that the opposite "maximum LNG" scenario was already implicit in the Transit UK scenario from the TYS, which assumes an aggressive, phased build-up of LNG imports.

1.32. While adding flow increments as described above, NGG was asked to keep the system in balance using supply substitution, ie by lowering the entry flows at other entry point(s) while increasing the flow at the entry point under consideration. More specifically, NG was asked to apply supply substitution at a node that had "least benefit" for the purpose of keeping the system in balance. The least helpful node is likely to be one that is geographically remote from the entry point under consideration and has a low degree of substitutability with it.

1.33. The "least helpful" supply substitution approach was chosen in order to provide an estimate of the upper bound of the incremental revenue functions, as it is likely to result in relatively high estimates compared to alternative approaches to supply substitution. For example, a "most helpful" approach (substituting from individual nodes) or a "pro-rata" approach (substituting across all nodes or a subset of nodes) is likely to result in lower estimates of incremental revenues. We would ideally have liked to ask NG to model a range of network balancing assumptions, but this was not feasible due to time and resource constraints. A load absorption approach to network balancing was not considered appropriate, because for the larger flow increments (eg, of 1,000 GWh/d) it would imply demand rising substantially above 1 in 20 levels.

Existing and new entry points

1.34. We asked NGG to estimate incremental revenues both for existing entry points and for potential new entry points, using the 2008/09 base network also for new entry points that may only come on-line in 2009/10 or later.

1.35. For the new entry points, NGG was asked to cover, at the minimum, the smallest likely flow rate, the anticipated flow rate, and the maximum flow rate in its analysis. In addition, we asked NGG to model the increments of 25, 100, 500 and 1,000 GWh/d on top of the anticipated flow rate.

1.36. As a final step, NGG was asked to calculate the total project cost and the unit costs for each of the network reinforcement projects identified in the analysis.

Summary of requested output

1.37. Our modelling request as set out above therefore was for three sets of results for a four-step incremental revenue function, for both existing and potential new entry points:

- 2008/09, Auctions+ supply scenario
- 2008/09, Transit UK supply scenario
- 2008/09, Global LNG supply scenario, and
- 2008/09, "minimum LNG" sensitivity.

Modelling output

1.38. NGG has so far provided estimates of incremental revenues (or costs) for the Transit UK supply scenario for existing entry points in 2008/09. It has also provided

preliminary estimates for some potential new entry points.[15] The Transit UK scenario increases NTS throughput significantly and, arguably, could lead to higher estimated costs of network reinforcement than the other supply scenarios. NGG has not yet provided estimates for the Auctions+ or Global LNG scenarios, or for the minimum LNG sensitivity, nor has it provided a comprehensive set of estimates for all potential new entry points that NGG and Ofgem are currently aware of.

1.39. For the existing entry points under the Transit UK scenario, NGG first derived estimates of the free increments. It applied the requested incremental flows of 25, 100, 500 and 1,000 GWh/d to the total flow, ie the sum of the baseflow and the free increment for each entry point. It subsequently calculated unit costs for the network reinforcement triggered by the incremental flows, expressed in £ million per GWh of incremental capacity (ie, the unit costs reflect gross investment costs and have not yet been annuitised). The results are shown in the table below.

1.40. NGG has argued that, because of the modelling assumptions used, it is likely that the results under other supply scenarios would be very similar to those under the Transit UK scenario. We have requested further evidence to test this assertion. We have also asked NGG to assume that any outstanding modelling results are still required, unless further evidence shows, to our satisfaction, that they are no longer needed.

[15] However, results are not reported here as we have not yet received a comprehensive set of results.

1.41. Table A10.6: Estimated free increments and unit costs in 2008/09 with Transit UK supply scenario, using "least helpful" supply substitution

			UNIT COST (£M/GWh)			
2008/2009 Transit UK Scenario Terminal	Baseflow on network (mscmd)	Free Increment (mscmd)	25 GWh/d (2.3mscmd)	100 GWh/d (9.2mscmd)	500 GWh/d (46.1mscmd)	1000 GWh/d (92.3mscmd)
Easington	119.03	20.00	0.24	0.16	0.58	0.54
Bacton	190.03	7.20	0.32	0.58	0.74	0.81
Isle of Grain	31.75	15.25	0.36	0.33	0.52	0.90
Milford Haven	45.57	37.79	2.53	2.77	2.09	1.87
St Fergus	111.38	56.50	0.51	0.43	1.36	1.68
Teeside	27.40	36.00	0.33	0.28	0.15	0.52
Barrow	22.20	20.00	0.81	0.20	0.18	0.30
Theddlethorpe	23.70	13.00	0.81	0.20	0.61	0.61
Point of Ayr	1.80	17.00	2.45	1.32	0.34	0.30
Hole House Farm	3.60	17.00	2.45	1.32	0.29	0.18
Humbly Grove	0.00	25.00	0.32	0.05	0.73	1.31
Hatfield Moor	0.00	26.50	1.45	0.26	0.70	0.41
Aldborough	0.00	26.00	0.24	0.20	0.61	0.44
Cheshire	0.00	25.00	0.81	0.20	0.04	0.04
Hornsea	0.00	23.30	0.56	0.55	0.72	0.51

1 mscmd = 10.83GWh/d

Source: NGG

Preliminary observations

1.42. This section sets out some preliminary observations on the analysis carried out by NGG on revenue drivers. These are initial thoughts and further work is required before we can draw any firm conclusions on the basis of the analysis that has been undertaken so far.

1.43. A few factual observations can be made on the subset of modelling results provided by NGG.

- Incremental unit costs, expressed in £/GWh, do not show a uniform relationship to the size of the flow increment. For some entry points, unit costs uniformly rise as the flow increments increase, for some they uniformly decrease, for some they show a U-shaped pattern, and for some they show a falling and rising pattern.
- Incremental unit costs are estimated to be relatively high (eg, greater than £1 million/GWh) for entry points including Milford Haven, St Fergus (large increments), Point of Ayr (small increments), Hole House Farm (small increments).
- The combination of a Transit UK supply scenario and "least helpful" supply substitution is likely to result in relatively high estimates of incremental revenues, compared to other supply scenarios and supply substitution approaches.

1.44. The four-step incremental revenue functions estimated by NGG can be regarded as proxies of the long-run average cost curves for incremental capacity at existing entry points. The initial modelling results (for the Transit UK supply scenario) show that long-run average costs vary significantly by entry point. Also, there are no uniform economies (or diseconomies) of scale in relation to the size of the flow increment. Comparison with modelling results for other supply scenarios

(eg, Global LNG and Auctions+) would provide further insight into the robustness of the estimated incremental revenue functions. However, such comparisons cannot be made yet due to a lack of data. Finally, the incremental revenues estimated so far are likely to be towards the upper bound of the range of estimates that could be derived, given market uncertainty and different possible modelling assumptions.

Future modelling work

1.45. NGG will be providing us with the remainder of the modelling outputs they have been asked to produce, unless further evidence shows, to our satisfaction, that (some) outputs are no longer required. We intend to make any further information available on our website.

1.46. Going forward, we may ask NGG to undertake further modelling work to inform policy development on revenue drivers and trigger levels.

1.47. Regarding the first piece of modelling, ie on network capability, we could ask NGG to undertake one or more of the following sensitivities:

- use supply substitution only for network balancing purposes
- develop ranges (rather than point estimates) for free increments, eg by using "least helpful" and "most helpful" supply substitution approaches
- extend the analysis to future years (subject to the proviso that forecast data become more uncertain in future years)
- run a sensitivity on the assumed baseflow scenario, eg by reducing flows at St Fergus and making an offsetting adjustment at a (restricted set of) other entry points, and
- run other plausible market scenarios, ie other than Auctions+ on the supply side (and, possibly, 1 in 20 on the demand side).

1.48. Regarding the second piece of modelling, ie on revenue drivers, once the full set of results (or at least a suitable subset) has been received, we could ask NGG to undertake one or more of the following sensitivities:

- use other approaches to supply substitution that may be appropriate for this work (ie, other than "least helpful")
- extend the analysis to other years (to test the robustness of estimates across years)
- run a sensitivity on any of the assumed baseflow scenarios, in the light of any further relevant information, and
- run other potentially plausible market scenarios.

1.49. Given the envisaged timescales for the TPCR process, including the publication of Initial Proposals in June 2006, and the resource-intensive nature of the modelling work, it is likely to be necessary to chose only a subset of the sensitivities set out above for further analysis..

Appendix 11 – Assessing the costs of amending the gas entry capacity arrangements

Introduction

1.1. This section provides a framework within which respondents can comment on the costs, benefits and level of complexity that may arise by implementing the proposals for the entry capacity arrangements. Respondent's views on this section will assist us in determining which options are likely to impose lower costs and minimise the burden on the industry before we finalise our preferred approach. This will form part of our work on impact assessments.

1.2. The section below highlights what we see as the key areas where material changes to the arrangements are being proposed. We summarise the nature of the changes and invite views. In providing comments on this section it would be helpful if respondents could identify:

- the impact of the proposals and quantify the impact where possible;
- the pros and cons of the options and again quantify these where possible;
- additional issues we need to consider in order to come forward with Initial Proposals in June; and
- whether there are alternative proposals which can be implemented at lower cost/ with higher benefits.

1.3. Respondents will have further opportunities to comment on the impact of our proposals in future consultations as the arrangements become more developed.

Gas entry incentives

1.5. There are three areas we would like to highlight, where material changes are being proposed. Namely:

- NGG NTS's obligations to release specified volumes of capacity at each entry point;
- the form of the revenue drivers to apply to NGG NTS in the event that they release incremental capacity; and
- potential additional restrictions on compensation, in some circumstances, if capacity rights need to be bought back by NGG NTS.

Capacity release obligations

1.4. Chapter 4 sets out proposals to remove the current arrangements whereby NGG NTS is obliged to release for sale specified volumes of entry capacity at each entry point in each year of the control. We consider that the current set of arrangements, which has not in practice facilitated substitution of baseline capacity between entry points in the light of changing demands for capacity, is too inflexible. The alternative

approach being proposed would require NGG NTS to establish a method for releasing capacity, and would apply the approved method on an ongoing basis.

1.5. The detail of how NGG NTS's obligations should be framed, and the governance surrounding development and regulatory oversight of such a method, is still open for debate. However, we think that the option is sufficiently well defined at this stage to seek views on what the impacts might be. We would welcome views in particular on:

- efficient allocation of available capacity;
- practical operation;
- transparency;
- risk;
- market entry; and
- NGG NTS's incentives to release capacity.

Revenue drivers

1.6. Chapter 4 sets out proposals to simply the design and operation of the revenue drivers. While we propose to retain entry-point specific revenue drivers, fixed for the duration of the price control, we intend to simply the regime by basing the incremental revenue allowance on a fixed return (likely to be equal to the cost of capital assumed for the RAV more generally) on the assumed cost of providing incremental capacity. We also proposed developing an automatic means of setting revenue drivers for smaller new entry points (with reference to the levels of revenue drivers at existing entry points).

1.7. We would welcome views in particular on the impact on:

- the structure of rewards available for NGG NTS;
- the complexity of the arrangements;
- practical operation; and
- market entry.

Compensation for buyback

1.8. In Chapter 4 we set out our rationale for excluding buybacks associated with delays to the delivery of incremental capacity from the buyback incentive, and we set out a possible approach for the incremental investment incentive.

1.9. We proposed that a pre determined buyback price should apply if NGG NTS is required to buyback capacity due to delays to the release of incremental capacity. We also proposed a lower (or zero) buyback price in some instances. We also set out a view that shippers and NGG NTS should be allowed to negotiate variations from this default set of arrangements.

1.10. We would welcome views on the different ways in which the pre-determined buyback price might be set, and the circumstances in which the buyback price might default to zero. For example, should it be related to average gas price, or set at a multiple of the price paid for the capacity? We would welcome views in particular on the impact of different options in terms of:

- how different types of risk (e.g. planning, project delivery, etc..) is allocated;
- how it might impact on investment decisions; and
- the potential value of an ability to negotiate variations to the default terms.

Appendix 12 – Gas offtake technical details

Introduction

Overview

1.1. This Appendix outlines our current thinking on issues that will need to be addressed in determining the incentive framework for NGG NTS as gas transmission licensee over for the next TPCR period with respect to the offtake of gas from the National Transmission System (NTS). In a number of areas, our views have developed significantly since the Second Consultation as a result of both responses received to this consultation, as well as informal consultation undertaken since December.

1.2. As part of the sale of four of the GDNs, we implemented incentives on the NTS for the period to 30 September 2008 (the "interim" period). Offtake arrangements are now in place for the intervening period from 1 October 2008 to 30 September 2010 (the "transitional" period), however NGG NTS incentives have not yet been determined for the transitional period.

1.3. We continue to propose that enduring offtake reform should take effect from 1 October 2007 and apply to the allocation of NTS offtake rights to NTS users from 1 October 2010 onwards (given investment lead times of circa 3 years).

1.4. As part of the TPCR, it is therefore necessary for Ofgem to consider NGG NTS incentives for both the transitional period, and for the enduring period (assumed necessary for the period from 1 October 2010 to 31 March 2012). We therefore structure this section to consider incentives relating to:

- the transitional regime, and
- the enduring regime.

1.5. A summary of respondents' views is provided in Appendix 5.

Structure of Appendix

1.6. This Appendix discusses the transitional regime, the enduring regime and the way forward.

1.7. With respect to the transitional regime, we consider:
- the high level principles applied
- the appropriate treatment of baselines
- the potential application of revenue drivers, and
- transitional incentives including consideration of the charges foregone and exit incentive, the constrained LNG incentive and the buyback and greater than 15 day incentive.

1.8. With respect to the enduring regime, we consider:

- the importance of user commitment models
- the high level options presented in the Second Consultation
- the potential nature of enduring offtake arrangements, and
- enduring incentives, baselines and revenue drivers including:
- the interaction of user commitment models with the 1 in 20 obligation
- baseline derivation
- the application of revenue drivers
- the implications of our revenue driver proposals
- proposals for a buyback incentive, and
- initial views in relation to payment flows.

Views invited

1.9. We would welcome views on any of the issues discussed in this Appendix and have provided a list of specific questions upon which we would particularly welcome views at the end of the two main sections of this appendix.

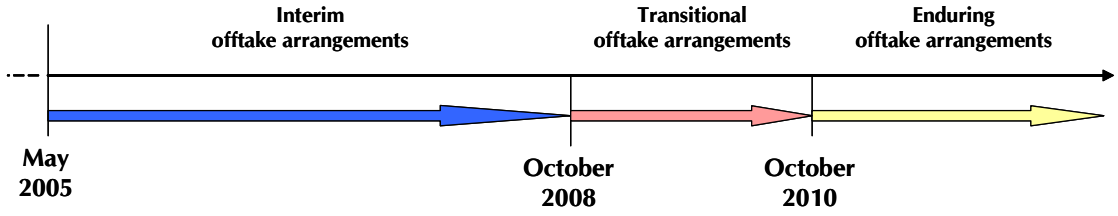
The transitional regime

Introduction

1.10. Given the Authority's decision, in June 2005, to delay the implementation of the enduring offtake arrangements by two years, it has been necessary to consider the arrangements for the allocation of NTS offtake rights to NTS connectees (that is the GDNs and customers directly connected to the NTS, including storage sites and connected system exit points - CSEPs - including interconnectors), for the period between 1 October 2008 (the time at which the interim arrangements end) and 30 September 2010 (the time after which the enduring arrangements begin). References to the "transitional" arrangements relate to the arrangements proposed for this two year period (assuming arrangements for the "enduring period" will apply from 1 October 2010 onwards).

1.11. The sequencing of these alternative offtake arrangements is illustrated in Figure A12.1 below.

Figure A12.1: Offtake arrangements going forward



1.12. The GDN incentives associated with these “transitional” arrangements were implemented in January 2006[16] and have been the subject of a separate consultation process[17]. As part of this consultation process, we stated that the appropriate form and scope of the NGG NTS incentives should be considered at the time of the TPCR to provide an opportunity for incentives to be set in the context of wider price control agreement and allowing us to consider more fully all interactions between entry and exit.

1.13. This section of this Appendix sets out our initial thoughts on the appropriate price control design in the context of gas transmission offtake during the transitional period, and is structured under the following headings:

- high level principles for the transitional period
- baselines
- revenue drivers, and
- transitional incentives.

High level principles

1.14. In the Second Consultation, we invited views on the extent to which incentives and revenue drivers for the transitional period should represent a continuation of the current "interim" NGG NTS incentives, and the extent to which they should be consistent with the enduring NGG NTS incentives.

1.15. It is our view that, as a general principle, the transitional incentives should represent a continuation of the interim incentives already specified. However, we believe that it remains appropriate to consider:
- whether the existing (interim) incentives are appropriate for the transitional period, and
- whether there are any elements of the enduring incentives framework that it would be appropriate to bring forward into the transitional period.

Baselines

1.16. Under the transitional capacity allocation mechanism, NTS users' existing capacity rights are rolled over within the transitional period and, in the event that additional capacity requests trigger specific investment on the NTS, National Grid Gas NTS (NGG NTS) and the connecting party will be required to agree to the terms of an Advanced Reservation of Capacity Agreement (ARCA) (with Ofgem adopting a dispute resolution role). The transitional arrangements have a number of

[16] 18/06 - Direction under Section 23 of the Gas Act 1986 - Modification of relevant gas transporter licences, Ofgem, 26 January 2006
19/06 - Direction under paragraph 3 of Special Licence Condition A2 - Modification of relevant gas transporter licences, Ofgem, 26 January 2006

[17] In September 2005, Ofgem published its initial proposals on incentives for the transitional period:
204/05 - Initial proposals on transitional incentive schemes supporting the offtake arrangements, Ofgem, 21 September 2005. In November 2005, Ofgem published its final proposals on incentives for the transitional period:
252/05 - 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.

weaknesses as highlighted in the Second Consultation. One issue that has particular relevance to the application of revenue drivers, as discussed below, is that the transitional arrangements do not represent a full user commitment model as investment to meet general load growth (consistent with NGG NTS's 1 in 20 obligation) will not necessarily be linked to a specific capacity request with an associated ARCA and financial commitment.

1.17. Given the transitional arrangements in place, it is envisaged that baselines for the period to 30 September 2010 will perform a single function as a high level delineation between TO funding and remuneration of incremental investment.

1.18. At present, baselines are specified at an aggregate level across GB for both firm and interruptible exit capacity until the end of the current price control period (ie, until 31 March 2007). Going forward, it is our initial view that baselines should not be specified for interruptible capacity (so that additional revenues are clearly linked to the provision of additional firm capacity) and should be at the same level (ie, practical maximum physical capacity) and degree of spatial aggregation (ie, nodal) as under the enduring regime[18]. Preliminary baseline numbers have been provided by NGG NTS and are presented in Annex 1.

1.19. It is our current view that it would not be appropriate to specify separate baselines for the GDN flexibility product in this period as flexibility requirements are not expected to trigger investment within the transitional period and flexibility is not acknowledged as a separate product within the framework applicable to TCCs. It is our initial view that, should significant investment be required to meet GDN flexibility requirements, remuneration could be addressed either at the next price control or through application of Income Adjusting Event provisions.

Revenue drivers

1.20. At present, incremental investment is remunerated by allowing the pass-through of NGG NTS estimates of financing and depreciation costs associated with such investment. However, it is our initial view that:

- there is scope for strengthening the current mechanism by specifying revenue drivers as part of TPCR
- incremental revenue should be contingent upon delivery of the investment being remunerated, and
- that the same basis for remunerating incremental investment should be applied throughout the price control period.

1.21. The general approach proposed for revenue drivers is discussed in the next section of this Appendix, in the context of the enduring regime. However, we note that, as the transitional arrangements do not represent a full user commitment model, as discussed above, it will be necessary for incremental revenue to be triggered absent an explicit user commitment / ARCA in some circumstances in order to recognise non-specific, load related reinforcement consistent with NGG NTS's

[18] We explain why our preferred model includes nodal baselines that represent practical maximum physical capacity in the context of the enduring regime in the next section.

assessment of its 1 in 20 obligation. It may, however, be appropriate for Ofgem to have some oversight of the case for such investments before they are remunerated through the application of revenue drivers. Furthermore, if separate baselines are not specified for the GDN flexibility product then it will not be necessary to specify revenue drivers in relation to the flexibility product in advance of the enduring regime.

Transitional incentives

1.22. The following incentive schemes were defined for the NTS in relation to transmission offtake for the interim period:

- charges foregone and exit investment incentive
- constrained LNG incentive, and
- buyback and greater than fifteen day interruptions incentive.

1.23. Each of these incentive schemes is considered in turn below in relation to its potential applicability during the transitional period.

Charges foregone and exit investment incentive

1.24. A charges foregone and exit investment incentive currently applies to the NTS.

1.25. This incentive scheme is a sliding scale incentive scheme, with the target determined as the aggregate of a target for charges foregone (ie, the deemed cost of procuring interruption from customers through the "interruptible discount") and a target for incremental investment costs. The performance measure against which the target is compared is defined to be the aggregate of the performance measures determined for charges foregone and incremental investment costs.

1.26. If the aggregate performance measure is less than the target defined then NGG NTS is subject to an upside sharing factor of 50%, with gains under the incentive capped at £1m. Conversely, if the performance measure exceeds the target defined, then NGG NTS is subject to a downside sharing factor of 25%, with losses under the incentive collared at £1m.

1.27. The cap on this incentive was reduced from £10m to £1m in 2004. NGG NTS's retained benefit from this incentive was therefore £6.1m, £7.0m and £1.0m in 2002/03, 2003/04 and 2004/05 respectively.[19]

1.28. Our initial view is that the charges foregone and exit investment incentive should not apply to the transitional period. In reaching this preliminary position we have been mindful of the following factors:

- the incentive is currently subject to quite restrictive caps and collars, which mean that the incentive placed upon NGG NTS has been reduced

[19] NTS System Operator incentive performance to date, NGG NTS, December 2005, published in Transmission Price Control area of work on the Ofgem web site.

- as discussed in the next section, an equivalent incentive is not proposed as part of the enduring regime, and
- given that it is the intention to implement changes to the incentive regime such that they take effect on 1 April 2007, investment decisions would, by this time have already been taken for the transitional period.

1.29. In order to simplify the licence drafting for the next price control period, where possible, and with regard to the factors listed above, our initial view is that this incentive should also be removed for the remainder of the interim period that overlaps with the next price control period ie, the 18 month period from 1 April 2007 to 30 September 2008.

1.30. We would welcome views from respondents on the proposed treatment of this incentive in the next price control period up to 30 September 2010.

Constrained LNG incentive

1.31. A constrained LNG incentive currently applies to the NTS. NGG NTS may choose to use constrained LNG to meet expected demand on the 1 in 20 day as a cheaper alternative to system investment or interruption. Due to NGG NTS's ownership of the constrained LNG storage facilities (through National Grid LNG), the scheme is separate from the exit investment scheme with no caps and collars and 100% sharing factors. This structure addresses the potential for distorting behaviour between the regulated gas transmission business and the competitive LNG business which is also owned by NG. If customers were to bear a proportion of the costs resulting from charges levied by the competitive business on the regulated business, then NG could benefit (at a cost to customers) from increasing such charges levied by its competitive business or if the regulated business contracted for increased levels of LNG as an alternative to interruption. As a result, deviations from the target are fully borne by NGG NTS rather than customers.

1.32. In 2002/3, 2003/4 and 2004/5, the retained benefit to NGG NTS was -£0.7m, £3.9m and £5.4m respectively given a net cost in each year of £6.6m, £2.3m and £1.2m respectively[20]. Targets for this incentive have already been specified for the remainder of the interim period, these being £2.6m for 2007/8 and £2.1m for 2008/9[21].

1.33. We are minded to retain the constrained LNG incentive in its current form with 100% sharing factors and no cap or collar. Indeed, we are minded to retain a similar incentive as part of the enduring regime. Furthermore, given the proposed removal of the charges foregone and exit investment incentive, it may be possible to simplify the licence drafting associated with this incentive.

1.34. We would welcome views from respondents on the proposed treatment of this incentive for the transitional and enduring periods. We would also welcome views

[20] NTS System Operator incentive performance to date, NGG NTS, December 2005, published in Transmission Price Control area of work on the Ofgem web site.
[21] National Grid Transco - Potential sale of gas distribution businesses. Final proposals for interim incentives and formal consultation under Section 23 of the Gas Act 1986, Ofgem, April 129/05, page 43.

from respondents on the appropriate level of the target for the last three years of the next price control period i.e. 2009/10, 2010/11 and 2011/12 should the current structure for this incentive be retained.

Buyback and greater than fifteen day interruptions incentive

1.35. A buyback and greater than 15 day interruptions incentive currently applies to the NTS.

1.36. This incentive has a sliding scale structure, with the target determined as the aggregate of the target for buyback costs and the target for costs incurred as a result of sites being interrupted for greater than fifteen days in any formula year. The performance measure against which the target is compared is defined to be the aggregate of the performance measures determined for buyback and greater than 15 day interruptions.

1.37. If the aggregate performance measure is less than the target defined then NGG NTS is subject to an upside sharing factor of 75%, with gains under the incentive capped to be equal to the greater than fifteen day incentive target. Conversely, if the performance measure exceeds the target defined, then NGG NTS is subject to a downside sharing factor of 50%, with losses under the incentive collared at £7m. In the interim period, the buyback target is defined to be zero, and the target for greater than 15 day interruptions is £1.73m and £1.68m in 2007/8 and 2008/9 respectively.

1.38. The interim incentives determined reflect the fact that they apply to a period that falls within investment lead times. Furthermore, within the interim period, capacity is assumed to be released by NGG NTS on an unconstrained basis. The zero buyback target was therefore established on the premise that NGG NTS could be expected to meet all reasonable demands for incremental offtake capacity over the interim period on an economic and efficient basis.

1.39. It is our initial view that the scope of the buyback incentive within the transitional period should, consistent with the proposed scope for the enduring period (as discussed in the next section), exclude investment related buybacks. We believe that this is appropriate given that the ARCA framework in place within the transitional period gives NGG NTS some discretion with regards to the agreed delivery dates for investment projects. As such, any buyback actions by NGG NTS in relation to the late delivery of investment would fall outside the scope of the proposed incentive and NGG NTS would therefore bear the associated buyback costs in full. Indeed, given that, in the transitional period, NGG NTS will continue to have rights to reduce offtake capacity to NTS users for maintenance purposes without the need to buyback such rights, it is our initial view that no buyback related costs should be allowed as part of the price control settlement for the transitional period.

1.40. We would welcome views from respondents on this proposal.

1.41. The interruptions regime will remain unchanged throughout the interim and transitional periods. As such, it is envisaged that the greater than 15 day incentive will be retained for the transitional period with the targets defined for the interim

period rolled forward taking into account NGG NTS performance relative to past targets and any historical or expected changes in the level of interruption.

1.42. It is noted that the incentive cap within the interim period is determined to be equal to the target for the greater than fifteen day incentive. It is our initial position that this should remain the basis for the determination of the cap. Indeed, we would welcome views on whether a symmetric incentive should be implemented such that the collar has the same magnitude as the cap.

Questions:

- ***Question A12.1*** **- Do you agree that for the period from 1 April 2007 to 30 September 2010, baselines should:**
- **not be specified for interruptible capacity?**
- **not be specified for GDN flexibility?**
- **be at the same level and degree of aggregation as during the enduring period (ie, nodal and based upon practical maximum physical capacity)?**
- ***Question A12.2*** **- Do you agree that incremental investment should be remunerated throughout the entire duration of the next price control period through the application of pre-specified revenue drivers?**
- ***Question A12.3*** **- Do you agree that the charges foregone and investment incentive should:**
- **a. not apply to the transitional period?**
- **b. be removed for the period from 1 April 2007 to 30 September 2008?**
- ***Question A12.4*** **- Do you agree that the constrained LNG incentive should:**
- **a. be retained for the transitional period?**
- **b. apply to the enduring period?**
- ***Question A12.5*** **- What do you believe is the appropriate level for the constrained LNG target for formula years 2009/10, 2010/11 and 2011/12?**
- ***Question A12.6*** **- Do you agree that all buyback costs should be treated as excluded revenue within the transitional period?**
- ***Question A12.7*** **- Do you agree that the greater than 15 day interruptions incentive should be retained?**
- ***Question A12.8*** **- What are your views on the appropriate level of the target, cap and collar for the greater than 15 day interruptions incentive?**

The enduring regime

The importance of user commitment models

1.43. The Second Consultation introduced the concept of a long term user commitment model for offtake, describing at a high level how a user commitment could work in practice, and the key advantages and disadvantages of such a model. Since the publication of the Second Consultation, we have had the opportunity to discuss the concept of user commitment with industry participants through the

Enduring Offtake Working Group (EOWG). As a consequence, our views have developed in terms of both the way in which a user commitment model may operate and the implications of such a model. In principle, we consider this model would involve:

- all NTS users (both existing and new users) being required to indicate their future usage of the NTS to NGG NTS,
- these signals of future usage should be provided sufficiently far in advance to allow NGG NTS to make an informed assessment of the appropriate level of NTS investments that are required (consistent with the level of user commitment), and
- signals made by users - both new and existing - should be backed by an appropriate level of financial commitment.

1.44. This proposal differs significantly from the "status quo" set of arrangements (defined in the Second Consultation as being the transitional offtake arrangements). Under the status quo arrangements, shippers serving transmission connected customers (TCC shippers) are not required to signal their requirements for NTS offtake capacity beyond 12 months ahead. These arrangements are different to those that currently apply to the gas distribution networks, who are required to submit requests for NTS offtake (flat) and NTS offtake (flexibility) capacity three years in advance in order to be guaranteed access to their required offtake volumes.

1.45. The adoption of a model in which all users, including existing users, are required to make a significant financial commitment to guarantee ongoing access to the NTS may have a number of significant benefits for customers. In particular, we consider that the improved investment signals provided by users under a user commitment model may reduce the risk of stranded assets emerging on the network - and consequently may reduce the risk that customers are required to pay for assets that are not required by NTS users. This benefit is likely to emerge as, instead of NGG NTS relying on forecasts of long term usage (that may be subject to significant margins of error), investment under a user commitment model would instead be driven by signals from users that are supported by financial commitments (and hence are likely to be more reliable). Fundamentally, this is because we consider that NTS users are better placed to assess their individual future needs for NTS offtake capacity services than any other party. It is important to reiterate that user commitment is required from existing connectees as well as new connectees, as it is only by having a view of the total requirements for offtake capacity that NGG NTS will be able to determine the level of efficient investment (if any) that will be necessary to meet the future needs of users. We recognise that the model to be adopted will need to be developed and consulted upon through Uniform Network Code (UNC) processes, however, we state our initial views on some key aspects of these models in this Appendix.

1.46. We consider that user commitments are particularly important given NGG NTS's recent FBPQ submission in which NGG NTS stated that around £0.9bn of NTS load related capital expenditure may be required in the next price control period (relative to a current regulatory asset value of approximately £2.5bn).

1.47. We also consider that long term user commitment models may promote security of supply, to the extent that they will give gas transporters greater clarity of the meaning of their "1 in 20" security of supply obligations. Under a user commitment model, NGG NTS (and importantly all existing and potential new NTS users) will have clarity that the network will be sized in accordance with signals provided by users. Gas distribution networks have a licence obligation to size their networks in a manner sufficient for them to meet a level of demand only exceeded one year in twenty (and therefore request a volume of NTS offtake capacity consistent with this), and other users will book NTS offtake capacity at levels consistent with their peak usage. We consider this represents increased clarity for all parties regarding the way in which NGG NTS will invest to meet its 1 in 20 security of supply obligation.

1.48. We also anticipate that a long term user commitment model would increase the transparency of offtake arrangements, through ensuring that all categories of NTS users are subject to equivalent access arrangements (including the range of products that are available for them to purchase). Depending upon the ultimate form of the capacity allocation mechanisms developed for the enduring offtake arrangements, we consider that this may have the additional benefit of reducing the likelihood that disputes may arise between users and NGG NTS.

Consideration of high level options in the Second Consultation

Options presented

1.49. The Second Consultation considered high level options for user commitment models defined in relation to the spatial definition of both baselines and the capacity product(s).

1.50. It is our proposal that for gas offtake in the enduring regime, baselines should have a dual role both as a high level separation between TO revenue allowances and remuneration of incremental investment as well as defining obligations for capacity release upon NGG NTS up to that baseline level.

1.51. Four high-level options for long term user commitment models were defined in the document, these being:

- Option Ex2: a model consistent with the February 2005 Initial Thoughts document, ie a model with nodal baseline, nodal product, and with a financial incentive on NGG NTS to substitute baseline capacity between nodes where appropriate
- Option Ex3: a model with a nodal product and zonal baselines
- Option Ex3A: a model with nodal product and global/network baselines, and
- Option Ex4: a model with a zonal product and zonal baselines.

1.52. These models are summarised in Table A12.1 below, relative to the status quo.

Table A12.1: Overview of long term user commitment models

	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	×	✓	×	×	×

Ofgem's view

1.53. As discussed in Annex 2, we consider that a model of offtake arrangements based on a variation of Option Ex2 is most appropriate for further development, and that this should be the subject of a forthcoming quantified impact assessment.

1.54. Following consideration of responses to the cost survey and respondents' views to the Second consultation, we consider that NTS offtake capacity rights should continue to be defined on a nodal basis. As outlined in Annex 2, we consider that a nodal product is likely to be most consistent with efficient network development and system operation, and also be most consistent with the preservation of security of supply.

1.55. In terms of baselines, we consider that setting these on a zonal or global basis could result in a lack of transparency in the selected capacity allocation mechanism, potentially giving NGG NTS an increased level of discretion, and raising the possibility of a need for ongoing regulatory intervention. We also consider that models that specify baselines in this way are likely to increase significantly the complexity of the mechanisms through which offtake capacity is allocated to NTS users by NGG NTS. Setting baselines at a zonal or global level of aggregation would also reduce the extent to which baselines accurately reflect a level above which NGG NTS would need to invest to increase capacity delivered. We therefore consider that setting baselines on a nodal basis is appropriate for the enduring offtake arrangements.

1.56. We continue to consider that, under a model of nodal baselines, a mechanism will be necessary to allow capacity to be substituted between nodes. We believe a mechanism such as this will give the arrangements sufficient flexibility such that NGG NTS will only be remunerated for incremental capacity to the extent that all opportunities for substitution across all other offtake points has been exhausted.

1.57. However, consistent with respondents' views to the Second consultation, we no longer consider that providing a financial incentive on NGG NTS to undertake

capacity substitutions is appropriate, given the potential financial cost to customers of the associated incentive payments. In addition, and as outlined in Annex 2, we consider that a substitution incentive could lead to a lack of transparency, increased NGG NTS discretion and may therefore lead to a number of disputes being referred to Ofgem for resolution.

1.58. Instead we consider that, rather than having a substitution incentive, it may be more appropriate to place a substitution obligation on NGG NTS. Under such an approach, baselines would be specified for each node by Ofgem (informed by NGG NTS analysis), and NGG NTS would have an obligation to substitute capacity between nodes to meet demand at other nodes. NGG NTS would only be remunerated for incremental capacity to the extent that all opportunities for substitution of baselines at other nodes had been exhausted. In the event that demand for incremental capacity at another node could be alleviated by baseline substitution, NGG NTS would then be required to apply to Ofgem to adjust the baselines of the affected nodes in accordance with calculated exchange rates (with the modified baselines applying thereafter in terms of both the application of revenue drivers and capacity release obligations).

1.59. It is our initial view that, in order to allow substitution across nodes, baselines could be modified without the need for formal licence modifications by referencing a separate, Ofgem approved, document.

1.60. Our favoured model for offtake arrangements represents a refinement of Option Ex2, as presented in the Second Consultation, in that it has a substitution obligation rather than a substitution incentive. An assessment of this model (Option Ex2A) is presented in Table A12.2 below.

Table A12.2: Qualitative assessment of Option Ex2a

	Long term user commitment models				
	Option Ex2A	**Option Ex2**	**Option Ex3**	**Option Ex3A**	**Option Ex4**
Efficient network development and system operation	✓✓	✓✓	✓	✓✓	✗✗
Preventing undue discrimination	✓✓	✓✓	✓✓	✓✓	✓✓
Promotion of competition	✓	✓	✓	✓	✓✓
Appropriate allocation of risk	✓✓	✓✓	✓✓	✓✓	✓✓
Simplicity / transparency	✗	✗	✗✗	✗✗	✗✗
Preservation of security of supply	✓✓	✓✓	✓✓	✓✓	✗✗
Minimise implementation and ongoing costs	✗	✗✗	✗	✗	✗✗
Clear and appropriate accountability and responsibility	✓	✗	✗	✗✗	✗✗
Compliance with applicable legal requirements	✓✓	✓✓	✓✓	✓✓	✓✓

Key:

✓✓	yes
✓	yes, but to a lesser extent than other options presented
-	little or no impact
✗✗	no
✗	no, but to a lesser extent than other options presented

1.61. For the majority of the assessment criteria outlined above, Option Ex2A has the same advantages and disadvantages (relative to the status quo) as Option Ex2. The key differences - as discussed above - are the additional advantages relating to both increased clarity of responsibilities for all parties, and reduced ongoing cost.

Comparisons with other models

1.62. At entry, capacity requirements across nodes have a tendency to vary to a greater extent than at exit as Great Britain's gas can be provided from a variety of different sources.

1.63. These different characteristics have implications for the determination of nodal baselines and, in particular, the specification of capacity release obligations in relation to individual nodes. At exit, the number of incidents where nodal baselines are likely to require adjustment in the event of a constraint or a new exit point is expected to be low (particularly given that the system is currently unconstrained in

all but the south west quadrant). However, because demand for locational capacity is more volatile at entry there is much greater uncertainty with regards to the appropriate level of capacity release that should be required at specific nodes ie, what the baselines for each node should be. This potential for volatility of baselines at entry means that "sterilisation" that is, where baseline specified, but unused, at one node, is actually required at another, is more likely to occur than at exit.

1.64. The approaches proposed at entry and exit aim to strike an appropriate balance between complexity and cost. For example, if the number of incidents of sterilisation is expected to be relatively low (as at exit) then dealing with such incidents on a case by case basis with Ofgem oversight may be appropriate. However, as the magnitude of expected incidents increases, such an approach becomes less appropriate as the need for regulatory intervention becomes significant. It is therefore appropriate at entry to allow NGG NTS greater flexibility with respect to capacity release and make detailed information available to the industry to limit the exercise of such discretion.

Enduring offtake arrangements

1.65. Since the publication of the Second Consultation document, we have held six meetings of the Enduring Offtake Working Group (EOWG). The informal consultation conducted through these meetings has been extremely helpful in developing thinking regarding the way in which a user commitment model could be specified and applied in practice.

1.66. At the EOWG meeting held on 8 March, NGG NTS and SSE presented "strawmen" models of the way in which user commitment could work in practice. Both of these presentations have been published on the Ofgem website[22]. Subsequent to this meeting, NGG NTS prepared a revised strawman, reflecting the debate at this meeting. This has also been placed on the Ofgem website for reference, and circulated to EOWG attendees.

1.67. The issues raised in both the presentations at EOWG and NGG NTS's subsequent strawman cover a broad range of areas. In the remainder of this section, we present our initial views on some of the key aspects of these models. However, it is important to note that we recognise that the model to be adopted will need to be developed and consulted upon through Uniform Network Code (UNC) processes and that Ofgem cannot fetter the discretion of the Authority with respect to any proposals that are raised.

Product definition

1.68. An issue that has been debated at the EOWG is the definition of the offtake capacity products offered by NGG NTS in the enduring offtake arrangements.

1.69. The strawman presented by NGG NTS proposes that both "flat" and "flexibility" products are offered to all NTS users. NTS exit (flat) capacity is defined as being the

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

daily right to offtake a quantity of gas, at a constant flow rate through the day. This is consistent with the flat capacity product currently booked by GDNs under existing arrangements. In contrast, the "flexibility" product would give users the right to offtake from the NTS at varying offtake rates over the day. This product is defined as being equal to the cumulative volume of gas taken in excess of the constant daily rate, over the period 6am to 10pm (which is the time at which the stock of gas held by GDNs is typically at its lowest, and therefore the system is likely to be at most stress).

1.70. An additional feature of the flexibility product proposed is that, at times at which the full purchased level of NTS exit (flat) capacity is not being used (ie, on off-peak throughput days), unused flat capacity rights may be "converted" into additional NTS exit (flex) capacity rights. Under this definition, rights to flexibility therefore "expand" as daily throughput decreases.

1.71. Following debate at the EOWG, our initial view is that all NTS users should be offered the same set of offtake capacity products, and on the same terms. In addition, we consider that users should signal their requirements for "flat" and "flexible" NTS offtake capacity. Our preliminary thinking is that the "expanding flexibility" product seems an appropriate way in which to define rights for offtake flexibility. However, we note that this definition of flexibility requires the specification of a robust conversion factor (through which unused flat capacity rights may be converted into flexibility rights). NGG NTS indicated at the EOWG meeting on 24 February that analysis was being undertaken on this issue, and the expectation was that a further two months would be required before a view could be reached on an appropriate level for the conversion factor. We therefore anticipate that NGG NTS will present its finding to the EOWG in early May 2006. We note that in NGG NTS's strawman, it was stated that the conversion factor could range from zero to 2/3, however, we also note our understanding that, historically, NGG NTS has been able to provide additional flexibility capacity at off-peak times and therefore it is our initial view that a conversion factor of zero, or close to zero, would not be appropriate.

1.72. We note that NGG NTS has suggested that it may be possible for the flat capacity and expanding flexibility products to be combined into a single “transmission capability” product. We believe that a combined, "expanding" product would have benefits relative to a two product model in terms of simplicity (both from a user perspective and also in relation to the determination of appropriate charges, baselines and revenue drivers). We would therefore encourage NGG NTS to consider the merits of a combined "expanding" product model relative to the two product model outlined in its strawman as part of the analysis that it is currently undertaking.

Long term capacity allocation mechanisms

1.73. Another area of significant debate at the EOWG has been the appropriate form of long term capacity allocation mechanisms for offtake capacity rights. Two forms of model are described in the NGG NTS strawman model. These are a “finite rights” approach and a “prevailing rights” approach.

1.74. Under a "finite rights" approach, all NTS users (ie, both existing connectees and potential new connectees) are required to make the same level of financial commitment in the unconstrained period to secure NTS offtake rights at regulated prices[23]. In the model, to guarantee access in this unconstrained period, all users are required to meet a “sustained demand” test, defined as being a commitment to purchase a specified volume of access rights for at least 4 years. This commitment applies whether or not the capacity already exists in the network.

1.75. In contrast, in the "prevailing rights" approach, all users (ie, existing connectees and potential new connectees) are treated equally in terms of requests for additional offtake capacity. In particular, in the NGG NTS strawman, to increase capacity beyond current holdings, a sustained demand test needs to be met (of 4 years). However, current users retain a rolling right to the level of access they currently have. In return, existing connectees are required to make a (rolling) financial commitment to pay for their existing level of offtake rights for a number of years ahead (set at 2.5 years in the NGG NTS strawman model). Existing connectees are therefore only able to reduce the level of offtake rights they require by giving NGG NTS 2.5 years notice.

1.76. We recognise that the “finite rights” approach as defined in the NGG NTS strawman has the disadvantage of requiring existing connectees to make a financial commitment for up to 7 years of offtake capacity charges in order to maintain guaranteed access to current levels of offtake. We recognise that such a commitment is likely to impose costs on users, and is a significant change from existing levels of financial commitment. However, we do consider this approach has the significant advantage in that all connectees are treated in an equal way with respect to the booking of capacity in the unconstrained period. In addition, by requiring all users to make the same level of financial commitment in the unconstrained period, NGG NTS will have investment signals for the same years from all connectees, enabling more efficient investment planning.

1.77. The "prevailing rights" approach, as outlined by NGG NTS in its strawman, requires a lower level of financial commitment from existing NTS users than the finite rights approach (2.5 years in the NGG NTS strawman), therefore imposing less cost on this class of users. In addition, EOWG attendees suggested that a level of user commitment of 1 or 2 years may capture the majority of benefits of the finite rights model, on the grounds that a significant majority of investment expenditure is typically incurred in the final two years of project delivery.

1.78. Our initial view is that the prevailing rights model is worthy of further development and consideration as a mechanism for introducing user commitment. It is for further consideration as to the extent of user commitment by existing users that would be appropriate under such an approach, but we would expect this to be informed by consideration of, amongst other things, investment lead times, the profile of investment costs typically incurred within investment lead times, and asset

[23] The "unconstrained period" has been defined by NGG NTS as being from the first year in which it is able to build to meet requests for capacity (4 years ahead given an assumed investment lead time of circa 3 years) up to 7 years ahead.

stranding risk. We suggest this issue is progressed through the EOWG, supported by further analysis from NGG NTS.

1.79. We also note that the NGG NTS strawman includes a facility through which users who are not parties to the UNC may be able to make a user commitment to reserve capacity in the unconstrained period, which is then subsequently booked by a party to the UNC. We recognise that this has been proposed in order to alleviate concerns from shippers regarding the contractual complexity and potentially an adverse impact on competition that may otherwise arise if shippers were required to make the user commitment rather than connectees themselves.

1.80. We also note that the NGG NTS strawman proposes that prices should be based upon prevailing NTS exit capacity charges.

1.81. As outlined above, long term allocation issues will need to be developed and consulted upon through UNC consultation processes. Furthermore, charging issues will be subject to charging consultations. However, we would also encourage discussions at meetings of the EOWG and any other working groups on these issues.

Medium / short term capacity allocation mechanisms

1.82. Under the NGG NTS strawman, NTS offtake rights are also released in the medium and short term (ie, within investment lead times, 3 years ahead of delivery).

1.83. In each year in the constrained period, users will be able to apply for annual firm NTS exit (flat and flex) capacity, through a nodal “pay as bid” capacity auction, held in August each year. This allocation will be subject to a reserve price, and the quantity of capacity made available will equal the remaining unsold capacity (ie, baseline less capacity already sold), plus any “non-obligated” capacity, sold by NGG NTS at its discretion, in response to offered prices (and incentives, yet to be defined).

1.84. NGG NTS will also hold daily “pay as bid” auctions, to allocate any unsold daily firm NTS exit (flat and flex) capacity rights. This allocation will also be subject to a reserve price. Under the strawman, the obligation to release baseline capacity will not apply on the day (therefore on-the-day releases would be at NGG NTS discretion).

1.85. Our initial view is that the majority of proposals for the constrained release of capacity seem appropriate, although we recognise that the detailed development of these arrangements would need to occur through UNC processes and consultation. However, we would encourage discussions at meetings of the EOWG and any other working groups on these issues.

Interruptions regime

1.86. In the NGG NTS strawman, long term interruption is managed through the long term contracting for the interruption of NTS capacity consistent with investment planning timescales. In the short term (at day ahead), a daily interruptible NTS exit (flat) capacity product is offered for sale. The NTS will have discretion regarding the

volume of interruptible rights made available at each offtake point, but the volume made available will, at a minimum, equal the expected level of unused rights (ie, fulfilling a “use it or lose it” role).

1.87. We have a preliminary view that it is appropriate to develop the arrangements outlined in the NGG NTS strawman further, given these are consistent with the proposals developed at the time of GDN sales. However, we consider it is important to understand in more detail how the process of contracting process for the interruptions of offtake capacity rights will work in practice (and would note that in the August 2004 conclusions document on interruptions arrangements, the Authority concluded that some form of clearly defined tender process would be most appropriate[24]). The nature of the interruption arrangements is ultimately an matter for UNC and charging methodology consultation processes.

1.88. However, we would also encourage discussions at meetings of the EOWG and any other working groups on these issues.

Enduring incentives - development of preferred option

Interaction of user commitment models with 1 in 20 obligation

1.89. As discussed above, we believe that the facilitation and encouragement of long term user commitments should form the foundation for enduring offtake reform. It has therefore been necessary to consider the interaction between a full user commitment framework and the NTS's 1 in 20 obligation.

1.90. Standard Special Condition A9 (Pipe-Line System Security Standards) imposes a "1 in 20" obligation upon both NGG NTS and the GDNs. This obligation requires the licensees to ensure that their pipe-line systems meet the peak aggregate daily demand for the conveyance of gas for supply to premises (taking into account the extent to which supply of gas to such premises might be interrupted) which is likely to be exceeded only 1 year in 20.

1.91. At present, in the absence of a framework for full user commitments, NGG NTS forecasts demand from the GDNs, TCCs and other NTS users and invests in its pipe-line system accordingly. However, it is our initial view that, within a full user commitment framework, it would only be appropriate for additional NTS capacity to be provided if NTS users have signalled that such capacity would be of value to them. In particular, in the case of GDNs, it is our view that NTS exit capacity built for GDNs should be consistent with the GDNs’ assessment of their NTS exit capacity requirements given their 1 in 20 obligation. As a result there would be greater clarity of responsibility between NTS users and NGG NTS. Furthermore, as the causality for investment would be unambiguous, users would be incentivised to provide long term investment signals.

[24] National Grid Transco - Potential sale of gas distribution networks businesses, Interruptions arrangements, Conclusions document on framework, Ofgem, August 2004 198/04

1.92. We are therefore minded to propose that NGG NTS would only be remunerated for incremental investment to the extent that there is an associated user commitment. Furthermore, we are minded to note that compliance with the NTS's 1 in 20 obligation could be achieved by investing in line with user commitments which signal peak aggregate daily demand.

1.93. The mechanisms proposed for remunerating incremental investment are discussed further below.

1.94. It is our initial view that it is neither necessary nor appropriate to modify Standard Special Condition A9 as it is not our intention to change the 1 in 20 obligation with which compliance is required - we merely propose to clarify how compliance with this obligation could be achieved in the context of a full user commitment model being adopted.

Baseline derivation

1.95. As discussed above, it is our initial view that baselines should be determined on a nodal basis and perform a dual function both as a high level separation between TO revenue allowances and remuneration of incremental revenues as well as defining obligations for capacity release upon NGG NTS up to that baseline level. Consistent with our proposals for the transitional regime, it is our initial view that baselines should not be specified for interruptible capacity (so that additional revenues are clearly linked to the provision of additional firm capacity).

1.96. However, it is our view that, if there is a separate flexibility product available to all NTS users, it would be appropriate to specify separate nodal baselines for this product.

1.97. However, it is also necessary to consider:
- the methodology that should be applied to determine the appropriate level of nodal baselines, and
- the scope of the baselines determined, for example, the extent to which baselines should take into account anticipated investment projects.

1.98. We consider each of these issues in turn below.

Baseline level

1.99. In the Second consultation, we outlined a number of different approaches that could be adopted to determine the appropriate level of baselines:
- a theoretical maximum physical capacity approach
- a practical maximum physical capacity approach
- an assessment based on existing / future demand - as proxied by 1 in 20 demand scenarios
- an assessment based on existing / future demand - as proxied by auction signals, and
- a combination of the capacity required to meet the 1 in 20 forecast and existing auction signals.

1.100. However, we would note that auction signals are only available for gas entry and, as such, the final two approaches listed above are of less relevance to gas offtake. We have therefore focused our consideration on the first three options, namely a theoretical maximum physical capacity approach, a practical physical capacity approach or a 1 in 20 demand approach.

1.101. As discussed above, it is our initial view that user commitments should determine the long term view of 1 in 20 demand. As such, we do not believe that it would be appropriate to determine baseline levels in accordance with an ex ante assessment of 1 in 20 demand. Instead, it is our initial view that nodal baseline levels should reflect the physical capability of the system.

1.102. Given the interdependence of offtake between one offtake point and another, we do not believe that a theoretical maximum physical capacity approach is appropriate as this would tend to over-state the amount of capacity available and either require NGG NTS to build more than is necessary or lead to significant buyback exposure for NGG NTS and customers and create issues with regards to the relationship between baselines and the TO price control allowance.

1.103. Instead, it is our initial view that a practical maximum physical capacity approach is appropriate as this reflects the actual physical capability of the system and therefore recognises (at least on an approximate basis) that capacity in excess of baselines is likely to incur incremental investment costs that require funding, and capacity below such levels is not. We acknowledge respondents' concerns that obligations should be placed upon NGG NTS to ensure the release of all available capacity at individual nodes. We consider that the obligation to offer for sale nodal baseline capacity levels and the proposed substitution obligation should mitigate such concerns.

1.104. We acknowledge that there is some subjectivity in the determination of practical maximum physical baselines and this is discussed further in Annex 1.

Baseline scope

1.105. We have considered the implications of an emphasis on user commitments for the determination of baselines given that baselines play a key role in defining the outputs which are funded as part of the TO price control allowance.

1.106. In determining baselines, and hence what is funded as part of the TO allowance, a range of approaches could be adopted. At one end of the spectrum, all anticipated investments could be funded ex ante as part of the TO allowance, and included within the baselines determined for the appropriate year. At the other end of the spectrum, only capacity that had been delivered at the start of the price control period would be funded ex ante as part of the TO price control allowance, and the baselines determined would reflect existing capacity levels and stay flat throughout the price control period.

1.107. As stated above, it is our initial view that NGG NTS should only be remunerated for incremental investment to the extent that there is an associated user commitment. As such, it is our initial view that investments that do not have an

associated user commitment should not be funded as part of the TO price control allowance. Furthermore, it is our initial view that, in order to incentivise the early delivery of investments, it may be appropriate to remunerate only such investments once they have been delivered. Under such an approach, only those investments that have been delivered would be included in the baselines and remunerated as part of the TO price control allowance (without the application of revenue drivers). Furthermore, the value of baselines would be static across the price control period.

1.108. NGG NTS has provided a preliminary indication of both practical maximum physical capacity baselines based on the capacity of the network on 1 April 2007. These are provided for comment in Annex 1. 1 in 20 baseline numbers have also been provided for the same year for reference.

Revenue drivers

1.109. The TO price control allowance remunerates the provision of baseline levels of capacity. However it is also necessary to consider the appropriate basis for remunerating incremental capacity delivered above those baseline levels. It is our initial view that the mechanism adopted should:

- incentivise capital efficiencies on the part of NGG NTS
- reduce the need for regulatory intervention during a price control period, and
- provide some remuneration of capital expenditures within the price control period.

1.110. We believe that the application of pre-specified revenue drivers would achieve these aims.

1.111. As discussed above, given the emphasis on user commitments, it is our initial view that the remuneration of future investment should be contingent upon an appropriate user commitment and therefore that revenue drivers should apply to all load related capital expenditure in the next price control, and that remuneration of such incremental investments should be contingent upon:

- an associated user commitment, and
- delivery of that capacity to incentivise early delivery where this is of value.

1.112. As noted above, it is our view that nodal substitution opportunities should be exhausted before investment is remunerated. It is also our initial view that NGG NTS should contract long term for the interruption of capacity before investing.

1.113. In determining revenue drivers, we hope to strike an appropriate balance between precision and simplicity. It is our initial view that the most appropriate approach may be to:

- specify zonal revenue drivers for small capacity increments required as a result of general demand growth on the assumption that cost variability across a group of nodes in a similar geographic location for such increments will not require node specific drivers
- specify project specific revenue drivers in relation to those large projects which are currently anticipated, such as Marchwood power station on the assumption that a single, nodal revenue driver will be unable to reflect the variability in unit costs associated with both very large and very small projects, and

- modify the licence in respect of unanticipated projects above a certain size threshold or with respect to new exit points.

1.114. We note that in its response, NGG NTS stated that it may be appropriate to index revenue drivers with respect to the price of steel. We would welcome views on whether such indexation would be appropriate.

Further implications of revenue driver proposals

1.115. The proposed application of revenue drivers as outlined above has a number of further implications. For example, it is our initial view that the proposed revenue drivers negate the need for an NTS exit investment incentive as they will, in and of themselves, incentivise capital efficiency.

Proposals for buy-back incentive

1.116. Many of the issues that are currently faced by the entry regime, and that the entry proposals aim to address, will be similar in nature to those that arise for the enduring offtake regime. As such, it is our view that there should be some commonality across gas entry and gas offtake proposals in the area of buybacks. Key points to note regarding our proposals are as follows:

- investment related buyback costs should be treated as excluded revenue and subject to an administered buyback price on a similar basis to the entry proposals outlined in Chapter 4
- it remains necessary to consider the extent to which NGG NTS should have some flexibility over investment lead times either by allowing them to apply for lead time extensions and / or making default lead times contingent on the necessary planning consents being obtained
- we would welcome views on whether there is merit in implementing a cap on the total exposure associated with any individual, investment related, buyback action at exit, as proposed at entry, and
- as proposed at entry, our initial view is that the costs of buybacks in the event of planned and unplanned outages (the key element of this being maintenance related buybacks) should be subject to a sliding scale incentive regime. We would welcome views regarding whether such buyback costs should also be subject to an administered price.

1.117. We would note that the above proposals assume that the formulation of capacity products or baselines do not place a greater buyback risk upon NGG NTS for which a buyback target is required.

Payment flows

1.118. In our February 2005 Initial Thoughts consultation on enduring offtake arrangements, we stated that an "Option 2A" approach to payment flows should be adopted. It was therefore initially envisaged that this payment flows model would be implemented on 1 October 2008, consistent with the original implementation date for the enduring offtake arrangements. However, following the delay of the implementation of the enduring offtake arrangements until 1 October 2010, it is necessary for us to consider whether the implementation of this payment flows

model should coincide with the introduction of the transitional or the enduring offtake arrangements.

1.119. In our Final Proposals consultation on transitional incentives for GDNs, we noted that the NTS and GDN-GT licences, as currently drafted, envisaged that the mechanism for payment flows would move to an Option 2A approach on 1 October 2008 (or such later date that the Authority otherwise directs in writing). In this document, we stated that we were not proposing to modify the licence drafting to change this timing at that time, but stated that the possibility of proposing a later date would be considered in due course.

1.120. Following consideration of respondents' views to date, we are minded to delay the implementation of the Option 2A payment flows model until 1 October 2010 to coincide with the introduction of the enduring offtake arrangements.

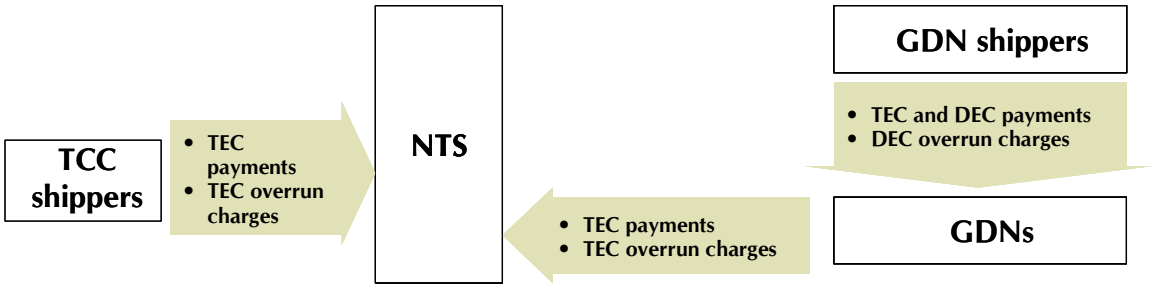
1.121. In this section we discuss this issue under the following headings:
- overview of the option 2A payment flows model
- summary of respondents' views, and
- our initial thoughts.

Overview of the option 2A payment flows model

1.122. Under this model, GDNs would have a central role in the payments process, effectively acting as an intermediary for all NTS-related payments from GDN shippers who convey gas to customers offtaking from the GDNs. As such, payment flows would be simplified, minimising the number of payment interfaces between shippers and network owners.

1.123. The payment flows under such an approach are illustrated below in Figure A12.2.

Figure A12.2: Option 2A payment flows



Key: TEC: Transmission Exit Capacity, DEC: Distribution Exit Capacity

1.124. As shown in Figure A12.2. both GDNs and TCC shippers would pay the NTS directly for their requested level of transmission exit capacity. GDN shippers would not make any payments directly to the NTS, but rather the relevant GDN would recover transmission exit capacity charges from shippers on its network. This

payment flows model was also explained in our Final Impact Assessment for GDN sales[25].

Summary of respondents' views

1.125. Two respondents to our Final Proposals for GDN transitional incentives, commented on the timing of the implementation of the Option 2A payment flows model. These respondents, both GDNs, were in favour of implementing this payment flows model in parallel with the introduction of the enduring offtake regime.

1.126. One respondent noted that a move to this new approach would have significant implications for the GDNs in terms of charging methodologies, setting charges and the associated system changes. This respondent stated that the Option 2A approach was discussed in the context of the enduring arrangements and therefore should not be implemented before those arrangements have been finalised.

1.127. The second respondent echoed these sentiments stating that such a model would require significant alterations to GDN charging systems and that, given that the introduction of the enduring arrangements would require further changes to the GDN charging systems, separate implementation would involve additional costs.

Ofgem's initial thoughts

1.128. Following consideration of views expressed to date by respondents, we are minded to postpone the introduction of the Option 2A payment flows model by two years such that it coincides with the implementation of the enduring offtake regime and, specifically, changes to the charging framework itself as part of these reforms. This would allow any changes to the charging systems required to be coordinated and managed efficiently.

1.129. However, we are aware that only a small sample of respondents have expressed their views on this matter to date. As a result, we do not propose to reach a final decision on this matter until further views have been considered. We would therefore welcome views from respondents on this matter as part of their responses to this consultation.

[25] 255/04a - National Grid Transco - Potential sale of gas distribution network businesses Final Impact Assessment, Ofgem, November 2004.

Questions:

- ***Question A12.10*** **- Do you agree that our emphasis on user commitment is appropriate?**
- ***Question A12.11*** **- Do you agree with our assessment of the high level options in the Second Consultation?**
- **a. Do you agree that NTS exit capacity product(s) should be specified on a nodal basis?**
- **b. Do you agree that baselines should be specified on a nodal basis?**
- **c. Do you agree that NGG NTS should be subject to a substitution obligation?**
- **Do you agree that the approaches proposed for entry and exit strike an appropriate balance between complexity and cost?**
- ***Question A12.12*** **- Do you agree that NGG NTS should only be remunerated for incremental investment to the extent that there is an associated user commitment?**
- ***Question A12.13*** **- Do you agree with our minded to position with regards to compliance with the 1 in 20 obligation?**
- ***Question A12.14*** **- Do you believe that there should be any other pre-conditions before incremental investment is remunerated eg, consideration of opportunities for long term buyback contracting, delivery of the investment?**
- ***Question A12.15*** **- Do you agree that the level of baselines should be determined in accordance with the practical maximum physical capacity of the network?**
- ***Question A12.16*** **- Do you agree that baselines should be static throughout the price control period?**
- ***Question A12.17*** **- Do you agree that revenue drivers are an appropriate tool for the remuneration of incremental investment?**
- ***Question A12.18*** **- Do you agree that the appropriate form of revenue drivers is:**
- **a. zonal revenue drivers for small capacity increments?**
- **b. project specific revenue drivers for large anticipated projects?**
- **c. licence modifications in the event of unanticipated investments which exceed a specified threshold or projects at new exit points?**
- ***Question A12.19*** **- Do you believe that revenue drivers should be indexed with respect to the price of key inputs such as steel?**
- ***Question A12.20*** **- Do you agree that revenue drivers negate the need for an NTS exit investment incentive?**
- ***Question A12.21*** **- Do you agree that, with respect to buyback:**
- **a. investment related buyback costs should be treated as excluded revenue and subject to an administered buyback price?**
- **b. the costs of buybacks in the event of planned and unplanned outages should be subject to a sliding scale incentive regime?**
- ***Question A12.22*** **- What is your view in relation to:**

- **a. the extent of flexibility that NGG NTS should have over investment lead times?**
- **b. whether there is merit in implementing a cap on the total exposure associated with any individual, investment related, buyback action at exit?**
- **c. whether operational buyback costs should also be subject to an administered price?**
- ***Question A12.23* - Do you agree that implementation of the "Option 2A" approach to payment flows should be postponed such that it coincides with the implementation of the enduring regime?**

Way forward

1.130. We welcome views from respondents on all aspects of this consultation.

1.131. We plan to publish a further consultation document in June 2006, which will further develop our proposals in relation to gas offtake following consideration of respondents' views and present our Initial Proposals. As part of this Initial Proposals consultation, we propose to conduct a draft impact assessment of the emerging framework of arrangements and we plan to discuss the potential cost implications of our proposals with industry participants in the coming weeks.

1.132. The informal consultation conducted through meetings of the Enduring Offtake Working Group (EOWG) has been extremely helpful in developing thinking regarding the way in which a user commitment model could be specified and applied in practice. We therefore propose that the EOWG should continue to meet on a regular basis to discuss, understand and refine potential solutions. We note that the next working group meeting is scheduled for 5 April 2006.

Annex 1: Preliminary baseline numbers

Overview

1.133. This annex provides preliminary baseline data for both GDN and other "transmission connected customer" (TCC) offtake points. The baseline data included in this annex has been provided by NGG NTS and is provided on an indicative basis. The intent of this appendix is to provide respondents with a preliminary view of the allocation of baselines to each NTS offtake point that would result under a practical maximum physical capacity approach to baseline determination. These baseline figures are based on a definition of capacity as currently contained within the UNC and will therefore require reviewing if the details of any of the products should change.

Modelling assumptions

1.134. Consistent with the concept of practical maximum physical capacity, the methodology used to prepare the data in this annex is based on a broad assumption that over the next ten years increasing reliance will be placed on gas sourced from more southerly NTS entry points, in particular Milford Haven, Grain LNG, Bacton and Easington. Sensitivity has been conducted on that assumption which is broadly reflected by the supply scenario analysis that has been fully described in National Grid's Ten Year Statement of 2005.

1.135. For the purposes of this exit capacity analysis, it is assumed that investments required to overcome transmission bottlenecks arising from those supply scenarios will be in place[26]. This analysis does not take into account any further range of possibilities (with respect to supply and demand distribution and the resulting size of the NTS network) that might be imposed on the NTS beyond the period described in the ten-year statement.

1.136. Therefore, NG NTS must be able to simultaneously meet the combined baselines at each offtake point without the need for exit investment (beyond that already planned) or significant buyback. Baselines have been allocated to offtake points that currently have interruptible access to the network where there is sufficient network capacity available after the allocation of baselines to firm connectees. As a consequence, baselines for currently interruptible offtake points may be relatively low or zero on parts of the network that are relatively constrained.

1.137. In particular, the practical maximum physical capability methodology has identified that the South West Quadrant (SWQ) is a constrained area. This means that the allocation of firm capacity is not as high as in other largely unconstrained areas. The allocation to interruptible direct connect loads has been set to zero within the constrained area to enable maximisation of the allocation of capability to firm customers. Outside the SWQ, as the NTS is less constrained, all interruptible load has been accommodated.

[26] Therefore the finalisation of baselines at offtake is dependent upon the policy adopted at entry.

1.138. It is also important to note that, in calculating these indicative baselines, the set of NTS offtake points for which capacity baselines have been allocated corresponds to the NTS connected offtakes NGG NTS anticipates will be operational on 1 April 2007. As a consequence, no baseline allocations have been made to offtake points that are forecast to become operational after this date. This is consistent with our initial view on the application of revenues, which is that revenue relating to new capacity should accrue from the date that capacity is due to be delivered.

Data table

1.139. The table presented below contains:

- GDN baseline data for flat capacity
- TCC data for NTS exit capacity, and
- 1 in 20 data

GDN baseline data for flat capacity

1.140. This data represents the "flat" capacity capability of the network for the duration of the transitional period (ie, for the period from 1 April 2007 to 30 September 2010). We consider that these baselines should be similar to those prepared for the enduring period (given that these will be prepared according to the same methodology). Note that separate "flexibility" baselines for GDNs are not specified for this period, however will be prepared for the enduring period (following the completion of ongoing analysis by NGG NTS).

TCC data for NTS exit capacity

1.141. The data presented for TCCs represents baselines for the same period (1 April 2007 to 30 September 2010) for NTS exit capacity (i.e. the combined NTS offtake capacity product provided to TCCs, as currently defined in the UNC). For the enduring period, baselines will have the same level, but will need to be revised to reflect the new definition of the flexibility product proposed by NGG NTS following completion of the analysis that it is currently being undertaken in this regard. Depending upon the outcome of this analysis and the resulting NGG NTS proposals, this could result in either a single set of baseline numbers or separate baselines for "flat" and "flexible" capacity. We propose to publish such data in the Initial Proposals consultation which is scheduled for publication in June 2006

1 in 20 data

1.142. The table below also provides "1 in 20" baseline data to provide some context for the practical maximum physical capacity numbers presented. These figures are the 1 in 20 demand forecasts for 2007/08 gas year, consistent with demand forecasts for that year as published within the Ten Year Statement. The demand forecasts for the GDNs are allocated to their offtakes consistent with their allocations of flat capacity under the UNC (i.e. Offtake Capacity Statements).
1.143.

Table A12.1.1: Preliminary baseline data

Offtake point	Type of offtake	1 in 20 demand (07/08)	Transitional baseline (GWh/day)
Bacton	GDN (EE)	3.29	5.25
Brisley	GDN (EE)	2.81	4.37
Great Wilbraham	GDN (EE)	32.10	51.05
Matching Green	GDN (EE)	81.38	39.27
Peterborough Eye/Tee	GDN (EE)	24.95	37.98
Roudham Heath	GDN (EE)	11.53	17.89
Royston	GDN (EE)	2.17	3.49
Whitwell	GDN (EE)	141.20	175.58
West Winch	GDN (EE)	8.47	16.47
Yelverton	GDN (EE)	71.92	75.52
Alrewas	GDN (EE)	90.60	37.04
Blaby	GDN (EE)	14.47	17.35
Blyborough	GDN (EE)	79.84	86.68
Caldecott	GDN (EE)	11.06	11.87
Thornton Curtis	GDN (EE)	106.14	105.30
Drointon	GDN (EE)	104.88	150.25
Gosberton	GDN (EE)	15.60	18.53
Kirkstead	GDN (EE)	1.11	1.33
Market Harborough	GDN (EE)	8.67	10.38
Silk Willoughby	GDN (EE)	3.23	3.86
Sutton Bridge	GDN (EE)	1.05	1.26
Tur Langton	GDN (EE)	50.37	88.62
Walesby	GDN (EE)	0.85	1.02
Asselby	GDN (NO)	3.04	3.38
Baldersby	GDN (NO)	1.22	1.34
Burley Bank	GDN (NO)	18.48	20.33
Ganstead	GDN (NO)	21.29	23.46
Pannal	GDN (NO)	135.74	145.18
Paull	GDN (NO)	34.88	37.51
Pickering	GDN (NO)	8.40	9.11
Rawcliffe	GDN (NO)	3.11	3.45
Towton	GDN (NO)	73.22	84.96
Bishop Auckland	GDN (NO)	64.15	69.59
Coldstream	GDN (NO)	1.79	1.95
Corbridge	GDN (NO)	0.07	0.07
Cowpen Bewley	GDN (NO)	50.07	52.92
Elton	GDN (NO)	38.97	42.04
Guyzance	GDN (NO)	1.85	2.01
Humbleton	GDN (NO)	0.14	0.15
Keld	GDN (NO)	1.59	1.63
Little Burdon	GDN (NO)	7.83	8.50
Melkinthorpe	GDN (NO)	0.32	0.33
Saltwick Pressure Controlled	GDN (NO)	8.57	9.21

Offtake point	Type of offtake	1 in 20 demand (07/08)	Transitional baseline (GWh/day)
Saltwick Volumetric Controlled	GDN (NO)	57.80	69.59
Thrintoft	GDN (NO)	5.38	5.84
Towlaw	GDN (NO)	0.52	0.56
Wetheral	GDN (NO)	24.88	27.04
Horndon	GDN (Lon)	38.41	47.80
Luxborough Lane	GDN (Lon)	148.20	171.42
Peters Green	GDN (Lon)	155.02	156.27
Peters Green South Mimms	GDN (Lon)	164.67	186.84
Winkfield	GDN (Lon)	21.05	20.21
Audley	GDN (NW)	7.55	8.21
Blackrod	GDN (NW)	97.67	102.22
Ecclestone	GDN (NW)	19.27	20.95
Holmes Chapel	GDN (NW)	19.17	20.84
Lupton	GDN (NW)	14.94	16.23
Malpas	GDN (NW)	0.45	0.49
Mickle Trafford	GDN (NW)	27.42	29.79
Partington	GDN (NW)	89.56	96.40
Samlesbury	GDN (NW)	116.24	127.41
Warburton	GDN (NW)	139.10	155.17
Weston Point	GDN (NW)	28.32	30.61
Aberdeen	GDN (Sc)	21.35	23.15
Armadale	GDN (Sc)	2.23	2.87
Balgray	GDN (Sc)	11.55	12.60
Bathgate	GDN (Sc)	22.51	23.36
Broxburn	GDN (Sc)	59.78	63.96
Careston	GDN (Sc)	3.09	3.31
Drum	GDN (Sc)	74.26	73.05
St Fergus	GDN (Sc)	0.89	0.92
Glenmavis	GDN (Sc)	139.32	158.94
Hume	GDN (Sc)	0.79	1.08
Kinknockie	GDN (Sc)	2.38	2.45
Langholm	GDN (Sc)	0.14	0.15
Lockerbie	GDN (Sc)	5.44	5.92
Netherhowcleugh	GDN (Sc)	0.18	0.19
Pitcairngreen	GDN (Sc)	1.62	1.73
Soutra	GDN (Sc)	8.21	8.37
Stranraer	GDN (Sc)	0.49	0.65
Farningham	GDN (So)	124.15	156.54
Shorne	GDN (So)	61.84	80.68
Tatsfield	GDN (So)	254.37	230.79
Winkfield (SE LDZ)	GDN (So)	99.22	108.55
Braishfield A	GDN (So)	94.95	85.98
Braishfield B	GDN (So)	43.18	45.54
Hardwick	GDN (So)	112.45	131.36
Ipsden 2	GDN (So)	13.50	11.71

Offtake point	Type of offtake	1 in 20 demand (07/08)	Transitional baseline (GWh/day)
Ipsden	GDN (So)	11.81	14.18
Mappowder	GDN (So)	45.73	45.21
Winkfield (SO LDZ)	GDN (So)	76.76	76.73
Aylesbeare	GDN (WW)	22.78	21.74
Cirencester	GDN (WW)	9.16	8.78
Easton Grey	GDN (WW)	31.26	29.52
Evesham	GDN (WW)	6.59	7.41
Fiddington	GDN (WW)	26.79	30.14
Ilchester	GDN (WW)	32.55	31.60
Kenn	GDN (WW)	70.97	67.77
Littleton Drew	GDN (WW)	2.85	2.72
Pucklechurch	GDN (WW)	27.54	27.12
Ross	GDN (WW)	4.28	4.82
Seabank (GDN)	GDN (WW)	58.68	55.07
Alrewas	GDN (WM)	121.87	161.61
Aspley	GDN (WM)	72.08	45.55
Audley	GDN (WM)	19.94	21.94
Austrey	GDN (WM)	78.70	78.78
Leamington	GDN (WM)	3.91	4.29
Lower Quinton	GDN (WM)	27.75	35.00
Milwich	GDN (WM)	22.22	24.44
Ross	GDN (WM)	15.10	16.55
Rugby	GDN (WM)	72.84	91.65
Shustoke	GDN (WM)	40.92	44.40
Stratford-upon-Avon	GDN (WM)	4.28	4.69
Maelor	GDN (WW)	51.88	57.58
Dowlais	GDN (WW)	91.73	98.46
Dyffryn Clydach	GDN (WW)	41.48	44.56
Gilwern	GDN (WW)	60.57	64.75
Abson (Seabank Power Station phase I)	TCC (Firm)	27.84	27.80
Ferny Knoll (AM Paper)	TCC (Firm)	1.08	1.10
Bacton (Great Yarmouth)	TCC (Firm)	20.04	20.00
Billingham ICI (Terra Billingham)	TCC (Firm)	43.55	43.60
Blackness (BP Grangemouth)	TCC (Firm)	13.87	27.30
Caldecott (Corby Power Station)	TCC (Firm)	21.12	21.10
Deeside	TCC (Firm)	0.00	28.50
Didcot B	TCC (Firm)	50.48	50.50
Eastoft (Keadby)	TCC (Firm)	36.07	36.10
Epping Green (Enfield Energy, aka Brimsdown)	TCC (Firm)	18.42	18.40
Goole (Guardian Glass)	TCC (Firm)	1.62	1.60
Gowkhall (Longannet)	TCC (Firm)	43.33	43.30

Offtake point	Type of offtake	1 in 20 demand (07/08)	Transitional baseline (GWh/day)
Moffat (Irish Interconnector)	IC	223.60	433.40
Shellstar (aka Kemira, not Kemira CHP)	TCC (Firm)	11.59	14.00
Middle Stoke (Damhead Creek, aka Kingsnorth Power Station)	TCC (Firm)	40.95	41.00
Rosehill (Saltend Power Station)	TCC (Firm)	57.85	57.80
Ryehouse	TCC (Firm)	38.67	38.70
Saddle Bow (Kings Lynn)	TCC (Firm)	17.98	18.00
Saltend BPHP (BP Saltend HP)	TCC (Firm)	9.10	9.10
Sandy Lane (Blackburn CHP, aka Sappi Paper Mill)	TCC (Firm)	4.55	4.60
Seabank (Seabank Power Station phase II)	TCC (Firm)	19.07	19.10
Harwarden (Shotton, aka Shotton Paper)	TCC (Firm)	11.59	11.60
Shotwick (Bridgewater Paper)	TCC (Firm)	5.52	5.50
Wragg Marsh (Spalding)	TCC (Firm)	42.03	42.00
St. Fergus (Peterhead)	TCC (Firm)	108.33	108.30
St. Neots (Little Barford)	TCC (Firm)	35.21	35.20
Stallingborough	TCC (Firm)	28.17	28.20
Stallingborough	TCC (Firm)	38.35	38.40
Stanford Le Hope (Coryton)	TCC (Firm)	36.62	36.60
Staythorpe PH1	TCC (Firm)	38.24	38.20
Staythorpe PH2	TCC (Firm)	38.24	38.20
Sutton Bridge	TCC (Firm)	37.48	37.50
Teesside (BASF, aka BASF Teesside)	TCC (Firm)	9.75	9.70
Teesside Hydrogen	TCC (Firm)	6.61	6.60
Terra Nitrogen (aka ICI/Terra Severnside)	TCC (Firm)	0.65	0.70
Thornton Curtis (Humber Refinery, aka Immingham)	TCC (Firm)	46.91	46.90
Thornton Curtis (Killingholme A)	TCC (Firm)	36.29	36.30
Tonna (Baglan Bay)	TCC (Firm)	26.76	26.80
Weston Point (Castner Kelner, aka ICI Runcorn)	TCC (Firm)	4.55	3.60
Weston Point (Rocksavage)	TCC (Firm)	36.18	36.20
Pickmere (Winnington Power, aka Brunner Mond)	TCC (Firm)	15.38	15.40
Zeneca (ICI Avecia)	TCC (Firm)	0.11	0.10
Blyborough (Brigg)	TCC (Int)	0.00	16.90
Burton Point (Connahs Quay)	TCC (Int)	0.00	73.20

Offtake point	Type of offtake	1 in 20 demand (07/08)	Transitional baseline (GWh/day)
Blyborough (Cottam)	TCC (Int)	0.00	17.60
Didcot A	TCC (Int)	0.00	0.00
Enron Billingham	TCC (Int)	0.00	121.50
Hollingsgreen (Hays Chemicals)	TCC (Int)	0.00	3.30
Barking (Horndon)	TCC (Int)	0.00	58.60
Eastoft (Keadby Blackstart)	TCC (Int)	0.00	2.40
Thornton Curtis (Killingholm B)	TCC (Int)	0.00	45.00
Medway (aka Isle of Grain Power Station, NOT Grain Power)	TCC (Int)	0.00	38.10
Peterborough (Peterborough Power Station)	TCC (Int)	0.00	23.30
Roosecote (Roosecote Power Station)	TCC (Int)	0.00	14.70
Shellstar (aka Kemira, not Kemira CHP)	TCC (Int)	0.00	2.30
Sellafield Power Station	TCC (Int)	0.00	12.30
Hatfield Moor Max Refill	Storage	0.00	30.00
Hole House Max Refill	Storage	0.00	120.00
Partington Max Refill	Storage	0.00	2.40
Glenmavis Max Refill	Storage	0.00	1.60
Barton Stacey Max Refill	Storage	0.00	0.00
Avonmouth Max Refill	Storage	0.00	0.00
Dynevor Max Refill	Storage	0.00	2.60
Garton Max Refill	Storage	0.00	211.00
Hornsea Max Refill	Storage	0.00	22.00
Rough Max Refill	Storage	0.00	160.00
Bacton (IUK)	IC	0.00	623.58
Bacton (BBL)	IC	0.00	0.00

Key	
GDN (EE)	East of England GDN
GDN (NO)	North of England GDN
GDN (Lon)	London GDN
GDN (NW)	North West of England GDN
GDN (Sc)	Scotland GDN
GDN (So)	South of England GDN
GDN (WW)	Wales and the West GDN
TCC (Firm)	Directly connected NTS customer currently with firm access
TCC (Int)	Directly connected NTS customer currently with interruptible access
Storage	Storage site directly connected to the NTS
IC	Interconnector

Annex 2: Preliminary impact assessment

1.144. The Second Consultation outlined two broad options for enduring offtake arrangements, these being a set of arrangements based upon a "status quo" approach (taken to be the transitional offtake arrangements), or arrangements based on a "long term user commitment" approach.

1.145. The document recognised that a number of different options for long term user commitment models could be adopted for offtake arrangements, including both the manner in which baselines could be set, and the nature of the product that could be offered to users.

1.146. Four high-level options for long term user commitment models were defined in the document, these being:

- Option Ex2: a model consistent with the February 2005 Initial Thoughts document, ie a model with nodal baseline, nodal product, and with a financial incentive on NGG NTS to substitute baseline capacity between nodes where appropriate.
- Option Ex3: a model with a nodal product and zonal baselines.
- Option Ex3A: a model with nodal product and global/network baselines, and
- Option Ex4: a model with a zonal product and zonal baselines.

1.147. These models are summarised in the table below, relative to the status quo.

Table A12.2.1: Overview of long term user commitment models

	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	×	✓	×	×	×

1.148. The Second Consultation outlined our initial view of the advantages and disadvantages of each of these models, as well as including a list of potential assessment criteria that could be adopted in assessing the options. We also committed to undertaking further analysis of the options for enduring offtake arrangements, in order to inform the proposals set out in this document.

1.149. The remainder of this annex presents our preliminary impact assessment of these models. We outline in turn our:

- progress on undertaking a quantitative assessment of each model;
- a qualitative assessment of each model; and
- initial conclusions regarding the most appropriate model of offtake arrangements to develop further.

Quantitative assessment

1.150. In January 2006, we published a pro forma questionnaire to industry, in order to gather views from customers, shippers and GTs on the potential cost implications of each of the high level options for enduring offtake arrangements outlined in the Second Consultation.

Overview of responses

1.151. We received nine cost submissions in response to the questionnaire, comprising:

- responses from the NTS, each of the GDNs and xoserve
- two responses from shippers, and
- one response from a Transmission Connected Customer.

1.152. We also received three responses stating that it was not appropriate to submit cost estimates at this stage, as they considered the options presented were not yet specified in a sufficient level of detail to make a meaningful assessment of the manner in which the proposals would affect their businesses. In addition, one of these respondents stated that further proposals regarding enduring offtake arrangements are currently being considered by the Enduring Offtake Working Group, and hence believed it would be imprudent to undertake an impact assessment at this stage.

1.153. In addition, eight of the nine respondents stated that it was difficult at this stage to make meaningful cost estimates at this stage, given the proposals were defined at a high level. Another respondent stated that cost estimates provided in response to the survey were subject to "very significant uncertainty" that could only be reduced once the precise form of offtake arrangements was understood in more detail.

Ofgem analysis

1.154. After reviewing all of the responses to the cost survey (and speaking directly to the majority of respondents), it is our view that we have not received cost estimates from a sufficiently large sample of industry participants to enable us to draw conclusions regarding the cost impact of each of the models for industry as a whole. In addition, those cost submissions we have received contain significant warnings that estimates are subject to a large degree of uncertainty. As a consequence, we do not consider the cost data we have received to be sufficiently robust to enable us to undertake a quantified impact assessment of the options for enduring offtake at this stage.

1.155. Despite the difficulties respondents have experienced in assigning firm costs to each of the proposed models, we have been able to make a number of qualitative observations from our analysis of the cost survey submissions.

1.156. Firstly, the majority of respondents (six out of nine) did not believe that there were significant reasons for there to be any differences in cost between any of the user commitment models, given the current stage of development of such models. Of the remaining three respondents (all of which were GDNs), views were divided over which model would be the least costly.

1.157. One of these respondents considered Option Ex4 to have the highest implementation and ongoing costs, on the basis that a zonal product model would require more sophisticated modelling tools than the other models presented. In contrast, another respondent considered that Option Ex4 would have the lowest implementation and ongoing costs, as this model would provide more opportunities for flexible operation of the distribution network. Finally, one respondent considered Option Ex2 would have the lowest ongoing costs, as this would avoid the additional complexity that definition of zonal arrangements would bring.

1.158. All of the respondents to the cost survey considered that long term user commitment models would be likely to require significant IT implementation and ongoing costs, in comparison to the status quo. In particular, the majority of respondents considered that significant IT expenditure would be required relating to the development and/or enhancement of existing decision making tools, necessary to optimise decision making in the context of the enduring offtake arrangements.

Initial view

1.159. Given significant uncertainties concerning the cost implications of the long term user commitment models, we agree with most respondents to the survey that it is not appropriate to differentiate between the models on the basis of a quantified cost assessment at this time.

1.160. However, we consider that the January cost survey was a useful exercise in that it enabled us to understand the potential categories of expenditure that respondents considered may be necessary in the event that a long term user commitment model for offtake arrangements is adopted. Our initial view, however, is that IT tools to support decision making by GDNs are already required under the transitional offtake arrangements, as these arrangements already place commercial incentives on GDNs to trade-off requests for NTS offtake rights with GDN investments. As a consequence, we do not anticipate that major expenditure in this area by the GDNs would be a direct consequence of a long term user commitment model for offtake arrangements (aside from relatively minor enhancements to existing systems).

1.161. In addition, we also consider that no pass through of costs incurred by the GTs (and Agency) regarding compliance with GT licence obligations to implement enduring offtake arrangements will be permitted (given that implementation of

enduring offtake arrangements was an obligation placed on the NTS and GDNs at the time of GDN sales).

Qualitative assessment

1.162. In the Second Consultation, we outlined an initial view of the benefits that may result from the adoption of a user commitment model, and the advantages / disadvantages of each of the different forms of user commitment models.

1.163. Since publication of the Second Consultation, numerous aspects of the enduring offtake arrangements have been discussed at the Enduring Offtake Working Groups, as well as in a number of other open meetings and industry workstreams[27]. As a consequence, our understanding of the implications of each of the proposed models has increased. We have also undertaken additional analysis of the potential benefits that we consider may accrue from the adoption of long term user commitment model for offtake arrangements, as well as of the relative benefits of each of the different models outlined in the Second Consultation document.

1.164. As stated above, we agree with the majority of respondents to the cost survey that it is not appropriate to undertake a quantitative assessment of long term user commitment models at this time. However, we do believe that it is possible to undertake a qualitative assessment of the benefits of the different models, relative to the status quo of the transitional offtake arrangements. This assessment is presented in Table 2 which follows.

[27] Including Industry Seminar on 24 February, and UNC Offtake Arrangements workstream on 15 February

Table A12.2.2: Initial benefits assessment of long term user commitment models

	Long term user commitment models			
	Option Ex2	Option Ex3	Option Ex3A	Option Ex4
Efficient network development and system operation	✓✓	✓	✓✓	××
Preventing undue discrimination	✓✓	✓✓	✓✓	✓✓
Promotion of competition	✓	✓	✓	✓✓
Appropriate allocation of risk	✓✓	✓✓	✓✓	✓✓
Simplicity / transparency	×	××	××	××
Preservation of security of supply	✓✓	✓✓	✓✓	××
Minimise implementation and ongoing costs	××	×	×	××
Clear and appropriate accountability and responsibility	×	×	××	××
Compliance with applicable legal requirements	✓✓	✓✓	✓✓	✓✓

Key:
✓✓ yes
✓ yes, but to a lesser extent than other options presented
\- little or no impact
×× no
× no, but to a lesser extent than other options presented

1.165. The categories of benefits assessed in relation to the user commitment models are outlined in turn below.

Efficient network development and system operation.

1.166. Compared to the status quo, all of the options presented will encourage long term commitment by users in order to guarantee access to the network. We consider that a consequence of this would be to improve the efficiency of investment signals provided to the NTS, therefore reducing the risk of inefficient investment being undertaken. Of those models presented, we consider Options Ex2 and Ex3A will lead to the largest benefits in terms of promoting efficient network development. This is because these options maximise the opportunity for NGG NTS to substitute baselines from areas of relatively low demand to areas of relatively high demand in the unconstrained period. Specifically, Option Ex3A defines baselines on a global

basis, and model Ex2 includes a facility whereby the NTS is able to reallocate baselines between nodes (subject to regulatory approval).

1.167. We also consider that those models that define product rights by node (i.e. models Ex2, Ex3 and Ex3A) are most likely to lead to more efficient network development and system operation. This is because defining offtake rights on a nodal basis gives the NTS more certainty regarding the volume of offtake that will arise at individual offtake points. In contrast, we consider that the zonal product model (Option Ex4) may require the NTS to make assumptions regarding the level of offtake at individual nodes, potentially leading to over-investment in the network (or a risk of significant buy-back costs).

Preventing undue discrimination

1.168. We consider that all of the options presented will have the benefit of reducing the potential for undue discrimination between NTS users, by ensuring that all users (both new and existing) are subject to equivalent access arrangements. This is in contrast to the status quo arrangements, in which only the GDNs are able to secure separate rights to flat and flexible offtake capacity.

Promotion of competition

1.169. All of the long term user commitment models will promote competition between NTS users, in that all participants will be able to secure access to the same defined products in the long and short term, and to a varying extent, will be able to trade these (allowing users to optimise capacity booking decisions more effectively). We consider that Option Ex4 will be most effective at promoting competition as, under this model, holders of capacity rights will be able to trade these freely within defined zones, leading to more liquid secondary markets for offtake capacity and promoting the more efficient allocation of rights among NTS users.

Appropriate allocation of risk

1.170. A key benefit of moving to any of the models that require long term commitment by NTS users to secure guaranteed access to the network is that there is an improved allocation of risk between industry participants and customers. In all of the models, those connectees that wish to secure long term rights to offtake from the NTS will be able to do so - but in exchange for these rights, they will be required to make a financially firm commitment.

1.171. We consider that this is an improvement over the status quo, in which shippers do not have to signal their intention to continue use of the network beyond a 12 month period. We therefore believe that all of the user commitment models will have clear benefits to customers - as well as to the NTS - in terms of the more equal allocation of risk between stakeholders. Specifically, this is because we consider that NTS users and shippers are best placed to assess their future needs for NTS offtake capacity services (as opposed to network planners), and are therefore best placed to manage and mitigate the associated risk.

Simplicity and transparency

1.172. We believe an important consideration in the selection an appropriate model for enduring offtake is that the arrangements and package of associated incentives are as simple and transparent as is possible. We continue to consider that a disadvantage of all of the user commitment models is that, at least initially, all of the models represent a more complex set of arrangements and incentives than the status quo.

1.173. Specifically, in Option Ex2, although a nodal set of arrangements may be more simple and transparent to implement and operate, it has been assumed that a substitution incentive will be placed on the NTS, which may significantly add to complexity. Options Ex3/3A and Ex4 require the development of zonal baselines, which we believe may lead to greater complexity in both the specification of revenue drivers for the NTS, and also in the initial allocation process. We also consider that Option Ex4 may lack transparency as under this model the NTS may be required to undertake the buy-back of offtake rights to ensure that holdings of (zonal) offtake rights at all nodes are consistent with network capability.

Preservation of security of supply

1.174. We consider it essential that the selected option enables the NTS to continue to make investment and operational decisions that are consistent with security of supply requirements. Options Ex2, Ex3 and Ex3A all define offtake capacity products on a nodal basis, therefore enabling the NTS to receive long term nodal signals for offtake rights. As these models also encourage long term user commitment, we consider that all of these models will promote security of supply on the NTS, by encouraging longer term booking by all NTS users.

1.175. In contrast, it is not clear that Option Ex4 will have a positive impact on security of supply, given that offtake rights are defined zonally under this option. As a consequence, the NTS will have less precise information regarding the level of offtake of gas from specific nodes within each defined zone, which may have negative implications for security of supply.

Minimise implementation and ongoing costs

1.176. An important consideration in determining which model of user commitment to adopt in the long term is the minimisation of the cost of the proposals. As discussed in the previous section, we do not consider it possible to undertake a quantitative assessment of costs at this time, given that all of the user commitment models these are still specified at a relatively high level (with 6/9 respondents stating this explicitly). However, it is apparent from those respondents who did submit data in response to the cost survey that all of the models are likely to lead to costs being incurred by NTS connectees, compared to the status quo.

1.177. In addition, we consider that a significant source of ongoing cost under Option Ex2 relates to the requirement for a substitution incentive to be placed on the NTS, providing a financial reward for moving baseline capacity from relatively low demand

nodes to nodes where signals have been received for additional (above baseline) levels of offtake capacity in the unconstrained period. Furthermore, and as discussed above, Option Ex4 could imply potentially significant buyback costs.

Clear and appropriate accountability and responsibility

1.178. A disadvantage of the status quo arrangements identified in the Second Consultation is that the requirement for connecting parties to enter into ARCA agreements has the potential to reduce transparency of the arrangements, and give NGG NTS a degree of discretion that may be viewed as being excessive. A perceived disadvantage of this is that significant involvement may be required by Ofgem in the settlement of disputes over the setting of ARCA terms.

1.179. In contrast, we anticipate that the capacity allocation mechanism implemented under a user commitment model would introduce increased certainty over the degree of user commitment that would be required to trigger incremental capacity, therefore reducing the risk that any disputes may arise between NGG NTS and parties requesting incremental offtake capacity that would require regulatory intervention.

1.180. In terms of specific models, we consider that Option Ex2 would have the advantage of reducing the degree of NGG NTS discretion through the specification in advance of nodal baselines, serving to clarify the initial level of offtake capacity that is available at each node. However, this model also places an incentive on NGG NTS to undertake substitutions of capacity between nodes in the unconstrained period (in order to reduce the risk of unnecessary investment). We consider that this has the potential to reduce the transparency of the nodal model, as the operation of the incentive would to a large extent rely upon the view of NGG NTS regarding the extent to which substitution of baselines between nodes is possible. This may lead to disagreements between NTS users and NGG NTS regarding the extent to which long term substitutions are possible and the potential for disputes to be raised with Ofgem.

1.181. We consider that the other user commitment models that define baselines on either a zonal or network-wide basis would give discretion to the NTS in the way that baseline capability is allocated across the network in the long term. As a consequence, we consider there is also a significant potential for dispute under options Ex3/3A and 4 that may lead to a degree of ongoing regulatory intervention.

Compliance with applicable legal requirements

1.182. It is important that the enduring offtake arrangements are defined in such a way as to be fully compliant with applicable legal requirements, including the Gas Act and relevant European Law. We consider that all of the long term user commitment models have the benefit of meeting the requirements of all relevant UK and EC legislation.

Conclusion

1.183. We consider that a model of offtake arrangements based on a variation of Option Ex2 is most appropriate for further development, and that this should be the subject of a forthcoming quantified impact assessment.

1.184. Following consideration of responses to the cost survey and respondents' views to the Second consultation, we consider that NTS offtake capacity rights should continue to be defined on a nodal basis. As outlined above, we consider that a nodal product is likely to be most consistent with efficient network development and system operation, and also be most consistent with the preservation of security of supply.

1.185. In terms of baselines, we consider that setting these on a zonal or global basis could result in a lack of transparency in the selected capacity allocation mechanism, potentially giving NGG NTS an excessive level of discretion, and raising the possibility of a need for ongoing regulatory intervention. We also consider that models that specify baselines in this way are likely to significantly increase the complexity of the mechanisms through which offtake capacity is allocated to NTS users by NGG NTS. We therefore consider that setting baselines on a nodal basis is appropriate for the enduring offtake arrangements.

1.186. We continue to consider that, under a model of nodal baselines, a mechanism will be necessary to allow capacity to be substituted between nodes. We believe a mechanism such as this will give the arrangements sufficient flexibility such that NGG NTS will only be remunerated for incremental capacity to the extent that all opportunities for substitution across a group of offtake points have been exhausted.

1.187. However, consistent with respondents' views to the Second consultation, we no longer consider that providing a financial incentive on NGG NTS to undertake capacity substitutions is appropriate, given the financial cost to customers of the associated incentive payments. In addition, and as outlined above, we consider that a substitution incentive could lead to a lack of transparency, increased NGG NTS discretion and may therefore lead to a number of disputes being referred to Ofgem for resolution.

1.188. Instead we consider that, rather than having a substitution incentive, it may be more appropriate to place a substitution obligation on NGG NTS. Under such an approach, baselines would be specified for each node by Ofgem (informed by NGG NTS analysis), and NGG NTS would have an obligation to substitute capacity between nodes to meet demand at other nodes. NGG NTS would only be remunerated for incremental capacity to the extent that all opportunities for substitution of nodal baselines had been exhausted. In the event that demand for incremental capacity at another node could be alleviated by baseline substitution, NGG NTS would then be required to apply to Ofgem to adjust the baselines of the affected nodes in accordance with calculated exchange rates (with the modified baselines applying thereafter in terms of both the application of revenue drivers and capacity release obligations).

1.189. It is our initial view that, in order to allow substitution across nodes, baselines could be modified without the need for formal licence modifications by referencing a separate, Ofgem approved, document. Furthermore, we note that exchange rates would only need to be specified in the event that a constraint occurs rather than for all nodes.

1.190. Our favoured model for offtake arrangements, although most resembling Option Ex2 as presented in the Second Consultation only differs in that it has a substitution obligation rather than a substitution incentive. An assessment of this model (named Option Ex2A) is presented in the table below.

Table A12.2.3: Qualitative assessment of Option Ex2a

	Long term user commitment models				
	Option Ex2A	**Option Ex2**	**Option Ex3**	**Option Ex3A**	**Option Ex4**
Efficient network development and system operation	✓✓	✓✓	✓	✓✓	✗✗
Preventing undue discrimination	✓✓	✓✓	✓✓	✓✓	✓✓
Promotion of competition	✓	✓	✓	✓	✓✓
Appropriate allocation of risk	✓✓	✓✓	✓✓	✓✓	✓✓
Simplicity / transparency	✗	✗	✗✗	✗✗	✗✗
Preservation of security of supply	✓✓	✓✓	✓✓	✓✓	✗✗
Minimise implementation and ongoing costs	✗	✗✗	✗	✗	✗✗
Clear and appropriate accountability and responsibility	✓	✗	✗	✗✗	✗✗
Compliance with applicable legal requirements	✓✓	✓✓	✓✓	✓✓	✓✓

Key:
- ✓✓ yes
- ✓ yes, but to a lesser extent than other options presented
- \- little or no impact
- ✗✗ no
- ✗ no, but to a lesser extent than other options presented

1.191. For the majority of the assessment criteria outlined above, Option Ex2A has the same advantages and disadvantages (relative to the status quo) as Option Ex2. The key differences - as discussed above - relate to additional advantages relating to both increased clarity of responsibilities for all parties, and reduced ongoing cost.

Appendix 13 – Summary historic and forecast data (NGET)

Introduction

1.1. This appendix sets out the historic and forecast data for NGET provided to us by NG through the HBPQ and FBPQ and other sources. The data is presented in its raw form without any checks or adjustments by us. All prices are 2004/05.

1.2. We have also requested the licensees to provide a narrative to support the raw forecast 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.

National Grid Electricity Transmission TO Commentary

1.3. This summary provides an overview of the forward business plan of NGET for the period 2007/8 to 2011/12.

Capital Expenditure

1.4. Our capital expenditure is driven by both the external drivers of changes in the generation and demand markets, known as load-related expenditure, and by the need to replace assets whose condition has deteriorated, known as non load-related expenditure.

Load Related Expenditure

1.5. In response to customer connection applications and the changing background of generation and demand described above, we expect to be required to invest almost £1.4bn over the next price review period. This includes:

- Around £270m of entry related infrastructure with new gas-fired and wind generation forecast in the South West, the Thames Estuary, Humberside and the North West.
- Just under £410m on demand related expenditure reflecting an anticipated continued high level of expenditure by DNOs to ensure compliance with security standards, and ongoing works to provide supplies to the national rail network.
- Approximately £740m of General infrastructure expenditure that is expected to be required to maintain compliance with the SQSS in light of the forecast changes in generation and demand. This expenditure includes reactive compensation and investment in the north of England to accommodate increasing flows from Scotland driven by new wind generation, and a number of projects to reconstruct and enhance existing substations.

Non-Load Related Expenditure

1.6. On a transmission system such as ours it is essential to aim to replace assets before they fail in service. In order to ensure that NGET understands which assets to replace and the optimum timing for such replacement, we have developed a mature

and robust asset management process. NGET also possesses a wealth of condition history and understanding of the mechanisms, which cause assets to deteriorate and fail. Based on this knowledge, NGET forecasts that non-load related expenditure will need to be approximately £2.5bn over the next price control period.

1.7. In the forthcoming period, the main areas of replacement expenditure will be on replacement of overhead lines, underground cables and switchgear. In each case, the individual replacement schemes are driven by detailed knowledge of the condition of the assets being replaced.

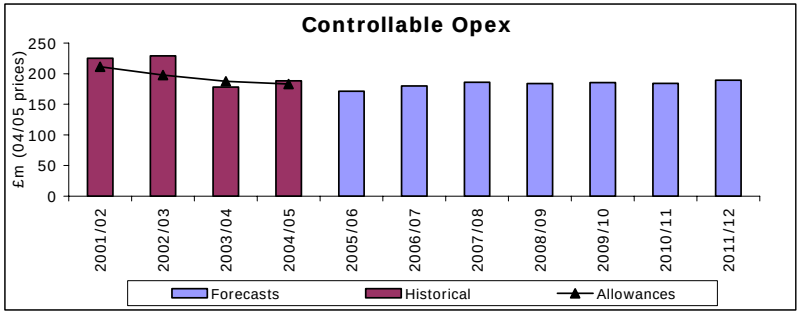
1.8. This replacement work is essential to maintain the short and long term reliability, safety and environmental performance of the transmission system. A measured ramp up of asset replacement rates has already commenced and will need to continue in order to maintain existing standards of supply reliability over the medium term because system access constraints limit the amount of asset replacement work that can be undertaken at any one time.

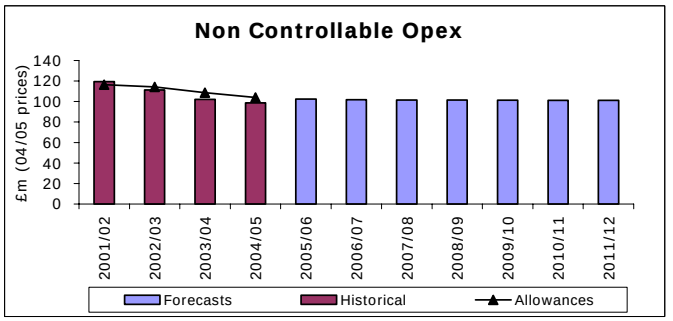
Operating Expenditure

1.9. Our operating expenditure plan reflects the full impact of savings achieved from the merger of National Grid's Gas and Electricity activities. Significant further efficiencies that are either already identified or are anticipated to be delivered in the future have also been incorporated and these savings largely offset the increasing opex drivers of maintaining more assets that are at the end or beginning of their asset lives and the external input cost drivers such as pension and insurance costs.

NATIONAL GRID ELECTRICITY TRANSMISSION OWNER

Operating costs [1]	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported Historical											
Controllable Opex	225.3	229.0	178.4	188.5							
Non Controllable	119.5	111.4	102.2	98.6							
Forecasts											
Controllable Opex					171.2	180.0	185.9	183.8	185.5	184.1	189.5
Non Controllable					102.3	101.8	101.6	101.4	101.2	101.0	101.1
Price Control Allowances											
Controllable Opex	211.5	197.9	187.8	183.2							
Non Controllable	116.5	114.2	108.6	104.1							



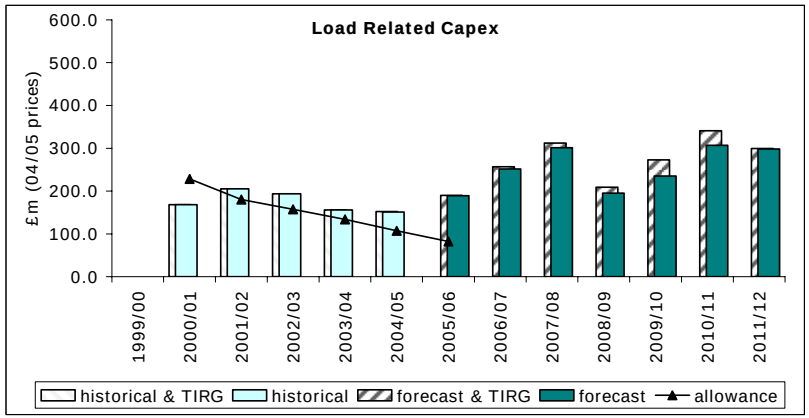


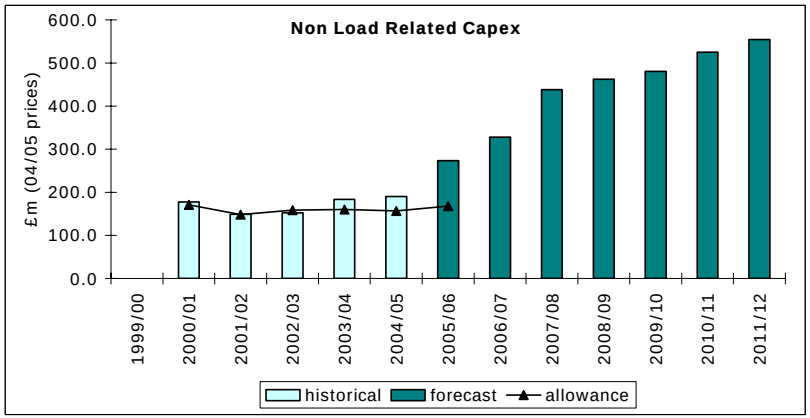
System Statistics	Actual 2001/02	2002/03	2003/04	2004/05	Forecast 2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Resources											
Year end RAV (£m)	5084	5101	5096	5145	5159	5609	5960	6210	6500	6881	7247
Total transmission circuit length (km)	14507	14507	14704	14644	14664	14664	14665	14648	14633	14643	14644
Total substation numbers (#)	436	439	442	445	445	442	442	444	448	448	450
Outputs											
Measured system maximum demand (GW)	51.9	54.8	53.5	53.8	56.7	57.2	57.7	58.2	58.6	58.7	59
Directly Connected Generation (GW)	60.1	58.9	59.1	59.7	59.8	60.3	59.7	61.1	62.5	62.5	63.3
Units transmitted to Grid Supply Points (TWh)	300.1	304.2	308.8	310.4	317	319	322	325	326	328	330
System utilisation based on ACS intact flow (MW.km) [2]	5733163	5273946	5809321	5776008	5838456		6299501		6121164		6716731
Performance											
Number of Transmission system incidents (#)	11	12	10	11							
Unsupplied energy (MWh)	473	215	900	888							
System availability (%)	95.4	95.8	95.3	95.3							
System unplanned unavailability (%)	0.35	0.29	0.49	0.47							

[1] The costs presented exclude a number of cost items including those associated with pension deficit repair payments and new EU regulations on Cross Border Trading.

[2] System utilisation data is only prepared for alternate years during the business planning process.

Capital Expenditure	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Reported historical													
Load realated capex		170.9	213.7	201.9	194.6	153.7							
Customer contribution to LR		-2.5	-8.4	-8.4	-38.8	-2.5							
Net load related capex		168.5	205.3	193.4	155.8	151.2							
Net load related capex + TIRG allowance		*168.5*	*205.3*	*193.4*	*155.8*	*151.8*							
Non load related capex		177.6	149.2	152.5	183.8	190.2							
Customer contribution to NLR		0.0	0.0	0.0	0.0	0.0							
Net non load related capex		177.6	149.2	152.5	183.8	190.2							
Forecast													
Load realated capex							193.2	251.9	301.4	233.1	243.3	312.4	298.3
Customer contribution to LR							-3.9	-0.6	0.0	-38.0	-7.9	-5.7	0.0
Net load related capex							189.3	251.3	301.4	195.1	235.4	306.7	298.3
Net load related capex + TIRG allowance							*189.9*	*256.7*	*312.3*	*209.0*	*272.9*	*341.0*	*299.5*
Non load related capex							273.4	340.6	452.5	482.8	486.9	525.1	554.4
Customer contribution to NLR							0.0	-12.7	-14.4	-20.6	-6.5	0.0	0.0
Net non load related capex							273.4	327.9	438.2	462.2	480.3	525.1	554.4
Total net historical/forecast capex		346.1	354.4	345.9	339.6	341.3	462.7	579.2	739.6	657.2	715.7	831.8	852.8
Price control allowances													
Load related capex		228.5	180.2	157.4	133.9	107.2	82.4						
Non load related capex		170.8	148.0	158.5	160.0	156.8	168.2						
Total capex		399.3	328.2	316.0	293.9	264.0	250.6						





Appendix 14 – Summary historic and forecast data (NGG)

Introduction

1.1. This appendix sets out the historic and forecast data for NGG provided to us by NG through the HBPQ and FBPQ and other sources. The data is presented in its raw form without any checks or adjustments by us. All prices are 2004/05.

1.2. We have also requested the licensees to provide a narrative to support the raw forecast 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.

National Grid Gas TO Commentary

1.3. This summary provides an overview of the forward business plan of NGG for the period 2007/8 to 2011/12.

Capital Expenditure

1.4. Our capital expenditure is driven by both the external driver of changes in the supply and demand markets, known as load-related expenditure, and by the need to comply with environmental and safety legislation and replace assets whose condition has deteriorated, known as non load-related expenditure.

Load Related Expenditure

1.5. £456m of expenditure is forecast to be required to provide capacity to facilitate new gas supplies. Over 90% of this expenditure has already been validated through the LTSEC (Long Term System Entry Capacity) auction process. As such the majority of the related capacity expansion work is already underway. Investment at Easington (to meet existing baselines), Grain and Milford Haven are in this category. In addition, investment at Bacton is required to deliver baseline capacity as a result of the signals received at Grain. The remaining 10% of entry expenditure is highly likely to be validated through the LTSEC auction process prior to the beginning of the forthcoming price control.

1.6. Exit expenditure of £425m is forecast to be required in the forthcoming price control period. Almost half this total is investment required to meet current licence or contractual obligations to provide capacity. This includes investment required in the South West to meet our 1 in 20 obligations and investment to connect Langage power station, which is the subject of an existing ARCA. Another significant portion of this total is investment to connect Marchwood power station.

1.7. We recognise that base case forecast capital expenditure for the forthcoming Price Control period represents a significant level of investment in the NTS and that, for some aspects of the forecast, there is a significant level of uncertainty over the actual costs that will be incurred, such that they may be lower or higher than the

forecast. However, we believe that the investment forecast represents a reasonable best view forecast of the expenditure requirement.

Non-Load Related Expenditure

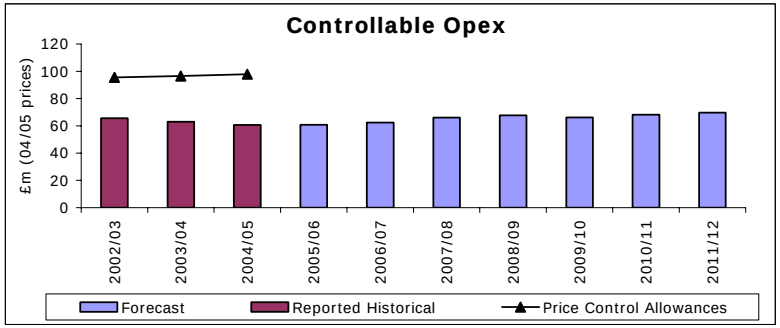
1.8. Significant ongoing investment is required to comply with the Integrated Pollution Prevention and Control (IPPC) regulations, which become effective on our gas compressor fleet from January 2006. Investment of £180m is forecast to be required in the forthcoming Price Control period. In addition, NGG forecasts expenditure required for asset replacement, driven by asset condition, of approximately £142m over the forthcoming Price Control period.

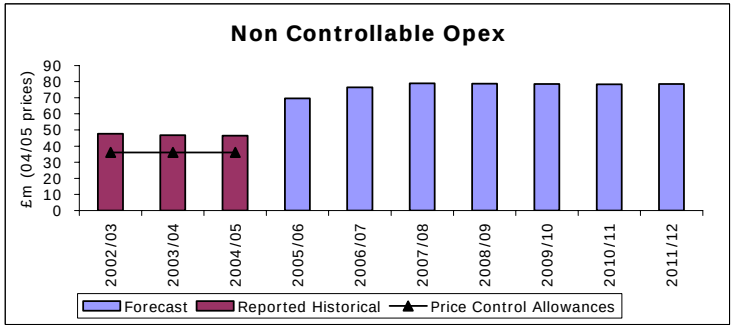
Operating Expenditure

1.9. Our operating expenditure plan reflects the full impact of savings achieved from the merger of National Grid's Gas and Electricity activities. Significant further efficiencies that are either already identified or are anticipated to be delivered in the future have also been incorporated and these savings largely offset the increasing opex drivers of maintaining more assets that are at the end or beginning of their asset lives and the external input cost drivers such as pension and insurance costs.

NATIONAL GRID GAS TRANSMISSION OWNER

Operating costs [1]	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported Historical										
Controllable Opex	65.5	62.9	60.6							
Non Controllable	47.7	46.7	46.4							
Forecast										
Controllable Opex				60.9	62.4	66.1	67.7	66.3	68.2	69.7
Non Controllable				69.7	76.3	78.9	78.7	78.6	78.4	78.4
Price Control Allowances										
Controllable Opex	95.5	96.5	97.8							
Non Controllable	36.1	36.1	36.1							

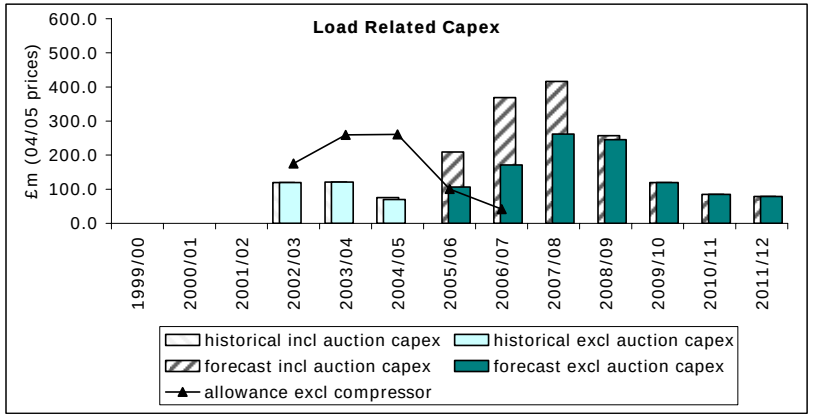


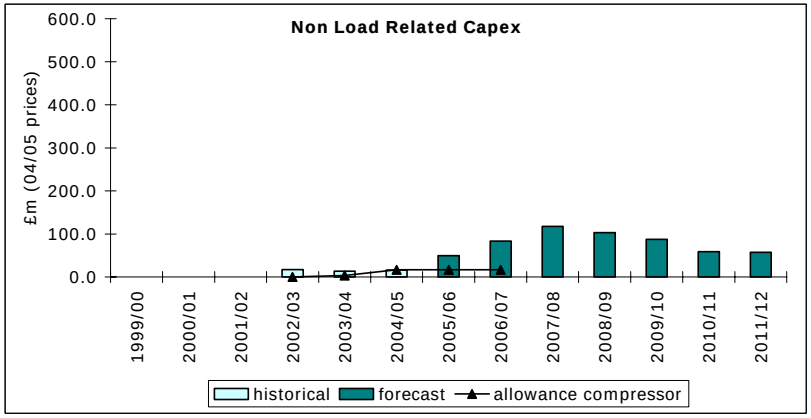


System Statistics	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Resources										
Year end RAV (£m)	2384	2435	2443	2616	2960	3210	3380	3478	3509	3532
Total NTS length (km)	6723	6824	6877	6885	6937	7160	7651	7778	7875	7926
Total installed compressor power (MW)	1114	1141	1181	1181	1181	1181	1289	1289	1309	1309
Outputs										
NTS Entry Point Actuals:Maximum Peak Day Winter (GWh/day)	4810	4539	4416							
NTS Entry Point Actuals:Maximum Peak Day Summer (GWh/da	4057	4296	4227							
NTS Entry Point Actuals:Maximum Peak Day (GWh/day)										
Transit UK Scenario				4703	4622	5943	6204	6376	6550	6414
Global LNG Scenario				4703	4622	5670	5865	5817	5790	5726
Auctions + Scenario				4703	4622	5713	5917	5664	5567	5507
NTS & DN Demand Actuals:Peak Day (GWh/day)	4692	4948	4933	5960	6078	6066	6245	6412	6527	6668
Performance										
Compressor use (run hours)	142045	146858	134090	113760	93240	88200	77400	75000	74760	72360

[1] The costs presented exclude a number of cost items including those associated with pension deficit repair payments and quarry and loss of development claims.

Capital Expenditure	1999/00 £m	2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported historical													
Load realated capex				125.1	122.8	68.0							
Customer contribution to LR				-4.9	-1.4	2.0							
Net load related capex				120.1	121.4	70.1							
Net load related incl auction capex				*120.1*	*121.3*	*75.7*							
Non load related capex				17.3	13.4	16.2							
Customer contribution to NLR				0.0	0.0	0.0							
Net non load related capex				17.3	13.4	16.2							
Forecast													
Load realated capex							111.4	181.1	266.6	251.1	123.9	89.3	83.5
Customer contribution to LR							-4.6	-9.4	-4.9	-6.1	-4.3	-4.1	-4.1
Net load related capex							106.7	171.6	261.7	245.1	119.6	85.3	79.4
Net load related capex incl action capex							*209.2*	*368.9*	*416.2*	*256.9*	*119.6*	*85.3*	*79.4*
Non load related capex							49.6	83.3	117.4	103.1	87.4	58.8	57.3
Customer contribution to NLR							0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net non load related capex							49.6	83.3	117.4	103.1	87.4	58.8	57.3
Total net historical/forecast capex				137.5	134.8	86.2	156.3	254.9	379.1	348.2	207.0	144.1	136.7
Price control allowances													
Load related capex				175.7	259.7	260.8	100.6	42.0					
Non load related capex				0.0	3.3	16.6	16.6	16.6					
Total capex				175.7	263.0	277.4	117.1	58.6					





Appendix 15 – Summary historic and forecast data (SPTL)

Introduction

1.1. This appendix sets out the historic and forecast data for Scottish Power provided to us by Scottish Power through the HBPQ and FBPQ and other sources. The data is presented in its raw form without any checks or adjustments by us. All prices are 2004/05.

1.2. We have also requested the licensees to provide a narrative to support the raw forecast 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.

Scottish Power Transmission Commentary

1.3. We have prepared our operating costs and capital expenditure forecasts for the period 2005/06 to 2011/12 on the basis of the minimum expenditure necessary to run an efficient business while maintaining existing safety, integrity and performance levels and complying with GB SQSS. We have a proven capital investment and opex delivery record and have established a resourcing and project delivery infrastructure that provides us with high confidence in our ability to develop our proposed future work programme.

Operating Costs

1.4. As a mature business, we have reached the point where, fifteen years after privatisation, the scope to reduce costs further is extremely limited. Over the period to 2011/12 we expect our controllable operating costs will increase above RPI as a consequence of upward cost pressures arising from a combination of a growing network, maintenance of an ageing asset base and an expected rise in input costs. The significant capital investment in additional network assets will have an immediate impact on asset inspection costs and in the longer term increase maintenance costs as assets become due for routine maintenance. The cost of future accrual of pension benefits will rise over time due to improvements in mortality and lower expectations for investment returns and falling bond yields.

Load Relating Capital Expenditure

1.5. A significant proportion of load related investment is necessary to support the large-scale development of renewable energy to meet the Government climate change targets. We have prepared our load related submission on the basis of a realistic forecast of the overall take-on of such developments taking account of uncertainty associated with the volume, location and timing of renewable generation connections in Scotland.

1.6. The uncertainty also creates the potential for significant volatility in our business particularly relating to our financing requirements and credit statistics. This concern can only be addressed through a flexible price control framework that ensures that

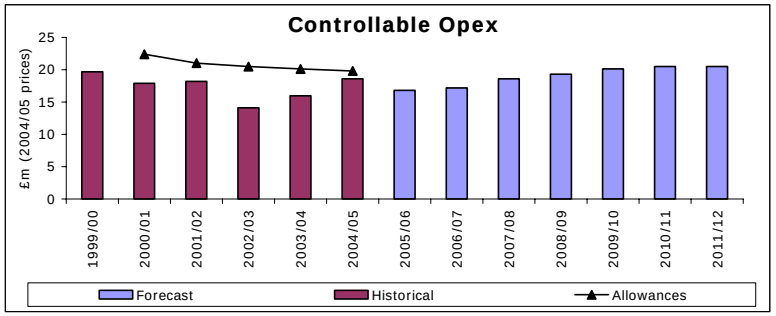
infrastructure businesses are adequately funded with sufficient and stable returns to attract and retain equity funding. Without such a framework, we are concerned that the capability of our business to provide a compliant network will be compromised. Introduction of the “plugs” charging methodology will increase price controlled infrastructure investment.

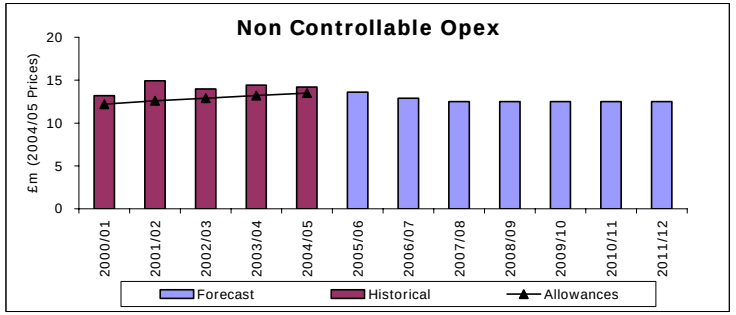
Non-Load Related Capital Expenditure

1.7. Our non-load related capital expenditure forecasts are based on detailed, fully prioritised work programmes developed through application of robust Asset Risk Management processes, policies and plant condition information. An increase in non-load related investment compared with current levels is necessary to ensure the long-term sustainability of the asset base whilst maintaining existing levels of safety, integrity, and performance as assets continue to age.

SCOTTISH POWER TRANSMISSION

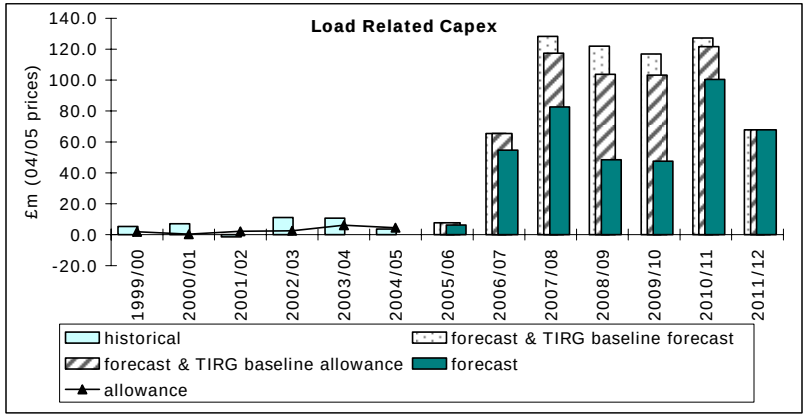
Operating costs	1999/00 £m	2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported Historical													
Controllable Opex (excluding interconnector costs)	19.7	17.9	18.2	14.1	16.0	18.6							
Non Controllable	13.5	13.2	14.9	14.0	14.4	14.2							
Forecast													
Controllable Opex							16.8	17.2	18.6	19.3	20.1	20.5	20.5
Non Controllable							13.6	12.9	12.5	12.5	12.5	12.5	12.5
Price Control Allowances													
Controllable Opex		22.4	21.0	20.5	20.1	19.8							
Non Controllable		12.2	12.6	12.9	13.2	13.5							

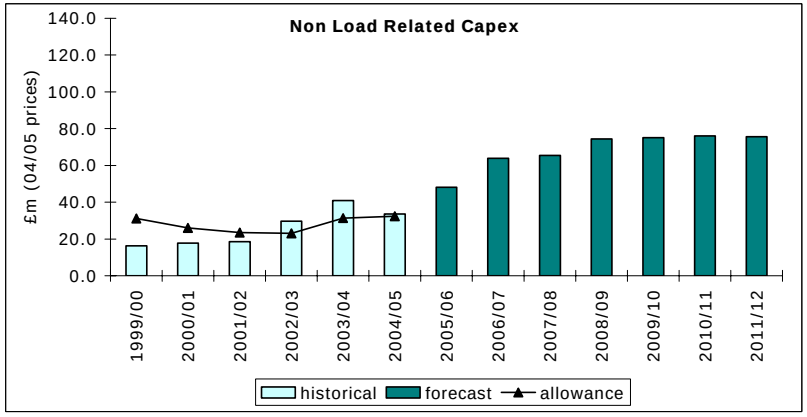




System Statistics	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Resources													
Year end RAV (£m)	652	627	593	583	583	705	708	760	826	874	917	1023	1092
Total transmission circuit length (km)	4011	3998	4057	4056	4043	4018	4028	4028	4015	4077	4093	4105	4139
Total substation numbers (#)	118	118	119	120	121	119	119	119	119	124	129	131	137
Outputs													
Measured system maximum demand (GW)	4.3	4.4	4.2	4.3	4.2	4.1	4.3	4.3	4.3	4.4	4.4	4.5	4.5
Directly Connected Generation (GW)	6.7	6.9	6.9	6.7	6.7	6.7	6.9	6.9	7.2	8.0	8.3	8.5	9.0
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	585500						
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							

Capital Expenditure	1999/00 £m	2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported historical													
Load realated capex	8.5	30.4	8.9	11.3	12.8	13.0							
Customer contribution to LR	-3.2	-23.3	-10.2	-0.2	-2.1	-9.4							
Net load related capex	5.3	7.0	-1.4	11.1	10.8	3.6							
Net load related capex +TIRG allowanc	*5.3*	*7.0*	*-1.4*	*11.1*	*10.8*	*3.7*							
Non load related capex	16.3	17.7	18.5	29.7	40.9	33.6							
Customer contribution to NLR	0.0	0.0	0.0	0.0	0.0	0.0							
Net non load related capex	16.3	17.7	18.5	29.7	40.9	33.6							
Forecast													
Load realated capex							7.3	57.7	87.7	49.2	48.1	100.8	68.0
Customer contribution to LR							-1.1	-3.1	-5.1	-0.8	-0.6	-0.4	-0.1
Net load related capex							6.2	54.6	82.6	48.4	47.5	100.4	67.9
Net load related capex + TIRG allowance							*7.7*	*65.5*	*117.4*	*103.7*	*103.2*	*121.6*	*67.9*
Net load related capex + TIRG reforecast							*7.7*	*65.5*	*128.3*	*121.9*	*116.9*	*127.2*	*67.9*
Non load related capex							48.1	63.9	65.4	74.4	75.0	76.0	75.6
Customer contribution to NLR							0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net non load related capex							48.1	63.9	65.4	74.4	75.0	76.0	75.6
Total net historical/forecast capex	21.6	24.7	17.2	40.8	51.7	37.2	54.3	118.5	148.0	122.8	122.5	176.4	143.5
Price control allowances													
Load related capex	2.0	0.4	2.1	2.6	6.2	4.5							
Non load related capex	31.1	26.1	23.5	23.1	31.4	32.3							
Total capex	33.1	26.4	25.6	25.7	37.6	36.8							





Note: The "TIRG Baseline Allowance" was set using preliminary estimates. The "TIRG Baseline Forecast" has been prepared after undertaking detailed pre-construction works on all of the TIRG projects. The movements in costs relative to the estimates are due to scope changes identified during the pre-construction works to overcome engineering/technical and environmental/planning issues. This forecast is to be reviewed by Ofgem.

Appendix 16 – Summary historic and forecast data (SHETL)

Introduction

1.1. This appendix sets out the historic and forecast data for Scottish Hydro Electric provided to us by Scottish Hydro Electric through the HBPQ and FBPQ and other sources. The data is presented in its raw form without any checks or adjustments by us. All prices are 2004/05.

1.2. We have also requested the licensees to provide a narrative to support the raw forecast 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.

Scottish Hydro Electric Transmission Commentary

Operating Costs

1.3. Following introduction of BETTA on 1st April 2005 all Cost of Sales, Licence fee and Interconnector costs were no longer payable. These costs were a "pass through" and therefore there is a corresponding reduction in Regulated Income.

1.4. Operating Costs within the forecast business plan questionnaire included £2.0m in 2005/06 and £5.0m in 2006/07 for pre construction costs (including public enquiry costs) on Beauly-Denny and Sloy circuits. It has been assumed that these costs will be recovered via Regulated revenue in these years.

1.5. Underlying operating coats are anticipated to increase by £2.2m in real terms over the forecast period. These increases reflect increases in headcount and operating costs associated with increased repairs & maintenance as the network becomes larger and more complex over the forecast period. In addition IT, Telecoms & insurance costs are expected to rise from current levels.

Capex

1.6. Capex expenditure is projected to rise sharply over the period from 2005-2010 within the SHETL Licence area. This is largely driven by the need to develop our network to meet the growing requirements of renewable generation connections.

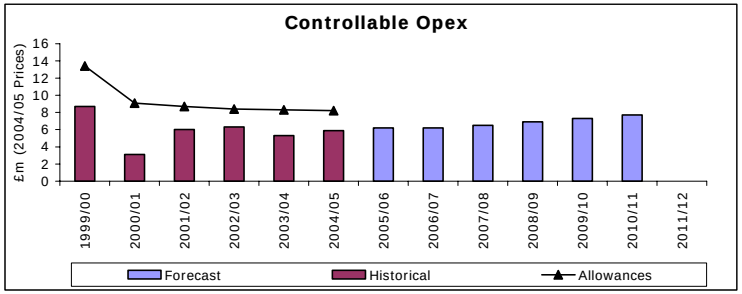
1.7. Our Load Related expenditure is split between that required to meet new demand and new generation. Demand related expenditure is expected to be essentially static over the period whilst generation grows markedly. Our price review submission is based on our best estimate scenario of how much contracted renewable generation will connect. Renewable generation led expenditure will see significant growth in sole use connections. Expenditure on our main infrastructure to support these connections will also see a large increase part of which has separately been the subject of agreement with Ofgem (TIRG mechanism – 2 schemes Beauly/Denny overhead line and Inverarnan Substation).

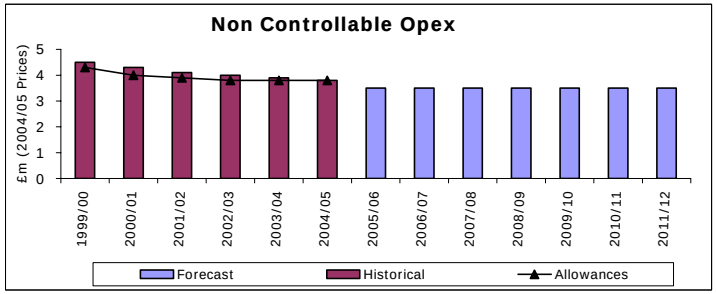
1.8. Main infrastructure related spend is a large part of our Capex plans and represents a huge investment in, and increase to, our Transmission network in the North of Scotland. There are five schemes included in our company forecast in addition to the two schemes already subject to the TIRG agreement as noted above. These represent the projected infrastructure required to support the growth in renewable generation. The first of these is the Beauly/Denny 400kV overhead line (TIRG).

1.9. SHETL non load related expenditure is projected to be in line with our regulated allowance during the previous period. We have identified sufficient expenditure to maintain the same risk profile to meet the requirements of our regulator, Ofgem.

SCOTTISH HYDRO ELECTRIC TRANSMISSION

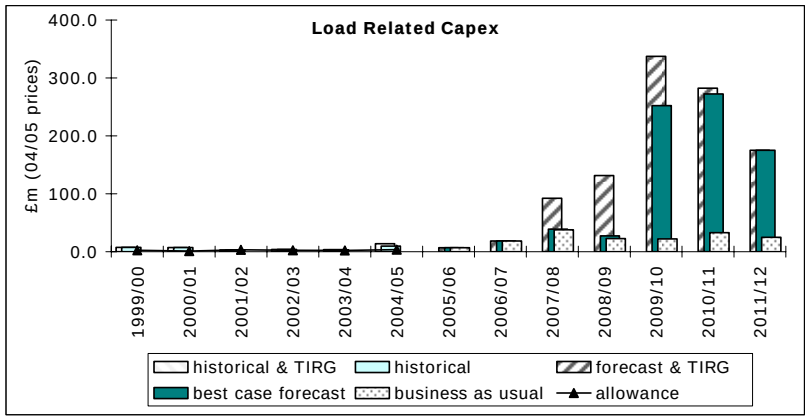
Operating costs	1999/00 £m	2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported Historical													
Controllable Opex (excluding any interconnector costs)	8.7	3.1	6.0	6.3	5.3	5.9							
Non Controllable	4.5	4.3	4.1	4.0	3.9	3.8							
Forecast													
Controllable Opex							6.2	6.2	6.5	6.9	7.3	7.7	8.1
Non Controllable							3.5	3.5	3.5	3.5	3.5	3.5	3.5
Price Control Allowances													
Controllable Opex	13.4	9.1	8.7	8.4	8.3	8.2							
Non Controllable	4.3	4.0	3.9	3.8	3.8	3.8							

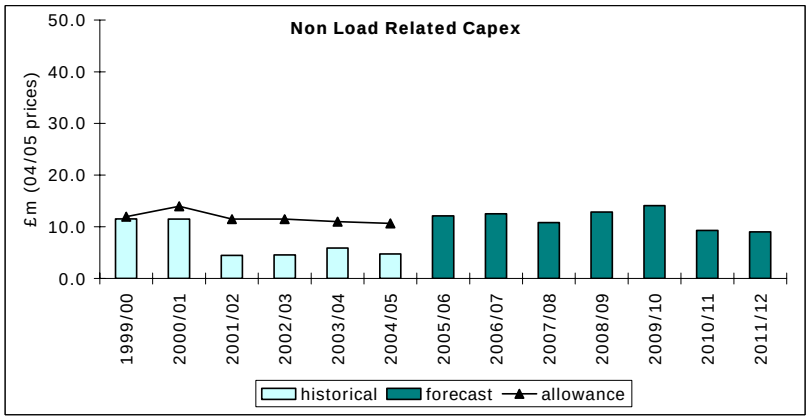




System Statistics	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Resources													
Year end RAV (£m)	254	250	243	238	232	271	282	303	396	532	878	1172	1358
Total transmission circuit length (km)	4887	4912	4912	4912	4912	4912	4,938	4,938	4,954	4,969	5,427	5,497	5,871
Total substation numbers (#)	89	89	89	89	89	89	89	89	103	107	115	115	118
Outputs													
Measured system maximum demand (GW)	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8
Directly Connected Generation (GW)	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.9	3.2	3.5	4.1	4.3
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							

Capital Expenditure	1999/00 £m	2000/01 £m	2001/02 £m	2002/03 £m	2003/04 £m	2004/05 £m	2005/06 £m	2006/07 £m	2007/08 £m	2008/09 £m	2009/10 £m	2010/11 £m	2011/12 £m
Reported historical													
Load realated capex	7.5	2.8	2.8	3.8	3.0	9.6							
Customer contribution to LR	0.0	4.4	0.0	0.0	0.0	0.0							
Net load related capex	7.5	7.2	2.8	3.8	3.0	9.6							
Net load related capex + TIRG allowanc	*7.5*	*7.2*	*2.8*	*3.9*	*3.5*	*13.7*							
Non load related capex	11.5	11.5	4.5	4.5	5.9	4.8							
Customer contribution to NLR	0.0	0.0	0.0	0.0	0.0	0.0							
Net non load related capex	11.5	11.5	4.5	4.5	5.9	4.8							
Forecast													
Load realated capex							6.8	22.4	45.6	31.0	259.5	273.0	176.4
Customer contribution to LR							0.0	-4.2	-6.6	-3.7	-7.1	-0.7	-1.2
Net load related capex							6.8	18.2	38.9	27.3	252.3	272.3	175.2
Net load related capex + TIRG allowance							*6.8*	*18.2*	*92.1*	*131.3*	*337.3*	*282.3*	*175.2*
Net load related capex ''business as usual'							*6.8*	*18.2*	*37.7*	*22.5*	*21.9*	*33.0*	*24.8*
Non load related capex							12.1	12.5	10.8	12.9	14.1	9.3	9.0
Customer contribution to NLR							0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net non load related capex							12.1	12.5	10.8	12.9	14.1	9.3	9.0
Total net historical/forecast capex	19.0	18.7	7.2	8.3	8.9	14.4	18.9	30.7	49.7	40.2	266.4	281.6	184.2
Price control allowances													
Load related capex	2.5	1.1	3.3	2.5	2.1	3.4							
Non load related capex	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							





Appendix 17 – Cost of capital study: terms of reference

Cost of Capital Study - Terms of Reference

1.1. Update recommendations of Joint Regulators report[28] on the most appropriate method(s) to employ in estimating the cost of capital to UK regulated network utilities, having regard to:

- up-to-date developments in academic research and analysis;
- the views of the Competition Commission on estimating the cost of capital for price control reviews;
- the practical application of multi-factor models; and
- the practicalities of estimating returns for unquoted companies in gas distribution.

1.2. Collect and analyse market data needed for estimation of the cost of capital to the Utility companies subject to the TPCR and GDPCR, including:

- selection of appropriate comparators,
- update of beta analysis,
- analysis of the more recent market trends, such as:
    - government and corporate bond yields, absolute, and as spreads to gilts;
    - comparisons against other similarly rated companies, in UK and Overseas;
    - the level of gearing, or stage in the business cycle and if this also affects equity returns; and
    - utility dividend yields in the US and the UK, and the extent to which institutional factors may be affecting these.
- assessment of likely future direction of these trends,
- evidence from corporate finance actions in the relevant and comparable sectors

1.3. Consideration of wider financial stability issues and incentive effects in relation to the estimation of cost of capital.

1.4. Recommendations as to the range of appropriate estimates to use for TPCR and GDPCR and the practical application thereof.

1.5. The primary sources of information available are:

- the existing data published in 2003, and updates to this data;
- the dataset from Exeter Enterprises which provides monthly estimates of the Fama French factors for the UK from July 1975 to December 2005;
- the “cleaned” dataset from Grant Thornton (collected from Datasteam and Bloombergs) which provides daily data on bonds issued by UK, European, and US Utilities from 1995 to 2005;
- the dataset from Grant Thornton on relevant accounting data on these same Utilities; to include turnover, PBIT, interest, tax, fixed assets (gross and net), gearing, beta, depreciation and capex; and

[28] "A study into certain aspects of the cost of capital for regulated utilities in the UK", Smithers & Co., February 2003 (available on the Ofgem website, Ref 08/030).

- other information sources as agreed.