Promoting choice and value for all gas and electricity customers

Transmission Price Control Review: Updated Proposals

Document type: Appendices

Ref: 170/06a

Date of publication: 25 September 2006

Deadline for response: 24 October 2006 to tpcr.responses@fgem.gov.uk

Target audience: Transmission licensees, Gas transporters, users of the transmission networks, consumer groups and other interested parties

Overview:

This document sets out the main appendices to our updated proposals for the transmission price controls that will apply from 1 April 2007. It sets out our further thinking on the allowances that we intend to provide to fund efficient expenditure of the transmission licensees over the period 2007 - 2012.

Our updated proposals are based on extensive consideration of historic and forecast cost assessments of the transmission companies, which, together with our initial financial assumptions, allow us to calculate revenue allowances for each company. We have also set out further thoughts and more detailed proposals in relation to price control and incentive design.

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Context

This document sets out our updated proposals for the electricity and gas transmission licensees' price controls for the five years from 1st April 2007.

Since the existing price controls were set, there have been a number of changes in the external environment, such as changing patterns of gas supply, changes in the electricity generation mix, as well as changes in wider energy policy, especially in relation to the environment. In our initial proposals document in June, we set out our thoughts on how the price controls could be designed to meet these objectives and challenges. We also set out our initial views on the allowances for capital and operating expenditure which would be required to allow the companies to operate their networks efficiently.

Since June, we have worked with the industry to develop an updated suite of proposals which address the issues of replacing and refurbishing aging network assets, uncertain demand for network capacity, financial issues such as the rate of return, the depreciation cliff edge, pensions and tax, as well as incentive design issues in electricity and gas.

Associated Documents

- TPCR 2007-2012 Updated Proposals - Consultation Document (Ref No. 170/06)
- TPCR 2007-2012 Initial Proposals, June 2006 (Ref No. 104/06)
- TPCR 2007-2012 Initial Proposals, Main Appendices, June 2006 (Ref No. 104b/06)
- TPCR 2007-2012 Initial Proposals, Appendix: Offtake Revenue Drivers and Baselines for NGG NTS , June 2006 (Ref No. 104c/06)
- TPCR 2007-2012 Initial Proposals, Draft Enduring Offtake Impact Assessment, June 2006 (Ref No. 104d/06)
- Access Reform in Electricity Transmission: Working group report and next steps, May 2006 (Ref No. 83/06a)
- A framework for considering reforms to how generators gain access to the GB electricity transmission system: A report by the Access Reform Options Development Group April 2006, May 2006 (Ref No. 83/06b)
- TPCR 2007-2012: Third Consultation, March 2006 (Ref No. 51/06)
- TPCR 2007-2012: Third Consultation, Supplementary Appendices, March 2006 (Ref No. 51/06b)
- TPCR Capital Expenditure Projections 2007-2012 (open letter), 1 February 2006 (Ref No. 21/06)
- TPCR Second Consultation, December 2005 (Ref No. 277/05)
- TPCR Initial Consultation, July 2005 (Ref No. 172/05)

Copies of the consultants reports and responses to the Ofgem consultation documents can also be found on the Ofgem website (www.ofgem.gov.uk).

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Appendix 7 – Offtake revenue drivers and baselines for NGG NTS

Introduction

Overview

1.1. This Appendix considers the incentive framework for NGG NTS as gas transmission licensee over the next TPCR period with respect to the offtake of gas from the National Transmission System (NTS) and highlights areas where our policy has changed since the publication of our Initial Proposals consultation.

1.2. As with previous consultations, this document considers the proposed incentive framework for NGG NTS for both the transitional and enduring offtake arrangements.

1.3. A summary of respondents' views to the Initial Proposals consultation is provided in Appendix 3.

Views invited

1.4. We would welcome views on any of the issues discussed in this Appendix and have provided a list of specific questions below upon which we would particularly welcome views.

Questions

Question A7.1: Do you agree with our updated proposals for the transitional period with respect to:
(1) Baseline levels
(2) Revenue drivers
(3) NGG NTS incentives

Question A7.2: Do you agree with our updated proposals for the enduring period with respect to:
(1) The treatment of "efficient over-building"
(2) Baselines
(3) The treatment of interruptible sites in the SW quadrant
(4) Revenue drivers
(5) Investment related buy-back actions
(6) The treatment of non-obligated capacity

The transitional regime

Introduction

1.5. In this section we consider the incentive arrangements that would apply to NGG NTS in the transitional offtake period under the following headings:

- Baselines;
- Revenue drivers, and
- Transitional incentives.

Baselines

1.6. The proposed scope and structure for transitional baselines remains unchanged relative to our Initial Proposals consultation.

1.7. Our Initial Proposals for transitional baselines were included in Annex 1 of Appendix 16 of the Initial Proposals consultation. Since publication of these numbers there have been minor revisions following consideration by NGG NTS of respondents' views and industry participant queries. The revised numbers are explained and presented in Annex 1.

Revenue drivers

1.8. The proposed framework for the application of revenue drivers in the transitional period remains unchanged relative to our Initial Proposals consultation.

1.9. An initial assessment of potential revenue drivers was provided for the enduring period in our Initial Proposals consultation. These proposed revenue drivers have been subject to further revision following the receipt of additional information from both NGG NTS and our consultants - these are presented later in this Appendix. It remains our view that the same revenue drivers should apply throughout the forthcoming price control period.

Transitional incentives

1.10. In the Initial Proposals consultation, we indicated that it would be appropriate to simplify the incentives that apply to NGG NTS for the transitional period relative to those that currently apply within the interim offtake period which ends on 30 September 2008.

1.11. Our proposals in relation to the charges foregone and exit investment incentive, and in relation to the buy back and greater than 15 day interruptions incentive remain unchanged.

1.12. With regard to the constrained LNG (CLNG) incentive, we have received further information from NGG NTS to inform the assessment of the appropriate level of an incentive target. We discuss both CLNG volumes and prices in turn below.

CLNG volumes

1.13. NGG NTS has identified potential CLNG requirements in both the south west and the south east. NGG NTS has assumed that CLNG requirements in the south west would be managed through the Avonmouth LNG facility and that CLNG requirements in the south east would be managed through a combination of the Transmission Services Agreement (TSA) that National Grid holds with BP and Sonatrach at Isle of Grain and through contracting for services from the Humbly Grove storage facility.

1.14. We consider that there is some uncertainty underlying the requirement for CLNG in the south east region. In response to questions from Ofgem, NGG has stated that, if peak day demand is experienced in the south east and supplies are not received from Isle of Grain, then there is insufficient transportation capability to sustain peak demand in the south east. This assumption is arguably unrealistic particularly given Winter Outlook forecasts of Isle of Grain flows are in the range of 13 mcm/d for winter 06/07 and rising to over 20 mcm/d in future years. NGG has however indicated that there is considerable uncertainty going forward as to where peak day gas supplies will enter the transmission system and that it needs funding to address a possible scenario where zero gas is received at Isle of Grain on the peak day.

CLNG prices

1.15. In analysing the price data submitted by NGG NTS we have had a number of concerns. Our principal concern is that NGG NTS has assumed that in contracting for CLNG in the south east, gas costs need to be taken into account; and in the case of Humbly Grove these costs are taken into account twice. For Humbly Grove, NGG NTS has assumed that it will need to purchase gas to inject into the facility for CLNG purposes. NGG NTS has also assumed that this gas is purchased at the winter gas price. In addition, for both Humbly Grove and the TSA contract, NGG NTS has assumed that, in the event that the winter peak day arises, it will need to purchase the gas itself on the day in question.

1.16. Our concerns relating to NGG's pricing assumptions are set out below:

- In a normal storage contract, a user pays only capacity charges and injection/withdrawal charges, rather than the costs of gas (in the event that it is not used)[1].
- To the extent that the purchase of the gas for injection at Humbly Grove is necessary we believe that it should be based on the cost of gas at the time it is injected into the facility for subsequent use. Given that injection ordinarily occurs in summer months, we believe the Humbly Grove gas costs should be on the basis of summer rather than winter prices.
- To the extent that NGG is required to utilise the CLNG service and purchase gas on the peak day, it takes ownership of the gas in question. By using this gas for transmission support, surplus gas is created elsewhere in the system which will need to be sold to the market. We do not think it is necessary to provide NGG with ex ante funding for these gas costs as they will be more or less offset by NGG's sale of gas on the same peak day. However, it will be important to ensure that to the extent that NGG NTS purchases gas for use on the peak day, it can keep the proceeds from the revenues of selling surplus gas.

1.17. We also note that NGG NTS's proposals for CLNG costs at Avonmouth have assumed the application of its PC 52 pricing methodology which set outs charges that NGG pay Avonmouth for the use of the NG Avonmouth facility. We consider that these charges are overstated and that it would be more appropriate to base these contracting costs closer to current LNG auction prices which are significantly lower.

Proposals on CLNG

1.18. In view of the above analysis we are proposing three scenarios for targets for the CLNG incentive:

- Scenario 1 – High case: This assumes that there is a south east and south west CLNG requirement. It also assumes that Humbly Grove gas is providing transmission support for the south east. Scenario 1 assumes that there is no excess charging for gas costs i.e. that they are incurred only once at summer prices, and that ex-ante funding is provided through the incentive target.
- Scenario 2 – Medium case: This adopts the same assumptions as Scenario 1, with the exception that there is no funding for any gas costs at Humbly Grove through the incentive target. Further it assumes that there is no CLNG requirement under the TSA contract for March in each formula year[2]. This reduces costs downwards. The medium case also assumes lower contracting costs at Avonmouth for the provision of south west CLNG.

[1] Although some funding for the financing costs of holding gas in store from year to year may be necessary.

[2] It is our view that the assumption, by NGG NTS, that the TSA requirement is needed in March each year is inappropriate as, in practice, when constraining LNG, NGG NTS use a declining monitor level that reflects the fact that the likelihood of different conditions changes as the winter progresses and the level will therefore typically be zero by the end of February.

- Scenario 3 - Low case. This assumes that there are no south east CLNG requirements as discussed above. It also assumes lower contracting costs at Avonmouth as with the medium case.

1.19. It is noted that we are not proposing to change the arrangements for sharing factors or caps and collars on CLNG. We propose that the sharing factor should remain at 100 per cent with no caps and collars. We consider that this remains appropriate, given that NGG's incentives could be distorted by its ownership of LNG storage facilities.

1.20. The proposed CLNG incentive targets for the period 2009/10-2011/12 are outlined in Table A7.1 below. As noted before, targets for the interim period have already been specified.

Table A7.1: Targets for CLNG incentive

Target	2007/8	2008/9	2009/10	2010/11	2011/12
High case	£2.6m*	£2.1m*	£4.9m	£3.7m	£3.1m
Medium case			£3.5m	£2.9m	£2.8m
Low case			£1.4m	£0.1m	0

*Targets for 2007/8 and 2008/9 have already been specified.

1.21. We would welcome views 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.

The enduring regime

The importance of user commitment models

1.22. We continue to consider that the implementation of user commitment models is important as outlined in our Initial Proposals consultation.

Enduring offtake arrangements

1.23. We note that on 13 September 2006, NGG NTS raised a proposed modification of the UNC in order to implement enduring offtake reform, namely Modification Proposal 0116, 'Reform of the NTS offtake arrangements'. We note that this proposal is subject to UNC processes and that nothing in this consultation can fetter the discretion of the Authority in considering this or any other modification proposal[3].

[3] We note that E.on has prepared an alternative proposal which will also be considered if the Modification Panel determines that Modification Proposal 0116 should be issued for

1.24. The proposal governs the release and allocation of two NTS exit capacity products, namely flat and flexibility capacity and is summarised at a very high level below.

Flat offtake rights

1.25. The main characteristics of NGG NTS's proposed modification in respect of flat capacity are:

- A "prevailing rights" approach to capacity allocation where users wishing simply to maintain their existing or "prevailing" capacity holdings are required to provide a financial commitment for a specified number of years;
- Where a user wishes to increase their prevailing holding, it would be required to provide a sustained commitment; and
- NGG NTS would have the ability to release unsold baseline capacity in the short term as well as any additional capacity it may elect to offer for sale on a discretionary basis. In addition NGG NTS would release a daily "use it or lose it" interruptible product and would have discretion regarding the release of any additional volumes of interruptible capacity.

Flexible offtake rights

1.26. Since June, NGG NTS has developed a number of changes to its flexibility product definition:

- NGG NTS has indicated that it would not expect to invest for flex as a separate product, but if the signals generated by the pay as bid auctions were significant it would consider bringing investment proposals forward to Ofgem at the relevant time;
- NGG NTS has indicated that it would offer for sale 22 mcm/day of capacity as an annual product in long term pay-as-bid auctions up to 5 years in advance. All parties including DNs and direct connects would therefore be able to access flex capacity in the long term through this auction process; and
- In order to manage diversity of DN requirements, NGG is proposing a zonal approach whereby the 22 mcm/day of flexibility available would be allocated nationally in the auction. Bidders would bid for capacity at particular zones and flex would be allocated to those that valued it the most, subject to certain specified constraints in the form of 17 zonal maxima and 4 regional maxima.

consultation.

Enduring incentives

Interaction of user commitment models with 1 in 20 obligation

1.27. We remain of the view that compliance with NGG NTS's 1 in 20 licence obligation could be achieved by investing in line with user commitments which signal peak aggregate daily demand. We consider that this would provide greater clarity of responsibility between NTS users and NGG NTS. In addition, as noted in the Initial Proposals consultation, causality for investment would be unambiguous with users having incentives to provide long term investment signals.

1.28. In its response, NGG NTS raised concerns regarding its remuneration in situations where it was considered to be efficient to 'over-build' relative to the immediate demand for capacity as revealed in the long-term capacity allocation process. This might potentially be a relevant consideration if the cost of 'over-building' is very low as a by-product of the technical design identified by NGG NTS. In considering explicit revenue adjustments to accommodate such a situation we need to be mindful of the fact that NGG NTS can be rewarded for anticipating future demand for capacity through the operation of the proposed revenue drivers - and these incentives should be allowed to operate as intended.

1.29. On balance we do not, therefore consider that a revenue adjustment mechanism to handle these circumstances should be codified as part of the price control regime. We would therefore propose handling any such applications from NGG NTS for additional funding to 'over-build' on an ad hoc basis. However, the hurdle for approval of such a 're-opener' is a high one, and NGG NTS would need to demonstrate why the factors cited above do not promote an efficient solution for consumers in each instance.

Baseline derivation

1.30. Our view on the appropriate scope of enduring baselines and the methodology that should be applied to determine the appropriate level of nodal baselines remains unchanged relative to our Initial Proposals consultation.

1.31. Given that, in June, NGG NTS had yet to develop a final proposal for product definition during the enduring period it was not possible to provide baseline numbers for the enduring period as part of the Initial Proposals consultation. However, it was our initial proposal that such baseline numbers should be consistent with the nodal baselines specified for the transitional period, with adjustments to:

- Reflect the proposed product definitions for the enduring period, and
- Adjust upwards the nodal baselines for five sites in the constrained south west quadrant that have historically been interruptible.

1.32. We have therefore specified a baseline for all interruptible sites equivalent to their current allowance, as reflected by their System Offtake Quantities (SOQs), therefore accommodating all interruptible load on the network.

1.33. To reflect the fact that the baselines have been adjusted upwards, above the practical maximum physical level for these nodes, it remains our proposal to include an additional revenue allowance in the SO allowed revenue, which will aim to provide remuneration for efficiently incurred contracting costs at these five sites. We propose that this revenue allowance should be £2.8m p.a. for the enduring period. This allowance is based upon NGG NTS's estimates of the potential costs of providing firm capacity through the use of constrained LNG. These estimates have been adjusted downwards consistent with the medium case scenario as adopted for the estimation of appropriate CLNG targets. Furthermore, we propose that 50% sharing factors should be applied to the extent that NGG NTS deviates from the target determined.

1.34. Following the specification of a flexibility product definition by NGG NTS, it is now possible to present our proposals for enduring period baselines. We therefore outline our proposals for flat and flexibility capacity baselines for the enduring period in Annex 1. With respect to the flexibility product, and consistent with the product definition proposed by NGG NTS, a national capacity release obligation for flexibility capacity is proposed at 22 mcm/day (238 GWh/day) for each year of the enduring period in the next price control period.

1.35. We continue to propose a framework for the reallocation of baselines. Under such a framework, we envisage that:

- NGG NTS will be obliged, under the terms of its licence, to consult on and develop a transparent methodology for baseline revisions. This methodology would address processes associated with substitution and the upward revision of baselines to reflect developments at offtake and entry. The methodology would need to reflect NGG NTS's statutory and licence obligations with respect to efficient network development;

- In terms of substitution, NGG NTS would be required under the terms of its licence, to use all reasonable endeavours to identify the potential for the substitution of unsold NTS flat capacity baselines such that the level of NTS obligated incremental flat capacity is minimised.;

- NGG NTS will be required to submit a report to Ofgem following each long term capacity allocation setting out how it proposed to substitute baseline capacity and seeking Ofgem's approval for any reallocation of baselines. Once approved the baselines will be changed with effect from the delivery date of the capacity bought in the long term allocation;

- NGG NTS will be required to publish a statement setting out revised baseline numbers, reflecting any revisions to the baselines that have been approved by Ofgem; and

- NGG NTS will also be required to submit to the Authority an annual statement explaining the basis upon which the licensee has reached the view that user demands cannot be satisfied in full by the substitution of baselines in order to demonstrate compliance with its obligations in this regard.

Revenue drivers

1.36. Our Initial Proposals for a revenue driver framework remain largely unchanged. However, we highlight refinements proposed to our revenue driver policy and the proposed revenue driver numbers below.

1.37. We continue to propose a zonal revenue driver for all capacity increments in the south west quadrant that are less than 15 GWh/day in size and nodal, project specific revenue drivers, for all projects above this threshold regardless of their location.

1.38. We continue to consider that it is not appropriate to specify zonal revenue drivers for areas outside of the constrained, south west quadrant as NGG NTS does not anticipate the need for incremental, load related investments anywhere other than the south west quadrant in the next price control period. In the event that there is exit investment in these areas, we propose to consider the appropriate revenue drivers on a case by case basis and modify the licence accordingly.

1.39. Following the receipt of further information from both NGG NTS and our capex consultants, we are now proposing that an appropriate revenue driver applicable to nodes in the south west quadrant would be £0.63m per GWh/day.

1.40. Table 7.2 below details our revised assessment of the efficient levels of capital expenditure for each of the five anticipated large projects identified by NGG NTS in its FBPQ. These revised estimates have been informed by further assessment of the efficient level of costs by our capex consultants.

Table A7.2: Allowed capital expenditure (£m, 2005/6 prices)

	Total capex
Langage power station Phase 1 (40 GWh/day)	56
Langage power station Phase 2 (18 GWh/day)	45
Marchwood power station (45 GWh/day)	29
Pembroke power station (87 GWh/day)	42
Grain power station (55 GWh/day)	86

1.41. In the case of both Pembroke and Grain power stations, we have continued to apply a factor of 80 per cent to our capex consultants' latest assessment of the efficient cost of pipe-line investment to reflect the potential scope for contracting

solutions to delivery of exit capacity at these sites. Furthermore, we note that the capex for Langage power station Phase 1 has been subject to an adjustment to reflect funding received with respect to this project in the current price control period. We also note that NGG NTS has stated that the Easton Grey to Littleton Drew pipeline, previously included as part of the south west demand, should be considered to be part of the Langage power station Phase 2 project, and this reallocation is reflected in the figures presented.

1.42. We have applied an annuitisation factor of 0.0991[4] to our assessment of allowed capital expenditure above to derive the project specific revenue drivers shown in Table 7.3 below.

Table A7.3: Project specific revenue drivers (£m, 2005/6 prices)

	Revenue driver
Langage power station Phase 1 (40 GWh/day)	5.6
Langage power station Phase 2 (18 GWh/day)	4.5
Marchwood power station (45 GWh/day)	2.9
Pembroke power station (87 GWh/day)	4.2
Grain power station (55 GWh/day)	8.5

1.43. Given that investment for flexibility is not anticipated any remuneration of investment for flexibility capacity will be dealt with on a case by case basis rather than through the ex ante determination of revenue drivers.

Entry / exit interactions

1.44. As noted above we continue to consider that the substitution obligation placed upon NGG NTS should be extended to oblige NGG NTS to increase exit baselines in the event that exit capacity is generated as a result of entry investments undertaken and vice versa.

Proposals for buy-back incentive

1.45. In Chapter 10 we provided a high-level overview of our proposed treatment of buy-back actions across both entry and exit regimes.

[4] This annuitisation factor has been derived assuming (1) a pre-tax rate of return on 6 per cent (2) associated operating costs equivalent to 1 per cent of investment costs (3) asset lives of 45 years, (4) 20 per cent of investment costs incurred in t-2 and 80 per cent in t-1 and (5) revenue drivers applicable for a 5 year period.

1.46. We continue to consider that investment related buyback costs should be treated as excluded revenue and subject to an administered cap of the buyback price on a similar basis to the entry proposals.

1.47. NGG NTS's current proposals assume default lead times of 38 months for NTS exit capacity projects, given the capacity application window proposed for July each year. We continue to consider that it may be appropriate to provide NGG NTS some flexibility over investment lead times. However, rather than allowing NGG NTS to apply to the Authority for lead time extensions we now consider that an alternative mechanism may be appropriate that reduces the need for ad hoc Ofgem intervention. Under our proposed mechanism, the ex ante determination of lead times could vary by project through the application of an extension permit system. It is envisaged that this framework would allow a specified number of projects to run over the "default" lead time and would allow the ex ante specification of shorter lead times to earn credits that could allow the delay of other projects.

1.48. Our current proposal is that the default lead time for exit projects be set at 38 months (3.2 years) with NGG NTS being provided extension permits for 365 days in total for 30Gwh/day for use, on an ex ante basis, during the next price control period. Ofgem's view is that these permits can only be exercised on an ex ante basis prior to the annual long term allocation and would apply for the enduring offtake arrangements only. As such, and subject to Ofgem's assessment of modification proposal 0116, the first opportunity for NGG NTS to utilise a permit would be July 2007.

1.49. Following further consideration of the potential exposure of NGG NTS to buy back actions associated with incremental investment, we have decided that it would be appropriate to establish an absolute cap on such exposure in each formula year. Our proposal is that this cap is set at £36m per annum for incremental exit investment.

1.50. Our proposals for the treatment of operational buy back actions remain unchanged since our Initial Proposals consultation. We note that a number of constraint management tools are proposed by NGG NTS in its modification proposal. However, it is not envisaged that any additional revenue allowance is necessary with respect to the use of these tools.

Treatment of non-obligated capacity

1.51. We continue to believe that NGG NTS should be incentivised in relation to the release of non-obligated and interruptible capacity. We envisage a sliding scale incentive, with a zero target, that would allow NGG NTS to retain 50% share of revenues from the sale of:

- Non-obligated incremental flat capacity;
- Non-obligated incremental flexibility capacity; and

- Interruptible capacity.

1.52. It remains our view that the obligation to release both flat and flexible baseline capacity should continue up to and including the gas day. As such, non-obligated incremental capacity would be capacity released above baseline for which a sustained demand signal had not been received.

1.53. It is our current view that NGG NTS gains under this incentive should be capped at £20m p.a. however, we would welcome views on this proposal.

Payment flows

1.54. Our proposal to implement an "Option 2A" payment flows model on 1 October 2010 to coincide with the introduction of the enduring offtake arrangements remains unchanged.

Way forward

1.55. We welcome views from respondents on all aspects of this consultation. These views will inform the development of our Final Proposals, which will be published in December 2006.

1.56. As stated earlier, on 13 September 2006, NGG NTS raised a proposed modification of the UNC in order to implement enduring offtake reform, namely Modification Proposal 0116, 'Reform of the NTS offtake arrangements'. We note that this proposal is subject to UNC processes and that nothing in this consultation can fetter the discretion of the Authority in considering this or any other modification proposal. We propose to release a Final Impact Assessment in parallel with the Authority's decision on any UNC modification proposal relating to enduring offtake reform that comes to the Authority for consideration.

1.57. We recognise that the codification of our proposals will also require industry consultation. As such, we propose to consult informally for the first time on initial licence drafting proposals in the coming weeks. We ultimately propose to publish a formal, statutory licence consultation in February following further informal consultation.

Annex 1: Indicative baseline numbers

Overview

1.58. This Annex provides indicative baseline data for both GDN and other "transmission connected customer" (TCC) offtake points for both the transitional and the enduring periods.

Transitional baselines

1.59. The transitional baseline data included in this Annex have been provided by NGG NTS, following some minor revisions to the baseline numbers presented in the Initial Proposals consultation.

1.60. It is noted that the baseline data provided in Table 7.1 below is based on the same NGG NTS modelling assumptions as those set out in the Initial Proposals consultation. As such, we only highlight variations from the transitional baseline presented in the Initial Proposals consultation below.

1.61. The table presented below contains:

- GDN transitional baseline data for flat capacity; and
- TCC transitional baseline data for NTS exit capacity.

1.62. The adjustments made, since our Initial Proposals consultation have been to re-distribute capacity over certain DNs' offtakes in order to accommodate their Offtake Capacity Statement bookings. There were also a few adjustments to baselines for TCCs following enquiries from the parties involved.

Enduring baselines

1.63. In the Initial Proposals consultation, we stated that enduring baseline numbers should be consistent with the nodal baselines specified for the transitional period with adjustments to:

- Reflect the proposed product definitions for the enduring period; and
- Adjust upwards the nodal baselines for the five sites in the constrained south west quadrant that have historically been interruptible.

1.64. As stated in paragraph 1.34, following the specification of a flexibility product definition by NGG NTS, it is now possible to present our proposals for enduring period baselines. With respect to the flexibility product, and consistent with the

product definition proposed by NGG NTS, a national capacity release obligation fro flexibility capacity is proposed at 238 GWh/day for each year of the enduring period in the next price control period.

1.65. The flat baselines for the enduring period are the same as those presented for the transitional period, with the exception of the five interruptible sites where baselines have been subject to upwards revision as discussed in our Initial Proposals consultation. The flat baselines for the enduring period are presented in Table A7.1.1 below with the revisions to SW interruptible sites highlighted in bold.

Table A7.1: Indicative baseline data for the transitional period and enduring periods

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Bacton	GDN (EA)	3.66	3.66
Brisley	GDN (EA)	3.11	3.11
Cambridge	GDN (EA)	0.00	0.00
Great Wilbraham	GDN (EA)	35.59	35.59
Matching Green	GDN (EA)	83.85	83.85
Peterborough Eye/Tee	GDN (EA)	25.45	25.45
Roudham Heath	GDN (EA)	14.70	14.70
Royston	GDN (EA)	2.67	2.67
Whitwell	GDN (EA)	161.87	161.87
West Winch	GDN (EA)	11.69	11.69
Yelverton	GDN (EA)	84.44	84.44
Alrewas	GDN (EM)	92.15	92.15
Blaby	GDN (EM)	11.03	11.03
Blyborough	GDN (EM)	90.89	90.89
Caldecott	GDN (EM)	11.08	11.08
Thornton Curtis (DN)	GDN (EM)	106.64	106.64
Drointon	GDN (EM)	107.51	107.51
Gosberton	GDN (EM)	15.79	15.79
Kirkstead	GDN (EM)	1.21	1.21
Market Harborough	GDN (EM)	9.48	9.48
Silk Willoughby	GDN (EM)	3.53	3.53
Sutton Bridge	GDN (EM)	1.15	1.15
Tur Langton	GDN (EM)	82.52	82.52
Walesby	GDN (EM)	0.93	0.93
Asselby	GDN (NE)	3.64	3.64
Baldersby	GDN (NE)	1.34	1.34
Burley Bank	GDN (NE)	20.31	20.31
Ganstead	GDN (NE)	23.15	23.15
Pannal	GDN (NE)	148.41	148.41

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Paull	GDN (NE)	38.14	38.14
Pickering	GDN (NE)	9.38	9.38
Rawcliffe	GDN (NE)	3.42	3.42
Towton	GDN (NE)	81.13	81.13
Bishop Auckland	GDN (NO)	69.26	69.26
Coldstream	GDN (NO)	1.93	1.93
Corbridge	GDN (NO)	0.07	0.07
Cowpen Bewley	GDN (NO)	53.71	53.71
Elton	GDN (NO)	33.26	33.26
Guyzance	GDN (NO)	2.19	2.19
Humbleton	GDN (NO)	0.15	0.15
Keld	GDN (NO)	1.70	1.70
Little Burdon	GDN (NO)	17.75	17.75
Melkinthorpe	GDN (NO)	0.34	0.34
Saltwick Pressure Controlled	GDN (NO)	9.22	9.22
Saltwick Volumetric Controlled	GDN (NO)	69.26	69.26
Thrintoft	GDN (NO)	5.16	5.16
Towlaw	GDN (NO)	0.55	0.55
Wetheral	GDN (NO)	26.86	26.86
Horndon	GDN (NT)	46.41	46.41
Luxborough Lane	GDN (NT)	165.30	165.30
Peters Green	GDN (NT)	348.98	348.98
Peters Green South Mimms	GDN (NT)	0.00	0.00
Winkfield	GDN (NT)	15.91	15.91
Audley	GDN (NW)	8.20	8.20
Blackrod	GDN (NW)	136.81	136.81
Ecclestone	GDN (NW)	21.14	21.14
Holmes Chapel	GDN (NW)	20.83	20.83
Lupton	GDN (NW)	16.23	16.23
Malpas	GDN (NW)	0.49	0.49
Mickle Trafford	GDN (NW)	29.58	29.58
Partington	GDN (NW)	96.29	96.29
Samlesbury	GDN (NW)	140.68	140.68
Warburton	GDN (NW)	107.25	107.25
Weston Point	GDN (NW)	30.64	30.64
Aberdeen	GDN (SC)	38.44	38.44
Armadale	GDN (SC)	3.01	3.01
Balgray	GDN (SC)	11.40	11.40
Bathgate	GDN (SC)	24.22	24.22
Broxburn	GDN (SC)	64.37	64.37
Careston	GDN (SC)	3.05	3.05
Drum	GDN (SC)	77.53	77.53
St Fergus	GDN (SC)	0.88	0.88

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Glenmavis	GDN (SC)	145.79	145.79
Hume	GDN (SC)	1.22	1.22
Kinknockie	GDN (SC)	2.35	2.35
Langholm	GDN (SC)	0.15	0.15
Lauderhill	GDN (SC)	0.00	0.00
Lockerbie	GDN (SC)	5.70	5.70
Netherhowcleugh	GDN (SC)	0.20	0.20
Pitcairngreen	GDN (SC)	1.59	1.59
Soutra	GDN (SC)	8.94	8.94
Stranraer	GDN (SC)	0.68	0.68
Mosside	GDN (SC)	0.00	0.00
Farningham	GDN (SE)	135.12	135.12
Shorne	GDN (SE)	67.06	67.06
Tatsfield	GDN (SE)	276.46	276.46
Winkfield	GDN (SE)	106.26	106.26
Braishfield A	GDN (SO)	99.23	99.23
Braishfield B	GDN (SO)	46.65	46.65
Hardwick	GDN (SO)	118.68	118.68
Ipsden	GDN (SO)	12.39	12.39
Ipsden 2	GDN (SO)	14.25	14.25
Mappowder	GDN (SO)	47.68	47.68
Winkfield	GDN (SO)	79.91	79.91
Aylesbeare	GDN (SW)	22.75	22.75
Cirencester	GDN (SW)	9.18	9.18
Coffinswell	GDN (SW)	0.00	0.00
Easton Grey	GDN (SW)	30.89	30.89
Evesham	GDN (SW)	6.58	6.58
Fiddington	GDN (SW)	26.64	26.64
Ilchester	GDN (SW)	33.07	33.07
Kenn	GDN (SW)	70.91	70.91
Littleton Drew	GDN (SW)	2.84	2.84
Lyneham	GDN (SW)	0.00	0.00
Pucklechurch	GDN (SW)	28.38	28.38
Ross	GDN (SW)	4.28	4.28
Seabank (DN)	GDN (SW)	57.62	57.62
Alrewas	GDN (WM)	130.79	130.79
Aspley	GDN (WM)	84.65	84.65
Audley	GDN (WM)	21.83	21.83
Austrey	GDN (WM)	86.09	86.09
Leamington	GDN (WM)	4.26	4.26
Lower Quinton	GDN (WM)	29.91	29.91
Milwich	GDN (WM)	21.04	21.04
Ross	GDN (WM)	16.52	16.52

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Rugby	GDN (WM)	80.08	80.08
Shustoke	GDN (WM)	44.76	44.76
Stratford-upon-Avon	GDN (WM)	4.68	4.68
Maelor	GDN (WN)	57.56	57.56
Dowlais	GDN (WS)	113.11	113.11
Dyffryn Clydach	GDN (WS)	47.92	47.92
Gilwern	GDN (WS)	46.67	46.67
Abson (Seabank Power Station phase I)	TCC - FIRM	27.80	**36.59**
Bacton (Great Yarmouth)	TCC - FIRM	20.00	20.00
Barking (Horndon)	TCC - INTERRUPTIBLE	58.60	58.60
Billingham ICI (Terra Billingham)	TCC - FIRM	43.60	43.60
Blackness (BP Grangemouth)	TCC - FIRM	27.30	27.30
Blyborough (Brigg)	TCC - INTERRUPTIBLE	16.90	16.90
Blyborough (Cottam)	TCC - INTERRUPTIBLE	17.60	17.60
Burton Point (Connahs Quay)	TCC - INTERRUPTIBLE	73.20	73.20
Caldecott (Corby Power Station)	TCC - FIRM	21.10	21.10
Deeside	TCC - FIRM	28.50	28.50
Didcot A	TCC - INTERRUPTIBLE	0.00	**87.29**
Didcot B	TCC - FIRM	50.50	50.50
Eastoft (Keadby Blackstart)	TCC - INTERRUPTIBLE	2.40	2.40
Eastoft (Keadby)	TCC - FIRM	36.10	36.10
Enron Billingham	TCC - INTERRUPTIBLE	121.50	121.50
Epping Green (Enfield Energy, aka Brimsdown)	TCC - FIRM	18.40	18.40
Ferny Knoll (AM Paper)	TCC - FIRM	1.10	1.10
Goole (Guardian Glass)	TCC - FIRM	1.60	1.60
Gowkhall (Longannet)	TCC - FIRM	43.30	43.30
Harwarden (Shotton, aka Shotton Paper)	TCC - FIRM	11.60	11.60
Hollingsgreen (Hays Chemicals)	TCC - INTERRUPTIBLE	3.30	3.30
Medway (aka Isle of Grain Power Station, NOT Grain Power)	TCC - INTERRUPTIBLE	38.10	38.10
Middle Stoke (Damhead Creek, aka Kingsnorth Power Station)	TCC - FIRM	41.00	41.00
Moffat (Irish Interconnector)	INTERCONNECTOR - FIRM, EXIT ONLY	433.40	433.40
Peterborough (Peterborough Power Station)	TCC - INTERRUPTIBLE	23.30	23.30
Pickmere (Winnington Power, aka Brunner Mond)	TCC - FIRM	15.40	15.40
Roosecote (Roosecote Power Station)	TCC - INTERRUPTIBLE	14.70	14.70

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Rosehill (Saltend Power Station)	TCC - FIRM	57.80	57.80
Ryehouse	TCC - FIRM	38.70	38.70
Saddle Bow (Kings Lynn)	TCC - FIRM	18.00	18.00
Saltend BPHP (BP Saltend HP)	TCC - FIRM	9.10	9.10
Sandy Lane (Blackburn CHP, aka Sappi Paper Mill)	TCC - FIRM	4.60	4.60
Seabank (Seabank Power Station phase II)	TCC - FIRM	19.10	19.10
Sellafield Power Station	TCC - INTERRUPTIBLE	12.30	12.30
Shellstar (aka Kemira, not Kemira CHP)	TCC - FIRM	14.00	14.00
Shellstar (aka Kemira, not Kemira CHP)	TCC - INTERRUPTIBLE	2.30	2.30
Shotwick (Bridgewater Paper)	TCC - FIRM	5.50	5.50
St. Fergus (Peterhead)	TCC - FIRM	108.30	108.30
St. Neots (Little Barford)	TCC - FIRM	35.20	35.20
Stallingborough	TCC - FIRM	28.20	28.20
Stallingborough	TCC - FIRM	38.40	38.40
Stanford Le Hope (Coryton)	TCC - FIRM	36.60	36.60
Staythorpe PH1	TCC - FIRM	38.20	38.20
Staythorpe PH2	TCC - FIRM	38.20	38.20
Sutton Bridge	TCC - FIRM	37.50	37.50
Teesside (BASF, aka BASF Teesside)	TCC - FIRM	9.70	9.70
Teesside Hydrogen	TCC - FIRM	6.60	6.60
Terra Nitrogen (aka ICI/Terra Severnside)	TCC - FIRM	0.70	**13.10**
Thornton Curtis (Humber Refinery, aka Immingham)	TCC - FIRM	46.90	46.90
Thornton Curtis (Killingholm B)	TCC - INTERRUPTIBLE	45.00	45.00
Thornton Curtis (Killingholme A)	TCC - FIRM	36.30	36.30
Tonna (Baglan Bay)	TCC - FIRM	26.80	26.80
Weston Point (Castner Kelner, aka ICI Runcorn)	TCC - FIRM	11.70	11.70
Weston Point (Rocksavage)	TCC - FIRM	38.19	38.19
Wragg Marsh (Spalding)	TCC - FIRM	42.00	42.00
Zeneca (ICI Avecia, aka 'Zenica')	TCC - FIRM	0.10	0.10
Hatfield Moor Max Refill	STORAGE SITE	30.00	30.00
Hole House Max Refill	STORAGE SITE	120.00	120.00
Partington Max Refill	STORAGE SITE	2.40	2.40
Glenmavis Max Refill	STORAGE SITE	1.60	1.60
Barton Stacey Max Refill	STORAGE SITE	0.00	**100.94**
Avonmouth Max Refill	STORAGE SITE	0.00	**2.30**
Dynevor Max Refill	STORAGE SITE	2.60	2.60

Offtake Point	**Type of Offtake**	**Transitional baseline (GWh/day)**	***Enduring flat baseline (GWh/day)***
Garton Max Refill	STORAGE SITE	211.00	211.00
Hornsea Max Refill	STORAGE SITE	22.00	22.00
Rough Max Refill	STORAGE SITE	160.00	160.00
Bacton (IUK)	INTERCONNECTOR	623.58	623.58
Bacton (BBL)	*INTERCONNECTOR*	*0.00*	0.00

Appendix 8 - Revenue drivers for NGET, SHETL and STPL

Introduction

1.1. This appendix provides further technical detail on how the proposed revenue drivers for NGET, SHETL and SPTL are proposed to operate. The parameters set out are based on information provided by the companies which is subject to further review by Ofgem. The numbers in this appendix might therefore be different in our final proposals.

Definitions

1.2. The revenue drivers we are proposing will be functions of generation and demand. We therefore need to define clearly how generation and demand will be measured.

New generation

1.3. We are proposing two different ways of measuring new generation, which will affect revenue allowances at different points in time. First, when a point has been reached pre-connection when it is reasonably certain that the project will proceed. We propose to trigger this when the generator has provided a sufficient level of financial commitment (or 'user commitment'). The mechanics of this will vary between SPTL and SHETL, as compared to NGET.

NGET

1.4. Generators have a direct contractual relationship with NGET, in its role as GB system operator, which requires the generator to post financial security prior to being connected. The generator currently has the choice of two ways of doing this. First, by providing security against a rolling 12 month estimate of the attributable actual costs incurred in order to connect the generator ('Final Sums'). Second, by providing security calculated as a multiple of transmission charges they will pay once they are connected ('Generic Final Sums').

1.5. We propose to recognise new amounts of generation pre-connection from the first point at which the cumulative amount they have provided security against (under either Final Sums or Generic Final Sums) is at least 25 per cent of the estimated total amount of security they will have provided by the time they connect. NGET will report the cumulative amount and the annual additional amount of new generation (MW) recognised in this way to Ofgem each year.

1.6. We propose to recognise the connection of new generation for NGET from the point at which Transmission Entry Capacity (TEC) (or its equivalent) has been allocated. Again, NGET will report on this annually to Ofgem.

SPTL/SHETL

1.7. SPTL and SHETL contract with NGET, rather than the connecting generator directly. Hence the rule that we propose for NGET does not work as well. SPTL and SHETL provide to NGET, for each new generation connection project, a quarterly progress report which includes information on forecast costs. If NGET has a problem with the level of user commitment being provided to it by the generator, then this will be reflected back to SPTL or SHETL. Otherwise NGET will be exposed to SPTL/SHETL costs which it cannot recover from the generator.

1.8. Hence, if SPTL or SHETL have not been told to cease works for a particular project (a line of communication provided for under the contractual interface between NGET and SPTL/SHETL), then it implies that NGET are content with the level of user commitment being provided by the user. We therefore propose to use the point at which SPTL or SHETL, for any individual new generation connection, has notified NGET (through its quarterly report) that it has spent at least 25 per cent of the anticipated total cost of the works required. SPTL and SHETL will report the cumulative amount and the annual additional amount of new generation (MW) recognised in this way to Ofgem each year.

1.9. We propose to define completion as when SPTL or SHETL has made available to NGET the assets specified as local infrastructure in its connection agreement with NGET. This is a formal part of the existing contractual interface. Again, SPTL and SHETL will report to Ofgem on this annually.

Generation closures

1.10. If a generator closes (i.e. hands back its Transmission Entry Capacity, TEC), then this can have the effect of reducing the need for investment. This, however, is more relevant to considerations of deep network reinforcement (where the impact of new connection and closures might be expected to net each other off to a greater extent) rather than local connection costs.

1.11. However, it would not necessarily be appropriate to count generation closures with immediate effect. The transmission companies will not necessarily know in advance whether a generator is going to hand back its TEC - and cannot necessarily respond immediately to halt investment that, as a result of the closure, is no longer required. We therefore propose to recognise closure information **with a lag of one year** for the deep reinforcement revenue drivers for SPTL and SHETL, and for the zonal surplus/deficit revenue driver for NGET.

Demand

1.12. For NGET the proposed revenue drivers also rely on measures of demand. For the zonal exit revenue driver we are proposing that the measure should be forecast local (i.e. DNO) peak demand, and for the zonal surplus/deficit revenue driver should be national peak demand. We consider that this distinction more accurately reflects the respective cost drivers.

Generation and demand starting points

1.13. The baseline allowances for load related capital expenditure we have included in the main RAV are based on assessment of forecasts for the seven year period from 1 April 2005 to 31 March 2012. To ensure consistency, the starting point for measuring changes in generation and demand (and hence zone surpluses or deficits, in the case of NGET) should therefore be the position as at 1 April 2005.

Zones

1.14. For NGET the revenue driver will be based on zones. The zones we are proposing at this stage, based on analysis provided by NGET, are as follows:

- South & South West
- Thames Estuary
- London
- South Wales
- East of England and Home Counties
- West Midlands
- East Midlands
- North West and North Wales
- North East

1.15. The proposed zones are derived from the system boundaries identified in NGET's Seven Year Statement (SYS) and have been informed by analysis of the 'clusters' of connection offers currently being processed. Connection offers with significant common works are, generally, in the same zone.

Revenue driver values

1.16. The method we propose for the revenue drivers is based around the concept of a 'Revenue Driver RAV'. If changes in the pattern of generation (and demand, for NGET) are such that we need to adjust revenues, then the adjustment will be based on (a) recognising an additional capital sum, and (b) allowing a revenue stream based on depreciation and return in respect of this capital sum.

1.17. The values for the revenue drivers listed below represent the capital sum that will be recognised for the purposes of deriving the additional revenue stream, if the relevant revenue driver is triggered.

SPTL

Local connection costs

1.18. There will be no additional revenue for SPTL until 1,734 MW of new (from 1 April 2005) generation has met the pre-connection ('user commitment') trigger described above.

1.19. Once this point has been reached, then 75 per cent of subsequent costs incurred by SPTL will be added to its Revenue Driver RAV on an 'as incurred' basis. Further, once the completion trigger has been reached for 1,734 MW of new generation, then a given £ per kW will be added to the RAV. We are presently considering ways of improving the accuracy of a £ per kW figure in order to reflect the major cost drivers of local connections. However, for illustration purposes, we shall assume a local connection revenue driver of £42.90 per kW, consistent with our consultants' views on entry triggered infrastructure capex, will be added to SPTL's Revenue Driver RAV (subject to Ofgem reserving the right to examine the efficiency of the 75 per cent of costs that were passed through).

1.20. As described in chapter 9 there will be adjustment to ensure that the difference between the actual capital expenditure and the capital sum used to derive the revenue stream is not greater than 15 per cent. This adjustment will be done once the completion trigger has been reached for 1,734 MW of new generation, and annually thereafter. It will be given effect through adjustments to the Revenue Driver RAV.

Deep reinforcement costs

1.21. The revenue driver we are proposing for deep reinforcement costs for SPTL is based on the specification of discrete numbers of individual allowances which will be triggered if certain specified conditions are met. The allowances have been calculated on the basis of the efficient cost of specific projects which we currently consider to represent appropriate network design in the event of the specified conditions being met. The specified costs and conditions are still subject to further analysis and review. However, we intend to publish relevant analysis provided by the licensees on our website, as it becomes available.

1.22. The deep reinforcement costs are, in effect, additions to SPTL's Revenue Driver RAV waiting to be triggered. Once the specified conditions are met using the pre-connection 'user commitment' trigger, then 75 per cent of the value specified in the table above would be added to SPTL's Revenue Driver RAV. The remaining 25 per

cent would be added when the conditions are met using the completion trigger. This provides SPTL with a financial incentive at the margin to get the works completed.

Calculating revenue allowances

1.23. The mechanisms described above provide for a Revenue Driver RAV to be created for SPTL. We are proposing that the revenue allowance should be calculated on the basis of the Revenue Driver RAV being depreciated over 20 years, and an allowed rate of return consistent with the main price control.

1.24. The mechanisms described above are intended to operate in respect of new generation projects that reach the pre-connection trigger point before 1 April 2012. Once these projects have reached completion or terminated, then un-depreciated value of the SHETL Revenue Driver RAV would be expected to be incorporated within the main SHETL RAV.

SHETL

Local connection costs

1.25. There will be no additional revenue for SHETL until 1,489 MW of new (from 1 April 2005) generation have met the pre-connection 'user commitment' trigger described above.

1.26. Once this point has been reached, then 75 per cent of subsequent costs incurred by SHETL will be added to its Revenue Driver RAV on an 'as incurred' basis. Further, once the completion trigger has been reached for 1,489 MW of new generation then a given £ per kW will be added to the RAV. We are presently considering ways of improving the accuracy of a £ per kW figure in order to reflect the major cost drivers of local connections. However, for illustration purposes, we shall assume a local connection revenue driver of £25.40 per kW, consistent with our consultants' views on entry triggered infrastructure capex, will be added to SHETL's Revenue Driver RAV (subject to Ofgem reserving the right to examine the efficiency of the 75 per cent of costs that were passed through).

1.27. As described in chapter 9 there will be adjustment to ensure that the difference between the actual capital expenditure and the capital sum used to derive the revenue stream is not greater than 15 per cent. This adjustment will be done once the completion trigger has been reached for 1,489 MW of new generation, and annually thereafter. It will be given effect through adjustments to the Revenue Driver RAV.

Deep reinforcement costs

1.28. The revenue driver we are proposing for deep reinforcement costs for SHETL is based on the specification of discrete numbers of individual allowances which will be triggered if certain specified conditions are met. The allowances have been calculated on the basis of the efficient cost of specific projects which we currently consider to represent appropriate network design in the event of the specified conditions being met. The specified costs and conditions are still subject to further analysis and review. However, we intend to publish relevant analysis provided by the licensees on our website, as it becomes available.

1.29. The deep reinforcement costs are, in effect, additions to SHETL's Revenue Driver RAV waiting to be triggered. Once the specified conditions are met using the pre-connection 'user commitment' trigger, then 75 per cent of the value specified in the table above would be added to SHETL's Revenue Driver RAV. The remaining 25 per cent would be added when the conditions are met using the completion trigger. This provides SHETL with a financial incentive at the margin to get the works completed.

Calculating revenue allowances

1.30. The mechanisms described above provide for a Revenue Driver RAV to be created for SHETL. We are proposing that the revenue allowance should be calculated on the basis of the Revenue Driver RAV being depreciated over 20 years, and an allowed rate of return consistent with the main price control.

1.31. The mechanisms described above are intended to operate in respect of new generation projects that reach the pre-connection trigger point before 1 April 2012. Once these projects have reached completion or terminated, then the un-depreciated value of the SHETL Revenue Driver RAV would be expected to be incorporated within the main SHETL RAV (subject to Ofgem reserving the right to examine the efficiency of the 75 per cent of costs that were permitted to be passed through).

NGET

1.32. We are proposing slightly different mechanics for NGET's revenue drivers as compared to SPTL and SHETL. We do however retain the concept of a Revenue Driver RAV, with additions to it if there are investment-triggering changes to zonal:

- Entry;
- Exit;
- Surplus; or
- Deficit.

1.33. Changes in zonal entry, exit, surplus or deficit will be measured relative to the actual position at 1 April 2007. As with SPTL and SHETL, the changes to these variables can be measured in two ways depending on whether new generation is recognised (a) when a pre-connection 'user commitment' trigger is met, or (b) when it is connected.

1.34. We are proposing that 75 per cent of relevant actual expenditure should be incorporated into NGET's Revenue Driver RAV on an 'as incurred basis' to accommodate changes in zonal entry, exit surplus or deficit. The remainder of the revenue allowance will be provided through further additions to NGET's Revenue Driver RAV consistent with measures of entry, surplus or deficit on the basis of connected generation (or the physical availability of addition exit capacity).

Calculating revenue allowances

1.35. The mechanisms described above provide for a Revenue Driver RAV to be created for NGET. This will provide revenues to accommodate changes in entry and exit (and zonal surpluses and deficits) relative to the position on 1 April 2007. The main allowances for capital expenditure, however, already include allowances for one possible scenario of changes in these variables.

1.36. The revenue drivers therefore need to top up or reduce allowances to the extent that actual generation and demand vary from what has been assumed in setting this baseline allowances. We are proposing to do this by defining a default profile for NGET's Revenue Driver RAV which, in effect, mirrors (and sets as negative) the associated part of the main RAV. If, therefore, the path of actual changes in generation and demand follow the path assumed in setting the baseline capital expenditure allowance, then the Revenue Driver RAV will be approximately zero.

1.37. We are proposing that the revenue allowance should be calculated on the basis of the Revenue Driver RAV being depreciated over 20 years, and an allowed rate of return consistent with the main price control.

1.38. The mechanisms described above are intended to operate in respect of new generation projects that reach the pre-connection trigger point before 1 April 2012. Once these projects have reached completion (or terminated) then the un-depreciated value of the NGET Revenue Driver RAV would be expected to be incorporated within the main NGET RAV (subject to Ofgem reserving the right to examine the efficiency of the 75 per cent of costs that were permitted to be passed through).

Appendix 9 - Gas Entry Incentives

Introduction

1.1. This appendix discusses the work we have carried out to further update our analysis of the levels of the gas entry baselines, revenue drivers and buyback parameters. It also indicates the ongoing work to finalise these for the December final proposals document.

Baselines

The June document position[5]

1.2. The June document included initial proposals for gas entry baselines for 15 main aggregate system entry points (or "ASEPs") for formula year 2008/09. Ofgem's intention was that the baselines would be set 'flat'[6].

1.3. The proposed baselines were derived from network modelling analysis undertaken by NGG NTS based on our modelling instructions. These instructions included assumptions on a number of technical parameters including the supply and demand scenarios and the method by which the network is kept in balance. The network modelling analysis was performed for three different supply scenarios from NGG NTS's December 2005 Ten Year Statement (namely, Auctions+, Transit UK and Global LNG). We asked NGG NTS to keep the network in balance using "least helpful supply substitution".

1.4. Our baseline proposals were then calculated from NGG NTS's modelling data by taking the average "baseflow" under the balanced network across the three supply scenarios and adding 90 per cent of the average "free increment" for each entry point. The underlying assumption was that NGG NTS can provide 90 per cent of the free increment at all entry points simultaneously, which we stated was untested.

[5] Technical terms in this section and in later sections, such as "least helpful supply substitution", "baseflows" and "free increments", are explained in more detail in our June 2006 initial proposals and in our March 2006 third consultation.

[6] Note however that for the first three years of the control there can be no user commitments that will not be known about on 1st April 2007. It is likely therefore these amounts can be included in the licence in a simple way (as increases above the baselines for formula year 2009/10 and decreases below the baseline for formula year 2007/08).

NGG NTS's position

1.5. NGG NTS responded that our proposed baselines are (on average) too high. NGG NTS considered that our baselines are above system capability, and that they are likely to trigger significant buy back exposure to customers under certain supply scenarios.

1.6. NGG NTS proposed an alternative set of baselines which on average are lower than our baselines. NGG NTS's proposed baselines have been derived by estimating zonal capabilities (i.e. the capability of the network across interacting groups of entry points within the same geographical area). Our baselines were derived by estimating nodal capabilities (i.e. the capability of the network for each entry point considered in isolation, with lesser consideration of the interactions between entry points). This difference in approach largely explains why on average NGG NTS's baselines are lower than ours.

1.7. NGG NTS's response and details of their proposed baselines based on zonal analysis can be found on our website.[7] Following the submission of its response, we have met with NGG NTS to discuss their concerns and NGG NTS has submitted additional data to us explaining its zonal approach.

1.8. Table A9.1 below shows the difference between Ofgem's proposed baselines in the June document and NGG NTS's proposed baselines in their response to the June document. NGG NTS's baselines are on average about 30 per cent lower than Ofgem's initial proposals. However, for a few entry points (Isle of Grain, Milford Haven, and Garton) NGG NTS's baselines were higher.

[7] See Annex to Chapter 4 in NGG NTS (24 July 2006), Transmission Price Control Review: Initial Proposals, Response by National Grid, available at Ofgem's website www.ofgem.gov.uk

Table A9.1: Ofgem's Initial Proposals for Baselines (2008//09) versus NGG NTS's Proposed Baselines

	Ofgem Initial Proposals (2008/09)	Ofgem Initial Proposals (2008/09)	NGG's Proposed Baselines (2008)	Difference (Ofgem *minus* NGG)
	mscm/d	**GWh/d**	**GWh/d**	**GWh/d**
Easington	136	1,473	1,062	411
Bacton	196	2,119	1,768	351
Isle of Grain	39	425	453	-28
Milford Haven [1]	81	877	950	-73
St Fergus	163	1,769	1,342	427
Teesside	63	684	234	450
Barrow	62	669	240	429
Theddlethorpe	42	451	227	224
Burton Point [2]	24	260	55	205
Hole House Farm	25	265	26	239
Barton Stacey [3]	21	232	90	142
Hatfield Moor (storage)	33	360	22	338
Garton [4]	24	255	420	-165
Cheshire	44	480	214	266
Hornsea	20	221	175	46
Sub-total	**973**	**10,539**	**7,278**	**3,261**
Glenmavis	n/a	n/a	n/a	n/a
Partington	n/a	n/a	n/a	n/a
Avonmouth	n/a	n/a	n/a	n/a
Dynevor Arms	n/a	n/a	n/a	n/a
Hatfield Moor (onshore)	n/a	n/a	n/a	n/a
Wytch Farm	n/a	n/a	n/a	n/a
Burton Agnes (Caythorpe)	n/a	n/a	n/a	n/a
Winkfield	n/a	n/a	n/a	n/a
Blyborough (Welton)	n/a	n/a	n/a	n/a
Tatsfield	n/a	n/a	n/a	n/a
Albury	n/a	n/a	n/a	n/a
Palmers Wood	n/a	n/a	n/a	n/a
Fleetwood	n/a	n/a	n/a	n/a

Note:
[1] NGG's proposed baseline is 650 GWh/d from Oct-07 to Dec-08 and 950 GWh/d from Jan-09
[2] Burton Point is referred to as Point of Ayr in the Initial Proposals
[3] Barton Stacey is referred to as Humbly Grove in the Initial Proposals
[4] Garton is referred to as Aldborough in the Initial Proposals
n/a = not available
Conversion factor mscm/d to GWh/d: multiply by 10.83

Ofgem's further thinking

1.9. We intend to set baselines at levels consistent with the simultaneous physical accommodation of possible flows under a wide range (although not all possible) scenarios across entry points. This means that we intend to set baselines such that exposure to (operational) buy back risk will be residual, and relatively low. For the avoidance of doubt this does not mean that the network needs to be designed to accommodate simultaneous flows at each entry point at the level of the baselines. Further analysis is required to assess the operational buy-back risks associated with different baseline proposals, in particular NGG NTS's views on the risks of Ofgem's proposals. We will continue working with NGG NTS to assess such risks and try and quantify them.

1.10. In response to concerns expressed by NGG NTS and some shippers, we can clarify that we intend to set baselines such that no baseline is less than the amount of obligated capacity that NGG NTS has already sold in respect of that entry point. We intend to adjust the baselines proposed in the June document to address this concern and will publish revised baselines shortly.

1.11. In order to implement this change, we plan to increase baselines at some entry points to reflect past sales of obligated capacity, and to turn down baselines at other entry points within the same "zone" (as defined in a recent paper[8] by NGG NTS on the release of entry capacity in the constrained period) on a *pro rata* basis, in order to keep the total system capability implied by the baselines constant relative to the June initial proposals. This means we plan to turn down baselines at other entry points within the same zone relative to the baselines figures for these other entry points in our June initial proposals.

Next steps

1.12. As noted above, further analysis is required to assess the operational buy-back risks associated with different baseline proposals. Ofgem will continue working with NGG NTS to assess such risks and try and quantify them. This analysis will inform the setting of baselines for the December final proposals. If the buy-back risks associated with our revised baseline proposals are relatively high, we are likely to adjust them downwards (on average).

1.13. There is some other outstanding work on the quantification of baselines. This includes:

[8] The paper is available on the Joint Office website at http://www.gasgovernance.com/Code/Workstreams/TransmissionWorkstream/2006Meetings/ It is listed under the papers for the Transmission Workstream meeting of 7 September 2006 and referred to as "01 September 2006 - Optimising Entry Capacity, NTS Strawman". Appendix 1 of this NGG NTS paper contains the entry zones proposed by NGG NTS.

- Obtaining further network modelling analysis from NGG NTS (as requested in January 2006) for the remaining 13 entry points (including, for example, the four constrained LNG points) for which NGG NTS has not yet delivered modelling outputs, which we require to set baselines for those entry points, and

- Deriving adjustments to the baselines for the other years of the next price control period (i.e. other than formula year 2008/09) to reflect the user commitment signals given during the current price control period. Although baselines will be set 'flat' (i.e. be the same in all years) the amount of user commitment, and therefore the amount of capacity NGG NTS is obliged to make available, will be known in respect of the first three years of the control[9].

1.14. Ofgem may undertake additional work in some other areas including:

- Commission additional network modelling from NGG NTS, based on our modelling instructions, that considers alternative ways of looking at interactions between entry points (i.e. different from the analysis already carried out by NGG NTS, based on our instructions or based on its own initiative)

- Undertake sensitivity testing of alternative modelling assumptions, for example new supply and demand scenarios which are likely to come to light over the next few months, as this year's TBE (Transporting Britain's Energy) process run by NGG NTS draws to a close (however, we would need to have access to this new data in a reasonably short time frame in order to be able to incorporate it into our December final proposals), and

- Consider other possibly relevant factors such as off-peak system capabilities (our proposed baselines are based on peak-day analysis), and interactions with offtake baselines.

Revenue drivers

The June document position

1.15. Our June document contained initial proposals for nodal revenue drivers for 15 main ASEPs derived from network modelling on a 2008/09 base network. No revenue driver proposals were provided yet for the remaining ASEPs.

1.16. Our proposed revenue drivers were based on network modelling undertaken by NGG NTS based on our modelling instructions. For each entry point, we instructed NGG NTS to estimate the network reinforcement costs associated with four different flow increments at that entry point considered in isolation, of 25, 100, 500 and 1,000

[9] Note that because of the new substitution obligation on NGG NTS before incremental capacity release, the level of capacity (other than obligated incremental capacity) that NGG NTS is obliged to provide at each entry point for these years can subsequently vary from the baselines set out in NGG NTS's licence.

GWh/d respectively, for each of the three supply scenarios in NGG NTS's December 2005 Ten Year Statement (i.e. Auctions+, Global LNG, Transit UK). Our revenue drivers reflect NGG NTS's own estimates of the gross investment costs for each flow increment, *averaged across the three supply scenarios*, and divided by the respective flow increment. They can therefore be characterised as "gross unit revenue allowances". We proposed to let these gross unit revenue allowances vary with the demand for entry capacity, and therefore set "capacity ranges" centred on each flow increment, with each capacity range having a different unit allowance.

1.17. Implicit in our quantification of revenue drivers in the June document was that NGG NTS is funded solely for the amount of incremental entry capacity (above baselines) that is triggered by new user commitments signalled through the long term auctions.

1.18. Table A9.2 below sets out the revenue drivers we proposed in the June document.

Table A9.2: Ofgem's Initial Proposals for Revenue Drivers (2008/09 network, 2005/06 prices)

	OFGEM Initial Proposals (2008/09) Capacity Range (GWh/d)				
	0 - 50	50-250	250-750	750+	Average
ASEP	**£/kWh**	**£/kWh**	**£/kWh**	**£/kWh**	**£/kWh**
Easington	0.274	0.257	0.600	0.382	0.378
Bacton	0.627	0.522	0.869	0.582	0.650
Isle of Grain	0.347	0.308	0.651	0.539	0.461
Milford Haven	1.818	1.647	1.673	1.114	1.563
St Fergus	0.233	0.396	1.556	1.111	0.824
Teesside	0.264	0.204	0.193	0.245	0.226
Barrow	0.324	0.208	0.211	0.174	0.229
Theddlethorpe	0.746	0.230	0.620	0.413	0.502
Burton Point	0.971	0.589	0.310	0.199	0.517
Hole House Farm	1.118	0.525	0.211	0.117	0.493
Barton Stacey	1.067	0.410	0.637	0.634	0.687
Hatfield Moor (storage)	0.535	0.196	0.476	0.260	0.366
Garton	0.398	0.287	0.628	0.359	0.418
Cheshire	0.309	0.085	0.201	0.107	0.175
Hornsea	0.450	0.415	0.588	0.343	0.449

NGG NTS's position

1.19. In their response to the June document, NGG NTS disagreed with our decision to average the network reinforcement costs across the three supply scenarios, arguing that this will not ensure that the network is developed with an appropriate degree of flexibility. NGG NTS believes that if it invests based on the average of the three supply scenarios, this would "probably lead to significant constraints on the system under credible supply scenarios", the costs of which would "could be

significant" and would be passed through to customers, in full or in part, through the operational buyback regime.

1.20. NGG NTS has therefore proposed that revenue drivers should be set based on the "highest of the [three supply] scenarios [for each entry point]", arguing that this would be more consistent with ensuring that a network is developed with an appropriate degree of flexibility.

1.21. NGG NTS's response and details of their proposals for revenue drivers can be found on our website.[10] Following the submission of its response, we have met with NGG NTS to discuss their concerns and NGG NTS has submitted some additional information to us explaining its position on revenue drivers.

1.22. Table A9.3 below illustrates the difference between Ofgem's proposed revenue drivers in the June document and the revenue drivers implied by NGG NTS's response to the June document, with the latter based on taking the maximum of gross investment costs across the three supply scenarios for each entry point. For each entry point, the table represents the revenue driver as an unweighted average of the four component gross unit revenue allowances that make up the full capacity range.

1.23. Table A9.3 shows that under NGG NTS's proposed approach, the revenue drivers would on average be significantly higher than Ofgem's, by around 30 to 150 per cent.

[10] See Chapter 4 in NGG NTS (24 July 2006), Transmission Price Control Review: Initial Proposals, Response by National Grid, available at Ofgem's website www.ofgem.gov.uk.

Table A9.3: Ofgem's Initial Proposals for Revenue Drivers (2008/09 network, 2005/06 prices) versus NGG NTS's Implied Revenue Drivers

	OFGEM Initial Proposals	NGG's Implied Revenue Drivers	Difference (NGG *minus* Ofgem)	% Difference (NGG *minus* Ofgem)
ASEP	**£/kWh**	**£/kWh**	**£/kWh**	
Easington	0.378	0.491	0.113	30%
Bacton	0.650	0.984	0.334	51%
Isle of Grain	0.461	0.652	0.191	41%
Milford Haven	1.563	2.317	0.754	48%
St Fergus	0.824	1.095	0.271	33%
Teesside	0.226	0.337	0.111	49%
Barrow	0.229	0.304	0.075	33%
Theddlethorpe	0.502	0.825	0.323	64%
Burton Point	0.517	1.121	0.604	117%
Hole House Farm	0.493	1.061	0.568	115%
Barton Stacey	0.687	1.374	0.688	100%
Hatfield Moor (storage)	0.366	0.605	0.238	65%
Garton	0.418	0.574	0.156	37%
Cheshire	0.175	0.440	0.265	151%
Hornsea	0.449	0.624	0.175	39%
Glenmavis	n/a	n/a	n/a	n/a
Partington	n/a	n/a	n/a	n/a
Avonmouth	n/a	n/a	n/a	n/a
Dynevor Arms	n/a	n/a	n/a	n/a
Hatfield Moor (onshore)	n/a	n/a	n/a	n/a
Wytch Farm	n/a	n/a	n/a	n/a
Burton Agnes (Caythorpe)	n/a	n/a	n/a	n/a
Winkfield	n/a	n/a	n/a	n/a
Blyborough (Welton)	n/a	n/a	n/a	n/a
Tatsfield	n/a	n/a	n/a	n/a
Albury	n/a	n/a	n/a	n/a
Palmers Wood	n/a	n/a	n/a	n/a
Fleetwood	n/a	n/a	n/a	n/a
n/a = not available				

Ofgem's further thinking

1.24. Ofgem is exploring with NGG NTS its view that the proposed revenue drivers (based on the average of the three supply scenarios) would lead to significant constraints on the system under credible supply scenarios and therefore to significant operational buyback exposure. In the absence of convincing evidence for this view, it does not seem appropriate to change our position on revenue drivers to the extent proposed by NGG NTS.

1.25. However, we consider that the network should maintain the existing level of network flexibility (as assumed in setting baselines) when there is a new demand for capacity. Also, we are proposing to set baselines at levels consistent with physically accommodating possible flows under a wide range of scenarios (although not all possible ones) and with the expectation of buy back risk being residual and relatively low. Therefore, it seems reasonable that our revenue drivers should enable NGG NTS to fund investment for new demand to such an extent that they do not lead to significant additional buyback costs under the same wide range of flow scenarios. Arguably, our proposed revenue drivers in the June document do not enable this, as NGG NTS would not receive sufficient funding to accommodate new demand under a supply scenario (used in the analysis) with higher than average investment costs.

1.26. We are therefore considering, for the December final proposals, to adjust our proposed revenue drivers upwards to a position that is nearer to a (plausible) flow scenario with higher than average investment costs. This does not necessarily mean however, as NGG NTS is proposing, that for each entry point we will pick the maximum of the cost figures across the three supply scenarios.

1.27. For example, it may be reasonable to adjust our nodal revenue drivers upwards by basing them on the investment cost estimates associated with the Transit UK scenario which is the highest cost scenario of the three supply scenarios. Alternatively, nodal revenue drivers could be adjusted upwards in other ways, for example by increasing all of the nodal revenue drivers in the June document by the same percentage figure.

1.28. Following the publication of the June initial proposals, we have been considering the unit cost assumptions underlying the revenue drivers. This is still work in progress, but initial indications are that NGG NTS's assumptions on pipeline unit costs are approximately 3 to 9 per cent above our estimates of efficient costs, depending on the assumed supply scenario. We intend to use the final conclusions of this work to inform our views on revenue drivers for the December final proposals.

Next steps

1.29. The key next step is to consider in what way, as discussed above, we adjust the revenue drivers upwards to a position that is nearer to a (plausible) scenario with higher than average investment costs. In order to do so, we may either use existing

modelling evidence (e.g. for the Transit UK scenario), or commission new modelling evidence (based on alternative modelling assumptions - for example, strict application of "least helpful supply substitution" throughout the analysis - which is not what NGG NTS has done so far but was what we asked for - should in principle result in upward adjustments to the revenue drivers proposed in the June document).

1.30. However, we are also considering adjusting any revised revenue drivers downwards, to account for interactions between entry points (e.g. in case of non-simultaneous flows from different entry points, the same piece of investment may be able to accommodate new demands at two interacting entry points, and hence NGG NTS only needs to receive this funding once and not twice) and for interactions with offtake revenue drivers.

1.31. We intend to make further adjustments to our proposed revenue drivers in the light of the ongoing work on unit costs assumptions described above.

1.32. There is some other outstanding work on the quantification of revenue drivers. This includes obtaining further network modelling analysis from NGG NTS (as requested in January 2006) for the remaining 13 entry points (including, for example, the four constrained LNG points) for which NGG NTS has not yet delivered modelling outputs, which we require to set revenue drivers for those entry points.

1.33. Ofgem may undertake additional work in some other areas including:

- undertake sensitivity testing of alternative modelling assumptions, for example using "least helpful supply substitution" throughout as explained above, or using new supply and demand scenarios (however as for baselines, we would need to have access to this new data in a reasonably short timeframe in order to be able to incorporate it into our December final proposals); and
- consider other possibly relevant factors such as: the resetting of revenue drivers (if at all) as a result of the new substitution obligation on NGG NTS for the unconstrained period; how to account for the sequential nature of investments at different entry points (if at all) in setting *ex ante* nodal revenue drivers; how to apply revenue drivers when there are sequential signals for obligated incremental entry capacity (from one year to the next) at the same entry point; and the final functional form for revenue drivers (including the setting of capacity bands).

Buy-back incentives

The June document position

1.34. Our proposal for buyback in the June document was to have an administered buyback price for buybacks relating to the delivery of incremental capacity. For buybacks relating to network operations the buyback price was uncapped. However NGG NTS would only bear a proportion of the operational buyback costs and its

overall exposure to these costs would be capped. These proposals were set out in Chapter 11 of the June document.

1.35. We sought to establish a relationship between the system average price (SAP) in the on-the-day commodity market (OCM) and the buyback price for each prompt buyback action taken since 1 April 2002. This relationship was used to estimate the administered buyback price. On this basis we proposed an administered buyback price of 0.52 p/kWh for the incremental buyback incentive.

1.36. For the operational buyback incentive, we proposed that the downside sharing factor should be increased to 50 per cent to reflect the reduced risk while the upside sharing factor remained at 50 per cent. We also proposed that the cap and collar should be increased to £36m.

NGG NTS's position

1.37. NGG NTS expressed serious concern that an uncapped exposure to incremental buyback costs would leave them with a very large downside risk. NGG NTS also argued that there should be a potential reward for taking on additional risks.

1.38. NGG NTS had concerns about its difficulties in gaining planning consents and therefore suggested that it should have its exposure to buyback deferred if there were delays in gaining such consents.

1.39. NGG NTS's thought was that it was inappropriate to discuss the parameters of the operational buyback incentive until other aspects of the control were determined.

1.40. NGG NTS's response to the June document including details of their views on the proposed buyback incentives can be found on our website.[11] Following the submission of its response, we have met with NGG NTS to discuss their concerns and NGG NTS has submitted additional information to us concerning the incremental buyback incentive.

Ofgem's further thinking

1.41. We have considered NGG NTS's concerns about its exposure to buyback costs under the incremental buyback regime and determined that it is appropriate to cap this exposure at £36m, as discussed in the main document.

[11] See Annex to Chapter 4 in NGG NTS (24 July 2006), Transmission Price Control Review: Initial Proposals, Response by National Grid, available at Ofgem's website www.ofgem.gov.uk.

1.42. We have considered NGG NTS's views on the process for gaining planning consent and, on the basis of the evidence presented, have extended the default lead time by 6 months. We have also introduced flexibility in establishing lead times set out in Chapter 10 of the main document. However we continue to consider that managing planning risk is an important part of the business of a network company and that it would be inappropriate to give NGG NTS exemption from exposure to these risks.

1.43. On future operational buyback risks above baselines, we intend to set revenue drivers to enable NGG NTS to fund investment for new demand such that they do not lead to significant additional (operational) buyback costs under a wide range of flow scenarios. Therefore, we do not anticipate that we would need to provide for an additional allowance for operational buy-backs, over and above the allowance provided to meet baselines, for operational buy back actions that result from accommodating future incremental obligated entry capacity. Our expectation is that, under our final revenue driver proposals, such incremental capacity would not lead to *additional* expected operational buy-back costs.

1.44. We are continuing to develop the parameters of the price control and will further develop the buyback parameters as part of that process.

Next steps

1.45. Further work on quantifying and fine tuning the buyback parameters will continue as the baselines and revenue drivers are developed. A key factor in this will be to consider the likely level of operational buyback exposure associated with different baseline proposals. This additional work will inform the setting of a target cost for the operational buyback incentive which has not been set so far.

Appendix 10 - Capex Incentives

Introduction

1.1. From an early stage in the TPCR, We highlighted and focussed on the challenges of setting an appropriate incentive framework within an environment of increasing investment. Chapter 7 of the Updated Proposals sets out our proposal to adopt a fixed 25 per cent incentive for capital expenditure from 1 April 2007. This appendix sets out how the fixed incentive might be applied in practice.

The incentive mechanism

1.2. The capital expenditure incentive mechanism applies to RAV additions whether above or below the level of the allowance. As with other incentive mechanisms in these Updated Proposals, the revenues provided are intended to be on a pre-tax basis (i.e. it is not intended that they give rise to further revenues in respect of the tax).

1.3. Using a pre-tax cost of capital of 6 per cent and an asset life of 20 years, an unmodified retention of an deviation from the allowance would imply that a transmission company would keep (bear) 3 to 45 per cent of the present value of a capex under- (over-) spend. Since the capital expenditure incentive mechanism requires that the fixed incentive rate faced by the companies is 25 per cent, then it is necessary to adjust revenue, to bring the net retention share back to 25 per cent. This can be done by reviewing the worked example of this adjustment as shown in table A10.1 below.

Real 2004/05 prices year ending March		2008	2009	2010	2011	2012	2013	
Pre-tax WACC	6.00%							
Actual Capital Expenditure in Year		110.0	100.0	100.0	100.0	100.0		
Allowance in Year		100.0	100.0	100.0	100.0	100.0		
Out performance/(underperformance)		-10.0	0.0	0.0	0.0	0.0		
Depreciation factors								
(Out performance)/underperformance depreciation factor			5%	5%	5%	5%	5%	
Cumulative deviation in the RAV								
Opening balance		0.0	-10.0	-9.5	-9.0	-8.5	-8.0	
Out performance/(underperformance)		-10.0	0.0	0.0	0.0	0.0	0.0	
(Out performance)/underperformance depreciation			0.5	0.5	0.5	0.5	0.5	
expired out performance							7.5	
Closing balance		-10.0	-9.5	-9.0	-8.5	-8.0	0.0	
Incentive Payment								
Depreciation allowance		0.00	-0.50	-0.50	-0.50	-0.50	-0.50	
Return allowance		-0.30	-0.59	-0.56	-0.53	-0.50	-0.24	
Implied capex reward (="reward")		**-0.30**	**-1.09**	**-1.06**	**-1.03**	**-1.00**	**-0.74**	
Present value of income benefit							**-4.21**	
Fixed incentive scheme								
incentive rate	25%							
Scheme reward (incentive rate x outperformance)		**-2.50**	**0.00**	**0.00**	**0.00**	**0.00**		
Present value of scheme reward							**-2.36**	
Present value of Excess reward							**-1.85**	
Revenue adjustment in 2012/13							**2.63**	

Appendix 11 - Reconciliation of NGET RAV

1.1. In November 2005, we published our final proposals for the one year extension of NGET's TO price control. Our revenue allowance in respect of 2006/07 was calculated with respect to an interim value of NGET's RAV, where RAV additions reflected the following:

- NGET's reported actual and projected load related expenditure for 2001/01 to 2005/06; and
- Ofgem's historical allowances in respect of NGET's non-load related capital; expenditure.

1.2. In total, our approach excluded approximately £146 million pending further analysis of expenditure during the TPCR, with much of this relating to 2005/06. The table below summarises our RAV calculations for the extension review:

Table A11.1 NGET one year price control proposals (2204/05 prices)

£ million	2001/02	2002/03	2003/04	2004/05	2005/06
RAV Analysis					
Opening Values	5,074	5,117	5,156	5,138	5,152
Depreciation	-322	-331	-340	-348	-357
Capex	364	370	323	362	364
Closing values	5,117	5,156	5,138	5,152	5,159

1.3. The table below sets out how we have reached our updated proposals for the opening RAV on 1 April 2007. Our proposed opening RAV for 1 April 2007 reflects the depreciated value of actual expenditure incurred by NGET in the period 2001/02 to 2005/06:

Table A11.2 TPCR updated proposals

£m, 04/05 real	2001/02	2002/03	2003/04	2004/05	2005/06
Opening value bf	5,019	5,047	5,046	5,025	5,046
Depreciation	-320	-329	-337	-345	-358
RAV additions	349	329	316	320	464
Adjustments	0	0	0	46	137
Closing value cf	5,047	5,046	5,025	5,046	5,289

1.4. The main differences are described below.

Opening RAV position

1.5. The opening RAV position for 2001/02 was based upon an expenditure of £398 million in relation to 2000/01. It appears that some of the expenditure related to NGET's SO function. As such we have adjusted the opening value for 2001/02 to actual expenditure for 2000/01 of £342 million.

RAV additions

1.6. The TPCR has concluded that actual expenditure over the period 2001/02 to 2005/06 does not appear to have been inefficiently incurred. These changes are reflected in the revised RAV additions line in table A11.2 above.

1.7. Following discussion with each of the transmission companies, we have revised our approach to inclusion of certain RAV items. As a consequence, we have included the depreciated value of TSS assets and the Anglo-Scottish interconnector as a one-off RAV adjustment. In setting the one-year extension we included TSS expenditure within capex additions.

1.8. The adjustments amount to:

- an adjustment for PLUGS (£46.0m);
- the addition of BETTA assets in 05/06 (£92.2m); and
- the inclusion of the depreciated TSS RAV (£35.7m) in 05/06.

Regulatory depreciation

1.9. The regulatory depreciation is a mechanistic calculation based on the inclusions in the RAV and the asset lives. The differences in depreciation allowances merely reflect the differences in the RAV inclusions.