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# TPCR4 Rollover: Final Proposals

## Final decision

**Reference:** 162/11

**Publication date:** 28 November 2011

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**Overview:**

The current gas and electricity transmission price controls (TPCR4) expire on 31 March 2012. To enable the next price controls to reflect fully the new RIIO model for regulation, we previously announced our decision to delay implementation of the new price controls until 1 April 2013. We will therefore implement a one-year rollover of the existing price controls to operate in the period 1 April 2012 to 31 March 2013. In August 2011, we consulted on our Initial Proposals on the financial parameters, incentives, uncertainty mechanisms and capital and operational expenditure allowances for this rollover year.

This document represents our final decision on the price control extension for the four transmission licensees, along with National Grid in their role as the system operator of the gas and electricity transmission systems. Our decisions have been informed by stakeholders, including formal submissions and bilateral discussions with the licensees. The allowances for the rollover year have been reviewed in the light of the recent RIIO business plan submissions.  We consider our approach strikes an appropriate balance between our principal objective to protect existing and future consumers and the need for a review proportionate to a one-year control.

The licensees have until Friday 16 December 2011 to accept Final Proposals. If the licensees accept Final Proposals, we will publish a statutory consultation on the licence conditions by 5 January 2011 to implement Final Proposals on and from 1 April 2012.

# Context

The Authority's principal objective in carrying out its functions under each of the Gas and Electricity Acts is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition. Regulation of network monopolies is necessary to protect the interests of consumers.

Regulation of Britain's energy networks encompasses a number of elements including the regulation of network businesses by means of price controls. The existing price controls employ incentive-based regulation often referred to as 'RPI-X regulation'. We undertook a fundamental review of the RPI-X approach under our RPI-X@20 review. RPI-X@20 looked to the future on behalf of existing and future consumers, to ensure that we have a regulatory framework that remains fit for purpose.

On 4 October 2010, the Authority launched its new approach to network regulation (RIIO). Our new RIIO model (Revenue = Incentives + Innovation + Outputs) is designed to drive real benefits for consumers; providing companies with strong incentives to meet the challenges of delivering a sustainable energy sector at a lower cost than under our previous approach. RIIO puts sustainability alongside consumers at the heart of what network companies do. It provides a transparent and predictable framework that rewards timely delivery.

Given the importance and scale of the challenges facing transmission network companies, we want to implement the new RIIO model at the next full price control review. We therefore decided to delay implementation of RIIO-T1 (previously known as TPCR5) by one year.

The existing price control (TPCR4) will be rolled over by one year to cover the gap between the expiry of TPCR4 on 31 March 2012 and the implementation of RIIO-T1 on 1 April 2013. On 31 March 2011 we published our decision on the strategy for RIIO-T1, and we received the licensees business plans on 29 July 2011.

We have taken a proportionate approach to the development of the TPCR4 rollover. Recognising it is a one-year price control, this means reflecting recent policy developments, not delaying critical investment and, as far as practical, facilitating the development of RIIO-T1.

# Associated documents

**Previous price control documents**

Rollover

- TPCR4 rollover Initial Proposals, 2 August 2011: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=63&refer=Networks/Trans/PriceControls/TPCR4Roll-over

  *Our consultants' reports on the licensees' projected capex can be found at the same location*

- Rollover: Draft licence conditions – Informal consultation, 21 October 2011: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=74&refer=Networks/Trans/PriceControls/TPCR4Roll-over

- Transmission Price Control Review 4 (TPCR4) rollover supplementary consultation, 7 October 2011: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/111007_TPCR4RO_Interimconsultation.pdf

- TPCR4 rollover policy update and initial analysis of business plans, 8 April 2011: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/TPCR4roll.pdf

RIIO-T1

- Initial assessment of RIIO-T1 business plans and proportionate treatment 24 October 2011: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/busplanletter.pdf
- Decision on strategy for the next transmission price control - RIIO-T1, 31 March 2011: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Other supporting documents

- Price Control Treatment of Network Operator Pension Costs Under Regulatory Principles, 22 June 2010 (Ref No. 76/10) http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf

- Updating the cost of capital for the Transmission Price Control Rollover - Ofgem - Phase 2 Final Report, 8 April 2011: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Rollover/Documents1/costcapitalrollover.pdf

- Smithers & Co. Ltd. - Report on the Cost of Capital provided to Ofgem, 1 September 2006: http://www.ofgem.gov.uk/Networks/Trans/Archive/TPCR4/ConsultantReports/Documents1/15576-smithers_co.pdf

A glossary of terms for all the RIIO-T1 and GD1 documents is on our website: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisiongloss.pdf

# Contents

# Executive Summary

Great Britain's (GB's) gas and electricity transmission companies face significant challenges over the coming years to develop the transmission infrastructure necessary to meet environmental challenges and to secure energy supplies. We are committed to ensuring these challenges are met in a way that provides value for money for consumers.

In light of the challenges outlined above and scale of investment required, we recently undertook a detailed review of energy network regulation, RPI-X@20. The review looked at how best to regulate energy network companies to enable them to meet these challenges. In October 2010, this review concluded with the introduction of the RIIO framework[1]. The existing transmission price control, Transmission Price Control Review 4 (TPCR4), covers the period from 1 April 2007 to 31 March 2012. To allow us to implement our new regulatory model, RIIO, at the next full price control, we are rolling over the current control for one year to cover the period 1 April 2012 to 31 March 2013. We refer to this one-year price control as the "rollover".

This document sets out our final decision for the rollover price control. Its publication follows a period of consultation that began in March 2010 with a consultation on the scope of the rollover. Since then we have issued four further consultations, developing our proposals with stakeholders in detail. In our initial scope consultation we stated that we considered it important that the rollover be proportionate with a one-year control in order to minimise the regulatory burden. Stakeholders agreed with this. In addition to protecting the interests of existing and future consumers[2] and maintaining consistency with our wider statutory duties, we therefore adopted proportionality as a guiding principle for the rollover. As such, the rollover largely extends the existing TPCR4 arrangements. It should not be seen as an early indicator of our approach to the RIIO price control.

Our decision set out in this doccument would increase the average annual residential electricity and gas bills by approximately £1 and £2, or approximately 0.3 per cent and 0.3 per cent, respectively. The key elements of the decision are described below.

**Expenditure baselines:** In our final operating expenditure (opex) and capital expenditure (capex) baselines we have made adjustments to the Initial Proposals based upon further information from Transmission Operator (TOs). As well as comments on the Initial Proposals, the companies have provided updated forecasts for opex and capex in 2012-13 as part of their submissions for the RIIO-T1 price control. In some cases the capex numbers presented are significantly different to their original forecasts. As a result, the final baselines are lower than those in our

[1] http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Decision%20doc.pdf
[2] Consumers' interests have been clarified by the Energy Act 2010 as their interests taken as a whole, including theirnterests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.

Initial Proposals. We consider the baselines will allow companies to prepare for RIIO-T1.

**Policy framework:** The TPCR4 policy framework consists of incentives and uncertainty mechanisms. Incentives are designed to encourage the licensees to behave in a manner that is beneficial to consumers[3], whilst uncertainty mechanisms flex the licensees' allowances in response to market signals or where costs are outside of their control. In line with our proportionate approach, the existing set of incentives will remain, and will not be added to for the rollover year. Incentives relating to efficiency, reliability and timely delivery will remain unchanged, whilst we have decided to tighten the SF6 leakage target for NGET and SPTL. We consider the full suite of uncertainty mechanisms currently in place to be inappropriate for a one-year control where the level of uncertainty is significantly lower. We have decided not to continue to log up the majority of the existing logging up cost categories. Only security costs associated with Critical National Infrastructure (CNI), and compensation paid by NGG for loss of land use will be logged up in the rollover year. We consider it important to allow the licensees to undertake investment where it is necessary in response to market signals and will allow the capex allowances for the rollover year to flex through maintaining the existing revenue driver mechanisms to retain this flexibility.

**Financial decision:** In line with analysis presented in our April consultation and our Initial Proposals, we intend to reduce the allowed return to 4.75 per cent (real vanilla)[4] for the rollover year. This compares with, 5.05 per cent in TPCR4. This is based on our view that the cost of debt has reduced by 50 basis points to 3.25 per cent (consistent with the reduction in the risk free rate highlighted by our consultants in their analysis). We have decided to leave the cost of equity assumption and notional gearing unchanged for all companies. This approach is in line with the methodology used in setting the allowed return for TPCR4. The rollover regulatory framework is significantly different from the new RIIO framework and therefore the allowed return for the rollover does not provide any indication of the appropriate allowed return for the RIIO price controls.

The licensees have until Friday 16 December 2011 to accept Final Proposals. If the licensees accept Final Proposals, we will publish a statutory consultation on the licence conditions by 5 January 2011 to implement Final Proposals on and from 1 April 2012.

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[3] The incentives placed on the licensees during TPCR4 and in the rollover can broadly be considered as efficiency, reliability, environmental, and ensuring timely delivery

[4] The vanilla weighted average cost of capital (WACC) is calculated using a pre-tax cost of debt and a post-tax cost of equity, with the ratio of debt to equity weighted by 'notional' gearing. Ofgem calculates notional gearing as the ratio of net debt to the Regulatory Asset Value (RAV). Since allowed revenues are indexed to RPI inflation, we set the parameters of the WACC on a real (ie excluding inflation), rather than nominal, basis.

# 1. Introduction

**Chapter summary**
This chapter explains the purpose and structure of this document, giving a summary of the TPCR4 rollover process to date. We also highlight interactions with other regulatory work, in particular our Transmission Investment Incentive framework through which the electricity TOs are funded for large projects.

## Purpose of this document

1.1. In October 2010, we set out our new model, RIIO, for regulating Great Britain's gas and electricity networks. We specifically designed RIIO to drive real benefits for consumers; providing network companies with strong incentives to step up and meet the challenges of delivering a low carbon, sustainable energy sector at a lower cost than would have been the case under our previous approach.

1.2. To enable full implementation of RIIO at the next transmission price control, we decided in December 2009 to delay implementation of the next price control, RIIO-T1, until April 2013. As such, we decided to roll over the current transmission price controls (TPCR4) for one year covering the period 1 April 2012 to 31 March 2013.

1.3. This document presents our Final decision on all aspects of the regulatory package for the rollover year for:

- National Grid Electricity Transmission plc (NGET)
- Scottish Hydro Electric Transmission Limited (SHETL)
- Scottish Power Transmission Limited (SPTL)
- National Grid Gas plc (NGG)

1.4. This document also sets out our baselines for National Grid[5] in its role as gas and electricity system operator (SO) for capex and opex associated with internal costs. Costs incurred externally in balancing the system are incentivised through separate SO Incentives schemes[6].

[5] National Grid plc (NG) is the owner of National Grid Electricity Transmission plc (NGET) and National Grid Gas plc (NGG). Where the name National Grid is used in this document it refers to both NGET and NGG.
[6] The incentive structure for balancing the electricity transmission network from 1 April 2011 to 1 April 2013 was decided in July 2011:
http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Decision%20Open%20Letter.pdf
National Grid are currently developing proposals on how best to extend the existing arrangements for gas system operation into the rollover year:
http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Open%20letter%20rolloverB.pdf

1.5. Across each of these licensees our decision consist of three elements:

- Operating and capital expenditure baselines (opex and capex respectively)
- Structure and detail of the incentives and uncertainty mechanisms
- Allowed return and other financial parameters

## Guiding principles

1.6. Our March 2010 consultation set out the objectives of the TPCR4 rollover:

- To protect the interests of existing and future consumers
- To be consistent with Ofgem's wider statutory duties
- To be proportionate to a one-year control and to minimise regulatory burden
- To reflect recent developments in policy
- Not to delay critical investment
- As far as practicable, to facilitate the development of RIIO-T1

1.7. Stakeholders broadly agreed with these objectives, and they have guided our policy development through to our final decision.

## Process to date

1.8. In October 2009, we consulted on the timetable for RIIO-T1, and hence the possible need to roll over TPCR4 by one year into 2012-13. In December 2009 we issued our decision to delay implementation of RIIO-T1 by one year and so roll over TPCR4 into 2012-13. We also set out our preferred approach to a number of key areas - capex, opex, financial issues, incentives and uncertainty mechanisms.

1.9. In our 30 June 2010 document, we communicated our decision on the scope of the TPCR4 rollover. Subsequently, in April 2011 we consulted in detail on how best to roll forward the existing incentives and uncertainty mechanisms, our treatment of historical capex, and on our proposed approach to setting the allowed return during the rollover year.

1.10. This document also presented the initial views of our consultants (KEMA) on the TOs' projected capex during the rollover year. Supplementing this document, in May 2011, we published a report by PPA Energy on National Grid's proposed capex during the rollover year relating to its SO function.[7]

[7] These associated documents can be found in the following location: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=32&refer=Networks/Trans/PriceControls/TPCR4Roll-over

1.11. We published our Initial Proposals for the rollover in August 2011 informed by stakeholder responses and further engagement with the licensees. The key components of these initial proposal versus our Final decision are detailed in table 1 below:

**Table 1 Key elements of our Initial Proposals vs Final decision**

| Aspect | Initial Proposals for TPCR4 rollover | Final decision for TPCR4 rollover |
|---|---|---|
| Capex and Opex baseline expenditure | **Opex** allowances set in line with 2009/10 expenditure , adjusted for efficiencies and justified incremental costs<br>**Capex** forecasts reduced where there is concern around deliverability in the rollover year, or insufficient justification. A provisional capex allowance set that will flex via the revenue drivers for the electricity licensees | **Only two changes from Initial Proposals:**<br>• Opex allowances set in line with 2010/11 expenditure , adjusted for efficiencies and justified incremental costs.<br>• Capex forecasts changed to reflect updated forecasts in the RIIO business plans. |
| Uncertainty mechanisms and incentives | *Uncertainty mechanisms*<br>Existing pass through to continue to be passed through.<br>No costs to log up during the rollover year.<br>Existing revenue driver mechanism to roll forward into the rollover year – no new revenue drivers to be introduced.<br><br>*Incentives*<br>Current set of incentives to continue into the rollover year.<br>Smooth the adjustment associated with the TPCR4 capex incentive for all TOs over a number of years. | *Uncertainty mechanisms*<br>**Only two changes from Initial Proposals:**<br>• quarry and loss costs to continue to log up during the rollover.<br>• SO costs associated with offshore to be included within an ex-ante allowance.<br><br>*Incentives*<br>**Only one change from Initial Proposals:**<br>• The smoothing of the TPCR4 capex incentive adjustment to be applicable to NGET only. |
| Allowed return | Cost of debt assumption revised to 3.25 per cent<br>Cost of equity assumption maintained at 7 per cent<br>Notional gearing maintained at 60 per cent. | **No change from Initial Proposals** |

1.12. Following stakeholder comment and further engagement with the licensees, we decided it was neccessary to consult further on a number of additional issues. On 7 October 2011 we issued a supplementary consultation outlining our view that an ex-ante baseline should be incorporated into the rollover for the following:

- SO costs associated with the offshore network for NGET - these costs were previously passed through to consumers
- capital expenditure associated with pre-construction works for a number of projects by SHETL – a provision existed to do this via our Transmission

Investment Incentives (TII) mechanism but for simplicity this expenditure has been incorporated into the rollover baseline capex.

1.13. The supplementary consultation also communicated our view that NGG should continue to log up costs incurred by them as a result of quarry and loss development claims during the rollover year. Stakeholders agreed with our proposed approach and it forms part of our final decision.

1.14. In addition to the detailed consultation on policy set out above, we have been developing the licences that will be in place during the rollover year. As the rollover is, broadly speaking, a continuation of the existing price control these changes are relatively minor and mainly confined to updating parameters such as incentive targets and expenditure baselines. Following a workshop with the licensees we issued an informal consultation[8] on the licence changes in October 2011. This consultation highlighted the changes we considered necessary to implement the rollover policy as communicated in our Initial Proposals. The consultation was supplemented with drafts of the rollover licence; this consultation closed on 18 November. We will publish an updated version of the licence shortly after the publication of this document. This updated licence will reflect any changes between Initial and Final Proposals, and the views of stakeholders in response to our consultatation.

## Interactions with the RIIO price control and other funding mechanisms

### RIIO-T1

1.15. Our general approach to setting the price control for the rollover year has been to extend the TPCR4 arrangements. However, we have been mindful of the interactions with the RIIO price control, which is being developed in parallel. The RIIO-T1 price control will apply from 1 April 2013 to 31 March 2021. A core element of the RIIO approach is the submission of 'well-justified' business plans by the licensees. We received the TOs' plans in July 2011[9] and these have been taken into account in our final funding decisions. The licensees have projected expenditure for the rollover year. In a number of cases their forecasts have changed from those submitted in October 2010 as part of their rollover.

### Transmission Investment for Renewable Generation (TIRG) and Transmission Investment Incentives (TII)

1.16. We are committed to encouraging network companies to play a full role in delivering a sustainable energy sector. Electricity transmission infrastructure has a

[8] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=74&refer=Networks/Trans/PriceControls/TPCR4Roll-over
[9] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1busplans.pdf

key role in meeting the demands of the 2020 and 2050 targets on carbon abatement and renewable deployment. In recent years, we have introduced two mechanisms to allow the TOs to fund strategic projects outside of the price control process and reinforce the GB transmission system to deal with these challenges. These are:

> **TIRG:** Transmission Investment for Renewable Generation (TIRG) is a mechanism designed to fund cost effective transmission projects specific to connecting renewable generation outside of the price control allowance to minimise delays. TIRG is comprised of four projects: Beauly Denny, Sloy, South West Scotland and the Anglo Scottish Interconnector. We have set out pre-construction and construction allowances for TIRG projects up until the year of commissioning, and provision is made within the TIRG mechanism to apply to change these allowances via an adjusting event.

> **TII:** In 2010 we introduced the Transmission Investment Incentives (TII) mechanism to allow funding within the price control for the licensees to deliver critical electricity transmission infrastructure projects that were not included in their base allowance for TPCR4. The TII mechanism was due to expire at the end of TPCR4. In June 2010, in line with our decision to extend the existing price control by one year, we confirmed that we planned to extend the TII framework into 2012-13. We will shortly publish a decision letter confirming the detailed policy for the TII mechanism in the rollover year. Funding arrangements beyond 1 April 2013 will be addressed under the RIIO framework.

1.17. As part of their business plan submissions the licensees provided estimates of their projected expenditure within the TPCR4 rollover year on projects that are currently funded via TIRG or TII, or for which they expect to require funding under TII. They expect these projects to account for a significant portion of their expenditure (as shown in chapter 2). We have considered the magnitude of their projected TII and TIRG capex programme in assessing financability. Given that setting allowances under the TIRG or TII mechanisms is outside the scope of the rollover, we have included a provisional funding allowance for TII expenditure in our allowed revenue for the rollover and will true-up over / under recovery as compared to the actual allowances determined under the TII mechanism. We will restate the allowances in the first year of the RIIO-T1 price control, this approach is described in detail in chapter 5 which also specifies the provisional funding allowances we have included for each TO in relation to TII expenditure.

## Allowed revenues and consumer impact

1.18. The table below sets out the allowed revenues that we intend to set for the rollover year. This takes into account the capex and opex baselines set out in Chapter 2, spreading the revenue adjustment associated with the provisional calculation of the capex incentive over a number of years is outlined in Chapter 3, and the financial costs including allowed return are set out in Chapter 4.

**Table 2 Forecast revenues for 2012-13**

| 2009-10 prices £m | NGET | SHETL | SPTL | NGG |
|---|---|---|---|---|
| Base revenue | 1,442.9 | 94.9 | 188.8 | 585.7 |
| TIRG forecast | 14.8 | 31.7 | 15.9 | - |
| Total revenue | 1,457.7 | 126.6 | 204.8 | 585.7 |

Source: Ofgem
Note: Totals may appear different to the sum of components due to rounding.

1.19. Base revenue includes the baselines for projects covered by the enhanced TII incentives undertaken in TPCR4 and expected expenditure in the rollover year. As described above, we are yet to make a decision on baselines for TII projects. When determining the projected expenditure during the rollover year, for the purpose of modelling allowed revenues and the financeability modelling outlined in chapter 4, we have used licensees' projected expenditure contained in their October 2010 business plans as updated by the RIIo business plan submissions in July 2011.

1.20. Table 3 below shows the licensees' latest forecasts for 2011-12 compared to the allowances for 2012-13.

**Table 3 Comparison of final decision and the licensees' forecast allowed revenues for 2011-12**

| 2009-10 prices £m | NGET | SHETL | SPTL | NGG |
|---|---|---|---|---|
| Operators' latest forecast for 2011-12 | 1,356.6 | 90.8 | 213.2 | 535.6 |
| Final proposals (2012-13) | 1,457.7 | 126.6 | 204.8 | 585.7 |
| Percentage change | 7% | 39% | -4% | 9% |

Source: Ofgem

1.21. Table 4 overleaf shows the impact of this increase in allowed revenue on the average consumer bills.[10]

[10] This is based on the average gas and electricity bills quoted in Ofgem's factsheet 97 dated 18.01.11 – Household Energy bills explained.

**Table 4 Impact of TO proposals on consumer's bills**

| Impact on consumer bills | Electricity | Gas |
|---|---|---|
| Average domestic bill (£) | 424 | 608 |
| Transmission component of domestic bill (%) | 4% | 3% |
| Transmission component of domestic bill (£) | 16.96 | 18.24 |
| Restated average domestic bill based on final proposals (£) | 425.31 | 609.71 |
| Bill increase (%) | 0.3% | 0.3% |
| Bill increase (£) | 1.31 | 1.71 |

Source: Ofgem

## Structure of document

1.22. The remainder of this document is structured as follows:

- Chapter 2 summarises our capex and opex baselines for the licensees for the rollover year.
- Chapter 3 sets out our policy scope for the rollover year for the TOs.
- Chapter 4 sets out our policy scope for the rollover year for National Grid in their role as SO.
- Chapter 5 sets out our approach to the financial aspects of the rollover, including allowed return and pension provisions.
- Chapter 6 sets out the next steps required following the publication of the Final Proposals to ensure the rollover price control is in place by 1 April 2012.

1.23. The Appendices provide further detail on the mechanism for RPI that will be in place during the rollover year and our approach to the electricity revenue drivers. They also present a detailed breakdown of the allowances for each of the licensees.

# 2. Summary of capex and opex baselines

**Chapter summary**
This chapter summarises our final decision on capex and opex baselines for each of the licensees for the rollover year. We describe the methodology used when deriving these baselines, and highlight changes we have made since Initial Proposals and reasons for these changes.

## Introduction

2.1. We have taken a proportionate approach to developing our capex and opex baselines, recognising that this is a one-year rollover. We are committed to allowing the licensees sufficient funding to undertake the investment required to develop the transmission infrastructure necessary to meet environmental challenges and to secure energy supplies over the coming years. We are also determined to ensure this investment is undertaken in a cost effective manner and that existing and future consumers do not have to fund inefficient or unnecessary expenditure. The approach to funding is broadly consistent with that applied when developing the current price control, TPCR4. Through our continuation of the existing revenue driver mechanisms, our decision incorporates a considerable amount of flexibility, allowing the TOs' capex allowances to flex to match the level of load-related investment they are required to undertake. Since the publication of Initial Proposals we have taken into account comments made by licensees and other stakeholders, updated forecasts, and further analysis.

## Other funding mechanisms

2.2. The decision outlined in this document represent one part of the licensees' funding allowance for the rollover year. A significant portion of their capex programme will be funded through additional funding arrangements that supplement base revenue in the price control. A number of large projects undertaken by the electricity TOs will continue to be funded through the TIRG and TII funding mechanisms described in chapter 1; whilst additional entry and exit capacity to the gas transmission network will continue to be funded via NGG's revenue drivers, described in detail in chapter 3. To put the capex baselines into perspective the following tables outline the projected capex funding granted through each of these mechanisms in the rollover year.

**Table 5 Rollover capex baselines in perspective - electricity TOs[11]**

| Electricity | | | |
|---|---|---|---|
| **2009-10 prices £m** | **NGET** | **SHETL** | **SPTL** |
| Rollover price control | 804.7 | 76.4 | 117.4 |
| TIRG | 0.0 | 146.3 | 45.2 |
| TII | 313.2 | 101.8 | 84.6 |
| **Total** | **1117.9** | **324.5** | **247.2** |

**Table 6 Rollover capex baseline in perspective - NGG[12]**

| Gas | |
|---|---|
| **2009-10 prices £m** | **NGG** |
| Rollover price control | 81.5 |
| Gas revenue drivers | 40.2 |
| **Total** | **121.7** |

2.3. These funding channels incentivise efficient capital expenditure through setting ex-ante allowances, and allow a return and depreciation on this expenditure. The incentive structure, and in the case of TIRG the allowed return, vary between the different funding mechanisms. All operational costs are included in the price control.

## Electricity revenue drivers

2.4. We intend to maintain the revenue drivers for the electricity TOs, through which the capex baselines will flex in response to changing patterns of generation and demand for network capacity. A revenue driver was established for each for the TOs through which their capex allowance would flex in response to new generation connecting to the transmission system. Three further revenue drivers were introduced for NGET to allow funding for reinforcements within their network and across the Anglo-Scottish boundary. A portion of the TOs projected spend for the rollover year will result in an adjustment to capex baselines through the revenue drivers. It would therefore be inappropriote to set an ex-ante allowance for these projects. We have however considered their projected spend when determining their allowed revenue. Where projected spend does not match actual spend any over or under recovery will be trued up as part of the RIIO price control. The portion of the TOs capex allowances which is ‘provisional’ in this manner is presented in the appendices 3 – 5. This approach is described in detail in chapter 3 and Appendix 2.

[11] Rollover price control allowances include projected capex on Critical National Infrastructure Security Costs. Projected capex for TIRG and TII projects are based on the licensees October Business plan submission as updated by the July 2011 RIIO submissions.
[12] Gas revenue drivers is the projected capex NGG will incur developing entry and exit capacity. It provides NGG with an ex-ante allowance that incentivises them by enabling them to keep the difference between projected and actual costs for 5 years.

## Capex allowances

### General approach

2.5. The licensees submitted their business plans to us in October 2010. These contain their projected opex and capex requirements for the rollover year. We employed KEMA and PPA consultants to assess the TO and SO capex forecasts, respectively. As part of this process, we visited the licensees, along with our consultants, to gain further understanding of their proposed capex programme.

2.6. In April 2011 we published each consultant's initial views on the licensees' capex projections. In a number of areas our consultants considered that the licensees had not fully justified the capex baselines they requested. Following the publication of Initial Proposals we have received comments from licensees and other stakeholders. We have considered these comments in our development of the final costs baselines together with the licensees' updated forecasts for 2012-13. PPA has also reviewed and commented on the responses on NGET and NGG's SO internal capex, but we have carried out our further analysis of TO capex in-house. As a result, we have made further revisions to the proposed capex baselines set out in our Initial Proposals.

### Comments on TOs' baselines

**Table 7 Final Proposals TO capex baselines compared to Initial Proposals**

| **Initial Proposals** | | | | |
|---|---|---|---|---|
| **2009-10 prices £m** | **NGET** | **SHETL** | **SPTL** | **NGG** |
| Load related (net of contributions) | 391.6 | 48.5 | 104.7 | 23.6 |
| Non load related | 439.7 | 19.7 | 65.4 | 52.2 |
| **Total** | **831.3** | **68.2** | **170.1** | **75.8** |
| **Final Decision** | | | | |
| **2009-10 prices £m** | **NGET** | **SHETL** | **SPTL** | **NGG** |
| Load related (net of contributions) | 383.5 | 57.9 | 60.4 | 23.6 |
| Non load related | 421.2 | 18.5 | 58.6 | 57.9 |
| **Total** | **804.7** | **76.4** | **119.0** | **81.5** |

2.7. The Final Proposals show lower baselines allowances for both NGET and SPTL and higher allowances for SHETL and NGG than those at Initial Proposals. The reasons for this are:

- NGET has reduced its forecast and also has applied a "delivery and efficiency overlay" to its 2012-13 expenditure forecast. We have taken both these factors into account in determining the final baseline.
- SPTL has also significantly reduced its load related forecast for 2012-13 from that proposed in October 2010.
- In the case of SHETL we have allowed additional preconstruction costs that were disallowed at Initial Proposals.

- NGG has provided more information regarding the likely costs of one of its feeders (Feeder 9), which we have accepted.
- We have taken information from the TOs supporting additional expenditure into account in determining final baselines. We have changed our expenditure assumptions where this information was sufficiently robust.

2.8. Details of all the changes are discussed in greater detail in Appendices 3 to 6.

#### Comments on SO Baselines

**Table 8 Final SO capex baselines compared to Initial Proposals**

| 2009-10 prices £m | NGET SO | NGG SO |
|---|---|---|
| **Initial Proposals** | 25.3 | 28.3 |
| **Final Proposals** | 27.8 | 30.6 |

2.9. We have made a slight upward adjustment to the allowances from those proposed at Initial Proposals. This is due to further justification for two IT systems (one for NGET and one for NGG) in 2012-13. However, in all other areas, NG has not provided us with sufficient information to support a change in expenditure assumptions. Further detail is provided in Appendix 7.

## Opex baselines

#### General approach

2.10. We have taken a proportionate approach to setting the controllable opex baselines for 2012-13.

2.11. In our April 2011 consultation we said that the opex baselines "would be informed by actual expenditure in the first 4 years of TPCR4 along with TOs' forecasts". [13] For Initial Proposals our approach was to start with the most recent year of actual expenditure (2009-10), take out one-off or non-recurring items, and assess whether the TOs' proposed changes to this expenditure level were justified. Where the 2009-10 expenditure was significantly in excess of the TPCR4 baselines, we applied an additional efficiency factor to take into account the scope for further efficiency savings.

2.12. For Final Proposals we have changed the start point for the calculation of opex baselines to 2010-11 actual expenditure as this information is now available. We consider this more recent expenditure is a better guide to future costs. We have also taken account of responses to Initial Proposals and the updated forecasts provided as part of the RIIO-T1 process.

[13] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/TPCR4roll.pdf

2.13. Non operational capex (which includes IT systems, land and buildings) is included within the controllable opex baselines. We have taken a similar approach in setting our baselines for this area of costs within 2012-13.

2.14. A proportion of the licensees' opex is outside of their control (for example licence fees and network rates). We allow these costs to be passed through to consumers. This approach is described in greater detail in chapter 3.

### Comments on TO baselines

2.15. The following table sets out the final baselines for controllable opex

**Table 9 Final Proposals for TO Controllable Opex compared to Initial Proposals and actual 2010-11 opex**

| 2009-10 prices £m | **NGET** | **SHETL** | **SPTL** | **NGG** |
|---|---|---|---|---|
| 2010-11 Actual | 196.7 | 6.5 | 20.8 | 53.8 |
| Initial Proposals | 198.4 | 7.1 | 17.9 | 62.8 |
| **Final Proposals** | **205.9** | **10.0** | **24.6** | **64.8** |

NB SPTL's 2010-11 actual figure has been adjusted for excess cost capitalisation

2.16. As with the capex baselines, we have received responses to Initial Proposals and updated forecasts as part of TOs' RIIO-T1 submissions. In all cases the Final Proposals are below the TOs' updated forecasts, but show an increase on Initial Proposals. The changes we have made are as follows:

- We have maintained our assumed efficiency factor of 1.5 per cent per annum in line with the original TPCR4 proposals and a 'catch-up' factor where actual opex is above the TPCR4 baselines.
- TOs have provided some additional justification for cost increases, notably for workforce renewal and training. We have accepted some of these but there still remain areas where costs increases are not fully justified.
- We have allowed a greater proportion of the non operational capex forecasts, but still remain concerned over the deliverability and justification of some IT projects.

2.17. Details of the specific changes for each TO are discussed in detail in Appendices 3 to 6.

### Comment on SO baselines

2.18. We have set our final baselines for the SO internal operating expenditure for NGET and NGG in the same way as for the TOs.

**Table 10 Final Proposals for SO Controllable Opex compared to Initial Proposals and actual 2010-11 opex**

| 2009-10 prices £m | NGET SO | NGG SO |
|---|---|---|
| 2010-11 Actual | 54.5 | 32.0 |
| Initial Proposals | 55.2 | 28.8 |
| **Final Proposals** | **59.4** | **31.0** |

2.19. We have received responses to Initial Proposals and updated forecasts as part of the SOs' RIIO-T1 submissions. As a result of this further information we have made the following changes:

- We have maintained our assumed efficiency factor of 1.5 per cent per annum in line with the original TPCR4 decision.
- The SOs have provided some additional justification for cost increases notably for workforce renewal and training. We have accepted some of these but there still remain areas where costs increases are not fully justified.

Details of the specific reductions for each SO are discussed in detail in Appendix 7.

2.20. We received a number of responses to the Initial Proposals. The responses from licensees are discussed in detail in the Appendices 3 to 7. Only one other respondent commented on the opex and capex baselines. It was agreed that the TO and SO Initial Proposals are reasonable and appropriate for the one-year rollover. With regards to network flexibility they argue that it is more appropriate to cover this as part of the RIIO-T1 price control.

# 3. Uncertainty Mechanisms and Incentives for the TOs

**Chapter summary**

This chapter sets out our Final decision for the incentives and uncertainty mechanisms for the TOs for the rollover year. We present our decision for National Grid in their role as SO in the following chapter. The decision has been informed by the views of stakeholders expressed throughout the price control process and most recently in response to our Initial Proposals. In line with our proportionate approach there is little change from TPCR4. The existing incentives remain, and the uncertainty mechanisms have only changed where we consider there to be sufficient certainty during a one-year control to allow funding through a base allowance.

3.1. Our final decision presented in this chapter reflect our desire to limit the scope of policy changes in the rollover. In our Initial Proposals, we presented the proposed incentives and uncertainty mechanisms for the rollover in detail. Stakeholders broadly supported our proposals, although there were a number of areas where they disagreed or felt more detail was required. In light of stakeholders views and further analysis our policy has changed since Initial Proposals in the following areas:

1. **Capex incentive revenue adjustment for SHETL, SPTL and NGG:** We have decided that the full revenue adjustment for SHETL, SPTL and NGG associated with the capex incentive should be made in 2012-13. We maintain our decision to spread the associated adjustment for NGET over a longer period, making 20 per cent of the adjustment in the rollover year. The different treatment is based on the relative magnitude of the adjustments and the impact they would have on transmission charges. This approach and the rationale is described in detail in this chapter.

2. **Logging up certain compensation costs incurred by NGG:** Given the uncertainty in projecting these costs we will allow them to continue to log up during the rollover year. This is described in further detail in this chapter.

3.2. In July 2011 we communicated our decision to update the methodology through which allowed revenues will be indexed for economy-wide inflation. This decision is due to come into effect in the rollover year. A detailed description of how this change will be implemented can be found in Appendix 1.

3.3. Following our Initial Proposals we have worked with the electricity licensees to provide further detail on how the existing revenue driver mechanisms will be extended in practice. A summary of our approach is detailed in this chapter, whilst full details can be found in Appendix 2.

3.4. The rest of this chapter sets out our approach to uncertainty mechanisms and incentives in the rollover year.

## Uncertainty mechanisms

3.5. In setting the allowances for the current price control it was clear that some of the TOs' expenditure could not be projected over a five-year horizon with any degree of certainty, and it would not be appropriate to define an allowance in advance. Uncertainty mechanisms were developed, through which expenditure can either be logged-up or passed through to consumers. Additionally revenue drivers were introduced through which the licensees' capex baselines would flex in response to market signals.

3.6. We will leave the revenue driver mechanisms unchanged for the rollover year, and continue to allow the existing set of pass-through costs to continue to be passed through to consumers. We do not consider it appropriate to allow a number of the existing logged up cost categories to continue to log up during the rollover. The full suite of uncertainty mechanisms is outlined in the table below, then described in detail.

**Table 11 Existing uncertainty mechanisms in electricity and gas for TPCR4**

| Mechanism | Gas | Electricity |
|---|---|---|
| **Logged-up costs** | Quarry and loss development claims[14] | |
| **Pass-through costs** | Licence fee<br>NTS prescribed rates<br>Independent system cross subsidy | Licence fee, network rates adjustment term, Interruptions[15], and additionally NGET are allowed to pass through a number of costs associated with their SO function[16] |
| **Revenue drivers** | The allowed revenue automatically increases on receipt of financially backed signals for additional entry and exit capacity | The allowed revenue adjusts based on:<br>Connected generation (all TOs) upgrades to Anglo-Scottish boundary (NGET only), and flows across boundaries within England and Wales (NGET only) |

### Revenue associated with logged up costs during TPCR4

3.7. As part of TPCR4 we allowed the licensees to log up costs in a specific number of categories where there was uncertainty in forecasting the expenditure for the whole price control period. This approach meant we did not have to project these

[14] These relate to compensation paid by NGG for certain loss of types of land use, mining, etc.
[15] The amount paid out by the licensee in relation to interruptions in their licence area.
[16] These costs are: **3rd party Licensing costs:** licensing costs associated with Offshore and the Scottish Transmission companies; **Distribution for offshore:** amount paid by NGET to distributors for use of system by offshore generation connected via embedded generation; **EU Inter TSO Scheme:** costs of participating in such Ofgem approved schemes.

costs in advance. In our Initial Proposals we proposed that, to protect consumers from inefficient spend, we will not allow the licensees to claim revenue for this expenditure until we have undertaken a full efficiency assessment after the end of the price control period. As such, we will assess the efficient expenditure in the RIIO control and subject to this the expenditure will enter the RAV on 1 April 2013. This affects the following areas of expenditure:

- BT 21st century networks[17] (applied to all TOs during TPCR4)
- Plugs[18] (SPTL & SHETL only)
- Cable tunnelling (NGET only)[19]
- Quarry and loss development claims[20]

3.8. Stakeholders broadly agreed with this approach. We will do this on a net present value (NPV) neutral basis so that companies are not penalised for the delay in allowing the investment.

**Logged up costs in the rollover year**

3.9. In our Initial Proposals, we proposed not to allow any costs to continue to log up during the rollover year. This was based on our view that there would not be sufficient uncertainty for it to be necessary. Stakeholders broadly agreed with this approach and we will not allow the following costs to continue to log up:

- BT 21st century networks (applied to all TOs during TPCR4)
- Plugs (SPTL & SHETL only)
- Cable tunnelling (NGET only)

3.10. We have included an allowance for expenditure on these cost categories in the base capex allowance. Further detail can be found in our detailed discussion of allowances (Appendices 3-6).

3.11. Following further discussions with NGG we considered it appropriate to continue to log up costs associated with claims and compensation for loss of land use due to the installation of gas transmission pipelines. We considered these costs to be uncertain, and as such that setting an ex-ante allowance would expose NGG to potential gains or losses due to events outside of their control. We consulted on this approach in a supplementary consultation letter in October[21] and stakeholders were in agreement with our proposal. We will allow such costs to continue to log up during the rollover year. To protect consumers from inefficient spend in this area NGG will continue to have a licence obligation to challenge as far as is reasonable these

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[17] Costs associated with telcom services necessary as a result of BTs transition to “packet” technology
[18] Scottish licensees were allowed to log up 50 per cent of the incremental costs of providing a more secure (N-1) connection design in relation to small wind farms (less than 100MW).
[19] cable tunnelling around the London area up to a value of £60m (in 2004/05 prices)
[20] These relate to compensation paid by NGG for certain loss of types of land use, mining, etc.
[21] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/111007_TPCR4RO_Interimconsultation.pdf

claims, and revenue will only be awarded to recompense these costs following a full efficiency review.

**Security costs associated with physical infrastructure**

3.12. A number of the TOs felt that they should recieve a return and depreciation on security costs associated with physical infrastructure as soon as they could be demonstrated as efficient. For all TOs the costs incurred during TPCR4 will be included in the RAV as of 1 April 2012 on a provisional basis. These costs are subject to ongoing assessment. Where efficient costs are incurred during the rollover year they will be included in the RAV as part of RIIO-T1.

**Pass-through costs**

3.13. In discharging their duties the TOs incur a number of costs which they cannot control directly. We currently allow the TOs to pass through a defined set of such cost categories to consumers. In our Initial Proposals we stated our view that we consider these costs still to be outside the control of the TOs. As such we consider it to be appropriate for all of these cost categories to continue to be passed through to consumers during the TPCR4 rollover year. Stakeholders agreed with this approach and we propose to allow the existing set of pass-through costs (detailed in Table 11) to continue to be passed through to consumers.

**Revenue drivers**

3.14. At the last price control we developed a number of revenue driver mechanisms to manage uncertainty over the price-control period. For example, in gas, the allowed revenues automatically increase following provision of new capacity – this is based on the amount and location of additional capacity. Similarly within electricity, the level of allowed revenues adjusts based on the volume of generation connecting to the network or the need to increase the capacity of boundaries in response to market signals. The nature of these revenue drivers and our approach for the TPCR4 rollover year varies across the sectors.

<u>Gas revenue drivers</u>

*Capacity investment incentive*

3.15. Revenue drivers are used to give NGG additional revenues following financially backed requests for additional capacity to flow gas onto or off the NTS. The revenue driver regimes differ for signals of capacity received before and after April 2007. These pre- and post-2007 regimes are described in detail in Appendix 5.

*Pre-2007 signals*

3.16. In June 2003 we set out the regime to remunerate additional entry capacity (revenue drivers were not in place for exit capacity at that time)[22]. NGG was remunerated on its SO and TO sides for specific periods linked to the delivery date of additional capacity. Adjustments between TO and SO were linked to the start and end of price control periods.

3.17. In our Initial Proposals, we set out an update on our thinking regarding this policy and stated that our provisionally preferred approach is for the initial TO / SO adjustment to take place on 31 March 2012 on a provisional basis, and the remaining adjustment to take place on 31 March 2017.

3.18. We maintain this position for Final Proposals. Our decision is that the initial TO / SO adjustment will take place on 31 March 2012 on a provisional basis, and the remaining adjustment to take place on 31 March 2017. This honours the intention of the regime which was introduced at a time when five-year price controls were in place.

*Post-2007 signals*

3.19. At TPCR4 we revised the remuneration regime for additional capacity that would apply to signals received after April 2007. This approach was common for entry and exit. For investment signals after 2007, NGG is remunerated on its SO and TO sides for specific time periods, but this is no longer linked to the timing of price controls. The revenue driver amounts are uplifted both for general inflation and for a combined index for materials and construction costs.

3.20. In our March 2010 document we said that we did not intend to reset any of the gas transmission revenue drivers that were set at or after TPCR4.

3.21. One TO responding to the June 2010 consultation thought the indexation factor for materials and construction costs may need consideration as it thought the factor was only set until 2011-12.

3.22. In our Initial Proposals we highlighted that our preferred approach was to keep the indexation factors for materials and construction at the same values. We consider that it would be disproportionate to redesign the revenue driver regime, reset revenue driver values and revise the indexation factor for materials and construction for a one-year period.

[22] See 'New entry terminals to Transco's National Transmission System: Ofgem's views on Transco's proposals and explanatory notes to accompany the section 23 notice of proposed modifications to Transco's gas transporter licence' published on 30 June 2003 with reference 62/03 on the Ofgem website http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=3807_New_entry_terminals_final.pdf&refer=Networks/ad

3.23. **For Final Proposals our decision is to maintain this regime in its current form, keep the values of the revenue driver figures in the licence for any incremental capacity signals received in the TPCR4 rollover year.** The materials and cost construction cost indexation factors are set for '2011-12 and later' in the gas transporter licence, therefore there is no issue around these factors being redundant in the TPCR4 rollover year.

*Milford Haven*

3.24. NGG received two signals for incremental entry capacity at Milford Haven at auctions in 2004. This was to deliver 650 GWh/day in October 2007 and 300 GWh/day in January 2009. The associated investment has been subject to delays. The investment should have been remunerated via the pre-2007 scheme (described above). Due to concerns about overspend on the Milford Haven project during TPCR4, Ofgem departed from the pre-2007 regime with regard to Milford Haven. As such we:

- Added £437m (2004-5 prices) to the TO RAV at TPCR4
- Gave a Load Related Expenditure (LRE) Allowance of £280m (2004-5 prices) for the TPCR4 period
- Applied a downward adjustment to NGG's TO allowed revenue of £9.5m (2004-5 prices) per year. This was to avoid double remuneration as NGG earned the SO revenue driver allowance when it was effectively being remunerated fully on the TO side (due to the TO RAV addition and LRE Allowance set out in the previous two points).
- Deferred the review of £75m (2004-5 prices) of capex and decided that it would be added to the RAV on 1 April 2012, subject to an efficiency assessment, with an allowance for financing and depreciation incurred during the period of logging up. This was due to revised forecasts being submitted late in the TPCR4 process. We also stated that this additional Milford Haven forecast expenditure of up to £75m would not be subject to the capex incentive.

3.25. Since TPCR4, NGG has notified us of further overspend in addition to the £792m (2004-5 prices)[23] outlined above.

3.26. In our June 2010 document we said that capex incurred during TPCR4 will enter the RAV on a provisional basis at the start of 2012-13. We will do a full efficiency assessment at RIIO-T1 and adjust the RAV accordingly. We did not make a specific distinction for the capex spent on the Milford Haven project in TPCR4.

3.27. As outlined in Chapter 5 we will provisionally include the £75m (2004-5 prices), £280m (2004-5 prices) and any overspend during TPCR4 to the TO RAV in 2012-13. These will be subject to an efficiency assessment during RIIO-T1 with any adjustments made on a retrospective basis. This is consistent with other capex spent in the TPCR4 period (as set out in Chapter 5).

[23] The £792m is comprised of the £437m added to the TO RAV, the £280m of Load Related Expenditure and the £75m of forecasts costs deferred for assessment.

3.28. In Initial Proposals our preferred approach was to keep the £9.5m (2004-5 prices) downward adjustment to the TO allowed revenue but review the figure. This is because NGG will continue to be remunerated on the SO side in 2012-13, whilst it will continue to be fully remunerated on the TO side.

3.29. For Final Proposals we will maintain a downward adjustment to the TO allowed revenue for the 2012-13 rollover year. We have deferred the review of the £9.5m (2004-5 prices) figure since any re-adjustment will be dependent on our overall assessment of the efficiency of the project. This review will take place in 2012 as part of the RIIO process. We will maintain the £9.5m (2004-5 prices) downward adjustment to the TO allowed revenue for the rollover year but include the revision during RIIO-T1 together with any necessary adjustment to the rollover year figure.

Electricity revenue drivers

3.30. We introduced a suite of revenue drivers for the electricity TOs as part of TPCR4. These adjust the TOs' baselines for capex automatically in response to changing patterns of generation and demand for network capacity. A revenue driver was established for each for the TOs through which their capex allowance would flex in response to new generation connecting to the transmission system. Three further revenue drivers were introduced for NGET; two of these adjust their funding for boundary reinforcements within their network in response to signals from generators and DNOs (distribution network operators); a further revenue driver makes adjustments to reflect any difference between the baseline and delivered capacity on the Anglo – Scottish Boundary.

3.31. All of these revenue drivers work in the same way, adjusting the licensees' allowed revenue by multiplying a unit cost allowance (UCA) - that was set as part of the last price control - by the deviation from the baseline that was assumed in setting the baseline capex allowance.

3.32. In our Initial Proposals we communicated our intention to maintain the existing revenue drivers into the rollover year, and not to introduce any new revenue drivers. Stakeholders agreed with the broad principle but had a number of questions as to how this proposal would be implemented in practice.

3.33. Following further engagement with the TOs we present in Appendix 2 full details of our approach. In summary we maintain our view that the existing revenue drivers should remain in place during the rollover year. The full suite of revenue drivers and the key parameters associated with each are presented in

3.34. Table 12 overleaf:

**Table 12 High-level approach to extending the TPCR4 revenue drivers into the rollover year (detailed parameters and description in Appendix 2)**

| Licensee | Revenue Driver | Key parameters |
|---|---|---|
| **SHETL** | Sole user triggered connection cost | • **Baseline:** The baseline will equal the connected generation on 31/3/12<br>• **UCAs:** The TPCR4 UCAs will remain, adjusted for inflation |
| **SPTL** | | |
| **NGET** | Additional Generation entry capacity | • **Baseline:** The baselines will be based on the background demand and generation projected at TPCR4.<br>• **UCAs:** The TPCR4 UCAs will remain, adjusted for inflation |
| | Zonal Surplus of generation capacity | |
| | Zonal Deficit of generation capacity | |
| | Anglo-Scottish boundary re-inforcement | • **Baseline:** The baselines will be based on the background demand and generation projected at TPCR4.<br>• **UCAs:** The TPCR4 UCAs will remain, adjusted for inflation |

## Incentives

3.35. The transmission licensees are currently subject to a number of incentives to encourage them to act in a way that benefits consumers. These incentives can be broadly categorised as efficiency incentives, reliability incentives, environmental incentives and incentives for timely delivery. In our Initial Proposals, we presented our view that no new regulatory incentives should be introduced for the TPCR4 rollover year, and that it would be disproportionate to revise each of the policy areas for a one-year rollover. We maintain this view, our decision is that the structure and parameters of the incentives are not changed from Initial Proposals.

3.36. Although stakeholders broadly supported our Initial Proposals, there were two significant areas on which the TOs disagreed. The first was our proposal to smooth the revenue adjustment associated with the TPCR4 capex incentive over a number of years. The second was our proposal to continue to decrease the SF6 leakage target in line with the TPCR4 rate of descent. On the first we have revised our position, on the second we maintain our view that our decision is proportionate to a one-year control and are not proposing to change the target from our Initial Proposals. The section below outlines the full details of the incentives for the rollover year, including the rationale for these decisions.

3.37. Table 13 below overleaf our the incentives we propose to remain in place during the rollover year:

**Table 13: Gas and electricity TO incentives**

| Incentive category | Gas | Electricity |
|---|---|---|
| **Efficiency** | Capex incentive | Capex incentive |
| **Reliability** | Incentives dealing with these issues are not in the scope of the TPCR4 rollover[24] | Reliability incentive |
| **Environmental** | | SF6 incentive |
| **Timely delivery** | Permit scheme and delivery incentives | Incentive for timely delivery not the scope of TPCR4 rollover[25] |

**Efficiency: Capex incentive – All TOs**

3.38. At the start of TPCR4, to incentivise the licensees to incur capex efficiently, we established a "capex incentive" for the gas and electricity transmission licensees. Under this they are exposed to 25 per cent of any capex under / over-spend as compared to their capex baseline. In our Initial Proposals, we presented our view that this incentive should remain during the rollover year, and that it should continue to be set to 25 per cent. Stakeholders agreed with this and considered it to be a proportionate approach. Our view has not changed and **our Final decision is to retain this incentive and maintain the 25 per cent sharing factor.**

3.39. The incentive works through applying a revenue adjustment at the end of the incentivised period. The associated revenue adjustment for TPCR4 is due to be calculated at the end of the current price control (i.e. in the rollover year). In our Initial Proposals we proposed to smooth this adjustment over a number of years for all the TOs, making 20 per cent of this adjustment in the rollover year. Our approach was driven by concerns about the impact on transmission charges of making this adjustment in full. The licensees disagreed with this proposal, considering it to be a retrospective change to policy. Since our Initial Proposals we have further considered the impact of allowing this revenue adjustment in full in the rollover year on transmission charges. In light of this, **our Final decision is to change our approach and make the capex incentive adjustment to SPTL, SHETL and NGG in full during the rollover year.** Given the magnitude of NGET's adjustment we still consider it appropriate to smooth the revenue adjustment and will apply 20 per cent of the adjustment in the rollover year. It is important to note that this revenue adjustment is provisional for the reasons outlined below. The following table illustrates the magnitude of this provisional adjustment:

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[24] Reliability of the NTS can be considered as being captured in the entry capacity operational buy-back incentive, which was recently reviewed in 2009. NGG's environmental incentive is encompassed in the SO external incentives, which is outside the scope of the TPCR4 rollover.
[25] We set out our views on outputs and incentives for timely connections in our decision document on strategy for the next price control (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionoutput.pdf). Following this, as part of project TransmiT, we have sought views on the scope and drafting of a proposed reporting requirement in relation to timely connections (http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110322_TransmiT_Connections_Consultation_FINAL.pdf)

**Table 14 Proposed provisional revenue adjustments associated with capex allowance[26]**

| Licensee | TPCR4 Capex incentive provisional revenue adjustment | Adjustment in the rollover year |
|---|---|---|
| NGET | £211.7m | £42.3m |
| SHETL | -£1.6m | -£1.6m |
| SPTL | £6.0m | £6.0m |
| NGG | £11.2m | £11.2m |

Provisional allowance and true-up

3.40. This adjustment will be provisional as the necessary information to calculate the TPCR4 capex incentive adjustment is not yet available. For each licensee their total capex from TPCR4 needs to be known. This will not be available until submission of their 2011-12 Regulatory Reporting Packs (RRPs) in summer of 2012. For the electricity licensees the capex allowance is adjusted in line with the revenue driver mechanism to account for any difference in outputs delivered (eg volume of connections) from the baseline.

3.41. NGET's revenue drivers are more complex than those in existence for Scottish TOs, in addition to flexing the capex allowance in line with the level of generation connected it also flexes in line with requirements to reinforce the capacity of boundaries between zones in response to shifting patterns of generation and demand. As stated in our Initial Proposals, prior to calculating NGET's capex incentive, we propose to first assess the impact of two policy developments that came into effect since the start of the current price control:

- **Connect and Manage** – The revenue driver for boundary reinforcements was designed under the previous "Invest & Connect" regime where there was a direct link between the connection of new generation and the requirement to undertake wider network reinforcements. The transition to a "Connect and Manage" approach means that connection can occur before these wider works complete.

- **TII** – The Transmission Investment Incentives mechanism, described in Chapter 1, was introduced after the start of TPCR4 to allow the licensees to fund increases in boundary capacity that were of a strategic or anticipatory nature and not directly in response to short-term signals.

3.42. We do not consider it appropriate to grant an increase in NGET's capex allowance for work that they either did not have to complete as a result of Connect and Manage or for work that was funded under the TII mechanism. In advance of

[26] The profiling of the remaining 80 per cent NGET adjustment will be dealt with as part of the RIIO price control. The deferral of this revenue adjustment will be done on a Net Present Value neutral basis. Our decision will be based on the impact on TNUoS charges and NGET's financeability.

calculating NGET's capex incentive, we will consider carefully the impacts of these policy developments on the need for NGET to undertake wider works.

Proposed dates for truing up the TPCR4 capex incentive and calculating the corresponding adjustment for the rollover

3.43. **TPCR4 true up:** The earliest date on which all of the data required to calculate the 'true' capex incentive adjustment for TPCR4 will be July 2012, following receipt of the licensees' RRP covering the year 2011-12.

3.44. **The rollover capex incentive:** After the conclusion of the rollover year the steps required to calculate the capex incentive for this period are broadly the same as those described above[27]. The earliest date on which all of the data required to undertake the assessments detailed above will be July 2013, upon receipt of the licensees' RRP covering the year 2012-13.

3.45. In our Initial Proposals we considered that, in light of these dependancies, we would true up the TPCR4 capex incentive and grant the corresponding adjustment for the rollover on 1 April 2014. Stakeholders agreed with this approach and it forms part of these Final Proposals.

**Reliability incentive: Electricity TOs**

3.46. The electricity TOs are incentivised to maintain a reliable system through a reliability threshold, against which their actual performance is measured and they are rewarded/penalised for any out/under performance. In our Initial Proposals we stated our view that it would be disproportionate with a one year price control to re-evaluate this mechanism and as such proposed to keep the existing targets. Stakeholders agreed this approach was proportionate with a one year control, but stressed the need to reassess these targets in light of the levels of investment being undertaken in the electricity transmission system. The reliability incentive is being reviewed in detail as part of the RIIO price control. **For Final Proposals we have decided that the existing reliability incentive continues to apply for electricity licensees, and that the parameters of the incentive remain unchanged.** The reliability targets are detailed below:

[27] The approach to adjusting the capex allowance in light of the revenue drivers differs slightly between the TPCR4 capex incentive calculation and the rollover; this is described in detail in appendix 2

**Table 15 Reliability targets for electricity TOs**

| | NGET | SPTL | SHETL |
|---|---|---|---|
| Upper target | 263MWh | 10 | 12 |
| Lower target | 237MWh | 8 | 10 |
| Upper collar | 619MWh | 22 | 27 |
| Maximum reward (% of revenue) | 1% | 0.5% | 0.5% |
| Minimum reward (% of revenue) | 1.5% | 0.75% | 0.75% |

### Environmental incentive (SF6 leakage – SPTL & NGET)

3.47. Sulphur hexafluoride (SF6) is a greenhouse gas used as an insulator in high-voltage switch-gear. It is one of the most potent greenhouse gases, with a global warming potential of 23,900 times that of carbon dioxide (CO2). SF6 emissions are not covered by the European Union Emissions Trading Scheme (EU ETS). To incentivise the licensees to reduce their emissions of this gas during TPCR4 we developed a mechanism to incentivise the licensees to focus on reducing leakage rates of SF6. Through the incentive, licensees are eligible to receive a payment should they beat annual leakage rate targets. The SF6 incentive scheme is only operational for NGET and SPTL. For each licensee their target has decreased at a steady rate during TPCR4 (NGET from 3 per cent to 2 per cent and SPTL from 2 per cent to 1.5 per cent).

3.48. In our Initial Proposals we stated our view that this rate of decrease should continue, resulting in targets of 1.75 per cent and 1.34 per cent for NGET and SPTL respectively. Both companies have suggested such targets would be difficult to achieve, instead suggesting the 2011-12 targets should be rolled forward. We consider the approach outlined in Initial Proposals to be in line with our proportionate approach to the rollover. **For Final Proposals we will set the previously communicated targets of 1.75 per cent and 1.34 per cent for NGET and SPTL respectively.**

### Timely delivery (Permits scheme)

3.49. We do not consider it appropriate to grant an increase in NGET's capex baselines for work that they either did not have to complete as a result of Connect and Manage or for work that was funded under the TO Incentives mechanism. In advance of calculating NGET's capex incentive, we will consider carefully the impacts of these policy developments on the need for NGET to undertake wider works.

3.50. NGG is incentivised to deliver capacity ahead of the default investment lead times via the permit scheme. NGG was given an initial allocation of entry (7,200 GWh) and exit (10,950 GWh) permits at TPCR4. It can earn more permits by offering (and users taking up this offer) to deliver incremental capacity ahead of the default lead time. It uses up the permits if it offers (and users take up this offer) to defer delivery of incremental capacity beyond the default lead time. Each permit held by

NGG at the end of TPCR4 provides it with a fixed amount of revenue which will be provided to NGG in 2012-13. The amount that can be earned from the scheme at the end of TPCR4 is capped at £36 million and £3 million for entry and exit permits respectively.

3.51. In our Initial Proposals we stated our preferred approach was to extend the permit scheme by one year and be based on the parameters of the existing scheme (using a pro-rata basis). We also indicated that NGG would receive its incentive payment in 2012-13. One respondent proposed that the price of each permit is pro-rated (ie is reduced to one fifth of the TPCR4 level) and the volume of permits is maintained at TPCR4 levels. NGG has not provided additional information that would lead us to consider that an alternative solution would be appropriate. We believe that in order to maintain the strength of this incentive the value of the permit should remain the same but the volume allocation needs to be pro-rated to reflect the one-year control.

3.52. Therefore we maintain that for Final Proposals, NGG will receive its incentive payout in 2012-13 based on the parameters set out in TPCR4. We will extend the permit scheme for one year with the parameters for the permit scheme for 2012-13 based on the existing scheme (using a pro-rata basis). On 1 April 2012, NGG will be given an initial allocation of entry permits (1440 GWh) and exit (2190 GWh) permits. The amount that can be earned from the scheme at the end of the TPCR4 rollover period is capped at £7,200,000 and £600,060 for entry and exit permits respectively. Each permit held by NGG at the end of the rollover period provides it with a fixed amount of revenue which will be provided to NGG in 2013-14. We consider this is proportionate to a one-year control.

# 4. Incentives and Uncertainty Mechanisms for the SO

**Chapter summary**

This chapter sets out our Final Proposals for the incentives and uncertainty mechanisms to apply to National Grid in their role as System Operator. Only the incentives and uncertainty mechanisms applying to SO internal costs are within the scope of this price control. The mechanisms for incentivising external costs (costs the system operator is required to pay to other parties in the industry in discharging their duties) are handled via a separate process. There has been no change in policy from our Initial Proposals, and in line with our proportional approach there is little change from TPCR4.

4.1. National Grid perform the role of system operator (SO) for the gas and electricity transmission systems. In their role as the gas transmission SO, they are responsible for ensuring that the gas national transmission system (NTS) remains within prescribed system pressure limits and that gas is transported from where it enters the NTS to where it exits the NTS. In their role as the electricity transmission SO they are responsible for making sure that supply and demand stay in balance and the system keeps within safe technical and operating limits.

4.2. The costs incurred undertaking these activities can be considered as internal or external. External costs are the costs the SO is required to pay to other parties in the industry in discharging their duties. For example in its role as the electricity SO National Grid have to buy and sell electricity in the balancing market to ensure supply and demand are matched. Setting allowances and incentivising efficiency for SO external costs is not within the scope of this price-control[28].

4.3. The remainder of this chapter presents our Final Proposals on how National Grid are to be incentivised to incur these internal costs efficienctly, and the nature and detail of mechanisms to establish uncertainty.

## Incentivising efficiency in internal SO costs

4.4. Internal costs relate to the costs incurred internally undertaking their duties as SO (eg staff and IT costs). As with the TOs this expenditure can be thought of as capex and opex.

[28] The existing mechanisms for incentivising these external costs will run to 1 April 2013. Further detail can be found at the following location: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Pages/SystOptIncent.aspx

### Incentivising efficient capex

4.5. As with the TOs, the SOs are currently incentivised to incur capex efficiently via a capex incentive through which they are exposed to 25 per cent of any capex under / over-spend as compared to their capex baseline. In our Initial Proposals, we presented our view that this incentive should remain during the rollover year, and that it should continue to be set to 25 per cent. We consider it is important to equalise this incentive with the capex incentive placed on National Grid's TO spend. Stakeholders agreed with this and considered it to be a proportionate approach. Our view has not changed and **our Final decision is to retain this incentive and maintain the 25 per cent sharing factor for both the electricity and gas SO.**

4.6. As with the capex incentive for the TOs we propose that a provisional revenue adjustment take place in the rollover year to reflect capex during TPCR4. Then, on 1 April 2014 this will be trued up, along with making the associated revenue adjustment based on capex incurred during the rollover year.

### Incentivising efficient opex

4.7. For the SO we also incentivise efficient opex through an opex incentive. This works in the same way as the capex incentive in that the licensee is exposed to a percentage of any under / over spend. As with the capex incentive the opex incentive applied to NG's internal SO functions is symmetrical.

4.8. **Electricity SO:** Throughout TPCR4 we have aligned the sharing factor for internal SO opex with the sharing factors for the external SO incentive scheme (costs paid to third parties by the SO). This alignment was to ensure that the SO was incentivised to efficiently allocate operational expenditure between internal and external activities. On 10 June this year we published our final proposals on the mechanism through which National Grid would be incentivised to incur external costs efficiently[29] from 1 April 2011 until the end of the rollover year. They will be subject to a symmetrical ±25 pre cent sharing factor. We therefore propose to apply a ±25 per cent sharing factor to their internal opex. Stakeholders agreed with this approach and the application of a ±25 per cent sharing factor forms part of this final decision.

4.9. **Gas SO:** Throughout TPCR4 the opex incentive for the SO was set to ±40 per cent, meaning NGG were exposed to 40 per cent of any over/under spend. In our Initial Proposals we stated that it was proportional with a one-year rollover to maintain this incentive, along with the ±40 per cent sharing factor. Stakeholders agreed with this approach and we propose that a ±40 per cent sharing factor is retained.

[29] http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/National%20Grid%20Electricity%20Transmission%20SO%20incentives%20from%201%20April%202011%20FINAL.pdf

## Uncertainty mechanisms

4.10. Generally speaking there is significantly less uncertainty projecting internal SO costs than there are projecting TO expenditure. This is due to the fact that the majority of the uncertainty associated with SO costs relate to external costs paid to third parties in balancing the system. As a result the uncertainty mechanisms are less complex. During TPCR4 only two uncertainty mechanisms exist, both apply only to the electricity SO. The first provides and adjusts funding in instances where, in their SO role NGET need to request a change to TO's outage plan. The second was to allow operating expenditure allowance for system operation costs associated with the offshore networks to be logged up. These, along with our approach for the rollover year are described below:

4.11. **Outage changes:** As part of TPCR4 we set the licensees an ex-ante allowance of £1m per year (in 2004-05 prices) to fund outage changes, as described above. This allowance was not subject to the opex sharing factor. An associated income adjusting term developed through which this allowance would flex if actual expenditure was materially different (by more than £300k) from this allowance. In our Informal Consultation on the licence changes, issued in October, we proposed to retain this mechanism. Stakeholders agreed and **we will retain the ex-ante allowance of £1m and the income adjusting event for the rollover year**. We consider this to be a proportionate approach and as part of the RIIO price control we are undertaking a detailed review of these arrangements.

4.12. **Costs associated with the offshore transmission regime:** When setting the TPCR4 price control, NGET were not granted an allowance for costs associated with the development and delivery of the offshore transmission regime. In 2007, we set out that, rather than include an allowance for these costs, we would require NGET to record these costs in detail and report them to us[30]. In 2009 we decided to allow such costs, where efficiently incurred, to be passed through to consumers[31]. In our interim consultation letter in October, we presented our view that we considered it appropriate to transition the funding arrangements for these costs to an ex-ante allowance. In common with other operational costs associated with system operation this ex-ante allowance will be subject to a 25 per cent sharing factor, we considered this would provide a greater incentive for NGET to incur these costs efficiently. Stakeholders broadly agreed with our proposal and **this logging up approach will not continue into the rollover year.** An allowance for these costs has been included in National Grid's opex baseline. This is detailed in Appendix 7.

[30] http://www.ofgem.gov.uk/Licensing/Work/Notices/ModNotice/Documents1/17094-3507.pdf
[31] http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/AA5A%20letter%20FINAL.pdf

# 5. Financial proposals

**Chapter Summary**

This chapter sets out our Final Proposals on allowed return, the Regulatory Asset Value (RAV) and pensions for the rollover year. In addition, it provides commentary on our view on financeability in the rollover year. Our Final Proposals to the allowed return are informed by stakeholder feedback to our April consultation and Initial Proposals, and are broadly in line with Initial Proposals.

### Introduction

5.1. Our general approach to the rollover is to retain the existing policies used in TPCR4 and update only where required and proportionate to a one-year control. We have not adopted RIIO principles. In terms of the financial elements of the rollover package, we have updated the allowed return to reflect market changes, in line with the TPCR4 approach, where there is sufficient evidence. The only policy change is in respect of pension costs where we have adopted the revised policy we set out in June 2010, which applies to all network companies.

5.2. It is important to note that TPCR4 and the rollover year rely on a different approach to setting the allowed return than the RIIO model. Therefore, stakeholders should not draw conclusions on the allowed return that we will set in RIIO-T1 and GD1 from our decision for the rollover. In considering the allowed return for the TPCR4 rollover year, our main aim is to consider changes to the TPCR4 assumptions in a way that is proportionate to the length of the TPCR4 rollover period.

## Allowed return

5.3. Our final decision, which is unchanged from Initial Proposals, is to reduce the allowed return to 4.75 per cent real vanilla weighted average cost of capital (WACC) for the rollover year, compared to 5.05 per cent in TPCR4 as set out below.

### Summary of Initial Proposals

5.4. Our Initial Proposals with regard to allowed return were:

- **Cost of debt:** We proposed to lower to 3.25 per cent, from 3.75 per cent used in TPCR4. We proposed that the debt premium of 1.25 per cent remains appropriate. However, we argued that for the rollover we should use a risk-free rate of 2.0 per cent rather than the 2.5 per cent used in TPCR4. This is based on an update of the Smithers Report (which formed the basis to the TPCR4 decision) by our consultants Europe Economics (EE). EE found a notable decline in the risk-free rate since 2006.
- **Cost of equity:** We proposed to leave unchanged at 7.0 per cent. Even though the risk-free rate has declined, TPCR4 relied on a 'total returns on equity' approach, and it is generally accepted that total returns are more stable than the individual components.

- **Notional gearing:** We proposed to leave unchanged at 60 per cent for all TOs.

**Summary of consultation responses**

5.5. We received responses from the three network operators and two suppliers. These are available on our website[32].

5.6. The responses from the two suppliers were largely supportive of our proposals. The TOs consultation responses indicated that they disagree with our proposal to reduce the cost of debt assumption. SPTL and SHETL said that if the cost of debt assumption is reduced, a compensating increase should be made to the cost of equity assumption. National Grid reiterated arguments it made previously, the main being that TPCR4 focused on the long-term risk-free rate, and that Ofgem has not shown a decline in this rate since TPCR4.

5.7. In light of National Grid's comments, we reviewed all of the published TPCR4 documents and found no clear evidence to support the claim that the review focused on the long-term risk-free rate. We have carefully considered the responses to our Initial Proposals and have concluded that they were robust and that they should not be amended for these Final Proposals.

**Our final decision**

5.8. We have previously set out that our approach to setting the allowed return for the rollover would follow the approach used in TPCR4, which in turn was largely based on the Smithers Report, while applying proportionality to account for this being a one-year price control.

5.9. Since the Initial Proposals were published, deterioration in the Euro-zone sovereign debt crisis has impacted financial markets in the UK. In the bond market, this has been reflected in a sharp decline in the yield on both conventional and index-linked gilts, and a contrasting spike in the debt premium paid by corporations rated in the BBB to A range (which is consistent with the credit ratings of network companies). In line with the approach in TPCR4, however, our view is that allowed revenue should not reflect volatility in spot rates. We, therefore, remain of the view that our Initial Proposals of the risk-free rate (2.0 per cent) and debt premium (1.25 per cent) remain appropriate.

5.10. Overall, our final decision is unchanged from the Initial Proposals, specifically:

- **Cost of debt:** Reducing the cost of debt assumption by 50bps to 3.25 per cent (real pre-tax). This reflects a reduction in the risk-free rate from 2.5 per cent to 2.0 per cent and no change to the debt premium at 1.25 per cent.

[32] Consultation responses to Initial Proposals can be found on the Ofgem website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=63&refer=Networks/Trans/PriceControls/TPCR4Roll-over

- **Cost of equity:** Leaving the cost of equity assumption unchanged at 7.0 per cent (real post-tax).
- **Notional gearing:** Leaving notional gearing unchanged at 60 per cent for all TOs.

## Financeability assessment

5.11. As noted above, for the rollover year we have assumed an opening notional gearing of 60 per cent - unchanged from TPCR4. We have undertaken our financeability assessment using this assumption for the rollover year, although it is usual to assess financeability over a longer period of time. Based on the numbers in the final proposals, the financeability assessment, for the rollover year, does not raise any concerns for any of the TOs.

5.12. In Initial Proposals we identified some potential financeability concerns for SHETL. This was driven by a substantial increase in notional gearing – above 70 per cent – as a result of expected capex of £592.9m in the rollover year. We therefore proposed to provide SHETL with a revenue uplift in order to cover the cost of a notional equity issuance. For these final proposals, SHETL's capex programme has been revised down to £324.5m in the rollover year. The reduction in capex and increase in allowed revenue since Initial Proposals is sufficient to eliminate any financeability concerns and we, therefore, do not include a revenue uplift in our final decision.

5.13. In any case, we note that financial ratios in a single period would not normally have a major impact on credit ratings if they can be expected to return to stable levels within a three to five year period. We will be in a better position to assess the longer-term financeability of the TOs as part of RIIO-T1.

### Allowance for issuing new equity true-up

5.14. Our Initial Proposals with regard to the TPCR4 allowance for the cost of notional equity issuances were:

- **NGET:** Leave the zero allowance unchanged.
- **NGG:** The mechanism did not apply to NGG and we did not propose to change this.
- **SHETL:** Leave the allowance unchanged.
- **SPTL:** Fully claw back the £2.5m allowance on a net present value (NPV) neutral basis, owing to SPTL significantly under-spending its allowed capex and, therefore, not facing the financeability concerns envisaged at the time of TPCR4.

5.15. SPTL noted in its consultation response that it did not include in it's charges the £2.5m allowed to it with regard to notional equity issuance costs in 2010-11, and hence that no amount should be clawed back. However, allowed revenue not recovered in one year is carried forward via the K factor[33]. As a result, we will claw back the amount taking into account the impact of the K factor.

## Other financial issues

### Opening RAV values

5.16. In Initial Proposals[34] we set out the provisional RAV calculations to 31 March 2013. We have updated these (again on a provisional basis) and the updated forecast is shown in the following table.

**Table 16 Provisional TO RAV as at 31 March 2013**

| 2009-10 prices £m | Opening RAV 1st April 2010 (provisional) | Additions | Depreciation | Disposals/ adjustments | Closing RAV 31st March 2013 |
|---|---|---|---|---|---|
| NGET | 7,016 | 2,538 | (1,483) | 647 | 8,718 |
| SHETL | 433 | 265 | (81) | 97 | 713 |
| SPTL | 868 | 405 | (205) | 42 | 1,110 |
| NGG | 4,023 | 293 | (395) | 61 | 3,982 |
| Total | 12,340 | 3,501 | (2,164) | 846 | 14,523 |

Source: Ofgem

5.17. These projections vary from those shown in the Initial Proposals document since they reflect the incorporation of actual 2010-11 capex and the resubmission of forecasts for 2011-12 and 2012-13. As set out above, in setting the rollover allowances we have incorporated provisional funding allowance for TII projects. These provisional allowances of NGET of £313.2m, SHETL £101.8m and SPTL £84.6m are based on the TOs' projected expenditure. We will true-up, on a NPV neutral basis, any difference between these provisional allowances and the final allowances determined under TII.

5.18. The adjustments shown include CNI expenditure treated as logged up to 31 March 2012, expenditure under the TII scheme, and addition of expenditure treated as work in progress (WIP) during the period. For the purpose of clarity the different elements of TO spend are added to RAV on the following basis:

- TIRG – following the completion of the five year post completion incentive period in accordance with scheme rules.
- Logging up – will be added to RAV (subject to an efficiency review) at the start of RIIO-T1.

[33] The K factor is the mechanism to correct for differences between allowed revenues and actual revenues
[34] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

- Critical National Infrastructure (CNI) spend to 31 March 2012 – was added to RAV at the start of the rollover year. Expenditure in the rollover year will be treated as logging up (see above).
- TII expenditure – was added to RAV at the start of the rollover year.
- Work in progress (WIP) – This was added to RAV at the start of the rollover year.
- Revenue driver expenditure for NGG which is remunerated under specific separate mechanisms and for which the expenditure will be added to RAV over the next few years.

5.19. There therefore remains some expenditure that has been incurred but has not yet been added to the RAV (logging, TIRG and some gas entry and exit spend). We refer to these as constituting a 'shadow' RAV, for which provisional values are summarised in the table below.

**Table 17 Estimated provisional TO 'Shadow' RAV at 31 March 2013**

| 2009-10 prices £m | Gas revenue driver | Logging up | TIRG | Total |
|---|---|---|---|---|
| NGET | 0 | 164 | 96 | 261 |
| SHETL | 0 | 0 | 293 | 293 |
| SPTL | 0 | 24 | 152 | 176 |
| NGG | 549 | 52 | 0 | 601 |
| Total | 549 | 240 | 542 | 1,331 |

Source: Ofgem

5.20. Both actual and shadow RAV numbers remain provisional until we have completed an efficiency review of the TPCR4 and rollover expenditure. We will conduct the efficiency review as part of the RIIO-T1 price control.

5.21. For the calculation of depreciation charges in the rollover year, we continue to use asset lives consistent with those used in TPCR4.

**Pensions**

5.22. In setting pension allowances we have introduced our proposals set out in our 22 June 2010 Pension decision document and detailed in our 31 March 2011 RIIO-T1 Financial Issues document. This means that for the TPCR4 rollover the key principles are:

- 15-year notional deficit recovery period
- True-up of deficit and ongoing costs from TPCR4 over nine years
- Allowance for ongoing contributions based on the latest actuarial rates, Pension Protection Fund (PPF) levies and pension scheme administration costs.
- All pension allowances are based on forecast data and will be subject to a true up adjustment (except ongoing pension costs) to actual spend in RIIO-T1.

The pension allowances for the rollover are set out in the following table.

**Table 18 TO pension allowances for 2012-13**

| 2009-10 prices £m | Allowances | | | | | | |
|---|---|---|---|---|---|---|---|
| | Deficit recovery | Ongoing pension costs | Admin costs | PPF levy | True-up | Total allowances per FP | Total allowances per IP |
| NGET | 28.7 | 19.3 | 0.9 | 1.0 | 1.8 | 51.7 | 51.3 |
| SHETL | 0.5 | 2.2 | 0.2 | 0.0 | 0.5 | 3.4 | 3.3 |
| SPTL | 0.2 | 2.3 | 0.1 | 0.1 | 0.5 | 3.1 | 2.8 |
| NGG | 26.3 | 6.7 | 1.4 | 2.9 | 15.5 | 52.7 | 54.5 |
| Total | 55.7 | 30.6 | 2.6 | 3.9 | 18.3 | 111.0 | 112.0 |

Source: Ofgem
Note: Totals may appear different to the sum of components due to rounding.

We have set the allowances applying our pension methodology. This includes pension deficit funding based on the updated valuations as at 31 March 2011. These valuations are set out in the following table:

**Table 19 Estimate of pension scheme established deficits, based on updated valuation as at 31 March 2011**

| 2009-10 prices £m | Updated valuation as at | Forecast deficit attributable to the licensee |
|---|---|---|
| NGET | 31-Mar-11 | 357.8 |
| SHETL | 31-Mar-11 | 5.8 |
| SPTL | 31-Mar-11 | 2.1 |
| NGG | 31-Mar-11 | 327.9 |
| Total | | 693.5 |

Source: Ofgem

5.23. For the rollover year, we fund deficits over a notional 15-year funding period using a 2.6 per cent discount rate, being the median rate of pre-retirement real discount rates. The other allowances are based on the latest actuarial rates for ongoing contributions and the companies' estimates of PPF levies and pension scheme administration costs.

**True-up adjustment for over- and under- funding in TPCR4**

5.24. The true-up of TPCR4 pension payments will commence during the TPCR4 rollover year. These adjustments are spread over the combined nine years of the TPCR4 rollover and RIIO-T1.

5.25. The adjustment to TPCR4 is split into two parts. One part covers the amounts that have been allowed in the indicative annual RAV calculations; this only applies to

NGET. The second covers the amounts expensed. The adjustment methodology is set out in appendix 6 of the March 2011 RIIO-T1 Financial Issues document.

5.26. To the extent that regulatory depreciation was foregone in TPCR4, we have allowed additional revenue in the rollover year and in RIIO-T1, with a NPV adjustment (at TPCR4 WACC) to reflect the delay in revenues. The same approach is taken in respect of the amount expensed, eg the cash amount in the table below:

**Table 20 Cash adjustment and amount included in closing TPCR4 RAV**

| 2009-10 prices £m | Total adjustment for TPCR4 period | Annual adjustment commencing in 2012-13 | Additions to/ (clawback of) closing RAV |
|---|---|---|---|
| NGET | 13.0 | 1.8 | 4.7 |
| SHETL | 4.0 | 0.5 | 0.0 |
| SPTL | 3.6 | 0.5 | 0.0 |
| NGG | 114.0 | 15.5 | 0.0 |
| Total | 134.6 | 18.3 | 4.7 |

Source: Ofgem

5.27. The true-up amounts shown above are provisional, pending completion of our pension efficiency review. We have applied the TPCR4 regulatory fraction to NGET and NGG. For SPTL and SHETL, we have applied the regulatory fraction derived as part of DPCR5 for these schemes, which are common to transmission and distribution, as well as encompassing unregulated businesses. Regulatory fractions applied are shown in the table below.

**Table 21 Regulatory fractions applied in TPCR4 RO**

| | Regulatory Fraction |
|---|---|
| NGET | 75.7% |
| SHETL | 7.1% |
| SPTL | 4.8% |
| NGG | 56.8% |

Source: Ofgem

5.28. We will adjust the regulatory fractions and true-up when setting RIIO-T1 allowances; or, if the information required to determine the regulatory fraction is delayed, at the first triennial reset and true-up of pension allowances in RIIO-T1. The cash amount is spread evenly over nine years as shown. For NGET there is also an adjustment increasing closing RAV in line with the policy applied in TPCR4.

## Tax allowances

5.29. As previously proposed, we have determined the allowed tax costs using applicable capital allowances and tax rates, using the same tax calculation methodology as was implemented at DPCR5 and set out in the March 2011 RIIO-T1 Financial Issues document. We have not introduced any policy changes, such as a tax trigger, which will be implemented in RIIO-T1. The tax claw back for excess gearing will be adjusted at RIIO-T1 for each year of TPCR4 and the rollover year.

## Network rates

5.30. We have retained the TPCR4 treatment of network rates as set out in Appendix 4 of the March 2011 RIIO-T1 Financial Issues document. This effectively treats these non-controllable costs as pass-through, subject to the companies demonstrating that they have taken reasonable actions to minimise rating valuations. These non-controllable costs for 2012-13 are as shown in Appendices 3-7.

# 6. Way Forward

**Chapter Summary**

This chapter sets out the process that we will follow to ensure that the all licence conditions are in place on 1st April 2012.

6.1. After the publication of Final Proposals the licensees will have until Friday 16 December 2011 to accept Final Proposals. During that time we will finalise the licence conditions that will implement Final Proposals. We have already undertaken a consultation[35] on the licence conditions. We will issue the statutory consultation notice containing the licence conditions by 5 January 2012 and will consult for a minimum of 28 days. We will then publish our decision to modify the licence conditions after considering responses to the statutory consultation

6.2. Changes to UK legislation as a result of the implementation of the European Third Package Directives[36] mean that we cannot refer matters to the Competition Commission before we publish our decision to modify the licence conditions. However, once the Authority has made its decision, the licence conditions cannot take effect for 56 days from the publication of the decision. This is to allow a party who wants to appeal the decision to modify the licences to take that decision to the Competition Commission.

6.3. The new price control period will begin on 1 April 2012.

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[35] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/111021_TPCR4RO_InformalLicenceconsultation.pdf

[36] Statutory Instrument 2011 No. 2704, The Electricity and Gas (Internal Markets) Regulations 2011, 9 November 2011

# Appendices

# Appendix 1 – Changes to our approach to inflation

1.1. In July 2011, we published a decision to change the method of indexation that will apply to allowances in the TPCR4 rollover, in 2012-13, and beyond.[37] Indexation is used to convert allowances, defined in the licence in the prices of a base year, to allowances in the prices of the relevant regulatory year.

1.2. Allowances, defined in the TPCR4 rollover licence and the RIIO-T1 and RIIO-GD1 licences, will be in 2009-10 prices. The new indexation methodology, outlined in our July 2011 decision letter, will use the forecast change in RPI[38] between the base year and the regulatory year to convert these allowances to the prices of the relevant regulatory year. As explained in our decision letter a true-up adjustment will then account for the difference between assumed economy-wide inflation, as measured by a forecast of RPI, and actual outturn RPI measured inflation in each regulatory year.

1.3. A decision was taken that TPCR4 rollover, RIIO-T1 and RIIO-GD1 allowances would be defined in the licence in 2009-10 prices. The adopting of a new approach to indexation means there are different options to rebase allowance form their current base year to 2009-10 prices. In this letter we discuss the different approaches that will be used for different types of revenue allowance. The principles guiding what approach to use reflects both our previous decision to apply the new method of indexation to all allowances from the TPCR4 rollover, in 2012-13, and to not make any retrospective changes to allowances in prior years. The table below summarises our approach.

**Table 22: Allowance summary**

| Allowance | Treatment going forward |
|---|---|
| Allowances being reset, eg base revenue | Reset in 2009-10 prices, new indexation method will apply in the licence |
| Allowances being maintained, eg revenue drivers | Rebased to 2009-10 prices by applying new indexation method from price base in current licence, new indexation method will apply in the licence |
| Historical allowances being maintained, eg TIRG and TII | Rebased to 2009-10 prices by using old indexation method to convert to nominal prices then new indexation method to convert to 2009-10 prices, new indexation method will apply in the licence |

[37] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=117&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

[38] Retail Prices Index

1.4. Where allowances are being reset, they will be reset in 2009-10 prices and the new method of indexation will be applied.

1.5. Where allowances are not being altered, eg those revenue drivers that will be maintained, they will be converted from the base prices as they are defined in the current licence to 2009-10 prices for inclusion in the new licence. This will be done by applying the new indexation method. For example to convert an allowance from 2004-05 prices to 2009-10 prices allowances will be multiplied by the below adjustment factor:

*Adjustment factor = average RPI for 2009-10 / average RPI 2004-05*

*= 215.77/188.15 = 1.1468*

1.6. For allowances prior to 2012-13 that will continue to be part of the licence, eg TII and TIRG, we will convert them to 2009-10 prices using the following steps:

- Convert current licence values (in 2004-05 prices) to nominal values using the indexation method in the TPCR4 licence.
- Use the new indexation method to convert these nominal values to 2009-10 prices. These values will be included in the TPCR4 rollover and RIIO-T1 licences.

1.7. For TII and TIRG revenues from 2012-13 onwards we will apply the new indexation method to inflate from original base prices in which allowances were derived. For example, for TIRG revenues we will inflate allowances in the licence from 2004-05 prices to 2009-10 prices using the new method. For TII, we will look at the price base in which funding requests were made and use the new method to convert to 2009-10 prices, eg the funding decision in January 2011[39] was made in 2010-11 prices so these values will be deflated to 2009-10 prices by dividing average RPI for 2009-10 by average RPI for 2010-11.

1.8. This approach for TII and TIRG applies the new methodology to deflate nominal 2011-12 allowances to 2009-10 prices. This requires using RPI for 2011-12 but actual RPI is currently unknown, it will not be known until April 2012. For calculations for 2012-13 onwards that take account of historical allowances, eg the capital expenditure incentive regime calculation in the TII condition, the values in the TPCR4 rollover licence will be used. We do not think that the difference between forecast RPI (as taken from the October 2011 HM Treasury forecasts[40]) used for rebasing these allowances and actual RPI for 2011-12 will cause a material difference in the allowances received. If RPI fluctuations in the remaining months of this regulatory year cause a material difference in the revenues calculated then we will re-examine the calculation and make any necessary adjustment to revenues as part of RIIO-T1.

[39] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Jan11_TII_OpenLetter_FINAL%20(2).pdf
[40] http://www.hm-treasury.gov.uk/d/201110forecomp.pdf

# Appendix 2 – Extending the Existing Electricity TOs' Revenue Drivers

1.1. As described in Chapter 3, our Final Proposals are to maintain the existing set of revenue drivers for the Electricity TOs into the rollover year. This Appendix provides further detail on how these proposals will be implemented, and the interaction between the revenue drivers and the capex incentive.

## Reasons for continuing with the revenue drivers into the rollover year

1.2. A significant portion of the capex projected for the rollover year contained in the licensees' business plans is for projects which, had they delivered output during the current price control, would have resulted in an adjustment to the capex allowance via the revenue drivers. For example, they may have connected additional generation resulting in a capex allowance increase (calculated by the Unit Cost allowance (UCA) multiplied by the MWs connected). In our Initial Proposals we communicated our view that we consider there to be two key advantages in continuing to adjust the capex baseline (against which actual capex will be incentivised) via the revenue drivers:

1. **Simplicity:** Where these projects are still ongoing during the rollover year (ie have commenced during TPCR4), estimating the capex requirement for the rollover year for a part of the project is extremely difficult and involves projecting the phase the project will be at in April 2012. Continuing to utilise the revenue drivers avoids this complexity.

2. **Flexibility:** Our technical consultants suggested that there was a degree of uncertainty over whether some load related capex projects proposed in the business plans would actually go ahead in the rollover year. Continuing to use the revenue drivers will allow the capex allowance to flex in line with requirements during the rollover year.

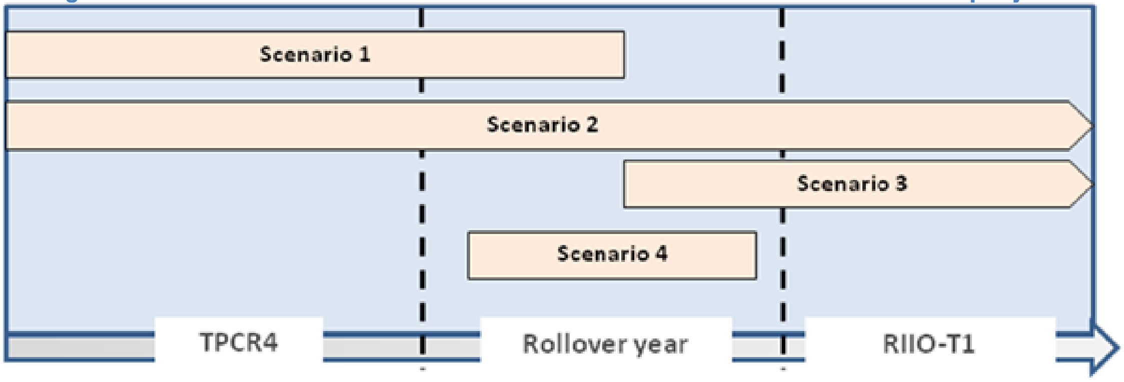
1.3. We also stated that we considered it proportionate to maintain the UCAs (inflated in line with RPI) that were in place at the start of TPCR4. The TOs broadly agreed with this approach, one stressed that, though it is proportionate for a one year rollover these unit cost allowances should not apply to projects completing beyond the rollover year. We will determine how to incentivise such projects as part of the RIIO price-control.

## Application of revenue drivers to the rollover year and the concept of regulatory Work in Progress (WIP)

1.4. By the end of TPCR4 the TOs are projecting to have incurred a significant amount of capex on projects that will complete beyond the end of the price control which were not included in the base capex allowance. These projects would have delivered outputs (eg connected additional generation) and ultimately resulted in an increase in the capex baseline via the revenue drivers if the current price control arrangements were to continue. It would not be appropriate to include expenditure on such projects in the actual capex for comparison with the TPCR4 capex baseline, since as the outputs are yet to be delivered there would be no commensurate change in the capex baseline. Such expenditure, referred to as regulatory Work in Progress (WIP), will enter the provisional RAV at the start of the TPCR4 rollover year and be excluded from the calculation of the TPCR4 capex incentive. Through this approach the effect will be to grant an allowance for the price control equal to the actual expenditure for these projects. Similarly, as we will continue to use the revenue drivers during the rollover year we will have a value for regulatory WIP included in additions to RAV at the start of RIIO-T1.

1.5. Although the revenue driver mechanisms for NGET are more complex than those for SHETL and SPTL, it is possible to consider our approach at a high level for all licensees by considering the different combinations of start and end dates for projects that would have resulted in a revenue driver adjustment had they completed during TPCR4. In our Initial Proposals we illustrated this by defining the revenue driver projects as belonging to one of the four scenarios illustrated below:

**Figure 1 Possible combinations of start / end dates for revenue driver projects**




1.6. The calculation of the associated adjustment to the rollover baseline capex allowance for each project is dependent upon which scenario they belong to. In scenarios one and four an output has been delivered and the corresponding adjustment to the capex baseline can be calculated. In scenarios two and three it is not possible to calculate such an adjustment and capex incurred on these projects will not be considered in calculating the capex incentive. It will enter the RAV un-incentivised (as WIP, described earlier), and incentivisation will take place as part of the RIIO price control. This approach is summarised in the table overleaf:

**Table 23 Deriving capex allowances during the rollover year for revenue driver projects**

| Scenario | Treatment |
|---|---|
| Scenario 1 | **Capex is incentivised through the revenue drivers:** The adjustment to the rollover capex baseline associated with the project is calculated as follows:<br>***Capex allowance = RD allowance– TPCR4 WIP***<br>Where:<br>• **RD allowance** is calculated in line with the TPCR4 revenue drivers<br>• **TPCR4 WIP** is the capex incurred on the project during TPCR4 |
| Scenario 2 | **Incentivisation of capex is deferred to RIIO:** Since the project is yet to achieve an output we cannot determine the efficient level of capex. Capex incurred enters the RAV un-incentivised. Actual expenditure on the project, ie the TPCR4 WIP (in Scenario 2) plus the capex incurred during the rollover is categorised as WIP. This WIP is taken into consideration in granting the allowances for RIIO. |
| Scenario 3 | |
| Scenario 4 | **Capex is incentivised through the revenue drivers:** As in Scenario 1, the actual capex is incentivised. This time the adjustment to the capex baseline is simply the revenue driver allowance as per the definition in Scenario 1. |

1.7. The actual WIP on each of the revenue driver projects will not be known until July 2012 when, as part of the licensees RRP submission, we will request the TOs to submit details of their final WIP position. That is the total capex incurred during TPCR4 on each project which is to be excluded from the TPCR4 capex incentive calculation as it has not delivered a commensurate adjustment to the capex baseline. This information will feed into both the recalculation of the TPCR4 capex incentive, and the calculation of the capex incentive adjustment for the rollover year[41]. As we describe in Chapter 3 the revenue adjustment associated with the TPCR4 capex incentive will take place in 2014. We will make both the true up of the TPCR4 capex incentive, and the calculation of the rollover capex incentive on an Net Present Value (NPV) neutral basis.

[41] This would apply to projects fitting into scenario 1 of the table above.

## Proposed base scenarios and unit cost allowances

1.8. In order to calculate the revenue driver adjustment to the capex baseline we need to set a baseline scenario, against which we can compare outturns, and multiply the difference by the unit cost allowance (UCA). Our proposed approach on this differs between the Scottish TOs and NGET.

### Scottish licensees

1.9. The existing revenue drivers for the Scottish licensees adjust their baseline capex allowance in line with the difference between the volume of generation connected[42], and the level of generation underpinning their baseline capex allowance. For the rollover year we propose to set their baseline equal to the level of generation connected at the end of TPCR4 (ie on 31 March 2012). Through this approach any incremental generation connections completing in the rollover year will result in an adjustment to the capex baseline as illustrated in Table 24, for the avoidance of doubt the table below outlines our proposed baselines and UCAs:

**Table 24 Final baselines and cost allowances for SHETL and SPTL's local infrastructure works revenue drivers**

| | Base scenario | UCA (£/MW - in 2009/10 prices)[43] |
|---|---|---|
| **SHETL** | The level of connected generation (defined as "relevant generation" in licence condition J5[44] | 27,500 |
| **SPTL** | | 61,900 |

1.10. We also propose to maintain the special treatment of high cost projects introduced as part of TPCR4. Through this approach projects projected to cost over £149,100/MW for SHETL and £186,900/MW for SPTL[45], are not subjected to the capex incentive and a return and depreciation is granted within the price control.

[42] Works have been contracted and constructed to deliver in the relevant Transmission Owner Construction Agreements (TOCA)
[43] Figures have been inflated using the updated approach to RPI indexation. Allowances in 2004-05 prices have been converted to 2009-10 prices by multiply by average RPI in 2009-10 divided by average RPI in 2004-05.
[44] Relevant Generation: The cumulative amount of generation connection capacity (excluding high cost projects) for which attributable transmission reinforcement works are completed and commissioned (in accordance with the System Operator Transmission Owner Code, STC) after 31 March 2005;
[45] Numbers expressed in 2009-10 prices.

**National Grid – Generation, zonal surplus and zonal deficit**

1.11. NGET's revenue drivers are more complex than those of the Scottish licensees. As well as a revenue driver for generation connection, three further revenue drivers were introduced specifically for NGET. Two of which adjust NGETs funding for boundary reinforcements within their network in response to signals from generators and DNOs (distribution network operators); a further revenue driver makes adjustments to reflect any difference between the baseline and delivered capacity on the Anglo – Scottish Boundary.

1.12. The revenue driver for generation connection, along with the two which flex the capex baseline in response to the requirement to increase the import or export capacity on a boundary (zonal surplus and zonal deficit) are all inter-related. The zonal surplus and zonal deficit revenue drivers flex NGET's capex allowance in line with the changes in flows between each zone and the wider network, and the associated requirement to reinforce the import or export capacity of these zones. When setting the TPCR4 price control we projected the levels of demand and generation at a zonal level, and included an allowance to fund the associated reinforcements in the baseline capex allowance.

1.13. Through the revenue drivers, this capex allowance will flex when actual levels of generation or demand differ from these projections (defined as the base scenario). The extent to which the capex allowance flexes is determined by multiplying the increase or decrease in zonal surplus or deficit by a UCA defined at a zonal level. The cost associated with boundary reinforcements varies considerably by zone and this is reflected in the range of UCA's detailed in Table 25 below.

**Table 25 UCAs by zone**

| | UCA capex (£/MW) - 2009/10 prices | | |
|---|---|---|---|
| | **New Entry** | **Zonal Surplus** | **Zonal Deficit** |
| South & South West | 20,100 | - | 26,700 |
| Thames Estuary | 20,100 | 80,300 | - |
| London | 80,300 | - | 334,400 |
| South Wales | 20,100 | 33,500 | 26,700 |
| East of England & Home counties | 13,400 | 86,900 | 20,100 |
| West Midlands | 6,700 | - | 53,600 |
| East Midlands | 6,700 | 73,500 | 13,400 |
| North West & North Wales | 40,100 | 60,200 | - |
| Yorkshire & Lincolnshire | 20,100 | 80,300 | - |
| North East | 20,100 | 66,900 | - |

1.14. Our decision is to retain these UCAs (RPI adjusted) for the rollover year.

1.15. Most zones are either importing or exporting zones, and as such only have a UCA associated with either adjustments in deficits or surpluses. Three of the zones were expected to require work to facilitate increased import and export during TPCR4 so were set UCAs for both deficit and surplus (for example South Wales was projected to switch from being an importing to an exporting zone during the price control).

1.16. Baseline values were defined for zonal surplus and demand. These were minimum values below which NGET would not receive a negative revenue adjustment. These were defined based on the principle that scaling back the capex allowance should only affect capex that was in response to signals during TPCR4. The baselines were defined as follows:

> **Surplus:** Where export capacity currently exists, the baseline is the current export requirement plus the existing surplus export capacity. Projected TEC reductions within the zone during TPCR4 were then subtracted from this baseline as it would not be necessary for NGET to consider this generation in reinforcing the network.
>
> **Deficit:** Where surplus import capacity currently exists, the baseline is the current import requirement plus any incremental existing import capacity. Projected TEC reductions within the zone were then added to the deficit baseline as NGET would have to upgrade the boundary accordingly.

1.17. As we communicated in our Initial Proposals we intend to maintain the revenue drivers mechanism for the rollover year. We consider this important to allow the rollover capex allowance to adjust in response to market signals and to allow us to incentivise work in progress (regulatory WIP) that will deliver an output during the rollover year.

1.18. In our October licence drafting consultation, we presented our provisional view that, in keeping with the approach outlined above for the Scottish licensees, the baseline for the rollover year would be the zonal surplus and deficit as at the end of TPCR4 (2011/12), and that this would also be the base scenario. Through this approach we considered that we would only need to set an ex-ante allowance for capex that would not result in an adjustment to the capex allowance via the revenue drivers (ie only non-load related capex, capex associated with TSS[46], and capex associated with exit triggered infrastructure and sole use demand connections).

1.19. Subsequent sensitivity analysis on this approach indicates that for a small increase in demand, NGET would receive a disproportionate increase in their capex allowance through the revenue drivers. Additionally we have compared the increase in capex allowance were the contracted level of generation to connect, the resultant increase in the capex allowance is significantly higher than NGET’s projected

[46] TSS is defined as “expenditure on schemes aimed primarily at improving the efficiency of system operation” - projects which are beyond the requirements of the security standards, but are cost beneficial as compared to potentially incurring future constraint costs.

expenditure. There is one key reason why this approach results in disproportionate adjustments to the capex allowance:

1.20. By setting the baseline to the actual surplus or deficit at the end of TPCR4, we are not taking into account existing import or export capacity. The TPCR4 baselines were developed on the principle that NGET should not receive an incremental capex allowance for capacity that already exists. By setting the baseline equal to the surplus at the end of 2011-12 we would ignore the impact of capacity and our methodology would not be in line with the that adopted in setting the baselines as part of TPCR4.

1.21. When undertaking work to develop the baseline and base scenario for TPCR4, we projected levels of generation connection and demand at a zonal level through to 2014.[47] Based on these projections it is possible to derive the assumed base scenario for the rollover year as detailed in Table 26 overleaf.

1.22. We have undertaken sensitivity analysis on the impact of different levels of generation and demand for the rollover year, and the resultant capex adjustment would not represent a disproportionate gain or loss for NGET. We have therefore decided to continue with the baseline scenario presented above during the rollover year.

1.23. NGET are projecting to incur capex of £193.6m on projects that will not deliver an adjustment to the baseline capex allowance through the revenue drivers. This has formed the basis of our ex-ante allowance.

[47] http://www.ofgem.gov.uk/Networks/Trans/Archive/TPCR4/ConsultationDecisionsResponses/Documents1/16341-20061129_TPCR%20FP%20Supplementary%20Appendices_in_final.pdf

Table 26 Baseline Scenario for rollover year

| | Baseline Scenario (MW) | | |
|---|---|---|---|
| | New Entry | Zonal Surplus | Zonal Deficit |
| South & South West | 2100 | -2939 | 2939 |
| Thames Estuary | 1840 | 6713 | -6713 |
| London | 0 | -7527 | 7527 |
| South Wales | 0 | 1604 | -1604 |
| East of England & Home counties | 0 | -1530 | 1530 |
| West Midlands | 250 | -3416 | 3416 |
| East Midlands | 0 | 4699 | -4699 |
| North West & North Wales | 844 | 2193 | -2193 |
| Yorkshire & Lincolnshire | 540 | 8244 | -6263 |
| North East | 0 | 531 | -531 |

1.24. We have undertaken sensitivity analysis on the impact of different levels of generation and demand for the rollover year, and the resultant capex adjustment would not represent a disproportionate gain or loss for NGET. We have therefore decided to continue with the baseline scenario presented above during the rollover year.

**National Grid – Anglo Scottish Boundary**

1.25. In addition to the revenue drivers detailed above, a revenue driver currently exists to flex NGET's capex baseline in line with reinforcement work completed on the boundary between Scotland and England. Through this revenue driver NGET's capex baseline adjusts upwards or downwards each year by £367,800 (in 2009/10 prices) multiplied by the difference (in MW) between the capacity between Scotland and England and the baseline assumed at the start of the price control. Our decision is to maintain this revenue driver along with the existing UCA.

1.26. As we are awarding no incremental capex allowance for boundary reinforcement in our capex baseline, we will maintain the boundary capacity target from 2011/12 into the rollover year. We will therefore set the boundary target in the rollover year to 3200 MW.

# Appendix 3–Baselines for NGET

1.1. This appendix provides more detail of our capex and opex baseline assumptions for NGET.

1.2. Our final decision is based upon responses to the Initial Proposals consultation and updated forecasts for 2012-13 provided as part of the RIIO-T1 business plan. We considered these responses, and took them into account in determining the assumed expenditure for rollover.

## Capital Expenditure

1.3. The table overleaf shows the details of our decision for capex baselines for NGET TO.

1.4. The capex projection and capex baselines has been split into “Base expenditure” and “provisional revenue driver” assumptions. “Base expenditure” is the ex-ante baseline for load related capex that will not adjust in line with the revenue drivers. The “provisional revenue driver” assumption is the provisional assumption for all revenue driver projects. As set out in Chapter 3 we have made a provisional assumption for such projects in line with the TOs’ business plan submissions. We will adjust this ex-post to reflect delivery during the rollover year.

1.5. In its response to Initial Proposals for non-load related capex, NGET argued that aligning baselines to historical averages was incorrect as it ignored new areas of expenditure. It also disagreed that its unit costs were higher than GB or KEMA averages, and it argued that risk and contingency differs on projects and therefore a reduction for high expenditure in this area cannot be applied to all non load related assets. NGET also provided a revised forecast for the rollover year as part of its RIIO-T1 business plan submission. It said that the overall expenditure in 2012-13 would be reduced by a “delivery and efficiency overlay.”

### Table 27 NGET Detailed capex baseline

| £m (at 2009/10 Prices) | NGET TO 2010/11 Expenditure | FBPQ Forecast | Revised Forecast after overlay adjustments | IP Baselines | FP Baselines | % Change IP to FP |
|---|---|---|---|---|---|---|
| **Capex** | | | | | | |
| Load Related | | | | | | |
| Base Expenditure | 436.1 | 193.6 | 193.6 | 193.6 | 193.6 | 0.0% |
| Provisional Revenue Drivers | | 208.6 | 219.1 | 208.6 | 219.1 | 5.0% |
| Regulatory WIP | | | | | | |
| Total | 436.1 | 402.2 | 412.7 | 402.2 | 412.7 | 2.6% |
| | | | | | | |
| Non Load Related | | | | | | |
| Transformers | 43.4 | 105.5 | 76.0 | 67.8 | 67.8 | 0.0% |
| Reactors | 1.7 | 7.6 | 8.4 | 7.6 | 8.4 | 10.3% |
| Switchgear | 49.3 | 97.5 | 86.4 | 69.0 | 69.0 | 0.0% |
| Overhead Lines | 78.9 | 123.7 | 82.2 | 100.0 | 82.2 | -17.8% |
| Underground Cables | 85.0 | 31.0 | 23.4 | 26.4 | 23.4 | -11.5% |
| Cable Tunnels | - | 81.2 | 73.2 | 65.0 | 65.0 | 0.0% |
| Protections and Control | 10.6 | 40.3 | 37.1 | 35.0 | 35.0 | 0.0% |
| Substation Other | 22.3 | 13.7 | 22.5 | 13.7 | 13.7 | 0.0% |
| Other TO | 58.8 | 64.0 | 55.4 | 51.1 | 54.2 | 6.2% |
| BT21CN | | 8.2 | 2.5 | 4.1 | 2.5 | -38.8% |
| Logged Up | 1.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| | 351.0 | 572.7 | 467.0 | 439.7 | 421.2 | -4.2% |
| Customer Contributions | (10.6) | (10.6) | (8.2) | (10.6) | (29.2) | 176.6% |
| Total | 776.4 | 964.3 | 871.5 | 831.3 | 804.7 | -3.2% |

1.6. The revised capex forecasts for NGET have been affected by the 'delivery' and 'efficiency' overlays applied to its business plan as part of the RIIO submission. These overlays were applied to re-phase capex during RIIO to ensure deliverability, and to provide a top-down efficiency aspiration. Although the overlays mainly affect the RIIO years, they also applied to expenditure in the rollover year.

1.7. NGET's revised load related forecast (£416.6m before overlays of £3.9m) is slightly higher than its Forecast Business Plan Questionnaire (FBPQ) forecast. We propose to allow £412.7m, which is NGET's revised forecast less a proportion of the efficiency overlay set out in its RIIO business plan tables. Our final baseline for NGET load-related expenditure is £10.5m higher than at Initial Proposals.

1.8. Our non-load related baseline for Final Proposals is £18.5m lower than Initial Proposals. NGET submitted a revised forecast of £532m which was lower than its original FBPQ forecast. NGET also informed us that the outturn would be lower due to delivery and efficiency overlays amounting to £65m. When these overlays are allocated, the overall forecast is £467m. The table below shows our allocation of the overlays to asset classes.

**Table 28 NGET - Allocation of Overlays to Non Load Related Forecasts**

| £m (at 2009/10 Prices) | Revised Forecast | Delivery Overlay | Efficiency Overlay | RIIO Forecast Adjusted |
|---|---|---|---|---|
| Transformers | 86.6 | (9.8) | (0.8) | 76.0 |
| Reactors | 9.5 | (1.1) | (0.1) | 8.4 |
| Switchgear | 98.4 | (11.1) | (0.9) | 86.4 |
| Overhead Lines | 93.7 | (10.6) | (0.9) | 82.2 |
| Underground Cables | 26.6 | (3.0) | (0.2) | 23.4 |
| Cable Tunnels | 83.4 | (9.4) | (0.8) | 73.2 |
| Protections & Control | 42.2 | (4.8) | (0.4) | 37.1 |
| Substation Other | 25.6 | (2.9) | (0.2) | 22.5 |
| Other TO | 51.2 | (5.8) | (0.5) | 45.0 |
| Quasi Capex | 11.9 | (1.3) | (0.1) | 10.4 |
| Logged Up | 2.9 | (0.3) | (0.0) | 2.5 |
| **Total** | **532.0** | **-60.0** | **-5.0** | **467.0** |

1.9. The main changes between Initial Proposals and Final Proposals are as follows:

- In most non load expenditure categories we have not changed our Initial Proposal baselines as NGET has not provided sufficient information to convince us to change our view. Also in many cases its adjusted forecast is not significantly higher than Initial Proposals. The exceptions to this are:
- Reactors – we have accepted the increased forecast from NGET.
- Overhead Lines – NGET's revised forecast is lower than Initial Proposals and we have accepted this.
- Underground Cables – NGET's revised forecast is lower than Initial Proposals and we have accepted this.
- Other TO costs– we have accepted the increased forecast from NGET.
- Logged Up Costs - these relate to replacement of telecom circuits when BT implements its 21st Century Networks project (BT21CN). Our baseline expenditure assumption has been reduced in line with NGET's revised forecast.

## Controllable Operating Costs

1.10. In its response to the Initial Proposals, NGET said that the proposed baseline would have a major adverse impact on stakeholder requirements in 2012-13 and the RIIO-T1 period. Its detailed comments were:

- The initial baselines double count the efficiency saving as some cost increases have not been allowed.
- The assumptions for recruitment and training are insufficient and will not enable NGET to remain at the current level of employees.
- Using the TPCR4 baselines as a proxy for the efficient level of expenditure is not correct.
- Some of the non operational capex IT projects have already been sanctioned and therefore stopping development would be inefficient, it would also impact on reliability and safety of the network.

1.11. For the purposes of calculating our final baselines, we have started with the most recent year of actual expenditure (2010-11) as set out in Chapter 2. We have adjusted this figure to exclude any atypical or exceptional costs within that year. The resultant figure therefore represents the recurring (or normalised) costs of running the TO business. We have then adjusted this figure by expected efficiency savings and specific areas of increases in cost.

1.12. The table below shows the details of our Final decision on controllable opex allowances for NGET (all prices are 2009-10, £m)

**Table 29 NGET Controllable Opex Baselines**

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 198.5 | 198.5 | 198.5 | 186.1 | -6.3% |
| Exceptional costs | (5.5) | (5.5) | (5.5) | (6.9) | 24.7% |
| **Recurring Cash Controllable Costs** | **193.0** | **193.0** | **193.0** | **179.2** | **-7.1%** |
| Efficiency Savings | (24.0) | (24.0) | (28.0) | (19.0) | -32.0% |
| **Cash Costs** | **169.0** | **169.0** | **165.0** | **160.2** | **-2.9%** |
| Proposed Increases in Costs | | | | | |
| Asset Growth and Diversity etc | 10.0 | 10.0 | 4.5 | 4.5 | 0.0% |
| IT Running Costs | 4.0 | 4.0 | 0.0 | 1.7 | |
| Real Price | 10.0 | 4.5 | 4.0 | 4.0 | 0.0% |
| Volume, Mix and other | 6.6 | 9.8 | 2.3 | 4.1 | 78.3% |
| Workforce Growth | 7.0 | 9.3 | 3.5 | 6.2 | 77.1% |
| Recruitment and Training | 11.0 | 13.0 | 5.5 | 8.7 | 57.6% |
| Total Proposed Increases in Costs | 48.6 | 50.6 | 19.8 | 29.2 | 47.3% |
| Non Operational Capex | 22.9 | 27.0 | 13.6 | 16.6 | 22.1% |
| **Forecast / Proposed Allowance** | **240.5** | **246.6** | **198.4** | **205.9** | **3.8%** |

1.13. The controllable opex allowance has been increased from Initial Proposals and represents a 16.5 per cent reduction from NGET's revised forecast operating costs. We have adjusted the start point as we now have actual expenditure for 2010-11, which is lower than in 2009-10. Efficiency savings are forecast at 1.5 per cent per annum plus additional savings on the basis that we expect NGET to reverse some of the overspend against TPCR4 baselines. The additional efficiency saving required has reduced as the overspend in 2010-11 has reduced.

1.14. As a result of NGET's response to consultation we have increased costs from Initial Proposals. The additional increases accepted are for; Optel site charges, insurance, and environmental liability costs. In relation to expenditure relating to workforce growth, recruitment and training, we have incorporated two thirds of the revised forecast (compared to half at Initial Proposals), as NGET has provided more robust evidence.

**Table 30 NGET Non-Operational Capex**

| Non Operational Capex | NGET TO | | | | |
|---|---|---|---|---|---|
| **£m (at 2009/10 Prices)** | **FBPQ Forecast** | **Revised Forecast** | **IP Baselines** | **FP Baselines** | **% Change IP to FP** |
| Property | 5.9 | 6.2 | 4.4 | 5.0 | 13.8% |
| Integrating the Alliances | 2.0 | 1.9 | 1.5 | 1.5 | 0.0% |
| RAMM / SAM | 2.4 | 2.8 | 0.2 | 1.4 | 600.0% |
| Front Office Replacement | 2.6 | 2.4 | 0.0 | 1.2 | |
| Other | 10.0 | 13.7 | 7.5 | 7.5 | 0.0% |
| **Forecast / Proposed Allowance** | **22.9** | **27.0** | **13.6** | **16.6** | **22.1%** |

1.15. The non-operational capex baseline is significantly lower than NGET's revised forecast although it is £3m higher than Initial Proposals. The reasons for the increase are as follows:

- We have included the entire training centre building costs within the property cost category as this is in the process of being built and a clear case for it had been demonstrated.
- We have included half of the costs of Remote Access Monitoring and Management (RAMM) / Strategic Asset Management (SAM) and front office replacement as the projects have been approved. We still have concerns about the deliverability of the entire programme of IT projects; hence we are not including all the forecast spend.

# Appendix 4 - Baselines for SHETL

1.1. This appendix provides more detail of our Initial Proposals capex and opex baselines for SHETL.

1.2. Our final decision is based upon responses to the Initial Proposals and updated forecasts for 2012-13 provided as part of the RIIO-T1 business plan. We considered these responses, and took them into account in determining the assumed expenditure for the rollover year.

## Capital Expenditure

1.3. The table overleaf summarises our Initial Proposals for SHETL.

1.4. The capex projection and capex baseline assumptions have been split into "base expenditure" and "provisional revenue drivers". "Base expenditure" is the ex-ante baseline for load related capex that will not adjust in line with the revenue drivers. "Provisional revenue drivers" is the provisional assumption for all revenue driver projects; as per the approach outlined in chapter 3 we have granted a provisional assumption for such projects in line with the TOs' business plan submissions. We will adjust this ex-post to reflect delivery during the rollover year.

1.5. In its response to Initial Proposals SHETL commented that the load related baseline did not incorporate preconstruction costs on TII projects and the non-load related expenditure baseline did not adequately cover transformer costs in remote locations. Preconstruction costs should be included in the baseline as for TPCR4.

### Table 31 SHETL detailed Capex Baselines

| | SHETL | | | | | |
|---|---|---|---|---|---|---|
| **£m (at 2009/10 Prices)** | **2010/11 Expenditure** | **FBPQ Forecast** | **Revised Forecast** | **IP Baselines** | **FP Baselines** | **% Change IP to FP** |
| **Capex** | | | | | | |
| Load Related | | | | | | |
| Base Expenditure | 33.1 | 61.2 | 38.3 | 49.4 | 38.3 | -22.5% |
| Provisional Revenue Drivers | | 13.7 | 30.1 | 13.7 | 24.9 | 81.8% |
| Total | 33.1 | 74.9 | 68.4 | 63.1 | 63.2 | 15.8% |
| Non Load Related | | | | | | |
| Transformers | 5.5 | 4.2 | 4.0 | 3.8 | 4.0 | 5.3% |
| Reactors | 0.0 | | 0.0 | 0.0 | 0.0 | |
| Switchgear | 1.4 | 4.1 | 4.2 | 4.1 | 4.2 | 2.4% |
| Overhead Lines | 0.8 | 4.6 | 4.1 | 3.9 | 4.1 | 5.1% |
| Underground Cables | 0.2 | 3.7 | 3.7 | 3.7 | 3.7 | 0.0% |
| Protections and Control | 0.3 | 0.7 | 0.7 | 0.7 | 0.7 | 0.0% |
| Substation Other | 0.3 | 1.8 | 1.8 | 1.8 | 1.8 | 0.0% |
| Logged Up | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Other TO | 2.1 | 1.7 | 0.0 | 1.7 | 0.0 | |
| | 10.7 | 20.8 | 18.5 | 19.7 | 18.5 | -6.1% |
| Customer Contributions | (14.1) | (14.6) | (2.2) | (14.6) | (5.3) | -63.7% |
| Total | 29.6 | 81.1 | 84.7 | 68.2 | 76.4 | 12.0% |

1.6. The load related allowance baselines represent a 7.6 per cent reduction on SHETL's revised forecast for 2012-13 and a slight increase on Initial Proposals. The reasons for the increase are as follows:

- We have included all pre-construction costs for TII projects (£8m). Pre construction funding for similar projects was included in the baselines at TPCR4 and therefore we consider it appropriate to do the same in the rollover year
- The figure for capital contributions has been changed to reflect revised capital expenditure for specific projects

1.7. The non-load related baseline represents a 6.1 per cent reduction on the Initial Proposals. This reduction is due to a lower forecast from SHETL which we have accepted in full.

## Controllable Operating Costs

1.8. In its response SHETL argued that our baseline did not reflect the costs the business will incur in 2012-13. It noted further:

- The baseline did not reflect the increase of costs due to the increasing capital programme.
- The efficiency assumption was unrealistic – 1 per cent was more appropriate.
- The indirect cost baseline did not allow for the impact of TIRG and TII projects.
- A non-operational capex forecast was missed off by SHETL in the FBPQ.

1.9. For the purpose of calculation of the Final Proposal allowance we have started with the most recent year of actual expenditure (2010-11) as set out in Chapter 2. We have adjusted this figure to exclude any atypical or exceptional costs within that year. The resultant figure therefore represents the recurring (or normalised) costs of running the TO business. We have then adjusted this figure by expected efficiency savings and specific areas of increases in cost.

1.10. The table below summarises our proposed opex baselines for SHETL.

**Table 32 SHETL Controllable Opex Baseline**

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 6.2 | 6.2 | 6.2 | 6.2 | 0.6% |
| Exceptional costs | 0.0 | 0.0 | 0.0 | 0.0 | |
| **Recurring Cash Controllable Costs** | **6.2** | **6.2** | **6.2** | **6.2** | **0.6%** |
| Efficiency Savings | (0.2) | (0.2) | (0.3) | (0.2) | -32.9% |
| **Cash Costs** | **6.0** | **6.0** | **5.9** | **6.0** | **2.2%** |
| Proposed Increases in Costs | | | | | |
| Direct Costs | 1.1 | 1.2 | 0.0 | 1.2 | |
| Indirect Costs | 1.9 | 2.8 | 1.2 | 2.7 | 125.0% |
| Total Proposed Increases in Costs | 3.0 | 4.0 | 1.2 | 3.9 | 225.0% |
| Non Operational Capex | 0.0 | 0.1 | 0.0 | 0.1 | |
| **Forecast / Proposed Allowance** | **9.0** | **10.1** | **7.1** | **10.0** | **41.3%** |

1.11. The controllable opex allowance has been increased by 39.4 per cent (£2.8m) from Initial Proposals. The reasons for the increases are:

- We have accepted all of the reasons put forward by SHETL that operating costs will increase due to the increased size of network.
- We have accepted that opex will also increase due to TIRG and TII projects; these are not captured in the overall project costs.

1.12. SHETL has also included £0.1m of non-operational capex relating to IT that was omitted from their FBPQ, which we have allowed.

# Appendix 5 - Baselines for SPTL

1.1. This appendix provides more detail of our Initial Proposals capex and opex baselines for SPTL.

1.2. Our final decision is based upon responses to the Initial Proposals and updated forecasts for 2012-13 provided as part of the RIIO-T1 business plan. We considered these responses, and took them into account in determining the assumed expenditure for the rollover year.

## Capital Expenditure

1.3. The table below summarises our Initial Proposals for SPTL.

1.4. The load-related capex projection and capex baseline has been split into “base expenditure” and “provisional revenue driver” assumptions. “Base expenditure” is the ex-ante baseline for load related capex that will not adjust in line with the revenue drivers. “Provisional revenue drivers” is the provisional assumption for all revenue driver projects. As set out in in Chapter 3 we have granted a provisional assumption for such projects in line with the licensees’ business plan submissions. We will adjust this ex-post to reflect delivery during the rollover year.

1.5. In its response to Initial Proposals SPTL said that the load and non load forecasts were now lower than originally submitted and in the case of load-related lower than our baselines. It also said that it was misleading to allocate all the £9.8m capitalisation adjustment to other TO capex and that it is unable to confirm the value of the adjustment, although it did not provide an alternative figure.

### Table 33 SPTL Detailed capex baselines

| | SPTL | | | | | |
|---|---|---|---|---|---|---|
| £m (at 2009/10 Prices) | 2010/11 Expenditure | FBPQ Forecast | Revised Forecast | IP Baselines | FP Baselines | % Change IP to FP |
| **Capex** | | | | | | |
| Load Related | | | | | | |
| Base Expenditure | 51.5 | 101.2 | 55.3 | 83.1 | 53.7 | -35.4% |
| Provisional Revenue Drivers | | 30.5 | 8.6 | 30.5 | 8.5 | -72.1% |
| Total | 51.5 | 131.7 | 63.9 | 113.6 | 62.2 | -45.2% |
| Non Load Related | | | | | | |
| Transformers | 14.0 | 9.5 | 12.3 | 9.5 | 12.3 | 29.8% |
| Reactors | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | |
| Switchgear | 10.4 | 19.0 | 16.7 | 15.0 | 15.0 | 0.0% |
| Overhead Lines | 9.5 | 41.1 | 28.1 | 28.0 | 28.1 | 0.3% |
| Underground Cables | 13.5 | 3.4 | 5.7 | 3.4 | 5.7 | 67.6% |
| Protections and Control | 1.4 | 8.5 | 4.6 | 8.5 | 4.6 | -46.1% |
| Substation Other | 6.0 | 2.1 | 2.5 | 2.1 | 2.5 | 19.0% |
| Other TO | 1.6 | 3.7 | 3.2 | 3.7 | 3.2 | -12.3% |
| Adjustment for Capitalisation | | 0.0 | 0.0 | -9.8 | -16.5 | 68.4% |
| BT21CN | 2.8 | 6.0 | 5.3 | 3.0 | 3.0 | 0.0% |
| Small Windfarm Connections | | 2.0 | 0.7 | 2.0 | 0.7 | -65.0% |
| Logged Up | | 0.0 | | 0.0 | | |
| | 59.3 | 95.3 | 79.2 | 65.4 | 58.7 | -10.3% |
| Customer Contributions | (10.3) | (8.9) | (3.5) | (8.9) | (3.5) | -60.6% |
| Total | 100.6 | 218.1 | 139.5 | 170.1 | 117.4 | -31.0% |

1.6. SPTL has significantly revised its load related forecast for 2012-13 from the one in the FBPQ, the reduction is 51.4 per cent due to delays in the consenting process for projects. It has removed a lot of projects including most of the ones we excluded at Initial Proposals. We have allowed the forecast with only a very slight adjustment. The adjustment relates to a small amount of expenditure relating to projects that we excluded at Initial Proposals.

1.7. The revised non-load related forecast also shows a reduction from the FBPQ and we have accepted the majority of these changes. The overall baseline represents a 25.9 per cent reduction on SPTL's revised forecast. The main reason for the reduction is as follows:

- We have increased the adjustments for capitalisation of related party margins, depreciation and excess capitalisation. This is consistent with similar adjustments in TPCR4. This is based on new information from SPTL and takes into account capitalised overheads supporting TIRG and TII projects. The adjustment is now a £16.5m reduction to the non-load related baseline, compared to a £9.8m reduction at Initial Proposals.

1.8. The table below shows the allocation of overheads between base capex and TIRG/TII projects and also the amount excluded.

**Table 34 SPTL Detailed capex baseline**

| £m (at 2009/10 Prices) | Overheads on Base Capex | Overheads on TIRG / TII |
|---|---|---|
| As per information from SPTL | 27.8 | 17.2 |
| **Overheads Disallowed** | | |
| Corporate Costs | 0.3 | 0.3 |
| Related Party Margins | 5.4 | 6.9 |
| Non operational depreciation capitalised | 0.9 | 1.1 |
| Overheads above the limit set at TPCR4 | 9.9 | |
| **Total** | **16.5** | **8.3** |

N.B.Overhead Components allocated based on share of total capex

## Controllable Operating Costs

1.9. In its response SPTL said that the opex baseline fell someway short of its expectations. The RIIO tables also provided an update of the forecast for 2012-13.

1.10. For the purpose of calculation of the final baseline we have started with the most recent year of actual expenditure (2010-11) as set out in Chapter 2. We have adjusted this figure to exclude any atypical or exceptional costs within that year. The resultant figure therefore represents the recurring (or normalised) costs of running the TO business. We have then adjusted this figure by expected efficiency savings and specific areas of increases in cost.

1.11. The table below summarises our final opex baseline for SPTL (all prices are 2009-10, £m).

**Table 35 SPTL Controllable Opex Baseline**

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 18.3 | 18.3 | 18.3 | 20.5 | 11.8% |
| Exceptional costs | 0.0 | 0.0 | (0.5) | (0.9) | |
| **Recurring Cash Controllable Costs** | **18.3** | **18.3** | **17.8** | **19.6** | **10.1%** |
| Efficiency Savings | 0.0 | 0.0 | (0.8) | (1.6) | 97.4% |
| **Cash Costs** | **18.3** | **18.3** | **17.0** | **18.0** | **6.0%** |
| Proposed Increases in Costs | | | | | |
| Tower Painting Costs | 0.7 | 0.7 | 0.0 | 0.0 | |
| Additional Direct Costs | | 0.7 | 0.0 | 0.0 | |
| Additional excess costs capitalised | | 4.8 | 0.0 | 5.7 | |
| Total Proposed Increases in Costs | 0.7 | 6.2 | 0.0 | 5.7 | |
| Non Operational Capex | 0.9 | 0.9 | 0.9 | 0.9 | 0.0% |
| **Forecast / Proposed Allowance** | **19.9** | **25.4** | **17.9** | **24.6** | **37.5%** |

1.12. The controllable opex baseline represents a 3.3 per cent reduction from SPTL's revised forecast operating costs. Despite this, the overall baseline has increased by

£6.7m from Initial Proposals. The main difference between Initial Proposals and Final Proposals is that we have also added the depreciation and excess capitalisation in line with the adjustment on non load related capex set out above. The calculation is shown in table below. Annual efficiency savings are based on two years not three as at Initial Proposals, but we have increased the efficiency savings required on the basis that we expect SPTL to reverse some of the overspend against TPCR4 allowances.

**Table 36 SPTL Controllable Opex Baseline**

| **£m (at 2009/10 Prices)** | **Actual Expenditure 2010/11** | **Forecast Adjustment in 2012/13** |
|---|---|---|
| Actual Costs before Adjustments | 15.3 | |
| Corporate charges charged to capital | 0.5 | 0.3 |
| Depreciation on Non Operational assets charged to capital | 1.0 | 0.9 |
| Overheads charge to capital above the limit set at TPCR4 | 3.9 | 9.9 |
| Total Adjustment | 5.4 | 11.1 |
| Adjusted Actual Costs | 20.7 | |
| Increase in Adjustment in 2012/13 | | 5.7 |

1.13. The non-operational capex baseline of £0.9m is unchanged and remains the same as our proposed Initial Proposals baseline.

# Appendix 6 - Baselines for NGG

1.1. This appendix provides more detail of our Initial Proposals capex and opex baselines for NGG.

1.2. Our final decision is based upon responses to the Initial Proposals and updated forecasts for 2012-13 provided as part of the RIIO-T1 business plan. We considered these responses, and took them into account in determining the assumed expenditure for the rollover year.

## Capital Expenditure

1.3. The table below summarises our Initial Proposals for NGG TO (all prices are 2009-10, £m):

1.4. In its response to Initial Proposals NGG disagreed with the proposal to disallow expenditure on network flexibility; it argued that this decision will increase risk. NGG's detailed comments were:

- It was imperative that a solution to the network flexibility problem at St Fergus was progressed as soon as possible to enable NGG to meet their 1 in 20 obligations.
- A lack of investment in this area now will increase constraint costs in the future.
- It does not believe using system management tools as an economic or efficient alternative.
- NGG said our non-load related capex baseline does not allow for any expenditure on Feeder 9 and costs for Feeder 9 in 2012-13 have now been clarified.

### Table 37 NGG Capex Baseline

| £m (at 2009/10 Prices) | 2010/11 Expenditure | FBPQ Forecast | Revised Forecast | IP Baselines | FP Baselines | % Change IP to FP |
|---|---|---|---|---|---|---|
| **Capex** | | | | | | |
| Load Related | 30.9 | 73.9 | 68.1 | 23.6 | 23.6 | 0.0% |
| Non Load Related | | | | | | |
| Emissions reduction | 31.9 | 7.6 | 23.0 | 7.6 | 7.6 | 0.0% |
| Asset health (condition driven) | 37.3 | 51.4 | 56.6 | 39.1 | 44.0 | 12.5% |
| Other | 5.2 | 3.8 | 3.8 | 3.8 | 3.8 | 0.0% |
| Costs of Discontinued Projects | | 0.0 | | 0.0 | 2.5 | |
| Quasi-Capex | 2.0 | 1.7 | 0.0 | 1.7 | 0.0 | -100.0% |
| Logged Up | 0.6 | 0.0 | | 0.0 | 0.0 | |
| | 77.1 | 64.5 | 83.4 | 52.2 | 57.9 | 10.9% |
| Total | 107.9 | 138.4 | 151.5 | 75.8 | 81.5 | 7.5% |

NB. The figures exclude TO Incremental capex (entry and exit)

1.5. We have not changed the load related allowance from that in the Initial Proposals. We consider that NGG has not provided enough additional information to convince us of the need for capex in relation to network flexibility in 2012-13.

1.6. NGG submitted a revised forecast for 2012-13 which was 33.2 per cent above its original forecast. A significant part of this relates to general emission reduction costs not related to specific sites, and with little justification. We have not included these costs as part of our baseline assumptions. The overall baseline has increased from Initial Proposals as we have included £4.8m for work on Feeder 9 in the Humber estuary.

## Controllable Operating Expenditure

1.7. The NGG responses to Initial Proposals are the same as for NGET (Appendix 3. paragraph 1.13)

1.8. For the purpose of calculating the final baseline we have started with the most recent year of actual expenditure (2010-11) as set out in Chapter 2. We have adjusted this figure to exclude any atypical or exceptional costs within that year. The resultant figure therefore represents the recurring (or normalised) costs of running the TO business. We have then adjusted this figure by expected efficiency savings and specific areas of increases in cost.

1.9. The table below summarises the final for NGG TO's opex.

### Table 38 NGG Controllable Opex Baseline

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 61.0 | 61.0 | 61.0 | 52.3 | -14.3% |
| Exceptional costs | (2.0) | (2.0) | (2.0) | 0.6 | |
| **Recurring Cash Controllable Costs** | **59.0** | **59.0** | **59.0** | **52.9** | **-10.4%** |
| Efficiency Savings | (5.0) | (5.0) | (5.0) | (3.3) | -33.3% |
| **Cash Costs** | **54.0** | **54.0** | **54.0** | **49.5** | **-8.3%** |
| Proposed Increases in Costs | | | | | |
| Asset Growth and Diversity etc | 1.4 | 1.4 | 0.0 | 0.0 | |
| Real Price | 5.0 | 2.9 | 2.9 | 2.9 | 0.0% |
| Volume and Mix and IT | 3.0 | 2.0 | 0.0 | 0.9 | |
| Gas Technical Drawings | 4.0 | 4.0 | 0.0 | 0.0 | |
| Workforce Growth etc | 3.0 | 5.0 | 1.5 | 3.3 | 122.2% |
| Supply and Demand Volatility | 1.0 | 1.0 | 0.0 | 0.5 | |
| Total Proposed Increases in Costs | 17.4 | 16.3 | 4.4 | 7.6 | 73.5% |
| Non Operational Capex | 13.5 | 11.3 | 4.4 | 7.7 | 74.9% |
| **Forecast / Proposed Allowance** | **84.9** | **81.6** | **62.8** | **64.8** | **3.2%** |

1.10. The controllable opex baseline has decreased slightly from Initial Proposals and now represents an 18.6 per cent reduction from NGG's revised forecast operating costs. We have adjusted the start point as we now have actual expenditure for 2010-11, which is lower than 2009-10. We have assumed two-thirds of NGG's proposed efficiency savings due to start from 2010-11 actual expenditure. We have accepted more of NGG's increases mainly relating to workforce growth and renewal where we have allowed two-thirds of the revised forecast.

1.11. Non-Operational Capex - this is shown in the table below

**Table 39 NGG Non-Operational Capex**

| £m (at 2009/10 Prices) | FBPQ Forecast | Revised Forecast | IP Baselines | FP Baselines | % Change IP to FP |
|---|---|---|---|---|---|
| Property | 1.5 | 1.7 | 1.1 | 1.0 | -11.1% |
| HPMIS | 4.7 | 2.0 | 0.0 | 2.0 | |
| RAMM / SAM | 1.7 | 1.9 | 0.1 | 1.0 | 850.0% |
| Front Office Replacement | 1.4 | 1.1 | 0.0 | 0.6 | |
| Other IT | 1.9 | 2.6 | 1.4 | 1.4 | 0.0% |
| Other | 2.3 | 2.0 | 1.7 | 1.7 | 0.0% |
| **Forecast / Proposed Allowance** | **13.5** | **11.3** | **4.4** | **7.7** | **74.9%** |

1.12. The non-operational capex baseline is significantly lower (31.8 per cent) than NGG's revised forecast although it is £3.3m higher than Initial Proposals. The reasons for the increase are as follows:

- We have allowed the entire training centre building costs within the property category as this is in the process of being built and a clear case for it had been demonstrated.
- The baseline assumption for the High Pressure Metering Information System (HPMIS) has dropped as NGG has revised its forecast for the project. The baseline matches the revised forecast.
- We have included half of the costs of Remote Access Monitoring and Management (RAMM) / Strategic Asset Management (SAM) and front office replacement as the projects have been approved. We still have concerns about the deliverability of the entire programme of IT projects; hence we are not proposing to include all of the forecast spend.

# Appendix 7 – Baselines for Internal SO (electricity and gas) expenditure

1.1. This appendix provides more details of the calculation of the Initial Proposals capex and opex baselines for the internal SO functions of NGG and NGET.

1.2. Our Final decision is based upon responses to the Initial Proposals and updated forecasts for 2012-13 provided as part of the RIIO-T1 business plan. We considered these responses, and took them into account in determining the assumed expenditure for the rollover year.

## SO Capital Expenditure

1.3. The tables below summarise our Initial Proposals for NGET SO and NGG SO (all prices are 2009-10, £m).

1.4. In their responses, NG disagreed with the Initial Proposals. They argued that the development of IT systems will minimise costs for future consumers, and the delivery of the IT systems in the rollover year is the foundation for their RIIO plans. NG believed its SO capex plan was deliverable and did not increase system risk, and that Energy Market Reform would not have an impact on the IT projects planned for 2012-13.

### Table 40 NGET Internal SO Capex Baseline

| £m (at 2009/10 Prices) | 2010/11 Expenditure | FBPQ Forecast | Revised Forecast | IP Baselines | FP Baselines | % Change IP to FP |
|---|---|---|---|---|---|---|
| **Capex** | 20.9 | 42.0 | 46.1 | 42.0 | 42.0 | 0.0% |
| less: | | | | | | |
| Stability Control System | | | | -4.0 | -1.5 | -62.5% |
| iEMS Replacement | | | | -1.4 | -1.4 | 0.0% |
| IS Data Centres | | | | -1.9 | -1.9 | 0.0% |
| Other Asset Health | | | | -4.4 | -4.4 | 0.0% |
| Non Scheme Based | | | | -1.0 | -1.0 | 0.0% |
| Other Adjustments | | | | -4.1 | -4.1 | 0.0% |
| **Total** | **20.9** | **42.0** | **46.1** | **25.3** | **27.8** | **9.9%** |

1.5. In most areas the additional information provided has not convinced us to change our expenditure assumptions. However there is a slight upward adjustment to the allowances from those proposed at Initial Proposals due to further justification for the Off-Line Transmission Analysis (OLTA) system. Here we propose an increase of £2.5m.

**Table 41 NGG Internal SO Capex Baseline**

| £m (at 2009/10 Prices) | 2010/11 Expenditure | FBPQ Forecast | Revised Forecast | IP Baselines | FP Baselines | % Change IP to FP |
|---|---|---|---|---|---|---|
| **Capex** | 9.6 | 31.0 | 41.9 | 31.0 | 31.0 | 0.0% |
| less: | | | | | | |
| iGMS Strategic Route Map etc | | | | -1.5 | 0.0 | -100.0% |
| IS Data Centres | | | | -4.1 | -4.1 | 0.0% |
| Security | | | | -2.9 | -2.9 | 0.0% |
| Other Adjustments | | | | -4.5 | -3.7 | -17.8% |
| **Sub Total** | **9.6** | **31.0** | **41.9** | **18.0** | **20.3** | **12.8%** |
| Xoserve | 1.0 | 11.7 | | 7.9 | 7.9 | 0.0% |
| Exit Reform | 2.4 | 2.4 | | 2.4 | 2.4 | 0.0% |
| **Total** | **13.1** | **45.1** | **41.9** | **28.3** | **30.6** | **8.1%** |

NB NGG SO Capex includes Xoserve and Exit Reform which are funded separately

1.6. As with NGET, NGG in most cases have not provided any convincing additional information to change our expenditure assumptions, apart from in the case of Integrated Gas Management System (iGMS). Here we propose an increase of £2.3m.

## SO Controllable Operating Costs

1.7. In their response to the Initial Proposals, NG say that the proposed baselines would have a major adverse impact on stakeholder requirements in 2012-12 and the RIIO-T1 period. Their detailed comments were:

- The Initial Proposals baselines double count the efficiency saving as some cost increases have not been included.
- Using the TPCR4 baselines as a proxy for the efficient level of expenditure is not correct.
- The assumption for recruitment and training is insufficient and will not enable NG to remain at the current level of employees.

1.8. For the purpose of calculation of the Final Proposal baselines we have started with the most recent year of actual expenditure (2010-11). We have adjusted this figure to exclude any atypical or exceptional costs within that year. The resultant figure therefore represents the recurring (or normalised) costs of running the SO businesses. We have then adjusted this figure by expected efficiency savings and specific areas of increases in cost.

1.9. The tables on the next page summarise our Initial Proposals for NG.

### Table 42 NGET Internal SO Opex Baseline

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 58.6 | 58.6 | 58.6 | 54.5 | -7.1% |
| Exceptional costs | (2.6) | (2.6) | (2.6) | (2.8) | |
| **Recurring Cash Controllable Costs** | **56.0** | **56.0** | **56.0** | **51.7** | **-7.7%** |
| Efficiency Savings | (8.0) | (8.0) | (8.0) | (5.3) | -33.3% |
| **Cash Costs** | **48.0** | **48.0** | **48.0** | **46.4** | **-3.4%** |
| Proposed Increases in Costs | | | | | |
| IT Running Costs | 1.0 | 2.9 | 0.5 | 0.5 | 0.0% |
| Real Price | 3.0 | 0.4 | 0.4 | 0.4 | 0.0% |
| Volume and Mix | 3.0 | 3.0 | 1.3 | 1.2 | -11.5% |
| Workforce Growth | 4.0 | 6.0 | 2.0 | 4.0 | 100.0% |
| Recruitment and Training | 6.1 | 7.5 | 3.0 | 5.0 | 66.7% |
| Offshore Transmission Project | | | | 2.0 | |
| Total Proposed Increases in Costs | 17.1 | 19.8 | 7.2 | 13.1 | 81.3% |
| **Forecast / Proposed Allowance** | **65.1** | **67.8** | **55.2** | **59.4** | **7.6%** |

### Table 43 NGG Internal SO Opex Baseline

| £m (at 2009/10 Prices) | FBPQ Forecast (based on 2009/10 actuals) | Revised Forecast (based on 2009/10 actuals) | IP Baselines (based on 2009/10 actuals) | FP Baselines (based on 2010/11 actuals) | % Change IP to FP |
|---|---|---|---|---|---|
| **Controllable Opex** | | | | | |
| Actual expenditure | 28.7 | 28.7 | 28.7 | 32.0 | 11.7% |
| Exceptional costs | (1.7) | (1.7) | (1.7) | (6.3) | 269.9% |
| **Recurring Cash Controllable Costs** | **27.0** | **27.0** | **27.0** | **25.7** | **-4.6%** |
| Efficiency Savings | (3.0) | (3.0) | (3.0) | (2.0) | -33.3% |
| **Cash Costs** | **24.0** | **24.0** | **24.0** | **23.7** | **-1.0%** |
| Proposed Increases in Costs | | | | | |
| IT Running Costs | 4.0 | 4.6 | 2.0 | 1.9 | -5.0% |
| Real Price | 1.0 | 0.3 | 0.3 | 0.3 | 0.0% |
| Supply and demand Volatility | 1.0 | 1.0 | 0.0 | 0.5 | |
| Workforce Growth etc | 2.0 | 4.6 | 1.0 | 3.1 | 206.7% |
| Other | 2.1 | 1.2 | 1.0 | 1.5 | 50.0% |
| Total Proposed Increases in Costs | 10.1 | 11.7 | 4.3 | 7.3 | 69.0% |
| **Forecast / Proposed Allowance** | **34.1** | **35.7** | **28.3** | **31.0** | **9.6%** |

1.10. The controllable opex baseline for NGET has been increased by £4.2m, but is still 12.4 per cent lower than the revised forecast submitted by NGET. For NGG the baseline has been increased by £2.2m and is 14.6 per cent lower than the revised forecast. As set out in Chapter 2, our assumed expenditure is based on 2010-11 actual expenditure. For both NGET and NGG we have assumed two-thirds of their own efficiency savings due to start from 2010-11 actual expenditure. We have accepted more of NGET's and NGG's increases mainly relating to workforce growth and renewal where we have allowed two-thirds of the revised forecast.

## Non-controllable costs

1.11. We have included £4.8m of xoserve opex costs for the NGG as set out in NG's forecasts and £7.9m of xoserve capex costs, in line with PPA's recommendations, giving a total of £12.7m. NG has not forecast any non-controllable costs for the electricity SO.

## SO Pension allowances

1.12. In Chapter 4 we explain how pension allowances are set for the rollover year. Our approach to the SO pension costs is consistent with this.

1.13. The SO pension allowances and regulatory fractions for the rollover are set out in the following tables:

**Table 44 SO Pension allowances for 2012-13**

| | Allowances | | | | | | |
|---|---|---|---|---|---|---|---|
| 2009-10 prices £m | Deficit recovery | Ongoing pension costs | Admin costs | PPF levy | True-up | Total Per FP | Total allowances per IP |
| NGET SO | 8.7 | 6.6 | 0.4 | 0.3 | 1.1 | 17.1 | 16.7 |
| NGG SO | 0.2 | 4.3 | 0.7 | 0.0 | (0.0) | 5.2 | 3.8 |
| Total | 8.9 | 10.9 | 1.1 | 0.3 | 1.1 | 22.3 | 20.4 |

**Table 45 SO regulatory fractions for 2012-13**

| | Regulatory fraction |
|---|---|
| NGET SO | 23.0% |
| NGG SO | 0.3% |

### True up adjustment for over- and under- funding in TPCR4

1.14. The true-up of SO TPCR4 pension payments will commence during the TPCR4 roll-over year. The approach to these is explained in chapter four and the SO funding uses the same approach. These adjustments are spread over the combined nine years of the TPCR4 roll-over and RIIO-T1.

1.15. The adjustment to TPCR4 is split into two parts. One part is the amount that has been allowed in the indicative annual RAV calculations; this only applies to NGET. The second is the amount expensed. The adjustment methodology is set out in appendix 6 to the RIIO-T1 Financial Issues document.

**Table 46 SO TPCR4 pension true up adjustments**

| 2009-10 prices £m | Total adjustment for TPCR4 period | Annual adjustment commencing in 2012-13 | Additions to / (clawback of) closing RAV |
|---|---|---|---|
| NGET SO | 8.1 | 1.1 | 0.0 |
| NGG SO | (0.1) | (0.0) | 0.0 |
| Total | 8.0 | 1.1 | 0.0 |

## SO RAV

1.16. Table 33 shows the provisional RAV calculations to 31 March 2013. These are based on the forecast spend for 2011-12 and the allowances now allowed for the rollover year.

**Table 47 SO RAV projection**

| 2009-10 prices £m | Opening RAV 1st April 2010 (provisional) | Additions | Depreciation | Closing RAV 31st March 2013 |
|---|---|---|---|---|
| NGET SO | 34 | 68 | (27) | 75 |
| NGG SO | 36 | 61 | (29) | 69 |
| Total | 70 | 129 | (55) | 144 |

# Appendix 8 – Summary of allowed revenues

1.1. The table below summarises the allowed costs and base revenues as assessed:

**Table 48 Summary of allowed costs and base revenues**

| 2012-13 £m (2009-10 prices) | NGET TO | SHETL | SPTL | NGGT TO | NGET SO | NGGT SO |
|---|---|---|---|---|---|---|
| Regulatory Asset Value (RAV) | | | | | | |
| Opening asset value including transfers | 8,133.5 | 570.7 | 985.0 | 4,185.3 | 59.2 | 50.0 |
| Total RAV additions | 1,115.4 | 178.2 | 198.3 | (68.4) | 27.8 | 30.6 |
| Depreciation | (530.8) | (35.5) | (73.2) | (135.3) | (11.9) | (12.0) |
| Closing asset value | 8,718.1 | 713.4 | 1,110.0 | 3,981.5 | 75.1 | 68.6 |
| Allowed costs | | | | | | |
| Fast pot expenditure | 210.5 | 10.0 | 24.6 | 64.9 | 59.4 | 31.0 |
| Pension costs | 51.7 | 3.4 | 3.1 | 52.8 | 17.1 | 5.2 |
| Depreciation | 530.8 | 35.5 | 73.2 | 135.3 | 11.9 | 12.0 |
| Tax allowance | 101.7 | 5.5 | 10.7 | 31.8 | 3.0 | 0.2 |
| Return | 391.0 | 29.8 | 48.6 | 189.5 | 10.8 | 3.2 |
| Non-controllable operating costs | 104.0 | 8.7 | 24.1 | 111.5 | - | 13.2 |
| Total costs | 1,389.8 | 92.9 | 184.3 | 585.8 | 102.1 | 64.8 |
| Price Control Revenue | | | | | | |
| Total of Allowed Costs | 1,389.8 | 92.9 | 184.3 | 585.8 | 102.1 | 64.8 |
| Capex & other Incentives | 53.1 | 2.0 | 4.5 | (0.1) | 14.3 | 152.8 |
| Transmission Investment Renewable Generation | 14.8 | 31.7 | 15.9 | - | - | - |
| Base price control revenue | 1,331.8 | 119.2 | 199.8 | 585.7 | 116.4 | 217.6 |
| Excluded revenues | 126.0 | 7.4 | 5.0 | - | - | - |
| Total revenue | 1,457.7 | 126.6 | 204.8 | 585.7 | 116.4 | 217.6 |
| Price Control Revenue for 11-12 as forecast | 1,356.6 | 90.8 | 213.2 | 535.6 | | |
| Annual change as % starting from forecast | 7% | 39% | -4% | 9% | | |

# Appendix 9 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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