Promoting choice and value
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TPCR4 Rollover: Initial Proposals

Consultation

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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 April, we consulted on our minded to position on the full policy scope of the rollover, and presented our consultants' views on the transmission owners' (TOs) expenditure forecasts for 2012-13.

Informed by the responses to this April Consultation, and following further discussions with the transmission licensees, this document sets out our initial proposals for the rollover year for consultation. In a number of instances, costs projected in the licensees' business plans have not been included in the allowances as we are yet to be presented with sufficient evidence that the investment is required and will go ahead during the rollover year. Where this is the case, we invite the licensees to submit further evidence to inform our final proposals.

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.

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 aim to be proportionate in carrying out 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

Technical support for TPCR4 rollover: Assessment of load and non-load related capex (KEMA), Final Reports, 2 August 2011:

NGET: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/110802TPCR4RO_NGET_KEMA.pdf

SP: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/110802TPCR4RO_SPTL_KEMA.pdf

SHETL: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/110802TPCR4RO_SHETL_KEMA.pdf

NGG: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/110802TPCR4RO_NGG_KEMA.pdf

Technical support for TPCR4 rollover: SO Capex (electricity and gas), PPA, Final Report, 2 August 2011:

http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/110802TPCR4RO_SO_PPA.pdf

Previous price control documents

Rollover

- 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

- 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 another year to cover the period 1 April 2012 to 31 March 2013. We refer to this one-year extension as the "TPCR4 rollover".

This document sets out our initial proposals for the revenues that the one gas and three electricity transmission owners (TOs), are allowed to collect from consumers in the rollover year. These initial proposals have been informed by the views of stakeholders. The initial proposals set out in this document would increase the average annual residential gas and electricity bills by approximately £2 and £1, or approximately 0.3% and 0.4%, respectively.

In March 2010, we set out the guiding principles we would use when setting the policy framework and allowances for the rollover year. In addition to protecting the interests of existing and future consumers[2] and maintaining consistency with our wider statutory duties, we considered it important that the rollover be proportionate with a one-year control, in order to minimise the regulatory burden. As such, the rollover is an extension of the existing TPCR4 arrangements and should not be seen as an early indicator of our approach to the RIIO price control. In keeping with this principle of proportionality, we have only focussed on the licensees' projected expenditure when setting their allowances. We have deferred a detailed assessment of the efficiency of historical spend until after the current price control. In summary, our approach to the rollover year is as follows:

Policy framework: The TPCR4 policy framework consists of incentives and uncertainty mechanisms. We place incentives on the licensees to behave in a manner that is beneficial to consumers[3]. Uncertainty mechanisms flex the licensees' allowances in response to market signals or where costs are outside of their control. We propose not to introduce any new incentives or uncertainty mechanism for the

[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 their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.
[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

rollover year and, wherever possible, simply to extend the existing policy. In general, we are rolling forward the incentive mechanisms put in place at the start of TPCR4. In a limited number of instances, such as the SF6 incentive for the electricity TOs, we propose to adjust the targets to continue to incentivise improvement. In other areas, such as the reliability incentive, we see no compelling justification to change the targets for a single year. 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 propose not to allow any costs to log up during the rollover year, with the exception of security costs associated with Critical National Infrastructure. We do, however, consider it important to allow the licensees to undertake investment where it is necessary in response to market signals and propose to allow the capex allowances for the rollover year to flex through maintaining the existing revenue driver mechanisms.

Allowances: The proposed opex and capex allowances presented in our initial proposals are derived from the forecasts and information provided to us and our consultants by the transmission companies, both through their formal business plan submissions and as a result of subsequent discussions. These forecasts were submitted in October 2010. In April 2011, we presented our consultants' initial views on the companies' expenditure forecasts. Across a number of cost categories our consultants considered that the proposed increase in expenditure during the rollover year had not been fully justified. As we are now significantly closer to the start of the rollover year we consider the licensees should be able to provide further evidence to justify their proposed expenditure. We invite them to do so and will take their views fully into account in formulating our Final Proposals.

Allowed return: In line with our analysis in our April consultation, we propose to reduce the allowed return to 4.75% (real vanilla)[4] for the rollover year. This compares with, 5.05% in TPCR4. This is based on our view that the cost of debt has reduced by 50 basis points to 3.25% (consistent with the reduction in the risk free rate highlighted by our consultants in their analysis). We propose to leave the cost of equity assumption and notional gearing unchanged for all companies. We consider that 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 allowed return proposed for the rollover does not provide any indication of the appropriate allowed return for the RIIO price controls.

We welcome views from all stakeholders on the proposals set out in this document by midday on **Monday 12th September 2011**. Informed by the views of stakeholders' and further engagement with the companies, we will publish our final proposals in early November.

[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).

1. Introduction

Chapter summary
This chapter explains the purpose and structure of this document. It also gives a summary of the TPCR4 rollover process to date.

Purpose of this document

1.1. In October 2010, we set out our new model, RIIO, for regulating 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 price control (ie TPCR4) for another year covering the period 1 April 2012 to 31 March 2013.

1.3. The purpose of this document is to present initial proposals on all aspects of the regulatory package for the rollover year for:

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

1.4. This document also outlines our proposed allowances for National Grid in their role as gas and electricity system operator for capex and opex associated with internal costs. Costs incurred externally in balancing the system are incentivised through separate SO Incentives schemes[5].

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

- Proposed structure and detail of the incentives and uncertainty mechanisms
- Proposed operating and capital expenditure allowances (opex and capex respectively)
- Proposed allowed return and other financial parameters

[5] The incentive structure for balancing the electricity transmission network from 1 April 2011 to 1 April 2013 was recently decided:
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

1.6. We have engaged with stakeholders throughout this process and will continue to do so. The proposals set out in this document have been informed by stakeholder's views.

Guiding principles

1.7. Our March 2010 consultation set out the objectives of the TPCR4 rollover. Our objectives for the review are:

- To protect the interests of existing and future consumers[6]
- 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 practical, to facilitate the development of RIIO-T1

Process to date

1.8. In October 2009, we consulted on the timetable for RIIO-T1, and hence the possible need to roll over the fourth transmission price control review (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.

1.9. We also set out our preferred approach to a number of key areas - capex, opex, financial issues, incentives and uncertainty mechanisms.

1.10. In June 2010, we communicated our high-level 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. This is presented in the table overleaf.

1.11. 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 their System Operator (SO) function[7].

[6] Consumers' interests have been clarified by the Energy Act 2010 as their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.
[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

1.12. Stakeholder's views in response to this consultation have informed these initial proposals[8].

Table 1: Summary proposed approach contained consulted on in our April 2011 document

Aspect	Approach and scope for TPCR4 rollover
Incentives and uncertainty mechanisms	*Uncertainty mechanisms* • Existing pass-through costs will continue to be passed through • No costs to log up during the rollover year • Existing revenue driver mechanism to roll forward into the rollover year – no new revenue drivers to be introduced *Incentives* • Current set of incentives to continue into the rollover year • SF6 leakage target to be reduced in line with electricity TO's performance to date
Treatment of historical capex	• Defer an ex-post efficiency assessment until the current price control (TPCR4) is complete. • Set the opening regulatory asset value (RAV) for the TPCR4 rollover year on a provisional basis, assuming all capex is efficient, adjusting in advance of RIIO-T1. • Delay logged up costs from entering the RAV until RIIO-T1
Allowed return	• Revise the cost of debt assumption • Maintain the cost of equity assumption • Maintain notional gearing

Interactions with the RIIO price control and other funding channels

RIIO-T1

1.13. Although the general approach to setting this price control has been to extend the TPCR4 arrangements, 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. A core element of the RIIO approach is that the licensees submit 'well-justified' business plans to Ofgem. The deadline for submission of these

[8] Non confidential responses can be found at the following location: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=32&refer=Networks/Trans/PriceControls/TPCR4Roll-over

plans for RIIO-T1 was 31 July. The licensees have not had an opportunity to incorporate these initial, or our final, proposals for the rollover into to their RIIO-T1 business plans. Licensees are therefore likely to have made a number of assumptions about the proposed allowances for the rollover year in those plans. In assessing the RIIO business plans, we will need to review the validity of these assumptions, and where appropriate make adjustments to the RIIO-T1 allowances.

Transmission Investment Incentives and TIRG

1.14. We are committed to encouraging network companies to play a full role in a sustainable energy sector, and acknowledge the importance of the electricity transmission infrastructure 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:

1.15. **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.

1.16. **TII:** We introduced Transmission Investment Incentives (TII) in 2009 to supplement capital allowances and revenue arrangements within TPCR4 to facilitate the timely delivery of critical electricity transmission infrastructure projects. We have extended these arrangements for the rollover year 2012-13.

1.17. As part of their business plan submissions the licensees have projected their expenditure on projects funded via the TIRG and TII mechanism within the rollover year. They expect these projects to account for a significant portion of their expenditure (illustrated in chapter 2). These projects are not within the scope of this document and we will communicate our decision on funding allowances through a separate process[9]. However, we have considered the impact of these projects when considering the deliverability of the capex program as a whole and the financeability of the licensees.

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 allowances set out in chapter 2, our proposal to spread the revenue adjustment associated with the

[9] Consultation documents on TII and TIRG can be found on the Ofgem website:
TII:http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Pages/InvestmentIncentives.aspx
TIRG:http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/TIRG/Pages/TIRG.aspx

provisional calculation of the capex incentive over a number of years outlined in chapter 3, and the financial costs including allowed return set out in chapter 4.

Table 2 Forecast revenues for 2012/13

2009-10 prices £m	NGET	SHETL	SPTL	NGG
Base revenue	1,430.1	95.0	187.9	638.3
TIRG forecast	13.0	24.3	16.0	-
Total revenue	1,443.1	119.4	203.9	638.3

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

1.19. Base revenue includes the allowance 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 allowances 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.

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

Table 3 Comparison of initial proposals 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	211.0	567.6
Initial proposals (2012-13)	1,443.1	119.4	203.9	638.3
Percentage change	6%	31%	-3%	12%

Source: Ofgem

1.21. The table 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 proposals on consumer's bills

Impact on consumer bills	Electricity	Gas
Average domestic bill (£)	424.0	608.0
Transmission component of domestic bill (%)	4%	3%
Transmission component of domestic bill (£)	16.96	18.24
Transmission component based on initial proposals (£)	18.06	20.51
Restated average domestic bill based on initial proposals (£)	425.1	610.3
Bill increase (%)	0.3%	0.4%
Bill increase (£)	1.10	2.27

Source: Ofgem

Structure of document

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

- Chapter 2 summarises our proposed capex and opex allowances for the licensees for the rollover year.
- Chapter 3 sets out our proposed policy scope for the rollover year, along with providing additional detail on how the revenue driver mechanism will be extended for the electricity licensees.
- Chapter 4 sets out our proposed approach to the financial aspects of the rollover, including allowed return and pension provisions.

1.23. The appendixes provide further detail on the allowances for each of the licensees.

2. Summary of Proposed Capex and Opex Allowances

Chapter summary
This chapter summarises the proposed capex and opex allowances for each of the licensees for the rollover year. We describe the methodology used when deriving these allowances, and highlight any areas in which we consider the licensees' case for funding is yet to be proven.

Question box

Question 1: We invite stakeholders to comment on our proposed operating cost allowances for the transmission companies.

Question 2: We invite stakeholders to comment on our proposed capital expenditure allowances for the transmission companies.

Question 3: We invite stakeholders to comment on our proposed operating cost allowances for the gas and electricity system operator.

Question 4: We invite stakeholders to comment on our proposed capital expenditure allowances for the gas and electricity system operator.

Question 5: We invite stakeholders to comment on our proposal our proposal to disallow expenditure relating to network flexibility on the gas transmission network.

Introduction

2.1. We have taken a proportionate approach to developing our capex and opex baseline allowances, 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 proposals incorporate a considerable amount of flexibility, allowing the TOs capex allowances to flex to match the level of investment they are required to undertake.

Other Funding Mechanisms

2.2. The proposals outlined in this document represent one part of the licensees' funding allowance for the rollover year. A significant portion of their capex programme is funded outside of the price control. A number of large projects undertaken by the electricity licensees are funded through the TIRG and TII funding mechanisms described in chapter 1; whilst additional entry and exit capacity to the gas transmission network is funded via NGG's revenue drivers. To put the capex allowances into perspective the following tables outline the projected capex allowance granted through each of these mechanisms in the rollover year.

Table 5 Rollover capex allowance in perspective - electricity licensees[11]

Electricity			
2009-10 prices £m	**NGET**	**SHETL**	**SPTL**
Rollover price control	878.8	68.2	170.1
TIRG	0.0	153.2	57.1
TII	387.1	371.5	135.1
Total	**1,265.9**	**592.9**	**362.2**

Table 6 Rollover capex allowance in perspective - NGG[12]

Gas	
2009-10 prices £m	**NGG**
Rollover price control	89.9
Gas revenue drivers	59.5
Total	**149.4**

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.

Capex Allowances

General approach

2.4. The licensees submitted their business plans to us in October 2010. These contained 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 on their proposed capex programme.

2.5. 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 made for the case for the capex allowances they requested. Following publication of these reports we have engaged further with both the licensees and our consultants, and made further revisions to the proposed capex

[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.
[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.

allowances. We have generally followed the recommendations of the consultants, but have made some amendments to KEMA's proposals, especially on network flexibility in gas transmission to reflect our view that expenditure in this area in the rollover year has not been sufficiently well-justified. We are publishing final reports from KEMA and PPA alongside these Initial Proposals.

2.6. We have only allowed capex for projects where the licensees have demonstrated both a needs case and that they have the capability to deliver during the rollover year. We acknowledge that there was always likely to be a degree of uncertainty over the proposed capex programme contained within the licensees' business plans as they were submitted 18 months in advance of the start of the price control. As we get closer to the control period we expect there to be more certainty over expenditure on projects, and the licensees will have further opportunity to demonstrate this in response to this consultation. Under our proposal to maintain the existing revenue driver mechanisms (described in detail in chapter 3) a significant number of these projects, should they be required, will result in an automatic adjustment of the capex allowance.

Comments on TO's allowances

Table 7 Proposed TO capex allowance compared to business plan forecast

TO Forecasts				
2009-10 prices £m	**NGET TO**	**SHETL**	**SPTL**	**NGG TO**
Non load related	572.7	20.8	95.3	64.5
Load related (net of contributions)	391.6	60.3	122.8	73.9
Total	**964.3**	**81.1**	**218.1**	**138.4**
Capex Allowances				
2009-10 prices £m	**NGET TO**	**SHETL**	**SPTL**	**NGG TO**
Non load related	439.7	19.7	65.4	52.2
Load related (net of contributions)	391.6	48.5	104.7	23.6
Total	**831.3**	**68.2**	**170.1**	**75.8**

2.7. In these Initial Proposals we recommend reductions in all licensees' forecasts. We have reduced the capex forecasts provided by TOs for the following reasons:

- There is a low level of certainty of expenditure on some load related projects
- We have concerns over deliverability of the capex programmes given the scale of increase forecast by the TOs and in some cases the low level of project sanctioning
- In some cases, there is insufficient justification for the volume of work.
- In some cases, unit costs are unjustifiably higher than the TO average or KEMA's own information
- In some cases there are unjustified high levels of additional costs to cover risk and contingencies

Question 5: We invite stakeholders to comment on our proposal our proposal to disallow expenditure relating to network flexibility on the gas transmission network.

2.8. We understand that the level of certainty around a number of load related capex projects is likely to be significantly higher now than it was in October last year when the licensees submitted their business plans. Where this is the case we invite the licensees to present evidence in response to this consultation in order to inform our final proposals.

2.9. Details of the reductions for each TO are discussed in detail in Appendices 2 - 5.

Comments on SO's Allowances

Table 8 Proposed SO capex allowance compared to business plan forecast

2009-10 prices £m	**NGET SO**	**NGG SO**
SO Forecasts	42.0	45.1
Capex Allowances	25.3	28.3

2.10. In conjunction with our consultants PPA, we have reviewed the forecasts put forward in the business plans and Forecast Business Plan Questionnaires (FBPQ) submitted by the licensees in October 2010.

2.11. PPA have proposed significant reductions in NGET and NGG forecasts for the following reasons:

- For some items, there is no clear business case for the expenditure.
- For others, it would be better to wait for the outcome of the Electricity Market Review (EMR) before committing expenditure. We would expect the SOs to provide further evidence in their response to these proposals.
- Some expenditure is not deemed critical to be spent in the rollover year.
- Generally, we have seen low levels of project approval.

2.12. In May National Grid responded to PPA's draft report, as a result PPA have made some minor adjustments to their proposed allowances in their final report, we consider PPA's analysis to be robust and our allowances reflect their analysis. Details of the specific reductions are discussed in detail in Appendix 6.

Opex allowances

General approach

2.13. We have taken a proportionate approach in setting the controllable opex allowances for 2012-/13.

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

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

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

Comments on TO allowances

2.17. As set out in the table below, our proposed opex allowances are between 10% and 26% lower than the TOs' forecasts, but are generally in line with their current levels of expenditure.

Table 9 Controllable Opex allowances as compared to actual 9/10 opex and the TO's forecast

2009-10 prices £m	**NGET TO**	**SHETL**	**SPTL**	**NGG TO**
2009/10 Actual	198.5	6.2	18.3	61.0
Allowances	**198.4**	**7.1**	**17.9**	**62.8**
TO Forecasts	240.5	9.0	19.9	84.9

2.18. We have reduced the forecasts provided by the TOs for the following reasons:

- We have assumed an efficiency factor of 1.5% per annum in line with the original TPCR4 proposals and a 'catch-up' factor where opex has been above TPCR4 forecasts.
- We found insufficient justification for some of the increases in costs.

[13] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/TPCR4roll.pdf page 3

- We have concerns over the deliverability and justification of some non operational capex projects.

2.19. Details of the specific reductions for each TO are discussed in detail in appendices two to five.

Comment on SO Allowances

2.20. We have proposed allowances for the SO internal operating expenditure for NGET and NGG in the same way as for the TOs.

Table 10 Controllable opex allowances as compared to actual 9/10 opex and the SO's forecast

2009-10 prices £m	**NGET SO**	**NGG SO**
2009/10 Actual	58.6	28.7
Allowances	**55.2**	**28.3**
SO Forecasts	65.1	34.1

2.21. We have reduced the forecasts provided by SO for the following reasons:

- There is insufficient justification for some of the increases in costs
- We have not allowed for any real increase in salary costs

Details of the specific reductions for each SO are discussed in detail in Appendix 6.

3. Incentives and Uncertainty Mechanisms

Chapter summary
This chapter sets out the incentives and uncertainty mechanisms for the rollover year. Our proposals are informed by stakeholder feedback to our April consultation. In the majority of cases our approach is unchanged to that we presented in April. Where this is the case we restate our approach. We discuss in detail those areas of policy where our proposed approach has changed from that communicated in our April consultation.

Question box

Question 6: We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year for the electricity and gas transmission licensees,

Question 7: We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year applicable to National Grid's internal costs in incurred in balancing the electricity and gas transmission systems.

Question 8: We invite stakeholders to comment on our proposed revised SF6 leakage targets for the rollover year.

Question 9: We invite stakeholders to comment on our proposal to apply the capex incentive adjustment over a number of years to protect users of the transmission system from fluctuating charges.

Question 10: We invite stakeholders to comment on our approach to maintain the existing revenue drivers for the electricity transmission licensees into the rollover year.

Question 11: We invite stakeholders to comment on our proposed timeline for the application of the rollover capex incentive and reconciliation of the provisional TPCR4 capex incentive.

3.1. In our April consultation, we presented the proposed incentives and uncertainty mechanisms for the rollover in detail. Stakeholders were broadly supportive of our proposals, although there were a small number of areas of disagreement. The initial proposals reflect our desire to limit the scope of policy changes in the rollover. We believe that it would be disproportionate to revise all policy areas for a one-year rollover. In this chapter we summarise the full range of incentives and uncertainty mechanisms. We then discuss in detail those areas that we were challenged by stakeholders. We have changed our proposed approach in two areas in response to stakeholder feedback. These are:

- **SF6 incentive:** A number of licensees considered our proposed reduced SF6 targets to be unattainable. We have revised our approach to setting this target.

- **Capex incentive revenue (NGET):** Since highlighting the uncertainty in calculating NGET's capex incentive adjustment, the licensee has submitted additional information and we now propose to make a revenue adjustment in the rollover year on a provisional basis.

3.2. At the end of the chapter we present further detail on our proposed approach to revenue drivers in the rollover year and outline the proposed timing of the calculation of the capital expenditure efficiency incentive.

Summary of incentive and uncertainty mechanism structure

3.3. The overall approach to incentives and uncertainty mechanism for the rollover year are set out in the tables below:

Table 11 Scope of uncertainty mechanisms for the rollover year

Uncertainty Mechanisms	
Logged up costs	**Only Critical National Infrastructure (CNI) costs will be logged up during the rollover year** In setting the TPCR4 price control it was clear that some of the licensees' expenditure could not be projected over a five-year horizon with any degree of certainty, as such we allowed certain categories of costs to log up: • NGG could log up costs associated with quarry and loss development claims[14]. • All of the electricity licensees were allowed to log up costs associated with BT 21st century networks[15]. • The Scottish TOs were allowed to log up costs associated with plugs[16]. • We allowed NGET to log up costs associated with cable tunnelling around the London area up to a value of £60m (in 2004/05 prices). As these costs are not subject to an efficiency incentive via the capex sharing factor, we consider it inappropriate for them to enter into the Regulatory Asset Value (RAV) in advance of a full efficiency review. As such these costs will enter the RAV on 1 April 2013. 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. We consider there to be limited uncertainty for a one year price control, and as such propose not to allow any logging-up of costs during the TPCR4 rollover year. We communicated this approach in our April consultation, and stakeholders were in agreement.

[14] These relate to compensation paid by NGG for certain loss of types of land use, mining, etc.
[15] Costs associated with telecom services necessary as a result of BT's transition to "packet" technology.
[16] Scottish TOs were allowed to log up 50% of the incremental costs of providing a more secure (N-1) connection design in relation to small wind farms (less than 100MW).

	The only exception to this is costs associated with Critical National Security (CNI). These costs have been logged up, however they are not remunerated in the same way as other logged up cost categories. CNI costs are funded are either logged up to the end of the period and then assessed or funded through an income adjusting event term in the licence where the costs exceed a given materiality threshold. We propose that CNI costs continue to be funded through this logging up mechanism for the 2012 /13 rollover period.
Pass through costs	**Costs which were passed through to consumers during TPCR4 will continue to be passed through during the rollover.** In discharging their duties the licensees 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. These are set out below: **NGG:** Licence fee, National Transmission System (NTS) prescribed rates, Independent System cross subsidy and security costs. **Electricity TOs:** Licence fee, network rates adjustment term, Interruptions[17]; in addition NGET are allowed to pass through a number of costs associated with their SO function[18]. We consider these costs are still outside the control of the licensees and that these cost categories continue to be passed through to consumers during the TPCR4 rollover year.
Revenue drivers	**Existing electricity revenue driver mechanism to continue. No new revenue driver mechanisms to be introduced for the rollover year.** In April we stated that we do not consider it to be proportional to introduce any new revenue driver schemes for the rollover year. In light of the levels of uncertainty over the projected capex for the rollover year we proposed to maintain the existing set of revenue drivers, stakeholder's broadly agreed with this approach but requested additional details. Our proposal on this remains unchanged. Further detail on how this work in practice is included at the end of this chapter. Revenue drivers are used to give NGG additional revenues following financially backed requests for additional capacity to flow gas onto or off the NTS. In April we proposed that the initial TO / SO adjustment for pre-2007 signals would take place on 31 March 2012 on a provisional basis, and the remaining adjustment to take place on 31 March 2017 as was the intention of the pre-2007 regime that reflected the five-year price controls. We also proposed that the TPCR4 regime is maintained for the rollover year.

[17] The amount paid out by the licensee in relation to interruptions in their licence area.
[18] 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.

Table 12 Scope of incentives for the rollover year

Incentives	

Efficiency	**TO capex incentive:**
	
	• **Revenue adjustment via the capex incentive to take place on a provisional basis for all TOs for the rollover year.**
	• **Capex incentive to remain unaltered at ±25% for all TOs during the rollover year**
	
	At the start of TPCR4, to incentivise the licensees to incur capex efficiently, we established a "capex incentive" through which the licensees would gain / lose 25% of any capex under / over-spend as compared to their capex allowance.
	
	In April we stated that we intend to continue to apply this incentive to the TOs. Stakeholders agreed with this approach. We also stated that we would apply a revenue adjustment to all parties with the exception of NGET on a provisional basis in the year 2012/13. We considered there to be too much uncertainty over a number of the inputs into NGET's capex incentive calculation to calculate their revenue adjustment, even on a provisional basis. Since April, NGET have presented more detailed evidence; we now propose to make a provisional adjustment to their revenue in 2012/13.
	
	SO capex incentive:
	
	• **Revenue adjustment via the capex incentive to take place on a provisional basis for all TOs in for the rollover year.**
	• **Capex incentive to remain unaltered at ±25% for the SOs during the rollover year**
	
	An identical capex incentive also applies to National Grid in their role as gas and electricity system operator; we propose adopt exactly the same policy:
	
	• We will calculate the TPCR4 capex incentive on a provisional basis and make a revenue adjustment in the rollover year.
	• Their capex incentive will remain in place during the rollover year.
	
	Opex incentive:
	
	• **National Grid's SO opex costs to be incentivised as follows:**
	  ○ **Gas:** ±40**%**
	  ○ **Electricity:** ±25**%**
	
	In their role as SO for the gas and electricity transmission networks National Grid are incentivised to incur opex efficiently (and arbitrage efficiently between their internal operational costs and external system balancing costs) through an opex incentive. As with the capex incentive the SO bear a portion of the benefit / cost of any under / over spend.

	Throughout TPCR4 the opex incentive for the gas SO was set to ±40%, meaning 40% of any over/under spend is borne by the company. We consider it proportional with a one-year rollover to maintain this incentive and maintain the ±40% sharing factor. We stated in April that we would consider aligning the electricity SO internal opex sharing factor with that used for incentivising external costs. 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[19] from 1 April 2011 until the end of the rollover year. They will be subject to a symmetrical ±25% sharing factor. We therefore propose to apply a ±25% sharing factor to their internal opex costs.
Reliability	**Existing reliability incentive to continue to apply for electricity licensees. Parameters of the incentive to remain unchanged.** The electricity licensees 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 April 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. One licensee suggested that their threshold should be increased due to the scale of investment in their network. We do not consider it appropriate to reassess the incentive for a one-year control, particularly as this work will be carried out when defining the RIIO output measures.
Environ-mental	**SF6 incentive structure and reward to remain unchanged from TPCR4. Leakage threshold adjusted from that proposed in our April consultation.** We have increased the SF6 leakage threshold as compared with our April consultation. This is discussed in detail later in this chapter.
Timely delivery	**Permit Scheme to be extended by one year, based on the parameters of the existing scheme (using a pro-rata basis). NGG will receive their incentive 2012/12 permit scheme payment.** One licensee did not believe it is appropriate to extend the permit scheme using a pro-rata basis as the risk of receiving an incremental signal requiring significant lead-time in TPCR4 could be spread over a five-year period. The licensee believed that another scheme would be more appropriate. We continue to maintain the position that it is proportionate for the one-year rollover that the permit is to be extended for one year. We recommend that the parameters for the permit scheme for 2012-13 are based on the existing scheme (using a pro-rata basis).

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

Investment Lead Times	**Default Investment Lead Times will remain unchanged from TPCR4.** We continue to maintain that it would be disproportionate to revisit the investment lead times for a one-year period. We have previously stated[20] that we would defer any review of the default incremental entry capacity lead time until the next full price control period (RIIO-T1).

Detailed discussion of changes to approach to incentives and uncertainty mechanisms

SF6 Incentive

3.4. 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 (CO_2). 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.

3.5. In our April 2011 consultation, we set out our intention to extend the SF6 incentive into the rollover year; we proposed that the level of incentive should remain at 0.2% of base revenue in line with the approach taken in TPCR4. The target leakage rate was set to reduce each year during the current price control and we proposed to continue that reduction. We continue to consider this to be a sensible approach.

3.6. The targets proposed in our April document were informed by the licensee's historical leakage performance, and were set at 1.64% and 1.23% of their SF6 inventory for NGET and SPTL respectively. Both licensees considered these targets to be onerous and sufficiently difficult to achieve that they would not act as a useful incentive; one other stakeholder considered the target to be proportionate with a one-year control. We agree that the target rate needs to be achievable in order for the incentive to work. However, it is important to note that the SF6 incentive is a 'one sided' measure, ie licensees are not penalised for missing the target but are rewarded for achieving it. It is therefore appropriate that the target be sufficiently challenging. In light of the responses received to our April document, we have adjusted our proposed leakage threshold for the rollover year.

3.7. We do not consider it proportional with a one-year control to perform a full "bottom up" assessment to determine the appropriate leakage target, particularly as

[20] http://www.ofgem.gov.uk/Networks/Trans/GasTransPolicy/EntryCapacity/Documents1/Decision%20letter_buy-back.pdf

SF6 leakage will form part of the environmental output measures that are being developed for RIIO. We therefore propose to continue with the current rate of decrease of the SF6 target for both NGET and SPTL. Through this approach we propose the following revised targets for the rollover year:

- **SPT:** 1.34%
- **NGET:** 1.75%

Question 8: We invite stakeholders to comment on our proposed revised SF6 leakage targets for the rollover year.

Provisional capex incentive revenue adjustment

3.8. At the start of TPCR4, to incentivise the licensees to incur capex efficiently, we established a "capex incentive" for the gas and electricity transmission licensee. Under this they gain / lose 25% of any capex under / over-spend as compared to their capex allowance. The incentive is to be calculated at the end of the price control by comparing actual and allowed capex within each year of TPCR4, and be applied as a revenue adjustment in the rollover year. For NGG and the system operators this is a simple matter of comparing the capex incurred on baseline projects to the ex-ante baseline allowance. The calculation for the electricity licensees is more complex.

3.9. 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. To avoid the licensees being penalised for "overspending" when they have incurred capex on a project that will not deliver a revenue driver adjustment to the capex allowance within the price control expenditure on such projects, referred to as "work in progress" (WIP) is subtracted from actual expenditure before calculating the capex incentive.

3.10. In April we communicated our view that we would make a revenue adjustment in the rollover year for NGG, SHETL and SPTL. We also indicated that there was significant uncertainty over the value of NGET's WIP. As a result we proposed to defer payment of their capex incentive. NGET opposed this approach and have since provided further information. We consider this information to provide greater certainty over the value of their WIP and to be sufficiently robust to enable us to make a revenue driver adjustment to NGET's revenue during the rollover year. As with the other transmission licensees this adjustment will be made on a provisional basis as the full set of data from TPCR4 would not be available.

3.11. For all of the TOs we are minded to smooth the revenue adjustment resulting from the capex calculation over a number of years in order to protect users of the transmission system from fluctuating transmission charges. We propose that the revenue adjustment made in the rollover year represent 20% of the overall provisional adjustment. The materiality of this proposed adjustment is outlined below.

Table 13 Provisional capex incentive revenue adjustment and proposed adjustment in rollover year

	Provisional revenue Adjustment (£m)	Proposed adjustment in rollover year (£m)
NGG	47.5	9.5
NGET	210.5	42.1
SHETL	(1.6)	(0.3)
SP	6.0	1.2

Question 9: We invite stakeholders to comment on our proposal to apply the capex incentive adjustment over a number of years to protect users of the transmission system from fluctuating charges.

The continued application of the revenue drivers into the rollover year

3.12. In April we confirmed that we would continue to incentivise efficient capital expenditure in the rollover year through the continuation of the capex incentive. Under this the licensees would again be exposed to 25% of any over / under spend against their capex allowance. This sharing factor means it is important that we set a capex allowance that on the one hand is sufficiently low that it represents value for money for consumers, and on the other hand allows the licensees to undertake necessary investment in an efficient manner. As we stated in April, we consider that this balance can best be struck by continuing to use the revenue drivers during the rollover year. Below we describe the advantages of this approach before discussing how it will work in practice.

Revenue drivers

3.13. A significant portion of the capex projected for the rollover year contained in the licensees' business plans is on 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 for generation within that zone multiplied by the MWs connected). We consider there to be a number of advantages in continuing to calculate the capex allowance for these projects (against which actual capex will be incentivised) via the revenue drivers that were in place at the start of TPCR4:

1. **Simplicity:** Where these projects will be "in flight" 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

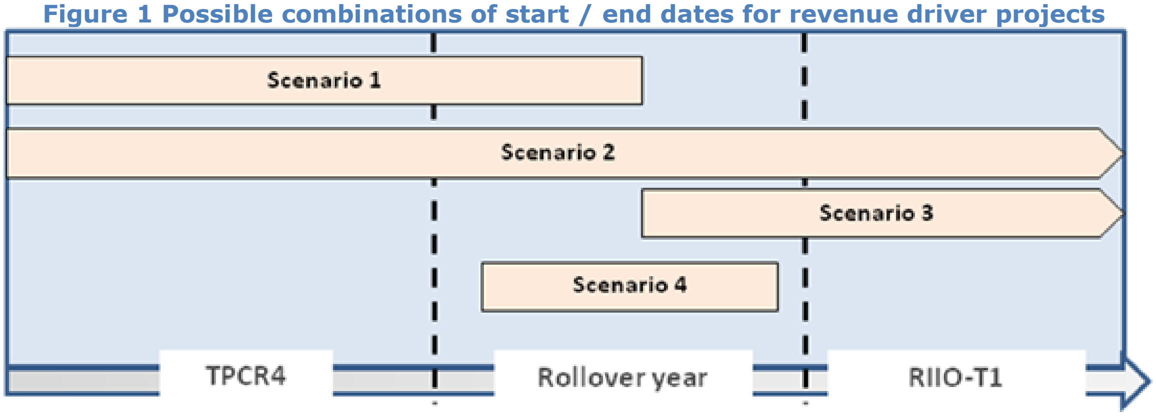
the revenue drivers will allow the capex allowance to flex in line with requirements during the rollover year.

Application of revenue drivers to the rollover year

3.14. At the end of TPCR4 the licensees 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 allowance 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 allowance, since as the outputs are yet to be delivered there would be no commensurate increase in the allowance. This capex will enter the provisional RAV at the start of the TPCR4 rollover year and be excluded from the calculation of the TPCR4 capex incentive. This approach means we will have implicitly granted an allowance for the price control equal to the actual expenditure for these projects. Similarly, as we are continuing to use revenue drivers during the rollover year we expect to have a value for WIP added to RAV at the start of RIIO-T1.

3.15. In our April document we presented the figure below to illustrate the different combinations of start and end dates for projects that would have resulted in a revenue driver adjustment had they completed during TPCR4.

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



3.16. We propose to grant a capex allowance for all of these projects on a provisional basis for the rollover year. The value for this would be that requested in the licensees FBPQ. The licensees will receive a return and appropriate depreciation on this allowance. Prior to calculating the final TPCR4 rollover capex incentive we will adjust the allowances for these projects based on actual outturns during the rollover period. This approach is described in the table overleaf:

Table 14 Deriving capex allowances during the rollover year for revenue driver projects

<table>
<tr><th>Scenario</th><th>Treatment</th></tr>
<tr><td>Scenario 1</td><td>Actual capex is incentivised, the Capex allowance for the rollover is calculated as follows:

Capex allowance[21] = RD allowance– TPCR4 WIP

Where:
• RD allowance is calculated in line with the TPCR4 revenue drivers
• TPCR4 WIP is the capex incurred on the project during TPCR4</td></tr>
<tr><td>Scenario 2</td><td rowspan="2">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, i.e. 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.</td></tr>
<tr><td>Scenario 3</td></tr>
<tr><td>Scenario 4</td><td>As in scenario 1, the actual capex is incentivised. This time the capex allowance is simply the efficient capex as per the definition in Scenario 1.</td></tr>
</table>

Question 10: We invite stakeholders to comment on our approach to maintain the existing revenue drivers for the electricity transmission licensees into the rollover year.

Timing of the capex incentive calculations and true ups

3.17. To calculate the revenue adjustment associated with the capex incentive for a given period the following conditions must be met:

- Actual expenditure during the period must be available and have been reviewed for efficiency.
- Adjustments made to the base allowance through the revenue drivers need to be calculated
- The magnitude of WIP (projects that are "in flight" and will ultimately result in a revenue driver adjustment) needs to be known and fully reviewed.

[21] It is possible where WIP at the end of TPCR4 exceeds the efficient capex allowance for the project that the adjustment to base capex will be negative.

3.18. Due to the magnitude of the revenue driver adjustments from TPCR4, and the fact that we will have four years worth of data (both actual expenditure and revenue driver adjustments), we decided in April to make a revenue adjustment for the TPCR4 capex incentive on 1 April 2012 on a provisional basis.

3.19. To avoid any distorting impacts on revenue allowances, and consequently customers transmission charges, we propose to spread this adjustment across a number of years and will make 20% of the provisional adjustment in the rollover year (as per question 10).

3.20. Once all the necessary data is available from the TPCR4 period we will be able to calculate the "actual" capex incentive. For all of the licensees the first step is to perform an efficiency assessment on their actual capex. At this stage we will have information to enable NGG's capex incentive to be calculated.

3.21. In order to calculate the capex incentive for the electricity licensees we must then make any necessary adjustments to the base capex allowance through the revenue drivers mechanism, and deduct the WIP from the actual capex incurred. Once this is complete we can calculate the capex incentive for SHETL and SP.

3.22. 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 based requirements to reinforce the capacity of boundaries between zones in response to shifting patterns of generation and demand. We stated in our April consultation that, prior to calculating NGET's capex incentive, we would 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 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.

3.23. 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 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.

3.24. The earliest date on which all of the data required to undertake the assessments detailed above will be July 2012, upon receipt of the licensees Regulatory Reporting Pack (RRP) covering the year 2011/12.

3.25. **The rollover capex incentive:** After the conclusion of the rollover year the steps required to calculate the capex incentive for this period are exactly the same as that described above with the addition of one extra step. Prior to comparing the capex incurred to the capex allowance, the capex that was awarded on a provisional basis through the approach described earlier in this chapter needs to be subtracted from the capex allowance. We consider this approach maintains the capex incentive structure since if the project delivers during the rollover year the base capex will be increased in line with the revenue drivers. If the project does not complete within the rollover period the project will be regarded as WIP and will be subtracted from the capex incurred in advance of calculating the capex incentive. The earliest date on which all of the data required to undertake the assessments detailed above will in July 2013, upon receipt of the licensees Regulatory Reporting Pack (RRP) covering the year 2012/13.

3.26. In light of these timing dependencies, we propose to calculate the capex incentive for the rollover year in 2013, once the full dataset is available and we have had the opportunity to undertake an efficiency review. Under this proposal, the associated revenue adjustment will take place on 1 April 2014[22]. We also propose to undertake an efficiency review of the TPCR4 expenditure in advance of this date and re-calculate the capex incentive based on actual expenditure and outputs delivered during TPCR4. Any difference between this and our provisional allowance will also be reconciled on 1 April 2014.

Question 11: We invite stakeholders to comment on our proposed timeline for the application of the rollover capex incentive and reconciliation of the provisional TPCR4 capex incentive.

[22] Any revenue adjustment on 1 April 2013 for the rollover year would not be informed by actual expenditure or outturns during the rollover year.

4. Financial proposals

Chapter Summary

This chapter sets out our initial proposals on allowed return, the Regulatory Asset Value (RAV) and pensions for the rollover year. In addition, it provides commentary on our current views on financeability in the rollover year. Our proposals are informed by stakeholder feedback to our April consultation. Our approach is unchanged on that we presented in April.

Question box

Question 12: Do you think the proposed allowed return is appropriate to a one year rollover?
Question 13: Do you agree with the adoption of the new pensions methodology for the rollover?

Introduction

4.1. Our general approach to the rollover is to retain existing policies as used in TPCR4 and update only where it is required and proportionate to a one year control. We have not adopted RIIO principles. In terms of the financial elements of the rollover package, the only change is in respect of pension costs where we have adopted the revised policy we set out in June 2010,[23] which affects all network companies. In addition, we have updated the allowed return to reflect market changes, where there is sufficient evidence, in line with the TPCR4 approach.

4.2. 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, or *vice versa*. 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

4.3. We propose to reduce the allowed return to 4.75 percent (real vanilla weighted average cost of capital (WACC))[24] for the rollover year, compared to 5.05 percent in TPCR4. This is based on reducing the cost of debt assumption by 50 basis points (bps) to 3.25 percent, reflecting a reduction in the risk-free rate from 2.5 percent to 2.0 percent; leaving the cost of equity assumption unchanged at 7 percent; and leaving notional gearing unchanged at 60 percent for all TOs.

[23] See 'Transmission Price Control 4 – Rollover (2012/13) Scope Decision and Consultation' published on 30 June 2010 with reference number 78/10 on the Ofgem website www.ofgem.gov.uk.
[24] The 'vanilla' 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).

Summary of policy update paper

4.4. In June 2010 we said we would review the elements of the cost of capital used in TPCR4 to see if there was sufficient evidence to justify making changes in the context of a one-year rollover. We published our thoughts on this in the policy update paper published in April 2011 alongside a report we had commissioned from Europe Economics (EE).[25] Our policy update paper had three key messages on allowed return:

4.5. **Cost of debt:** We indicated that there appeared to be sufficient evidence to lower the assumption to 3.25 percent, from 3.75 percent used in TPCR4. This view was based on EE's update of the Smithers Report[26] (which formed the basis of the TPCR4 decision). EE found a notable decline in the risk-free rate in the period since 2006, and we suggested that this was sufficient evidence to use the lower end of the Smithers risk-free rate range (2.0 percent) rather than the top end of the range (2.5 percent) that was used in TPCR4. Our analysis suggested that there was not sufficient evidence to change the debt premium assumption of 1.25 percent.

4.6. **Cost of equity:** We indicated that although there was some evidence of a decline in the cost of equity there was not sufficiently strong evidence to reduce the assumption at this stage. We suggested leaving it unchanged at 7 percent. Whilst 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.[27]

4.7. **Notional gearing:** We said that we intend to leave this unchanged at 60 percent, but indicated that we would consider reducing SHETL's notional gearing if, due to the size of its capex programme in the rollover year (relative to its opening RAV), we identified potential financeability concerns absent any change.

Summary of consultation responses

4.8. We received responses from the three network operators and three suppliers. These are available on our website.[28] We have carefully considered the responses to our April policy update and have concluded that our initial assessment was robust and that these Initial Proposals should reflect our April document.

4.9. All three network companies argue in their consultation responses that it is inappropriate to change the allowed return for the rollover year. They, therefore, all agree with our proposal that the cost of equity assumption should be left unchanged.

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[25] Europe Economics – Updating the Cost of Capital for the Transmission Price Control Rollover (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Roll-over/Documents1/costcapitalrollover.pdf)
[26] Smithers & Co. Ltd. - Report on the Cost of Capital provided to Ofgem (http://www.ofgem.gov.uk/Networks/Trans/Archive/TPCR4/ConsultantReports/Documents1/15576-smithers_co.pdf)
[27] See, for example, Competition Commission – Bristol Water plc - a reference under section 12(3)(a) of the Water Industry Act 1991 (http://www.competition-commission.org.uk/rep_pub/reports/2010/fulltext/558_appendices.pdf)
[28] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=32&refer=Networks/Trans/PriceControls/TPCR4Roll-over.

They disagree with our suggestion that there is sufficient evidence to reduce the cost of debt assumption, although they each approach the argument from a different perspective. Suppliers were supportive of our proposals or considered we were being too generous.

4.10. The network companies also argue that it is inappropriate to reconsider the allowed return or individual elements of the allowed return as the TPCR4 proposals were accepted in the round. We do not accept this as an argument for not making changes in the rollover as the network companies will have the opportunity to consider these proposals in the round for the rollover year.

4.11. We discuss the substantive points raised in the consultation on the individual elements of allowed return in each section below.

Our initial proposals

4.12. We have 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.

4.13. **Risk-free rate:** The Smithers Report recommended using a risk-free rate of 2.5%. As EE identified in its report, the key paragraph from the report is:

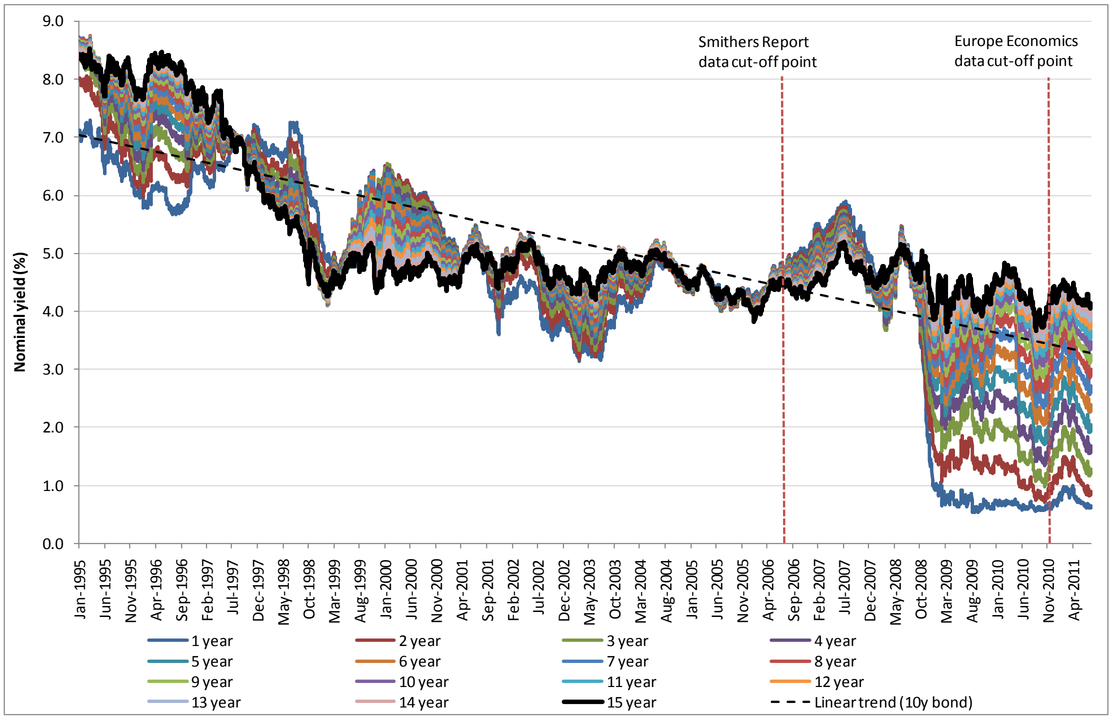
4.14. ”… the best current market-based estimate of the forward-looking real interest rate is the nominal yield on medium-dated bonds, less the Bank of England’s inflation target of 2%: thus a figure around 2 to 2.5%, remarkably close to that in the benchmark “Taylor Rule”.”[29]

4.15. Both EE and we interpret this to mean that the Smithers Report advocates the use of the latest market data as the best indicator of the future cost of debt. It does not advocate the use of forward rates to estimate the future cost of debt (as suggested by one respondent), nor does it advocate relying on long-term historical averages (as suggested by another).

4.16. One network company argued that data for the last three years has been distorted by the financial crisis and cannot be seen to represent long-term trends. However, EE’s analysis shows a sustained and clear downward trend in the real risk-free rate over the last 15 years (replicated in Figure 2 and reiterated in Figure 3 overleaf). This has been reflected in the gradual reduction in risk-free rate used by regulators over time, as shown in Figure 4. We, therefore, think there is strong evidence that the risk free rate has reduced since TPCR4 and that we should use the lower end of the Smithers range of 2.0-2.5 percent.

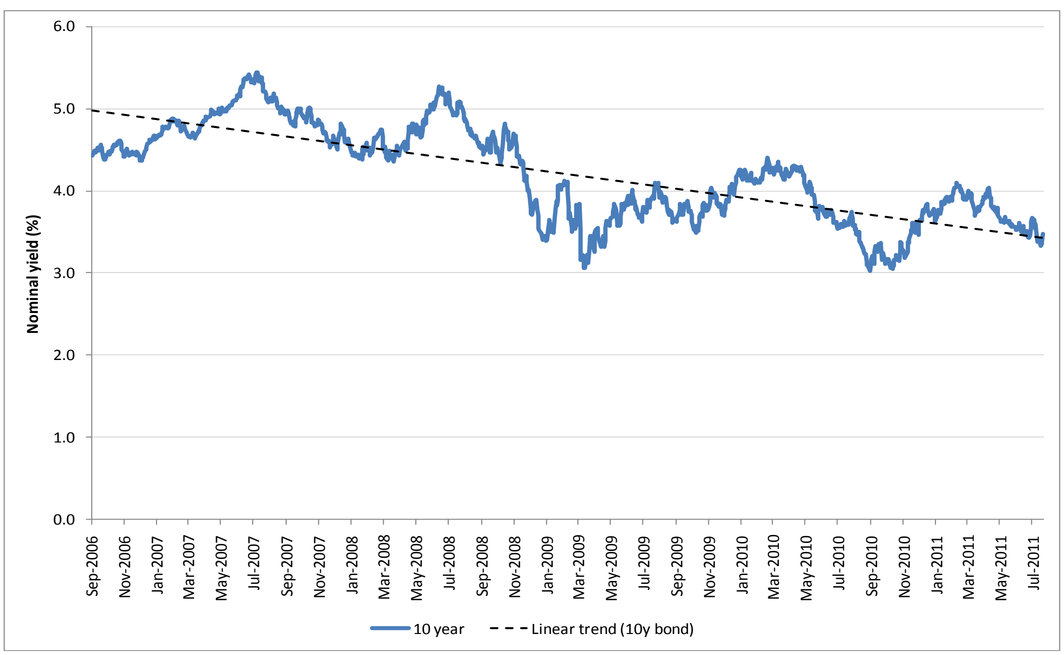
[29] Smithers & Co. Ltd. - Report on the Cost of Capital provided to Ofgem (http://www.ofgem.gov.uk/Networks/Trans/Archive/TPCR4/ConsultantReports/Documents1/15576-smithers_co.pdf)

Figure 2 Yield on short and medium-term nominal government bonds



Source: Bank of England

Figure 3 Yield on 10-year nominal gilts since the Smithers Report



Source: Bank of England

Figure 4 Risk-free rate values used by regulators since TPCR4

Decision year	Regulator	Review	Risk-free rate used by regulator (%)
2006	Ofgem	TPCR4	2.5
2007	CC/CAA	Heathrow & Gatwick	2.5
2007	Ofgem	GDPCR	2.5
2008	NIAUR	SONI	2.5
2008	CC/CAA	Stansted	2.0
2008	CER/NIAUR	Best New Entrant	2.51
2009	Ofgem	DPCR5	2.0
2009	Ofwat	PR09	2.0
2009	CER/NIAUR	Best New Entrant	1.75
2010	CC/CAA	Bristol Water	2.0
2010	CAA	NATS	1.75
2010	CER/NIAUR	Best New Entrant	1.75
2011	Ofcom	BT Openreach (consultation)	1.5
2011	NIAUR	SONI	2.0
2011	Ofgem	TPCR4 Rollover (proposed)	2.0

Source: Various regulatory decision and consultation documents

4.17. **Debt premium:** Neither the TPCR4 Final Proposals nor the Smithers Report specify the methodology by which the debt premium was calculated. However, consistency with the Smithers Report's approach to estimating the risk-free rate would suggest that the latest market figures should be used. TPCR4 Final Proposals considered spot spreads to be unusually low at the time and opted for a range of 1.0-1.5 percent, which roughly corresponds to 10-year averages on A and BBB spreads at the time.

4.18. The 10-year averages are now around 10bps higher than at the time of TPCR4 Final Proposals. This does not seem material in the context of a one-year rollover. Furthermore, since we are proposing to reduce the risk-free rate by 50bps, as opposed to the 100bps decline shown in market yields according to EE's analysis, it does not seem appropriate to raise the debt premium.

4.19. **Cost of debt:** In summary, we are not persuaded by the arguments that we should not adjust the cost of debt assumption for the rollover year. We, therefore, propose to reduce the cost of debt assumption by 50bps to 3.25 percent (real pre-tax), reflecting a reduction in the risk-free rate from 2.5 percent to 2.0 percent.

4.20. **Cost of equity:** As the April 2011 rollover update paper noted, under the TPCR4 methodology of total market returns to equity, evidence suggests not changing the cost of equity assumption. We, therefore, propose to leave the cost of equity assumption unchanged at 7.0 percent (real post-tax).

4.21. **Notional gearing:** We propose to leave notional gearing unchanged at 60 percent for all TOs.

4.22. In the April 2011 rollover update paper we noted that we would consider reducing notional gearing for SHETL because of their large proposed capital programme relative to their existing RAV. This was identified as a possible additional mechanism by which to address potential financeability concerns, on top of the TPCR4 approach of assuming notional new equity issuance.

4.23. In its consultation response, SPTL argues that its expenditure levels resulted in a similar ratio of investment to RAV as SHETL, and hence that it too should potentially have a lower notional gearing level. However, SPTL's analysis only took into account base capex, and did not take into consideration TIRG and TII expenditure. When these elements are taken into account there is a significant difference in the ratio of investment to opening RAV, as shown in the table below. We do not, therefore, accept SPTL's argument.

Figure 5 Ratio of investment to opening RAV

£m 2009-10 prices	NGET TO	SHETL	SPTL	NGG TO
Opening RAV	8,093	566	1,062	4,040
Opening 'shadow' RAV	234	227	139	457
Opening RAV total	8,327	793	1,201	4,497
Investment entering RAV	1,266	440	305	90
Investment entering 'shadow' RAV	0	153	57	60
Investment total	1,266	593	362	149
Investment / opening RAV ratio	**15%**	**75%**	**30%**	**3%**

Source: Ofgem
Note: the investment entering shadow RAV in the year reflects actual capex (ie a proxy for the cash requirement) in the year whilst table 15 shows the net shadow additions which reflect changes in classification between shadow and real RAV.

4.24. The large investment programme, relative to RAV, for SHETL does have some impact on our financeability assessment (described more fully below). However, we believe that, consistent with the approach used in TPCR4, making an assumed small notional equity injection to deal with the increase in RAV gearing that would otherwise arise is sufficient to address any potential financeability concerns. We, therefore, propose to leave notional gearing at TPCR4 levels for all TOs.

4.25. **Asymmetric risk:** In its consultation response, National Grid argues that reducing the allowed return at this time would represent asymmetric risk for investors since the allowed return was not raised for the TPCR3 rollover.

4.26. This claim seems to be based on the idea that Ofgem should have applied the DPCR4 allowed return (assessed during the previous year) to the TPCR3 rollover year. However, the TPCR3 rollover Final Proposals clearly state that we considered the market evidence at least at a high level before deciding to retain the existing allowance:

4.27. "Recent market evidence suggests that an appropriate assumption for NGET's real post-tax WACC would be around 4.4 per cent. Assuming a 30 per cent tax rate, this is equivalent to the current allowed pre-tax rate of return of 6.25 per cent."[30]

4.28. The decision to provide a different allowed return in the TPCR3 rollover to DPCR4 recognised the possibility that the electricity transmission and electricity distribution businesses could face different levels of risk. As we stated at the time:

4.29. "...there may be differences in the risk profiles of NGET and the distribution companies. It therefore does not necessarily follow that the allowed rate of return for NGET should be the same as for the electricity distribution companies."[31]

4.30. Lastly, when the allowed return was set for TPCR4 (a year later) it was again unchanged, suggesting that there was no evidence to support a higher allowed return. We, therefore, consider that our approach at this time is consistent and does not represent asymmetric risk to investors.

Financeability assessment

4.31. As noted above, for the rollover year we have assumed an opening notional gearing of 60 percent - 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 horizon. The financeability assessment of NGET TO, SPTL and NGG TO does not provide any concerns based on the numbers (capex, opex, pensions etc.) in this Initial Proposals document. The assessment of SHETL does provide some concern, particularly as its notional gearing rises sharply in the rollover year.

4.32. We consider that it is appropriate to keep notional gearing below 70 percent, in line with the limit we set in TPCR4. In the context of a level of capital expenditure of £593m[32] compared to an opening RAV of £793m[33], it is appropriate to assume a level of notional equity injection to mitigate the rise in notional gearing. We estimate that a notional equity issuance of £62m for SHETL in the rollover year will bring its credit metrics into levels that are consistent with our financeability criteria. Consistent with the TPCR4 methodology, we propose to provide SHETL a 5 percent allowance for the cost of issuing notional new equity, i.e. £3.1m.

4.33. Consistent with the TPCR4 approach, this allowance for the cost of issuing notional new equity would be subject to a true-up once actual spend in the rollover

[30] See 'Extending National Grid Electricity Transmission Ltd's Transmission Owner Price Control for 2006/07 - Initial proposals' published in September 2005 with reference number 206/05 on the Ofgem website www.ofgem.gov.uk.
[31] Ibid.
[32] Including TIRG spend.
[33] Including 'shadow' RAV.

year is known. The methodology for the true-up is described in the TPCR4 Final Proposals.[34]

4.34. While we propose to make the financeability adjustment for SHETL, it is important to note that credit rating agencies typically consider a three to five year period when assessing network companies. Financial ratios in a single year would not normally have a major impact on ratings if they can be expected to return to stable levels within the three to five year period. We will be in a better position to assess the TOs' longer-term financeability as part of RIIO-T1.

Allowance for issuing new equity true-up

4.35. In TPCR4 it was assumed that both SHETL and SPTL would need to issue notional new equity in order to remain financeable (based on the notional financial structure). We made allowances for the cost of issuing notional new equity (calculated at 5 percent of the assumed amount of new equity), with a true-up mechanism if investment levels were different from forecasts. We made no such allowance for NGET and the mechanism did not apply to NGG.

4.36. In line with the methodology outlined in TPCR4 Final Proposals, we have re-run the financial model with actual spend (and TO's forecasts for 2010-11 and 2011-12) replacing TPCR4 allowed spend. Our subsequent assessment of financeability metrics suggests that SHETL's allowance should not be changed, nor should NGET's zero allowance.

4.37. SPTL has materially underspent against its allowance for TPCR4, with the result that even without the notional equity injection its credit metrics are stronger than was assumed in the TPCR4 Final Proposals with the notional equity injection (as shown in the table below). Consistent with the TPCR4 true-up mechanism, we propose that SPTL's TPCR4 allowance for the cost of issuing notional new equity of £2.5m (in 2004-05 prices, which is equivalent to £2.87m in 2009-10 prices) be fully clawed back on a Net Present Value (NPV) neutral basis.

Figure 6 SPTL's credit ratios for the final year of TPCR4

	Allowed spend, no equity issuance	Allowed spend, with equity issuance	Actual spend, no equity issuance
Funds From Operations (FFO) interest cover	2.8x	3.0x	3.5x
FFO/Net debt	11%	12%	14%
Net debt/RAV	69%	65%	60%

Source: Ofgem

[34] See 'Transmission Price Control Review: Final Proposals' published on 3 December 2006 ref#: 206/06

Other financial issues

Opening RAV values

4.38. In the RIIO March decision paper[35] we set out the provisional RAV calculations to 31 March 2010. We have now updated these and rolled forward to 31 March 2013 (again on a provisional basis) using TO forecasts for 2011 and 2012 and Ofgem allowed capex for 2013. The updated forecast is shown in the following table.

Table 15 Provisional 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	6,934	2,760	(1,489)	760	8,964
SHETL	396	658	(79)	0	974
SPTL	868	609	(211)	42	1,308
NGG	4,009	284	(393)	53	3,952
Total	12,206	4,310	(2,173)	855	15,198

Source: Ofgem

4.39. The adjustments shown include expenditure treated as logged up over the period, expenditure under the TII scheme and, for NGET, addition of expenditure treated as work in progress (WIP) during the period.

4.40. There remains some expenditure that has been incurred but has not yet been added to the RAV (notably TIRG and some gas entry and exit spend), which is remunerated under specific separate mechanisms and for which the expenditure will be added to RAV over the next few years. We refer to these as constituting a 'shadow' RAV, for which provisional values are summarised in the table below.

Figure 7 Estimated provisional 'Shadow' RAV at 31 March 2013

2009-10 prices £m	NGET	SHETL	SPTL	NGG
Opening RAV (shadow) 1/4/2012	234	227	139	457
Net additions	(140)	150	39	103
Depreciation	(5)	(11)	(5)	(6)
Closing RAV 31/3/2013	89	366	172	554

Source: Ofgem

[35] See 'Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues' published on 31 March 2011 with reference number 46/11 on the Ofgem website www.ofgem.gov.uk.

4.41. The net additions shown above reflect the capex in the year offset by previously logged up costs which transfer into the actual RAV. The shadow position for NGET reduces since c£140m of logged up costs are transferred into actual RAV, leaving only TIRG expenditure outside of actual RAV.

4.42. 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.

4.43. Where actual RAV additions have varied from those set at TPCR4, the capex incentive mechanism is used to calculate any adjustment to revenue (depreciation and return) that is due to the companies. The values involved are: NGET £210m, SHETL -£2m, SPTL £6m and NGG £48m. These adjustments reflect changes in the profiling of capex together with (in the case of NGET) return and depreciation for capex revenue driver spend that has been treated as WIP up to the end of TPCR4.

4.44. In view of the high level of this adjustment (particularly for NGET), we will spread these values on a NPV neutral basis over five years. This will enable us to ensure that any variations in network charges are reduced.

4.45. We will further consider the spreading of these adjustments in the light of the companies' RIIO-T1 business plans ahead of Final Proposals for the rollover, so as best to minimise price volatility for customers.

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

Pensions

4.47. In setting pension allowances we have introduced our proposals set out in our 22 June 2010 Pension decision document[36] and detailed in our 31 March 2011 RIIO-T1 Financial Issues document.[37] This means that for the TPCR4 rollover the key principles are:

- 15-year notional deficit recovery period
- True-up of deficit and ongoing costs payments 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.

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

[36] See 'Price Control Treatment of Network Operator Pensions Costs Under Regulatory Principles' published on 22 June 2010 with reference number 76/10 on the Ofgem website www.ofgem.gov.uk.
[37] See 'Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues' published on 31 March 2011 with reference number 46/11 on the Ofgem website www.ofgem.gov.uk.

Table 16 TO pension allowances for 2012-13

2009/10 prices £m	Allowances					
	Deficit recovery	Ongoing pension costs	Admin costs	PPF levy	True-up	Total
NGET	29.8	18.6	0.9	1.0	1.1	51.3
SHETL	1.0	1.8	0.1	0.0	0.5	3.3
SPTL	0.1	2.2	0.1	0.1	0.4	2.8
NGG	29.8	7.2	1.6	2.9	12.9	54.5
Total	60.7	29.7	2.7	4.0	14.9	112.0

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

Deficit funding 2012-13

4.49. We have set the allowances applying our pension methodology. This includes pension deficit funding based on the latest available triennial valuations, to 31 March 2010 for NGET and NGG, and updated valuations to the same date for SPTL and SHETL. These valuations are set out following table:

Table 17 Pension scheme established deficits at 31 March 2010

2009/10 prices £m	Triennial valuation date	Forecast deficit attributable to the licensee
NGET	31-Mar-10	370.6
SHETL	31-Mar-09	12.2
SPTL	31-Mar-09	1.5
NGG	31-Mar-10	371.3
Total		755.6

Source: Ofgem

4.50. We fund deficits over a notional 15-year funding period using a 2.6 percent rate of return, 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

4.51. 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.

4.52. 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 to the March 2011 RIIO-T1 Financial Issues document.

4.53. 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 18 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 TO	8.4	1.1	2.2
SHETL	3.4	0.5	0.0
SPTL	2.8	0.4	0.0
NGG TO	95.2	12.9	0.0
NGET SO	5.3	0.7	1.1
NGG SO	(9.8)	(1.3)	0.0
Total	105.3	14.3	3.3

Source: Ofgem

4.51. The true-up amounts shown above are provisional, pending, in particular, 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 below.

Table 19 Regulatory fractions applied in TPCR4 RO

	Regulatory fraction
NGET	75.7%
SHETL	7.0%
SPTL	4.8%
NGG	58.6%

Source: Ofgem

4.54. 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

4.55. 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 clawback for excess gearing will be adjusted at RIIO-T1 for each year of TPCR4 and the rollover year.

Network rates

4.56. 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 minimising rating valuations. These non-controllable costs for 2012-13 are as shown in Appendix 6.

Appendices

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by Monday 11 September and should be sent to:

Gareth Walsh
Senior Manager, Transmission and Governance
Transmission
9 Millbank
London
SW1P 3GE
Email: TPCR4.Rollover@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, Ofgem intends to publish our final proposals in November 2011.

CHAPTER: Two

Question 1: We invite stakeholders to comment on our proposed operating cost allowances for the transmission companies.

Question 2: We invite stakeholders to comment on our proposed capital expenditure allowances for the transmission companies.

Question 3: We invite stakeholders to comment on our proposed operating cost allowances for the gas and electricity system operator.

Question 4: We invite stakeholders to comment on our proposed capital expenditure allowances for the gas and electricity system operator.

Question 5: We invite stakeholders to comment on our proposal our proposal to disallow expenditure relating to network flexibility on the gas transmission network.

CHAPTER: Three

Question 6: We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year for the electricity and gas transmission licensees,

Question 7: We invite stakeholders to comment on our initial proposals for the structure of the incentives and uncertainty mechanisms for the rollover year applicable to National Grid's internal costs in incurred in balancing the electricity and gas transmission systems.

Question 8: We invite stakeholders to comment on our proposed revised SF6 leakage targets for the rollover year.

Question 9: We invite stakeholders to comment on our proposal to apply the capex incentive adjustment over a number of years to protect users of the transmission system from fluctuating charges.

Question 10: We invite stakeholders to comment on our approach to maintain the existing revenue drivers for the electricity transmission licensees into the rollover year.

Question 11: We invite stakeholders to comment on our proposed timeline for the application of the rollover capex incentive and reconciliation of the provisional TPCR4 capex incentive.

CHAPTER: Four

Question 12: Do you think the proposed allowed return is appropriate to a one year rollover?

Question 13: Do you agree with the adoption of the new pensions methodology for the rollover?

Appendix 2 –NGET proposed allowances

1.1. This appendix provides more detail of our proposed capex and opex allowances for NGET.

1.2. We published our initial thinking and reports from our consultant, KEMA, in April. NGET provided a response to the consultation. They provided detailed comments on each of the non-load related categories. The main arguments were that some of KEMA's analysis was not well justified and potentially misleading and the evidence did not support KEMA's proposals. NGET also argued that there are no delivery issues with load related capex and that the increased forecasts are achievable. They suggested that the proposed reductions also ignored the increase in customer activity and the investment required for a low carbon future. Together with our consultants, we have reviewed the licensee's responses to the April document and reflected these where appropriate in these proposals.

1.3. We are publishing the final KEMA reports alongside this document. They contain the full details of their findings along with their recommendations for allowances. In most cases we have accepted these recommendations in full, but in some cases we have made further adjustments.

1.4. These initial proposals are based on the current information we have from NGET. We invite NGET to provide updated information in response to these initial proposals.

Capital Expenditure

1.5. The table overleaf shows the details of our proposals for capex allowances for NGET TO (all prices are 2009/10,£m):

1.6. The capex projection and capex allowance has been split into "base expenditure" and "provisional revenue drivers". "base expenditure" is the ex-ante allowance for load related capex that will not adjust in line with the revenue drivers. "Provisional revenue drivers" is the provisional allowance for all revenue driver projects; as per the approach outlined in chapter 3 we have granted a provisional allowance for such projects in line with the licensees' business plan submissions. We will adjust this allowance ex-post to reflect delivery during the rollover year. Regulatory WIP in the year 09/10 refers to expenditure on projects that will ultimately result in an increase in the capex allowance via the revenue drivers but which have not yet completed.

Table 20 NGET Detailed capex allowance

	NGET TO				
£m	**2009-10 Expenditure**	**Forecast 2012-13**	**Proposed Allowances**	**% Decrease**	**Notes**
Load Related	436.9				
Base Expenditure		193.6	193.6	0.0%	1
Provisional Revenue Drivers		208.6	208.6	0.0%	1
Regulatory WIP	93.3	0.0	0.0		
	530.2	**402.2**	**402.2**	**0.0%**	
Non Load Related					
Transformers	64.6	105.5	67.8	35.7%	2
Reactors	8.5	7.6	7.6		
Switchgear	49.4	97.5	69.0	29.2%	3
Overhead Lines	50.6	123.7	100.0	19.2%	4
Underground Cables	58.7	31.0	26.4	14.8%	5
Cable Tunnels	-	81.2	65.0	20.0%	5
Protections and Control	26.8	40.3	35.0	13.2%	6
Substation Other	17.2	13.7	13.7	0.0%	
Other TO	69.6	64.0	51.1	20.2%	7
BT21CN	-	8.2	4.1	50.0%	8
Logged Up	18.0	0.0	0.0		
	363.5	**572.7**	**439.7**	**23.2%**	
Customer Contributions	**(18.0)**	**(10.6)**	**(10.6)**	**0.0%**	
Total	**875.7**	**964.3**	**831.3**	**13.8%**	

1.7. Our reasons for the proposed allowances and associated adjustments to NGET's forecasts are:

1. In its report, KEMA proposed a reduction in the load-related allowance for NGET. The reduction related solely to revenue driver projects. Our policy is to provide an indicative allowance for 2012-13 based on the TOs' forecasts and then to true this up based on the revenue driver unit cost allowances. We have therefore ignored KEMA's proposed reduction. The "load provisional" figure is the provisional allowance for all revenue driver projects. We have allowed NGET's full baseline capex forecast.
2. Transformers – NGET's forecast has been reduced as it appears to be high in relation to expenditure in previous years and relies on modelling output rather than condition assessment. NGET appears to have purchased transformers that exceed the replacement volumes indicated by their own modelling. Despite the reductions the allowance proposed exceeds current expenditure levels.
3. Switchgear – the forecast has been reduced due to proposed expenditure in 2012/13 being significantly above previous levels and there is insufficient information to justify the increase. In addition, unit costs are higher than the TO

or KEMA's estimates, project contingencies relating to particular schemes appear to be high, and substation infrastructure has been reduced in line with historical expenditure. Despite this the allowance proposed is higher than historical levels of expenditure.
4. Overhead Lines – the forecast has been reduced due to unit costs being higher than KEMA's estimates, overheads being deemed higher than normally accepted levels, and forecast fittings only volumes being higher than the average for historical years. We have increased KEMA's estimate by 25 per cent to allow for greater overhead line refurbishment.
5. Underground Cables and Cable Tunnels – the forecast has been reduced in line with KEMA's view that project on-costs covering risk and contingencies are high.
6. Protection and Control – the forecast has been reduced due to NGET's costs being higher than the GB average. In the first three years of TPCR4 replacement volumes have been reduced due to life extensions and development of 'upgrade' options for some substation control systems. The proposed allowance therefore aligns more with NGET's current protection and control spend, but is higher than the current average expenditure.
7. Other TO – the forecast is higher than TPCR4 average, and the proposed reduction brings it in line.
8. Costs for the replacement of telecom circuits when BT implement their 21st Century Networks (BT21CN) have been reduced by half as there appears to be some uncertainty over the timing of the expenditure. These costs were previously logged up in TPCR4.

Controllable Operating Costs

1.8. The operating costs are separated into those costs that are controllable by the licensee and those that are not. We propose that the non controllable costs are treated as pass through items for price control purposes. Therefore this analysis focuses upon the controllable operating costs.

1.9. For the purpose of calculation of the appropriate allowance we have started with the most recent year of actual expenditure (2009/10). 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 licensee business. We will have additional data available for 2010/11 before final proposals which we will use to update our analysis.

1.10. The table overleaf shows the details of our proposals for controllable opex allowances for NGET (all prices are 2009/10, £m)

Table 21 NGET Controllable Opex Allowance

£m	Forecast 2012-13	Proposed Allowances	Notes
Controllable Opex			
2009-10 Actual expenditure	198.5	198.5	
Exceptional costs in 2009-10	(5.5)	(5.5)	1
Recurring Cash Controllable Costs 2009-10	**193.0**	**193.0**	
Efficiency Savings	(24.0)	(24.0)	2
Additional Efficiency Savings		(4.0)	2
Cash Costs	**169.0**	**165.0**	
Proposed Increases in Costs			
Asset Growth and Diversity etc	10.0	4.5	3
IT Running Costs	4.0	0.0	4
Real Price	10.0	4.0	5
Volume, Mix and other	6.6	2.3	6
Workforce Growth	7.0	3.5	7
Recruitment and Training	11.0	5.5	8
Total Proposed Increases in Costs	48.6	19.8	
Non Operational Capex	22.9	13.6	9
Forecast / Proposed Allowance	**240.5**	**198.4**	

1.11. The proposed allowance represents a 17.5% reduction from NGET's forecast. The reasons for this are:

1. Exceptional Costs – these relate to exceptional or one off costs that were not part of the recurring costs of running the transmission business in 2009-10 including reorganisation, feasibility costs, clean up costs and dispute costs.
2. Efficiency – NGET have forecast £24m worth of efficiencies. We consider that there is scope for further efficiency savings given the difference between historical spending and allowances and so have applied a further efficiency factor.
3. Asset Growth and diversity – we have accepted the increases relating to asset growth, post delivery support agreements and part of the asset painting increase as we do not consider that NGET has fully justified the increase in expenditure.
4. IT running costs – NGET have not explained why there is a need for increases in such costs. We would expect IT opex to reduce as a result of increased spending on IT capex.
5. Real Price increases – we expect there to be no real pay increases in the rollover year, given the current economic climate.
6. Volume and Mix – relate to a variety of upward cost pressures. We have accepted the need for increases in NGET's regulatory team and workload, but not others such as additional site care and insurance costs where NGET has not provided sufficient justification.
7. Workforce Growth - we have only accepted half of the increased costs as we consider that there is insufficient justification for the increase. We accept there is a need to renew the workforce as people retire and the network expands, and our allowance recognises the lead time to recruit and train appropriate staff.

8. Recruitment and Training - we have not seen sufficient justification for the significant increases and therefore we have accepted half of increase. We accept there is a need to renew the workforce as people retire and the network expands. Although we do not consider that NGET has fully justified its forecast expenditure, our allowance recognises the lead time to recruit and train appropriate staff.
9. Non Operational Capex – this is shown in the table below and discussed further below.

Table 22 NGET Non Operational Capex

Non Operational Capex	**NGET TO**		
£m	**Forecast 2012-13**	**Proposed Allowances**	**Notes**
Property	5.9	4.4	11
Integrating the Alliances	2.0	1.5	11
RAMM / SAM	2.4	0.2	10
Front Office Replacement	2.6	0.0	10
Other	10.0	7.5	11
Forecast / Proposed Allowance	**22.9**	**13.6**	

10. We have reduced the allowance in respect of 2 systems – Front Office Replacement and Remote Access Monitoring and Management (RAMM) where there seems uncertainty over whether forecast expenditure will actually be incurred in 2012/13.
11. We have then reduced the balance by 25 per cent to take account of efficiencies within projects and general concern about deliverability and justification of projects.

1.12. Although the allowance is 40.5 per cent lower than forecast it is more in line with the average historical expenditure between 2007-08 and 2009-10 of £11.1m.

Appendix 3 SHETL proposed allowances

1.1. This appendix provides more detail of our initial proposals capex and opex allowances for SHETL.

1.2. We published our initial thinking and reports from our consultant, KEMA, in April. In SHETL's response to the consultation it did not agree with the reductions in non load related capex, arguing that these did not take account of specific circumstances and that increases in expenditure were deliverable. SHETL questioned the rationale for disallowing all load related schemes with low certainty of delivery, arguing that there may be some expenditure on these schemes. Together with our consultants, we have reviewed the licensee's responses to the April document and reflected these where appropriate in these proposals.

1.3. We are publishing the final KEMA reports alongside this document. They contain the full details of their findings and also their suggested allowances. In most cases we have accepted these suggestions in full, but in some cases we have made further adjustments.

1.4. These initial proposals are based on current information we have from SHETL. We invite SHETL to provide updated information in response to these initial proposals.

Capital Expenditure

1.5. The table overleaf summarises our initial proposals for SHETL (all prices are 2009-10, £m).

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

Table 23 SHETL detailed Capex Allowance

	SHETL				
£m	**2009-10 Expenditure**	**Forecast 2012-13**	**Proposed Allowances**	**% Decrease**	**Notes**
Load Related	32.3				
Base Expenditure		61.2	49.4	19.3%	1
Provisional Revenue Drivers		13.7	13.7	0.0%	1
	32.3	**74.9**	**63.1**	**15.8%**	
Non Load Related					
Transformers	5.9	4.2	3.8	9.5%	2
Reactors	0.0		0.0		
Switchgear	0.7	4.1	4.1	0.0%	
Overhead Lines	3.8	4.6	3.9	15.2%	3
Underground Cables	-0.3	3.7	3.7	0.0%	
Protections and Control	0.3	0.7	0.7	0.0%	
Substation Other	1.1	1.8	1.8	0.0%	
Logged Up	0.0	0.0	0.0		
Other TO	1.7	1.7	1.7	0.0%	
	13.2	**20.8**	**19.7**	**5.3%**	
Customer Contributions	(9.2)	(14.6)	(14.6)	0.0%	
Total	36.3	81.1	68.2	15.9%	

1.7. Our reasons for the proposed allowances and associated adjustments to SHETL's forecast are as follows.

1. KEMA considers that there is significant uncertainty as to whether some projects will go ahead because of uncertainty over planning consents and delivery timescales. It has therefore disallowed expenditure on projects with low certainty of delivery. KEMA has also questioned the deliverability of the whole capex programme given the scale of the increase anticipated by SHETL. KEMA noticed an adjustment of £2.6m relating to pre-construction costs for Transmission Investment Incentive (TII) projects. The TII expenditure should be funded under that mechanism and not via base capex. We have revised this to £8.3m based on the information in the FBPQ. Following KEMA's report we have decided to allow funding for two demand related schemes where SHETL have provided additional evidence in response to the April consultation to support their forecast that the schemes will go ahead in 2012-13. We have also ignored some of KEMA's suggested adjustments where these related to revenue driver projects.
2. Transformers – SHETL's unit costs are considered high in relation to KEMA's estimates and TO average. The allowance has been reduced to bring unit costs into line. We have also adjusted KEMA's figures to account for additional costs incurred in remote locations.
3. Overhead Lines – SHETL has significantly reduced expenditure on overhead lines in the TPCR4 period relative to our baselines. In this period conductors have been found to be in better condition than originally anticipated and this has caused

some of the underspend. KEMA has suggested a reduction in 2012/13 for similar reasons. KEMA also expresses concerns over deliverability of proposed work. Our reduction brings the allowance into line with average expenditure over the TPCR4 period.

Controllable Operating Costs

1.8. The operating costs are separated into those costs that are controllable by the licensee and those that are not. It is proposed that the non controllable costs are treated as pass through items for price control purposes. Therefore this analysis focuses upon the controllable operating costs.

1.9. For the purpose of calculation of the appropriate allowance we have started with the most recent year of actual expenditure (2009-10). 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 licensee business. We will have additional data available for 2010-11 before final proposals which we will use to update our analysis.

1.10. The table below summarises our proposed opex allowances for SHETL (all prices are 2009-10, £m).

Table 24 SHETL Controllable Opex Allowance

£m	Forecast 2012-13	Proposed Allowances	Notes
Controllable Opex			
2009-10 Actual expenditure	6.2	6.2	
Exceptional costs in 2009-10	0.0	0.0	
Recurring Cash Controllable Costs 2009-10	**6.2**	**6.2**	
Efficiency Savings	(0.2)	(0.3)	1
Cash Costs	**6.0**	**5.9**	
Proposed Increases in Costs			
Direct Costs	1.1	0.0	2
Indirect Costs	1.9	1.2	3
Total Proposed Increases in Costs	3.0	1.2	
Non Operational Capex	0.0	0.0	4
Forecast / Proposed Allowance	**9.0**	**7.1**	

1.11. The proposed allowance represents a 21.1% reduction from SHETL's forecast. The reasons for this are as follows.

1. We have assumed a 1.5% efficiency per annum in line with the original TPCR4 proposals

2. We have not allowed increases in direct costs of maintaining the expanded network as most of this expansion is in the construction phase and should not incur maintenance expenditure in the rollover year.
3. We have accepted there will be increases in business support costs due to the increasing size of SHETL's network and costs associated with RIIO T1. We have allowed some increases in engineering indirect costs to account for additional costs of a larger network and costs associated with RIIO T1. Half of the increase in engineering indirect costs and all of the costs relating to stores and procurement should be part of the TIRG or TII project construction costs.
4. SHETL do not have any non-operational capex specifically allocated to the business and therefore no allowance is proposed.

Appendix 4 SPTL proposed allowances

1.1. This appendix provides more detail of our initial proposals capex and opex allowances for SPTL.

1.2. We published our initial thinking and reports from our consultant, KEMA in April. In its response to the consultation SPTL argued that reduction in non load related expenditure had been made due to a misunderstanding of certain projects by KEMA. It also suggested that reducing expenditure in the rollover would prevent them increasing expenditure in RIIO-T1. With regard to load related expenditure it accepted there is some uncertainty within the proposed schemes but that an appropriate funding mechanism should be provided to address this. Together with our consultants, we have reviewed SPTL's responses to the April document and reflected these where appropriate in these proposals.

1.3. We are publishing the final KEMA reports alongside this document. They contain the full details of their findings and also their suggested allowances. In most cases we have accepted these suggestions in full, but in some cases we have made further adjustments.

1.4. These initial proposals are based on current information we have from SPTL We invite SPTL to provide updated information in response to these initial proposals.

Capital Expenditure

1.5. The table overleaf summarises our initial proposals for SPTL (all prices are 2009-10, £m).

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

Table 25 SPTL Detailed capex allowance

£m	2009-10 Expenditure	Forecast 2012-13	Proposed Allowances	% Decrease	Note
Capex					
Load Related	47.0				
Base Expenditure		101.2	83.1	17.9%	1
Provisional Revenue Drivers		30.5	30.5	0.0%	1
	47.0	131.7	113.6	13.7%	
Non Load Related					
Transformers	9.4	9.5	9.5	0.0%	
Reactors	0.0	0.0	0.0		
Switchgear	11.1	19.0	15.0	21.1%	2
Overhead Lines	7.9	41.1	28.0	31.9%	3
Underground Cables	9.2	3.4	3.4	0.0%	
Protections and Control	1.0	8.5	8.5	0.0%	
Substation Other	2.4	2.1	2.1	0.0%	
Other TO	0.2	3.7	3.7	0.0%	
Adjustment for Capitalisation		0.0	-9.8		4
BT21CN	0.0	6.0	3.0	50.0%	5
Small Windfarm Connections	0.0	2.0	2.0	0.0%	5
Logged Up	0.3	0.0	0.0		
	41.5	95.3	65.4	31.4%	
Customer Contributions	(9.4)	(8.9)	(8.9)	0.0%	
Total	79.1	218.1	170.1	22.0%	

1.7. Our reasons for the proposed allowances and associated adjustments to SPTL's forecasts are as follows.

1. KEMA considers that there is significant uncertainty as to whether some projects will go ahead in the rollover year because of issues over planning consents. KEMA has disallowed expenditure on projects with low certainty of delivery. It has also questioned the deliverability of the whole capex programme given the scale of the increase anticipated by SPTL. We have reversed some of the KEMA adjustments where these related to revenue driver projects.
2. Switchgear – expenditure proposed in 2012-13 is significantly above previous levels of expenditure. KEMA has reduced the forecast as the reasons for the increase are not clear, and they expect some schemes will be deferred due to deliverability constraints. KEMA suggest that SPTL should gather further condition information to enable it to forecast better the need and timing of the proposed expenditure.
3. Overhead Lines – proposed expenditure is significantly higher than previous years. KEMA are concerned over the deliverability of such an increase and also consider that the condition of lines may be better than expected leading to a reduction in expenditure required.
4. The Other TO category includes an adjustment (£9.8m) for capitalisation of related party margins, depreciation and excess capitalisation. Similar

adjustments have been made to actual capex in the in TPCR4 period to date i.e. up to 2009-10.

5. Logged Up – Costs for replacement of telecom circuits when BT implement their 21st Century Networks (BT21CN) have been reduced by half to bring them in line with previous expenditure and also to take account of uncertainty in timing. Costs relating to the connection of small windfarms have been allowed in full.

Controllable Operating Costs

1.8. The operating costs are separated into those costs that are controllable by the licensee and those that are not. It is proposed that the non controllable costs are treated as pass through items for price control purposes. Therefore this analysis focuses upon the controllable operating costs.

1.9. For the purpose of calculation of the appropriate allowance we have started with the most recent year of actual expenditure (2009-10). 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 licensee business. We will have additional data available for 2010-11 before final proposals which we will use to update our analysis.

1.10. The table below summarises our proposed opex allowances for SPTL (all prices are 2009-10, £m).

Table 26 SPTL Controllable Opex Allowance

£m	**Forecast 2012-13**	**Proposed Allowances**	**Notes**
Controllable Opex			
2009-10 Actual expenditure	18.3	18.3	
Exceptional costs in 2009-10	0.0	(0.5)	1
Recurring Cash Controllable Costs 2009-10	**18.3**	**17.8**	
Efficiency Savings	0.0	(0.8)	2
Cash Costs	**18.3**	**17.0**	
Proposed Increases in Costs			
Tower Painting Costs	0.7	0.0	3
Non Operational Capex	0.9	0.9	4
Forecast / Proposed Allowance	**19.9**	**17.9**	

1.11. The proposed allowance represents a 10.1% reduction from SPTL's forecast. The reasons for this are as follows.

1. Related party margins charged by SP Power Systems to SPTL within the 2009-10 actual figures has been deducted in line with the policy set out at TPCR4.
2. We have assumed a 1.5% efficiency per annum in line with the original TPCR4 proposals.

3. We have disallowed an increase in tower painting. This work was allowed for at TPCR4, but SPTL chose to delay starting the work until 2009-10. We believe if they had started tower painting in 2007-08 much of the work would be complete.
4. Non Operational Capex - we have accepted SPTL's forecast.

Appendix 5 NGG proposed allowances

1.1. This appendix provides more detail of our initial proposals capex and opex allowances for NGG.

1.2. We published our initial thinking and reports from our consultant, KEMA in April. In their response to the consultation NGG argued that the level of sanctioning on non load related projects has increased from the FBPQ submission in October 2010 and therefore the reductions are not appropriate. It also argued that costs will be incurred in the rollover year on schemes where Ofgem have not given any allowance. Concerning the load related forecast NGG argued that the case for network flexibility is accepted by stakeholders and investment in the area is required in 2012/13. Together with our consultants, we have reviewed the licensee's responses to the April document and reflected these where appropriate in these proposals.

1.3. We are publishing the final KEMA reports alongside this document. They contain the full details of its findings and also its suggested allowances. In most cases we have accepted these suggestions in full, but in some cases we have made further adjustments.

1.4. We invite NGG to provide updated information in response to these initial proposals.

Capital Expenditure

1.5. The table below summarises our initial proposals for NGG TO (all prices are 2009-10, £m):

Table 27 NGG Capex Allowance

	NGG TO				
£m	**2009-10 Expenditure**	**Forecast 2012-13**	**Proposed Allowances**	**% Decrease**	**Notes**
Load Related	**45.1**	**73.9**	**23.6**	**68.1%**	**1**
Non Load Related					
Emissions reduction	37.2	7.6	7.6	0.0%	
Asset health (condition driven)	38.6	51.4	39.1	23.9%	2
Other	3.3	3.8	3.8	0.0%	
Costs of Discontinued Projects	0.0	0.0	0.0		
Quasi-Capex	0.4	1.7	1.7	0.0%	
Logged Up	0.4	0.0	0.0		
	79.9	**64.5**	**52.2**	**19.1%**	
Total	**125.0**	**138.4**	**75.8**	**45.2%**	

NB. The forecast and proposed allowances exclude £59.5m of TO Incremental capex (entry and exit)

1.6. Our reasons for the proposed allowances and associated adjustments are:

1. KEMA has recommended reducing the network flexibility forecast significantly due to concerns over whether these projects should be associated with and financed by revenue drivers or SO incentive arrangements. In addition to KEMA's recommendation, we have not seen adequate justification of the need for this expenditure in the rollover year. We would expect greater information on why such needs were not anticipated in response to the user commitment signals where they relate to existing users, and why they could not be incorporated into the appropriate commercial arrangements and revenue drivers for new users. We would also expect NGG to demonstrate the appropriateness and cost effectiveness of investment deemed necessary to address flexibility requirements not covered by operational measures and commercial mechanisms. From the evidence we received so far, we do not believe that the case for investment in network flexibility has yet been made and in particular why such investments are necessary in the rollover year. We have therefore proposed no allowance for network flexibility. KEMA also states that many of the projects have still to be sanctioned by NG before construction work can start. Other load related spend has been allowed in full.
2. The reductions in asset health (condition driven) expenditure are due to the concern that NGG will not gain the necessary planning permissions for the Humber Crossing project to go ahead in 2012-13, a gas quality metering project that was allowed for in TPCR4 and therefore requires no further allowance, and a reduction in the cost estimate for the power turbines re-lifing to the central estimate.

Controllable Operating Expenditure

1.7. The operating costs are separated into those costs that are controllable by the licensee and those that are not. It is proposed that the non controllable costs are treated as pass through items for price control purposes. Therefore this analysis focuses upon the controllable operating costs.

1.8. For the purpose of calculation of the appropriate allowance we have started with the most recent year of actual expenditure (2009-10). 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 licensee business. We will have additional data available for 2010-11 before final proposals which we will use to update our analysis.

1.9. The table overleaf summarises our initial proposals for NGG TO's opex allowances (all prices are 2009-10, £m).

Table 28 NGG Controllable Opex Allowance

£m	Forecast 2012-13	Proposed Allowances	Notes
Controllable Opex			
2009-10 Actual expenditure	61.0	61.0	
Exceptional costs in 2009-10	(2.0)	(2.0)	1
Recurring Cash Controllable Costs 2009-10	**59.0**	**59.0**	
Efficiency Savings	(5.0)	(5.0)	2
Cash Costs	**54.0**	**54.0**	
Proposed Increases in Costs			
Asset Growth and Diversity etc	2.0	0.6	3
Real Price	5.0	2.9	4
Volume and Mix and IT	3.0	0.0	5
Gas Technical Drawings	4.0	0.0	6
Workforce Growth etc	3.0	1.5	7
Supply and Demand Volatility	1.0	0.0	8
Other	(0.6)	(0.6)	
Total Proposed Increases in Costs	17.4	4.4	
Non Operational Capex	13.5	4.4	9
Forecast / Proposed Allowance	**84.9**	**62.8**	

1.10. The proposed allowance represents a 26.0% reduction from NGG's forecast. The reasons for this are:

1. Exceptional Costs – these relate to exceptional or one off costs that are not part of the recurring costs of running the transmission business including reorganisation, feasibility costs, clean up costs and dispute costs.
2. Efficiency – These are the efficiencies that have been proposed by NGG.
3. NGG have not made a clear case for increases in costs due to asset growth and diversity. We accept that similar to electricity there may be some need for costs to increase and therefore propose a small increase to the allowance, but further detail is required to justify a larger increase.
4. We accept the need for some real price increases other than for pay. We expect there to be no real pay increases in the rollover year, given the current economic climate.
5. Volume and Mix – relate to a variety of upward cost pressures. We consider NGG has provided insufficient detail to allow us to understand where the cost increases stem from and why they are needed.
6. Gas technical drawings – we have not accepted the need for this expenditure as we consider that this is something NGG should already have in place.
7. We accept there is a need to renew the workforce as people retire and the network expands. Although we do not consider that NGG has fully justified its forecast expenditure, our allowance recognises the lead time to recruit and train appropriate staff.
8. Supply and demand volatility – this relates to increased modelling for changes in gas supply and demand patterns. NGG have not provided sufficient information

as to the need for such an increase in the rollover year. This is in line with not accepting the allowance for network flex capital expenditure.

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

Table 29 NGG Non Operational Capex

Non Operational Capex	**NGG TO**		
£m	**Forecast 2012-13**	**Proposed Allowances**	**Notes**
Property	1.5	1.1	11
HPMIS	4.7		10
RAMM / SAM	1.7	0.1	10
Front Office Replacement	1.4		10
Other IT	1.9	1.4	11
Other	2.3	1.7	11
Forecast / Proposed Allowance	**13.5**	**4.4**	

10. We have reduced the allowance in respect of 3 systems – High Pressure Metering Information System replacement (HPMIS), Front Office replacement and Remote Access Monitoring and Management (RAMM) where there seems uncertainty over whether expenditure will be incurred in 2012-13.
11. We have then reduced the balance by 25 per cent to take account of efficiencies within projects and general concern about deliverability as we consider that the need for the forecast expenditure is not clearly demonstrated and justified.

1.11. Although the proposed allowance is 67.6 per cent lower than NGG's forecast it is in line with historical expenditure trends.

Appendix 6 – SO (electricity and gas) proposed allowances

1.1. This appendix provides more details of the calculation of the initial proposals capex and opex allowances for the internal SO functions of NGG and NGET.

1.2. We published our initial thinking and report from our consultant, PPA, in April. In its combined consultation response for NGET and NGG National Grid argued that PPA had misunderstood its FBPQ submission, that delaying expenditure into RIIO-T1 would cause deliverability, and security risks and customer benefits would not be maximised. They suggested that reducing expenditure for 2012/13 also places reliance on ageing systems and therefore increases risk. Together with our consultants, we have reviewed the licensee's responses to the April document and reflected these where appropriate in these proposals.

1.3. We are publishing the final PPA report alongside the initial proposals. This contains the full details of their findings and also their suggested allowances. We have accepted their suggestions in full.

1.4. These initial proposals are based on current information we have from NGET and NGG. We invite NGET and NGG to provide updated information in response to these initial proposals.

SO Capital Expenditure

1.5. The tables below summarise our initial proposals for NGET SO and NGG SO (all prices are 2009-10, £m).

Table 30 NGET Internal SO Capex Allowance

	NGET SO				Notes
£m	**2009-10 Expenditure**	**Forecast 2012-13**	**Proposed Allowances**	**% Decrease**	
Capex	10.8	42.0	42.0		
less:					
Stability Control System			-4.0		1
iEMS Replacement			-1.4		2
IS Data Centres			-1.9		3
Other Asset Health			-4.4		4
Non Scheme Based			-1.0		5
Other Adjustments			-4.1		6
Total	**10.8**	**42.0**	**25.3**	**-39.9%**	

1.6. Reasons for the proposed NGET SO allowances are:

1. Stability control system – NGET has not provided sufficient rationale for this expenditure in 2012-13.
2. iEMS replacement – we believe expenditure on iEMS should be reduced pending clarification of the impact of Electricity Market Review (EMR) which could have a significant impact on what is required from any changes.
3. IS data centres and property costs – it appears that no scheme has been approved at the present time. We propose to reduce this to facilitate a review taking account of the multiple sites and to establish the least cost option.
4. Other asset health – expenditure relating to TOGA has been allowed, but other work is not considered a critical priority and could be delayed until a future year.
5. Non scheme based expenditure - during TPCR4 this allowance was set at around £1 million per year. The proposal for it to rise to £4.6 million per year should be justified by schemes and so we have scaled back the allowance from £4.6 million to £3.6 million.
6. Other Adjustments – these relate to other enhanced SO and Asset health capex projects. PPA suggested NGET need to provide more detailed justification for these projects. Full details are shown in the PPA report.

Table 31 NGG Internal SO Capex Allowance

	NGG SO				**Notes**
£m	**2009-10 Expenditure**	**Forecast 2012-13**	**Proposed Allowances**	**% Decrease**	
Capex	10.8	31.0	31.0		
less:					
iGMS Replacement			-1.5		1
IS Data Centres			-4.2		2
Security			-2.9		3
NetSip			-0.2		4
IS Capex			-1.3		5
Other Adjustments			-2.9		7
Sub Total	**10.8**	**31.0**	**18.0**	**-41.9%**	
Xoserve	1.4	11.7	7.9	-32.5%	
Exit Reform	2.9	2.4	2.4		
Total	**15.1**	**45.1**	**28.3**	**-37.3%**	

NB NGG SO Capex excludes Xoserve and Exit Reform which are funded separately**.**

1.7. Reasons for the proposed NGG SO allowances are:

1. iGMS Strategic Route Map – NGG have not provided a clear case for this project. There is scope for this this project to be delayed pending further progress with EMR and other market developments, together with a clearer IT strategy. Some expenditure has been allowed for further research and planning.
2. Data centres – the sanctioning of this project appears to be incomplete. It is unclear whether the proposed investments, as outlined in these plans, are the least cost option. Therefore, we propose to reduce the allowance so as to encourage NGG to review the proposals taking account of NG's multiple sites with the aim of establishing the least cost option.

3. Security – we suggest that this project is rescheduled over three years so that the peak of expenditure is avoided, the programme and spend is spread over a longer period and the resulting risks are reduced.
4. NetSip – there appear to be no mandate for this work. Its timing, scope and need should be reviewed. Some expenditure has been allowed to allow for further research and planning.
5. IS Capex - relates to the Telex Infrastructure refresh. Expenditure in this area is currently low and is sanctioned on a yearly basis. In view of the large amount of other SO capex in 2012-13 it is suggested that the proposed increases are delayed and that the programme is reviewed as part of RIIO-T1 price control review.
6. Other – these reductions relate either to asset health and business capability projects that PPA suggest should be deferred for further consideration in RIIO or they appear from the information provided to be speculative.
7. xoserve - expenditure here is currently low. The requirements seem to be speculative and it is therefore proposed that the expenditure is scaled back.

SO Controllable Operating Costs

1.8. The operating costs are separated into those costs that are controllable by the licensee and those that are not controllable. It is proposed the non controllable costs are treated as pass through items for price control purposes. For SO non controllable costs are very small. Therefore this analysis focuses upon the controllable operating costs.

1.9. For the purpose of calculation of the appropriate allowance we have started with the most recent year of actual expenditure (2009-10). 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 licensee business. We will have additional data available for 2010-11 before final proposals which we will use to update our analysis.

1.10. The tables on the next two pages summarise our initial proposals for NGET SO and NGG SO (all prices are 2009-10, £m).

Table 32 NGET Internal SO Opex Allowance

£m	Forecast 2012-13	Proposed Allowances	Notes
Controllable Opex			
2009-10 Actual expenditure	58.6	58.6	
Exceptional costs in 2009-10	(2.6)	(2.6)	1
Recurring Cash Controllable Costs 2009-10	**56.0**	**56.0**	
Efficiency Savings	(8.0)	(8.0)	2
Cash Costs	**48.0**	**48.0**	
Proposed Increases in Costs			
IT Running Costs	1.0	0.5	3
Real Price	3.0	0.4	4
Volume and Mix	3.0	1.3	5
Workforce Growth	4.0	2.0	6
Recruitment and Training	6.1	3.0	6
Total Proposed Increases in Costs	17.1	7.2	
Forecast / Proposed Allowance	**65.1**	**55.2**	

1.11. The proposed allowance represents a 15.2% reduction from NGET's forecast. The reasons for this are:

1. Exceptional Costs – these relate to exceptional or one off costs that are not part of the recurring costs of running the System Operator business including expenditure associated with reorganisation.
2. We accept the efficiency savings proposed by NGET and NGG.
3. IT running costs - we have accepted half of this increase although more detail is required to fully assess this. We have also allowed some of the increase in SO expenditure as there is more requirement for IT systems here than in TO.
4. We accept the need for some real price increases, although not for salaries as we believe increases should not be above the rate of inflation.
5. Volume and mix - this relates to a variety of upward cost pleasures. WE have accepted some in line with the approach for NGET TO but further justification is required.
6. We accept there is a need to renew the workforce as people retire and the network expands. Our proposed allowance recognises the lead time to recruit and train appropriate staff, although we need further information to assess this issue more comprehensively.

Table 33 NGG Internal SO Opex Allowance

£m	Forecast 2012-13	Proposed Allowances	Notes
Controllable Opex			
2009-10 Actual expenditure	28.7	28.7	
Exceptional costs in 2009-10	(1.7)	(1.7)	1
Recurring Cash Controllable Costs 2009-10	**27.0**	**27.0**	
Efficiency Savings	(3.0)	(3.0)	2
Cash Costs	**24.0**	**24.0**	
Proposed Increases in Costs			
IT Running Costs	4.0	2.0	3
Real Price	1.0	0.3	4
Supply and demand Volatility	1.0		5
Workforce Growth etc	2.0	1.0	6
Other	2.1	1.0	7
Total Proposed Increases in Costs	10.1	4.3	
Forecast / Proposed Allowance	**34.1**	**28.3**	

1.12. The proposed allowance represents a 17.0% reduction from NGG's forecast. The reasons for this are:

1. Exceptional Costs – these relate to exceptional or one off costs that are not part of the recurring costs of running the System Operator business including expenditure associated with reorganisation.
2. We accept the efficiency savings proposed by NGG as being reasonable and achievable.
3. IT running costs – we have accepted half of this increase although more detail to fully assess this is required.
4. We accept the need for some real price increases, although not for salaries as increases should not be above the rate of inflation.
5. Supply and demand volatility - this relates to increased modelling for changes in gas supply and demand patterns. We do not believe there is a need for such an increase in the rollover year. This is in line with not accepting the case for network flex capital expenditure.
6. We accept there is a need to renew the workforce as people retire and the network expands. The allowance recognised the lead time to recruit and train appropriate staff, although we need further information to assess this issue more comprehensively.
7. Other – this has been reduced in line with other opex items.

Non-controllable costs

1.13. We have included £4.8m of xoserve opex costs for the gas SO 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

1.14. In chapter four we explain how pension allowances are set for the rollover year. Our approach to the SO pension costs is consistent with this.

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

Table 34 SO Pension allowances for 2012-13

	Allowances					
2009-10 prices £m	**Deficit recovery**	**Ongoing pension costs**	**Admin costs**	**PPF levy**	**True-up**	**Total**
NGET	9.1	6.2	0.4	0.3	0.7	16.7
NGG	0.2	4.0	0.9	0.0	(1.3)	3.8
Total	9.2	10.2	1.3	0.3	(0.6)	20.4

Table 35 SO regulatory fractions for 2012-13

	Regulatory fraction
NGET	23.0%
NGG	0.4%

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

1.16. 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.

1.17. 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 36 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	5.3	0.7	1.1
NGG	(9.8)	(1.3)	0.0
Total	(4.5)	(0.6)	1.1

Appendix 7 – Summary of allowed revenues

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

	NGET_TO	SHETL	SPTL	NGGT_TO
	2012/13	2012/13	2012/13	2012/13
	£m 09/10	£m 09/10	£m 09/10	£m 09/10
Regulatory Asset Value (RAV)				
Opening asset value	**8,092.6**	**566.4**	**1,062.1**	**4,040.2**
Total RAV additions	1,407.8	442.8	323.4	46.2
Depreciation	(536.0)	(34.9)	(78.0)	(134.6)
Closing asset value	**8,964.3**	**974.3**	**1,307.6**	**3,951.8**
Allowed costs				
Fast pot expenditure	198.4	7.1	17.9	62.8
Pension costs	51.3	3.3	2.8	54.5
Equity issuance costs	-	3.1	(3.2)	-
Depreciation	536.0	34.9	78.0	134.6
Tax allowance	90.7	1.3	11.4	85.8
Return	400.1	35.8	55.5	188.3
Non-controllable operating costs	96.5	8.9	24.1	113.6
Total costs	**1,373.1**	**94.4**	**186.6**	**639.5**
Price Control Revenue				
Total of Allowed Costs	1,256.1	90.9	178.3	637.4
Capex & other Incentives	57.0	0.6	1.4	(1.2)
TIRG	13.0	24.3	16.0	-
Base price control revenue	1,326.1	115.9	195.7	636.2
Excluded revenues	116.9	3.5	8.2	2.1
Total revenue	**1,443.1**	**119.4**	**203.9**	**638.3**

Price Control Revenue for 11/12 as forecast	1,356.6	90.8	211.0	567.6
Annual change as % starting from TPCR4	10%	99%	8%	14%
Annual change as % starting from forecast	6%	31%	-3%	12%

Appendix 8 - Feedback Questionnaire

1.18. 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?

1.19. Please send your comments to:

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