TPCR4 rollover policy update and initial analysis of business plans

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Target audience: Consumers and their representatives, electricity and gas transmission licensees, electricity and gas distribution licensees, generators, shippers, suppliers, investors, environmental organisations, government policy makers and other interested parties

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 March 2010 we consulted on the scope and objectives for the TPCR4 rollover. In June 2010, we published our decision on a number of high-level items and consulted further on the detailed scope of the TPCR4 rollover.

Informed by the responses to the June Consultation and the licensees business plans this document presents our preferred approach on the scope of the TPCR4 rollover, on which we seek stakeholders' views. We also set out a summary of the transmission owners' (TOs) expenditure forecasts for 2012-13 along with our consultants' views on these.

Our preferred approach has been guided by the need to strike a balance between our primary duty to protect consumers and the need for a review proportionate to a one-year control.

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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 have 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.

We aim to be proportionate when 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 implementation of RIIO-T1.

Associated documents

Supporting analysis

- 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
- Technical support for TPCR4 rollover: Assessment of load an non-load related capex (KEMA), 8 April 2011:
  NGG:
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Rollover/Documents1/BPNGG.pdf
  NGET:
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Rollover/Documents1/BPNGET.pdf
  SP:
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Rollover/Documents1/BPSPT.pdf
  SHETL:
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4Rollover/Documents1/BPSHETL.pdf

Previous price control documents
Rollover

- Transmission Price Control 4 - Rollover (2012-13) Scope Decision and Consultation, 30 June 2010 (Ref No. 8/10) http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

RIIO-T1

- Decision on strategy for the next transmission price control - RIIO-T1 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Other supporting documents

- Transmission Investment Incentives: Decision on requests for funding from 2011/12 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisioncosts.pdf
- 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

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

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Summary

The existing transmission price control, transmission price control review 4 (TPCR4), covers the five-year 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 price 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".

In March 2010 we consulted on the high-level scope and objectives of the TPCR4 rollover. In addition to our principal objective to protect the interests of existing and future consumers, and being consistent with our wider statutory duties, we consider it important that the TPCR4 rollover is proportionate to a one-year control and where possible that the regulatory burden is kept to a minimum. For this reason, and to facilitate a simpler transition to RIIO-T1, we stated our intention not to introduce any new policy for the TPCR4 rollover.

Whilst not as complex as a full price control, we need to make a number of decisions on how existing policy should adapt for 2012-13. We are committed to take decisions that represent best value for consumers. In June 2010 we communicated our high level approach in a number of policy areas and consulted on the detailed policy implementation. Following an assessment of the responses to the June consultation and inspection of the licensees' business plans we present our preferred approach on the scope of the TPCR4 rollover for stakeholder's comments.

In relation to finance and cost assessment we are consulting on:

- keeping the allowed cost of equity unchanged and revising the allowed cost of debt
- deferring an ex-post efficiency assessment until the end of TPCR4. We intend to 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. Logged up costs will not enter the RAV until RIIO-T1.

In relation to policy we intend:

- on not introducing any new revenue drivers for the TPCR4 rollover year
- to maintain the current SF6 incentive for electricity transmission owners (TOs) and to set SF6 leakage targets on the basis of past performance
- to leave the categories of costs that are passed through to consumers unaltered
- on not allowing any costs to log up during the TPCR4 rollover year
- to maintain a 25% sharing factor for capital expenditure (capex) over / under-spend for both TOs and system operators (SOs); and to make a provisional revenue adjustment at the end of TPCR4 in line with the capex incentive for NGG, SHETL and SP; defer this adjustment for NGET until the end of the TPCR4 rollover period.
- to maintain the current 40% sharing factor for gas SO operational expenditure (opex) under / over-spend, and continue to align the electricity SO opex incentive with the mechanism for incentivising SO external costs
- for the gas capex investment incentives: Pre-2007 regime – to make TO/SO RAV adjustments in March 2012 and March 2017. Post-2007 regime – to keep indexation factors for materials and construction at same values.
- to keep the £9.5m downward adjustment to the TO allowed revenue for Milford Haven, but review the figure
- to keep default lead times at current lengths. Extend the permit scheme to 2012-13

Each licensee has submitted a forecast business plan questionnaire (FBPQ) detailing their proposed expenditure for the year. These FBPQs indicate that the licensees are forecasting a significant increase in costs compared with existing allowances. In collaboration with technical consultants we have assessed these forecasts, and held meetings with the licensees to gain further insight, where required. This work is at an early stage and we present our initial views for stakeholder comment in this document.

1. Introduction

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 TPCR4 rollover 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 present:

- our preferred approach on the policy and financial scope of the TPCR4 rollover
- a summary of the transmission owners' (TOs) expenditure forecasts for the TPCR4 rollover year along with our consultants' views on these forecasts

1.4. Stakeholders' views have informed our provisional approach. This includes through our consultation process, meetings with the TOs and presentations to large, medium and small user groups. Appendix 4 provides a summary of the responses to our June 2010 consultation.

Guiding principles

1.5. The March 2010 consultation documents set out the objectives of the TPCR4 rollover. Our objectives for the review are[1]:

- To protect the interests of existing and future consumers[2]
- 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

1.6. In October 2009, we consulted on the timetable for RIIO-T1, and hence the possible need to TPCR4 rollover 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] A full description of the guiding principles can be found in Appendix 2.
[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.

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

1.8. In June 2010, we communicated our high-level decision on the scope of the TPCR4 rollover. This is presented in the table below.

Table 1: Summary of scope decisions in June 2010 document

Aspect	Approach and scope for TPCR4 rollover
Capex	▪ We are deferring a full assessment of historical capex until RIIO-T1. We will make adjustments to the RIIO-T1 settlement and the opening regulated asset value (RAV) for any capex found to be inefficient or ineligible. ▪ We will focus on forecast capex, investigating historical capex only where needed to support scrutiny of forecasts. ▪ Capex incurred during TPCR4 (excluding logged-up costs) will enter a provisional RAV on an indicative basis for the TPCR4 rollover. ▪ "Logged-up" costs will continue to be logged up, with an efficiency assessment and adjustments to the opening RAV taking place at RIIO-T1.
Opex	▪ Opex will be informed by actual expenditure in the first four years of TPCR4 (2007-2011) along with the TOs' opex forecasts. ▪ We will make an adjustment for efficiency on a TO specific basis.
Financial Issues	▪ We will review the allowed return. ▪ Tax: We will update the capital allowance figures and the tax calculation in line with recent legislation. ▪ Pensions: We will adopt the principles established during the recent review of pension costs, initially set out in the most recent electricity distribution prices control (ie DPCR5), wherever possible. ▪ Capitalisation and depreciation: We do not propose to change the treatment adopted in TPCR4. ▪ Calibration: We will construct a financial model and conduct return on regulated equity (RoRE) analysis as per DPCR5.

1.9. We also consulted further in a number of policy areas. Stakeholder's responses to these questions have informed our provisionally preferred approach to the scope of the TPCR4 rollover.

1.10. On 31 October 2010, the licensees submitted their business plans to Ofgem. The business plans set out the TOs' forecasts of their operational and capital expenditure (opex and capex) for the TPCR4 rollover year along with a description of these forecasts.

1.11. In January 2011, we visited each TO (with our consultants KEMA) in order to discuss the business plans in greater detail. These visits provided an opportunity to clarify the TOs' proposals. KEMA has undertaken a review of capital expenditure for both electricity and gas TOs. We have asked them to provide a recommended range of allowances covering load related expenditure (LRE) and non load related expenditure (NLRE). We are publishing their initial reports alongside this document.

1.12. We undertook a similar exercise with PPA Energy in respect of the gas and electricity SO capex. We will publish PPA's initial report later in April 2011.

Structure of document

1.13. The remainder of the document is structured as follows:

- Chapter 2 presents our preferred approach on the policy for the TPCR4 rollover year, including incentives, uncertainty mechanisms and cost allowances.
- Chapter 3 sets out the TOs' and SOs' capex forecasts for 2012-13 compared to existing values in TPCR4. In this chapter we also present our consultants' views and our areas of concern where we believe further work is required.
- Chapter 4 sets out the TOs' and SOs' operating expenditure forecasts for 2012-13. We compare these, set out areas of concern and highlight where we believe more work is required.
- Chapter 5 sets out our preferred approach to the allowed return, tax and pensions.
- Chapter 6 sets out the process that we will follow in arriving at our final price control proposals.

1.14. Appendix 2 provides further context on the price control process and areas of interaction with other regulatory work. Further supplementary information can be found in the other appendices.

2. Policy

This chapter communicates our preferred approach on the policy scope for the TPCR4 rollover year. We seek the views of stakeholder's on our preferred approach.

Questions from this chapter are listed in Appendix 1.

2.1. In March 2010, we consulted on the principles for the TPCR4 rollover. Then in June 2010 we consulted on a number of high-level policy decisions. Informed by the responses to this consultation we present our preferred approach to policy for the TPCR4 rollover year. This chapter contains a number of questions and the views of stakeholders on these issues will inform our initial proposals.

Uncertainty mechanisms

2.2. In setting the allowances for the current price control it was clear that some of the TOs' expenditure could not be projected over a five-year horizon with any degree of certainty, and it would not be appropriate to define an allowance in advance. A number of uncertainty mechanisms were developed and in deciding whether these mechanisms should continue for the TPCR4 rollover year we need to assess whether the uncertainty that existed over a five-year timeframe is present over a single year. Three uncertainty mechanisms were employed at TPCR4. These are summarised in Table 2 and explained below.

Table 2: Uncertainty mechanisms in electricity and gas

Mechanism	Gas	Electricity
Logged-up costs	Quarry and loss development claims[3]	BT 21st century networks[4] plugs[5] (SPTL & SHETL only) Cable tunnelling (NGET only)[6]
Pass-through costs	License fee NTS prescribed rates Independent system cross subsidy Security costs	License fee, network rates adjustment term, Interruptions[7], and additionally NGET are allowed to pass through a number of costs associated with their SO function[8]
Revenue drivers	The allowed revenue automatically increases on receipt of financially backed signals for additional entry and exit capacity	The allowed revenue adjusts based on: Connected generation (all TOs) upgrades to Anglo-Scottish boundary (NGET only), and flows across boundaries within England and Wales (NGET only)

[3] These relate to compensation paid by NGG for certain loss of types of land use, mining, etc.
[4] Costs associated with telcom services necessary as a result of BTs transition to "packet" technology
[5] Scottish licensees 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).
[6] cable tunnelling around the London area up to a value of £60m (in 2004/05 prices)
[7] the amount paid out by the licensee in relation to interruptions in their license area
[8] 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 distributers for use of system by offshore generation connected via embedded generation; **EU Inter TSO Scheme:** costs of participating in such Ofgem approved schemes

Logged-up costs

2.3. As part of TPCR4 we allowed the licensees to log up the costs in a specific number of categories where there was uncertainty in forecasting the expenditure for the whole price control period. These categories are set out in Table 2. This approach meant we did not have to project these costs in advance. But to protect consumers from inefficient spend we do not allow the licensees to claim revenue for this expenditure until we have undertaken a full efficiency assessment at the end of the price control period.

2.4. In our June 2010 publication we communicated our decision not to carry out an efficiency review of historical investment until RIIO-T1. This includes an assessment of logged-up costs, as such we proposed to defer these costs entering the RAV until 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.

2.5. Based on our assessment of the TOs' business plans we consider that there is limited uncertainty in forecasting the costs in each of these logged-up categories for a one-year rollover. We therefore propose not to allow any logging-up of costs during the TPCR4 rollover year. Instead we will make provisions for these cost categories in the base allowance for 2012-13.

Question 1 : Do stakeholders agree with our view that it is not necessary to allow any cost categories to log-up during the TPCR4 rollover year, but for forecasts to be included in the base allowances?

Pass-through costs

2.6. In discharging their duties the TOs incur a number of costs which they cannot control directly. We currently allow the TOs to pass through a defined set of such cost categories to consumers. These are set out in Table 2.

2.7. We consider these costs are still outside the control of the TOs. As such we consider it to be appropriate for all of these cost categories to continue to be passed through to consumers during the TPCR4 rollover year.

Question 2: Do stakeholders agree that it is appropriate to continue to pass through the current set of pass-through costs to consumers?

Revenue drivers

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

Gas revenue drivers

Capacity investment incentive

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

Pre-2007 signals

2.10. In June 2003 we set out the regime to remunerate additional entry capacity (revenue drivers were not in place for exit capacity at that time).[9] NGG was remunerated on its SO and TO sides for specific periods linked to the delivery date of additional capacity. Adjustments between TO and SO were linked to the start and end of price control periods.

2.11. In our June 2010 document we said that capex incurred during TPCR4 will enter the TO RAV on a provisional basis at the start of 2012-13. We will do a full efficiency assessment at RIIO-T1 and adjust the RAV accordingly (see Chapter 5).

2.12. We set out an update on our thinking regarding this policy below. As the TO RAV adjustments are linked to the start of price control periods there may be uncertainty as to when these take place given the extension of TPCR4 by one year and the use of eight year price controls under the RIIO framework. Our provisionally preferred approach is for the initial TO / SO adjustment to take place on 31 March 2012 on a provisional basis, and the remaining adjustment to take place on 31 March 2017. This honours the intention of the regime which was introduced at a time when five-year price controls were in place.

Question 3: Do stakeholders agree that it is appropriate to make TO/SO adjustments in response to the gas revenue drivers on 31 March 2012 and 31 March 2017?

2.13. Respondents also raised the issue of remuneration of the signal for additional capacity at Fleetwood. This is addressed below in the section 'other policy areas'.

Post-2007 signals

2.14. At TPCR4 we revised the remuneration regime for additional capacity that would apply to signals received after April 2007. This approach was common for entry and exit. For investment signals after 2007, NGG is remunerated on its SO and TO sides for specific time periods, but this is no longer linked to the timing of price controls. The revenue driver amounts are uplifted both for general inflation and for a combined index for materials and construction costs. We describe this regime in greater detail in Appendix 5.

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

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

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

2.17. **We confirm our previous view, which is to maintain this regime in its current form, keep the values of the revenue driver figures in the licence for any incremental capacity signals received in the TPCR4 rollover year. Our preferred approach is to keep the indexation factors for materials and construction at the same values**. We consider that it would be disproportionate to redesign the revenue driver regime, reset revenue driver values and revise the indexation factor for materials and construction for a one-year period. The materials and cost construction cost indexation factors are set for '2011-12 and later' in the gas transporter licence, therefore there is no issue around these factors being redundant in the TPCR4 rollover year.

Milford Haven

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

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

2.19. Since TPCR4, NGG has notified us of further overspend in addition to the £792m (2004/5 prices)[10] outlined above.

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

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

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

2.22. **Our provisionally preferred approach is to keep the £9.5m (2004/5 prices) downward adjustment to the TO allowed revenue but review the figure**. This is because NGG will continue to be remunerated on the SO side in 2012-13, whilst it will continue to be fully remunerated on the TO side.

Question 4: Do stakeholders agree that it is appropriate to keep the £9.5m (2004/5 prices) downward adjustment to the TO allowed revenue but review the figure?

Electricity revenue drivers

2.23. We introduced a suite of revenue drivers for the electricity licensees as part of TPCR4. These adjust the TO's allowances for capex automatically in response to changing patterns of generation and demand for network capacity. We made such provisions for all licensees with respect to new generation connecting to the system. We made further provisions to adjust NGET's funding for boundary reinforcements within their network in response to signals from generators and DNOs (distribution network operators). NGET's allowance for capex flexes further to reflect any difference between the baseline and delivered capacity on the Anglo – Scottish Boundary. All of these revenue drivers essentially work in the same way, adjusting the licensees allowed revenue by multiplying a unit cost allowance (UCA) - that was set as part of the last price control - by the deviation from the baseline that was assumed in setting the baseline capex allowance. The timing of the revenue flows associated with this increased allowance varies between the licensees.

2.24. In our June consultation we communicated that we would defer our decision on whether revenue drivers should form part of the settlement for the TPCR4 rollover year until we had assessed the licensees business plans and solicited stakeholders' views. In response to the consultation two of the TOs were supportive of the use of the revenue drivers for the TPCR4 rollover period, although one noted the need to update the UCA and baselines. The third licensee suggested that the revenue drivers may not be required for the TPCR4 rollover year as there is not the same uncertainty in a one-year price control.

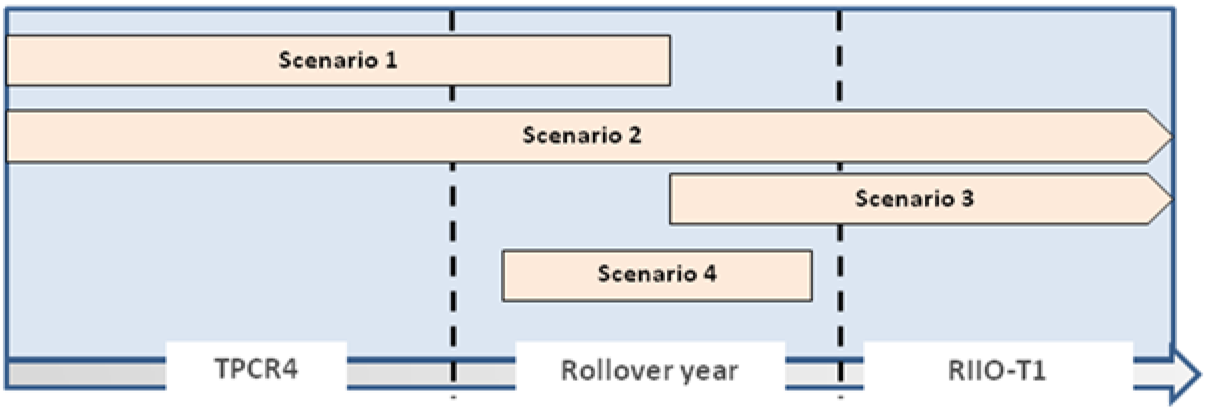
2.25. Having assessed the TO's business plans we are of the view that there is a degree of uncertainty over their proposed expenditure for the TPCR4 rollover year. Some of the proposed spend on connecting new generation relates to projects that are yet to receive full consents, and further doubts exist over the deliverability of elements of the capex programme. This level of uncertainty is, however, significantly less than existed when setting the current price control. In light of this decreased uncertainty and the significant amount of work that would be required, both regulatory and on the part of the licensees, we propose not to develop any new revenue drivers for the TPCR4 rollover year.

Question 5: Do stakeholders agree with our view that no new electricity transmission revenue driver need be introduced for the TPCR4 rollover year?

2.26. According to the TOs business plans, at the end of the current price control there will be a significant number of projects underway, which were not included in the projections on which the base capex allowance was calculated. 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 arrangement were to continue. Unless we make special provision for these projects they are likely to result in the TOs overspending in the current price control (as the capex allowance will not have increased to account for this additional spend) and under-spending in the TPCR4 rollover year (since their capex allowance will increase in line with the delivered output but some expenditure will already have been incurred). We refer to these projects as Work in Progress (WIP). They will enter the provisional RAV at the start of the TPCR4 rollover year and be excluded from the calculation of the capex incentive described in the next section. This approach means we will implicitly grant an allowance equal to the actual expenditure for these projects at the end of the current price control.

2.27. The figure below illustrates the price controls within which projects requiring funding during the TPCR4 rollover year could begin and end. We propose to base the methodology we use for allowing capex for these projects on which of the 4 scenarios the projects fit in to.

Figure 1: Scenarios for revenue driver projects starting or ending in the TPCR4 rollover year



2.28. **Scenarios 1 and 2** relate to projects that will have already received a capex allowance for WIP implicitly as described above.

2.29. **Scenario 1:** Where the project starts in the current price control and is projected to end in the rollover year the capex allowance for the TPCR4 rollover year will be informed by the licensees FBPQ submission. Prior to calculating the capex incentive at the end of the TPCR4 rollover period we will adjust this capex allowance to allow for funding already made in TPCR4 through WIP and re-calculate the allowance as follows:

Baseline allowance adjustment = efficient capex – WIP

2.30. In the formula above we will calculate the efficient capex in line with the TPCR4 revenue drivers. 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.

2.31. **Scenario 2:** Where a project finishes in RIIO-T1, and funding has implicitly been allowed in TPCR4 through our approach to WIP, we intend to set a capex allowance for the TPCR4 rollover year informed by the funding requested by the TO in their FBPQ. As part of the RIIO price control we will decide whether expenditure on these projects during the TPCR4 rollover year should be subject to the capex incentive. In allowing funding for the project during RIIO-T1 we will take into consideration the allowance granted through the project's treatment as WIP at TPCR4 and the allowance granted in the TPCR4 rollover year. The methodology used to derive the funding for these projects into the RIIO-T1 price control will be developed as part of the RIIO-T1 price control.

2.32. **Scenarios 3 & 4:** Where projects start in the TPCR4 rollover year we consider it would not be appropriate to allow funding in line with the revenue driver mechanisms and unit cost allowances defined when developing TPCR4. Instead we intend to incorporate an allowance for these projects into the base capex for the TPCR4 rollover year. Where these projects continue into the RIIO price control we will take into consideration the allowances made for these projects in the TPCR4 rollover year when developing the capex allowances for the RIIO-T1 price control.

Question 6: Do stakeholders agree with our start and finish date based approach to determining capex allowances for TPCR4 revenue driver projects during the TPCR4 rollover year?

Incentives

2.33. The licensees are subject to a number of incentives to encourage them to act in a way that benefits consumers. These incentives can be broadly categorised as efficiency incentives, reliability incentives, environmental incentives and incentives for timely delivery.

2.34. In our March 2010 document, we consulted on our view that no new regulatory incentives should be introduced for the TPCR4 rollover year, and that the existing targets should be rolled-forward with the exception of any adjustments to address areas where there has been significant misalignment between TPCR4 baselines and outturn values. We noted that a number of polices need to be modified for the TPCR4 rollover year. Respondents in general agreed with this approach.

2.35. This section describes these incentives in detail. Table 3 illustrates the use of these incentives across the two sectors.

Table 3: Gas and electricity incentives

Incentive category	Gas	Electricity
Efficiency	Capex incentive System operator expenditure	Capex incentive System operator expenditure
Reliability	Incentives dealing with these issues are not in the scope of the TPCR4 rollover[11]	Reliability incentive
Environmental		SF6 incentive
Timely delivery	Permit scheme and delivery incentives	Incentive for timely delivery not the scope of TPCR4 rollover[12]

[11] Reliability of the NTS can be considered as being captured in the entry capacity operational buy-back incentive, which was recently reviewed in 2009. NGG's environmental incentive is encompassed in the SO external incentives, which is outside the scope of the TPCR4 rollover.
[12] We are currently engaging with the industry on whether regulatory and/or commercial changes may be appropriate to facilitate timely connections as part of project TransmiT
http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110322_TransmiT_Connections_Consultation_FINAL.pdf

Efficiency Incentives

2.36. **Capex incentive (TOs):** At the start of TPCR4, to incentivise the licensees to incur capex efficiently, we established a "capex incentive" for the gas and electricity transmission licensees through which the licensees would 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. We consider it appropriate to continue to incentivise efficient capex through this mechanism into the TPCR4 rollover year and, in line with the principles of the TPCR4 rollover intend to maintain the current 25% sharing factor.

Question 7: Do stakeholders agree with our proposal to maintain the capex incentive in the TPCR4 rollover year and keep the sharing factor unchanged at 25%?

2.37. For both gas and electricity licensees, in order to calculate the capex incentive we will need to project the licensees expenditure over the final year of the price control, this introduces a degree of uncertainty. Furthermore, as we discussed earlier we will not have undertaken a full efficiency review until the end of the price control and any calculation of the capex incentive would have to be on a provisional basis.

2.38. **Capex Incentive Gas –** For NGG we plan to calculate the capex incentive on a provisional basis and make adjustments as part of the RIIO price control to reflect actual expenditure in 2011-12 and any expenditure that may have been disqualified following an ex-post efficiency review.

2.39. As discussed previously, there was £75m (in 2004/5 prices) of capex related to Milford Haven which we deferred for review at TPCR4. In our final proposals for TPCR4[13] we stated that this will not be subject to the capex incentive. Therefore, in relation to Milford Haven, the capex related with the LRE allowance of £280m (2004/5 prices) and the overspend above the £792m (2004/5 prices) will be subject to the capex incentive.

2.40. **Capex Incentive – electricity –**The calculation of the capex incentive for the electricity licensees is made more uncertain due to the existence of the revenue drivers. These introduce two additional areas of uncertainty:

1. **Adjustment to capex allowance –** The revenue drivers will flex the capex allowance to reflect differences between actual outturns (eg volumes of connected generation), and the projections used as a baseline for the base capex allowance. For all licensees there is a small degree of uncertainty around the amount of generation that will connect during the remainder of the price control, and the corresponding adjustment that will be required to the capex incentive. There is further uncertainty around the degree to which NGET's capex allowance will change. This will also flex in response to the need to increase the network capacity across boundaries, both within NGET's system and with Scotland. The magnitude of the revenue driver adjustment is based on a large number of variables including Generators Transmission Entry Capacity (TEC) and projected demand from Distribution Network Operators (DNOs).
2. **WIP** – As described earlier WIP relates to expenditure on projects that were not included in the baseline capex and would, if completed during TPCR4, have resulted in an adjustment via the revenue drivers to the base capex allowance. It would not

[13] See 'Transmission Price Control Review: Final Proposals' published on 4 December 2006 with reference number 206/06 on our website www.ofgem.gov.uk.

be logical to regard expenditure on these projects as an overspend. As such, they are deducted from the actual expenditure in advance of calculating the capex incentive, the value of this adjustment is to be determined by the Authority. Deriving a provisional value for this adjustment for the Scottish licensees is relatively simple as there are only a small number of projects relating to connecting new generation that could be classified as WIP and these can be clearly identified. Given the wider range of revenue drivers in existence for NGET, identifying a project as WIP requires a full understanding of what the project will ultimately deliver, and an assessment as to whether this is above and beyond what was covered in the baseline capex allowance. NGET have presented a list of 135 projects that they regard as WIP, and we will need to undertake a robust analysis of these projects before calculating their capex incentive.

2.41. As mentioned earlier NGET's allowed capex will flex based on reinforcements required to the capacity of boundaries between zones in response to fluctuations in generation and demand. Before making any adjustment to NGETs allowed capex to reflect these revenue drivers we must also assess the impact of 2 policy developments that come into effect after 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.
- TO Incentives – The TO 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.

2.42. We do not consider it appropriate to grant an increase in NGETs capex allowance for work that they either did not have to complete as a result or Connect and Manage or for work that was funded under the TO Incentives mechanism. We will consider carefully the impacts of these policy developments on the need for NGET to undertake wider works before making an adjustment to their allowed revenue in line with the capex incentive.

2.43. We propose to make an adjustment to SHETL and SPTL's revenue during the TPCR4 rollover year on a provisional basis, and make an adjustment as part of RIIO-T1 based on actual outturns during the final year of TPCR4.

2.44. For NGET, reflecting the greatly increased levels of uncertainty, we propose to defer calculation of the capex incentive until the completion of the price control. As part of this process we will need to assess the actual value of expenditure that should be treated as WIP. We will also assess the impact of Connect and Manage and TO Incentives in advance of making any revenue driver adjustment. We will ensure this deferral is carried out on a NPV neutral basis.

Question 8: Do stakeholders agree with our proposal to allow the capex incentive payment on a provisional basis for SPTL, SHETL and NGG, making any further adjustments as part of the RIIO price control?

Question 9: Do stakeholders agree with our proposal to defer payment of NGETs capex incentive until we have performed a detailed assessment of projects regarded as WIP, and fully considered the impact of connect and manage and TO incentives?

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

2.46. The costs incurred undertaking these activities can be considered as internal or external. External costs are the costs the system operator is required to pay to other parties in the industry in discharging their duties. For example in their role as the electricity SO National Grid have to buy and sell electricity in the balancing market to ensure supply and demand are matched. Setting allowances and incentivising efficiency for SO external costs is not part of the price control process.

2.47. Internal costs relate to the costs incurred internally undertaking their duties as system operator (eg staff and IT costs). As with the transmission owners this expenditure can be thought of as capex and opex. The licensees submitted their projected expenditure against both of these categories in their FBPQs last October, and our early assessment of these submissions can be found in chapters 4 and 5 of this document.

2.48. Last June we stated our intention to 'maintain the structure of the internal SO incentive schemes as much as possible, updating the parameters to ensure alignment with the objectives and incentive structure of the external SO incentive scheme'.

2.49. As with the TOs, the SOs are incentivised to incur capex efficiently via a Capex incentive defining the percentage of any over / under-spend against their capex allowance by which National Grid in their role as system operator within the respective sector will lose / gain. This is currently set at ±25% for both gas and electricity SOs . To ensure capex is allocated efficiently between National Grid's TO and SO function we intend to maintain the alignment with the TO capex incentive and set the sharing factor to ±25% for the TPCR4 rollover year.

2.50. As with the transmission companies calculation of the revenue adjustment to reflect performance against the capex incentive throughout TPCR4 is due to occur in April 2012. We consider the complexity in calculating the capex incentive adjustment to be similar to that described earlier for NGG since there are no revenue driver adjustments to be made. We propose to apply the capex incentive and make a revenue adjustment in 2012-13 to National Grid in their role as SO within both gas and electricity transmission.

Question 10: Do stakeholders agree with our proposal to maintain the SO capex incentive for National Grid in their role as gas and electricity SO for the TPCR4 rollover year and keep the sharing factor set to ±25%? Do stakeholders also agree with our proposed approach to make a provisional revenue adjustment in 2012-13 in line with the SO capex incentive, and true this up as part of the TPCR4 rollover?

2.51. We also incentivise efficient opex through an opex incentive. This works in the same way as the capex incentive in that the licensee bears a percentage of the benefit / cost of any under / over spend. As with the capex incentive the opex incentive for National Grid for their internal gas SO functions is symmetrical and currently set to

±40%. We consider it would be proportional with a one-year rollover to maintain this incentive and maintain the ±40% sharing factor.

2.52. For electricity, throughout TPCR4 we have aligned the sharing factor for internal SO opex with the sharing factors for the external SO incentive scheme (costs paid to third parties by the system operator). This alignment was to ensure that the SO was incentivised to efficiently allocate operation expenditure between internal and external activities. We propose to maintain this alignment and will set the opex sharing factor once the sharing factor for external costs has been agreed.

Question 11: Do stakeholders agree with our proposal to maintain the gas internal SO opex sharing factor at ±40%, and align the electricity SO internal sharing factor with that used for incentivising external costs?

Reliability Incentives

2.53. **Electricity:** The TOs are incentivised to maintain a reliable system. Each of the licensees is set a target for reliability, and are rewarded for beating this target and penalised if they under-perform. The target is in the form of a range, and if their performance is within this range they are neither penalised nor rewarded. National Grid's reliability is measured by the amount of un-served energy (MWh), whilst SP and SHETL's reliability is determined by the number of outages experienced on their system. The rewards and penalties are capped for the licensees a % of their total revenue for the year. Table 4 below details the parameters of the reliability incentives in the final year of the current price control

Table 4: Existing reliability targets for electricity TOs

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

2.54. We consider it would be proportionate with a one year rollover to leave the reliability incentive unchanged, and use the parameters from 2011-12 in the TPCR4 rollover year.

Question 12: Do stakeholders agree with our proposed approach to leave the electricity reliability incentive scheme and its parameters unchanged for the TPCR4 rollover year?

2.55. **Gas:** Reliability of the NTS can be considered as being captured in the entry capacity operational buy-back incentive. If NGG is unable physically to deliver existing capacity it has previously sold it may have to buy this capacity back from users. NGG is incentivised to reduce its costs of buying back capacity. We recently reviewed this incentive in 2009[14]. Therefore, to minimise regulatory burden, we do not consider it appropriate to review this as part of the TPCR4 rollover.

Environmental Incentive

2.56. **Electricity - SF6 Incentive:** 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[15] that of carbon dioxide (CO2). SF6 emissions are not covered by the European Union Emissions Trading Scheme (EU ETS). To incentivise the TOs to reduce their emissions of this gas at TPCR4 we developed a financial incentive.

2.57. The introduction of the scheme required the establishment of consistent methods of measurement and reporting, which meant the scheme was not simultaneously introduced for all TOs. The scheme was applied to NGET from 2007-08 and to SPT from 2008-09. The scheme has not yet been introduced for SHETL.

2.58. We set annual target leakage rates for both NGET and SPT, based upon the percentage leakage of SF6 from the total volume of SF6 used as insulation. The incentive allows for 0.02% of regulated revenue for actual leakage rates lower than the target.

2.59. As shown in Table 5, NGET have outperformed by on average 0.38% per annum whilst SPTL outperformed by 0.02% beyond the target each year.

Table 5: SF6 Leakage Performance

SF6 leakage (as percentage of total volume)		2007-08	2008-09	2009-10
NGET	Target	3.0%	2.75%	2.50%
	Actual	2.92%	2.12%	2.07%
	Over/(under) performance	0.08%	0.63%	0.43%
SPTL	Target	n/a	2.0%	1.83%
	Actual	2.40%	1.98%	1.81%
	Over/(under) performance	n/a	0.02%	0.02%

2.60. The target leakage rates continue to reduce for the remainder of the control period, with targets in place of 2.0% and 1.5% for 2011-12 for NGET and SPTL respectively. Although the scheme has not been introduced for SHETL, progress has been made on the measurement of SF6 leakage.

2.61. In our June 2010 document we sought views on whether the SF6 scheme should continue into the TPCR4 rollover year and, if so, whether the structure should be modified. Respondents were generally supportive of this incentive. Though one suggested the decline in the target rate should be slowed for the TPCR4 rollover year.

2.62. Given this is a one-year rollover, we do not consider that it would be proportionate to introduce significant changes to the existing scheme. We propose to continue with

14 See 'Review of entry capacity operational buy-back incentive and default incremental entry capacity lead time' published on 26 November 2009 (with Ref No 142/09) on the Ofgem website www.ofgem.gov.uk.
15 As measured by the 1995 Intergovernmental Panel on Climate Change (IPCC) Global Warming Potential (GWP) values
http://www.decc.gov.uk/en/content/cms/statistics/climate_change/gg_emissions/intro/intro.aspx

the general approach taken in TPCR4. There are two key aspects to the scheme we are reviewing. These are target leakage rates and available reward/payment.

2.63. We consider it would be appropriate to continue to reduce the target. As such, we propose setting a target based on performance to date in TPCR4. On average SPTL and NGET reduced their SF6 emissions by 17.8% per annum during TPCR4 to date. Applying this historical improvement rate to the 2011-12 target would suggest target for 2012-13 of 1.64% and 1.23% for NGET and SPTL. During TPCR4 the level of reward available for beating the targets was set at 0.2% of regulated revenue. This simple approach sets out a clear reward for TOs if they manage to reduce leakage rates beyond the targets set and maintaining it at TPCR4 levels is a proportionate response.

2.64. Our provisionally preferred approach is to continue with the current approach to SF6 incentives with targets set based on performance in TPCR4 (ie 1.64% and 1.23% for NGET and SPTL respectively) and rewards kept at 0.2% of regulated revenue. If SHETL demonstrate a robust methodology for measuring SF6 leakage, and sufficient historical data we will consider whether it is appropriate to set an SF6 leakage reduction target for the TPCR4 rollover year.

Question 13: Do stakeholders agree with our provisionally preferred approach to continuing to incentivise a reduction in the leakage rate of SF6 gas, updating the target leakage rates to reflect performance during TPCR4?

2.65. **Gas Incentives:** NGG, as part of its SO activities is incentivised to reduce its venting of natural gas. This is captured in the external SO incentives, which are outside of the scope of the TPCR4 rollover.

Incentives for timely delivery

Default investment lead times

2.66. NGG's licence sets out the default investment lead times for the provision of additional entry and exit capacity. The default lead time for entry is 42 months and for exit is 36 months. NGG is incentivised to deliver incremental capacity ahead of these lead times via the permit scheme (see section under next heading).

2.67. In our June 2010 document we sought views on NGG's incentives to deliver investment in a timely manner. Most respondents were in favour of continuing such incentives for timely delivery of capacity. One TO noted that the Planning Act 2008 may impact on the default entry lead times.

2.68. **Our provisionally preferred approach is to maintain the default investment lead times at their current lengths**. We consider that it would be disproportionate to revisit the investment lead times for a one-year period. Also in our decision on the review of the entry capacity operational buy-back incentive and default incremental entry capacity lead time November 2009[16] we noted that we would defer any review of the default incremental entry capacity lead time until the next full price control period ie RIIO-T1.

[16] See 'Review of entry capacity operational buy-back incentive and default incremental entry capacity lead time' published on 26 November 2009 with reference number 142/09, on the Ofgem website www.ofgem.gov.uk.

Question 14: Do stakeholders agree that it would be appropriate to maintain the default investment lead times for NGG at their current length?

Permit scheme

2.69. NGG is incentivised to deliver capacity ahead of the default investment lead times via the permit scheme. This was introduced at TPCR4 and works as follows. NGG was given an initial allocation of entry and exit permits at TPCR4. It can earn more permits by offering (and users taking up this offer) to deliver incremental capacity ahead of the default lead time. It uses up the permits if it offers (and users take up this offer) to defer deliver incremental capacity beyond the default lead time. Each permit held by NGG on 31 March 2012 provides it with a fixed amount of revenue which will be provided to NGG in 2012-13. The amount that can be earned from the scheme is capped at £36 million and £3 million for entry and exit permits respectively.

2.70. In our June 2010 document we sought views on NGG's incentives to deliver investment in a timely manner. Most respondents were in favour of continuing such incentives for timely delivery of capacity. Though one TO indicated that it wanted to discuss the impact of the Planning Act 2008 on the permit scheme as it considered this may increase delivery times.

2.71. Our provisionally preferred approach is that NGG receives the incentive payout in 2012-13 and that the permit scheme be extended for one year**.** We consider this is proportionate to a one-year control. We recommend that the parameters for the permit scheme for 2012-13 are based on the existing scheme (using a pro-rata basis). We have yet to see evidence of the impact of the Planning Act 2008 and for reasons of proportionality would not seek to review this at this stage.

Question 15: Do stakeholders agree that it would be appropriate to give NGG the permit scheme payout in 2012-13 and extend the permit scheme for one year by pro-rating existing parameters?

Other policy areas

Fleetwood

2.72. Fleetwood is a new entry point on the NTS which was signalled at auctions in September 2006. It was scheduled to provide capacity from October 2010 but the storage project behind this entry point was refused planning permission. NGG did not reinforce the NTS in the manner required for providing capacity at Fleetwood as it did not want to invest in an asset it believed would not be required. This decision appears efficient. But, NGG maintains it should be entitled to revenues relating to this project and intends to recover these from all shippers via the commodity charge. In our June 2010 consultation we set out our initial view to address this issue independently of the TPCR4 rollover unless circumstances prevent full consideration of this matter through other routes. One respondent to the June 2010 consultation thought this revenue should be scaled back by Ofgem whilst another seemed to agree with Ofgem's approach to address this through other routes. In February 2011 Ofgem received an Income Adjustment Event (IAE) notice which proposed that NGG only be allowed to collect costs it had incurred in the Fleetwood project and not the full amount of revenue driver entitlement.

We published our consultation on this issue in March 2011[17]. The Authority has until 7 May 2011 in which to make a decision on the income adjustment.

2.73. If NGG keeps the full revenue driver allowances from Fleetwood, then it takes on the associated capacity obligation. In which case, all subsequent network modelling should be based on a network that can accommodate these flows. This may influence our views on which elements of NGG's capex submission should be funded in respect of the TPCR4 rollover and RIIO-T1.

Entry capacity baselines

2.74. NGG has a licence obligation to make available specified amounts of capacity at the various entry and exit points. In the June 2010 consultation document we considered that the baseline capacity at the entry point of Dynevor Arms should be reallocated, following the closure of the LNG storage site there. However, we said this issue does not directly relate to the TPCR4 rollover and should be considered separately. A couple of respondents to the June 2010 consultation asked for a quick review of baseline obligations in light of the closure of the LNG storage facility at Dynevor Arms. As a result of recent developments on the LNG price control, the LNG storage site at Partington no longer provides Operating Margins (OM) or commercial services and Glenmavis no longer has liquefaction capability. Therefore we may also have to reallocate baselines for these in the near future. **Once the future of these sites has been resolved we intend to carry out a robust assessment of the need to reallocate baselines.**

Critical national infrastructure

2.75. In addition to the cost categories which were identified at TPCR4 to log-up costs there has emerged a set of costs relating to critical national infrastructure (CNI). Costs relating to CNI have also been logged-up so as to make provision for them in the licence. This work is being undertaken in parallel to the TPCR4 rollover work.

[17] See 'Consultation letter: Income Adjusting Event claim for the Canataxx incremental entry signal at Fleetwood' published on 7 March 2011 with reference number 28/11 on the Ofgem website www.ofgem.gov.uk.

3. Business plan assessment - Capex

We set out the TOs' capex forecasts for 2012-13 in the context of their historical spend and the forecasts for the early years of RIIO-T1. We explain how these plans compare with our existing cost baselines for TPCR4. We then describe the work we carried out together with our consultants, KEMA, to assess these costs. We present KEMA's view on the range of cost baselines for TO capex and highlight areas of concern where we believe further analysis and clarification is required.

Question box

Question 1: Are the forecasts put forward by the transmission companies reasonable given the significant increase over 2011-12 allowances and historical costs?
Question 2: Do you agree with our consultants' assessment of the TO's forecasts?
Question 3: Do you agree with our proposed "next steps" set out in this chapter?
Question 4: Do you consider there is a case for investment in network flexibility by NGG in 2012-13?

Introduction

3.1. This chapter sets out the issues in determining allowances for Capex for TOs and where applicable SOs. We set out the background giving an overview of the process, the companies forecast for the TPCR4 rollover year and our consultants initial range of allowances. Anticipatory investment projects covered by the Transmission Investment for Renewable Generation (TIRG) and Transmission Investment Incentives (TII) arrangements are handled separately and are outside the scope of this review.

3.2. We have undertaken an initial review of capex. Our analysis is still ongoing and we invite the views of stakeholders.

Background

3.3. In July 2010 we requested TOs to complete a Forecast Business Plan Questionnaire (FBPQ) setting out their forecasts for years up to and including 2012-13 and setting these in the context of initial forecasts for the earlier years of the RIIO-T1 period. These were submitted to us at the end of October 2010. We appointed KEMA to assist us in carrying out our review of these forecasts and to make appropriate recommendations on capex for the TOs. Ofgem and our consultants have reviewed the forecasts and had initial meetings with the companies to discuss them in more detail.

3.4. In addition we appointed PPA Energy to assist in reviewing SO internal capex. Together with PPA Energy we have reviewed the forecasts and met with National Grid (NG) to discuss them in more detail.

3.5. This is still an initial review and our analysis is ongoing.

Summary of forecasts from TOs

3.6. The TOs are forecasting that overall costs will increase significantly in 2011-12 taking baseline costs together with other projects being undertaken on the transmission network, such as TIRG and TII. Table 6 overleaf summarises the step change from the 2011-12 allowances to the 2012-13 forecasts costs set out in the FBPQs.

Table 6: Summary of forecasts for TOs

Ref	Item	Derivation	NGET			NGG-NTS			SPTL			SHETL		
			Allowance £m	FBPQ £m	+/-	Allowance £m	FBPQ £m	+/-	Allowance £m	FBPQ £m	+/-	Allowance £m	FBPQ £m	+/-
			11/12	12/13		11/12	12/13		11/12	12/13		11/12	12/13	
A	LRE		290.2	391.6	101.5	0.7	73.9	73.2	67.5	122.8	55.2	22.6	60.3	37.7
B	NLRE		477.5	564.4	86.9	46.3	64.6	18.2	74.5	87.2	12.69	12.0	20.8	8.8
C	BaseCapex	(=A+B)	767.7	956.1	188.3	47.0	138.4	91.4	142.1	210.0	67.9	34.6	81.1	46.5
D	Opex		176.3	240.4	64.1	68.6	84.9	16.2	18.3	19.0	0.6	6.8	9.0	2.2
E	Sub-Total	(=C+D)	944.0	1,196.5	252.5	115.7	223.3	107.7	160.4	229.0	68.6	41.5	90.1	48.6
F	Logged Up Costs			8.2	8.2		14.1	14.1		8.0	8.0		-	-
G	TIRG			-	-			-		57.1	57.1		153.2	153.2
H	Security			45.7	45.7			-		-	-		-	-
I	TO Incentive			387.1	387.1			-		135.1	135.1		371.5	371.5
J	Increment. Capex						59.6	59.6						
	Total	(=E+F+G+H+I+J)	**944.0**	**1,637.6**	**693.5**	**115.7**	**297.0**	**181.4**	**160.4**	**429.1**	**268.7**	**41.5**	**614.8**	**573.3**

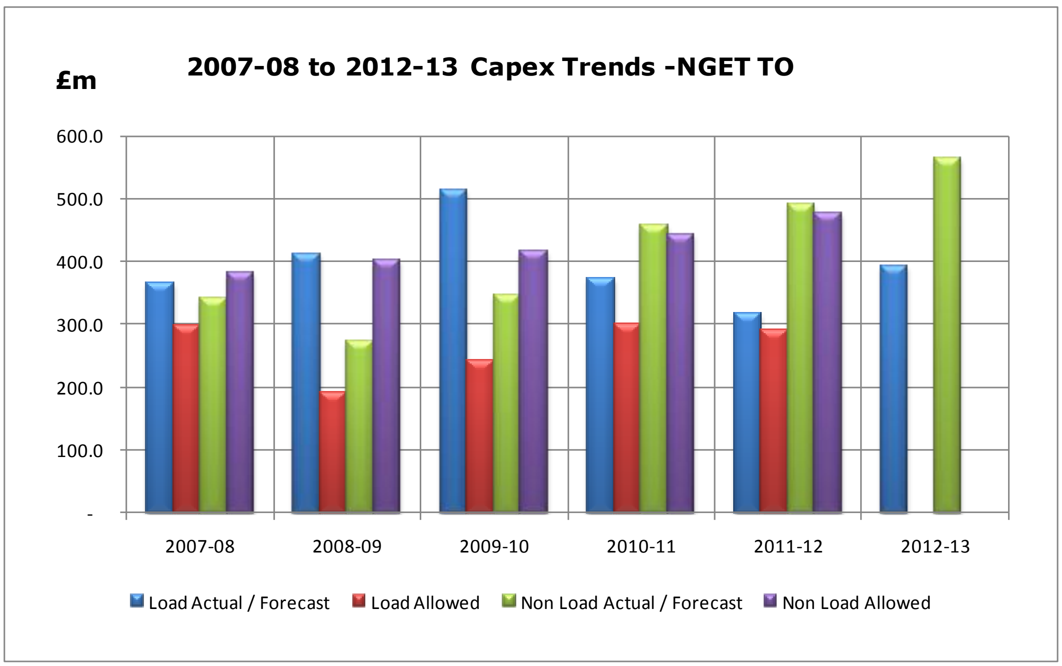
3.7. All TOs have argued that increasing connection of renewable generation, connecting a wide range of customers and managing a diversity of assets approaching the end of their anticipated life are contributing factors driving the need for increased investment on the Networks. We consider these issues put forward by the TOs in more detail below.

Overview for baseline[18] capex forecasts for electricity

NGET

3.8. Figure 2 shows NGET's recent and forecast spend for LRE and NLRE capex.

Figure 2: Capex trends 2007-08 to 2012-13, NGET TO



3.9. NGET's actual baseline LRE has exceeded allowances in the all years of TPCR4 - although there is greater parity towards the end of the period. NGET is expecting a significant increase in expenditure in 2012-13 from the final year of TPCR4. It should be noted that the graph for LRE includes regulatory work in progress. NGET have under spent against the NLRE allowances for all years up to 2009-10 but it expects this trend to reverse towards the end of TPCR4. NGET has argued that this is due to an extension of asset lives in some asset classes which has been brought about by its own research.

[18] Baseline capex excludes TIRG and TII.

Load Related Expenditure (LRE)

3.10. NGET's LRE forecast is based on the "Gone Green" scenario – which aims to deliver 30% of UK's electricity from renewable sources. In terms of generation, and from their forecast, NGET is expecting an increase in generators connecting which is driving up investment in entry-related infrastructure. NGET are forecasting that nearly 12 GW of additional load will connect between now and 2012-13. For more information on load related expenditure, please see Appendix 6.

Non Load Related Expenditure (NLRE)

3.11. For NLRE, NGET have based their forecasts on the need to replace assets based on condition, performance and criticality in order to sustain acceptable levels of reliability, safety and performance.

3.12. NGET have based their plans around the replacement of lead asset categories including the following list below (see Appendix 6 for more details):

- transformers and quadrature boosters
- reactors
- circuit breakers
- protection and control
- overhead lines and cables

In identifying which assets should be replaced, NGET predominantly determine replacement using Network Output Measures (NOMs) based on asset condition and criticality which have been developed over the TPCR4 period. However, as the lead time to replace assets can be as high as four years some of the assets forecast for replacement were not determined on this basis.

Deliverability

3.13. NGET acknowledges that deliverability of the full capex programme is a key challenge facing them given forecast baseline, TIRG and TII expenditure for 2012-13. They consider that the capex programme provides an opportunity for them to develop the partnership models in which suppliers can plan resources on a longer-term basis.

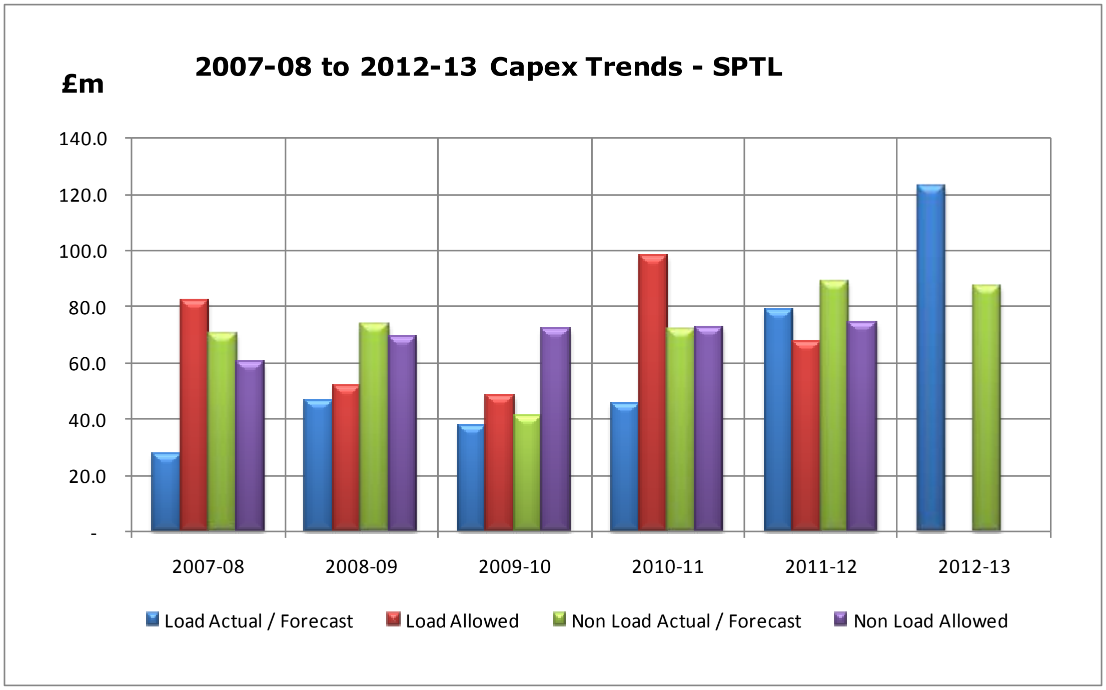
3.14. At the start of TPCR4 NGET restructured its supplier relationships to mitigate against resource constraints and secure commitment from suppliers. It formed Alliance contracts or long term partnerships with leading companies.

3.15. NGET believes not only do the Alliance partnerships give them access to increasingly scarce engineering resources but that it also allows NGET's own staff to benefit from wider knowledge and experience of the partner companies through earlier involvement in the design process.

SPTL

3.16. Figure 3 shows the trend for capex – both LRE and NLRE for SPTL from 2007-08 to 2012-13 as indicated from the information they provided.

Figure 3: Capex trends 2007-08 to 2012-13, SPTL



3.17. There has been significant volatility in baseline LRE relative to allowances, with a significant under-spend in 2007-08 followed by expenditure close to allowance in 2008-09 and 2009-10 and a significant under-spend again in 2010-11. SPTL are forecasting an over-spend in LRE in 2011-12. SPTL said that the variation reflected the volatility and uncertainty of renewable generation connections. Non-load related expenditure is relatively close to allowances for most years with the exception of 2009-10.

Load Related Expenditure (LRE)

3.18. SPTL have also developed their LRE forecasts on the "Gone Green" investment scenario. They have stated that around 80 per cent of forecast investment through to 2018 is to support the large scale development of renewable energy to meet Government targets. For more information, please see appendix 6.

Non Load Related Expenditure (NLRE)

3.19. SPTL has explained that forecasts for NLRE have been developed in line with its asset management policies and procedures including use of the Network Output Measures (NOMs) developed during TPCR4. The detailed condition information, along with site criticality has been used to ensure that plans reflect SPTL's most important investment priorities. See Appendix 6 for more details.

Deliverability

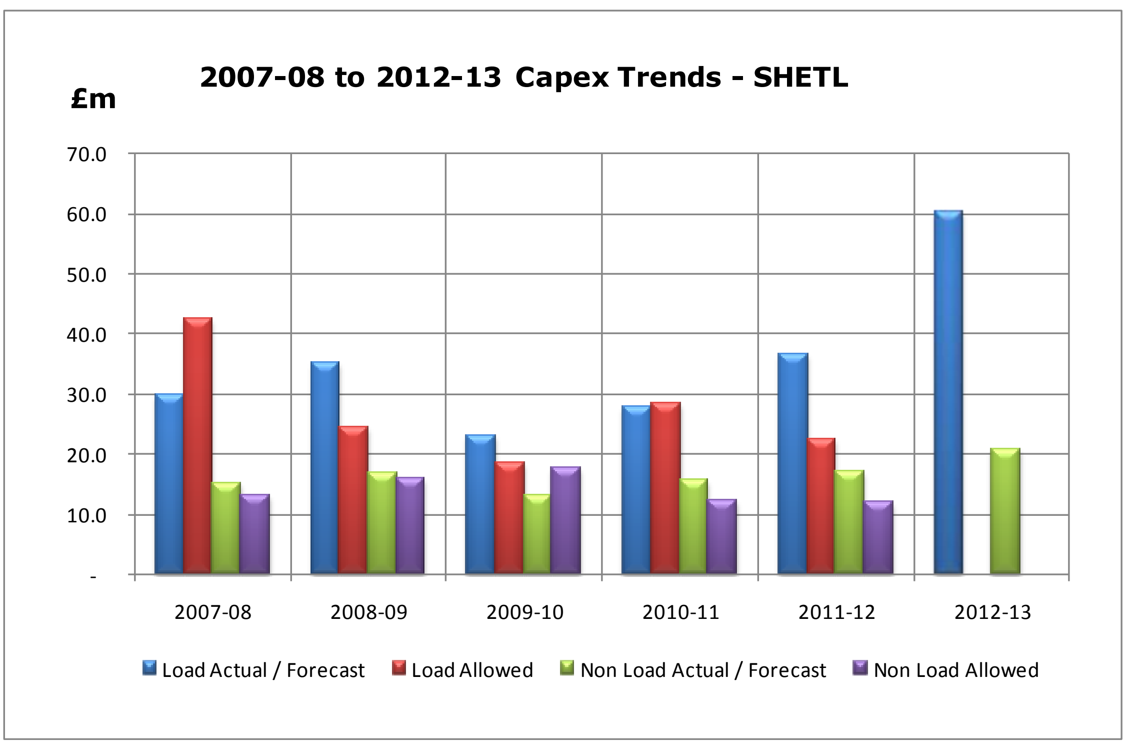
3.20. SPTL said that it recognised that the forecast level of expenditure is unprecedented.

3.21. To address this SPTL have engaged their parent group to enhance their delivery capability. In SPTL's view the relationship will allow access to new resources and experience and they are confident that they can meet the challenges of the full capex programme.

SHETL

3.22. Figure 4 shows Capex trends for SHETL from 2007-08 to 2012-13 as taken from the information they provided.

Figure 4: Capex trends 2007-08 to 2012-13, SHETL



3.23. With the exception of 2007-08, SHETL has spent close to its LRE allowances or significantly overspent them. It has overspent NLRE allowances with the exception of 2009-10.

Load Related Expenditure (LRE)

3.24. In relative terms SHETL is forecasting a significant increase in LRE for the TPCR4 rollover period as it seeks to connect approximately 1.5GW of renewable generation to its network. For further information see Appendix 6.

3.25. SHETL's load-related schemes are driven by growth in demand and aggregation of load from small embedded generators. It has also identified "Renewables Related" capex – where there is large renewable sole use generation connection investment. Included in this category is pre-construction expenditure for capital reinforcement.

3.26. SHETL considers that there is a high degree of confidence in the proposals for 2012-13 as the developers' consents and their own consents are well progressed. SHETL states that expenditure is growing as many of the projects are connecting at a greater distance from the network and are also requiring large reinforcements since existing capacity has already been taken with prior connections.

Non Load Related Expenditure (NLRE)

3.27. For SHETL there is also a relatively large increase in NLRE. This reflects asset replacement or refurbishment of existing plant and circuits where the need is driven primarily by condition and criticality.

3.28. SHETL's asset replacement programme takes into account work to develop output measures for asset health and criticality as part of TPCR4. Asset replacement modelling is also carried out to provide a sense check of the proposed programme.

3.29. SHETL's NLRE schemes for the TPCR4 rollover include:

- 132kV overhead line reconductoring works
- Transformer replacements. SHETL said that the increased costs of this work are driven mainly by:
    - extended outage requirements to clear existing bay equipment
    - construction within restricted areas
    - additional re-engineering and site management costs
    - 132kV switchgear replacements - SHETL have noted the variance in costs due to site, design, operating voltage and protection requirements.
    - 132kV gas compression cable replacement.

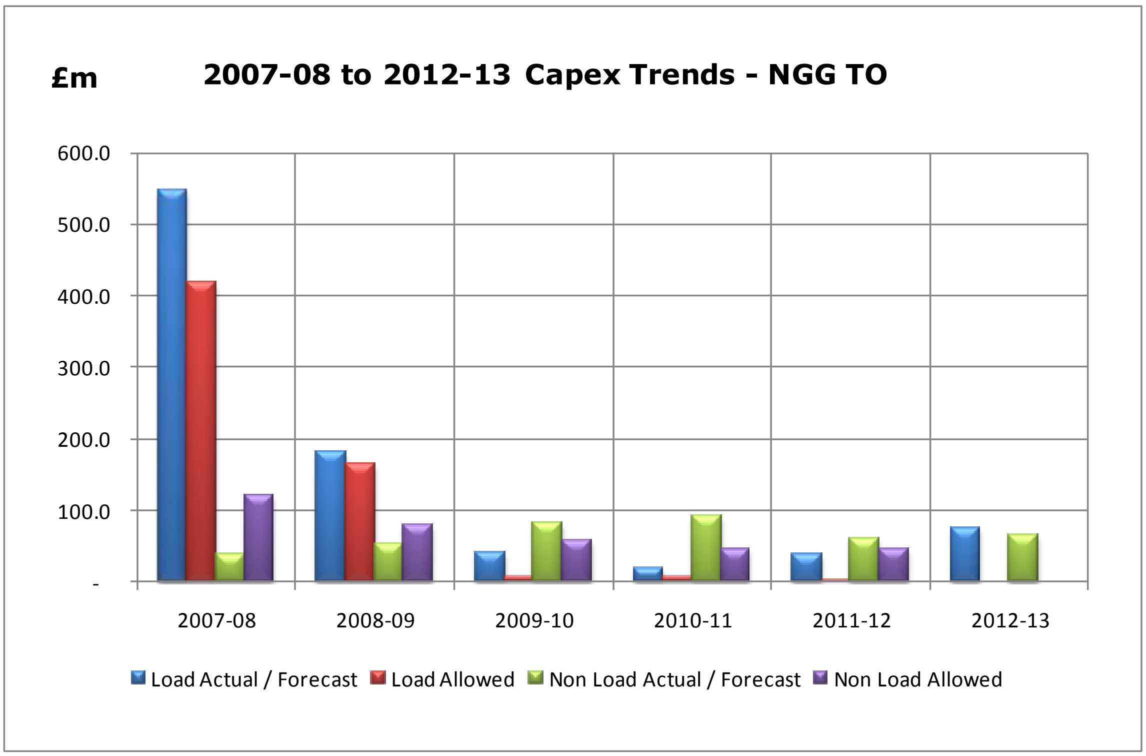
Deliverability

3.30. SHETL have the greatest relative increase in transmission expenditure of all the TOs. SHETL has said that it remains confident that despite the challenges the full capex programme can be delivered.

Overview for capex forecast for NGG TO

3.31. Figure 5 shows the capex trends for NGG in its TO activities for 2007-08 to 2012-13. from the information they provided in the FBPQ

Figure 5: Capex trends 2007/8 to 2012-13, NGG TO



3.32. The high level of LRE in the early years of TPCR4 is attributed to the Milford Haven project. The efficiency of this project will be assessed as part of the RIIO-T1 review. Expenditure in the later years of TPCR4 tails off with the reduction in Milford Haven expenditure. However, in 2012-13 NGG has identified a new category of LRE – Network Flexibility requirements ("network flex") associated with changing flow patterns on the NTS.

3.33. NGG under-spent NLRE allowances in the early years of TPCR4 but this trend is reversed in the later years. For 2012-13 asset health investment and emissions reduction have driven increases in forecasts from the 2011-12 allowances.

Load Related Expenditure (LRE) and Network Flex

3.34. NGG said that the changing state of flows into the NTS create a need to reconfigure the system, in order to make it more flexible and more resilient to the new demands being placed on it. It said that these changes are not covered by incremental load and do not trigger incremental revenue drivers. For more information please see Appendix 6.

Non Load Related Expenditure (NLRE)

3.35. Non Load Related Expenditure is driven by investment on asset health and emissions reduction. See Appendix 6 for more details.

Summary of forecasts from SOs

3.36. NGG and NGET both forecast significant increases in their SO capex.

NGET SO Capex

3.37. NGET SO has stated that increased expenditure is needed to develop resilient and reliable IT systems for operation of the Electricity Transmission System (Asset Health). NGET has also stated that de-carbonisation of energy production and related changes to the generation market and transmission network creates a more complex environment for system operation. This requires investment in new IT systems ("Enhanced SO Capability"). See Appendix 6 for more details.

NGG SO Capex

3.38. NGG SO is also forecasting changes to the future operating environments. NGG believe investment is needed in the Integrated Gas Management System (iGMS) and the Gemini System. See Appendix 6 for more details.

Initial comments on TO forecasts

3.39. We have reviewed the TO submissions with our consultants KEMA. In reviewing the submissions, and in the light of the significant expenditure increases proposed, we have and will carefully examine the forecasts, looking at the underlying cases presented by the TOs.

3.40. KEMA supplemented the process by undertaking a detailed review of a sample of schemes for both load related and non load-related schemes to check the cost and reasonableness of the proposals. Table 7 sets out the TOs' forecasts and KEMA's estimated ranges - for more detail see Appendix 6 - which also sets out the specific areas KEMA are questioning.

3.41. We are publishing the initial reports of KEMA separately. However KEMA have highlighted specific areas which we will give consideration to when we set the allowances. These are summarised below.

Table 7: TO capex allowances in 2012-13: TO forecasts and KEMA estimates

TO	Expenditure category	TO forecast (£m)	KEMA estimate (£m)
NGET	Non-Load Related	564.4	385 - 456
	Load Related	477.5	329.1 - 365.4
SPTL	Non-Load Related	74.5	67 - 73.4
	Load Related	67.5	98.0 - 115.2
SHETL	Non-Load Related	20.8	18.9-20
	Load Related	60.2	55.1 - 63.3
All Electricity TOs	Non - Load Related	659.7	470.9-549.4
	Load Related	605.2	482.2-543.9
NGG	Non-Load Related	64.6	43.3 – 52.6
	Network Flex	50.3	9.8-14.0
	Total	114.9	53.1-66.6

NGET TO

3.42. Although we are close to the TPCR4 rollover year, there are still significant uncertainties in load-related projects associated with the connections of new generation given that some schemes are still in development and may face issues with planning consent. KEMA note that the Connect and Manage regime introduces further uncertainty as customers have greater control over the timescales of the connection. They give their recommendations in Appendix 6.

3.43. KEMA are satisfied with the design of load-related schemes based on a sample of projects. However, they have concerns about some of the costs, particularly substation costs and the level of overheads applied (including risk premiums and contingencies).

3.44. KEMA have a number of concerns about Non Load Related Expenditure discussed more fully in Appendix 6.

SPTL

3.45. KEMA have concerns numerous issues for Load Related Expenditure. They give their recommendations in Appendix 6.

3.46. KEMA have a number of concerns about Non Load Related Expenditure discussed more fully in Appendix 6.

SHETL

3.47. KEMA have concerns numerous issues for Load Related Expenditure. They give their recommendations in Appendix 6.

3.48. For NLRE, KEMA have fewer concerns – with the only significant issue being unit costs for transformers. KEMA are recommending the range given in Appendix 6 for the TPCR4 rollover year.

NGG - TO

3.49. KEMA have identified significant challenges to NGG in relation to its planned work in the area of network flexibility. It has concerns over the certainty of the spend, whether the spend is already covered by existing revenue driver mechanisms and whether NGG should have anticipated these items when original revenue drivers were set. On the latter point if the rationale used by NGG to justify the need for network flexibility was evident at the time we set revenue drivers, then this should have been captured in the modelling to set revenue drivers. Ofgem remain unconvinced that there is any need to spend the money on network flexibility in 2012-13.

3.50. For NLRE KEMA are also identifying challenges to NGG. These include the sanctioning of schemes being ratified in the 2012-13, the lack of apparent application of NOMs and that some projects apparently have had allowances granted previously.

Comments on SO forecasts

3.51. We have worked with PPA Energy to review the business plans and ensure the proposals are justified and sufficiently robust. We sought clarification on spend in certain areas and held a cost meeting with National Grid to discuss the plans in greater detail.

3.52. PPA Energy's initial report will be published later in April 2011. PPA Energy have raised the following issues with NG's forecasts at this stage.

3.53. For both NGET SO and NGG SO there is a lack of clarity regarding the overall IT strategy, and policies seem to adopt an approach to hardware and software "refreshes" that seem inconsistent with normal practice for complex applications.

3.54. In terms of timing, given the planned implementation for 2012-13 PPA Energy have concerns about the deliverability of the programme and believe it could introduce considerable risk given the context of the real time environments for both electricity and gas SO functions.

3.55. For electricity PPA Energy are questioning:

- The stability control system, where PPA Energy believe no clear case has been presented
- iEMS (Integrated Electricity Management System) replacement hardware, where PPA Energy state that this should be delayed pending the Electricity Market Reform (EMR) review
- Certain asset health expenditure, where this is not a critical priority

3.56. For gas PPA Energy are questioning:

- iGMS (Integrated Gas Management System) strategic route map, where no clear case has been presented and PPA Energy believe this should be delayed pending the EMR review and the development of clearer IT strategy
- NetSip project, where there is no apparent mandate for this work
- IS Capex, where the timing of this work for 2012-13 has not been clearly made and can be deferred until the main review
- xoserve, where the requirements for the proposed spend are too speculative.

Given these challenges PPA Energy are recommending the range given in Table 8 for NGET SO and NGG SO

Table 8: PPA recommendations - SO Activities

SO	ITEM	SO Forecast (£m)	LOW CASE (£m)	HIGH CASE (£m)
NGET SO	Capex	42.0	15.6	28.5
NGG SO	Capex	45.1	21.9	30.6

Proposed next steps

3.57. We will continue to refine our analysis and revise our cost baselines where appropriate. We would welcome views on any of the issues or ranges for cost baselines set out in this document. We will take into account responses to this document including further representations from the TOs and other stakeholders in reaching our initial proposals for the cost baselines.

4. Business plan assessment - opex

We set out the TOs' operating expenditure forecasts for 2012-13 in the context of their historical spend and the forecasts for the early years of RIIO-T1. We explain how these plans compare, our areas of concern and where we believe further analysis and clarification is required.

Question 1: Are the forecasts put forward by the TOs reasonable given the significant increase over 2011-12 allowances?
Question 2: Do you agree with our assessment of the TOs' forecasts?
Question 3: Should Workforce Renewal and Staff Recruitment be made a separate allowance from the general opex?
Question 4: Do you agree with our proposed "next steps"?

Background of assessment

4.1. The review of operating expenditure (opex) followed the same timelines as described in the previous chapter for capex. In July 2010 we requested transmission companies to complete a FBPQ setting out their forecasts for years to and including 2012-13 and setting these in the context of initial forecasts for the earlier years of the RIIO-T1 period. These were submitted to us at the end of October 2010.

4.2. We have undertaken an initial review of operating expenditure. Our analysis is still ongoing and we invite the views of stakeholders.

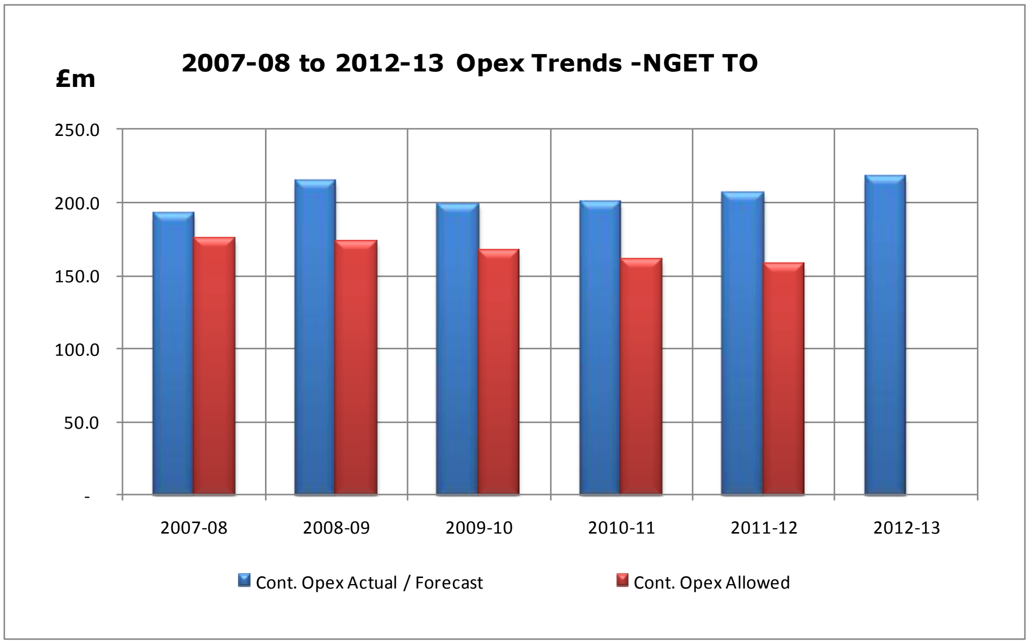
Summary of TO activities

4.3. NGET TO, NGG TO and SHETL are all forecasting increases in opex relative to existing allowances. They are arguing that as transmission networks increase in size the TOs will require additional funds to support these activities. SPTL have broadly maintained a flat profile for the TPCR4 rollover.

National Grid – NGET TO and NGG TO

4.4. Figure 6 shows the trend in NGET's controllable opex for 2007-08 to 2012-13 as taken from the information they have provided.

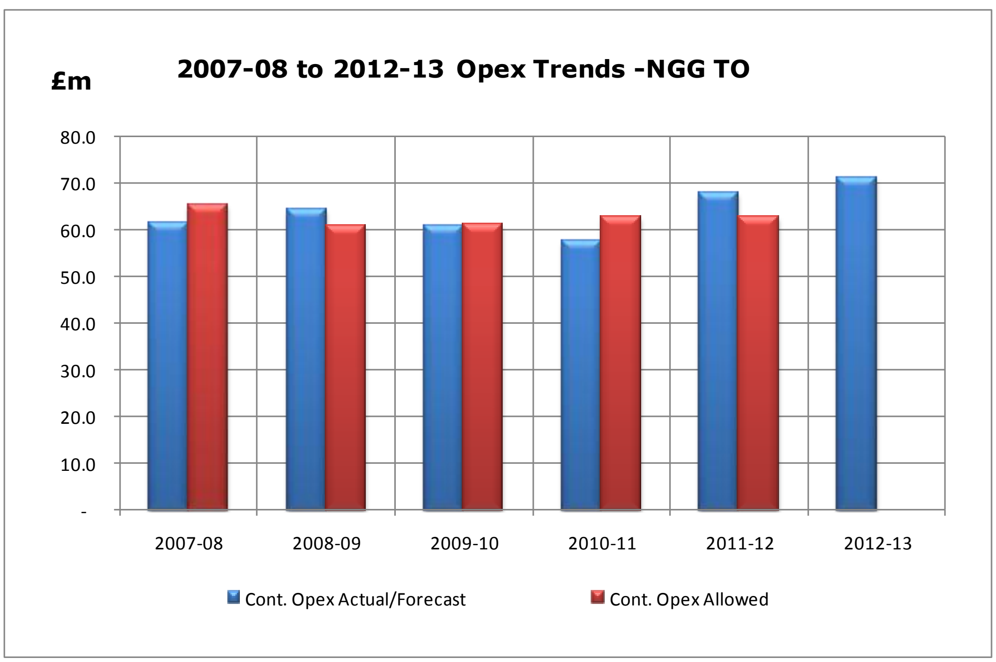
Figure 6: Opex trends 2007-08 to 2012-13 - NGET TO



4.5. NGET has overspent the allowances in each year of TPCR4 to date and forecasts further overspend in 2010-11 and 2011-12.

4.6. Figure 7 shows the trend in controllable opex 2007-08 to 2012-13 for NGG TO taken from their FBPQ.

Figure 7: Opex trends 2007-08 to 2012-13 - NGG TO

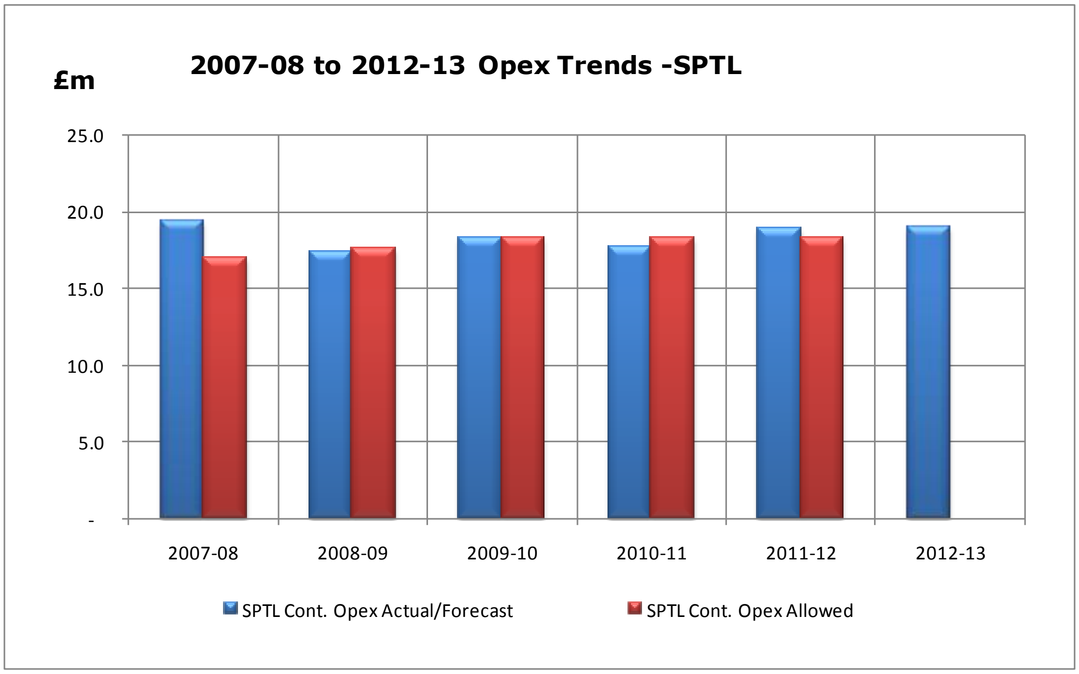


4.7. NGG's actual and forecast expenditure is broadly in line with allowances for most of TPCR4, with the exception of 2011/12, where it forecasts a small overspend. NG forecast asset diversity, growth and condition (covering both NGET and NGG) as the key factors driving increases in opex in 2012-13, see Appendix 6 for more details.

SPTL

4.8. Figure 8 shows the trend in controllable opex for 2007-08 to 2012-13.

Figure 8: Opex trends 2007-08 to 2012-13 - SPTL

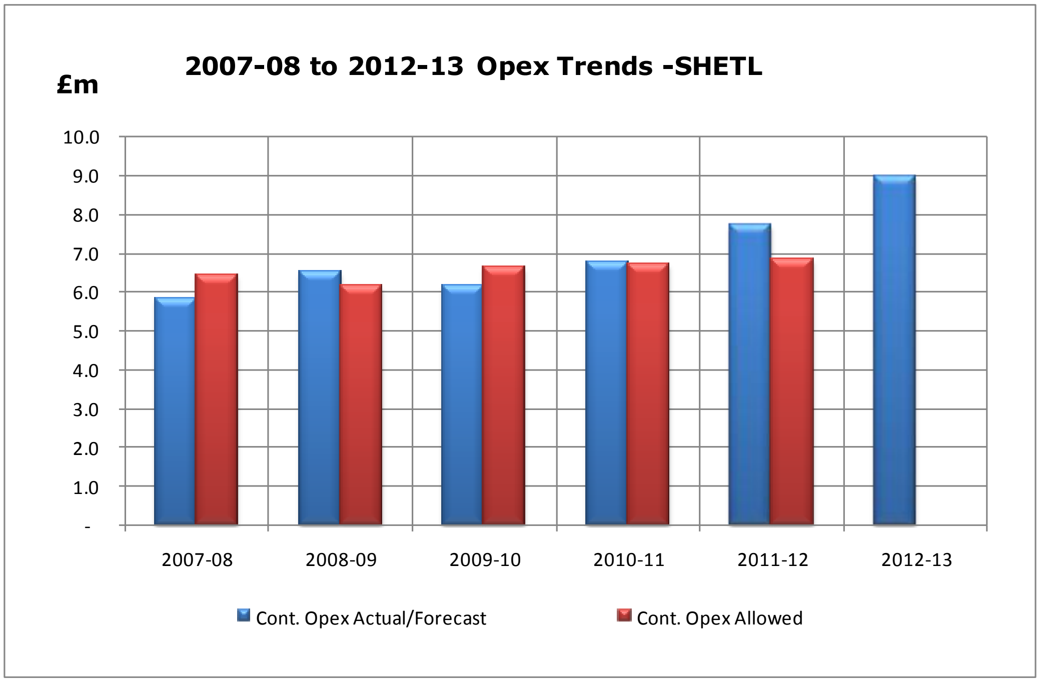


4.9. SPTL stated that it has reached a point where the scope to reduce costs further is extremely limited. It said that it faces upward cost pressures due to the combination of a growing network and ageing asset base – requiring further condition assessment and increased intervention. SPTL also noted that the additional capital investment in the network will increase maintenance and inspection costs.

SHETL

4.10. Figure 9 shows the trend in controllable opex for 2007-08 to 2012-13.

Figure 9: Opex trends 2007-08 to 2012-13 - SHETL



4.11. SHETL has been spending broadly in line with allowances during TPCR4. SHETL have stated that the increase in the size of the business will increase opex costs as additional resources are required to maintain, operate and support the larger network.

Comments on TO forecasts

4.12. We are considering a range of methods for setting opex allowances for the TPCR4 rollover period. One method is simply to roll forward the existing allowances. This could be viewed as proportionate given this is a one year extension. Another option would be to calculate the Recurring Cash Controllable (RCC)[19] costs for the TPCR4 rollover.

4.13. In using these two methods we can develop a range for which allowances can be set for the TPCR4 rollover year.

4.14. We provide our provisional comments on the issues raised by the TOs below:

[19] The Recurring Cash Controllable (RCC) represents the underlying cash costs associated with the TO but is more specifically defined as the ongoing cash operating costs excluding non-recurring (or one off) costs that are controllable by the transmission company.

NG

4.15. We have questions about the level of NGET's opex through the TPCR4 period. We note that during the TPCR4 period NG implemented a series of transformations for back office processes and shared service functions – including utilisation of offshore contractors. Despite this NG is forecasting that they are unable to bring costs closer to allowances for later years within the period and so savings from these initiatives, although having some effect, have still to make a significant financial impact. It is also not clear when these savings will materialise.

4.16. Whilst recognising the potential for upward cost pressures our view is that NG must have clear strategies to mitigate these and manage costs. For real price effects and wage pressure we recognise the need to attract and retain skilled workers. However this need has to be balanced against a wider economic background where other sectors are showing significant restraint in pay growth. In terms of other input prices we will seek greater clarification about the transformation of procurement strategies and how this will deliver future savings. We will also consider whether procurement strategies can help reduce costs for other commodity inputs.

4.17. In relation to workforce renewal we have questions about whether NG would be able to spend on these areas even if allowances were granted – given the challenges facing the industry at large. We may therefore require greater certainty about the plans for this spend.

SPTL

4.18. Although SPTL have spent within allowances for the TPCR4 period we are considering whether further reductions are possible. We also may seek greater clarification about related party margins.

SHETL

4.19. We suggest that funding mechanisms for TIRG and anticipatory investment already cover notional allowances for increased activity. Therefore any increases in support costs due to these activities should be removed from forecasts when determining the opex allowances.

Range

4.20. Given our views on options for Opex Allowances (excluding Non Operational Capex) for 2012-13 we provide our indicative range in Table 9.

Table 9: Opex Range (excluding Non Operational Capex)

TO	TO Forecast (£m)	Ofgem HIGH CASE (£m)	Ofgem LOW CASE (£m)
NGET	217.6	213.9	158.4
NGG	71.4	76.8	62.9
SPTL	19.0	18.3	16.2
SHETL	9.0	9.0	6.8

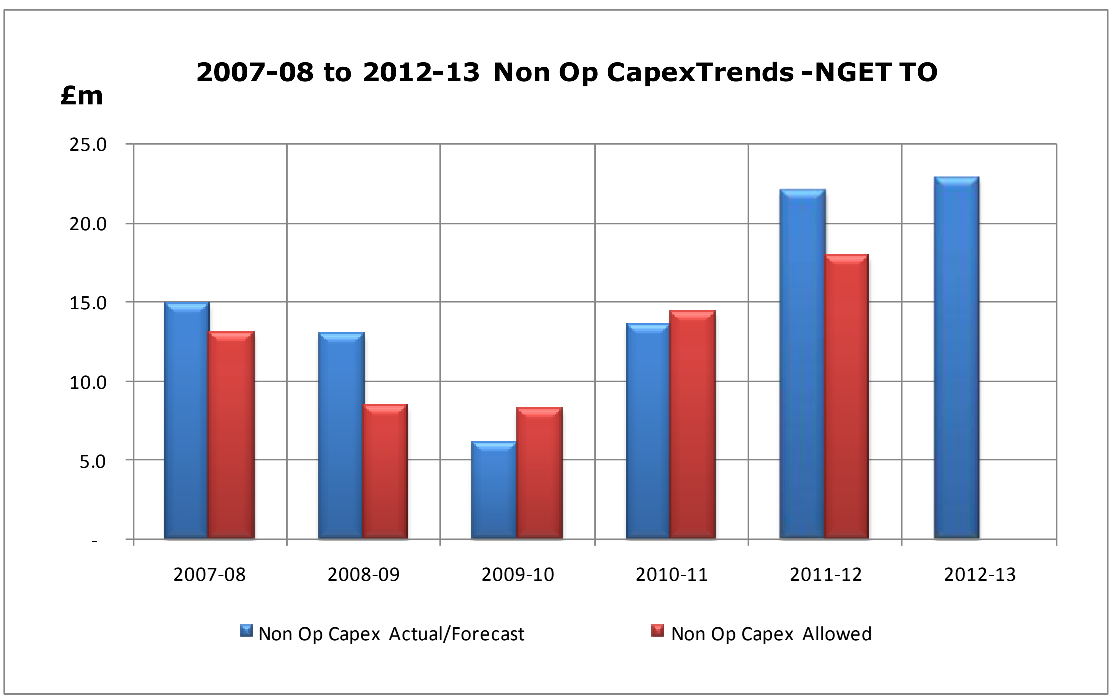
Non operational capex forecasts

4.21. Non operational capex ("non op capex") is expenditure on capital items other than the operational system – for instance vehicles. This expenditure is traditionally capitalised from an accounting perspective but remunerated as opex for the purposes of the price control. At TPCR4 non op capex allowances were only granted to NGET, NGG and SPTL.

NGET

4.22. NGET's expenditure for the price control period to and including the TPCR4 rollover year is shown in Figure 10.

Figure 10: Non-operational capex trends - NGET TO



4.23. For most years within the period NGET have overspent against allowances. There is a ramp up in forecast expenditure at the end of the TPCR4 period and this expected to continue in to the TPCR4 rollover year.

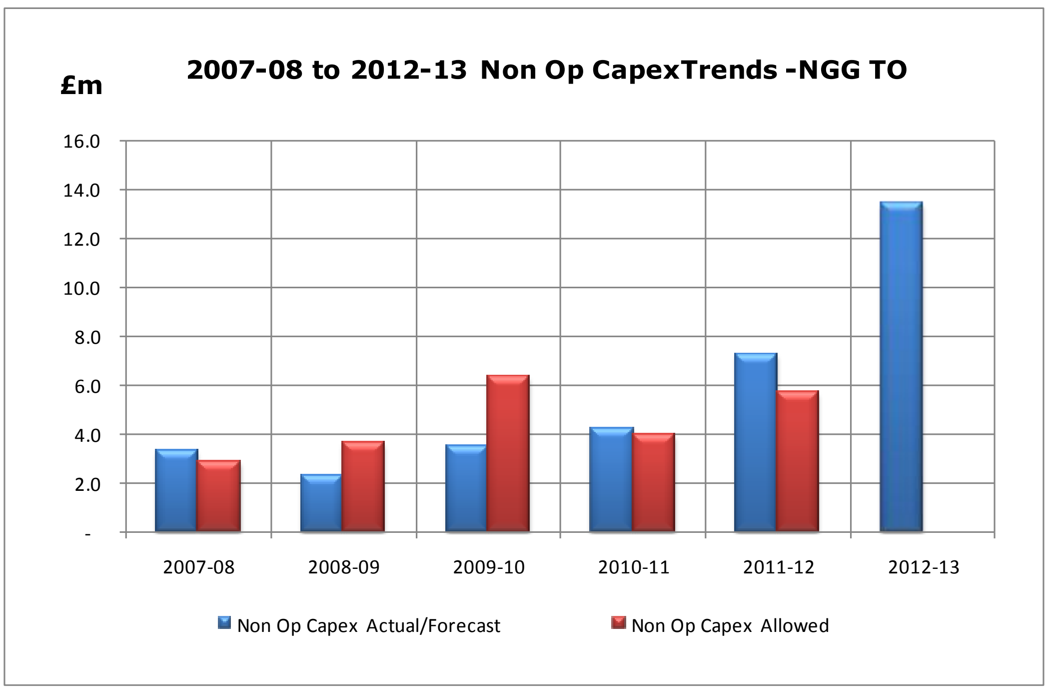
4.24. NGET have stated that non op capex is increasing as investment is needed in asset health to:

- Ensure the capability for remote asset monitoring to maintain safety and reliability as well as delivering future customer benefit – this includes targeted refreshes where NG note that 2012-13 marks the start of the next six year cycle.
- Greater integration of construction IT Systems to optimise capital planning and delivery
- Workplace sharing to drive out further value out of NG property

NGG

4.25. NGG's Non Operational capital expenditure from 2007-08 to 2012-13 is shown in the Figure 11.

Figure 11: Non-operational capex trends - NGG TO



4.26. Despite small variations NGG's actual and allowances have been on parity with the exception of 2009-10. From 2011-12 to 2012-13 there is a significant ramp up in expenditure.

4.27. According to NGG the projects driving the increase in the TPCR4 rollover year are:

- High Pressure Metering Information System (HPMIS) replacement – where current IT infrastructure is old. This includes equipment to measure and monitor gas quality
- Gas asset management system integration – where there is a programme to re-platform and bring into support a range of systems engaged in policy compliance, safety and environmental management activities.
- Strategic Asset Management (SAM) – a programme that will co-ordinate delivery of remote access to site data on a real time basis.

Ofgem comments on non op capex

NG (NGET TO and NGG SO)

4.28. Our concerns with non op capex closely mirror those we have already expressed for IT areas – such as SO capex. Insofar as these expenditures relate to IT we are concerned about the overall IT strategy and seek greater clarity regarding the proposed level of system refreshes.

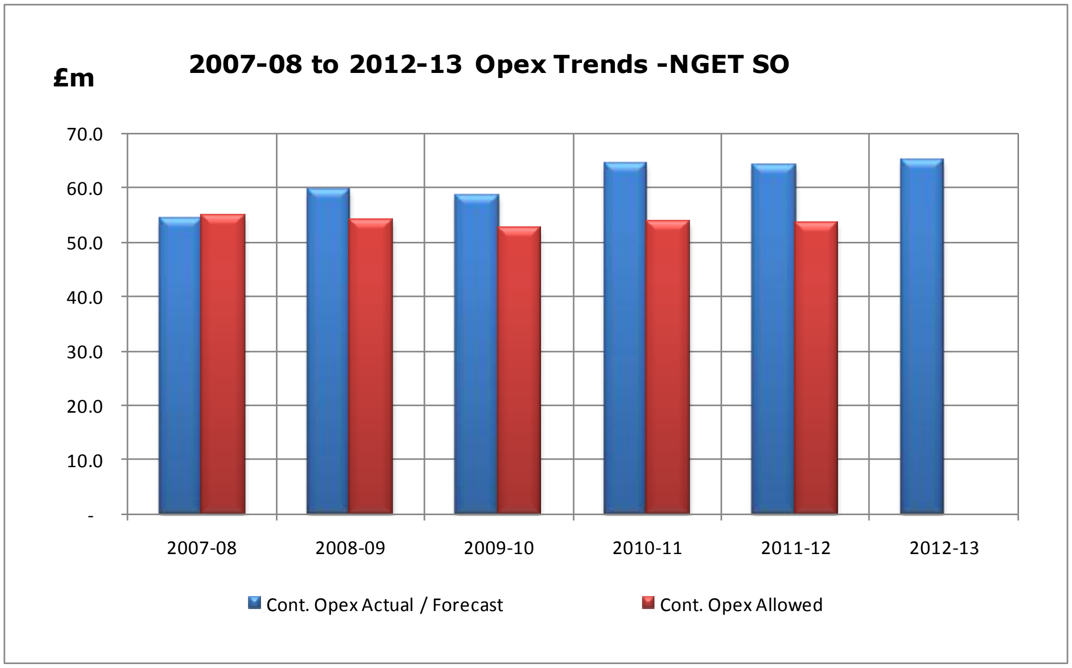
4.29. We are also concerned about the potential overlap between the number of non op capex projects and possible wider IT projects within NG. We need greater assurance that unnecessary and wasteful duplication is not taking place.

4.30. We would also question whether greater synergies can take place between electricity and gas and whether this is being fully exploited.

SO opex

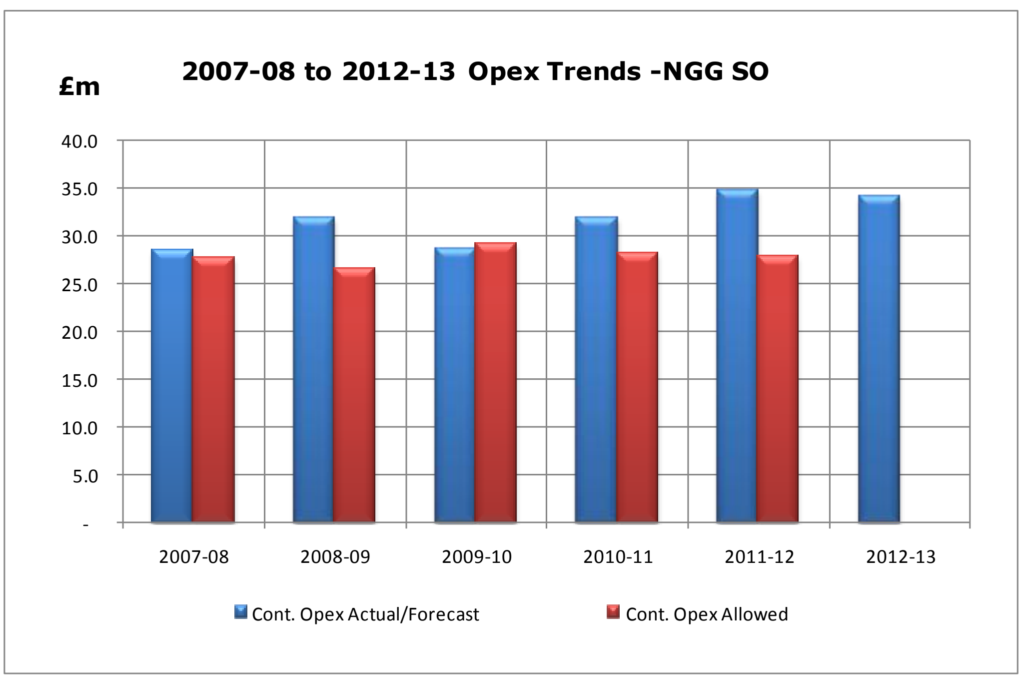
4.31. Figure 12 shows the trend for SO Opex costs for NGET from 2007-08 to the TPCR4 rollover year in 2012-13. With the exception of 2007-08 NGET SO has incurred a small overspend in each of the years.

Figure 12: Opex trends - NGET SO



4.32. For NGG the SO trend over 2007-08 to 2012-13 is given in the Figure 13.

Figure 13: Opex trends - NGG SO



4.33. For all years NGG has incurred a small overspend from allowances determined in TPCR4. For 2012-13 the profile is expected to remain broadly consistent with the previous years.

Proposed Next Steps

4.34. We will continue to refine our analysis and revise our cost baselines where appropriate. We would welcome views on any of the issues driving opex cost increase set out in this document. We will take into account responses to this document including further representations from the TOs and other stakeholders in reaching our initial proposals for the opex cost allowances. We will publish our initial proposals in August 2011.

5. Update on our approach to financial issues

This chapter provides an update on our view of the appropriate allowed return and confirms our approach to tax and pensions.

Question 1: We are seeking stakeholders' views on whether the available evidence supports leaving the assumed cost of equity unchanged for the TPCR4 rollover year.
Question 2: We are seeking stakeholders' views on whether there is sufficient evidence to support updating the assumed cost of debt for the TPCR4 rollover year.
Question 3: We are seeking stakeholders' views on whether we should review SHETL's notional gearing for the TPCR4 rollover year.

Allowed return

5.1. In the June 2010 document we indicated that we would set out in April 2011 which elements of the allowed return, if any, we consider should be reviewed in the light of market evidence. Our initial view is that there is insufficient evidence to merit changing the cost of equity assumption and sufficient evidence to reduce the cost of debt assumption. We will set out specific proposals on the value of the allowed return in our initial proposals, which will be published in August 2011.

5.2. Responses to the June 2010 document focused on the overall financeability implications of our approach to setting the allowed return for the TPCR4 rollover year. A summary of the consultation responses is provided in Appendix 4.

5.3. It is important to note that TPCR4 and the TPCR4 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 TPCR4 rollover, or *vice versa*. In considering the allowed return for the TPCR4 rollover year, our main aim has been to consider changes to the TPCR4 assumptions in a way that is proportionate to the length of the TPCR4 rollover period.

5.4. We commissioned Europe Economics (EE) to analyse how market rates have changed since the TPCR4 Final Proposals and the implications for the way we set the allowed return for the TPCR4 rollover year. We have published their report today[20].

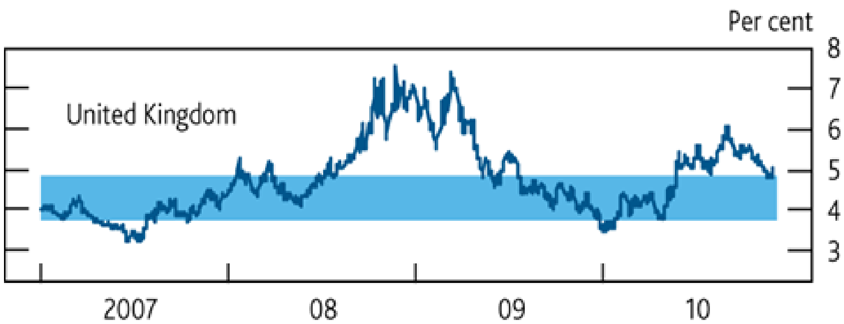
5.5. Consistent with our approach to determining allowed return for the TPCR4 rollover year, we have revisited the basis of the decision on allowed return under TPCR4. EE reproduced the analysis Ofgem carried out during TPCR4, updating it for the latest market data and trends. The TPCR4 analysis was heavily based on the Smithers report.[21] As discussed in the EE report, the most significant change has

[20] See 'Updating the cost of capital for the for the transmission price control rollover' by Europe Economics, published on 8 April 2011 on the Ofgem website www.ofgem.gov.uk.
[21] See 'Report on the Cost of Capital provided to Ofgem' by Smithers & Co (2006), published on 26 September 2006 on the Ofgem website www.ofgem.gov.uk.

been in the risk-free rate, which has declined by around 100 basis points (bps). As a consequence EE recommend updating both the cost of equity and the cost of debt.

5.6. In TPCR4 we referred to total market returns on equity to set the assumed cost of equity (implicitly assuming an equity beta of one). Expected market returns to equity are considered to be stable over time[22]. For example, Figure 14 shows that over the time in which the risk-free rate has declined by around 100 bps, the Bank of England's estimate of the equity risk premium has increased by roughly the same amount. This lends weight to the argument that it would not be proportionate to modify the allowed return on equity from the TPCR4 assumption. **We seek stakeholders' views on whether the available evidence supports leaving the cost of equity assumption for the TPCR4 rollover year unchanged.**

Figure 14: Bank of England estimate of the equity risk premium



* Figure adapted from Bank of England Financial Stability Report (December 2010). The Figure shows the equity risk premium (ERP) as estimated through a multi-stage dividend discount model. The shaded area shows the interquartile range for the ERP in the UK since 1998.

5.7. For the cost of debt, however, there has been a clear and sustained downward trend in market measures of the real risk-free rate. This has been reflected by recent regulatory determinations setting a lower risk-free rate than in the past[23]. In TPCR4 the Smithers Report calculated a range of 2.0-2.5 per cent for the risk-free rate. At the time we picked the upper bound. Given the changes in market rates since then, we think there may be sufficient evidence for it to be appropriate to update the cost of debt assumption by using the lower end of the range from the Smithers report (ie a risk-free rate of 2.0 per cent). This would result in a cost of debt allowance of 3.25 per cent for the TPCR4 rollover year, compared to 3.75 per cent in TPCR4. **We are seeking stakeholders' views on whether there is sufficient evidence to support updating the cost of debt for the TPCR4 rollover year.**

5.8. Again, we would emphasise that the approach adopted here reflects the position reached for TPCR4, rather than the approach adopted for RIIO price controls.

[22] See p. N21 of 'Bristol Water plc - a reference under section 12(3)(a) of the Water Industry Act 1991' published on 4 August 2010 on the Competition Commission website www.competition-commission.org.uk.
[23] For example, Ofcom is currently consulting on a risk-free rate of 1.5%, and the Civil Aviation Authority (CAA) set a risk-free rate of 1.75% in the 2010 price control review of National Air Traffic Services (NATS).

5.9. The overall approach to the TPCR4 rollover has been to minimise as far as possible the number of changes. We would not normally make any changes to the level of notional gearing. However, given the size of SHETL's capex programme (relative to its RAV), there may be an argument to set a lower notional gearing for SHETL, subject to financeability testing. **We are seeking stakeholders' views on whether we should review SHETL's notional gearing for the rollover year.**

Setting the opening RAV

5.10. The provisional RAV numbers to March 2010 and the investment that is not currently incorporated in the RAV are shown in the Transmission Annual Report.

5.11. There are a number of adjustments that are made to the transmission RAV numbers for incentive schemes. These are all carried out on a provisional basis until we have fully confirmed the costs and the delivery of related outputs. In particular, the expenditure made by NGG at Milford Haven is subject to further review.

Tax

5.12. Following the March 2010 consultation document, we have decided to maintain our provisional approach. We will determine expected tax costs using applicable capital allowances and tax rates, using the same tax calculation methodology as was implemented at DPCR5. This will reflect recent changes in capex and pensions expenditure. We will not introduce any policy changes, such as the tax trigger. This will be implemented in RIIO-T1.

Pensions

5.13. As set out in the June 2010 document, we will introduce our proposals set out in our 22 June 2010 Pension decision document.[24] The key principles that will be adopted during the TPCR4 rollover are:

- 15-year notional deficit recovery period
- True up of deficit and ongoing costs payments from TPCR4
- Allowance for ongoing contributions based on the latest actuarial rates

5.14. We will commence the true-up of TPCR4 pension payments during the TPCR4 rollover year. These adjustments will be spread over the nine years of the TPCR4 rollover plus RIIO-T1. These are set out in the Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues document.

[24] 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.

6. Way forward

This chapter sets out the process that we will follow in arriving at our final proposals.

Next steps and timetable

6.1. Appendix 1 contains instructions on how to respond to this consultation document by 13 May 2011. We will publish all non-confidential responses on our website.

6.2. Following this consultation process we will consider and evaluate all comments received in developing our initial proposals.

6.3. We will continue to follow an open and transparent process to arrive at our final proposals for the TPCR4 rollover. The table below indicates the key dates for the TPCR4 rollover.

Table 10: Key dates for TPCR4 rollover

Date	Event
April 2011	Publish 'TPCR4 rollover policy update and initial analysis of Business Plans'
August 2011	Publish Initial Proposals
November 2011	Publish Final Proposals
January 2012	Publish Licence Amendment Consultation
March 2012	Issue Regulatory Instructions and Guidance (RIGs)
1 April 2012	New licences come into effect - New price control period begins

Appendices

Index

Appendix 1 - Consultation questions from this document

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 13 May 2011 and should be sent to:

Gareth Walsh
Ofgem (Smarter Grids and Governance Team)
9 Millbank
London
SW1P 3GE
020 7901 1867
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 develop and publish our Initial Proposals in August 2011. Any questions on this document should, in the first instance, be directed to Gareth Walsh (using the above details).

CHAPTER: Two

Question 1 : Do stakeholders agree with our view that it is not necessary to allow any cost categories to log-up during the TPCR4 rollover year, but for forecasts to be included in the base allowances?

Question 2: Do stakeholders agree that it is appropriate to continue to pass through the current set of pass-through costs to consumers?

Question 3: Do stakeholders agree that it is appropriate to make TO/SO adjustments in response to the gas revenue drivers on 31 March 2012 and 31 March 2017?

Question 4: With respect to Milford Haven do stakeholders agree that it is appropriate to keep the £9.5m (2004-5 prices) downward adjustment to the TO allowed revenue but review the figure?

Question 5: Do stakeholders agree with our view that no new electricity transmission revenue driver need be introduced for the TPCR4 rollover year?

Question 6: Do stakeholders agree with our start and finish date based approach to determining capex allowances for TPCR4 revenue driver projects during the TPCR4 rollover year?

Question 7: Do stakeholders agree with our proposal to maintain the capex incentive in the TPCR4 rollover year and keep the sharing factor unchanged at 25%?

Question 8: Do stakeholders agree with our proposal to allow the capex incentive payment on a provisional basis for SPTL, SHETL and NGG, making any further adjustments as part of the RIIO price control?

Question 9: Do stakeholders agree with our proposal to defer payment of NGETs capex incentive until we have performed a detailed assessment of projects regarded as WIP, and fully considered the impact of connect and manage and TO incentives?

Question 10: Do stakeholders agree with our proposal to maintain the SO capex incentive for National Grid in their role as gas and electricity SO for the TPCR4 rollover year and keep the sharing factor set to ±25%? Do stakeholders also agree with our proposed approach to make a provisional revenue adjustment in 2012-13 in line with the SO capex incentive, and true this up as part of the TPCR4 rollover?

Question 11: Do stakeholders agree with our proposal to maintain the gas internal SO opex sharing factor at ±40%, and align the electricity SO internal sharing factor with that used for incentivising external costs?

Question 12: Do stakeholders agree with our proposed approach to leave the electricity reliability incentive scheme and its parameters unchanged for the TPCR4 rollover year?

Question 13: Do stakeholders agree with our provisionally preferred approach to continuing to incentivise a reduction in the leakage rate of SF6 gas, updating the target leakage rates to reflect performance during TPCR4?

Question 14: Do stakeholders agree that it would be appropriate to maintain the default investment lead times for NGG at their current length?

Question 15: Do stakeholders agree that it would be appropriate to give NGG the permit scheme payout in 2012-13 and extend the permit scheme for one year by pro-rating existing parameters?

CHAPTER: Three

Question 1: Are the forecasts put forward by the transmission companies reasonable given the significant increase over 2011-12 allowances and historical costs?

Question 2: Do you agree with our consultants' assessment of the TO's forecasts?

Question 3: Do you agree with our proposed "next steps" set out in this chapter?

Question 4: Do you consider there is a case for investment in network flexibility by NGG in 2012-13?

CHAPTER: Four

Question 1: Are the forecasts put forward by the TOs reasonable given the significant increase over 2011-12 allowances?

Question 2: Do you agree with our assessment of the TOs' forecasts?

Question 3: Should Workforce Renewal and Staff Recruitment be made a separate allowance from the general opex?

Question 4: Do you agree with our proposed "next steps"?

CHAPTER: Five

Question 1: We are seeking stakeholders' views on whether the available evidence supports leaving the assumed cost of equity unchanged for the TPCR4 rollover year.

Question 2: We are seeking stakeholders' views on whether there is sufficient evidence to support updating the assumed cost of debt for the TPCR4 rollover year.

Question 3: We are seeking stakeholders' views on whether we should review SHETL's notional gearing for the TPCR4 rollover year.

Appendix 2 – Further context

This appendix sets out the context of the TPCR4 rollover in terms of the need for price controls, what the guiding principles of the TPCR4 rollover are and the interaction of TPCR4 rollover with other policy areas (including RIIO-T1, anticipatory investment and the liquefied natural gas (LNG) price control).

Price controls

The transmission network consists of the high voltage electricity wires and high pressure long distance gas pipelines which convey electricity from power stations and gas from offshore, storage and liquefied natural gas (LNG) facilities. They are owned and operated by privately owned companies who have territorial monopolies. To protect the interests of consumers, we regulate these companies using price controls.

There is one TO in gas and three in electricity:

- National Grid Gas plc (NGG), which owns the high pressure gas transportation system across Britain
- National Grid Electricity Transmission plc (NGET), which owns the high voltage electricity network in England and Wales
- SP Transmission Limited (SPTL), which owns the high voltage electricity network in the south of Scotland
- Scottish Hydro Electric Transmission Limited (SHETL), which owns the high voltage electricity network in the north of Scotland.

In addition to their TO responsibilities, NGG and NGET are the designated gas and electricity SOs. They therefore have responsibility for day-to-day system operation, including balancing of the system and constraint management. The controls for NGG and NGET also include allowances for internal SO costs for NGG SO and NGET SO and some external costs for NGG SO. All other external SO cost allowances are determined via a separate process[25].

The current price control period (TPCR4) was set for the period 1 April 2007 to 31 March 2012. To accommodate fully the conclusions of the RIIO review in the next transmission price control, following consultation, we announced in December 2009 a one-year 'adapted rollover' of TPCR4 from 1 April 2012 until 31 March 2013.

[25] We develop SO incentive schemes that are designed to encourage NGET and NGG to manage the costs of operating each system effectively. The SO incentive schemes establish cost targets that NGET and NGG are expected to achieve in performing their SO roles.

Interaction with related policy areas

RIIO-T1

In October 2010 we announced the RIIO (Revenue = Incentives + Innovation + Outputs) framework, which changes the way we regulate electricity and gas transmission and distribution networks. This follows on from our RPI-X@20 project which reviewed the way we had regulated network companies over the previous 20 years. The RIIO framework was developed to deliver 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[26]. The RIIO framework will first be implemented in the transmission sector at RIIO-T1 which covers the price control period from 1 April 2013, ie directly after the application of the TPCR4 rollover.

Table 11: RIIO-T1 and TPCR4 rollover timetable

Year	Month	RIIO-T1 milestone	TPCR4 rollover milestone
2011	July	Business plans submitted to Ofgem	
	August		Publish Initial Proposals
	October	Initial Business Plan appraisal consultation	
	November		Publish Final Proposals
	December	Fast-track recommendation consultation	
2012	January		Publish Licence Amendment consultation
	February	Fast-track decision	
	March		Issue Regulatory Instructions and Guidance (RIGs)
	April		New licences come into effect - New price control period begins
	July	Publish Initial Proposals	
	December	Publish Final Proposals	
2013	January	Consultation on licence changes	
	March	Issue Regulatory Instructions and Guidance (RIGs)	
	April	New price control period begins	

[26] See 'Regulating energy networks for the future: RPI-X@20 decision document' published on 4 October 2010 with reference number 128/10 on our website www.ofgem.gov.uk.

As part of the TPCR4 rollover we will not be introducing any new policy or adopting an approach which misaligns with RIIO-T1. The TOs will submit their RIIO-T1 business plans in July 2011. When assessing these business plans we will consider the allowances we are granting the TOs for the TPCR4 rollover year. Work-in-progress will also be considered in developing the RIIO-T1 settlement.

Approach to anticipatory investment

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 mechanism 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:

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.

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 TPCR4 rollover year 2012-13.

As part of their business plan submissions the licensees have projected their expenditure on projects funded via the TIRG and TII mechanism within the TPCR4 rollover year. They expect these projects to account for a significant portion of their expenditure. These projects are not within the scope of this document and we will communicate our decision on funding allowances through a separate process[27]. However, we will consider the impact of these projects when considering the deliverability of the capex program as a whole and the financeability of the licensees.

LNG price control

NGG owns three LNG storage facilities, which provide a combination of commercial and regulated services. The regulated services are provided at regulated prices. In August 2010 we started a review of these regulated prices, which was outside the remit of the TPCR4 rollover.

[27] 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

In February 2011 we concluded the review of the regulated prices. Our final proposals[28] used a pre-tax allowed return of 6.25 per cent. This was the same figure used in the previous LNG price control (concluding in 2008) and at TPCR4. We noted that this was higher than that used at the electricity distribution price control review which covers the period from 1 April 2010 to 31 March 2015 (DPCR5), but considered this was justified because the LNG storage business faces more risky and volatile revenues than a typical network monopoly.

These regulated prices will be in effect until 31st March 2013, after which they will adopt the approach agreed under RIIO-T1.

We outlined in the final proposals to the LNG price control that the choice of allowed return of 6.25 per cent should not be taken as a signal of the intentions for the TPCR4 rollover (nor RIIO-T1 and RIIO-GD1).

[28] See 'National Grid LNG facilities price control - Final Proposals', published on 21 February 2011 with reference number 18/11 on the Ofgem website www.ofgem.gov.uk.

Appendix 3 – Objectives of the TPCR4 rollover

Our intention is that the TPCR4 rollover should have the minimum scope consistent with our duties and the principle of better regulation. We consider that this will ensure that the TPCR4 rollover represents a proportionate intervention that minimises the risk of making decisions which are inconsistent with the conclusions of the RPI-X@20 project. We only propose to deviate from this approach:

- To reflect agreed policy developments; and/or
- If there are areas of work we could undertake now which would smooth the path of RIIO-T1 but which will be independent of the conclusions from the RPI-X@20 project.

We propose that the objectives of the TPCR4 rollover should be as follows:

- **To protect the interests of existing and future consumers**[29]– Consumers' interests are protected by having high quality transmission networks supporting a high standard of security of supply delivered at an efficient cost. Therefore, while the review is a 'rollover' it should provide an appropriate level of scrutiny of transmission companies' forecasts, sense-checked against their historical performance.

- **To be consistent with Ofgem's wider statutory duties** – including the need to secure that licence holders are able to finance their ongoing activities which are the subject of obligations on them. When carrying out our duties we also have regard to the need to contribute to the achievement of sustainable development and to the effect on the environment from regulated activities. We also have regard to the need to secure that all reasonable demands for electricity and gas can be met. The Authority shall also have regard to statutory guidance on social and environmental matters issued by the Secretary of State. A revised version of its Social and Environmental Guidance was formally issued to the Authority on 18 January 2010.

- **To be proportionate to a one-year control and to minimise regulatory burden** – Recognising that the proposals will only apply for one year and that the review will extend the existing control mechanisms, the review should not introduce fundamentally different arrangements relative to the preceding price control. To develop new arrangements in the year before the introduction of the new framework (resulting from the RPI-X@20 project) would create greater uncertainty and undermine the purpose of the TPCR4 rollover. Our approach should also seek to maximise administrative efficiency in terms of the resource requirements and costs of both Ofgem and the industry. Relevant considerations include the number of consultation papers published and the requirement for consultancy support.

[29] 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.

- **To reflect recent developments in policy** – There have been a number of areas where changes have been made to the process for calculating key price control parameters in the period since the final decisions for TPCR4. For example, Ofgem has recently completed a review of the treatment of pension costs that will affect all future network price controls and in setting DPCR5 Ofgem gave consideration to the cost of capital. The DPCR5 process also built in arrangements for greater stakeholder engagement. In addition, there is a need to update certain price control parameters, for example, the revenue drivers in light of: (a) our work on TO incentives[30]; and (b) the Connect and Manage[31] access regime which is expected to be implemented by Government, to appropriately reflect the relationship between investment and the volume of generation connected. While it may be disproportionate to reflect all changes in policy in the one year rollover, any proposal for the TPCR4 rollover should be considered in the context of avoiding inconsistency with recent developments in policy.

- **Not to delay critical investment** – A large amount of transmission investment is needed in the near future, including facilitating the achievement of the Government's carbon targets. For electricity, this investment has been highlighted in a study by the Electricity Networks Strategy Group[32], and we accept that requirements for additional investment may be identified. It is critical that no necessary investment is delayed by our decision to roll over TPCR4 until 31 March 2013.

- **As far as practical, to enable an efficient process to develop RIIO-T1** – Whilst we intend to manage the TPCR4 rollover as a distinct exercise, separate from our work on RIIO-T1, we recognise that there may be an interaction with work that would subsequently have to be taken forward as part of RIIO-T1. We will look for areas where non-overlapping work undertaken as part of the TPCR4 rollover will either remove or reduce the need to perform certain tasks as part of RIIO-T1.

[30] Our TO incentives work was taken forward following the Transmission Access Review. http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx
[31] Details of the consultation on Connect and Manage can be found on the DECC website: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx
[32] The ENSG study is available on the ENSG website: http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf

Appendix 4 - Summary of responses to June 2010 consultation

This section contains a summary of the consultation responses to the "Transmission Price Control 4 - Rollover (2012-13) scope decision and consultation" paper published on 30 June 2010. The full set of responses is available on our website www.ofgem.gov.uk. This section is organised according to the responses to the five specific questions we set out in that paper along with other general comments.

We received five responses, these were from each of the TOs (National Grid, SPTL and SHETL), plus submissions from Centrica Energy and EDF Energy.

Do you think it is appropriate that the revenue drivers should be used in the rollover year to determine the allowed capex for the electricity TOs?

Two of the TOs were supportive of the use of the revenue drivers for the TPCR4 rollover period, although one noted the need to use up to date information in determining the specifics. One TO was of the view that the revenue drivers may not be needed for the TPCR4 rollover as there is not the same uncertainty in a one year price control around the volume of new generation connections. They also indicated that it might be appropriate to use the revenue drivers for some but not all TOs.

One respondent suggested that any review of revenue drivers should aim to give clarity as soon as possible as the level of investment is significant and needs to be carried out in a timely manner. Another respondent felt that it was reasonable to extend the revenue drivers but asked for clarification of the treatment of interest associated with capex corrections.

Do you believe the SF6 incentive scheme should continue into the rollover year and, if so, is the current structure appropriate or should it be modified?

Overall the TOs were supportive of this environmental incentive. However, one TO felt that a comprehensive ‘carbon footprint’ approach, similar to that established in electricity distribution, should be trialled during the TPCR4 rollover removing the need for a specific SF6 incentive. Another TO indicated that the scope for continuing to make reductions in SF6 emissions was reducing and suggested that the decline in the target rate should be slowed.

One respondent noted that the SF6 incentive scheme was still relatively new and that they would need more detailed information on its performance before they could develop an informed view on its appropriateness

NGG have incentives to deliver capacity in a timely manner and we hope to continue this type of incentive for the rollover year. How do you feel this can be best achieved during the rollover year?

The TOs had a general agreement to continue these incentives.

One TO indicated it would like to discuss a number of issues including: implications of the Planning Act 2008 on the permit scheme; the permit scheme for exit and its view that this was initially set up for small projects; the appropriateness of some unit revenue drivers; and the indexation of the revenue drivers for steel and construction costs which it considers to not extend beyond 2011-12.

One respondent noted that any reform of these incentives should be focused on improving the existing incentives; this could be done as follows:

- A revenue driver is triggered but no obligation or investment is incurred by NGG, then the revenue driver should be scaled back by Ofgem. Another respondent considered that there should be flexibility to address the Fleetwood issue that this refers to, should parallel routes fail to resolve it.
- A quick review of baseline obligations should be conducted to ensure that there are clearly no erroneous requirements eg Dynevor Arms (this was supported by another respondent on a proportionate basis)
- Any review or reform of capacity incentives should be clearly flagged to industry at an early stage, along with potential outcomes to remove unexpected outcomes

Do you believe that the current structure of the SO internal incentive scheme should roll over (accounting for updates to external SO incentive parameters as is currently the case)?

Four respondents agreed that this would be a consistent and proportionate approach for Ofgem to adopt. One of these suggested that the electricity SO scheme should keep intact the link with the external Balancing Services Incentive Scheme (BSIS) parameters. Whilst another of these noted that great care is needed in updating incentive parameters to ensure that networks companies are not able to obtain windfall benefits.

We are in the process of finalising our approach to stakeholder engagement for the rollover period, do you agree with the proposed approach detailed in this paper?

Four respondents agreed with this approach, one of which preferred their resources to be focused on RIIO-T1. A couple of respondents requested transparency such that TOs provide customers with an impact of the TPCR4 rollover (which could be done through existing gas industry fora) and data published early to better inform consultation responses. They also supported the approach of using working groups to consider particular issues with papers circulated in advance.

Other comments

One respondent noted that additional allowances should only be made to the TOs on the basis of clear benefits to consumers and not adversely affecting the balancing between cost and risk.

Capex

One respondent noted it will be important to include "pre-preconstruction" allowances for future enhanced TO incentive capex in the rollover base capex allowances. They also expressed their concerns over Ofgem adopting an average unit cost approach as it did in DPCR5. The same respondent considered it would be more appropriate for Ofgem to review a sample of schemes to better understand the TOs' forecasts and consider actual expenditure further as part of Ofgem's comprehensive historic assessment of TPCR4 capex for RIIO-T1.

One respondent believed that in setting the opening RAV for the rollover year, Ofgem's assessment should take account of the TOs' performance under the incentive.

One respondent expressed their disappointment that Ofgem has decided to exclude the addition of logged-up costs (and by implication, expenditure associated with securing critical network infrastructure) until the completion of its historic expenditure review at RIIO-T1. Therefore, it believed that Ofgem should include in the TPCR4 rollover opening RAV expenditure associated with securing critical network infrastructure and not delay until RIIO-T1.

One respondent considered that the funding mechanism within the TIRG projects should not be modified.

Financial issues

One respondent considered that it will be essential to ensure that Ofgem's final proposal for the allowed return does not cause unacceptable financeability issues for the network companies.

One respondent requested Ofgem to minimise the regulatory risk through providing potential inferences, intended or otherwise, upon the main and partially overlapping, RIIO-T1 Price Control Review.

One respondent was comfortable about the proposed TPCR4 rollover tax approach as it follows that used at DPCR5.

One respondent requested full visibility of the financial model and return on regulatory equity (RORE) and any associated methodologies as soon as these become available.

One respondent generally agreed with the proposed approach on capitalisation and depreciation. However, it was concerned about the impact upon financeability over calculating depreciation allowances, and urged Ofgem to provide as much transparency and flexibility in any financial modelling to ensure open and informed consideration of alternative scenarios and their impacts.

One respondent was generally comfortable with Ofgem's position on pensions, but noted their concern about deemed deficit recovery period. With regard to the pensions overpayments, another noted that importance of ensuring that there is NPV neutrality for activity brought forward.

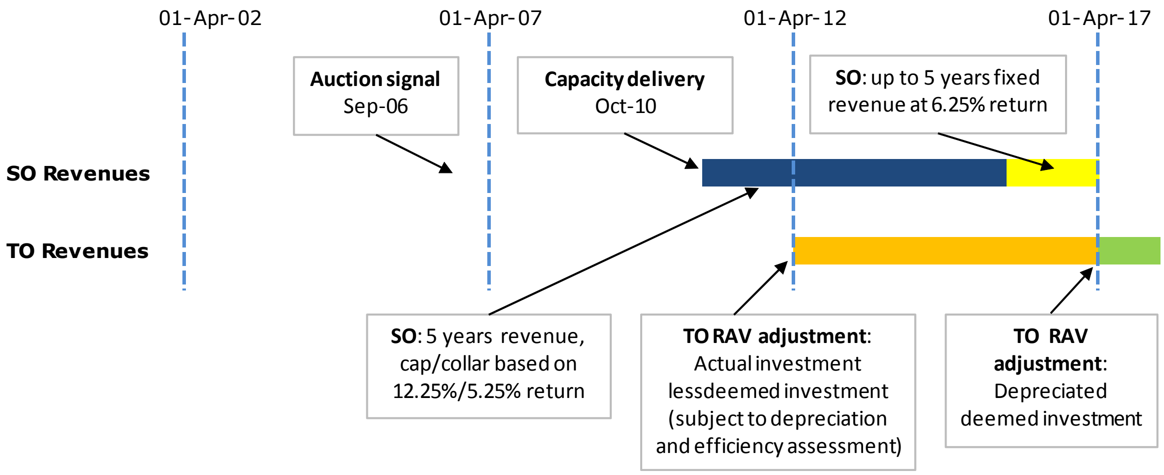
Appendix 5 – Policy details

This appendix sets out the detail on how some policies currently work.

Gas capacity investment incentive

Pre-2007 signals

Figure 15: Pre-2007 capacity investment incentive scheme



In June 2003 we[33] set out the regime to remunerate additional entry capacity (revenue drivers were not in place for exit capacity at that time). NGG was remunerated on its SO and TO sides for specific periods linked to the delivery date of additional capacity and the start and end of price control periods. This is described as follows.

- On the SO side:
  - **For the first five years after delivery** - NGG earns auction revenue from sales of this additional capacity subject to upper and lower limits. These limits are based on rates of return of 5.25 per cent and 12.25 per cent on the deemed investment (this equals the unit revenue driver multiplied by the capacity increase). This is shown by the blue box in figure 15.
  - **After the five year incentive period until end of current price control** - NGG earns fixed rate of return of 6.25 per cent on deemed investment. This is shown by the yellow box in figure 15.

[33] See 'New entry terminals to Transco's National Transmission System: Ofgem's views on Transco's proposals and explanatory notes to accompany the section 23 notice of proposed modifications to Transco's gas transporter licence' published on 30 June 2003 with reference 62/03 on the Ofgem website www.ofgem.gov.uk

    - **After this** - NGG earns no further SO revenues.
- At the price control review after delivery of the capacity the investment is assessed for efficiency and an adjustment made to the TO RAV as follows: *Actual efficient depreciated investment less Depreciated deemed investment*.
- At the following price control the remaining depreciated deemed investment is added to the TO RAV.
- On the TO side:
    - **During the first price control after delivery** - NGG earns revenue on the TO RAV adjustment. This is shown as the orange box in figure 15.
    - **After this for the remainder of the economic life of the investment** - NGG earns revenue on the further TO adjustment. This is shown as the green box in figure 15.

Post-2007 signals

At TPCR4 we revised the remuneration regime for additional capacity that would apply to signals received after April 2007. This approach was common for entry and exit. For investment signals after 2007, NGG is remunerated on its SO and TO sides for specific time periods, but this is no longer linked to the timing of price controls. This works as follows:

- On the SO side - NGG is remunerated for a fixed five-year period after delivery
- On the TO side - After this five-year period the efficient investment is added to the TO RAV and so provides NGG with return, depreciation, etc

The revenue driver amounts are uplifted both for general inflation and for a combined index for materials and construction costs.

Appendix 6 - Business plan assessment: Capex

Introduction

This section looks in more detail at the Capex Review. Here we consider the arguments put forward by the Transmission Operators for increased investment. We also set out the comments from our technical consultants.

NGET - LRE

NGET has stated that they have a high degree of confidence that the majority of projects will materialise given the proximity of the TPCR4 rollover year. However they recognise that for some projects there may be a degree of uncertainty as issues such as planning consent and project delivery could impact upon timescales. NGET has also indicated that the new Connect and Manage arrangements could also impact on the timescales for generation projects as only local enabling works need to be completed prior to connection rather than wider reinforcement work.

In terms of demand connections NGET has a range of "in-flight" projects currently underway and continuing into 2012-13 and projects expected to start in 2010-11 and 2011-12 continuing into the TPCR4 rollover year and in some cases RIIO-T1. This work relates to projects being undertaken for Network Rail, new Grid Supply Points (GSPs) and GSP reinforcement.

Although in recent years the economic downturn has seen a general fall in demand submissions NGET have highlighted that in some sites there has been demand growth and these require reinforcement.

NGET have also identified a need to spend on general infrastructure. This is work driven by the combination of general changes in the balance of demand and generation and the subsequent management of power flows across the network. These projects include both reactive and non-reactive investment.

NGET - NLRE

Transformers and quadrature boosters

Transformers are assets which transfer energy to different voltage levels. NGET has targeted transformer replacement at maintaining security of supply – taking into consideration future generation and demand needs whilst maintaining the current and historical levels of reliability, safety and environmental performance. NGET is forecasting an increase in investment in these areas from 2012 but not an associated increase in volumes for this from 2012. NGET state that "increased investment is planned from 2012 onwards" [including the TPCR4 rollover year] however an increase in replacement volumes does not occur in 2012-13. This is primarily due to the system access constraints imposed by a number of key circuits and substations being identified as Category 'A' sites for the Olympic Games.

Quadrature boosters provide the facility to control the power flowing through specific parts of the transmission system thereby maximising the utilisation of the system and available capacity. Planned expenditure is based on asset condition and network criticality. This strategy also ensures the availability of strategic spares.

Shunt Reactors

Shunt Reactors assist in managing reactive compensation on the system to maintain voltage compliance with the planning criteria of security standards and to provide adequate black start capabilities. NGET are planning an increase in investment in this area in 2012-13 in the TPCR4 rollover year, replacing four units based on condition and criticality.

Switchgear

Switchgear is a generic term for all equipment in a standard bay of assets used for HV transmission, with the lead asset being circuit breakers. For the TPCR4 rollover, investment on switchgear is forecast to increase. NGET has identified the need for increased investment based on a basket of priorities including condition, defect history, service experience and family history. Furthermore the proposed investment aims to cover both replacement (installing new equipment) and refurbishment (enhancing the asset and extending it beyond its technical anticipated life).

Protection and Control

Protection equipment refers to assets which protect the main system under fault conditions. Control equipment refers to discrete systems which enable the transmission system to be operated remotely and also provide information on the operational state of the asset. Metering assets are also included within this category.

NGET has forecast a requirement to increase expenditure to manage the performance, reliability and obsolescence of the assets. This includes metering assets where a large portion of the population is reaching the end of their technical life.

Overhead Lines

NGET is forecasting increases in overhead line expenditure from 2010-11 up to and including 2012-13. NGET has determined the expenditure based on replacement priorities. The proposed expenditure covers a range of schemes:

- full Refurbishment where there is replacement for conductors, fittings and tower steelwork for a specified length of circuit

- fittings only for a specified length of circuit where only the hardware supporting the conductors, spacers and dampers are replaced
- steelwork where only the tower steelwork is replaced for a specified number of towers
- earthwire only – where the single conductor at the peak towers is replaced on its own for a specified length of circuit.

Underground Cables

Expenditure on underground cables is forecast to increase from 2009-10 for all years up to 2012-13 – peaking in 2010-11.

The underlying driver for this is system security and environmental concerns. NGET is planning a replacement programme which targets the most “at risk” cables.

SPTL – LRE

There is significant generation expected to connect to the SPTL area. Given the current status of certain specific project consents SPTL do not expect any renewable generation connections to complete in 2012-13 but they do expect eight renewable generation connections in 2013-14 totalling 827MW – with much of the capital investment associated with these connections being undertaken in 2012-13.

The total contracted connections for renewable generation is high with a portfolio of almost 2400MW. Additionally SPTL have several offshore connections under offer totalling 3000MW. When taking together the connected, contracted and ‘under offer’ transmission connections then the connections portfolio is in excess of 7GW. SPTL said that it may have further connections if other applications go ahead.

SPTL - NLRE

Overhead Lines

SPTL’s overhead line strategy expenditure involves major refurbishment of assets at the end or near the end of their technical life and intermediate (light) refurbishment of circuits in mid life.

The projects include:

- Several 132kV circuits at the end of life where through network reconfiguration and selective undergrounding sections of the overhead line circuits are removed
- 132 kV circuits at the end of their technical life which require major refurbishment – including full reconductoring, reinsulation and steelwork refurbishment
- Several 275kV / 400kV at the end of their technical life which require major refurbishment – including full reconductoring, reinsulation and steelwork refurbishment.

Transformers

The strategy for transformers involves replacement of assets at or near end of life, particularly those with high readings for Dissolved Gas Analysis (DGA) and poor condition assessment. The programme is focussed on two main areas:

- replacement of certain transformers where there is a type issue
- refurbishment of other transformers with poor DGA and condition, primarily 132kV GSP transformers

Switchgear

Replacement plans for switchgear are focussed on assets at or near the end of their life. These have been identified through a combination of type-based operational adequacy assessment and condition reports. Delivery is focussed on air blast circuit breakers and bulk oil breakers.

Cables

SPTL's forecast expenditure for cables is associated with replacement of assets at the end, or near the end, of their technical life – particularly those with poor health rankings. The main focus of the plan is a programme of replacement of gas compression cables which is due for completion in the TPCR4 rollover year.

Protection

SPTL are using a type-based asset risk method approach to quantify consistently the health of protection relay types for the entire protection population. A programme of work has been scoped to replace all end of life protection assets on the system by 2018.

Telecoms

The bulk of this expenditure relates to modernisation work for maintaining the integrity of underground pilot wires and fibre wrap optic used on tower lines. SPTL said that fibre wrap is of particular concern as there has been fibre failures and evidence of degradation within the population of assets.

System Control and Data Acquisition (SCADA)

SPTL have identified the need for expenditure on SCADA to address obsolescence issues with the central system hardware and legacy Ferranti MKIIA Remote Transmission Unit RTUs on the transmission system.

SHETL – LRE

SHETL's load-related schemes are driven by growth in demand and aggregation of load from small embedded generators. It has also identified "Renewables Related" capex – where there is large renewable sole use generation connection investment. Included in this category is pre-construction expenditure for capital reinforcement.

SHETL considers that there is a high degree of confidence in the proposals for 2012-13 as the developers' consents and their own consents are well progressed. SHETL states that expenditure is growing as many of the projects are connecting at a greater distance from the network and are also requiring large reinforcements since existing capacity has already been taken with prior connections.

NGG – LRE

NGG have stated that the flow patterns are changing dramatically. Traditionally the flow has been from North to South but with supplies from the UK continental shelf in decline and new supply projects located in more southerly areas the combined effect is making supply patterns more unpredictable.

To ensure NGG is able to respond to requirements it has identified strategic investment including:

- Rationalisation of Bacton terminal to increase operational flexibility and robustness
- Modifications at Kings Lynn compressor station to facilitate the required quick reversal of flow direction
- The design and installation of new flow control valves to meet reconfiguration requirements at various points around the network
- Installation of an electric drive at Lockerley compressor station to provide the required level of standby and redundancy
- Modifications to existing compressors and the installation of new compressor units, to improve system operation capability and efficiency.

NGG TO - NLRE

Asset Health

NGG has stated that increases in asset replacement are driven by the need to manage performance, safety, reliability and compliance standards for specific asset groups driven by NOMs.

The NTS consists of a large number of secondary assets which support the primary assets (entry points, pipelines, multijunctions, compressor units and exit points). The NLRE primarily relates to this secondary asset group where the strategy is to maintain the overall condition of the primary asset group and to minimise disruption to customers by maintaining their reliability, performance and condition.

The secondary assets have a high degree of cost variability given design specifications, requirements and equipment innovation. Using the NOM methodology NGG has identified investment in the following areas:

- Gas analysers
- Fiscal metering
- River crossings – including Feeder 9 Humber crossing
- Control systems
- Cathodic protection
- Compressors - exhaust and air intake
- Compressors - power turbine
- Compressors - gas generators

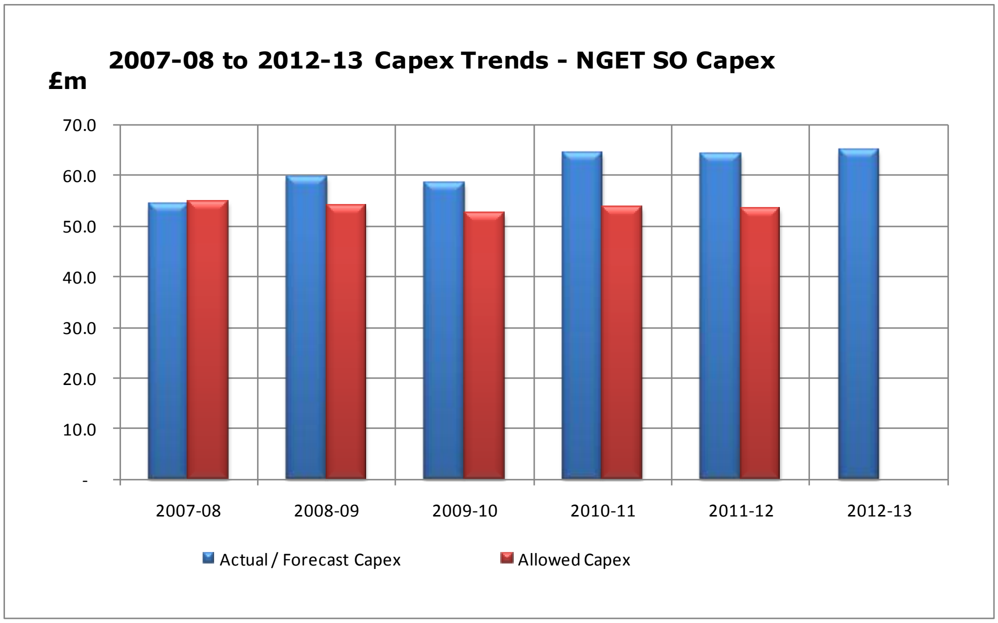
Emission Reductions

NGG has identified more NLRE driven by emissions reductions. NGG said that environmental legislation requires them to satisfy legally binding emissions limits. The Environment Agency places an explicit requirement on NGG to determine the most appropriate investment for emissions prevention or reduction in the light of compressor utilisation.

SO Capex

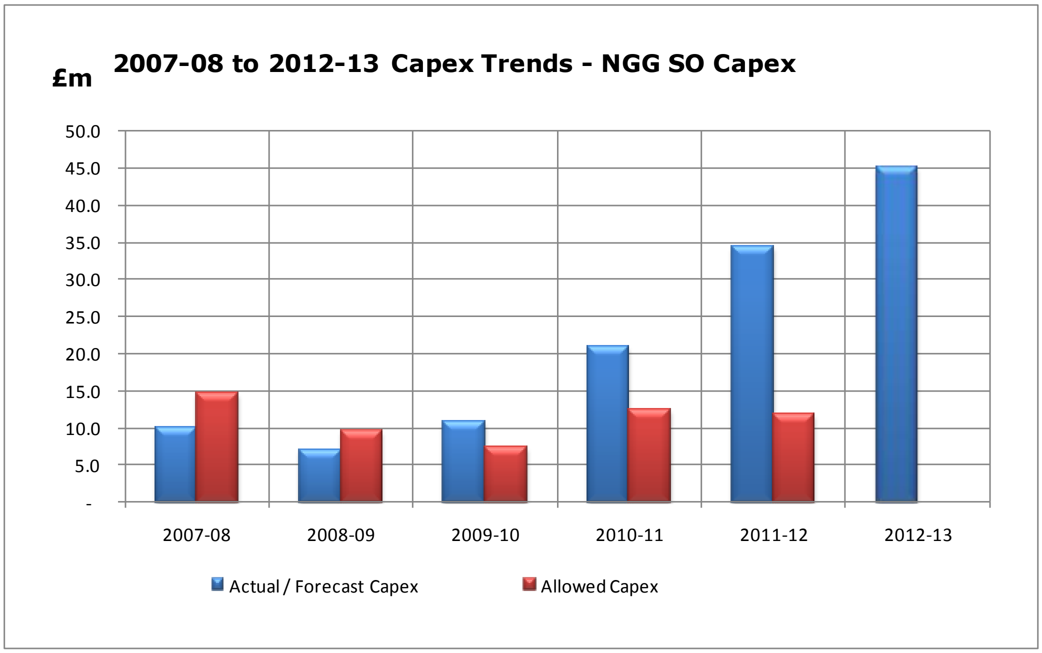
The figure below shows the SO capex trends for both NGET and NGG. This data has been taken from the FBPQ's provided by National Grid for both activities.

Figure 16: SO Capex trends - NGET



NGET SO had parity between allowances and actuals in 2007-08 but for all other years there has been a small overspend. Forecast expenditure for the TPCR4 rollover year is also expected to increase upon existing TPCR4 allowances.

Figure 17: SO Capex trends - NGG



For NGG SO the early years saw allowances exceed actuals but this trend reversed from 2009-10 onwards. Furthermore the overspend has become more pronounced in 2011-12 and NGG SO are forecasting a ramp up in expenditure for the TPCR4 rollover year.

The factors driving these trends are discussed in greater detail below.

NGET - SO

Asset Health

NGET invested significantly at the start of TPCR4. However, it said that new investment is required to cover the following areas:

- Electricity Management System (EMS) – software system upgrades are planned and new hardware refreshes are forecast
- Balancing Mechanism – NGET is seeking to replace current systems

Enhanced SO Capability

NGET believes to meet the future challenges associated with a more complex operating environment it needs to invest in the following areas:

- Enabling change – enhancing data management, simulation and infrastructure to more efficiently enable future developments
- Improved modelling and decision making – enabling more scenarios to be modelled
- Operational control and automation – utilisation of improved functionality for controlling voltage and monitoring,
- Situational awareness – giving the control engineer a more accurate and informative view of the state of network

NGG SO

iGMS

iGMS is a suite of applications used to operate the NTS – including Supervisory Control and Data Acquisition (SCADA) systems. Given the changes to the operating environment with more unpredictability in supply NGG wants to re-engineer the system

Gemini System

Gemini is the system which supports gas capacity management, energy balancing and associated invoicing process on behalf of transporters and the shipper community. It is closely integrated with iGMS and shares common infrastructure. It is owned by NGG but managed by Xoserve. Following a health check NGG are proposing a re-platforming exercise given the age of the infrastructure.

Comments on TO forecasts

NGET TO

Ofgem appointed KEMA has our technical consultants and they have reviewed in depth the business plans put forward by the Transmission Operators. We also appointed PPA Energy as consultants for reviewing the SO activities of National Grid – for both gas and electricity.

Although we are close to the TPCR4 rollover year, there are still significant uncertainties in load-related projects associated with the connection of new generation given that some schemes are still in development and may face issues with planning consent. KEMA note that the Connect and Manage regime introduces further uncertainty as customers have greater control over the timescales of the connection.

KEMA are satisfied with the design of load-related schemes based on a sample of projects. However, they have concerns about some of the costs, particularly overheads applied. Based on these issues KEMA are recommending the range of allowances in Table 12.

Table 12: KEMA recommendations - LRE allowances for NGET TO

2012/13 Rollover Year (£m)	NGET F'cast	KEMA Estimate
LOAD RELATED EXPENDITURE		
Generation connection - sole-use	1.0	1.0
Demand connection - sole-use	38.2	38.2
Total LRE - sole-use	39.2	39.2
Infrastructure - entry triggered	236.4	163.4 - 199.7
Infrastructure - general reactive (excl TIRG /TSS)	2.5	2.5
Infrastructure - general non reactive (excl TIRG /TSS)	53.9	53.9
Infrastructure - exit triggered	60.7	60.7
Infrastructure - TSS	9.4	9.4
Total LRE - Infrastructure	363.0	289.9 - 326.2
TOTAL	**402.2**	**329.1 - 365.4**

For NLRE KEMA are challenging:

- Transformers, Switchgear Overhead lines and Protection & Control – where in KEMA's view there is evidence of high unit costs
- Cable tunnels – KEMA are concerned about the forecasts for on-costs and contingency allowances.

In those areas where costs are being challenged KEMA are recommending the range indicated in Table 13.

Table 13: KEMA recommendations - NLRE allowances for NGET TO

2012/13 Rollover Year (£m)	NGET F'cast	KEMA Estimate
NON-LOAD RELATED EXPENDITURE		
Assets - replacement and refurbishment		
Transformers	105.5	62.7 - 72.9
Reactors	7.6	7.6
Switchgear	97.5	63.8 - 74.2
Overhead Lines	123.7	74 - 86
Underground Cables	31.0	24.4 - 28.4
Cable tunnels	81.2	60.1 - 69.9
Protection & control	40.3	32.4 - 37.6
Sub-station other	13.7	12.7 - 14.7
Other NLRE		
Other TO	56.7	43.2 - 50.2
Quasi capex	7.3	7.3
TOTAL	**564.4**	**385 - 456**

More generally KEMA also raised questions about the deliverability of the full capex programme given the scale of the forecast increase.

SPTL

KEMA have raised concerns about the certainty of SPTL's load-related expenditure forecasts given issues associated with planning consents both for developers of the generation projects and SPTL's associated connection schemes. This relates to the forecasts for both generator sole use expenditure and wider infrastructure schemes. As a result KEMA are recommending the range in Table 14 for LRE.

Table 14: KEMA recommendations - LRE allowances for SPTL

2012/13 Rollover Year (£m)	SPTL F'cast	KEMA Estimate
LOAD RELATED EXPENDITURE		
Generation connection - sole-use	20.1	11.7 - 14.3
Demand connection - sole-use	0.0	0
Total LRE - sole-use	20.1	11.7 - 14.3
Infrastructure - entry triggered	91.1	65.9 - 80.5
Infrastructure - general reactive (excl TIRG /TSS)	0.0	0
Infrastructure - general non reactive (excl TIRG /TSS)	18.0	18.0
Infrastructure - exit triggered	2.4	2.4
Infrastructure - TSS	0.0	0
Total LRE - Infrastructure	111.5	86.3 - 100.9
TOTAL	**131.7**	**98.0 - 115.2**

For NLRE, KEMA have concerns regarding SPTL's asset replacement forecasts for switchgear and overhead lines. They have questioned the underlying rationale to extend and accelerate the replacement programme for switchgear in 2013. For overhead lines KEMA believe there is insufficient condition data to justify the extent of the replacement programme being proposed. Given these issues KEMA are recommending the range indicated in Table 15. We note that SPTL does not believe it is appropriate to compare allowances to actuals at a disaggregated level.

Table 15: KEMA recommendations - NLRE allowances for SPTL

2012/13 Rollover Year (£m)	SPTL F'cast	KEMA Estimate
NON-LOAD RELATED EXPENDITURE		
Assets - replacement and refurbishment		
Transformers	9.5	9.5
Reactors	0.0	0.0
Switchgear	19.0	13.9 - 16.1
Overhead Lines	41.1	25.9 - 30.1
Underground Cables	3.4	3.4
Protection & control	8.5	8.5
Sub-station other	2.1	2.1
Other NLRE		
Other TO	3.7	3.7
Quasi capex		
TOTAL	**87.2**	**67.0 - 73.4**

In terms of deliverability KEMA also raise concerns about how much of the full capex programme can be delivered given the existing constraints of the supplier base within the wider market.

SHETL

KEMA have concerns about the degree of uncertainty relating to whether load-related projects will go ahead, particularly for sole use work relating to demand connections and entry triggered infrastructure projects. KEMA have raised questions about the consent status for the developers' projects, the contracted date for the work, SHETL's scheme consent status and SHETL's own project planning status. As a result KEMA are recommending the range set out in Table 16.

Table 16: KEMA recommendations - LRE allowances for SHETL

2012/13 Rollover Year (£m)	SHETL F'cast	KEMA Estimate
LOAD RELATED EXPENDITURE		
Generation connection - sole-use	11.3	11.3
Demand connection - sole-use	21.8	14.9 - 18.3
Total LRE - sole-use	33.1	26.2 - 29.6
Infrastructure - entry triggered	34.9	22.0 - 26.8
Infrastructure - general reactive (excl TIRG /TSS)	0.0	0
Infrastructure - general non reactive (excl TIRG /TSS)	0.0	0
Infrastructure - exit triggered	1.0	1.0
Infrastructure - TSS	2.0	2.0
Total LRE - Infrastructure	37.9	25.0 - 29.8
Capitalised Overheads	3.9	3.9
TOTAL	**74.9**	**55.1 - 63.3**

For NLRE, KEMA have fewer concerns – with the only significant issue being unit costs for transformers. KEMA are recommending the range in Table 17 for the TPCR4 rollover year.

Table 17: KEMA recommendations - NLRE allowances for SHETL

2012/13 Rollover Year (£m)	SHETL F'cast	KEMA Estimate
NON-LOAD RELATED EXPENDITURE		
Assets - replacement and refurbishment		
Transformers	4.2	3.3 - 3.8
Reactors	0.0	0.0
Switchgear	4.1	4.1
Overhead Lines	4.6	3.6 - 4.2
Underground Cables	3.7	3.7
Protection & control	0.7	0.7
Sub-station other	1.8	1.8
Other NLRE		
Other TO	0.0	0.0
Quasi capex		
Capitalised Overheads	1.7	1.7
TOTAL	**20.8**	**18.9 - 20.0**

For deliverability KEMA recognise that SHETL is taking pro-active steps to ensure delivery of the programme but given the size of the increases consider that the challenges still remain considerable.

NGG - TO

KEMA have identified significant challenges to NGG for network flexibility. It has concerns over the certainty of the spend, whether the spend is already covered by existing revenue driver mechanisms and whether NGG should have anticipated these items when original revenue drivers were set. On the latter point if the rationale used by NGG to justify the need for network flexibility was evident at the time we set revenue drivers, then this should have been captured in the modelling to set revenue drivers. Ofgem remain unconvinced that there is any need to spend the money on network flexibility in 2012-13.

Based on these challenges KEMA recommend the range in Table 18.

Table 18: KEMA recommendations - network flex for NGG TO

2012/13 TPCR4 rollover Year LRE (Flex)	NGG Forecast (£m)	KEMA Estimate (£m)
Network Flex	50.3	9.8 – 14.0

Moreover KEMA are challenging the following specific issues:

The projects at Peterborough (Compressor re-wheel and Flow Control Valve replacement), Bacton (rationalisation) and for the replacement of existing Flow Control Valves (FCVs) at three locations yet to be determined do not appear to have been adequately justified.

In KEMA's view the compressor replacements at Asselby and Moffat appear to be principally driven by reducing flows at St. Fergus, albeit replaced by incremental flows at other entry points and therefore should be signalled by incremental capacity to support these incremental entry flows. The Lockerley compressor replacement appears to be principally driven by load growth. KEMA therefore consider that all these projects should be excluded from the flexibility category of expenditure as they are more readily identified as being subject to revenue drivers.

For NLRE KEMA are also identifying challenges to NGG. These include the sanctioning of schemes being ratified in the 2012-13 and that some projects apparently have had allowances granted previously. Based on these issues KEMA are recommending the range in Table 19.

Table 19: KEMA recommendation - NLRE allowances for NGG

2012/13 TPCR4 rollover Year NLRE	NGG Forecast (£m)	KEMA Estimate (£m)
Asset Health Total	**51.4**	**30.2 – 39.5**
Emissions Reduction	7.6	7.6
Other	3.8	3.8
Quasi-Capex	1.7	1.7
TOTAL	**64.6**	**43.3 – 52.6**

Within the larger asset groups (e.g. Fiscal Metering and Power Turbines) certain amounts of asset health expenditure has yet to be sanctioned, suggesting that in KEMA's view the relative priority and value of these projects remain to be ratified for inclusion in the TPCR4 rollover year.

The ongoing work to obtain planning consent for the most appropriate approach for the Feeder 9 project continues, with a high risk that the process will not have progressed sufficiently for the anticipated initial design and site study work to take place in the TPCR4 rollover year. It is therefore suggested that the proposed certain expenditure, in KEMA's opinion, may not be required in the TPCR4 rollover year. This amount has, therefore, been deducted from the forecast.

Detailed review of the entry phase 2 gas quality metering work reveals that, in KEMA's opinion, some of this has previously been allowed, and this expenditure has slipped into the TPCR4 rollover year. Since this spend has previously been allowed it is not clear, again in KEMA's view that any further allowance is necessary. Hence this amount has been deducted from the proposed expenditure.

For emissions reduction; the proposed spend has been agreed by KEMA.

Appendix 7 - Business plan assessment: opex

Introduction

This section looks in more detail at the Opex Review. Here we consider the arguments put forward by the Transmission Operators for increased expenditure.

Summary of TO activities

National Grid - NGET and NGG

NG has forecast a significant increase in opex despite achieving efficiencies over the TPCR4 period. This increase is driven by amongst other factors the impact of Real Price, effects, the need to attract, retain and grow the workforce and the effect of managing a growing and diverse asset base. These are considered in more detail below.

Real Price Effects - both NGET and NGG

NG is forecasting significant rises in input costs such as labour, electricity and civil prices above the RPI. NG state that not only are these costs outside of their control they are also greater than those assumed in TPCR4.

Workforce Growth and Training - both NGET and NGG

NG rely on suitably skilled people to deliver customer requirements. With increased global demand for critical engineering skills coupled with a reduction in supply NG argues significant investment is required to grow the workforce to implement the larger, more flexible smarter transmission network.

To respond to the skills shortage NGET are seeking to take forward training initiatives. For electricity these include dedicated training and simulation facilities in the Electricity National Control Centre (ENCC), foundation engineering schemes and apprenticeship programmes.

In terms of recruitment NG said that it is facing increasing competition for a small pool of skilled workers. To mitigate this NG are forecasting a need for greater resources to recruit new entrants into the industry and recruit skilled engineers from a wider base.

Asset Growth, Diversity and Condition - NGET

NGET has identified the need to maintain an increasing population of assets nearing the end of their technical life on the transmission network.

In terms of Asset Growth NGET has seen a growth in its asset base as they continue to invest in the network. NGET state that the consequential effect is that this requires more maintenance and insurance going forward to ensure that safety, system reliability and risk are efficiently managed.

In terms of Asset Condition NGET state that "a higher proportion of transmission assets in use today are more than forty years old in comparison to the start of the TPCR4 period." Consequentially these assets need replacing or require some form of intervention to maintain reliability.

Asset Growth, Diversity and Condition - NGG

NGG have stated that the majority of the NTS was constructed in the 1960s and 1970s and designed with a 40 year technical life. To ensure primary assets are continually fit for purpose the need to maintain and replace secondary assets supporting them arises.

Furthermore NGG also state the age of the assets present obsolescence issues. For example certain assets may have to be made in line with certain specifications to ensure continued quality.

Gas Technical Drawings - NGG

NGG have stated that the quality and accuracy of technical drawings for operational sites is becoming more critical given the potential investment taking place. The need to enhance the gas drawings covers:

- improving quality and completeness of data for existing drawings
- ensure construction projects are not subject to unplanned additional cost and delays
- enable more accurate planning of routine maintenance

Volume and change mix and other- both NGET and NGG

NG has also set out a range of other factors driving increases in opex such as an increase in the regulatory burden, delivering enhanced resilience for the London Olympics and increasing insurance premiums due to a growing workforce and external rates.

Efficiencies identified - both NGET and NGG

In NG’s response they have also identified efficiency initiatives which have been aimed at reducing opex costs. These savings include:

- Continuous Improvement

- Procurement Transformation – NG are proposing a series of changes to transform the procurement function. They are planning to embed procurement processes to ensure more robust challenge and reviews take place. Furthermore it also anticipated that the transformation will deliver organisational and operational models with the potential for economies of scale.
- IS transformation – where NG is seeking to rationalise information services and provide common systems platforms that can utilise economies of scale and provide greater standardisation thereby eliminating unnecessary duplication.
- Transactional shared services – where NG has outsourced transactional activities to an offshore provider.

Other individual efficiency initiatives such as improvements of non-routine maintenance and energy savings at some operational sites.

In addition, NGG TO participates in a pan European benchmarking study with eight other major gas transmission companies. The focus of the benchmarking is primarily opex costs and asset performance. From participation in the group NG has shared knowledge and identified best practice. According to NG the results from 2009 showed they were a leading performer for both cost effectiveness and asset performance.

Appendix 8 - The Authority's Powers and Duties

Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

The Authority's powers and duties are largely provided for in statute (such as the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Acts of 2004, 2008 and 2010) as well as arising from directly effective European Community legislation.

References to the Gas Act and the Electricity Act in this appendix are to Part 1 of those Acts.[34] Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This appendix must be read accordingly.[35]

The Authority's principal objective is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems. The interests of such consumers are 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.

The Authority is generally required to carry out its functions in the manner it considers is best calculated to further the principal objective, wherever appropriate by promoting effective competition between persons engaged in, or commercial activities connected with,

- the shipping, transportation or supply of gas conveyed through pipes;
- the generation, transmission, distribution or supply of electricity;
- the provision or use of electricity interconnectors.

Before deciding to carry out its functions in a particular manner with a view to promoting competition, the Authority will have to consider the extent to which the interests of consumers would be protected by that manner of carrying out those functions and whether there is any other manner (whether or not it would promote competition) in which the Authority could carry out those functions which would better protect those interests.

In performing these duties, the Authority must have regard to:

[34] Entitled "Gas Supply" and "Electricity Supply" respectively.
[35] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[36]; and
- the need to contribute to the achievement of sustainable development.

In performing these duties, the Authority must have regard to the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[37]

Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[38] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
  protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and secure a diverse and viable long-term energy supply, and shall, in carrying out those functions, have regard to the effect on the environment.

In carrying out these functions the Authority must also have regard to:

- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

The Authority may, in carrying out a function under the Gas Act and the Electricity Act, have regard to any interests of consumers in relation to communications services and electronic communications apparatus or to water or sewerage services (within the meaning of the Water Industry Act 1991), which are affected by the carrying out of that function.

The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated

[36] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Acts in the case of Electricity Act functions.
[37] The Authority may have regard to other descriptions of consumers.
[38] Or persons authorised by exemptions to carry on any activity.

National Competition Authority under the EC Modernisation Regulation[39] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[39] Council Regulation (EC) 1/2003.

Appendix 9 - Feedback questionnaire

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:

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

Please send your comments to:

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