RIIO T1

nationalgrid

Managing risk and uncertainty

National Grid
Electricity Transmission

March 2012

Target audience

All stakeholders

About this document

This document sets out the risks and uncertainties we have considered associated with the delivery of our plans for the RIIO-T1 submission. We provide narrative on the options we have considered and justification for the inclusion of the specific uncertainty mechanisms we have proposed to manage and balance any ensuing risks.

Managing risk and uncertainty

Our risk management strategy for RIIO-T1

Table of Contents

Key changes since July 2011

1 In Ofgem's feedback on our July 2011 submission they stated that there were too many uncertainty mechanisms and that they should be tested with stakeholders. As part of our stakeholder engagement activities in the autumn of 2011 we discussed our approach to risk management and our proposed uncertainty mechanisms.

2 Stakeholders were supportive of the use of uncertainty mechanisms as opposed to a higher rate of return, but wanted to clearly understand the implications of those mechanisms and what the impact would be on customer charges

3 We have therefore been engaging with stakeholders through both our Talking Networks events and existing industry meetings in order to improve transparency around the mechanisms, and also to highlight the potential impact on customers' charges due to any additional risk.

4 We have completed further work on the quantification of risks. In particular, we have analysed additional generation and demand scenarios and sensitivities and analysed the cost risks that we face in more detail.

5 We have also refined our approach to some of the risks that we are facing under the business plan period.

(a) We have sought to simplify the arrangements by withdrawing the design standard and offshore network uncertainty mechanisms, and by simplifying the generation connection, demand-related infrastructure and wider boundary capability volume-drivers.

(b) We have also drafted a network development policy to bring further transparency to wider works decisions. The draft policy has been included as an annex to this submission.

(c) We have established robust criteria to identify those wider works projects that will be taken forward under the within-period cost determination arrangements.

(d) We have developed a matrix of unit cost allowances for our volume-driver mechanisms, including drivers for generation connection costs, demand-related infrastructure costs, wider boundary reinforcement costs and the costs of meeting planning requirements.

(e) We have developed proposals for the network output measures secondary deliverables arrangements which allocate the associated risks between National Grid and customers.

6 We are developing ways of improving both the predictability and stability of our charges in response to stakeholder comments. This includes increasing the granularity of revenue information provided to customers, and also improving accessibility to the tools customers need to forecast future charges.

Summary

Overview

7 Under the RIIO-T1 framework, the price control settlement will be based on forecasts of output requirements, demand for network services over time, the cost of delivery (including input prices) and financing costs. The nature of the regime whereby many elements are agreed upfront (and the eight year length of the control) will mean that the certainty associated with forecasts and user requirements will reduce over time. As a result, there is a risk that:

(a) the revenues raised from consumers could be higher or lower than necessary to cover the costs of providing network services, with consumers paying more or less for network services than was necessary; and

(b) the outputs (and potentially secondary deliverables) that are set at the time of the control may turn out to be insufficient or inappropriate

8 Therefore, the main sources of uncertainty relate to the delivery of outputs, the input prices and the volumes of activity required. As part of the RIIO-T1 framework, Ofgem has proposed three main options to deal with this uncertainty, namely:

(a) risk sharing through the efficiency incentive rate

(b) uncertainty mechanisms; and

(c) a mid-period review of the output requirements.

9 Additionally, Ofgem has stated that it expects network companies to bear their own business risk and that uncertainty mechanisms should only be used to manage risks that are outside of our control and could significantly impact costs. This means that the overarching principle for uncertainty mechanisms under the RIIO-T1 model is that we should manage the uncertainty that we face, in order to ensure the most efficient outcome for consumers.

10 We have therefore undertaken an exercise to better understand the risks that we will face over the forthcoming RIIO-T1 price control period and have included our proposals for uncertainty mechanisms where we believe these should apply.

Our approach

11 We have built upon our existing approach to risk management and the wide range of analysis conducted across the business, in order to quantify the risk we are facing. The aim of our work in this area has been to understand the risks that the business will face during RIIO-T1, how those risks might best be managed and evaluate the relationship between the uncertainty mechanisms proposed by both Ofgem and National Grid and the required rate of return.

12 To facilitate this work, we have undertaken a review of the risks to which our businesses are subject and have proposed a set of uncertainties for detailed analysis. For each area of uncertainty we have considered carefully how we

might manage the risk by considering the management actions which could be taken. In so doing, we have considered the uncertainty mechanisms proposed by Ofgem and the alternatives we have developed. In assessing these uncertainty mechanisms we have taken account of the effect of the proposed strengthening of the incentive rate on capital expenditure and the impact of a longer price control period. We have adhered to the principle that risk should sit with the party best able to manage it.

13 We have developed a risk model to better understand the relationship between the risks, management responses, uncertainty mechanisms and our financial performance. The scale of variation of each of the key uncertainties, the impact of management responses and the design of uncertainty mechanisms have all been used as inputs to this model, building on analysis undertaken across the business. The model uses probabilistic techniques to evaluate the impact on financial performance for the RIIO-T1 price control. Performance against the TPCR4 price control has also been assessed in order to provide a comparison.

14 This model has allowed us to evaluate the impact that uncertainty mechanisms and associated parameters have on our financial performance, and we use the comparison with the TPCR4 period to understand whether the allowed rate of return is commensurate with the residual risk exposure. The modelling also allows us to assess the effectiveness of the range of management responses that might be adopted.

15 Based on our understanding of the proposed regulatory arrangements for the RIIO-T1 period, our initial modelling suggests that returns on equity will be less certain than during TPCR4, i.e. the spread of possible returns is greater. These results are further described in the ‘Finance’ annex to this submission and are intuitive, given the strengthening of incentives on capex and the proposal to define a wider and more tightly monitored set of agreed network outputs.

16 We have proposed a package of uncertainty mechanisms that together have the effect of reducing the spread of returns during the RIIO-T1 period to levels which are as close as possible to those that have prevailed during the TPCR4 period, while being consistent with the guiding principle that risks should be placed with the party best able to manage them.

17 These mechanisms are shown in the table below, together with our July 2011 proposals for comparison.

<table>
<tr><th rowspan="2">Uncertainty</th><th colspan="2">Proposed uncertainty mechanism</th></tr>
<tr><th>July 2011</th><th>March 2012</th></tr>
<tr><td rowspan="2">Wider reinforcement works</td><td colspan="2">Network Development Policy with volume-drivers based on incremental boundary capacity delivered</td></tr>
<tr><td>Within-period determination for projects with sufficient materiality</td><td>Within-period determination for projects which are sufficiently material and are only triggered by a subset of scenarios or have a low user commitment</td></tr>
<tr><td rowspan="2">Costs of meeting planning requirements</td><td rowspan="2">Volume- based on length of underground cable and cost of other mitigations</td><td>Volume-driver based on length of underground cable</td></tr>
<tr><td>Volume-driver based on extent of DNO works required as mitigation</td></tr>
<tr><td>Real price effects</td><td colspan="2">Copper price tracker with dead-band and time-lag</td></tr>
<tr><td>Offshore network impact</td><td>Specific re-opener for changes to the offshore regime that would otherwise undermine other uncertainty mechanisms (i.e. local generation connection and wider works revenue drivers are not calibrated for significant changes to the balance between offshore and onshore interconnection)</td><td>Uncertainty mechanism removed.
Reliance on wider works and local generation connection mechanisms</td></tr>
<tr><td rowspan="2">Demand-related infrastructure</td><td>Volume-drivers based on number of new transformers for different reinforcement types</td><td>Simplified volume-drivers based on number of new transformers</td></tr>
<tr><td colspan="2">Volume-driver for associated overhead lines and cables</td></tr>
<tr><td rowspan="3">Local generation connection</td><td colspan="2">Volume-drivers based on connection capacity</td></tr>
<tr><td colspan="2">Zonal volume-driver for other enabling works</td></tr>
<tr><td colspan="2">Volume-driver for associated overhead lines and cables</td></tr>
<tr><td>Network renewal volumes</td><td>Appropriate design of Network Output Measures secondary deliverables</td><td>Network Output Measures secondary deliverable treatment proposed</td></tr>
<tr><td>Design standard changes</td><td>Specific re-opener for fundamental changes with a materiality threshold. The impact on our allowances would be determined as part of the regulatory impact assessment conducted for any important change.</td><td>Uncertainty mechanism removed.
Reliance on mid-period review of outputs</td></tr>
</table>

Uncertainty	Proposed uncertainty mechanism	
	July 2011	March 2012
Critical National Infrastructure	Specific re-opener windows with materiality threshold	
Climate change: Flood and erosion protection	Specific re-opener windows with materiality threshold	
GB and EU market facilitation	No uncertainty mechanism proposed	Specific re-opener for opex and IS systems impact of significant market changes

Our approach to risk management

Risk analysis process

18 In order to be able to assess the risks that may impact the achievement of our business objectives, it is essential for us to be able to understand them. This knowledge will enhance the management's ability to make better decisions, deliver strategic and operational performance targets, protect corporate reputation, drive shareholder value and ensure value for money for customers and other stakeholders.

19 In assessing our risk management approach we have been guided by the Turnbull Guidance (Revised Turnbull Guidance, para 4, October 2005):

'A company's objectives, its internal organisation and the environment in which it operates are continually evolving and, as a result, the risks (operational, financial, compliance and other) it faces are continually changing. A sound system of internal control therefore depends on a thorough and regular evaluation of the nature and extent of the risks to which the company is exposed. Since profits are, in part, the reward for successful risk-taking in business, the purpose of internal control is to help manage and control risk appropriately rather than to eliminate it.'

20 In response to Turnbull and other best practice guidance, we use two separate but complementary processes: Risk Management and Compliance Management. These have been designed primarily as management tools but they also:

(a) contribute toward a better informed decision making process to help businesses achieve their objectives

(b) strengthen and streamline the system of internal control

(c) support and reinforce an open, proactive and 'risk and compliance aware' work culture

(d) closely align to business planning, performance management, and internal audit planning

(e) contribute toward a relevant and cost effective insurance programme

(f) facilitate the identification of opportunities (upside) as well as risks (downside)

(g) help protect reputation and shareholder value

(h) enable National Grid to clearly demonstrate good corporate governance to its stakeholders

(i) ensure compliance with the listing requirements of the London Stock Exchange.

21 Risk is, and has always been, an essential and critical component of every-day working life. Compliance also now has a high profile due in part to a number of high level corporate failures, and therefore needs to be effectively managed. Given its importance, a risk management process is embedded in all elements of our business. This is a ground up and top down process whereby each department has its own risk register – an active document which each team uses to identify and assess the risks against achieving its business objectives. Risks are assessed for financial and reputational impact, likelihood and a control opinion. Risks are assessed before and after management actions or other risk mitigation measures are taken into account.

22 Risks are escalated up through the business based on their financial or reputational impact and are reported to the Transmission Executive on a quarterly basis. This forms a core part of the assurance process, ensuring the Executive are aware of the key risk issues and the controls in place (where they are within our control) to manage them as well as the remediation plans underway to reduce any unacceptable controllable risks down to an acceptable level.

23 The price control review provides an opportunity for us to review our risk appetite. The regulatory arrangements that will be put in place for the RIIO-T1 period will inevitably depart from those in place today under the TPCR4 framework. The changes have the potential to fundamentally alter the risks to which the business is exposed and, therefore, the risks that customers and other stakeholders might be asked to bear. Given the potential impact of these changes it is right for us to revisit the fundamental risk drivers of the business, in order to understand the nature of these risks and their potential materiality.

24 In certain instances it might be suitable for us to bear more risk going forward into RIIO-T1 than it was previously in TPCR4 provided that this increase in risk is reflected in the determination of the allowed cost of capital. However, in addition to this, the change in incentive rate relating to capital expenditure will increase risk in a number of areas where there is little we can do to manage it. This creates the need for new uncertainty mechanisms, or the enhancement of existing uncertainty mechanisms.

25 We have built upon our existing approach to risk management and the wide range of analysis conducted across the business in order to understand the risks we face under RIIO-T1. In order to ascertain which of those risks identified through our risk register process we should analyse further, we have filtered down to the risks that have a large range of uncertainty surrounding them and the potential to materially impact the risk faced by the business if left unmitigated.

26 There are some risks that are completely (or largely) beyond our control, or where the only available actions are prohibitively expensive and clearly would not provide value. In such cases it is not clear that it is in consumers' best interests for us to bear those risks (and act as an insurer earning a premium) or whether the consequence of these uncertainties would be more efficiently passed through to customers. We have based our analysis on the principle that risks should fall on those parties best able to manage them.

27 It may be in the consumer's best interests to be exposed to particular risks where this brings value by, for example:

(a) Lowering our allowed rate of return

(b) Reducing financeability concerns; and/or

(c) Reducing consumers' exposure to forecasting uncertainty at the price control review.

28 Where we believe that there are good arguments for risks to fall on end consumers, the uncertainty mechanisms that would achieve this are described and justified. For those risks which can be managed by system users, we will continue to pursue developments to the commercial regime to better reflect risks to those system users that cause them, such that they are able to make more efficient decisions.

29 To support our risk analysis work for RIIO-T1, we have developed a risk model to better understand the relationship between risks, uncertainty mechanisms and our financial performance. The scale of variation of each of the key uncertainties and the design of uncertainty mechanisms we have developed have been used as inputs to this model, building on analysis undertaken across the business. The model uses probabilistic techniques to evaluate the impact on financial performance for the RIIO-T1 price control and is compared against the TPCR4 price control performance for reference.

Key drivers of risk and uncertainty

Identifying the full set of risks

30 The risks we face that have considerable uncertainty surrounding them can result from a number of different drivers. Many are market driven, governed by the choices made by commercial entities pursuing their own incentives. A number are policy/regulatory risks, arising from the potential for domestic or international public policy to change as new information is revealed and new objectives are identified, which could have an impact on delivering the outputs customers require. There may also be operational risks arising from uncertainty over the performance of our network and its assets. The impact of these drivers can broadly be categorised as either a scope change to our workload plan (e.g. legislative changes requiring different or greater actions to be taken than planned for), a volumetric change (e.g. more secondary assets requiring maintenance than anticipated) or a cost change (e.g. steel prices increasing by more than expected at the start of the period).

31 We have identified that there can be several different layers of risk where multiple drivers occur such as volume and cost, or scope plus cost.

32 We describe below the elements of our business environment that are subject to major uncertainty. It is these fundamental drivers that create uncertainty over the volume of work that we will need to undertake, and/or costs that we will incur, in delivering the outputs to its customers over the RIIO-T1 period.

33 To facilitate this work we have undertaken a review of the key drivers of uncertainty which we will be exposed to, based on the risks we have identified today. This review identified a long list of potential uncertainties and risk factors which we have grouped into a shorter, more tractable list of risks for more detailed analysis, which we believe are the factors with the greatest range of uncertainty and / or risk associated with them.

34 The shortlist of uncertainties that are described in this report are:

Cost risks

(a) Construction uncertainty

(b) Real price effects

Volume risks

(a) Local generation connections

(b) Demand-related infrastructure

(c) Wider reinforcement works

(d) Costs of meeting planning requirements

(e) Offshore network impact

(f) Network renewal volumes

(g) Design standard changes

(h) Critical National Infrastructure

(i) Climate change: Flood and erosion protection

(j) GB and EU market facilitation

Quantifying risk

35 We have provided an indication of the likely range for these uncertainties. For each we have identified a credible range based on bottom up analysis and the impact of this range on National Grid's capital expenditure, operational expenditure and output performance. In some cases, the scale of the underlying variation is well understood and can be estimated with a reasonable level of confidence. In other cases the variation is more difficult to forecast and the estimates are necessarily cruder. Work has continued to refine this analysis following our July 2011 business plan submission, and our July 2011 and present view of the scale of each of these uncertainties are shown in the table below:

<table>
<tr><th rowspan="3">Uncertainty</th><th colspan="3">Standard deviation
(£m over the RIIO-T1 period)</th><th rowspan="3">Reason for change</th></tr>
<tr><th rowspan="2">July 2011 business plan</th><th colspan="2">March 2012 business plan</th></tr>
<tr><th>Without RPE</th><th>With RPE</th></tr>
<tr><td>Wider reinforcement works</td><td>724</td><td>663</td><td>775</td><td>Improved modelling; All boundaries</td></tr>
</table>

Uncertainty	Standard deviation (£m over the RIIO-T1 period)			Reason for change
	July 2011 business plan	March 2012 business plan		
		Without RPE	With RPE	
Costs of meeting planning requirements	556	454	512	Improved modelling of cost risks
Offshore network impact	158	157	157	No change
Demand-related infrastructure	131	60	66	Improved modelling of volume risks – more scenarios
Local generation connections	128	129	146	Improved modelling of volume risk – more scenarios
Network renewal volumes	82	70	77	Volumes updated
Design standard changes	46	47	51	Minor changes only
Critical National Infrastructure	19	31	32	Improved modelling of volume risk
Climate change: Flood and erosion protection	2	2	2	Minor changes only
GB and EU market facilitation	NA	9	9	Uncertainty identified explicitly

36 The construction and real price effect risks apply across our baseline expenditure forecast and therefore contribute to the standard deviations for all other risks. The standard deviations are shown with and without real price effects.

Management response

37 For each area of uncertainty we have considered carefully how the risk might be managed by National Grid, building on our existing risk management tools but also including a range of approaches that are not adopted at present. There are three generic types of management action that might be taken.

(a) Actions that the business will take to reduce the probability of an adverse event

(b) Actions that the business will take to 'buy' an option to reduce the impact if an adverse event occurs

(c) Actions that will be taken when the adverse event occurs to mitigate the effect

38 There is inevitably some cost associated with any potential management action and this cost will need to be considered against the potential effect. For example, exposures to certain input prices can be hedged in advance, but to do so will involve paying a premium and/or "giving up" the potential upside should those prices fall. Similarly, adverse impacts of certain shocks can be managed by, for example, carrying a larger inventory of strategic spares.

39 For each management action we have therefore considered whether it represents value for money for customers based on the information available. To do this we have examined:

(a) The associated costs, including any knock-on impact to our output performance (e.g. if resources might need to be diverted from some other activity);

(b) The scope for mitigating the risk through the available actions; and

(c) The associated timescales.

40 Building on existing practice, we have identified a set of management responses to address the set of risks identified above. A selection of these management responses are summarised in the table below.

Uncertainty	Management responses
All	Re-profile non-load related expenditure based on network output measures
	Develop new smart techniques by developing commercial arrangements and specialised service contracts with users
Costs of meeting planning requirements	Commit sufficient resources to ensure planning applications include an effective presentation of need case, the consideration of stakeholder views and an exploration of alternative options
	Explore alternative technology options, such as Gas Insulated Line
Construction	Resanction process to ensure managerial review
	Feedback experience from completed projects to improve future forecasting
Real price effects	Hedging against commodity prices
	Hedging against currency fluctuations
	Procurement activities including forward purchase

Uncertainty	Management responses
Network renewal volumes	Development of numerical techniques to forecast asset degradation
	Availability of appropriate spares to cover failure of high criticality assets
	Deploy enhanced asset monitoring approaches (for example, additional line surveys, monitoring equipment) and mitigation options (for example, establish safety management zones)
	Insurance[1]
Design standard changes	Keep standards up to date to reflect the latest technology, characteristics of user requirements and commercial opportunities
	Application for a derogation against the requirements of the security standards
Critical National Infrastructure	Engagement with DECC on the prioritisation and timing of increased requirements
Climate change: Flood and erosion protection	Engagement with Environment Agency on future approach to funding
GB and EU market facilitation	Engagement at ENTSO-E, CUSC Panel, etc.

41 As noted above we have not excluded from analysis management responses that are not employed at present. We have instead included a wide set of management responses to inform debate. It is right to adopt this approach since the RIIO-T1 period brings with it challenges for the electricity transmission system, associated with continuing and accelerating the journey towards a low carbon energy network. Furthermore, RIIO-T1 could bring fundamental changes to existing regulatory arrangements. Both of these developments might make previously rejected management responses viable.

Uncertainty mechanisms and risk allocation

42 There are some risks that are completely (or largely) beyond the control of National Grid, or where the only available actions are prohibitively expensive and clearly would not provide value. In such cases it is not clear that it is in consumers' best interests for National Grid to bear those risks (and act as insurer earning a premium) or whether the consequence of these uncertainties should simply be passed through to customers. Based on our analysis, we have considered carefully the allocation of the associated risks between National Grid, users and connectees to the transmission systems and end consumers. This review has been based on the principle that risks should fall on those parties best able to manage them.

43 To support the work described in this document we have developed a risk model to better understand the relationship between risks, management responses, uncertainty mechanisms and our financial performance. We have

[1] Further details in Appendix B: National Grid's approach to insurable risks

also developed a simplified version of the risk model and published this for stakeholders. The scale of variation of each of the key uncertainties, the impact of management responses and the design of uncertainty mechanisms described above have all been used as inputs to the model, building on analysis undertaken across the business. The model uses probabilistic techniques to evaluate the impact on financial performance for the RIIO-T1 price control. Performance against the TPCR4 price control is also assessed in order to provide a comparison.

44 This model has allowed us to evaluate the impact that uncertainty mechanisms and associated parameters have on our financial performance, and use the comparison with to understand the allowed rate of return which is commensurate with the residual risk exposure. This analysis is presented in the finance annex to this submission.

45 We have further developed the empirical work we have undertaken since our July 2011 business plan submission. We still anticipate the need for significant engagement with Ofgem over the analysis and the regulatory treatment of different types of risk. While such a programme of engagement should enhance the quality of the analysis, a full characterisation of all forms of uncertainty is not possible.

46 In this context we have evaluated the uncertainty mechanisms proposed by Ofgem and some alternatives developed by National Grid. In assessing these uncertainty mechanisms we have taken account of the effect of the proposed significant strengthening of the incentive rate on capex for the RIIO-T1 period. This single parameter is a key determinant of the extent to which risks are borne by ourselves and the proposed strengthening, absent any countervailing changes, will unambiguously increase the riskiness of the regulatory environment.

47 In certain instances it might be more efficient for National Grid to bear more risk going forward than it has done in the past provided that this increase in risk is reflected in the determination of the allowed cost of capital. However, the change in incentive strength for capex will increase risk in a number of areas where there is little that can be done by National Grid to manage that risk. This creates the need for new uncertainty mechanisms, or the enhancement of existing uncertainty mechanisms.

48 We have considered the types of uncertainty mechanism outlined in Ofgem's Strategy annex on uncertainty mechanisms as set-out below:

(a) Uncertainty mechanisms fully calibrated at the price control review

(i) Indexation – Provision that adjusts the revenue the company is allowed to collect from customers according to changes in a specified price index (e.g. the RPI or a published input price index).

(ii) Volume driver – Provision allowing revenue to vary as a function of a volume measure (e.g. number of new connections)

(iii) Revenue trigger – Provision allowing revenue to increase/decrease by a specified amount (or in a specified way) if and when certain trigger events occur during the price control period (e.g. revenue drivers)

(iv) Use it or lose it mechanism – If revenue set aside for a specified activity or purpose is not used as intended, revenue can be adjusted to remove this allowance (e.g. specific clawback provision)

(b) Forward-looking revenue adjustment determined by Ofgem during the price control review period:

(i) Revenue adjustment based on updated cost assessment if trigger event occurs (e.g. specific re-opener) – Provision allowing for a specific part of the company's revenue allowance to be reviewed and potentially adjusted by Ofgem during the price control period, on a forward-looking basis, if and when specified conditions are met (e.g. new entry points in gas or current TII scheme in electricity).

(c) Revenue allowance determined after company incurs relevant expenditure

(i) Pass-through items – Provides that the company will be fully or partially compensated for costs incurred in specified areas or on specified items (e.g. Ofgem licence fees).

(ii) Logging-up of actual expenditure subject to ex post efficiency review – Provides that a company will be fully compensated for actual expenditure on a certain activity, through the revenue allowance set at the next price control review, at least insofar as Ofgem determines the relevant expenditure was efficiently incurred (e.g. "known unknowns" such as those currently covered by logging-up – BT 21st Century Networks in Electricity or Quarry and Loss claims in Gas).

(iii) Backward-looking revenue adjustment based on benchmarking analysis of outturn costs – A company will receive an amount of revenue, in respect of a particular activity or output, which Ofgem will determine based on benchmarking analysis of other companies' actual expenditure on that activity or output. This mechanism may be considered where the activity or output is new and there is no historical expenditure data to use for benchmarking at the time the price control is set.

49 The set of uncertainty mechanisms that we propose for the RIIO-T1 period is summarised in the table below, together with our July 2011 proposals for comparison.

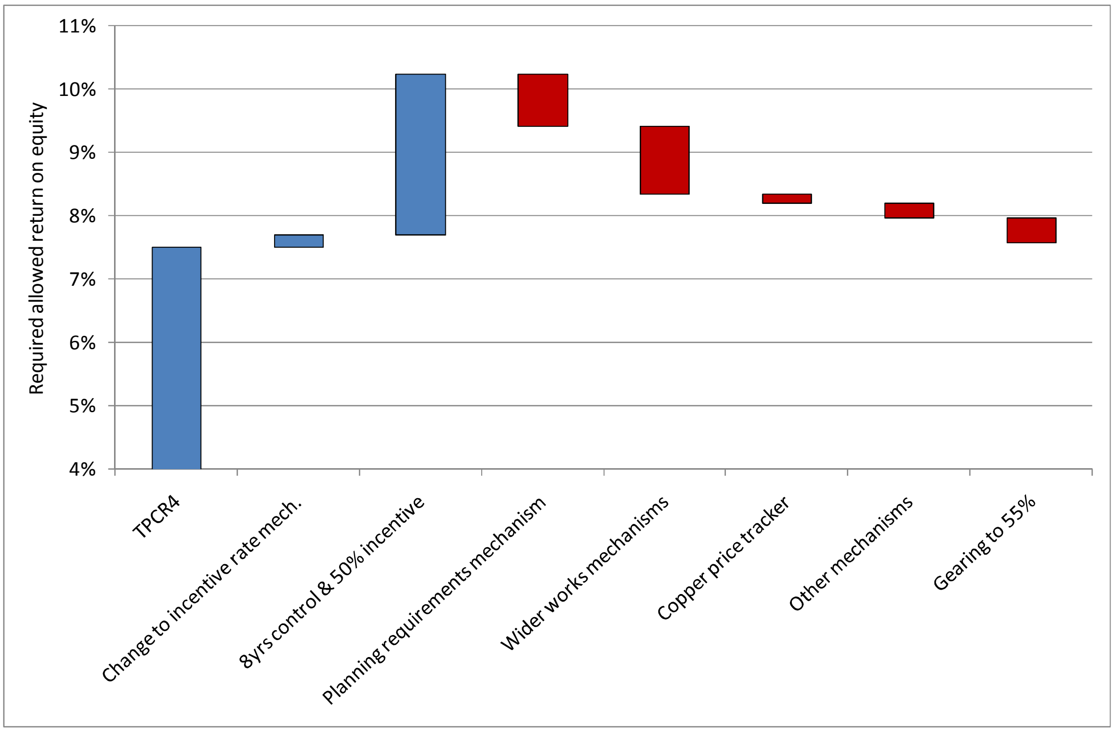
Uncertainty	Proposed uncertainty mechanism	
	July 2011	March 2012
Wider reinforcement works	Network Development Policy with volume-drivers based on incremental boundary capacity delivered	
	Within-period determination for projects with sufficient materiality	Within-period determination for projects which are sufficiently material and are only triggered by a subset of scenarios or have a low user commitment
Costs of meeting planning requirements	Volume-driver based on length of underground cable and cost of other mitigations	Volume-driver based on length of underground cable
		Volume-driver based on extent of DNO works required as mitigation
Real price effects	Copper price tracker with dead-band and time-lag	
Offshore network impact	Specific re-opener for changes to the offshore regime that would otherwise undermine other uncertainty mechanisms (i.e. local generation connection and wider works revenue drivers are not calibrated for significant changes to the balance between offshore and onshore interconnection)	Uncertainty mechanism removed. Reliance on wider works and local generation connection mechanisms
Demand-related infrastructure	Volume-drivers based on number of new transformers for different reinforcement types	Simplified volume-drivers based on number of new transformers
	Volume-driver for associated overhead lines and cables	
Local generation connection	Volume-drivers based on connection capacity	
	Zonal volume-driver for other enabling works	
	Volume-driver for associated overhead lines and cables	
Network renewal volumes	Appropriate design of Network Output Measures secondary deliverables	Network Output Measures secondary deliverable treatment proposed
Design standard changes	Specific re-opener for fundamental changes with a materiality threshold. The impact on our allowances would be determined as part of the regulatory impact assessment conducted for any important change.	Uncertainty mechanism removed. Reliance on mid-period review of outputs

<table>
<tr><th rowspan="2">Uncertainty</th><th colspan="2">Proposed uncertainty mechanism</th></tr>
<tr><th>July 2011</th><th>March 2012</th></tr>
<tr><td>Critical National Infrastructure</td><td colspan="2">Specific re-opener windows with materiality threshold</td></tr>
<tr><td>Climate change: Flood and erosion protection</td><td colspan="2">Specific re-opener windows with materiality threshold</td></tr>
<tr><td>GB and EU market facilitation</td><td>No uncertainty mechanism proposed</td><td>Specific re-opener for opex and IS systems impact of significant market changes</td></tr>
</table>

50 Following feedback on our business plan, we have summarised the detail of the uncertainty mechanisms that we are now proposing as part of this business plan submission in Appendix A.

51 Based on our understanding of the proposed regulatory arrangements for the RIIO-T1 period, our initial modelling suggests that returns on equity will be less certain than during TPCR4, i.e. the spread of possible returns is greater. These results are further described in the ‘Finance’ annex to this submission and are intuitive, given the strengthening of incentives on capex and the proposal to define a wider and more tightly monitored set of agreed network outputs.

52 We have proposed a package of uncertainty mechanisms that together have the effect of reducing the spread of returns during the RIIO-T1 period to levels which are as close as possible to those that have prevailed during the TPCR4 period, while being consistent with the guiding principle that risks should be placed with the party best able to manage them. This is summarised by the chart below.



53 We accept that by reducing this spread of returns, this will have the potential to increase the uncertainty of allowed revenues in the RIIO-T1 period. This in turn will impact on customers' transmission charges. We have therefore engaged with stakeholders at both our Talking Networks events and existing industry meetings to explain this relationship and gain feedback as to their concerns.

54 Stakeholders commented that stable charges were an ideal, but understood the broader implications of stability. A level of volatility in charges was accepted, provided such changes were transparent and predictable.

55 We have considered these comments, and also some potential suggestions from stakeholders. As a result, we intend to increase the level of information we provide in our five year charging forecasts (Condition 5 reports), particularly in relation to forecast revenues. We also will look to enhance the tools we provide to customers to forecast charges, with a view to improving their ease of use. We believe that such developments will help users make informed forecasts of their future charges.

56 Additionally we are continuing to investigate the possibilities for increasing the stability of transmission charges, mindful of the need to co-ordinate with other industry initiatives (e.g. Project TransmiT).

Construction uncertainty

What is it? *Cost uncertainty associated with constructing assets, including cost estimation uncertainty, project scope changes caused by unexpected site conditions and policy changes*
How big? *The cost uncertainty for an individual project has a standard deviation of 73% at initial estimate stage, reducing to 28% at the contract tender stage*
What are we going to do about it? *Feedback loop from project completion to future project cost estimation; resanction process to ensure managerial review*
Risk sharing arrangements?
Efficiency incentive rate for over/underspends

Context

57 Construction uncertainty refers to all cost uncertainty which is not explained by either a change to the volume required or real price effects. It includes the uncertainty associated with estimating project costs significantly ahead of delivery[2] and project scope changes driven by unanticipated site conditions, and policy changes.

58 Unanticipated site conditions may include weather, outage changes, the condition of closely-associated assets being better or worse than predicted and the knock-on effects of plant failures.

59 This uncertainty is greatest at project inception and reduces as further information is gathered, site surveys are completed and quotations or tenders are received.

Quantification

60 In order to quantify this uncertainty, we have completed an exercise to determine the construction uncertainty associated with our TPCR4 projects. In completing this analysis we have considered projects that:

(a) formed part of our TPCR4 submission;

(b) have a forecast and completion cost greater than £100k; and

(c) are complete or due to be complete in 2012/13

61 We have only compared cost forecasts and costs at completion for a number of schemes where the functional output was retained. We have therefore tried to ensure that this uncertainty does not include any element of volume uncertainty.

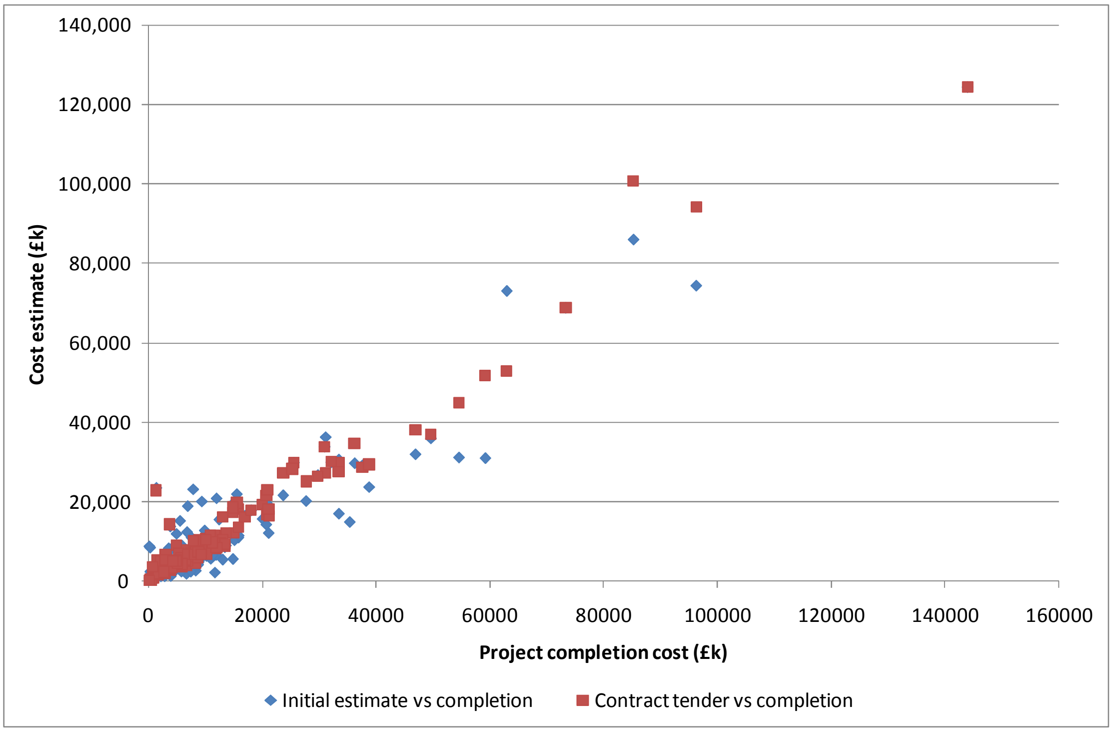
[2] At the TPCR4 price control, we were forecasting in December 2005 out to 2011/12 whereas we are now forecasting in November 2010 out to 2020/21, an increase of 4 years

62 To gain an understanding of how this risk reduces as the project develops, and further information is gathered, we have looked at the variance between:

(a) the initial estimate (IP1 stage) and the cost at project closure (IP4 stage); and

(b) the contract tender stage or (for our Alliances) target cost stage (IP3 stage) and project closure

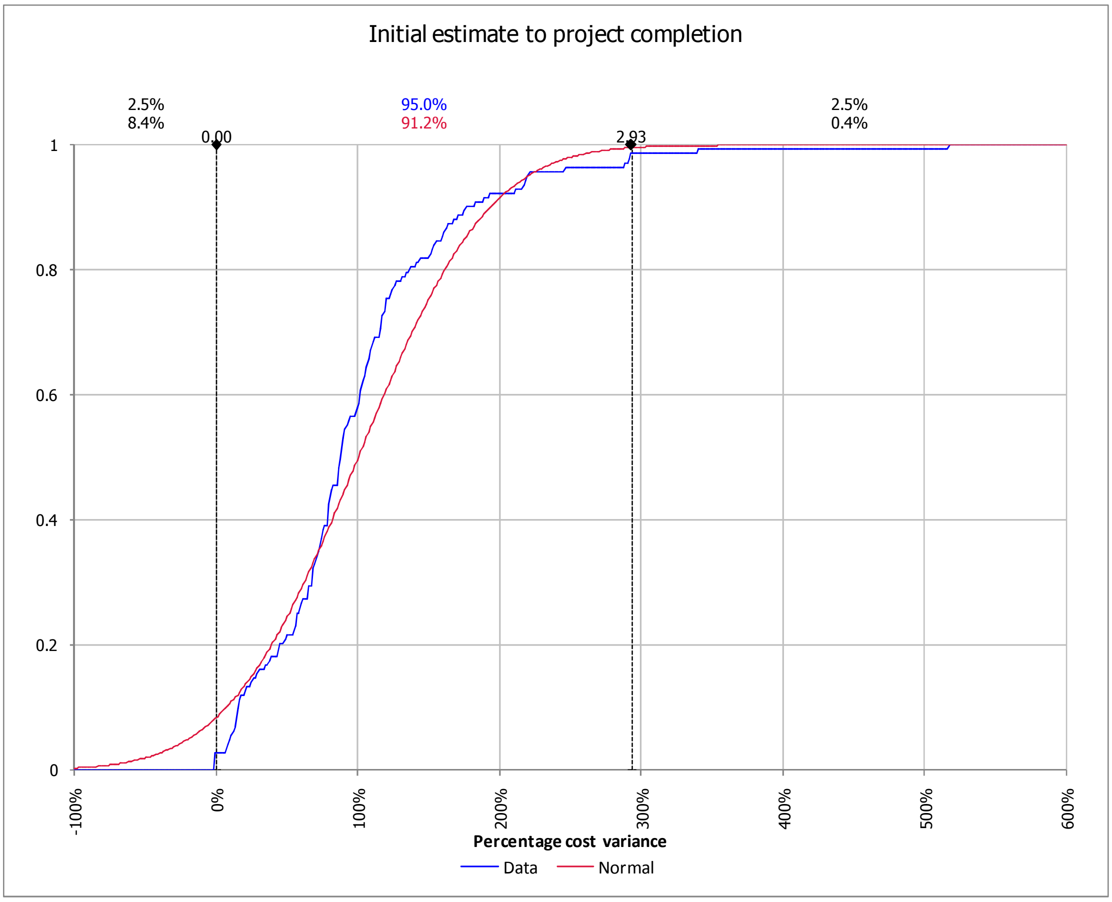
63 The results of this analysis are shown in the graph below.

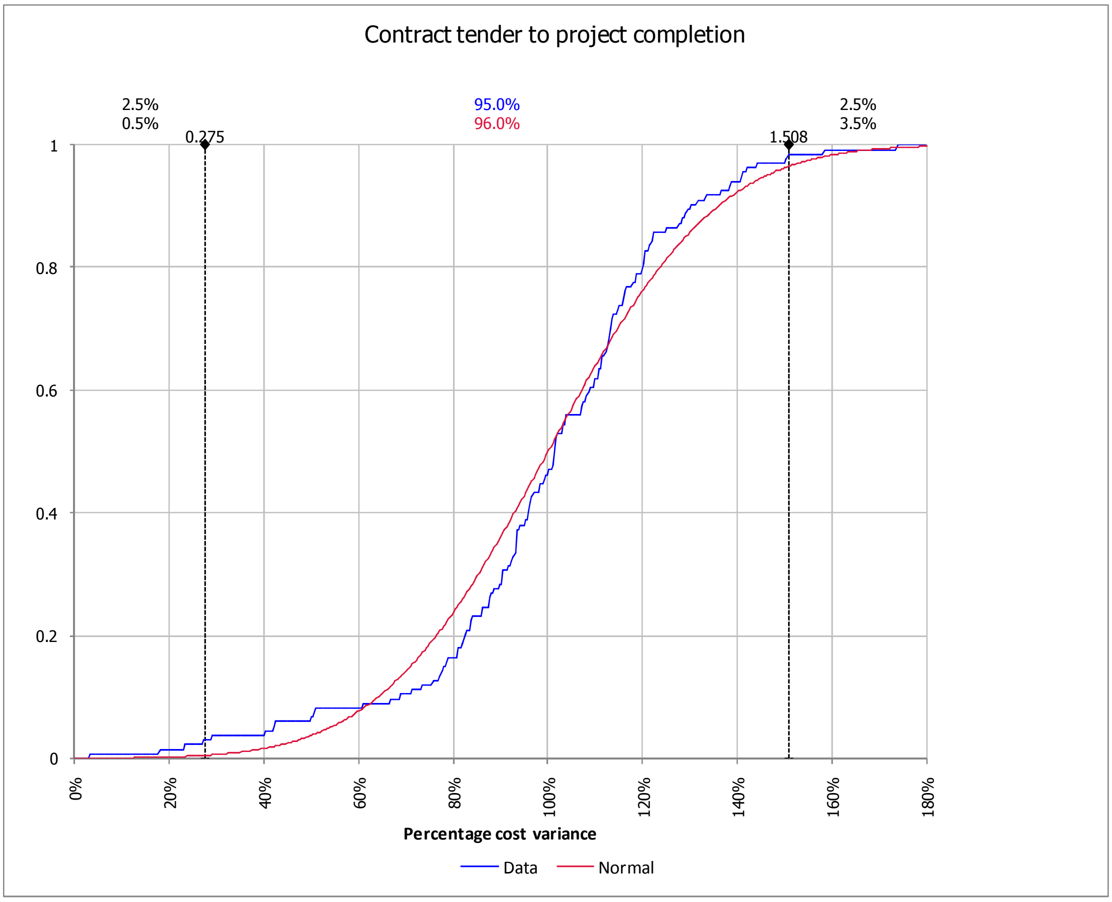


64 The graphs show that the uncertainty associated with the initial estimate is higher than the uncertainty associated with the contract tender. The initial estimate data covers 140 projects with a total cost of approximately £2bn. The data has a standard deviation of 73% (with 95% confidence limits of -69% and 140%). The contract tender data covers 134 projects and has a standard deviation of 28% (with 95% confidence limits of -55% and 44%).

65 The mean of the initial estimate data was 120% (i.e. on average, the cost at completion was 20% higher than the original estimate) and the mean of the contract tender data was 103%. In order to model this uncertainty, we have corrected the data to achieve a mean of 100% in both cases. We have then used a normal distribution with the standard deviations mentioned above.

66 A comparison of the data and the best-fit distributions for both initial estimate and contract tender are shown in the graphs below.


Initial estimate to project completion
2.5%
8.4%
95.0%
91.2%
2.5%
0.4%
0.00
2.93
1
0.8
0.6
0.4
0.2
0
-100%
0%
100%
200%
300%
400%
500%
600%
Percentage cost variance
Data
Normal


Contract tender to project completion
2.5%
0.5%
95.0%
96.0%
2.5%
3.5%
0.275
1.508
1
0.8
0.6
0.4
0.2
0
0%
20%
40%
60%
80%
100%
120%
140%
160%
180%
Percentage cost variance
Data
Normal

67 These distributions have been used to apply the construction uncertainty to all the capital projects, including those which would be required to address the uncertainties described in this document. Where costs are being forecast well in advance of delivery (e.g. for capital schemes in the baseline business plan to be delivered in last six years of the RIIO-T1 period or Unit Cost Allowances for wider works volume drivers established at the price control), we have applied the uncertainty between initial estimate and project completion. Where costs are being forecast closer to contract placement (e.g. for capital schemes in the baseline business plan to be delivered in the first two years of the RIIO-T1 period or wider works schemes taken forward using the specific re-opener mechanism), we have applied the uncertainty between the contract tender and project completion.

68 In addition to the scheme-by-scheme construction risk, we have also considered whether these risks could be correlated across a number of projects or all projects.

69 There are a number of drivers of construction risk that are likely to lead to a correlation across projects:

(a) Sustained poor weather conditions (e.g. 2007 floods);

(b) A type fault that limits access at a number of substations (e.g. FMJLs);

(c) Technical, environmental or safety policy changes (e.g. working at height); and

(d) National events that limit access to overhead lines, cables and to an some extent substations (e.g. Foot and Mouth disease).

70 We would also expect real price effects to cause a correlation between the construction risk of individual projects, but this is being handled with a separate mechanism.

71 We have been unable to reliably quantify a construction risk correlation between projects and therefore we have assumed that all risks are independent.

Management response

Resanction process

72 The sanction process is described in detail in our 'Load-related detailed plan' annex. Projects are sanctioned with a cost range, which is built up from the known construction risks at the time of sanction. We sanction at P(50) in the range P(20) to P(80). If the forecast cost at completion moves outside this range, then a resanction is required.

73 The resanction provides an opportunity for a full managerial review of the project. This ensures that the need case for a particular project is not undermined by an increase to the scheme costs, and allows alternative options to be considered.

Feedback from project completion

74 There is a feedback loop between scheme completion and the initial estimation of project costs (IP1) process. The initial cost estimation process uses a spreadsheet which contains approximately 300 standard units delivered as part of capital works. The relevant volumes of lead assets and closely-associated secondary assets (e.g. a transformer, its foundation and unit protection) are selected and multiplied by the related unit costs stored in a central repository. These unit costs are updated based on recent experience on delivered projects and market intelligence.

75 This allows learning points from delivered projects to be considered when compiling future cost estimates. In addition, the (IP1) process includes the option to apply complexity factors to the future project cost estimation. This allows our experience of the construction risks for different project locations to be applied to future cost estimates.

Risk sharing arrangements

76 In terms of the allocation of this risk, it should fall on National Grid since we can manage the process for cost estimation and the project resanction process.

77 The only portion of this risk that should fall on consumers is the risk that the outcome is significant enough to cause National Grid financial distress, and therefore it is better for consumers to self-insure the uninsurable risk.

78 We are therefore proposing that the risk sharing arrangements provided by the efficiency incentive rate should be adequate provided there is also a facility for a re-opener with a high materiality threshold to deal with exceptional circumstances.

Real price effects

What is it? *With an eight year price control period, growing investment levels and high global demand for commodities the risk we face in relation to price rises above RPI is increasing*
How big? *The table on page 10 shows the standard deviation for each of the volume risks with and without real price effects*
What are we going to do about it? *We have explored hedging to lessen this risk but the level of investment uncertainty makes them impractical*
Risk sharing arrangements?
Copper price tracker to remove the risk of windfall gains or losses due to the volatility of price changes in this commodity
Efficiency incentive rate for over/underspends

Overview

79 We are provided with protection from unanticipated inflation through the use of RPI in the calculation of its allowed revenue. However, this protection is incomplete, since the basket of goods and services procured by us are very different to those covered by the RPI. Consequently, we anticipate that input costs will increase at a greater rate than RPI. Ofgem has recognised and accepted this principle in previous reviews, e.g. DPCR5.

80 In this section we provide an overview of the level of real price inflation we expect to face over the RIIO-T1 period. Our expectation is that this expected level will be allowed for, through increases in cost allowances. What is relevant for this document is the risk that price growth departs from these assumed levels. It is this risk that is identified and quantified below.

Baseline RPEs

81 The market prices of inputs required for the build and maintenance of the transmission system are impacted over the RIIO-T1 period by external factors such as:

(a) Global supply and demand of commodities including steel, aluminium, oil and copper

(b) UK supply and demand for skilled engineering and construction labour

(c) Flow through of wholesale market pressures in electricity prices

(d) Exchange rate movements due to strengthening or weakening of the sterling currency

(e) Factory gate prices driven by supply and demand factors which give rise to pricing of equipment at the level the market will sustainably withstand rather than cost plus overhead

82 These factors translate into Real Price Effects (RPEs) which are defined as above or below Retail Price Index (RPI) movements in price. RPEs impact on the prices of both capex and opex work and are generated from several input

areas. The table below shows the average exposure in our business plan to each area:

Percentage of plan exposed to RPEs

	NGET	
	Opex	**Capex**
Internal manpower	47%	13%
Contractor manpower	13%	25%
Civils	5%	12%
Copper	Nil	15%
Steel	Nil	5%
Aluminium alloy	Nil	5%
Oil	Nil	5%
Electricity	3%	Nil
Total exposure	**68%**	**80%**

83 Given the categories of expenditure we expect to undertake during RIIO-T1, our greatest exposure is to real growth in labour costs and to rising copper prices.

84 The weightings used for the capex percentages are based upon the cost make up of plant components and project types. For opex this is based on the expenditure within the plan for the elements involved. This process is explained further in the sections below. We have used external forecasts in each of these areas to predict baseline RPE figures which are included in our plan. We propose that these form the basis of ex-ante allowances in the area. In addition, we propose that an uncertainty mechanism is developed around copper prices which utilises a cap and collar approach to reduce the likelihood of windfall gain or loss over the period.

85 As shown in the table above, 60% of our opex costs relate to payroll meaning they are exposed to real pay inflation, and recent volatility in the price of commodities has highlighted the exposure of our capital plan to above RPI price rises. As a result RPEs are a major consideration in each annual business plan we undertake. Through our business planning processes we have developed methods and models to calculate the impacts for our plans on a consistent basis. These same methodologies were used when building our business plan which formed the RIIO-T1 submission.

RPE calculation methodology - Capex

86 We have developed a Commodity Pricing Model (CPM) which maps each of the schemes in our investment plans into commodity exposures. These mappings can then be used to calculate the RPEs based on forecast indices at a commodity level which is specific to the mix of goods we are forecasting to purchase.

87 Within the CPM each line in the investment plan is assigned to a ‘Scheme group’ which are baskets of projects with similar content and cost drivers (for

example circuit breakers). This effectively standardises every project undertaken down to its constituent parts.

88 Each 'Scheme group' is then mapped to a set of standard cost codes which are called Utilities Vendor Data Bases (UVDBs) which incorporate the standard breakdown of costs for that scheme group. As with all standard cost codes there is some simplification in doing this but it gives an easier way to manipulate the data.

89 The UVDB cost codes are then mapped to commodities which cover 100% of the costs with the 'RPI' category covering elements which have no specific commodity exposure:

Mapping within the CPM

Scheme	Scheme Group	Fixed	2010	2011	2012	2013	2014
Revere #7 Rebuild	**Substation**	**No**	**441,800**	**3,866,000**	**360,000**	**0**	**0**

UVDB 3.75: Substation Services

UVDB	1.13	1.24	3.75	3.78
Weighting	**8.5%**	**4.9%**	**84.6%**	**2%**

Index	Man	Civil	Oil	Steel	Cu	Alu	RPI
Weighting	**50%**	**15%**	**0%**	**0%**	**0%**	**0%**	**35%**

Manpower	2009	2010	2011	2012	2013	2014
Price Forecast	**100%**	**104%**	**107%**	**111%**	**115%**	**120%**

90 Once this mapping is performed (most of which is standardised by the CPM) indices for each of the commodities can be input into the model and the RPE is calculated. The diagram above shows the 'commodities' covered by the model are:

(a) Manpower (covers both contractor and internal)

(b) Civils (i.e. construction plant and equipment)

(c) Oil

(d) Steel

(e) Copper

(f) Aluminium alloy

91 Note that within table 2.14b of the submission the first two items are shown separately with oil, steel, copper and aluminium alloy blended as the materials capex forecasts.

Mapping creation

92 As can be inferred from the above the validity of the scheme group to UVDB to commodity mapping is important in this model. There is an accuracy to time and complexity trade-off inherent in these mappings in that the less simplified the mappings (i.e. higher numbers of scheme groups and UVDBs) the more accurate the result but this then makes the process more complex and time consuming.

93 We were aware of the importance of this mapping and the accuracy trade-off when we were developing the CPM. For this reason we involved independent consultants (Gardiner, Theobald and Fairways - GTF) with experience of creating similar models and analysis in producing the mappings and helping to develop our thinking in the area. In 2006, in conjunction with GTF we analysed our capital plan, originally looking at all 279 line items with a view to analysing their commodity mix. We realised that this was not practical so instead drilled down to the top 50 schemes which covered 80% of our direct investment. We have used this work to inform our CPM model, and subsequent UVDB scheme groups – which are summarised in the table below:

Scheme group to commodity mapping

Scheme group	Civils	Manpower	Oil	Copper	Aluminium	Steel (fabricated)	RPI
Switchgear	10.8%	35.8%	5.1%	16.6%	0.6%	6.7%	24.4%
Transformers	7.5%	30.1%	5.1%	28.4%	1.2%	8.8%	18.9%
Substations	12.3%	41.0%	5.1%	4.5%	-	4.7%	32.4%
Overhead Lines Refurbishment	16.3%	49.7%	5.1%	0.7%	18.2%	4.8%	5.4%
Overhead Lines Fittings	10.0%	35.6%	5.2%	28.9%	7.2%	4.4%	8.7%
Cables	6.9%	30.3%	5.0%	37.7%	3.3%	5.0%	11.9%
Tunnels	44.0%	38.9%	6.5%	0.5%	-	2.3%	7.8%

94 Since the original mapping was set up GTF have performed a refresh of the analysis on top 50 schemes in our plan which has been included in Appendix C. This showed that there have been some changes in the mix of work which makes up the majority of our capex programme but this is mainly due to the inclusion of HVDC schemes and more underground tunnels. Outside of these items the mix is similar to our historical analysis and hence is reliable and robust data.

95 To account for these differences, within the CPM HVDC schemes are treated independently with splits to scheme group assessed on a scheme-by-scheme

basis. Each HVDC scheme has been broken down between cables and converter stations and apportioned to scheme groups accordingly. The plan expenditure relating to converter stations is assigned to the 'substations' scheme group, this being the best match for commodity modelling purposes. This ensured that HVDC schemes were not assigned as 'cables' in their entirety, which would have meant increased exposure to higher and more volatile copper inflation.

Comparison versus other methods

96 As noted above there are simplifications in this mapping process because of the use of 'standard' schemes but the process does give close alignment to the basket of goods we purchase and therefore our specific commodity exposure. Other methods for calculating RPEs could be used with the most popular being the use of standard construction indices. These standard construction indices (such as those from the Office of National Statistics (ONS) and the department for Business Innovation and Skills (BIS)) are general indices used to give a guide of price movements for a defined basket of goods such as construction (non-housing) or more specific to an industry such as Electricity Distribution for example.

97 Whilst these indices can be useful indicators of industry price increases (hence we have used them as part of the independent evidence to sense check our RPE forecasts) they are not specific to transmission. They are therefore subject to a different basket of goods than we are exposed to and could over or under calculate the RPE we have seen historically, or will see in the future. For example the construction (non-housing) index from the ONS uses a basket of goods which incorporates all types of construction work undertaken in the UK, not just transmission construction. As can be seen from the analysis above we are exposed quite heavily to changes in the price of commodities such as copper. Other construction types which feed into the basket of goods will be much more exposed to materials whose prices are not as volatile or increasing as much, such as concrete. This will skew the index to be lower than our more specific analysis.

98 As we map our schemes back to their base commodities we can forecast RPE movements using readily available indices for the specific commodities. This means we do not need to rely on the application of indices skewed by other companies or industries as no specific transmission indices are available. This will make the analysis we have performed closer to reality for our own RPE exposure despite the simplifications made to standardise goods.

99 Also of note in this area is the recent water price controls within which Ofwat implemented the use of the Construction Output Price Index (COPI) as its core measure of capital cost inflation.[3] COPI tracks construction-wide inflation and deflation which have impacted the regulated water companies. At present industry commentators note that COPI is unable to reflect the true cost of inflation within water companies capital projects, and as such potentially exposes water companies to a significant deficit over their price controls.

[3] See EC Harris – Terry Povall & Simon Rawlinson – Source http://www.utilityweek.co.uk/

100 The use of COPI (or a similar index) suggests that the indexation of commodities is largely reflective of industries such as civil, construction and general building firms, and not of an Electricity Transmission network. Use of these indexes would not only dilute the genuine pressures faced by a regulated entity for costs above RPI, but they could also depress the ability to deliver capital works due to budgetary constraints, driven by an inflationary deficit. This shows that use of a standard construction index could expose us to windfall gains or losses depending on factors outside of our industry sector.

Comparison versus other regulated entities

101 It is worth noting the comparison between the RPEs we are exposed to compared to other regulated entities such as Electricity Distribution Network Operators (DNOs) and the Scottish transmission companies. This is especially relevant given that comparisons will be made between entities under the RIIO regime. This will help to explain why the RPE risk we are exposed to is higher than other regulated entities and why we are proposing that an uncertainty mechanism based on the price of copper is developed for use in the RIIO-T1 period.

102 As noted above our capital works use a high proportion of specialist electricity materials in their construction, averaging 32% of our capital plan per annum. The commodities (such as copper and aluminium) that make up this category are similar, if not identical to, the DNOs specialist electrical materials; however our analysis suggests that our exposure to these specialist materials is higher than a DNO. DPCR5 introduced a standard mix of work to calculate RPEs from. This set the specialist materials exposure at 15% of capex, which is approximately half of our exposure. This difference is probably due to the high proportion of cable, switchgear and transformer work we undertake which is more exposed to copper and other commodities. Whilst the DNOs would generally have a variety of work that they will undertake their exposure to materials is not only less but also more standardised, as discussed in the DPCR5 final proposals.

103 Comparing our plan to that of the Scottish transmission companies shows that we have a much higher proportion of capex work which we are proposing to be funded on an ex-ante basis[4]. This is opposed to using within period determinations to set the allowance for specific projects. Whilst we are proposing two of our schemes are treated this way (Eastern HVDC and Wylfa – Pembroke HVDC) this is a much smaller proportion of our plan to those treated this way for either Scottish Power or SSE.

104 When a scheme's funding is determined during the period the unit costs are usually set with reference to the latest values. This means that any variances in RPE between the point of setting the price control and setting the within period allowances can be accounted for in the allowances received. This is not the case for schemes funded on an ex-ante basis, exposing the schemes to more risk of windfall gain or loss in relation to RPE.

105 These two differences – both greater exposure to commodity price movements and a lower proportion of within period determination schemes – expose us to greater RPE risk than either the DNOs or the Scottish transmission companies. In order to rebalance this risk we are therefore

[4] 90% of capital expenditure for NGET, against 21% for SHETL and 63% for SPTL

seeking an uncertainty mechanism in relation to the commodity with the most volatility: copper.

RPE calculation methodology – Opex

106 For opex the exposures to prices rises are more direct and simple to calculate compared to capex. We directly purchase the material which exposes us to RPEs rather than a piece of equipment which is manufactured using base commodities. For example we directly buy electricity for use at our substations like any consumer and the manpower in our opex costs is either internal or contractors directly employed by ourselves. The more direct nature of the exposure to RPE means that we have not needed to develop a model like the CPM to forecast RPEs and can instead use readily available indices to calculate our exposure.

107 Instead of using a model in opex we calculate the percentage of the plan exposed to RPE in each year (be it internal manpower or civils for example) and then use the forecast RPE movements to calculate the overall cost in the plan. This is performed on a bottom up basis for each of our directorates (e.g. Asset Management) using common assumptions and then amalgamated to give the overall opex RPE. We have had to manipulate our usual business planning workings in order to split these RPEs across the three areas of opex (direct, closely associated indirect and business support) and fill in the simplified table requested by Ofgem. This process has altered our RPEs slightly from those originally calculated but we recognise that the simplified summary of RPEs in table 2.14b is useful for Ofgem to compare across regulated entity.

108 The next sections take each of the RPE areas in our plan and either outlines the evidence for the price movements included in our plan or points the reader to where this can be found elsewhere in the submission.

Manpower

109 Labour is a key input to our business and is our single largest category of expenditure. Manpower exposure within our plan splits between specialist engineering skills and general skills. For labour with general skills, we anticipate that there will be real wage growth over the course of the RIIO-T1 period, as long run relationships re-establish themselves. For the highly skilled and increasingly scarce specialist labour on which we will depend to deliver our plan, we anticipate more upward pressure on wages, as the individuals in this group will increasingly recognise the strong demand for their services.

110 Evidence and justification for the RPE assumptions in our plan for each of these areas and the range of independent views is contained within the 'Efficiency and value for money' annex of our narrative (within the pay benchmarking section) because the assumptions are linked to our benchmarking of pay levels. This is not repeated here. In summary the RPEs expected over plan period are:

Staff	2011/12	2012/13	2013/14	2014/15 onwards
Real pay growth – general	(0.5%)	0%	0.8%	1.5%
Specialist premium	-	0.3%	0.5%	0.5%
Overall real pay growth	(0.5%)	0.3%	1.3%	2.0%

Managers	2011/12	2012/13	2013/14	2014/15 onwards
Real pay growth – general	(0.5%)	0%	0.8%	1.5%
Specialist premium	-	0.1%	0.25%	0.25%
Overall real pay growth	(0.5%)	0.1%	1.05%	1.75%

Cumulative real pay growth	By 2020/21
General skills (for business support opex)	11.3%
Blended 50% general / 50% specialist	16.2%

Civils

111 We have based the civils RPE forecasts in our plan on reports from a leading industry commentator, Gardiner, Theobald and Fairways (GTF). We have also tested GTF data against other industry analysis as outlined below. GTF utilise industry metrics and benchmarks to give a view of future cost movements. In practice there is a natural lag between movements in underlying commodity prices and the capital price increases that we experience due to procurement lead times. This ranges from six months to two years typically dependent on the plant type. For this reason we have incorporated a one year lag into our forecasts for RPEs over the RIIO-T1 period compared to the GTF forecasts when used in capex. In summary this gives the following RPEs over the RIIO-T1 period[5]. The difference between assumptions for opex and capex is due to forecast procurement lag in capex.

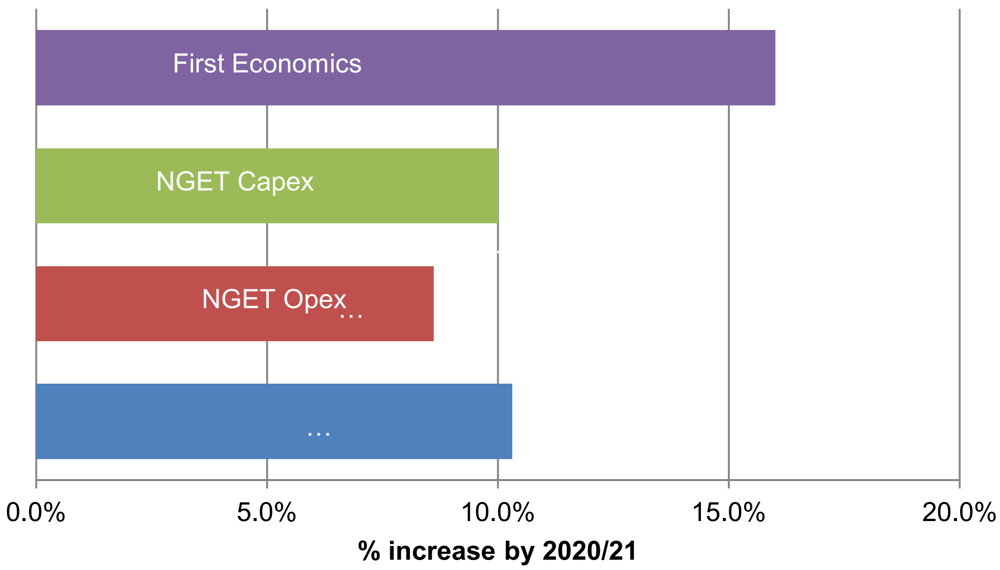
	'11/12	'12/13	'13/14	'14/15	'15/16	'16/17	'17/18	'18/19 onwards
Civils opex	(1.2%)	(0.4%)	(0.1%)	1.5%	2.6%	1.3%	1.6%	1.6%
Civils capex	-	(1.2%)	(0.4%)	(0.1%)	1.5%	2.6%	1.3%	1.6%

[5] The figure for 2017/18 has been taken as the long term average because over a ten year period forecasts will revert to this and GTF have not forecast beyond this point.

Cumulative RPE growth	By 2020/21
Civils opex	10.3%
Civils capex	8.6%

112 Whilst our forecasts for civils are based on GTF forecasts they are in line with the forecasts from First Economics who assumed a 10% increase by 2020/21 and the UK Treasury report on infrastructure costs[6] which forecasts an RPE rise of ~16% by 2020/21.

Comparison of forecasts for civils by end of 2021



Materials capex

113 The materials capex index on table 2.14b is based on a blended index for steel, copper, aluminium alloy and oil. As with civils we have based the copper, steel and aluminium alloy RPE forecasts in our plan on reports from GTF and incorporated a one year lag. In addition, we have tested GTF data against other industry analysis as outlined below. In summary this gives the following RPEs over the RIIO-T1 period[7] (with 2011/12 increases being zero):

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19 onwards
Copper	12.4%	(0.2%)	3.3%	3.0%	1.0%	1.0%	1.2%
Steel	7.0%	(0.1%)	0.6%	1.4%	2.2%	2.9%	4.0%
Alu. alloy	6.5%	0.5%	1.2%	2.3%	0.4%	1.3%	1.5%

6 http://www.hm-treasury.gov.uk/iuk_cost_review_index.htm

7 The figure for 2017/18 has been taken as the long term average because over a ten year period forecasts will revert to this and GTF have not forecast beyond this point

114 In our July submission we embedded an £83m RPE efficiency into our NGET capex forecasts. This was based on purchasing equipment when the copper price is in a trough and thus reducing the impact of RPE. Following feedback from Ofgem we have now embedded this efficiency into the updated 2.14b tables. In order to achieve this we have updated the copper index to reflect this.

115 We have based the oil RPE forecasts in our plan on our internal model for forecasting these costs in external publications such as the ten year statements and the Offshore Development Information Statement (ODIS). The internal model is based on several independent market forecasts including Experian and the Internal Energy Agency (IAE); we also compared GTF's forecasts for oil against these. In summary, this gives the following RPEs over the RIIO-T1 period:

	2011/12	2012/13	2013/14	2014/15	2015/16
Oil	-	4.7%	1.1%	4.8%	6.0%

	2016/17	2017/18	2018/19	2019/20	2020/21
Oil	4.5%	3.0%	3.0%	3.0%	2.8%

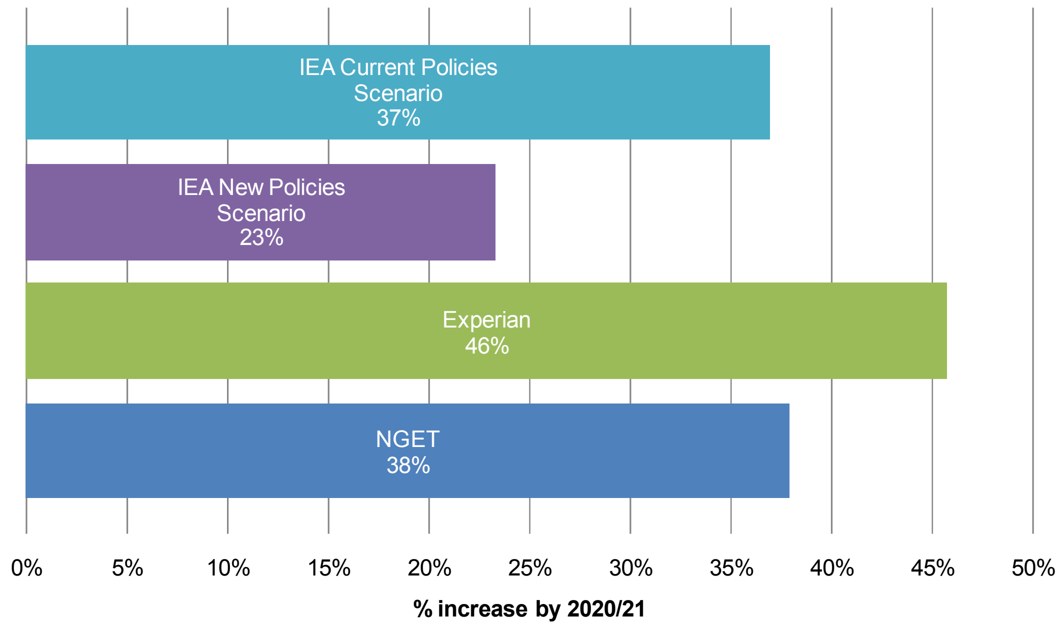
116 These forecasts are lower than the average increases seen during the TPCR4 period and give rise to cumulative cost increases over the plan period for materials capex as follows

Cumulative RPE growth	By 2020/21
Copper	26.4%
Steel	27.9%
Aluminium alloy	18.0%
Oil	37.9%
Blended materials capex[8]	**27.2%**

117 Comparing our RPE forecast for oil to the independent forecasts shows the following cumulative RPE increases over the period to 2020/21:

[8] See translation tables in the summary section for detail on how this blending is performed and why

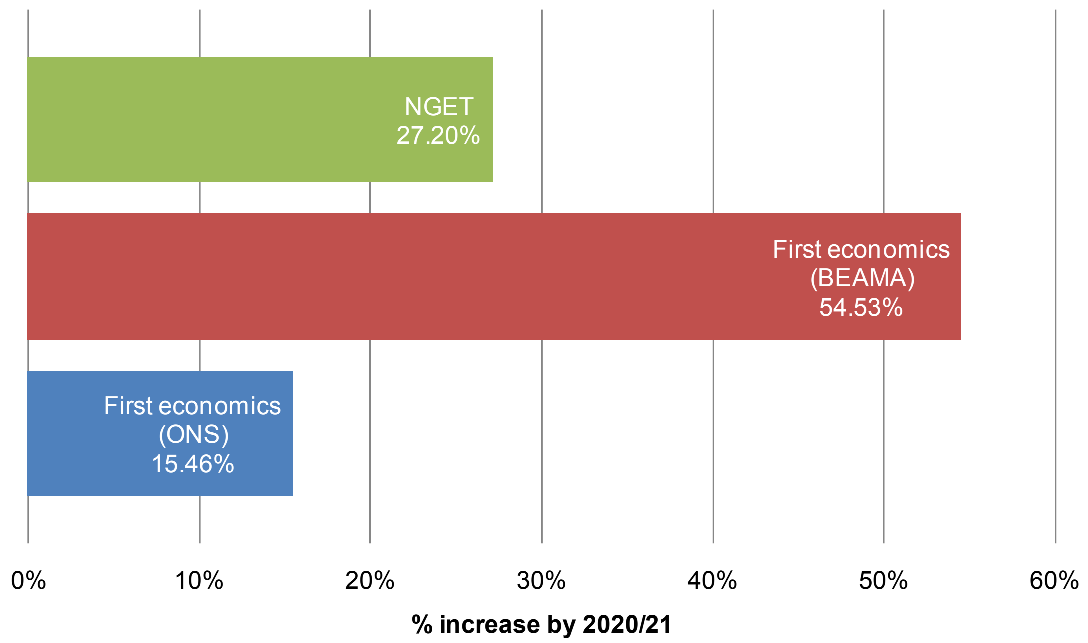
Comparison of forecasts for oil by end of 2021



118 On this basis our forecasts for oil are in line with other predictions. In addition they are lower than forecast by GTF.

119 More generally, comparing the overall blended RPEs for capex materials to the First Economics report shows that we are taking a central point between First Economics' two forecasts for electricity materials. In their latest report First Economics suggest that electricity materials costs are equally likely to flow with either ONS dataset or BEAMA. The RPE from both of these are shown below against our forecasts.

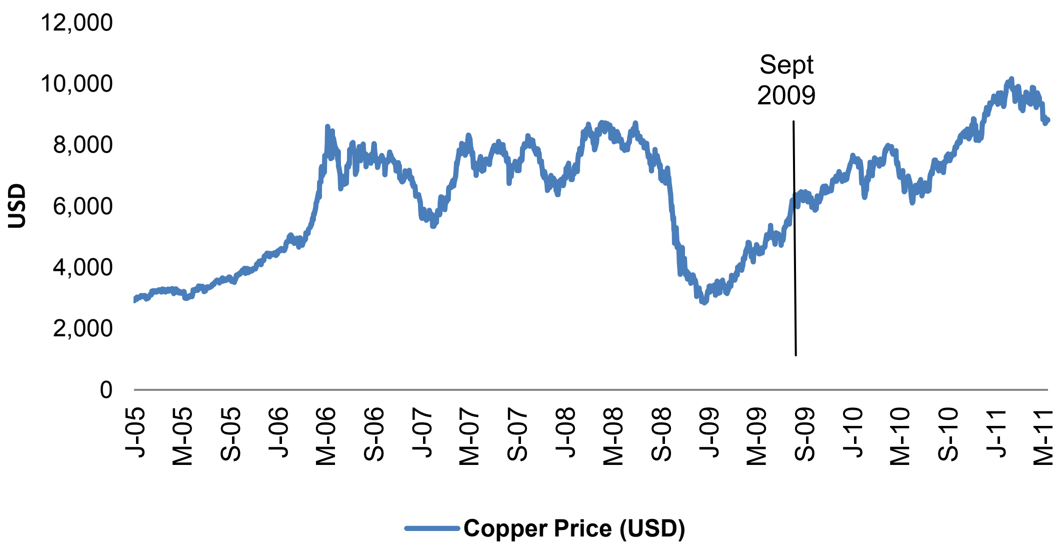
Comparison of forecasts for electrical materials by end of 2021



120 An important item to note in this area is that the unit costs in our plan are in 2009/10 prices based on our costs from 2010/11. These were analysed from data in September 2010 to give time to factor into our first RIIO-T1 submission. They were set at this point to feed into internal business planning processes and to ensure we could 'lock-down' our plan far enough in advance of submission to ensure all analysis and narratives could be completed. As we have an average one year lag in RPE flowing through to our unit costs this effectively means that the base commodity prices that feed into our unit costs are from September 2009.

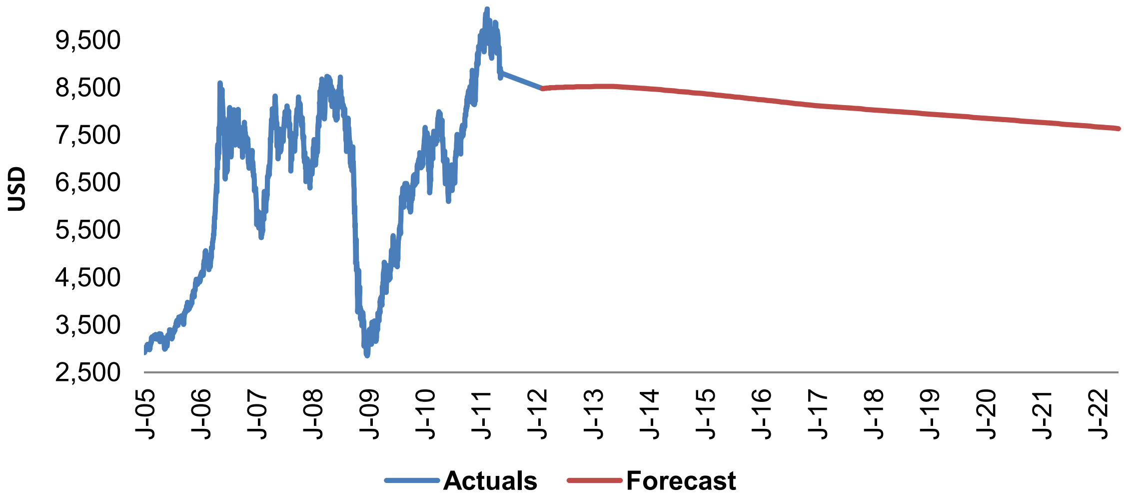
121 Over the last few years, copper prices – which make up a high proportion of the forecast increase in specialist electricity materials as noted above – have been volatile and during September 2009 they were just starting to increase again after a slump in 2008. Our RPE forecasts need to be considered from this point when the price of copper averaged USD$6,212 per LME, rather than the price of copper in say quarter 2 of 2011 (just before first submission) of USD$9,270:

Copper prices from 2005 to 2011 (LME[9])



122 The graph below shows the same data with LME forward price forecasts included on the graph. This shows that the cost of copper is forecast to increase from September 2009 (our base month) to 2020/21, mainly due to the actual increases that have occurred between 2009 and 2011. The LME forecast that the price of copper will increase to USD$7,789 by 2020/21. This is a 25% increase from September 2009, which is comparable to our 26.2% forecast RPE:

[9] London Metal Exchange (www.lme.com)



Electricity

123 The RPE forecasts for own use electricity (at substations for example) are outlined in the tables below:

	2011/12	2012/13	2013/14	2014/15	2015/16
Electricity	15.1%	0.7%	16.3%	10.8%	4.2%

	2016/17	2017/18	2018/19	2019/20	2020/21
Electricity	3.9%	4.3%	5.2%	5.5%	4.7%

Cumulative RPE growth	By 2020/21
Own use electricity	95.6%

124 RPE forecasts for own use electricity have been based on the same internal model used for forecasting oil prices. The internal model is based on several independent market forecasts including Experian and the Internal Energy Agency (IAE). Within the model the electricity price rises are driven by the price rises for oil using historical levels of correlation between the two fuels and adjustments for the time of year. This is then manually adjusted for other factors (such as future generation capacity and regulatory outcomes).

125 As the electricity prices in the model are calculated based on the oil price forecasts the evidence above for oil forecasts can also be applied to the electricity price RPE increases. In addition we have reviewed:

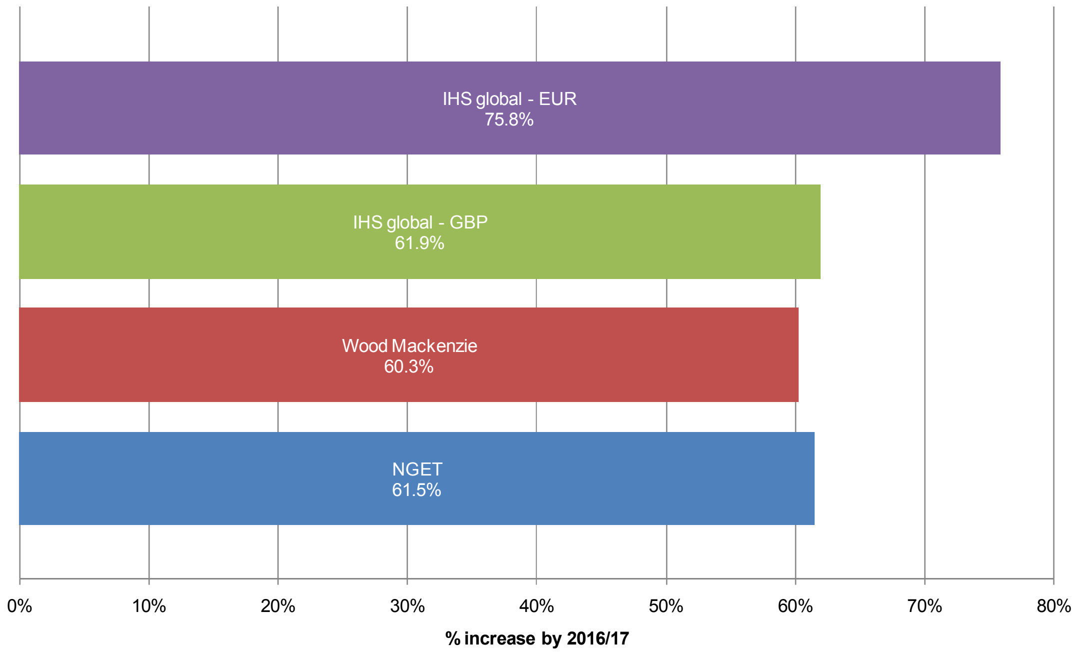
(a) Forward rate curves for electricity purchasing

(b) Forecasts from Wood Mackenzie

(c) Forecasts from IHS global

126 These do not cover all of the ten year period of our forecasts but the Wood Mackenzie and IHS forecasts do include figures up to 2016/17. Comparisons of the cumulative RPE forecasts are shown in the graph below. We have included both the Euro and GBP denominated forecasts from IHS:

Comparison of forecasts for own use electricity by 2016/17



127 In addition, the forward rate curves for the next three years are in line with our forecasts with a 46% increase expected by 2014/15 compared to 49% in our forecasts.

Transport fuel

128 The RPE forecasts for transport fuel are outlined in the tables below and are in line with the un-lagged oil forecasts:

	2011/12	2012/13	2013/14	2014/15	2015/16
Transport fuel	4.7%	1.1%	4.8%	6.0%	4.5%

	2016/17	2017/18	2018/19	2019/20	2020/21
Transport fuel	3.0%	3.0%	3.0%	2.8%	2.0%

Cumulative RPE growth	By 2020/21
Transport fuel	40.6%

129 Fuel is used in all our commercial and non-commercial vehicles and with the price rises in oil over the last five years the price of fuel has been rising steadily. Looking forward this is expected to continue but at a slightly dampened rate. Whilst we will attempt to minimise the impacts of the increases by using less travel (e.g. by utilising more video conferencing facilities) the growth in our workforce over the next decade will increase the usage of fuel overall. The price rises projected for fuel will therefore have an impact on our costs over the RIIO-T1 period.

130 The use of oil indices for the fuel RPE will not 100% correlate with the price of fuel because of movements in fuel tax which are not within the underlying price movements of oil. The latest budget includes an 8p per litre increase in fuel tax which will come into effect in 2012. This, along with any other tax changes that occur over the next ten years, is not factored into our RPE forecasts. We have used the oil forecast as it is readily available and will be directionally correct (if anything it understates the expected RPE, at least in the early years).

Total baseline RPEs

131 Using these assumptions and the relative exposures in our capex and opex plans the total baseline RPEs within our plan are as outlined in table 2.14b:

	£m
TO capex	1,046
TO opex	158
SO opex	34
Total	**1,238**

132 These are the gross RPE figures as reported within table 2.14b. These exclude efficiency savings embedded into our plans which reduce the impact of the movements (see later for more detail).

Comparison to first submission

133 These figures have changed from our submission in July due to:

(a) **Simplifying RPE assumptions**: Following feedback from Ofgem we simplified some of our opex RPE assumptions to fill in table 2.14b. This produces a difference in RPE forecasts compared to the original submission, mainly in relation to real pay. This is because our forecast RPE indices for labour costs are different between staff and managers, general and specialist skills. The mix between these four areas differ across direct opex, closely associated opex and business support opex due to the different requirements of these parts of the business. These differences could be reflected using different indices but this cannot be shown in table 2.14b so we have used a simplified calculation assuming 25% of labour is in each category (e.g. staff specialist) based on the overall figures.

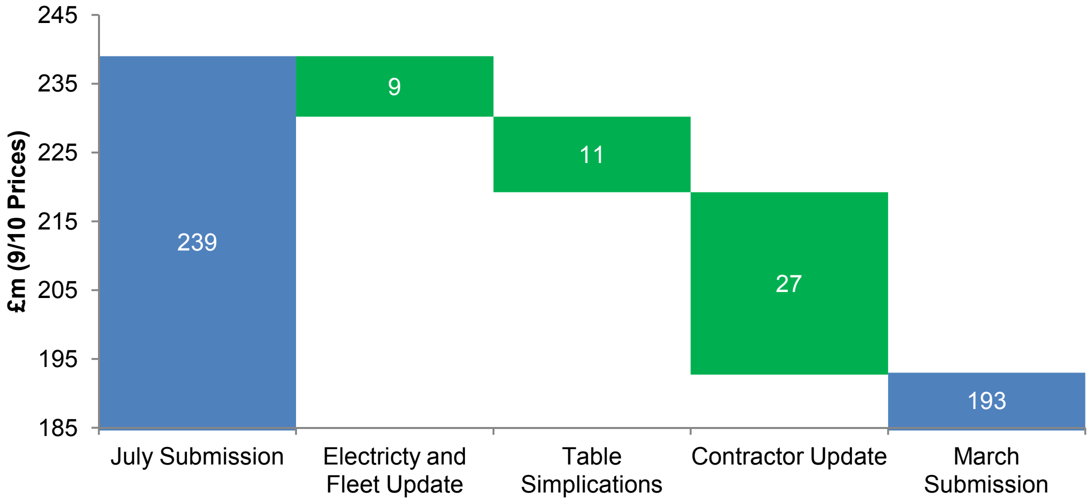
The impact of this is two-fold: firstly the RPEs are different between SO, TO, direct opex, closely associated and business support opex compared to the submission in July and secondly the overall opex RPE figures reduce by £11m over the plan period.

(b) **Updated indices:** Since July, external evidence has changed and we have had another year of RPE to check whether our forecasts are valid. We have therefore changed our forecast indices for electricity costs, transport fuel and contractor costs. These changes have reduced our opex RPE assumptions by £36m (£9m for electricity and fleet, £27m for contractors) from the first submission.

(c) **Changes to our underlying plans**: Since July we have updated a number of schemes in our capex plan which has meant that the profile of RPE has adjusted accordingly. This has reduced our capex forecast by £60m across the period, due to project timing effects and underlying scheme changes.

134 The opex changes are summarised by the waterfall below:

Comparison of opex RPE first to second submission



Translation into table 2.14b

[redacted]

[redacted]	

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	
	[redacted]	
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	
[redacted]	[redacted]	[redacted]
	[redacted]	
	[redacted]	
	[redacted]	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Uncertainty quantification

135 RPEs have always impacted on our costs, but the new regulatory regime introduces a higher level of risk to networks in the RIIO-T1 period compared to previous periods. The increased risk arises due to:

(a) **Forecast risk:** A longer price control period (eight years, rather than five) producing more risk of forecast RPEs being different to the actual impact by the end of the plan period with another three years' compounding effect

(b) **Exposure risk:** An increase in the capex sharing factors from 25% to between 40 and 50% which exposes networks to more of the difference between actual and forecast expenditure and related volatility

136 These factors are symmetric in that actual costs could be higher or lower than forecast but the absolute size of the risk falling onto networks is increasing due to the rising capital programme, resulting in more possibility of windfall gain or windfall loss. The increase in risk comes at a time when there is a higher level of investment in the energy industry and industrialisation of developing economies such as India and China is heating up. This means any RPE impacts are likely to be higher (all other things being equal) due to the increase in demand. The rise in risk is also coincident with uncertainty surrounding both the forecast rates and their impact on transmission costs due to:

(a) Historical and expected future volatility in the commodity markets which has produced price swings of plus/minus ~20% around a base increase in the price of copper over the last ten years[10]

(b) Recent global commodity demand fluctuations due to economic instability altering investment patterns

(c) Uncertain timings and scale surrounding RIIO-T1 energy industry investment as a result of customer-led generation and demand changes

Understanding the exposure

137 The RPE risks and uncertainties outlined above are more prevalent in certain input costs because of the volatility of their prices, the extent that we can influence the price as well as the materiality of its impact on our planned expenditure. For example a high proportion of our plan relates to internal labour so there is a high baseline RPE impact for this cost, but we can arguably control the price of internal labour more than the price of copper and it is less volatile.

138 The diagram below draws together this review and illustrates the:

(a) Relative materiality (size of bubble) of different cost categories based on the exposure of our totex plan to each input;

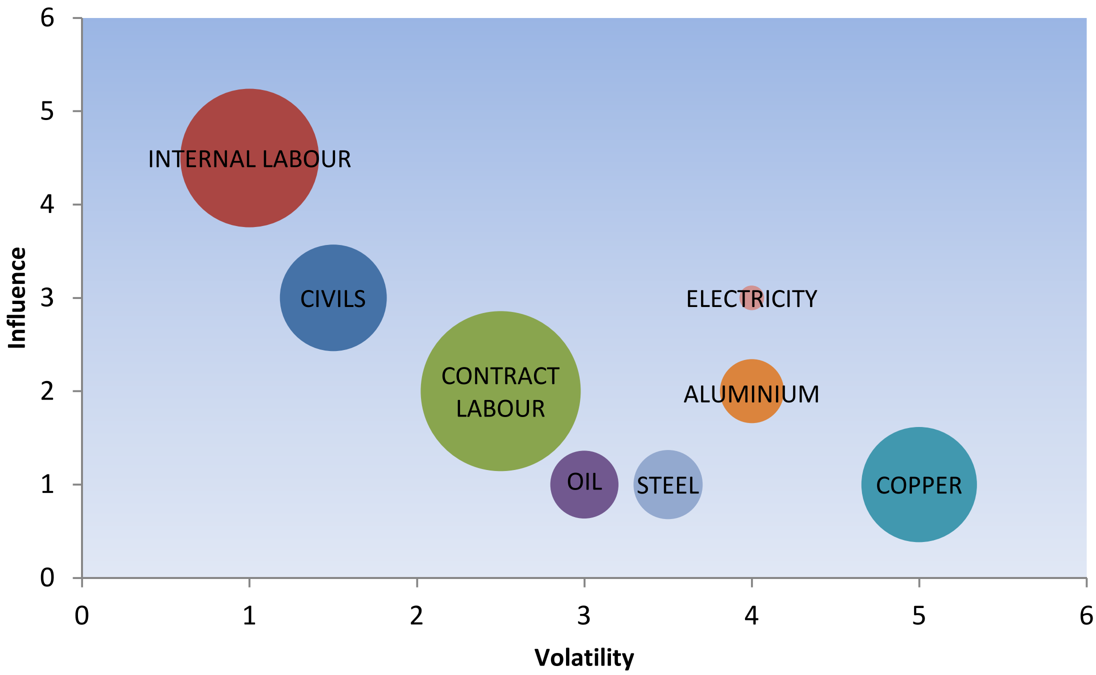
(b) Volatility of the underlying inputs; and the level of influence that we have over the price.

139 Influence and volatility are rated one to five with a higher figure denoting higher volatility and higher influence. These are based on historical volatility and our rating of the extent to which we can control any price increases. In the diagrams any input with a large bubble in the bottom right quadrant is one which is highly volatile, over which we have little influence and that would

[10] Source: Standard deviation of ONS Copper import price variances

have a material impact on planned costs if it varied from the baseline assumptions:

Input costs ranked by influence, volatility and materiality



140 This presentation shows that the main areas of risk for us are:

(a) Copper due to the high exposure in the plan coupled with low influence and high volatility

(b) Steel and aluminium mainly due to their high volatility and our low influence

(c) Contract labour due to the materiality of impact on the plan.

141 It is these areas which will primarily be impacted by the risks and uncertainties outlined in the RPE uncertainty section above and where any difference to baseline RPEs would be most keenly felt.

Range of uncertainty

142 During the TPCR4 period, costs of commodities rose sharply due to global pressures. This gave rise to increases in our unit costs and resulted in an extra ~£0.5bn capex in the TPCR4 period compared to RPE allowances. These increases were not predicted at the time of TPCR4 submission with price rises in metals and oil higher than GTF forecasts at the time by an average of 11% per annum.

143 With RPEs having such a material impact in the TPCR4 period and in light of the increased risk and uncertainty in this area we have used two methods to size the uncertainty we are facing:

(a) Reviewing a number of external forecasts in coming to our baseline assumptions

(b) Projecting the same forecast error that occurred in the TPCR4 period (i.e. 11% p.a.) onto our baseline commodity RPE forecasts for capex (both as an upward and downward pressure).

144 Whilst this second approach is projecting historical differences into the future (and there is no certainty over the extent to which history will be repeated) it is a credible outcome because there is no more chance of forecasts being correct now compared to previous years. The main RPE changes that would result incorporating the TPCR4 forecasting error assumption for capex and other external forecasts are:

		RPE change £m	Based on
NGET capex	Baseline	1046	
	High case change	+1524	TPCR4 forecasting error
	Low case change	-524	First Economics assumptions (ONS data for materials)
NGET opex	Baseline	193	
	High case change	+80	Hay Group pay assumptions
	Low case change	-20	First Economics pay assumptions

145 The range of uncertainty in the opex plan is lower because of the low risk or materiality in the RPEs which impact this area being internal labour and electricity mainly. Taking these items into consideration we have used +£1.5bn to -£0.5bn as a credible range for RPE impacts. Once 50% sharing factors are factored in the potential range of costs is £0.75bn to -£0.25bn.

Management response

146 Our business plan assumes that RPEs will increase capex and opex costs over the RIIO-T1 period. We are assuming that management actions will mitigate the impact of unconstrained increases in costs in the plan through the inclusion of specific efficiencies. These are targeted at beating the forecast price rises. In summary these efficiencies relate to:

(a) Incorporating the one year lag in prices into our RPE forecasts which reduces the impacts on our plan by £308m

(b) Opex efficiencies to reduce the expected price rise in electricity prices through strong procurement to beat the price and demand management to minimise usage.

147 With the level of uncertainty over the RIIO-T1 period it is certain that RPE impacts on our plan will not end up being as per our baseline assumptions. There are options open to us to manage this risk and its impact on our costs which we could exercise throughout the period. These actions are focused around capex (as this is where the main exposure lies) and cover:

(a) Mitigating the impacts of volatility through procurement activities

(b) Hedging against the price movements

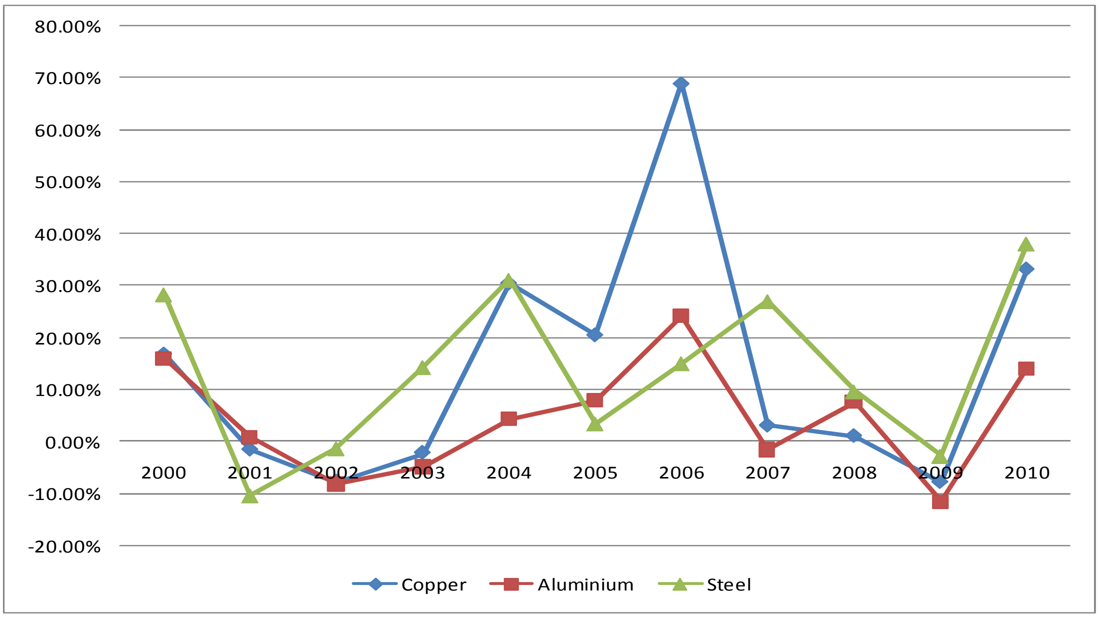
(c) Forward purchasing of equipment when prices are low

(d) Using long-term partnerships to deliver our capex

Mitigating volatility

148 During the last decade the price of commodities have been highly volatile, with price swings above and below an underlying upward price trend:

Year-on-year volatility in prices (source: ONS data)



149 Historical unit costs analysis shows that we have mitigated the volatility of RPEs over the TPCR4 period through leveraging our suppliers' use of forward purchasing. We are expecting that we can continue this into the RIIO-T1 period and that we can therefore smooth the expected volatility. The savings embedded into our plan in relation to opportunistic purchasing of copper help us to do this.

Hedging

150 An effective hedging strategy could potentially minimise, if not remove, the risk of commodity price rises above those in our baseline plan. We would not be able to remove the underlying price increases though unless the hedging markets expect price increases below those included in our plan (and based on the data available to us we can see no reason why this should be the case). There are two main options open to us in this area:

(a) Entering into a 'call option' on the price of commodities which would reduce the risk of unexpected price increases

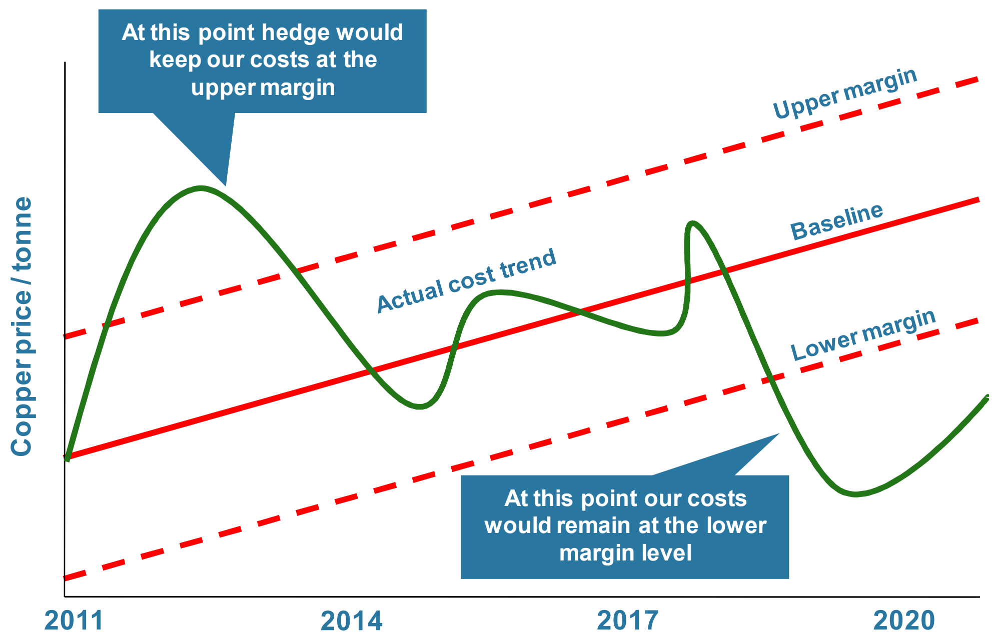
(b) Using a 'zero cost collar' which would effectively lock us in to a price within a limited range

151 To be feasible these options need to be economic and efficient compared to the alternative of letting price rises flow into costs and managing the impacts, otherwise we would not be justified in using them. We could use these methods for copper given the exposure in the plan to movements in this commodity.

152 The benefit of a call option comes at a price. For a five year hedge the premium can be as much as 30% of the value of the hedge strike price. This means that if we were hedging at £100 per tonne this would cost us £30 per tonne, which we would include in our plan and would be included in our charges. Using copper as an example in May 2011 we were quoted a 27% premium for a call option. Our baseline plan includes £2.2bn for copper so a premium of 27% on this would add £594m to our plan. Use of such a hedge could be called into question if prices ended up reducing during the period of the hedge. In this case our capex would reflect the lower costs but the premium of £594m would still be a cost to consumers. At this stage we do not think it would be justified to include this level of premium in our business plan so we are not proposing to use this approach to manage the future volatility of input prices.

153 Use of a zero cost collar hedge would lock in the price within a range; this is achieved by constructing a call option and a put option which effectively eliminates the premium.[11] A zero cost collar hedge like the call option removes the risk of price increases; however this hedge also removes possible price reduction if the market price drops.

Zero cost collar hedge illustration



154 This removes some of the risk involved with commodity prices, however there are problems with this approach:

(a) With the level of uncertainty in investment needs and timing over the RIIO-T1 period (see elsewhere in this document) we do not know how

[11] A cost may remain depending on the range used

much copper will be required for our capital works. Our baseline plan assumes a level of investment which we have translated into an exposure to copper, but the likelihood of this occurring exactly as we are planning is highly unlikely. It would be inefficient to take a hedge out for the total copper exposure in our baseline plan because we could end up hedging against an exposure that does not materialise. We would therefore only be able to hedge up to 50% of the exposure to be confident that the level appears in actual expenditure. Even then the timing of the copper requirements could be materially different to that assumed in a hedge, still leaving us over or under hedged at points during the period.

(b) Using our risk modelling (see later in this document) we have applied a zero cost collar hedge to the copper RPE risk we are exposed to over the period. A collar for 100% of copper in our plan would substantially reduce the risk, however a 50% level (the maximum we would potentially use) does not mitigate the risk enough. The related return requirements in using this method would be higher than we think it is reasonable to propose.

(c) If the price of copper drops over the period our related capex costs would not go below the bottom of the range included in the hedge. This would mean consumers were being charged at a rate higher than the market price. In addition there would be management costs involved with this approach in terms of employing people with trading experience.

(d) The hedges would be subject to accounting rules which would introduce volatility into our profits as the hedges would have to be market valued at each year end. As commodity prices are volatile this could make distributable reserves fluctuate over the period, materially reducing the ability to pay dividends. The payment of dividends is critical to investor confidence and this could have an impact on the financeability of our business.

Forward purchasing

155 By purchasing equipment at points when the prices are in troughs we could minimise the impacts of RPE rises. We have already embedded savings from this strategy into our base plan and, assuming the volatility of copper remains in any changes to our baseline assumptions, this efficiency should be scalable. We may also be able to increase this strategy but it would not remove all upward cost risk unless all equipment could be purchased in advance. This would involve large costs for storage but also could be proven inefficient if prices subsequently drop or if it turns out that we do not need the equipment because of the uncertainty involved with the investment requirements over the RIIO-T1 period. Our plan is to forward purchase to the extent it is economic to do so but this will only cover a small proportion of the overall exposure.

Long-term partnerships

156 As explained within the ‘How we will deliver’ annex of our submission we have long-term partnerships with global construction companies to deliver a large proportion of our capital works. These alliances have many deliverability

benefits but will also enable us to leverage our partners' scale to minimise the impact of RPE movements on the price of our capex. We have embedded 1% per annum capex efficiencies into our plan which will do just that. One of the ways the scale of our partners will help us in this area will potentially to be able to forward purchase more material than would be economic for us to do and spread the costs and benefits across all their customers.

Risk sharing arrangements

157 In previous price control periods the risk surrounding RPEs has fallen completely on networks with shielding provided by the capex incentive rates. In the RIIO-T1 period the risk is higher and there is also more exposure surrounding the impacts. We have an opportunity to manage some of this risk, and hence a portion should remain with us, but since significant elements of this risk cannot be effectively managed we are proposing that some of this risk should be socialised through the use of an uncertainty mechanism to limit exposure to inside an agreed boundary.

158 The portion of RPE risk we are proposing to transfer via an uncertainty mechanism is the risk of an actual outcome that is material enough to either cause us financeability issues or have to defer capex and impact on outputs. Without an uncertainty mechanism covering some of our risk there would be a higher risk of windfall gains or losses and we would be seeking a higher return on equity to adequately fund us for the increased exposure. To minimise charges it would probably be better for consumers to assume this risk, rather than be subject to an inflated return on equity figure.

159 Based on levels of materiality and controllability this would limit the mechanism to copper prices. There are remaining risks around other areas, but copper prices are the only area which could give rise to increases above our baseline plan which we could not control and would be material enough to cause potential financeability issues. Whilst the efficiency rate will shield us from some of the financial impact of the RPEs being different to plan RPE movements gave financing concerns in the TPCR4 period. In this period the sharing factor for capex was lower than it will be in the RIIO-T1 period.

Risk sharing mechanisms

160 There are several options that could be used for uncertainty mechanisms around the price of copper, most of which are variations on an index tracker. Copper has an active global market and is covered by several widely recognised indices. This gives readily available independent information which can be used in the design of a mechanism. In assessing whether an uncertainty mechanism option is justified we have considered:

(a) the impacts on resulting charges with a particular focus on minimising price volatility

(b) ensuring that we still have an incentive to manage the risk as best we can through procurement activities and other actions outlined above

(c) the symmetry of the mechanism to ensure that it covers both upward and downward price movements

(d) the ease of putting the uncertainty mechanism into practice

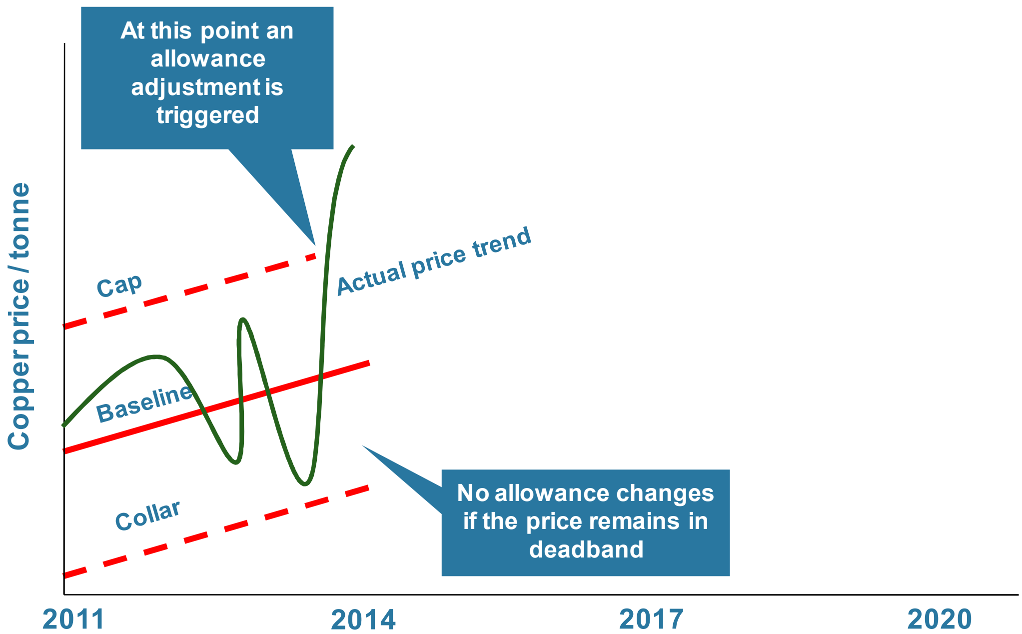
Option 1: Straight tracker

161 The option of a straight tracker to one of the copper indices would be the simplest uncertainty mechanism to use. This would mean that as copper prices moved in the market our allowance for RPEs in this area would move accordingly. Revenue movements would be completely symmetric under this mechanism, in that our allowances could go down and up to an equal extent.

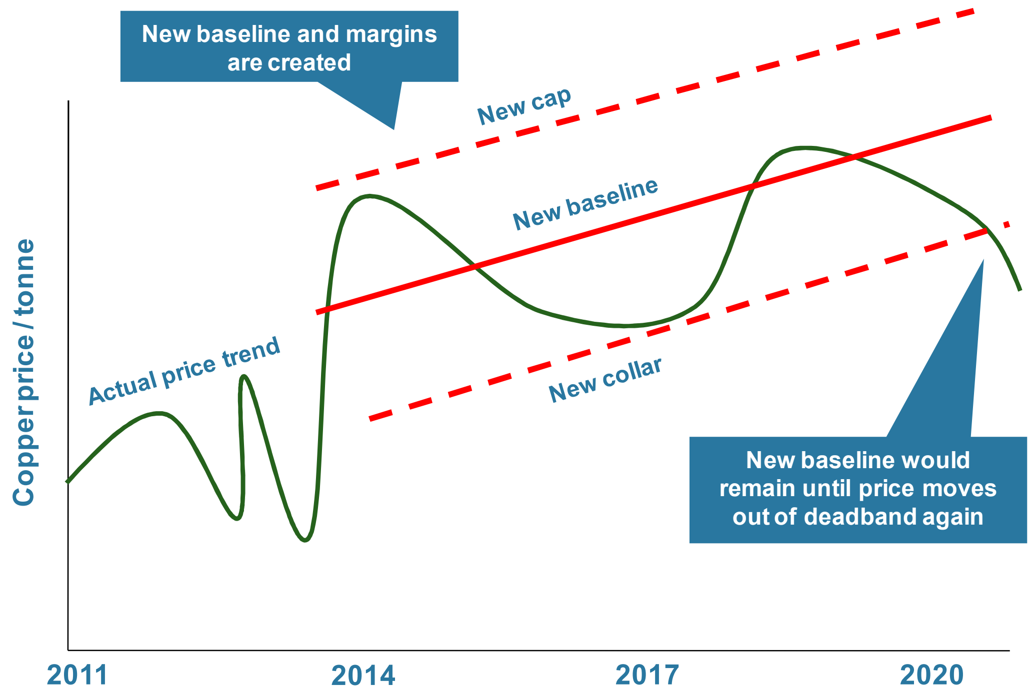
162 Whilst this approach is both simple and symmetric it would not pass the other two requirements outlined above. Changes to allowances would flow through to customer charges, increasing the volatility and reducing the predictability of our bills. With regular changes in the prices of copper, allowances would likely be changed several times a year; this would not be acceptable to customers who have told us they want predictability of prices. In addition, we would face a reduced incentive to manage the impact of RPEs if this uncertainty mechanism was adopted. Any savings we deliver would not flow through to lower consumer bills because our revenue would be set on the market rate.

Option 2: Tracker with a cap and collar

163 Similar to the zero cost collar hedge outlined above a cap and collar could be introduced to a tracker mechanism in order to reduce the drawbacks of using a straight tracker. As with a zero cost collar the mechanism would be designed with a margin around a baseline figure (in this case our baseline RPE increases). If the price of copper or steel per the agreed index remains within this margin (or deadband) our allowances for RPE would not be altered. Once the price goes outside this margin a price change, either upwards or downwards, would be triggered:



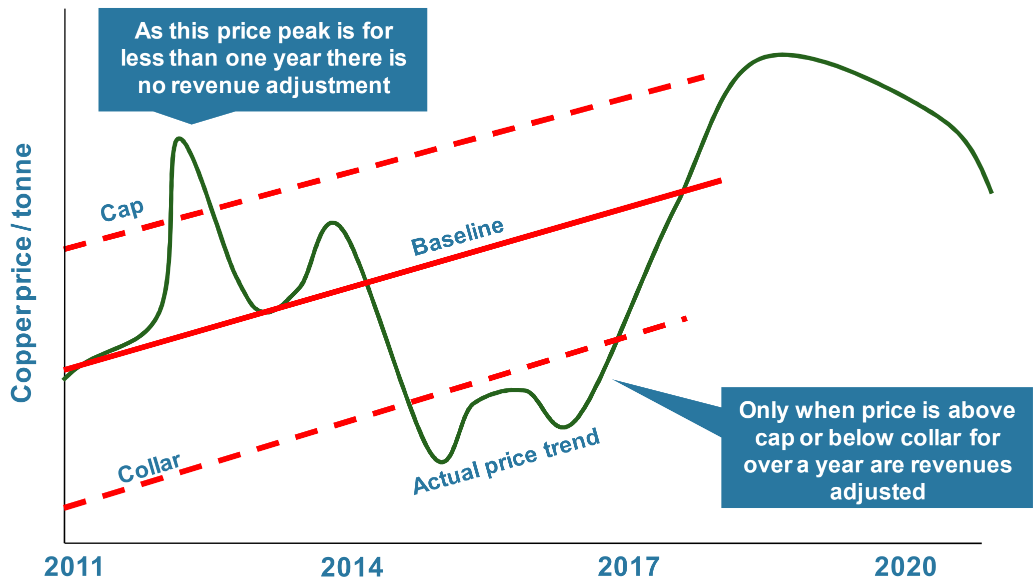
164 When the allowance change is triggered a new baseline with a surrounding deadband is set. This would then remain until the price moves outside the deadband again:



165 This design reduces the volatility of customer bills compared to a straight tracker. It also means that we still have an incentive to generate savings and minimise the RPE impact. This design therefore reduces the drawbacks from the previous option but a level of volatility still remains. With copper prices moving up and down by an average of 20% year on year over the last ten years it could be that prices are still adjusted every year – or more – under this mechanism.

Option 3: Tracker with a cap and collar incorporating a price rise lag

166 To reduce the volatility on prices further, a price rise lag could be introduced into the tracker mechanism. This would mean that if prices per the index rose above the cap or fell below the collar, RPE allowances would not be adjusted unless the prices remained above this level for a pre-determined amount of time (in example length of time is one year) on a rolling average basis. In this way allowances would only be adjusted for the underlying increases in price, rather than any short term price peak or trough, and would only be adjusted prospectively, not retrospectively.



167 Use of a rolling average, rather than absolute increases, would cover the risk that prices could be above the cap or below the collar for 364 days of the year and then dip down or up for one day. Revenues should be adjusted in these cases because there would be an overall impact on copper prices.

168 As the reason for the uncertainty mechanism is to cover the risk of material price rises, rather than the volatility of prices, this lag approach seems a more acceptable design. It would also place more incentive on us to deliver savings because we would be exposed to the higher prices for the length of the lag, as well as the period of time the price remains in the dead-band.

169 Whilst not as simple as a straight tracker, this mechanism should be easy enough to operate, as long as the rules underlying it are clearly defined. The potential for some volatility in customer prices would remain but this would occur with any uncertainty mechanism design. As outlined in the 'Innovation Strategy' annex of our narrative we will be looking to minimise any such volatility during the period anyway by reviewing our charging methods. Customers would also have a years' notice of any changes. There also remains some disincentive to look for efficiency savings when the prices near or go above the cap with this mechanism but the majority of this disincentive has been removed through the longer period of exposure to price increases.

Option 4: Re-opener at the mid period review stage

170 An alternative to a tracker mechanism would be to use the mid-period review for RIIO-T1 as a point to reassess RPE increases and potentially use a re-opener to adjust revenues on a prospective basis for the remainder of the price control. This would bring the period of exposure down to four years from eight and reduce the risk of windfall gain and loss. We would still, however, be exposed to more risk than we were during the TPCR4 period under such a mechanism. This is because the level of investment we are forecasting is much higher in the RIIO-T1 period, meaning that the impact of a sharp rise or sharp fall in the price of copper (or other commodities) would be felt more keenly than during the TPCR4 period. With £0.5bn extra cost due to RPEs in the TPCR4 period under the lower investment level this risk is still substantial.

Proposal

171 We are proposing that the ex-ante allowances take into account our base RPE forecasts in our plans. Additionally, we propose an uncertainty mechanism in line with option three – a tracker which uses a cap, collar and a price lag. This would mean that our risk, of exposure to volatility with RPE is shared with customers, with the greater proportion of risk remaining with ourselves. Use of this mechanism would cover us for the proportion of the incremental risk under the RIIO regime which gives rise to potential financial distress and minimises the costs of this cover to the end consumer.

172 The table below summarises the detailed specifications for our proposed uncertainty mechanism:

Feature	Value
Base month	Sept 2009
Base copper price	USD$6,212
Index	LME
Cap	+10% of base price plus ex-ante allowance
Collar	-10% of base price plus ex-ante allowance
Lag	One year
Trigger point	Rolling average needs to be above cap or below collar for one-year
Revenue change	Prospective from point of trigger

Residual risk

173 Use of an uncertainty mechanism in line with those outlined above does not remove all the risk surrounding RPEs from our plan. The following residual risks remain with us:

(a) **RPEs within dead-band:** the use of a dead-band still leaves a risk of fluctuation in steel prices to be managed by us, with the size of the dead-band determining the level of exposure.

(b) **RPEs outside of copper:** We will still have all the risk surrounding price movements for input prices other than copper. With recent increases in areas such as steel, aluminium and oil this is still sizeable. Increasing demand for specialist engineering skills suggests that the risk surrounding contract labour RPE is growing and might become increasingly difficult for us to manage and/or mitigate. For example, future uncertainty of workloads might make it necessary to secure additional support from outside contractors, at a time when contractors' order books are likely to be full. We might need to pay a premium to secure access to resources under these circumstances. The same could be true for the plant and equipment that would be required to deliver schemes at relative short notice in the middle of an already full programme of work, i.e. equipment manufacturers might require a premium over list prices.

(c) **Overheating market:** The last item points to the potential of an overheated market. Evidence within our overhead line unit costs and data from Mott McDonald suggests that this overheating may already be in existence in certain areas of the market. It could be concluded from this that suppliers will keep charging the rate that applied previously because there is enough demand in the market. Mott McDonald think that there is a hidden RPE cost in the factory gate price of equipment which relates to suppliers' energy and labour costs, i.e. the prices of key materials are increasing at a faster rate than RPI as a consequence of a wide range of factors, not just commodity price inflation. These are not factored into any of our forecasts due to lack of visibility.

174 The design of the uncertainty mechanism covered above does not shield us from these risks; instead they remain with us to manage. The risk modelling section illustrates the impact of these items on the risk we are expecting to experience.

Interaction with other uncertainties

175 There are clear interactions between the RPE uncertainty we are exposed to and other uncertainties discussed elsewhere in this document. We have discussed how the levels and nature of load related capex could be different to that assumed in our plan. This could have a material impact and hence we are proposing an uncertainty mechanism to cover this risk.

176 Changes in load-related capex would have impacts on the RPE levels in our plan though as well. If more capex was required then we would be exposed to higher RPE, similarly a change in the mix could alter the overall exposure to an individual commodity and hence alter the actual RPE that occurs over the period.

177 We have considered these interactions in two ways:

(a) How a credible change to our load related requirements would change both the value of RPE over the RIIO-T1 period (assuming no change in forecast indices)

(b) Incorporating RPE levels into the unit costs of the other uncertainty mechanisms

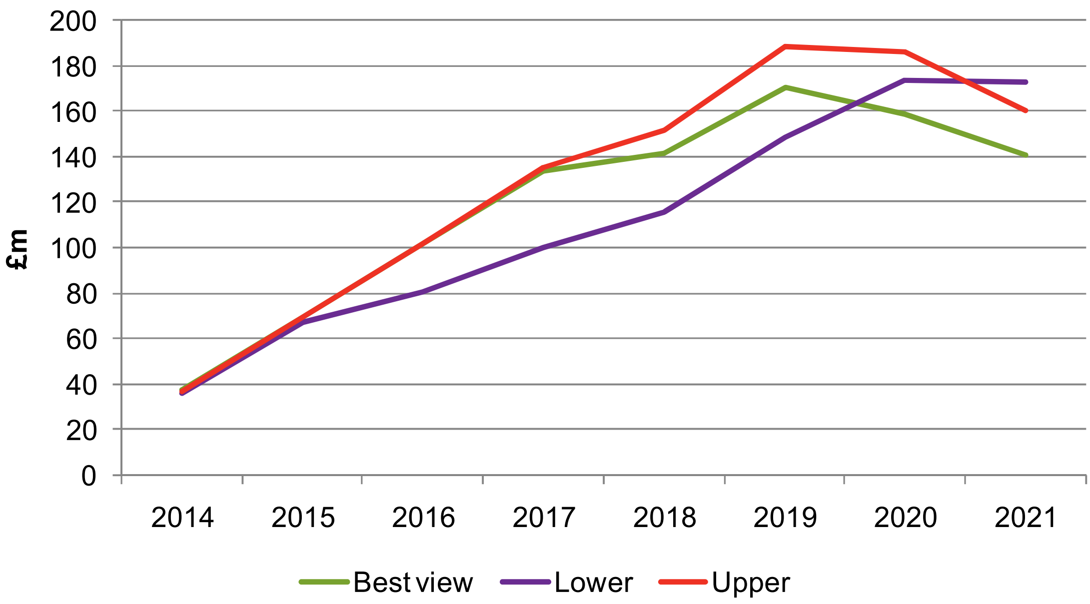
178 Our best view plan is based around our Gone Green scenario; however as would be expected RPE levels change under the upper (Accelerated Growth) and lower (Slow Progression) scenarios due to different levels and nature of capex involved. The details of the three generation and demand scenarios are discussed elsewhere in our submission (for example the 'Future of Energy ' annex) but in summary the changes from Gone Green are:

(a) The upper scenario (Accelerated Growth) assumes that renewable generation builds up more quickly than in Gone Green. Levels of load-related investment in the RIIO-T1 period are higher than in Gone Green with additional investments including a second East Coast HVDC link, additional overhead line re-conductoring in North Wales and additional reactive compensation equipment. In addition, with increased levels of load-related investment early in the RIIO-T1 period, further non-load investment is delayed to the second part of the RIIO-T1 period compared to Gone Green.

(b) The lower scenario (Slow Progression) assumes that there is a slower build-up of lower carbon generation on the network compared to Gone Green and the level of load related investment in the RIIO-T1 period is lower than for the Gone Green scenario. For example the East Coast HVDC link needed against the Gone Green scenario is not included. A number of investments to provide capacity in the East Anglia, Thames Estuary and London areas are also excluded from the Slow Progression scenario. With lower levels of load-related investment early in the RIIO-T1 period, increased non-load investment is assumed in the first part of the RIIO-T1 period compared to Gone Green.

179 We have reflected the knock-on changes to RPE within the upper and lower scenarios detailed in our financial tables. The graph below summarises the changes on our total capex RPE forecast over the RIIO-T1 period. The reduction for RPE under the lower scenario is £56m over the RIIO-T1 period with a £77m increase under the upper scenario.

RPE under the three generation and demand scenarios



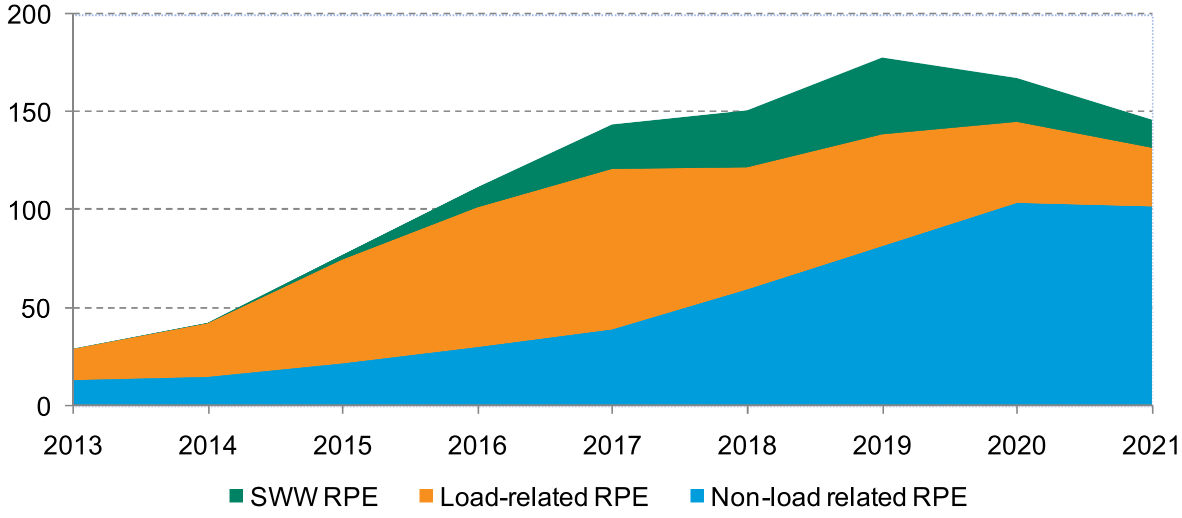
180 The interaction between load-related capex and RPE is reflected in the design of our uncertainty mechanisms. As discussed above we have two projects in our best view plan whose funding is subject to within period determination through the Strategic Wider Works (SWW) mechanism. Whilst the RPE in relation to these costs are included in our RPE forecasts we are not proposing that they are funded on an ex-ante basis – they are included to ensure consistency of the tables. This RPE totals £141m over the RIIO-T1 period.

181 Similarly the RPE included in our submission which relates to load-related capex is subject to change during the RIIO-T1 period. We are proposing that an RPE element – consistent with our baseline assumptions for price rises - is contained in the load-related uncertainty mechanism design. This will ensure that we are only funded for RPE in relation to the load-related capex that

occurs over the RIIO-T1 period, rather than the level in our plan. The total value of load-related RPE is £439m over the RIIO-T1 period.

182 The graph below shows our RPE forecast over the RIIO-T1 period broken down into the three elements: RPE subject to within period determination, RPE subject to load-related uncertainty mechanisms and RPE which we are proposing an ex-ante allowance for totalling £439m:

Planned RPE split by proposed funding method



Local generation connection analysis

What is it? *Uncertainty associated with the volume and cost of projects to connect new generation to the main transmission network*
How big? *The cost risk over the RIIO-T1 period (including real price effects) has a standard deviation of £146m, reducing to £121m with the application of our proposed uncertainty mechanisms*
What are we going to do about it? *We can influence the volume and location of new generation connections by providing cost reflective price signals, but ultimately this is outside our control*
Risk sharing arrangements?
National volume driver for substation costs, with a unit cost allowance of £23/kW (£24.2/kW with RPE adjustment)
Zonal volume driver for 'within zone' works, with a range of unit cost allowances from £2.7/kW to £36.8/kW (£2.8/kW to £38.7/kW with RPE adjustment)
Volume driver for new overhead lines, with a unit cost allowance of £1.2m/circuit km (£1.28m/ circuit km with RPE adjustment)
Volume driver for new cables, with a set of unit cost allowances from the IET report (+11.5% with RPE adjustment)
Efficiency incentive rate for over/underspends

Context

183 We are facing increasing uncertainty with respect to the quantity, type and location of generation and level of demand connected to the transmission network over the next 10 years as the energy sector is decarbonised. Whilst there was uncertainty when coal and oil-fired power stations were replaced with gas fired power stations, the gas fired power stations were in broadly similar locations to the older stations. We also have a mature society and this has resulted in relatively stable demand with modest growth prior to the recession. This low growth in demand has resulted in the total generation capacity connected to the system staying broadly at the same levels. Consequently, the electrical loading on the system has remained similar, other than for the localised effects of generation closures and openings.

184 Renewable generation is likely to have a very different geographic distribution from fossil-fuelled plant, and future generation projects may vary in capacity from a few MW for small renewables to 2000 MW and more for large nuclear stations resulting in increased volumes of generation connected to the transmission system and increased power transfers levels and volatility. The requirements to be imposed on the future transmission network are thus becoming increasingly uncertain.

185 The current uncertainty is, in part, driven by the volume and geographic variability of generation projects which may connect to the system. The table below summarises all the projects that have applied to National Grid for connection in England & Wales, as recorded in the 2011 Seven Year Statement and the known offshore windfarm developments which have presently not entered into a contractual agreement with National Grid. We consider it unlikely that all these projects will proceed, and those that proceed

are unlikely to commission in accordance with their original contracted timescales. In order to plan our network it is therefore necessary to take one or more views of how the generation market might actually develop.

186 One such view – National Grid's current "Gone Green"[12] scenario – is also presented in the table for comparison with the contracted position.

Generation Type	SYS 2011 New Generation (Contracted and known offshore development projects)		Gone Green Scenario New Generation	
	2013-2020	Post 2020	2013-2020	Post 2020
Nuclear	11130	12190	2870	10610
Gas	12336	824	6557	6786
Coal	1600	800	0	3940
Onshore Wind	360	0	659	0
Offshore Wind	14860	600 (39397[13])	10936	15700
Biofuel/BioMass	1983	0	1229	464
Marine	800	1200	86	2125
Interconnectors	2400	0	3400	0
Total	45469	15614	25737	39625

187 Between 1990 and 2010, circa 34GW of generation connected to the transmission system at a rate of circa 1.7 GW per year. However, as we move forward, we anticipate connecting some 23 to 41GW of additional generation[14] over the RIIO-T1 period at a rate of 3 to 5.125GW of generation per annum.

Quantification

188 The range of expenditure for local generation connection works across the major scenarios that we have considered is shown in the table below. In addition to the Gone Green, Slow Progression and Accelerated Grwoth scenarios, we have also looked at a High Demand and a Low Demand scenario. These new scenarios explore the impact of different demand levels, and include revised generation backgrounds.

[12] Gone Green identifies potential generation to 2030; the latest commissioning date amongst the SYS contracted plant is 2024

[13] The total capacity of offshore wind projects known to National Grid is 39,397 MW. Some of these are already in service, under construction or have contracted commissioning dates and are included in the "contracted" columns in the Table. The remainder have no contracted dates; we have made forecasts of commissioning in our scenarios, for example the Gone Green scenario shown in the Table includes assumed dates for projects that are not yet contracted.

[14] This has been updated to include interconnectors as generators

189 The volume of generation connections is higher in Gone Green than in Slow Progression across GB, but in England & Wales Slow Progression has a slightly higher volume of connections than Gone Green.

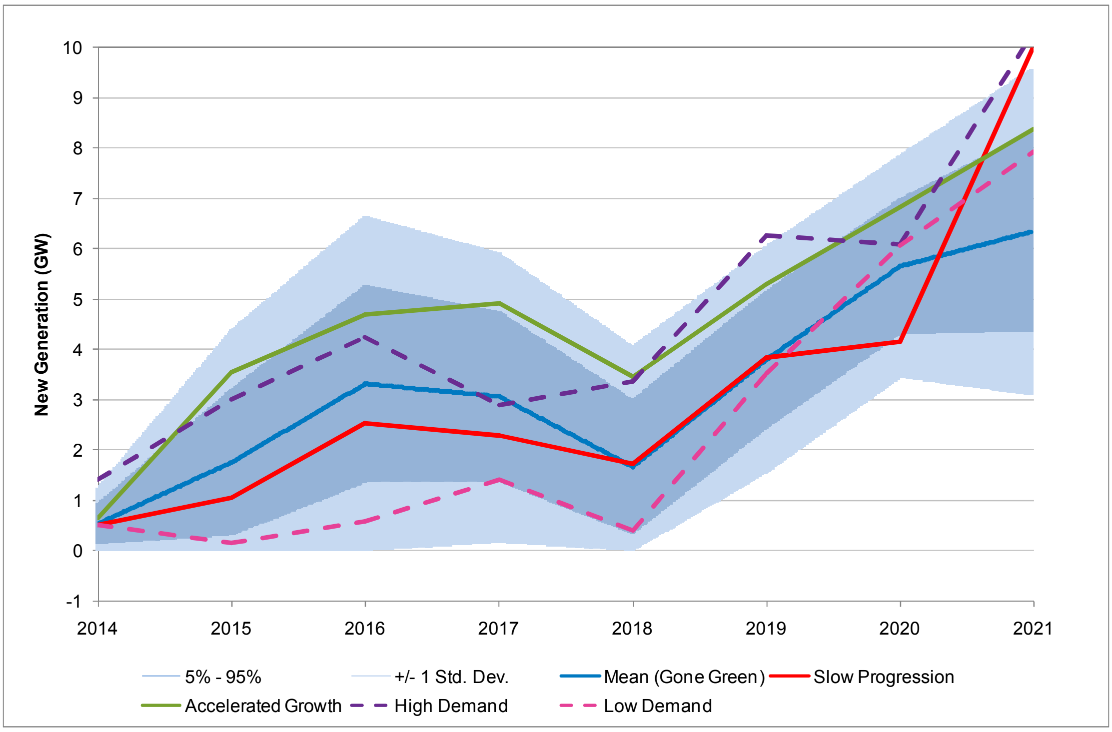
Scenario	Total MW	Capital expenditure (£m)								
		2014	2015	2016	2017	2018	2019	2020	2021	Total
Slow Progression	26098	181.9	223.5	217.3	271.1	218.4	197.0	71.3	50.8	1431.1
Gone Green	25737	177.6	257.8	279.2	272.2	167.4	122.4	51.2	39.1	1366.7
Accelerated Growth	37760	271.1	247.8	244.4	264.7	172.1	119.2	49.5	37.1	1406.0
High Demand	37581	358.0	266.9	339.9	270.6	92.0	46.9	29.3	28.2	1431.7
Low Demand	20524	37.6	177.1	273.9	230.1	189.7	189.6	158.7	78.2	1335.0

190 In order to understand the range of this uncertainty, we have considered the volume and cost uncertainties. We have modelled the potential volume of connections based on the scenarios described above.

191 From this we have developed probabilistic distributions to describe the uncertainty associated with the volume of new generation connections in each year.

192 We have assumed a normal distribution with a mean value equivalent to the gone green position. We have calculated the range of new generation connected in each year across all scenarios. We have assumed that this range represents a credible range of generation connected in each year, and set the standard deviation of the distribution as 50% of this range. The distribution has also been collared at 0MW (since it is not possible to get less than 0MW of new connections).

193 The resulting distribution has been superimposed on the scenarios in the graph below.



194 In order to calculate a capital cost uncertainty from the volume uncertainty described above, we have investigated the costs associated with all known local generation connection schemes and established a unit cost.

195 We have built on the work completed to define the unit cost for our July 2011 business plan submission, and divided generation connection costs into:

(a) Connecting substation unit costs (£/kW)

(b) These costs have a significant range and therefore to gain a more accurate picture of the uncertainty, we have further divided this category into new and existing substation costs

(c) Within-zone reinforcement works unit costs (£/kW)

(d) These costs cover all other local enabling works, such as equipment to manage short-circuit levels and increase the rating of circuits

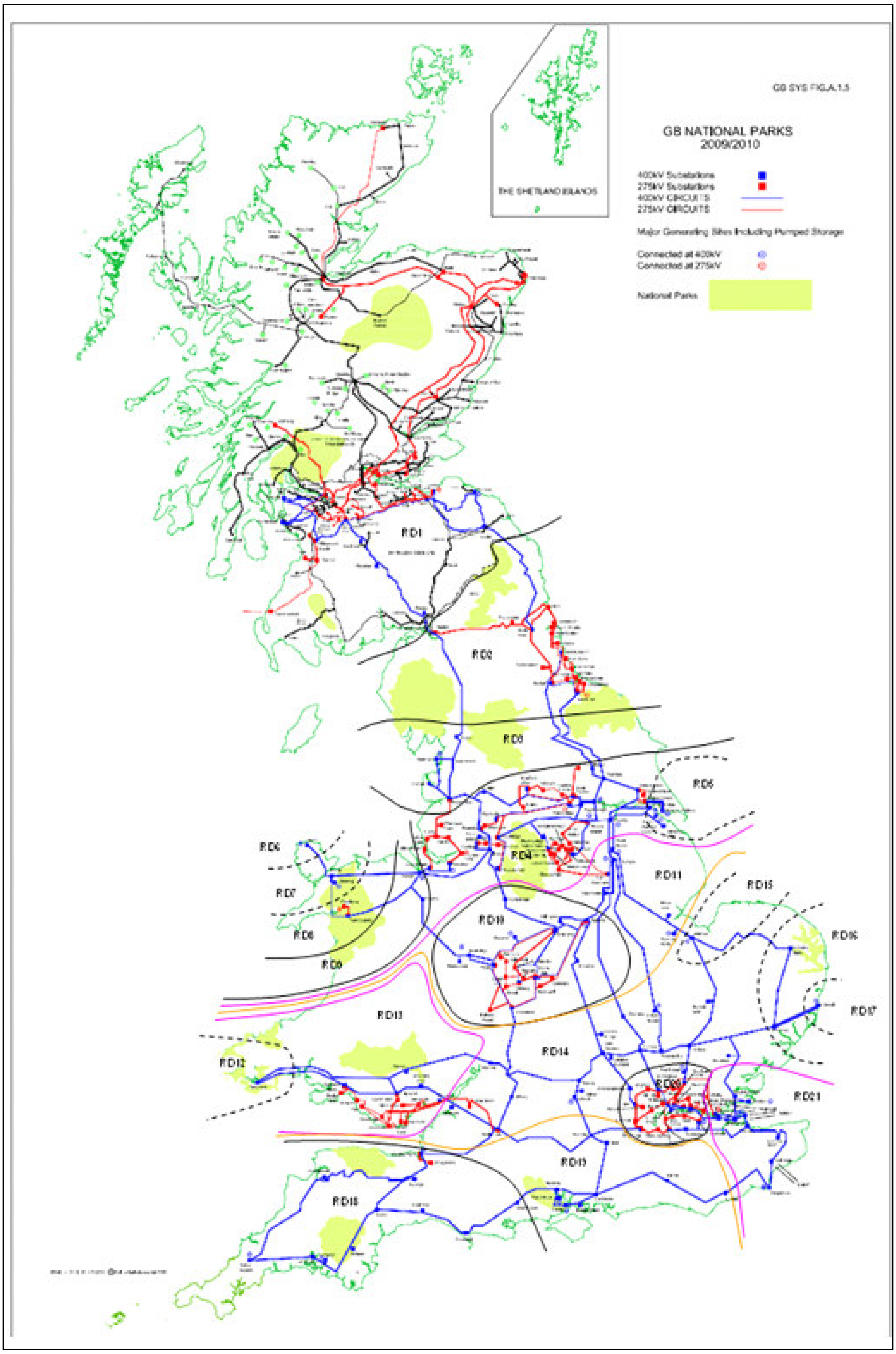
(e) New overhead line and cable unit costs (£/km)

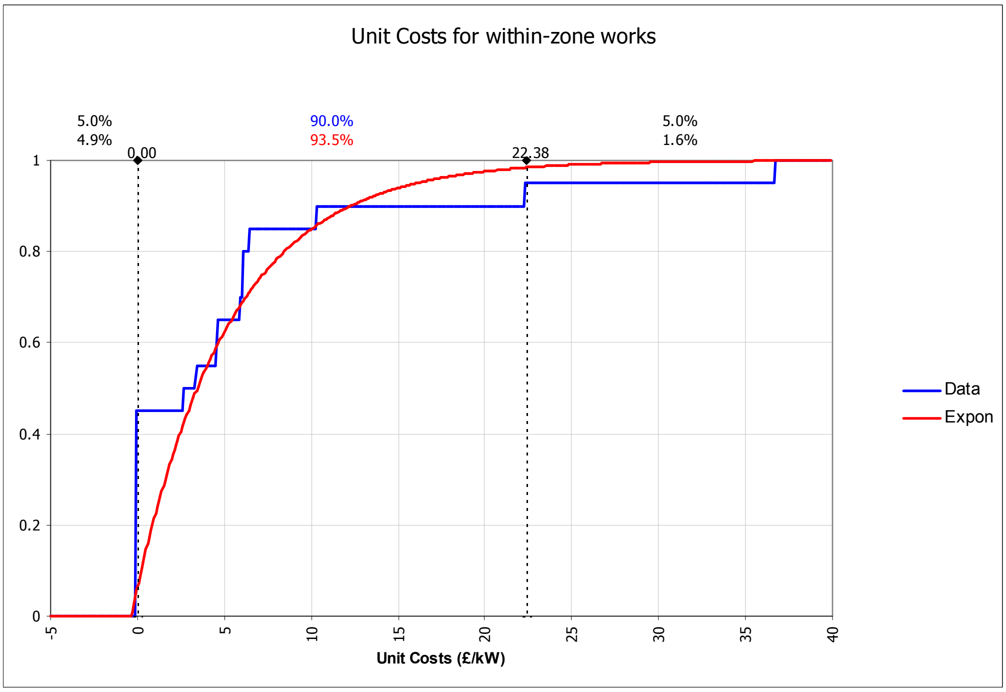
(f) These costs cover overhead lines and cables that are used to connect new substations to the main transmission system

196 The 'within-zone' reinforcement works that we have identified are set-out in the table below. The data is presented in the form of revenue driver zones, created to represent the most critical boundaries on the transmission network. The zones in which no 'within-zone' costs have been identified are not listed. These zones are shown on the map below.

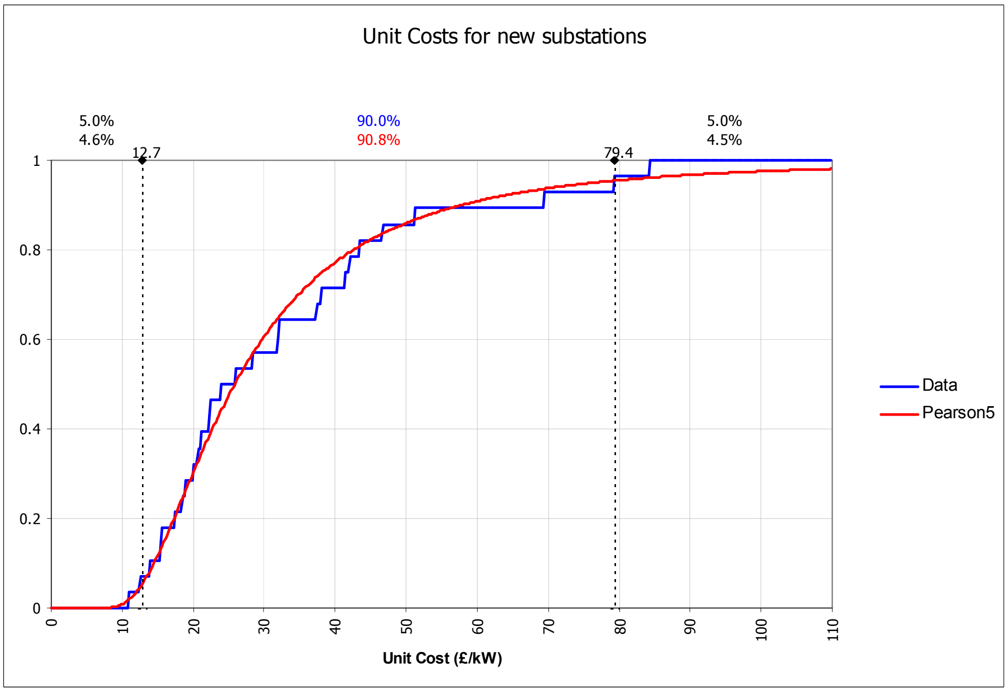
Zone	Cost (£m)	Gen connected (MW)	Gen closure (MW)	Change in demand (MW)	Power flow change (MW)	UCA (£/kW)	UCA incl RPE (£/kW)
2	17.3	4899	0	-151	5050	3.4	3.6
3	9.7	3590	0	-15	3605	2.7	2.8
4	28.6	4690	488	-204	4406	6.5	6.8
5	14.8	2490	0	-3	2493	5.9	6.2
6	18.3	4899	960	-6	3945	4.6	4.8
9	51.1	860	0	-529	1389	36.8	38.7
11	5.2	840	0	-12	852	6.2	6.5
13	25.6	2684	245	-36	2475	10.4	10.9
17	97.1	4340	0	0	4340	22.4	23.6
18	22.7	4855	0	-50	4905	4.6	4.8
21	16.8	7146	4452	-50	2744	6.1	6.4

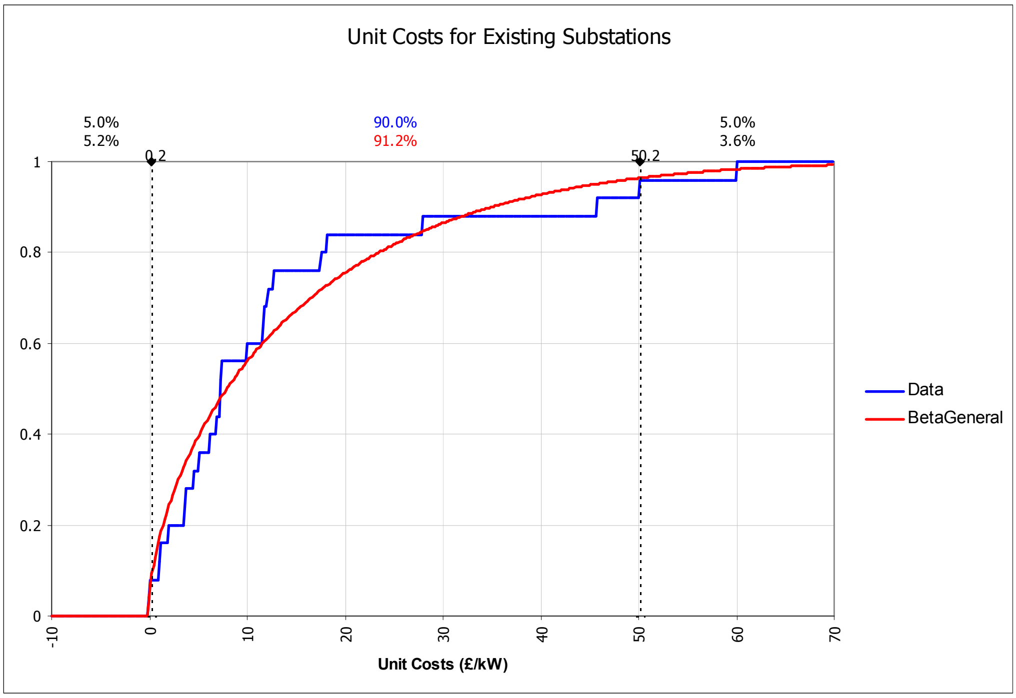
197 The table demonstrates that these costs are not consistent across zones due to geographical factors that add complexity to the local network reinforcements. However, to simplify the modelling of this uncertainty, we have calculated a probabilistic distribution based on all of these costs to be applied nationally. The cumulative probability of the raw data and the associated probabilistic distribution (an exponential distribution) is shown in the graph below.


GB SYS FIG.A.1.5
GB NATIONAL PARKS
2009/2010
400kV Substations
275kV Substations
400kV CIRCUITS
275kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
National Parks
THE SHETLAND ISLANDS



198 In addition to the 'within-zone' uncertainty, we also need to model the new and existing connecting substation costs. The cumulative probability of the raw data and the associated probabilistic distributions (Pearson 5 and Beta General distributions) for these uncertainties are shown in the graphs below.





199 For overhead lines, we have used our business plan submission to derive probabilistic distributions for volume (km) and cost (£/km). All the new overhead line projects associated with generation connections were given a probability and modelled as a binomial distribution. The resulting distribution for the RIIO-T1 period had a standard deviation of 13km. This was then uniformly profiled across each of the years of the RIIO-T1 period.

200 For the new overhead line unit cost, we derived a mean and standard deviation from all the significant new greenfield overhead line projects in the business plan. We considered all costs, including security and an allocation of non-unit costs (e.g. civils, roads, land and fencing at the circuit ends). The resulting distribution had a mean of £1.195m per circuit km and a standard deviation of £319k.

201 These unit cost distributions do not include an allowance for real price effects, and therefore we have calculated adjustments by taking the appropriate project groupings from our Gone Green plan. These adjustments are summarised in the table below.

Unit cost allowance	Real price effect adjustment factor
Substations	+5.2%
Within-zone costs	+5.2%
New overhead line sections	+6.6%
New underground cables	+11.5%[15]

202 This simply models the uncertainty around a particular unit cost, and therefore we also need to apply the construction uncertainty described in the section above. The majority of the generation connection projects in our business

[15] Cables have a higher adjustment factor due to the increased copper content

plan are at the initial estimate stage, and therefore to model the overall risk we have assumed the construction cost variance associated with an initial cost estimate.

203 We have performed a Monte Carlo simulation to calculate the overall local generation connection cost. We have sampled:

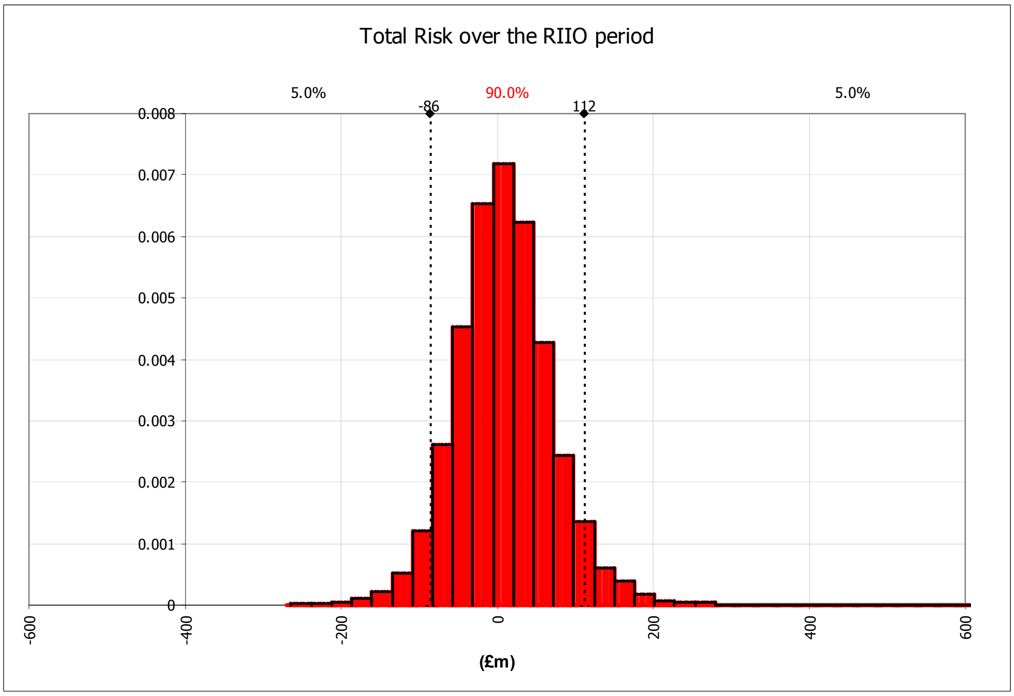
(a) the volume of generation connections (kW);

(b) unit costs for new substations, existing substations, within-zone works (£/kW) and overhead lines (£/km)

(c) the volume of overhead line (km); and

(d) the construction cost (%).

204 This resulted in the distribution shown below over the RIIO period. The distribution has a standard deviation of £129m. When real price effects are added, the standard deviation increases to £146m. This is slightly higher than the standard deviation of £128m that was calculated for this uncertainty as part of the July 2011 submission, although we modelled real price effects as a separate uncertainty in the July analysis.



Risk sharing arrangements

205 We have developed mechanisms to deal with the generation connection uncertainty based on the proposals contained in Ofgem's "Decision on Strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1 uncertainty mechanisms"[16]. Ofgem stated that the starting point

[16] Supplementary Annex (RIII-T1 and GD1 Overview papers) dated 31st March 2011

was the use of volume-drivers for those projects for which neither the need nor the timing was certain at the time of the price control review.

206 The overall aim of these proposals is to ensure that our allowances are adjusted up or down in accordance with the actual level of generation connection. This will act to reduce the overall level of risk that we will face, and will also protect consumers and ourselves from generation connection forecast error.

207 At each stage of development, we have sought to demonstrate that any additional complexity is justified on the additional accuracy that it delivers and the consequential impact that has on the overall risk that we face.

Development of connections volume-drivers

208 As described above, an initial analysis of the costs of connecting new generation to the transmission system highlighted a variation with a standard deviation of £129m. This represents the risk, for both consumers and ourselves, associated with an ex ante allowance agreed at the price control review to cover the cost of local generation connections.

Volume-driver for all local connection costs

209 The simplest risk sharing arrangement would be a single volume-driver for generation connections. Allowances would be adjusted based on the difference between the actual volume of generation connections in a particular year (in kW) and the baseline level established at the price control review and funded with an ex ante allowance. This volume difference (positive or negative) would then be multiplied by a unit cost allowance (in £/kW) to calculate the appropriate adjustment to annual allowances.

210 We have calculated a simple overall unit cost allowance as the mean of the unit costs for each of the individual projects considered. This gives a unit cost allowance of £47.5/kW.

211 The application of the unit cost allowance addresses the volume uncertainty, but does not address the new overhead line volume and cost risks, the unit cost risk or the construction risk. It also fails to differentiate between the unit costs for connections at new and existing substations. The Monte Carlo analysis used to calculate the range of the uncertainty was repeated with this unit cost allowance.

212 The resulting distribution has a standard deviation of £111m, which represents an improvement compared to an ex ante allowance.

213 The main sources of this residual risk are:

(a) the inclusion of the highly variable costs for new overhead lines and cables; and

(b) the inclusion of ‘within-zone’ reinforcement works.

Volume-drivers for substation costs, 'within-zone' costs and overhead line and cable costs

214 In order to achieve a further improvement in the accuracy of the uncertainty mechanism, we have extended the analysis by sub-dividing the generation connection uncertainty mechanism into the following:

(a) a volume driver for overhead lines and cables, based on length of line (km) and the appropriate unit cost allowance (£/km);

(b) a zonal volume driver for 'within zone' enabling works, based on connection capacity (kW) and a unit cost allowance (£/kW); and

(c) a volume driver for local generation substation costs, based on connection capacity (kW) and a unit cost allowance (£/kW)

215 The volume-driver for new cables is only applicable to short lengths which do not require Major Infrastructure Planning Unit (MIPU) consent and are therefore not covered by the 'costs of meeting planning requirements' mechanism described later in this document.

216 Each of the volume-drivers will adjust allowances based on the difference between actual volumes and the baseline level established at the price control review and funded with an ex ante allowance. For substation costs, the total volume of generation connections (in kW) is relevant. For the zonal 'within-zone' costs, the volume of generation connections in each zone is relevant, and for overhead lines and cables, the length of new overhead line and cable circuits is relevant.

217 Each of these volume differences (positive or negative) would then be multiplied by the relevant unit cost allowance (in £/kW for local substations and 'within-zone' works, and £/circuit km for overhead lines and cables) to calculate the appropriate adjustment to annual allowances.

218 The unit cost allowances for the overhead lines and 'within zone' works were set to the mean of the respective distributions described above, that is £1.195m per circuit km (£1.274m per circuit km with real price effects) for overhead line and £4/kW (£4.2/kW with real price effects) for 'within-zone' works.

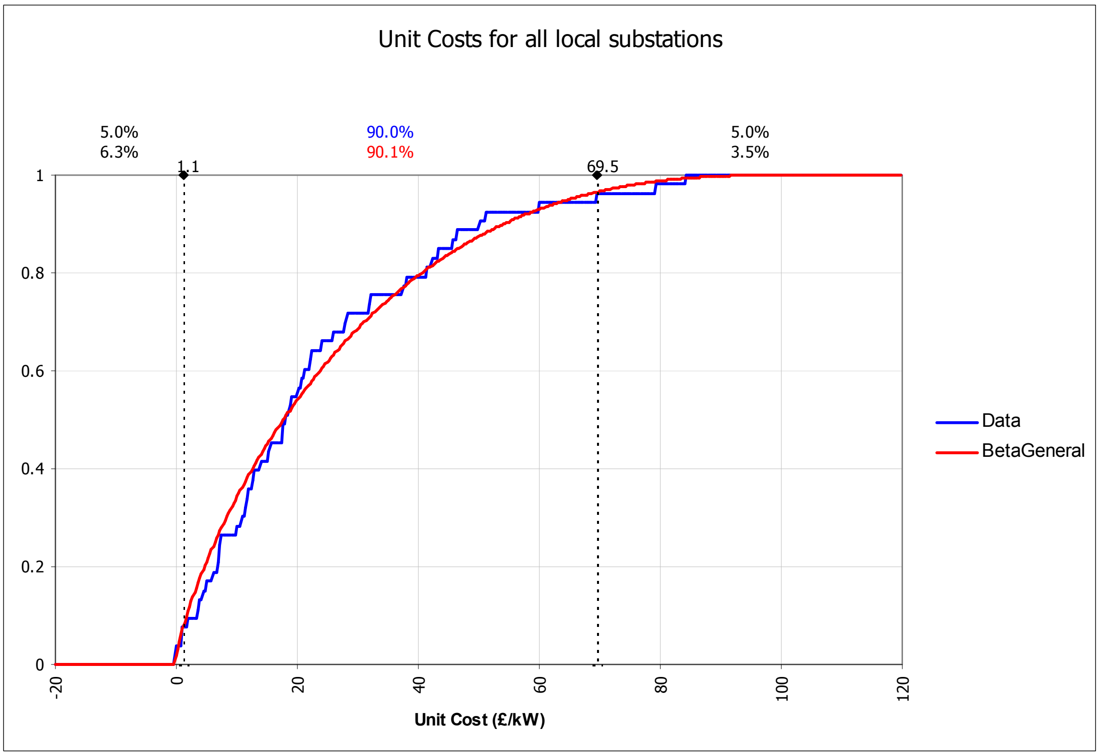
219 For cables, we intend to utilise the relevant incremental capital unit costs for undergrounding from the Institution of Engineering and Technology (IET) study[17] on the whole life costs of installing new transmission lines as per their 31 January, 2012 report. These costs are summarised in the table below for clarity.

220 Since the adjustment to our allowances will only occur when different volumes of underground cable are delivered, we need to adjust the unit costs to include financing costs. We have completed this adjustment based on the proposals contained in the finance annex to this submission and standard spend profiles for overhead line and cable schemes. These revised unit cost allowances are also listed in the table below. The figures in brackets include the real price effects adjustment.

[17] http://www.theiet.org/factfiles/transmission.cfm

Type	Length	Rating (MVA)	Additional capital cost (/km)	Adjusted to include financing costs (/km)
Underground cable	3km	2 x 1595	10.33 (11.5)	10.91 (12.1)
	3km	2 x 3190	18.83 (21.0)	19.93 (22.2)
	3km	2 x 3465	20.03 (22.3)	21.20 (23.6)

221 The graph below shows the cumulative probability of the raw data and the associated probabilistic distribution for all local generation substation costs.



222 The unit cost allowance for local generation substations costs, excluding overhead line and 'within-zone' enabling costs, was set to the mean of this distribution, £23.5/kW (£24.7/kW with real price effects).

223 In order to assess the improvement in accuracy of the volume-driver, the Monte Carlo analysis was repeated. This resulted in a distribution that has a standard deviation of £79m, increasing to £121m with real price effects, an improvement on the risk associated with an ex ante allowance.

224 The standard deviation with real price effects is significantly higher than that without, although it should be noted that the copper price tracker described in the previous section has been modelled separately.

Volume-drivers for the cost of connections at new substations, the cost of connections at existing substations, 'within-zone' costs and overhead line and cable costs

225 In order to achieve a further improvement in the accuracy of the uncertainty mechanism, we then sub-divided the local connecting substation volume-driver as follows:

(a) A volume driver for connections at new substations

(b) A volume driver for connections at existing substations

226 The operation of the 'within-zone' cost and overhead line and cable cost volume-drivers would be as described above. For the substation costs, it would be necessary to develop a robust definition of new and existing substations, and establish separate volume-drivers for connections and new and existing substations.

227 These volume-drivers would adjust allowances based on the difference between actual connection volumes at new and existing substations with baseline levels established at the price control review and funded with an ex ante allowance.

228 The volume differences (positive or negative) for both new and existing substations would then each be multiplied by the relevant unit cost allowance (in £/kW) to calculate the appropriate adjustment to annual allowances.

229 The unit cost allowances for the new and existing local generation substation costs were set to the mean of the respective distributions described above, £33.5/kW (£35.3/kW with real price effects) for new substations and £13.6/kW (£14.3/kW with real price effects) for existing substations.

230 In order to assess the improvement in accuracy of the volume-driver, the Monte Carlo analysis was repeated with separate unit cost allowances for new and existing substations and the 'within zone' and overhead line costs treated separately. This resulted in a distribution that has a standard deviation of £77m, a slight reduction in the uncertainty.

Summary and conclusions

231 The accuracy of the volume-driver options that we have considered is demonstrated by the associated standard deviation of differences between volume-driven allowance and actual forecast costs. These are summarised in the table below:

Option	Standard deviation (£m)
No volume-driver	£132m
Volume-driver with single unit cost allowance for all local connection costs	£111m
Volume-driver for substation costs Volume-driver for new overhead lines and cables Volume-driver for within-zone works	£79m
Volume-driver for substation costs with separate unit cost allowances for new and existing substations Volume-driver for new overhead lines and cables Volume-driver for within-zone works	£77m

232 The table shows that the set of volume-drivers for new and existing substations, 'within-zone' costs, overhead lines and cables provide the lowest standard deviation. However, splitting new and existing substations will involve additional complexity and only provides a slight improvement over a single unit cost allowance for all substations.

233 We therefore propose the uncertainty mechanisms summarised below for local connection costs.

	Baseline		Volume-driver	
	Allowance	**Output**	**Volume**	**Unit cost allowance**
Substation costs	Forecast substation cost for gone green generation connections by year (£m)	Gone green generation connections by year (kW)	Actual annual connection volume (kW) – gone green generation connections (kW)	£23/kW (£24.7/kW with RPE)
Within-zone costs	Forecast within-zone cost for gone green generation connections by zone by year (£m)	Gone green generation connections by zone by year (kW)	Actual annual connection volume by zone (kW) – gone green generation connections by zone (kW)	Zonal £2.7/kW to £36.8/kW (£2.8/kW to £38.7/kW with RPE)
Overhead lines and cables	Forecast overhead line and cable cost for gone green generation connections by year (£m)	Gone green new overhead line and cable circuit lengths (km)	Actual annual new overhead line (and/or cable) length (km) – gone green new overhead line length (km)	**Overhead lines** £1.2m/cct km (£1.27m/ cct km with RPE) **Cables** Additional £10.91m/km to £21.2m/km (£12.1m/km to £23.6m/km with RPE)

Local demand related infrastructure analysis

What is it? *Uncertainty associated with the volume and cost of the infrastructure element of exit capacity reinforcements to meet customer demand*

How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £66m, reducing to £32m with the application of our proposed uncertainty mechanisms*

What are we going to do about it? *Regular planning co-ordination meetings with Distribution Network Operators and other key demand customers.*

Risk sharing arrangements?

National volume driver for substation costs, with a unit cost allowance of £4.6m/SGT (£4.96m/SGT with RPE adjustment)

Volume driver for new overhead lines, with a unit cost allowance of £1.2m/circuit km (1.28m/circuit km with RPE adjustment)

Volume driver for new cables, with a set of unit cost allowances from the IET report (+11.5% with RPE adjustment)

Efficiency incentive rate for over/underspends

Context

234 There is uncertainty in both the cost and volume of exit capacity reinforcements (to meet increased and/or new demand) to the transmission system.

235 In deriving our best estimate of future local demand-related infrastructure for the business plan, we have extrapolated data submissions from Distribution Network Operators to cover the full RIIO-T1 period and applied the security standards to identify reinforcement requirements. We have also used information provided by [redacted] to derive other reinforcement requirements.

236 The cost of the connection assets (those provided solely for a particular customer) are recovered directly from the relevant customer via connection charges and treated as excluded services. However, there are associated demand-related infrastructure costs which are also triggered as a consequence of providing additional exit capacity and this section deals with the uncertainty associated with this category of expenditure.

237 Typically, additional exit capacity (additional SGT capacity) is provided in response to a request from a customer. In providing this additional exit capacity we would seek to meet the customer's requirements in the most economic and efficient manner. However, the costs associated with provision of additional exit capacity are dictated by the ability to accommodate demand at an existing substation, the requirement to establish a new dedicated transmission substation, and any associated additional transmission capacity required to accommodate this additional load from the main interconnected transmission system.

Quantification

238 We have explored the volume uncertainty using a number of demand scenarios, including high and low demand scenarios (+17.5%, -16.4% variation around the Gone Green demand forecast) that we have developed since our July 2011 business plan submission. These scenarios (from 47GW to 67GW in 2020 against a Gone Green demand of 57GW) represent our view of the plausible demand range.

239 In order to understand the impact that the different demand scenarios will have on our demand-related infrastructure requirements, we have estimated the impact on local demand peaks and developed a spreadsheet model which performs a high level assessment in accordance with Engineering Recommendation P2/6[18]. The model output is the number of additional SuperGrid Transformers (SGTs) required at Grid Supply Points. Reinforcements are deemed to be required when the required capacity at a site exceeds 105% of the available capacity.

240 The results of this analysis are summarised below. This analysis excludes any new SGTs or Grid Supply Points required as mitigations against new transmission circuits as described in the 'costs of meeting planning requirements' section of this document.

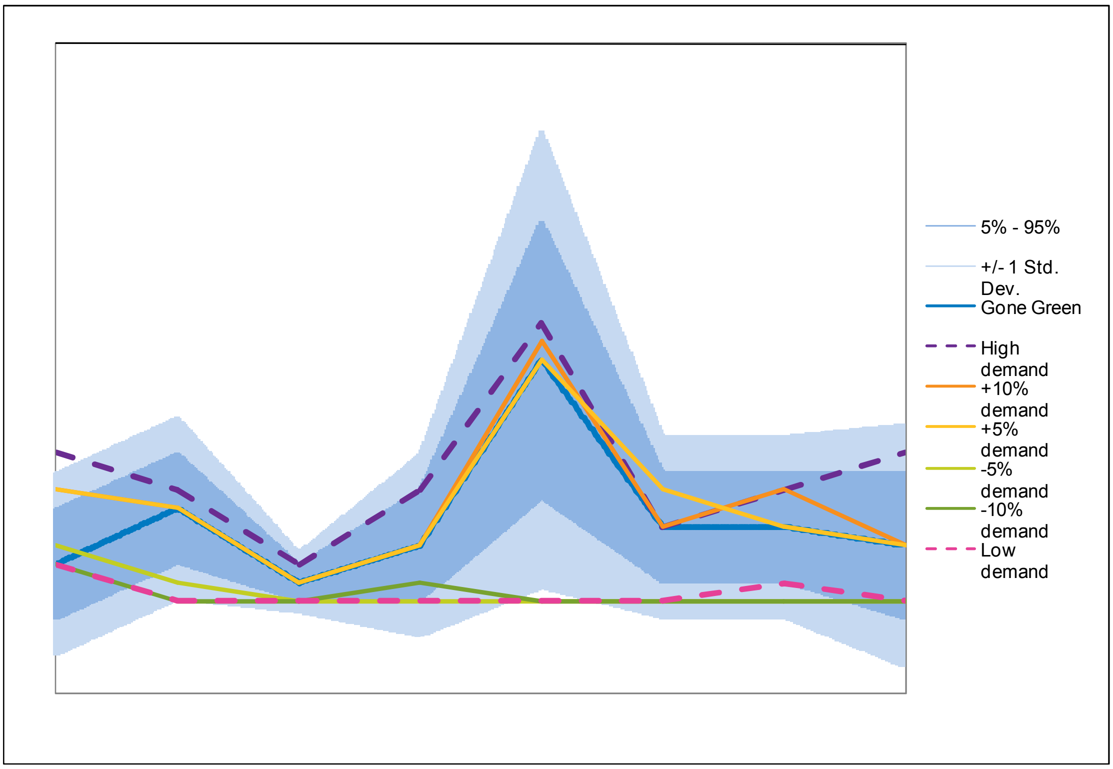
Scenario	2014	2015	2016	2017	2018	2019	2020	2021	Total number of additional SGTs
Business Plan	2	5	1	3	13	4	4	3	35
High demand (+17.5%)	6	5	1	3	13	4	4	4	40
+10% demand	8	6	2	6	15	4	6	8	55
+5% demand	6	5	1	3	14	4	6	3	42
-5% demand	6	5	1	3	13	6	4	3	41
-10% demand	4	5	0	1	1	4	1	1	17
Low demand (-17.5%)	4	4	0	2	2	2	1	1	16

241 In order to understand the range of this uncertainty, we have considered the volume and cost uncertainties separately. We have developed probabilistic distributions to describe the uncertainty associated with the volume of additional SGTs in each year based on the scenarios described above.

[18] ENA Engineering Recommendation P2/6 "Security of Supply" is used by National Grid and DNOs to ensure there is sufficient transmission and distribution capacity to meet customer demand.

242 We have assumed a normal distribution with a mean value equivalent to the gone green position. We have calculated the range of additional SGTs connected in each year across all scenarios. We have assumed that this range represents a credible range of additional SGTs in each year, and set the standard deviation of the distribution to be 50% of this range. The distribution has been collared at zero additional SGTs.

243 The resulting distribution has been superimposed on the scenarios in the graph below.



244 In order to calculate a capital cost uncertainty from the volume uncertainty described above, we have established a unit cost (in £/SGT) for the demand-related infrastructure costs associated with additional SGTs.

245 We have built on the work completed to define the unit cost for our July 2011 business plan submission, and divided demand-related infrastructure costs into:

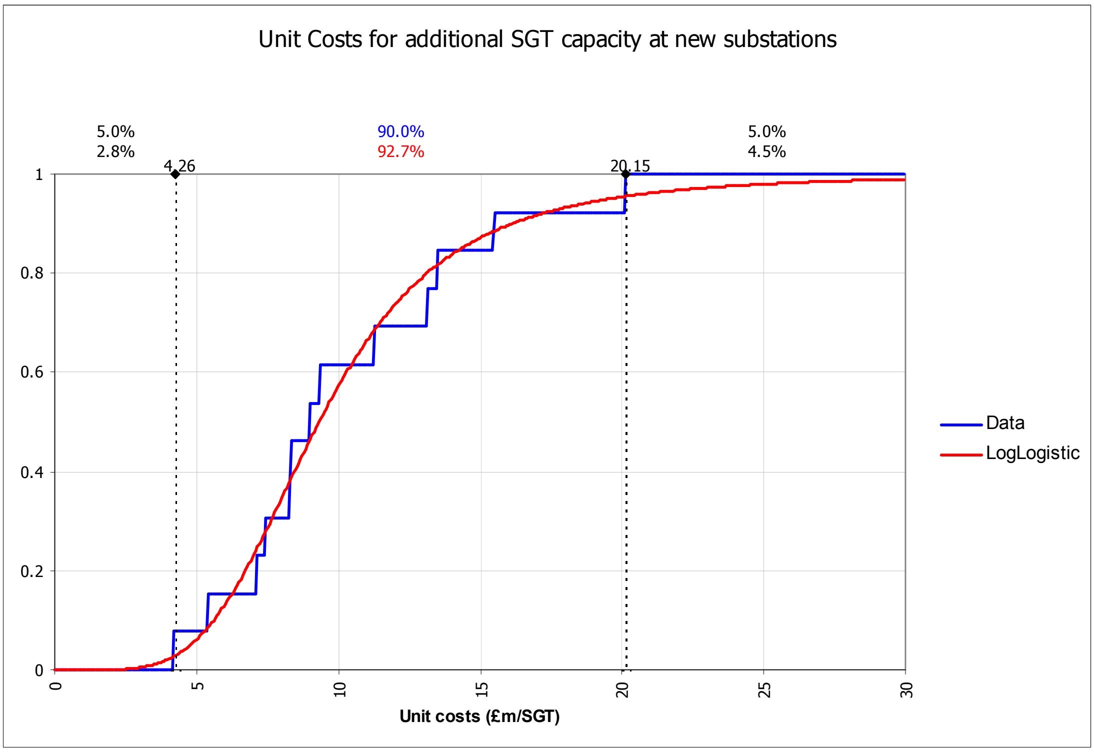
(a) Substation unit costs (£/SGT)

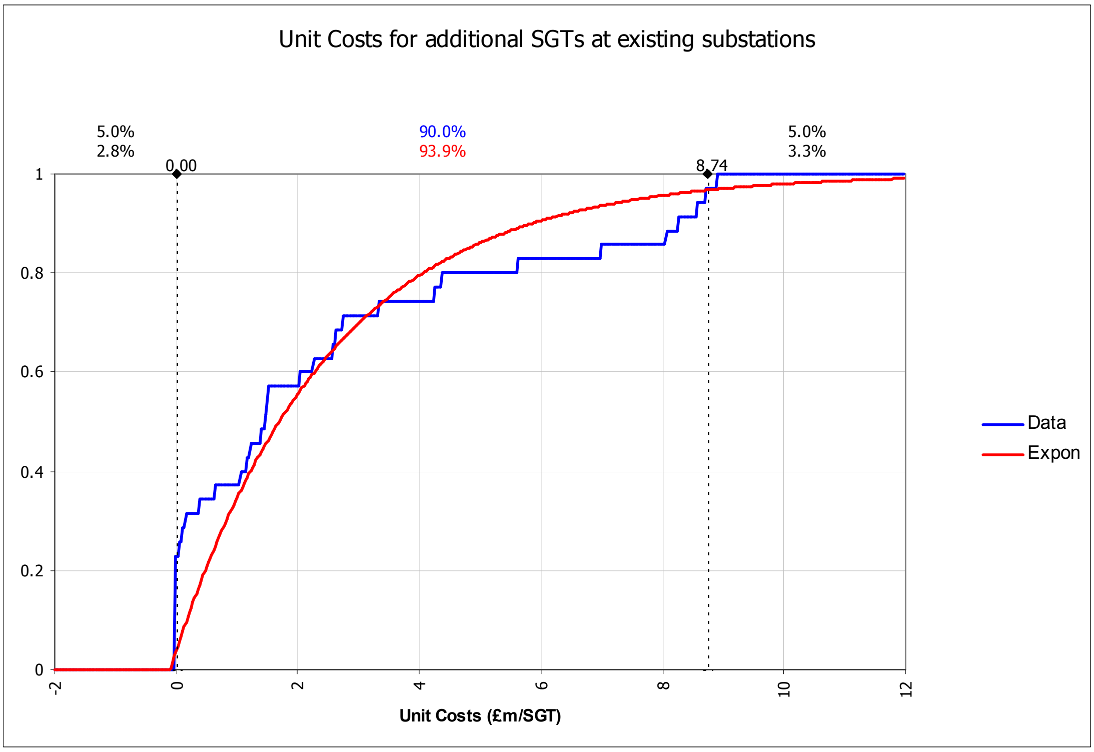
(b) These costs have a significant range and therefore to gain a more accurate picture of this uncertainty, we have further divided this category into new and existing substations.

(c) New overhead line and cable unit costs (£/km)

These costs cover overhead lines and cables that are used to connect new substations to the main transmission system.

246 In order to model this uncertainty, we have derived probabilistic distributions for the new and existing substation costs. The cumulative probability of the raw data and the associated probabilistic distributions (loglogistic and exponential distributions) are shown in the graphs below.





247 Given the potential impact, it is important to identify the overhead line element of the uncertainty. However, we have very few new overhead lines to deliver

additional exit capacity in our business plan submission and therefore we have not modelled this element of the risk.

248 These unit cost distributions do not include an allowance for real price effects, and therefore we have calculated adjustments by taking the appropriate project groupings from our Gone Green plan. These adjustments are summarised in the table below.

Unit cost allowance	Real price effect adjustment factor
Substations	+7.8%
New overhead line sections	+6.6%
New underground cables	+11.5%[19]

249 This simply models the uncertainty around a particular unit cost, and therefore we also need to apply the construction uncertainty described in the section above. Given the need to establish unit cost allowances for the full RIIO-T1 period at the price control review, we have assumed the construction cost variance associated with an initial cost estimate.

250 We have performed a Monte Carlo simulation to calculate the overall demand-related infrastructure cost. We have sampled:

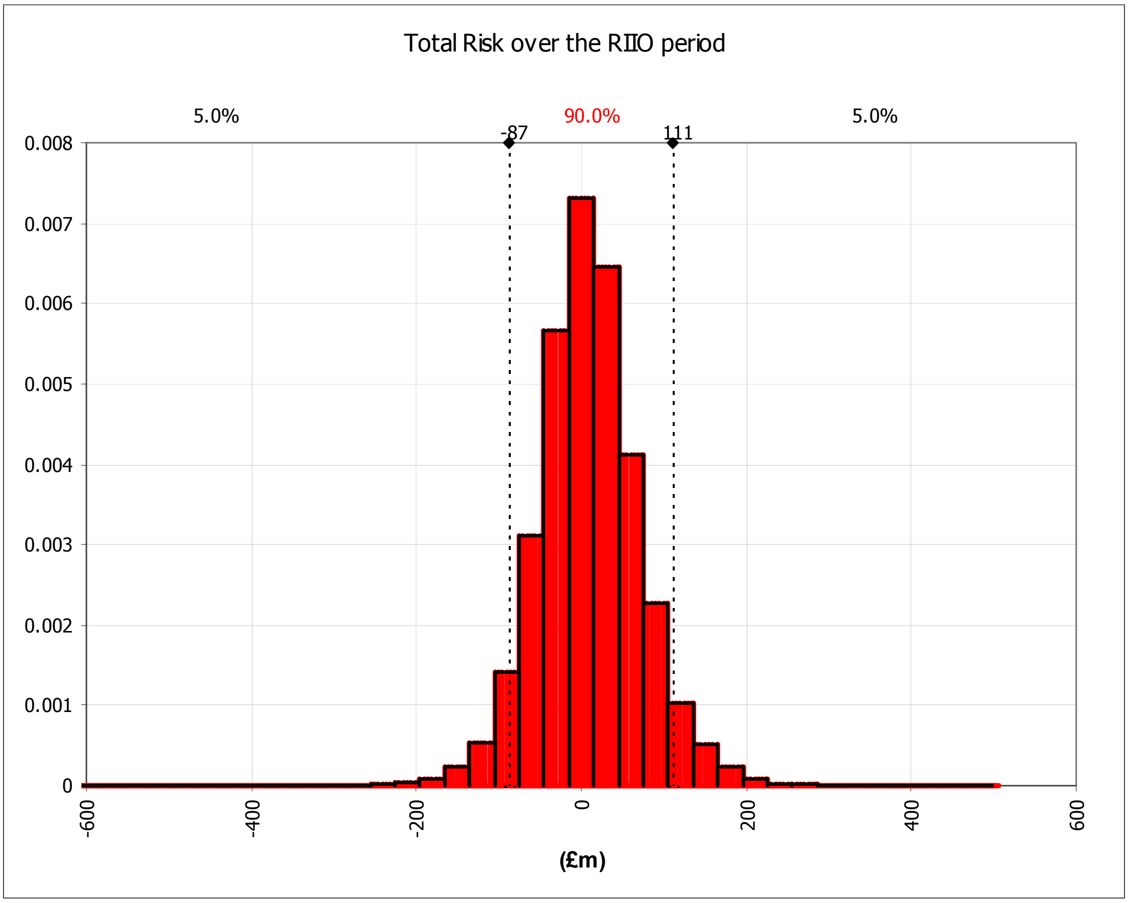
(a) the volume of additional SGTs (#);

(b) unit costs for new substations and existing substations (£/SGT); and

(c) the construction cost (%).

251 This resulted in the distribution shown below over the RIIO period. The distribution has a standard deviation of £60m. When real price effects are added, the standard deviation increases to £66m. This is considerably lower than the standard deviation of £131m that was calculated for this uncertainty as part of the July 2011 business plan submission. The reduction is due to the improved modelling of the volume and cost uncertainties.

[19] Cables have a higher adjustment factor due to the increased copper content



Risk sharing arrangements

252 The demand-related infrastructure uncertainty is similar in nature to the generation connection uncertainty, that is, neither the need nor the timing of projects is certain at the time of the price control review. For this reason, we are proposing the use of volume-drivers.

253 The overall aim of these proposals is to ensure that our allowances are adjusted up or down in accordance with the actual number of exit reinforcements. This will act to reduce the overall level of risk that we will face, and will also protect consumers and ourselves from exit connection forecast error.

254 At each stage of development, we have sought to demonstrate that any additional mechanism complexity is justified on the additional accuracy that it delivers and the consequential impact that has on the overall risk that we face.

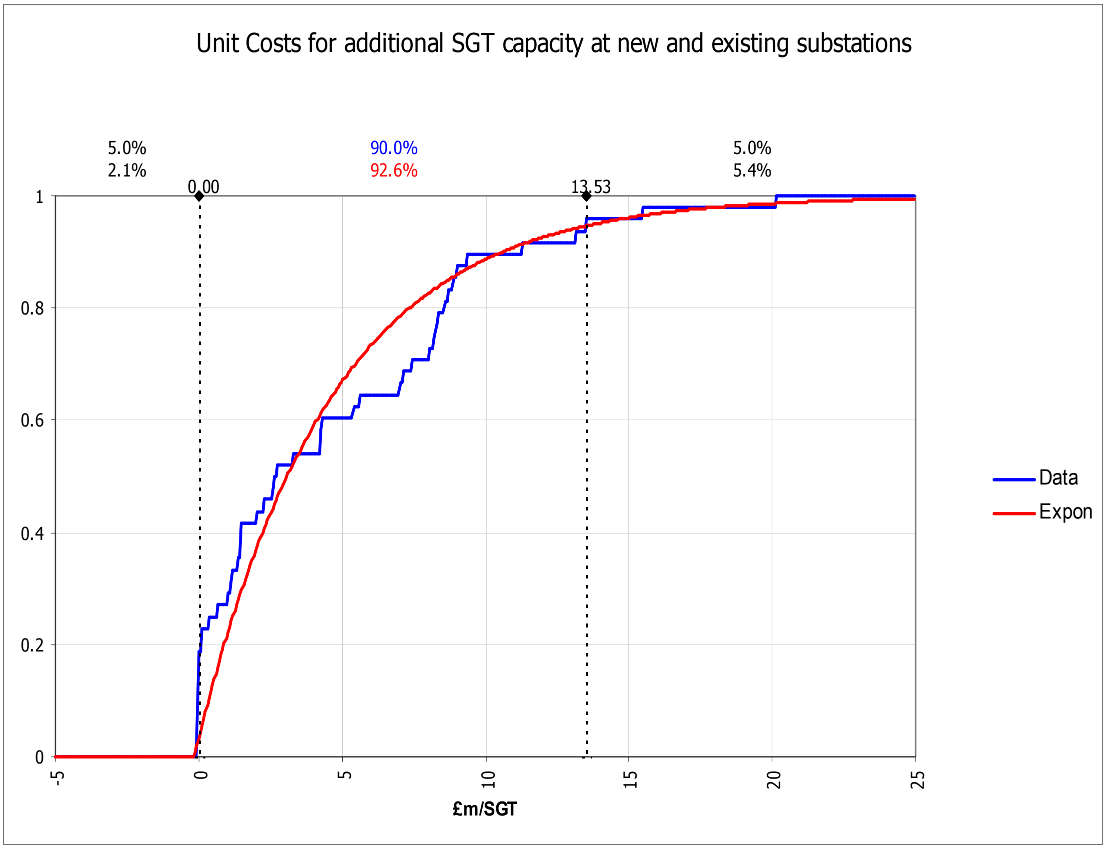
Development of demand-related infrastructure volume-drivers

255 As described above, an initial analysis of the demand-related infrastructure costs associated with connecting new supergrid transformer capacity to the transmission network highlighted a variation with a standard deviation of £62m. This represents the risk, for both consumers and ourselves, associated with an ex ante allowance agreed at the price control review to cover demand-related infrastructure costs.

Volume-driver with for all demand-related infrastructure costs

256 The simplest risk sharing arrangement would be a single volume-driver for demand-related infrastructure costs. Allowances would be adjusted based on the difference between the actual number of additional SGTs that are delivered in a particular year and the baseline level established at the price control review and funded with an ex ante allowance. This volume difference (positive or negative) would then be multiplied by a unit cost allowance (£/SGT) to calculate the appropriate adjustment to annual allowances.

257 The graph below shows the cumulative probability of the raw data and the associated probabilistic distibrution for all substation costs. The simple overall unit cost allowance was set to the mean of this distribution, £4.56m/SGT (£4.92/SGT with real price effects).



258 In addition to these demand-related infrastructure substation works, when a new grid supply point (GSP) is being established, it will be necessary to connect this new GSP to the transmission system by means of an overhead line, direct-buried cables, or by providing a dedicated tunnel[20] to accommodate the required cable network.

[20] There are a number of potential new GSPs in London which will require a dedicated tunnel in order to connect them to the existing network

259 In order to maintain consistency with the treatment of local generation connection costs, we are proposing an uncertainty mechanism for these works based on length and unit cost allowances.

260 The Monte Carlo analysis used to calculate the range of the uncertainty was repeated with this fixed unit cost allowance. The resulting distribution has a standard deviation of £31m, increasing to £32m with real price effects, an improvement on the risk associated with an ex ante allowance.

Volume-drivers for demand-related infrastructure costs at new and existing substations

261 In order to achieve a further improvement in the accuracy of the uncertainty mechanism, we then sub-divided the substation volume-driver as follows:

(a) A volume-driver for additional SGTs at new substations

(b) A volume-driver for additional SGTs at existing substations

262 It would be necessary to develop a robust definition of new and existing substations, and establish separate volume-drivers for exit reinforcements at new and existing substations.

263 These volume-drivers would adjust allowances based on the difference between the actual number of additional SGTs at new and existing substations with baseline levels established at the price control review for each and funded with an ex ante allowance.

264 The volume differences (positive or negative) for both new and existing substations would then each be multiplied by the relevant unit cost allowance (in £/SGT) to calculate the appropriate adjustment to annual allowances.

265 The unit cost allowances for the additional SGTs at new and existing substations were set to the mean of the respective distributions described above, £10.5m/SGT for SGTs at new substations and £2.5m/SGT for SGTs at existing substations.

266 In order to assess the impact of this change to the volume-driver, the Monte Carlo analysis was repeated with the application of separate unit cost allowances for reinforcements at new and existing substations. This resulted in a distribution that has a standard deviation of £30m, which represents a slight improvement over the risk achieved with a single unit cost allowance.

Summary and conclusions

267 The accuracy of the volume-driver options that we have considered is demonstrated by the associated standard deviation of differences between volume-driven allowance and actual forecast costs. These are summarised in the table below:

Option	Standard deviation (£m)
No volume-driver	£62m
Volume-driver for all demand-related substation costs Volume-driver for new overhead lines and cables	£32m
Volume-driver for demand-related substation costs with separate unit cost allowances for new and existing substations Volume-driver for new overhead lines and cables	£30m

269 The table shows that the volume-drivers for demand-related infrastructure costs reduce the uncertainty when compared with a fixed ex ante allowance. Since splitting unit cost allowances between reinforcements at new and existing sites would involve additional complexity without providing an improvement in accuracy, we propose an uncertainty mechanism for demand-related infrastructure based on a volume-driver for demand connection schemes with a single unit cost allowance.

270 We therefore propose the uncertainty mechanisms summarised below for demand-related infrastructure costs.

	Baseline		Volume-driver	
	Allowance	**Output**	**Volume**	**Unit cost allowance**
Substation costs	Forecast demand-related infrastructure cost by year (£m)	Gone green additional SGT volume by year (#)	Actual annual additional SGT volume (#) – gone green additional SGT volume (#)	£4.6m/ SGT (£4.96m/ SGT with RPE)
Overhead lines and cables	Forecast overhead line and cable cost for gone green demand connections by year (£m)	Gone green new overhead line and cable circuit lengths (km)	Actual annual new overhead line (and/or cable) length (km)	**Overhead lines** £1.2m/cct km (£1.27m/ cct km with RPE) **Cables** Additional £10.91m/km to £21.2m/km (£12.1m/km to £23.6m/km with RPE)

Wider reinforcement works analysis

What is it? *Uncertainty associated with the volume and cost of main transmission system boundary reinforcements to meet changing generation and demand patterns*
How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £775m, reducing to £542m with the application of our proposed uncertainty mechanisms*
What are we going to do about it? *The volume of main transmission system reinforcements required is outside our control. We propose a network development policy to bring additional transparency to decisions around the choice and timing of main transmission system boundary (or wider) reinforcements*
Risk sharing arrangements?
Within-period determination for projects with high cost, low user commitment and uncertain need
Volume-driver based on a central forecast for all other projects, with boundary specific unit cost allowances
Efficiency incentive rate for over/underspends

Context

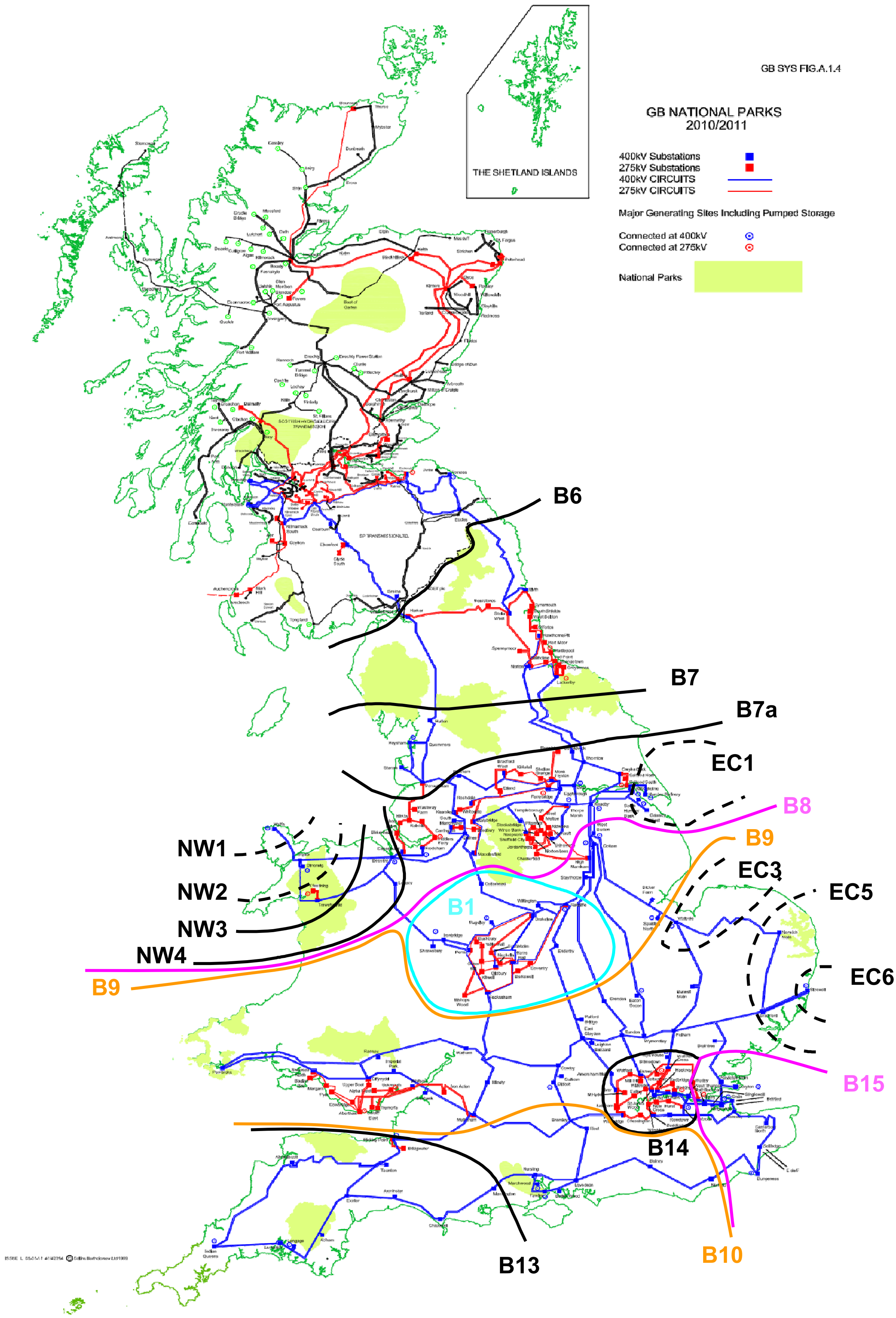
271 The most significant uncertainty facing the transmission network during the RIIO-T1 period is the quantity, type and location of the connected generation. In addition to the local generation connection uncertainty described above, this also impacts the need for reinforcement of the wider transmission network.

272 This problem is compounded in circumstances in which the lead-time for reinforcement of the wider transmission network is greater than the lead-time for the development of new generation projects.

273 The connect and manage access arrangements have broken the contractual link between new generation connection dates and the completion of wider works. This means that new generation projects with short lead-times can now connect to the transmission system prior to the completion of the associated wider transmission system reinforcements. This leads to a significant uncertainty regarding the need and timing of wider transmission system reinforcements.

274 In these circumstances, we need to balance the risks of investing too early in wider transmission reinforcements, which include the risk of inefficient financing costs and an increased stranding risk, with the risks of investing too late, which include inefficient congestion costs.

275 A number of transmission system boundaries have been identified which can be used to illustrate the outputs delivered by our wider reinforcement works. These boundaries are shown geographically below, and include a number of the main system boundaries described in the Seven Year Statement supplemented by additional boundaries identified as part of the recent Transmission Owner Investment Incentives work.


GB SYS FIG.A.1.4
GB NATIONAL PARKS
2010/2011
400kV Substations
275kV Substations
400kV CIRCUITS
275kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
National Parks
THE SHETLAND ISLANDS
B6
B7
B7a
EC1
B8
B9
EC3
EC5
NW1
NW2
NW3
NW4
B1
EC6
B15
B14
B13
B10

276 The range of wider works expenditure across the five scenarios considered is shown in the table below.

Scenario	Capital expenditure (£m)								
	2014	2015	2016	2017	2018	2019	2020	2021	Total
Slow Progression	532.3	677.4	549.6	459.9	366.9	397.6	489.5	440.7	3,913
Gone Green	639.5	867.4	848.9	871.8	609.3	595.6	345.0	176.0	4,953
Accelerated Growth	670.8	882.3	873.5	887.7	638.1	679.8	497.1	242.8	5,372
High Demand	685.3	682.5	609.4	592.2	565.9	537.8	316.2	125.8	4,115.1
Low Demand	333.3	410.8	365.8	237.0	185.5	218.5	242.0	246.1	2,239.0

Quantification

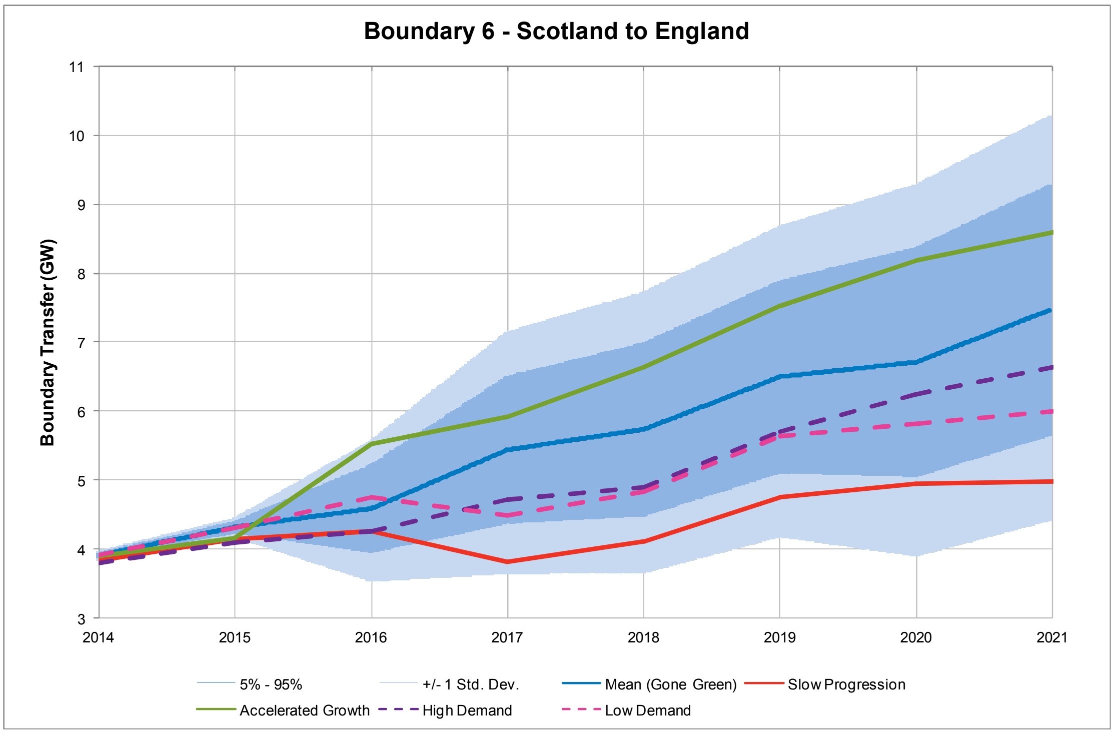
277 In our July 2011 business plan submission, we simplified the modelling of the wider works uncertainty by basing the volume uncertainty on the boundary transfers for the Gone Green and Slow Progression scenarios only and by restricting our analysis to the three boundaries with the potential to drive the most significant reinforcement costs during the RIIO-T1 period. These are the Scotland to England boundary (B6), a North Wales export boundary (NW3) and an East Coast boundary (EC5).

278 In order to improve the accuracy of our modelling for this risk, we have considered additional demand and generation scenarios and extended our analysis to cover all the wider transmission system boundaries that are triggering reinforcement during the RIIO-T1 period.

279 In order to understand the range of this uncertainty, we have considered the volume and cost uncertainties separately. We have modelled the potential boundary power transfers required (in MW) based on the scenarios shown in the table above.

280 We have developed probabilistic distributions to describe the uncertainty associated with the power transfer required across each of the boundaries in each of the years. We have assumed a normal distribution with a mean value equivalent to the gone green position. We have calculated the range of power transfers required in each year across all scenarios. We have assumed that this range represents a credible range of generation connected in each year, and set the standard deviation of the distribution as 50% of this range.

281 In order to test these assumptions, we have then plotted the resulting power transfer distribution and superimposed the power transfers required for each of the scenarios. A sample of these plots based on the B6 boudary between Scotland and England is shown below.



282 This sample graph shows that the probabilistic distribution gives good coverage of the scenarios that we have considered.

283 In order to calculate the capital cost uncertainty, we have created tables for each boundary which show power transfers required against the cost and capacity of the wider works reinforcements that deliver this capability. These tables include all the wider reinforcement projects that we have considered in developing our business plan, including those that are more likely to be taken forward under the within-period cost determination mechanism.

284 This allows the power transfer required to be sampled from the probabilistic distributions described above and for the associated capital cost to be 'looked up' using the tables.

285 In order to make this problem soluble, it has been necessary to make the simplifying assumptions listed below.

(a) Fixed order of wider reinforcements considered

(b) This means that, for some transfer samples, it may be possible to achieve a lower cost solution by ordering the reinforcements in a different way. This means that the table in the model would tend to overestimate the wider works capital cost risk.

(c) Cost of wider works reinforcements that increase the capability of a number of boundaries is divided across those boundaries

(d) This means that the full cost of these reinforcements will only be returned if there is a need for additional capability across all relevant boundaries. For this reason, it may be possible for the tables to return a solution at a cost that could not be achieved. This would tend to underestimate the wider works capital cost risk.

286 A sample ‘lookup table’ for the B6 boundary between Scotland and England is shown below.

Required power transfer (MW)		Reinforcement	Cost (£m)
From	To		
0	3300	Current network	0
3300	4300	Series & shunt compensation	86.8
4300	6400	Western HVDC link	296.9*
6400	8500	Eastern HVDC link	325.7*
8500	10600	Second eastern HVDC link	134.3*
10600	11200	Reconductoring	6.5

*Total cost of reinforcement divided across a number of boundaries

287 We have also investigated the correlation between the required power transfers across different boundaries by examining the results of probabilitic generation connection modelling completed for the Seven Year Statement and supplementing this with specific analysis. A correlation matrix was calculated based on this information.

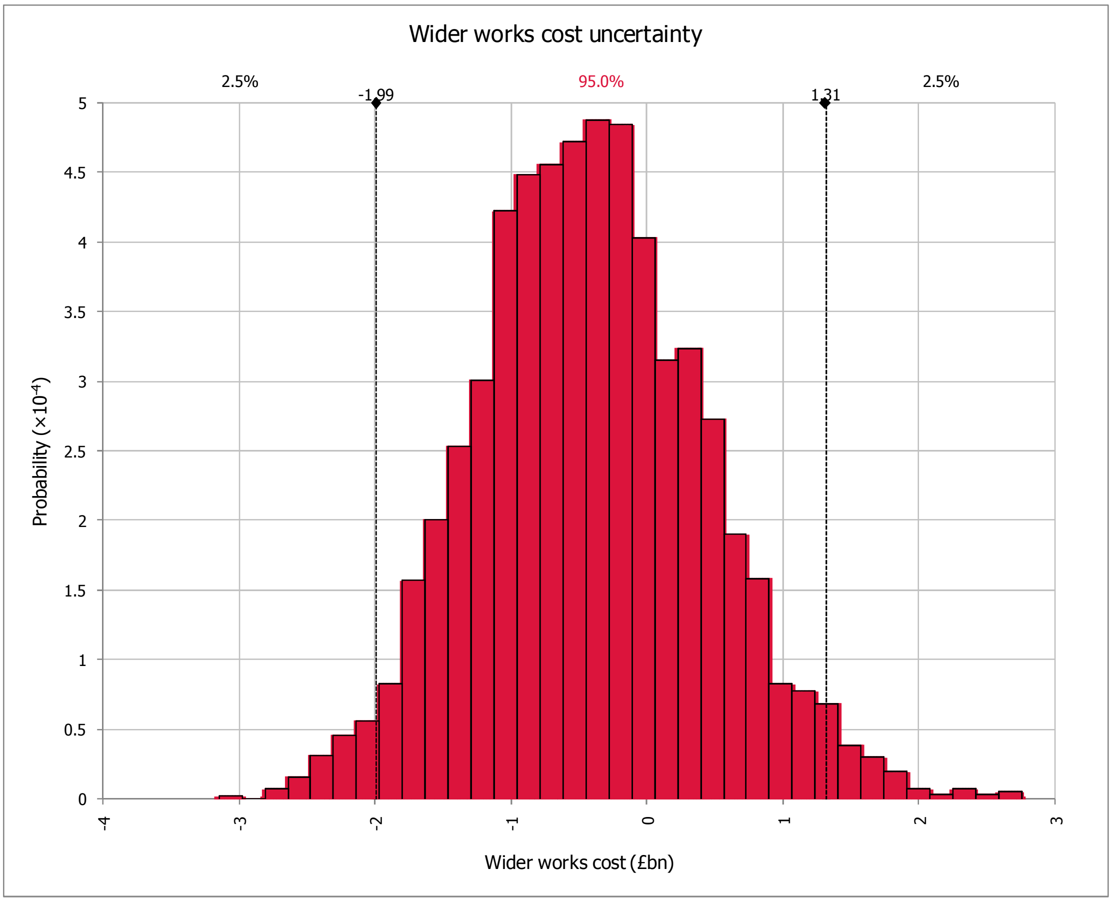
288 These unit cost distributions do not include an allowance for real price effects, and therefore we have calculated an adjustment by taking the appropriate project groupings from our Gone Green plan. The adjustments is summarised in the table below.

Unit cost allowance	Real price effect adjustment factor
Boundaries	+5.5%

289 This simply models the uncertainty around a particular unit cost, and therefore we also need to apply the construction uncertainty described in the section above. We have assigned either the construction cost variance associated with the initial estimate or the contract tender stage to each of the wider reinforcement projects listed in the lookup tables depending on their state of development.

290 This means that projects which are close to delivery such as the Western HVDC link have been assigned the construction cost variance associated with the contract tender stage. Projects which are further into the future have been assigned the construction cost variance associated with the initial estimate stage.

291 When all wider boundaries are considered, the cost distribution has a standard deviation of £663m. This uncertainty is shown in the graph below. When real price effects are added, the standard deviation increases to £775m. . The correlation matrix for boundary required power transfers was applied, but this only caused a slight increase to the standard deviation.



292 This represents a significant uncertainty over the RIIO-T1 period but, even if the volume of generation is as forecast, there remains significant uncertainty regarding which particular power stations open and close. These variations could have a significant impact on wider boundary capability and therefore reinforcement works required.

Risk sharing arrangements

293 In developing uncertainty mechanisms for wider works, we have developed possible alternative options based on two of the high-level mechanisms described in the outputs annex to Ofgem's decision on strategy for RIIO-T1 and RIIO-GD1, namely:

(a) Network Development Policy and volume driver agreed during the price control review

(b) Within-period cost determination

294 We have given consideration to a volume-driver based on outturn required boundary transfer.

295 The overall aim of these proposals is to ensure that our allowances are adjusted up or down in accordance with the actual wider transmission system boundary capability required by our customers. This will act to reduce the overall level of risk that we will face, and will also protect consumers and ourselves from wider reinforcement works forecast error.

296 We have given consideration to the benefits of completing pre-construction works to keep future options open. We have not made specific proposals regarding the treatment of this type of expenditure, and would welcome the opportunity to explore the appropriate funding treatment further with Ofgem.

Network Development Policy and volume driver

297 We would propose a Network Development Policy as part of the price control review, and we have included a draft of this policy as an annex to this business plan submission.

298 We will deliver incremental capability consistent with the Network Development Policy (within agreed thresholds).

299 We propose that our allowances will be automatically adjusted based on a volume driver. Given the necessary complexity of the Network Development Policy, and Ofgem's feedback on the complexity of our proposals in the July 2011 business plan submission, we propose to simplify the arrangements for the volume driver.

300 Given the criteria that we have proposed for the use of the specific re-opener mechanism (described later), it is likely that the volume driver will be required to adjust allowances for relatively short-lead time transmission reinforcements. There is a limited degree to which scenarios can diverge over short lead-time windows, so we propose to simplify the volume driver such that it is based on the central scenario only.

301 We therefore propose that the volume driver operates such that the ex ante allowance for year t+3 is adjusted up or down based on a cost benefit analysis of operational and transmission investment costs for the central scenario. For example, if analysis of the central demand and generation forecast scenario in year t shows that there is a benefit of increasing the North to Midlands (B8) boundary capability by 200MW in year t+3, then our indicative allowance for year t+3 would increase by 200MW × unit cost allowance for boundary 8 subject to the incremental boundary capability being delivered.

302 The incremental boundary capacity delivered by reinforcements that are taken forward under the within-period cost determination mechanism will adjust the baseline for the volume-driver calculation to avoid reinforcements being funded by both mechanisms.

303 Given that, on average, commitments have to be made in year t for reinforcements which are delivered in year t+3, this indicative allowance adjustment would not be recalculated the following year if the central scenario were to change. When we move forward to year t+3, indicative allowance reductions are made automatically, and indicative allowance increases are confirmed when the boundary capability increase has been delivered.

Unit cost allowances

304 We have calculated unit cost allowances to apply for required power transfers above and below the gone green baseline for each of the main transmission system boundaries. These unit cost allowances are based on all the wider transmission reinforcements we have considered in developing our business plan, with the exception of the projects which are very likely to be covered by the within-period cost determination described later.

305 The unit cost allowances have been calculated based on a profile of expenditure for each of the reinforcements. The unit cost allowance shown in the table has been calculated assuming that the adjustment to allowances will be made in the year of delivery on an NPV neutral basis.

306 The costs presented in the table comprise our costs only, that is, Scottish Transmission Owner costs for shared reinforcements are not included. For example, the total cost of the series compensation includes both cost incurred by Scottish Power as well as ourselves but only the cost borne by National Grid has been used in the determination of the unit cost allowances.

307 For reinforcements that impact multiple boundaries within our transmission owner area, our share of the reinforcement cost has been apportioned between each of the boundaries in proportion to the capability provided.

308 Boundaries B13, NW1, NW2, NW3, EC1, EC3 and EC5 have been treated as local boundary groups, and therefore these boundaries have been assessed against the security standards generation connection criteria (Chapter 2 of the security standards) rather than main interconnected transmission system criteria. For this reason, we have presented generation capability accommodated for these boundaries rather than required transfer capacities.

309 The unit cost allowances for a number of main transmission system boundaries are shown in the table below, with figures including real price effects shown in brackets.

Boundary	Unit cost allowances (£/kW)	
	For required power transfer above gone green baseline	For required power transfer below gone green baseline
B6	87 (92)	
B7	64 (67.5)	
B7a	54 (57)	130 (137)
B8	NA	17 (18)
B9	10 (11)	68 (72)
B13	155 (164)	
B14	119 (126)	49 (52)
B14e	106 (112)	
NW1	57 (60)	
NW2	55 (58)	50 (53)
NW3	67 (71)	50 (53)
EC1	85 (90)	
EC3	33 (35)	
EC5	82 (87)	

Impact assessment

310 We have assessed the impact of a Network Development Policy with simplified volume-driver on all boundaries.

311 As described above, an initial analysis of the costs of wider works for all boundaries highlighted a variation with a standard deviation of £663m. This represents the risk, for both consumers and ourselves, associated with an ex ante allowance agreed at the price control review to cover these boundary reinforcement costs.

312 In order to assess the effectiveness of the volume-driver, we first need to exclude projects that are likely to be treated by the within-period cost determination. The Monte Carlo analysis used to calculate this range was repeated with these schemes removed, and this reduced the standard deviation of the wider works uncertainty from £663m to £532m.

313 The Monte Carlo analysis was then repeated with volume drivers for each of the boundaries and the unit cost allowances shown in the table above.

314 The resulting distribution has a standard deviation of £435m, which is a significant improvement on the risk associated with an ex ante allowance for this subset of wider transmission reinforcement works.

315 In this analysis, we have assumed that the reinforcements chosen based on the criteria contained in the Network Development Policy are consistent with the changes to the boundary capability funded by the simplified volume driver.

316 In reality, there are likely to be some circumstances in which we need to reinforce to remain compliant with our Network Development Policy, but the

simplified volume driver would not adjust our allowances. We have ignored this risk because we do not expect it to be material and to model it fully would be disproportionate.

317 The unit cost allowances shown in the table above include some averaging across multiple projects. In order to improve the accuracy of the volume-driver, we also calculated a set of unit cost allowances which explicitly represent all of the relevant wider transmission reinforcements.

318 We repeated the Monte Carlo analysis to assess this full set of unit cost allowances. The resulting distribution has a standard deviation of £433m, which represents a slight reduction in the risk associated with the unit cost allowances shown in the table above.

319 The accuracy of the volume-driver options that we have considered is demonstrated by the associated standard deviation of differences between volume-driven allowance and actual forecast costs. These are summarised in the table below:

Option	Standard deviation (£m)
No uncertainty mechanism	£663m
Costs associated with projects likely to be treated by within-period cost determination removed No uncertainty mechanism	£532m
Costs associated with projects likely to be treated by within-period cost determination removed Volume-driver with averaged unit cost allowances	£435m
Costs associated with projects likely to be treated by within-period cost determination removed Volume-driver with reinforcement specific unit cost allowances	£433m

320 The table shows that the reinforcement specific unit cost allowances provide the lowest standard deviation. However, the use of reinforcement specific unit cost allowances will make the operation of the volume-driver very complex and only offers a marginal benefit over the averaged unit cost allowances.

321 We therefore propose the use of the volume-driver with averaged unit cost allowances.

Within-period cost determination

322 It may be more efficient for large investment projects to be subject to additional regulatory scrutiny before investment is committed. This would ensure that a project-specific need case was developed and would facilitate further stakeholder engagement on the potential reinforcement options.

323 Following Ofgem feedback on our July 2011 business plan submission, we have further refined the qualification criteria for the use of the within-period cost determination mechanism.

324 We have sought to develop criteria that ensure that the regulatory treatment of particular reinforcements is proportionate. In addition to the cost of the project, the other elements that are relevant to the level of scrutiny are:

(a) Level of user commitment; and

(b) Whether the reinforcement is required under all future scenarios or a subset

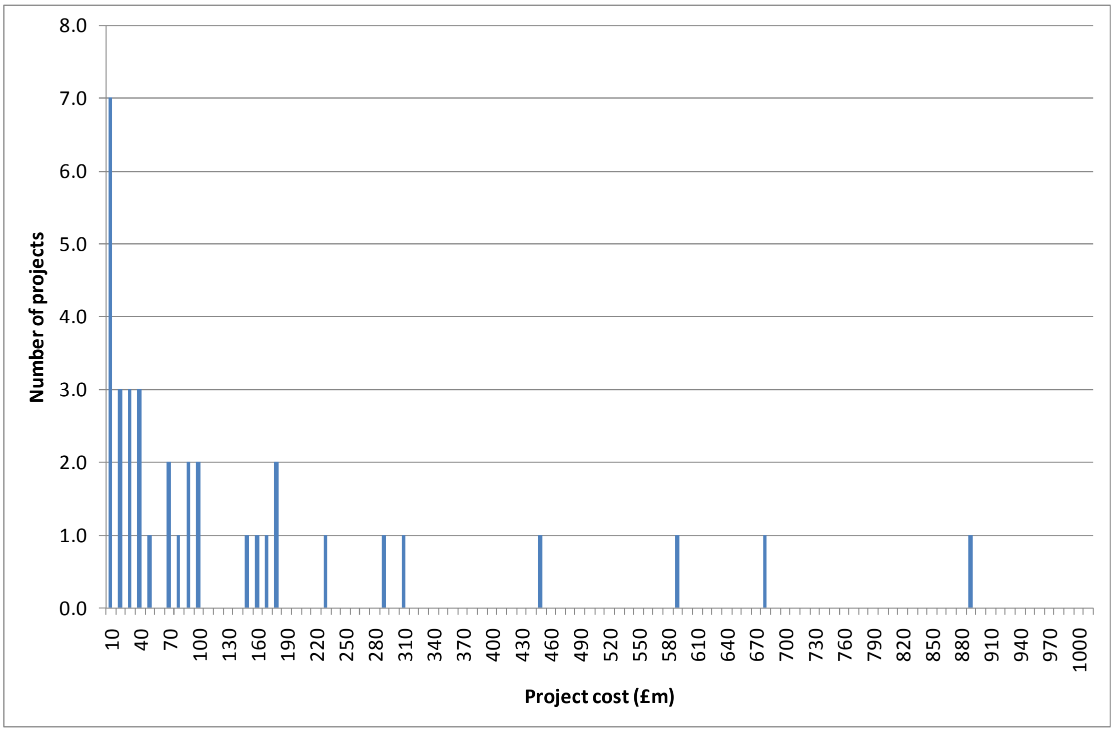
325 The level of user commitment is a measure of whether the reinforcement is being developed to anticipate future user signals or in response to existing user signals. Reinforcements that have a high level of user commitment are being developed in response to user signals and hence users have made a financial commitment to these reinforcements. These reinforcement do not, therefore, require the same level of regulatory scrutiny because the risk that consumers will be exposed to stranded costs is lower.

326 Reinforcements that are required under all of the future scenarios should also qualify for a lower degree of regulatory scrutiny, since the risk that they will become stranded is lower.

327 We have assumed that schemes which are currently being considered under the Transmission Investment Incentives work that will be in construction by the start of the RIIO-T1 price control period will be treated as part of the an ex ante allowance and not subject to the within-period cost determination mechanism.

328 In order to combine the criteria described above with the cost materiality, we have looked at the cost of all the wider works projects triggered by either the slow progression, gone green or accelerated growth scenario. The results are shown in the graph below.

329 Projects include all work elements that are required to provide the output of additional boundary capacity. For example, if there is a scheme that delivers a new overhead line and separate schemes for the substations at either end required to integrate the new line with the remainder of the transmission network, then all three schemes will be considered as a single reinforcement project.



330 The graph shows that there is a cluster of 25 projects with a cost below £150m. The total cost of these projects is £1,020m. There are then eight projects with a cost of between £150m and £500m, summing to a total cost of £1,925m and a further three projects with a cost above £500m, summing to a cost of £2,151m.

331 To ensure that additional regulatory scrutiny is focused on the appropriate reinforcements, we propose the following:

(a) Projects with a cost lower than £150m are all treated with the volume-driver mechanism;

(b) Projects with a cost higher than £500m are all treated with a within-period cost determination;

(c) Projects with a cost between £150m and £500m are treated with the volume-driver if they are supported with a high level of user commitment and are required under all three generation scenarios. Otherwise they are treated with a within-period cost determination.

332 These criteria are summarised in the table below.

Project cost[21]	<£150m	£150m to £500m	>£500m
Simplified volume-driver	All	High [>70% of boundary capability increase] user commitment; or Triggered by all scenarios before 2023	None

[21] Note: We propose to specify the materiality thresholds based on outturn prices to simplify the tracking of projects against the criteria throughout the RIIO-T1 price control period.

333 The criteria described above support the simplification of the volume-driver mechanism. Projects that are not triggered under all scenarios or have high costs (and therefore are likely to have long lead-times) are treated with the within-period cost determination mechanism.

334 The assessment of whether schemes are triggered by all scenarios is extended beyond the RIIO-T1 period to avoid the need to perform numerous within-period cost determinations for small cost projects at the end of the price control period.

335 When the need case for a particular reinforcement has been established, we will agree a forward-looking change to allowances together with the associated output targets with Ofgem.

Wider works summary

336 National Grid proposes to use the Network Development Policy and volume driver for the majority of wider reinforcement works.

337 Following engagement with stakeholders, we have proposed a Network Development Policy, and included this as an annex to this business plan submission.

338 We have also proposed a simplified volume-driver to support the use of the Network Development Policy and presented a set of associated main boundary unit cost allowances.

339 National Grid also proposes the use of the within-period cost determination for significant cost schemes and has refined the criteria that will be used to determine which schemes are taken forward under this mechanism. The criteria fully support the simplification of the volume-driver mechanism.

340 The volume-driver arrangements for wider works are summarised in the tables below.

	Baseline		Volume-driver	
	Allowance	Output	Volume	Unit cost allowance
Simplified volume-driver	Forecast wider transmission reinforcement costs for gone green scenario by year (£m)	Gone green wider boundary capabilities by year (kW)	Gone green forecast required boundary transfer from year t-3 for year t (kW) - gone green forecast required boundary transfer at the price control for year t (kW)	Boundary specific; Above gone green; Below gone green

Costs of meeting planning requirements

What is it? *Uncertainty associated with the level of undergrounding or broader visual amenity mitigation required to establish significant new transmission routes*
How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £512m, reducing to £210m with the application of our proposed uncertainty mechanisms*
What are we going to do about it? *Commit sufficient resources to ensure quality submissions to planning authorities; Pursue the development of alternative options to underground cable; Explore smart alternatives to new routes*
Risk sharing arrangements?
Volume-driver based on length of new underground cable, with a matrix of unit cost allowances based on the Institution of Engineering and Technology (IET) study
Volume-drivers for distribution works required to mitigate the impacts of new transmission routes
Efficiency incentive rate for over/underspends

Context

341 Given the highly consultative nature of the new planning regime, it is very difficult to forecast the cost of new transmission routes as there is a high degree of uncertainty around the level of undergrounding or broader visual amenity mitigation that will be required as part of new transmission routes. Ultimately this will be determined via extensive consultation processes on the individual projects, by the local constraints, visual amenity issues and environmental designations in the areas affected by the projects, and by the judgement taken by the Secretary of State (assuming the Localism Bill is enacted) when considering our consent applications. In short, the cost of meeting planning requirements is driven by a range of policy decisions over which National Grid has limited control and little clarity ahead of time.

342 In our 'baseline' plan, we have included a provision which equates to 10% undergrounding of all the new transmission routes required to meet the Gone Green generation and demand assumptions new build, although it should be noted that this does not represent a National Grid forecast.

Quantification

343 Given the difficulties associated with forecasting, we have based the credible range of the volume uncertainty purely on the feedback we have received from our stakeholders. This gives a range of undergrounding of between 5% and 50% of all new overhead line routes.

“” *Several stakeholders had very strong views in favour of undergrounding because of the effect on visual amenity. They were very much in support of increasing the extent of undergrounding, as well as retrospective undergrounding.*

Stakeholder comments, stage two workshop, 31st March

"We do not consider that the commitment to underground 10% of new lines goes far enough in meeting this concern, and instead suggest that the figure should be much higher, for example 50%."
Coalition of environmental organisations including CPRE, Campaign for National Parks and Friends of the Lake District, May 2011 consultation response

"In the current planning environment we believe it would be prudent to allow up to 10% of new line to be underground, this would significantly reduce the risk of extended project delays."
Exxon Mobil, May 2011 consultation response

344 In order to model this uncertainty, we have assumed a lognormal distribution with a mean of 17% and a standard deviation of 11%. This distribution has been utilised because it gives a good representation of the full range of stakeholder views that we have received, and does not extend below zero.

345 The capex impact is directly related to the higher capital cost of underground cable compared to overhead line. The main influencing factors are the length, the rating and any consequential requirements for reactive compensation and switching station equipment. The associated opex impact is comparatively small.

346 For the purposes of quantifying this uncertainty, we have calculated the average cost per route km from the matrix of incremental capital unit costs for undergrounding from the Institution of Engineering and Technology (IET) study[22]. This gives a figure of £14.63m/km.

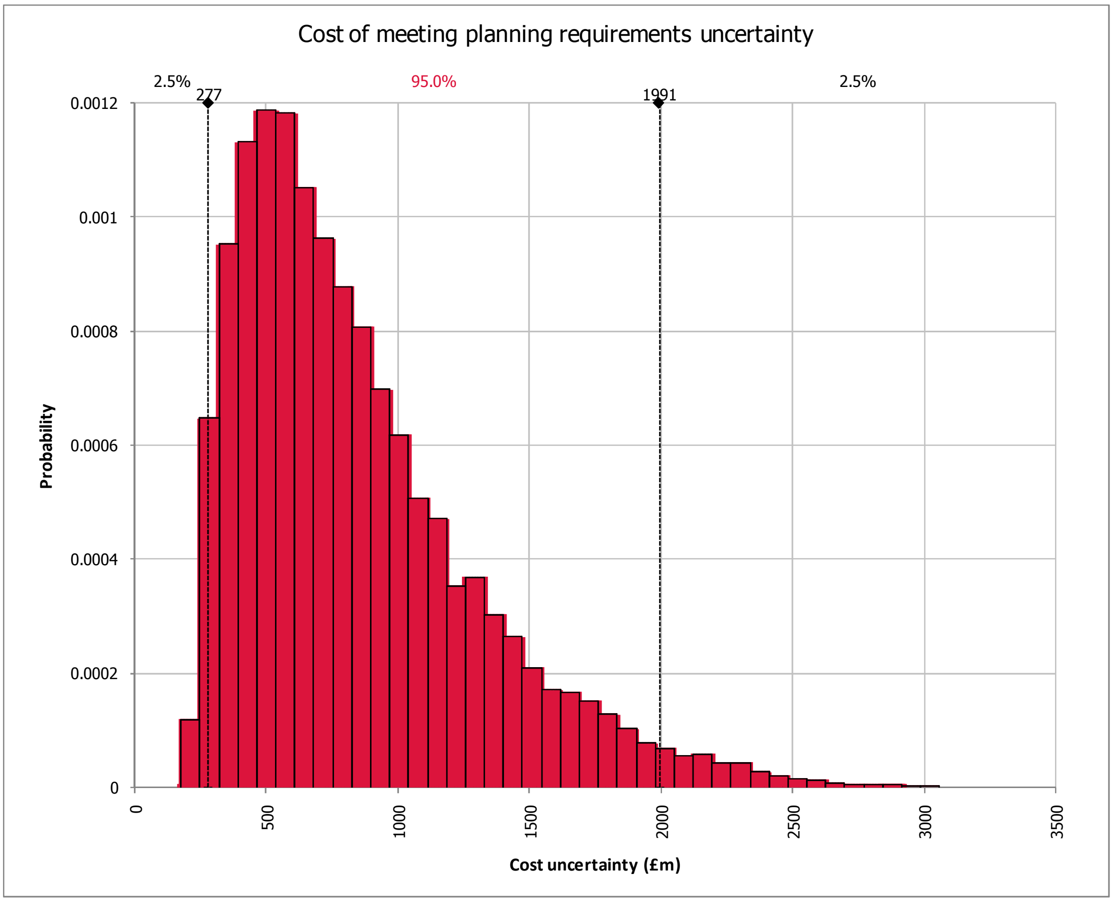
347 This unit cost does not include an allowance for real price effects, and therefore we have calculated an adjustment by taking the appropriate project groupings from our Gone Green plan. The adjustment is shown in the table below.

Unit cost allowance	Real price effect adjustment factor
Undergrounding	+11.5%

348 This does not cover the construction uncertainty, and therefore we have also applied the probabilistic distribution described in the construction uncertainty section above. Given the need to establish unit cost allowances for the full RIIO-T1 period at the price control review, we have assumed the construction cost variance associated with an initial cost estimate.

349 We have performed a Monte Carlo simulation to combine the volume and cost distributions in order to calculate a cost distribution for each year of the RIIO-T1 period. This gives the distribution of costs for the full period shown in the graph below. The distribution has a standard deviation of £450m. When real price effects are added, this increases to £512m.

22 http://www.theiet.org/factfiles/transmission.cfm



350 We have also considered the various other output impacts. The main impact is on the transmission losses output, but again this is not material. The physical properties of cables mean that they generally cause lower transmission losses than the equivalent overhead line solutions.

Management response

351 Whilst we have limited control over this driver of uncertainty, we have considered what actions could be taken to manage the associated costs:

Actions that we will take to ensure an appropriate outcome:

352 We will commit sufficient resources to ensure a quality IPC/MIPU submission which includes effective presentation of the need case, consideration of stakeholder views and an assessment of different delivery options. We have included provisions in our business plan to ensure that this is completed, particularly in Construction, Electricity Network Investment, and Land and Development in Asset Management.

353 This approach will ensure that the relevant decision-making body will have access to complete and reliable information on the costs of any decision, in order to ensure the outcome best meets the needs of all stakeholders.

354 This management response has already been reflected in the uncertainty range described above.

Actions that we will take to 'buy' an option to reduce the impact if an adverse event occurs

355 There are a number of alternative technology options that could provide underground transmission routes at a lower cost in the future. One such alternative technology option is the use of Gas Insulated Lines (GIL). This technology provides an alternative to High Voltage AC cables by adapting existing Gas Insulated Switchgear (GIS) technology using a mixture of SF6 and nitrogen as the insulating gas. If installed (in tunnels) ratings can match that of overhead lines and unlike cables no additional reactive compensation is required.

356 We have already started to pursue the development of this option, and will continue to during RIIO-T1. There are a number of tentative technologies (i.e. laboratory prototypes, demonstrators, etc) under development that could further reduce the cost of undergrounding, but these remain unproven at present. We need to verify and demonstrate that these technologies are robust and safe to deploy in an operational environment before proposing their adoption.

357 Again, this management response has already been reflected in the uncertainty range described above.

Actions that will be taken when the adverse event occurs

358 For new routes which are required to accommodate increased power flows arising from the growth of generation and/or demand in different regions, it may be possible to develop smart solutions that defer or completely avoid the need for a new transmission route. However, given the very significant increases in capacity provided by new routes, it is unlikely that smart solutions will avoid all requirements.

359 Given the very significant costs associated with new routes, we would typically seek to exhaust all such possible solutions before proposing a new route. In addition, new routes are often required to provide a new connection to the transmission system and these would not be avoided by smart solutions. We therefore believe that there will typically be limited scope for us to be able to abandon a proposed new route, unless the relevant planning authorities require substantially more undergrounding than had been envisaged. Where the level of undergrounding required is very significant it is possible that the resulting increase in cost could render the project uneconomic (i.e. the project benefits might no longer outweigh the costs), and that alternative solutions that had previously been rejected might become preferred.

Risk sharing arrangements

360 We can manage the submission which includes an effective presentation of the need case and a full exploration of all viable options, but in our view the risk of increased capital expenditure being required for undergrounding solutions should not fall on National Grid. For each planning decision, a trade-off between visual amenity, cost and many other factors will have to be performed, and a decision to underground a higher percentage of a route on a specific project may be the correct decision in light of these factors. A decision to include a higher level of undergrounding than that assumed in our

baseline plan is therefore unrelated to National Grid's performance in compiling and presenting the associated consent application. It would simply reflect the considered view of the planning authority based on all information presented, including information provided by parties other than National Grid.

361 With regard to undergrounding on new routes it might be more efficient for a portion of the risk to fall on customers since they can choose locations mindful of the potential for planning delays. This transfer of risk could be achieved through potential exposure to higher locational transmission charges if underground rather than overhead technologies are required.

362 It is also noted that a higher portion of the risk falls on end consumers since they are largely the public who are benefiting from the improved visual amenity resulting from greater use of undergrounding.

363 It is also more efficient for consumers to bear the majority of this risk. Since it is difficult to forecast accurately the extent to which undergrounding will be required and the cost of undergrounding can be large relative to overhead alternatives, the resulting (largely) uncontrollable risk is material. National Grid could bear this risk on behalf of customers, but would require an increase in the allowed rate of return to do so and this is unlikely to provide value for money for customers.

"We would wish to see more detail behind any flexibility mechanism before we can indicate total support: however, in principle given the planning consent challenges posed, a flexibility mechanism may be a good way of overcoming cost increasing above initial assumed baseline business plan estimates."

E.ON May 2011 consultation response

364 However, once the level of undergrounding that is required has been established, National Grid can manage the construction activities and therefore should bear the risks associated with the delivery of the relevant undergrounding.

Mechanism

365 In order to achieve this transfer of risk to consumers, we are proposing a volume driver for undergrounding and other exceptional mitigation measures (for example, undergrounding of Distribution Network Operator overhead lines).

366 This mechanism is preferred because it reduces consumer exposure to forecast error, lowers the cost of capital that would otherwise be required, provides the greatest transparency of the costs of undergrounding and other mitigation measures to customers, and minimises the administrative burden during the RIIO-T1 period.

Adjusting allowances

367 The simplest risk sharing arrangement would be a single volume-driver for the marginal cost of underground cable. Allowances would be adjusted based on the difference between the ex ante allowance for undergrounding (£) in a particular year and the actual volume of underground cable installed in that year (in km) multiplied by the relevant unit cost allowance (in £/km).

368 The trigger for this mechanism would be the decision of the Secretary of State or other relevant planning authority as to which elements of an application should be undergrounded or subject to other mitigations.

369 The application of this volume-driver would address the volume uncertainty for underground cables, but would not address other potential visual amenity mitigations that may be required. The most significant of these would be additional works on distribution network owner assets, for example, the undergrounding of a 132kV distribution route so that the overhead route can be used as a new route at transmission voltage.

370 In order to address this, we propose to supplement the simple volume-driver for underground cable with additional volume-drivers for undergrounding distribution routes, dismantling distribution towers, new distribution overhead lines and new distribution switchbays.

371 These other volume-drivers would operate in the same way as the simple driver for the marginal cost of undergrounding described above. The volume of additional work on distribution assets completed in any particular year would be multiplied by the relevant unit cost allowances to calculate the appropriate adjustment to our allowances.

372 As with the volume of undergrounding, we would need to show how the actual volume of distribution assets installed in any particular year was consistent with the relevant decision of the Secretary of State.

Unit cost allowances

373 In order to establish unit cost allowances for transmission works, we propose to utilise the matrix of incremental capital unit costs for undergrounding from the Institution of Engineering and Technology (IET) study[23] on the whole life costs of installing new transmission lines as per their 31 January, 2012 report. These costs are summarised in the table below for clarity. These costs have only recently been published, and we will complete further analysis to confirm their suitability against the range of schemes we are forecasting for the RIIO-T1 business plan.

374 Since the adjustment to our allowances will only occur when different volumes of underground cable are delivered, we need to adjust the unit costs to include financing costs. We have completed this adjustment based on the proposals contained in the finance annex to this submission and standard spend profiles for overhead line and cable schemes. These revised unit cost allowances are also listed in the table below. The figures in brackets include the real price effects adjustment.

[23] http://www.theiet.org/factfiles/transmission.cfm

Type	Length	Rating (MVA)	Additional capital cost (/km)	Adjusted to include financing costs (/km)
Underground cable	3km	2 x 1595	10.33 (11.5)	10.91 (12.1)
	3km	2 x 3190	18.83 (21.0)	19.93 (22.2)
	3km	2 x 3465	20.03 (22.3)	21.20 (23.6)
	15km	2 x 1595	8.187 (9.1)	8.63 (9.6)
	15km	2 x 3190	15.673 (17.5)	16.58 (18.4)
	15km	2 x 3465	16.873 (18.8)	17.84 (19.9)
	75km	2 x 1595	7.835 (8.7)	8.26 (9.2)
	75km	2 x 3190	15.127 (16.9)	16.00 (17.8)
	75km	2 x 3465	16.344 (18.2)	17.29 (19.3)
HVDC LCC	75km	2 x 1500	8.519 (9.5)	8.99 (10.0)
	75km	2 x 3000	14.369 (16.0)	15.20 (16.9)
HVDC VSC	75km	2 x 1500	10.715 (11.9)	11.32 (12.6)
	75km	4 x 1500	21.453 (23.9)	22.72 (25.3)

375 We propose the 3km figure for distances between 0 and 3km; the 15km figure for distances between 3km and 15km and the 75km figure for all other distances.

376 As described above, when considering other potential visual amenity mitigations, the most significant is likely to be works on distribution networks. We have therefore developed a set of unit costs for distribution works based on our most-likely unit costs (for 132kV bays) and the average figures from the DPCR5 proposals.

Description	Unit cost allowance
Undergrounding of DNO overhead line (based on 132kV underground cable)	£1.097m/km
DNO tower dismantling	
New DNO overhead line (based on reconductoring of 132kV tower line and assuming three towers per km)	£0.665/km
New DNO switchbays (based on NGET unit cost – average of air-insulated and gas-insulated switchgear)	

377 These works may also involve the establishment of new Grid Supply Points, but we would expect the demand-related infrastructure mechanisms described above to adjust our allowances in these circumstances.

Impact assessment

378 As shown above, an initial analysis of the costs of wider works for these boundaries highlighted a variation with a standard deviation of £450m. This represents the risk, for both consumers and ourselves, associated with an ex ante allowance agreed at the price control review to cover the cost of meeting planning requirements.

379 We have developed the simple volume-driver for undergrounding costs in order to explore the effectiveness of the volume-driver mechanism. We repeated the Monte Carlo analysis with this mechanism and the results are presented in the table below.

Uncertainty mechanism	Standard deviation (£m)
No mechanism	£454m
Volume-driver based on unit cost for undergrounding and other mitigations	£210m

Summary

380 National Grid's uncertainty mechanism proposals for the costs of meeting planning requirements are summarised in the table below.

	Baseline		Volume-driver	
	Allowance	Output	Volume	Unit cost allowance
Under-grounding costs	Forecast based on 10% under grounding of new transmission routes across a mix of ratings (£m)	NA	Length of new underground cable (km) in particular year multiplied by relevant unit cost allowance (£/km) – forecast by year (£m)	Matrix of additional costs for under grounding from 31 January, 2012 IET report (+11.5% with RPE)
Other mitigations	Forecast based on Gone Green generation background	Based on Gone Green background	Volume of distribution assets to be installed – forecast by year	Matrix of unit cost allowances for distribution works

Offshore network impact

What is it? *Uncertainty associated with the impact of the connection of offshore wind on the onshore transmission network*
How big? *The cost risk over the RIIO-T1 period has a standard deviation of £157m*
What are we going to do about it? *Active engagement in the development of the arrangements*
Risk sharing arrangements?
Efficiency incentive rate for over/underspends

Context

381 The connection and integration of offshore wind from around the UK coastline will play a significant role in meeting the EU environmental targets. Whilst radial point to point connections have adequately provided a route to market for near shore wind so far, a more efficient way of connecting wind is needed for the increased volumes and distances of offshore windfarms that are expected.

382 Given the uncertain nature of the rate of deployment of wind generation in the UK and the rest of North West Europe, an integrated offshore transmission system allows for flexibility in approach to deal with this uncertainty. To do otherwise increases the risk of asset stranding and under-utilisation, with extensive onshore consenting risk.

383 At this time, the development of the offshore regime is uncertain. In developing our business plans, given that the integrated network (i.e. designing the onshore and offshore network as a single entity to minimise overall costs) results in the most economic and efficient solution, we have identified on-shore network reinforcements on the assumption that a co-ordinated integrated network solution will be developed.

384 The regional reinforcement strategies and subsequent generation, demand and wider works uncertainty mechanisms are based on this assumption. The onshore connection points for offshore windfarm development assume that a co-ordinated integrated network solution will be developed. Similarly, major reinforcements in our baseline plan including the Wylfa – Pembroke HVDC link and the Eastern HVDC link between substations in Scotland and Hawthorne Pit could ultimately be developed to compliment (or be part of) an integrated off-shore network.

385 The following examples illustrate this further.

(a) If an integrated off-shore network were not to be developed, a revised connection would be considered for the Triton Knoll off-shore windfarm development. This could lead to increased on-shore reinforcement including a new substation and section of overhead line.

(b) For the Wylfa – Pembroke HVDC link (cost circa £625m), the timing depends on the build-up of offshore wind generation in the Irish Sea and the size of nuclear units adopted at Wylfa. The need for the link is likely to be in the window between 2018 and 2022, and we are proposing that it will be subject to the wider reinforcement works within-period determination provisions described in the generation and demand section above. If an integrated off-shore solution was to be developed ahead of these timescales, the design of the Wylfa – Pembroke link could be revised. For example, it might be more efficient to have the northern end HVDC converters on an offshore platform.

386 So, at this time, the exact extent, timing and ownership of an offshore network are uncertain. With respect to extent and timing, if an offshore network were not to be developed, more onshore reinforcement is likely to be required to deliver large volumes of off-shore generation. Similarly, the early development of an extensive offshore network might revise or reduce the onshore reinforcement requirements.

Quantification

387 The marginal onshore cost of the radial offshore solution over an integrated offshore solution is estimated to be £600m over the RIIO-T1 period.

388 It is possible that changes to the offshore regime could cause additional onshore costs, for example, if offshore windfarms were to be developed more quickly than assumed under the Gone Green background, then the marginal costs would be greater.

389 It is also possible that changes could be made which would reduce onshore costs, for example, by changing the balance between the reinforcements completed on and offshore.

390 Based on further consideration of the examples in our business plan, we have developed a distribution to represent this uncertainty over the RIIO-T1 period. We have assumed that an additional scheme of the size of the Wylfa – Pembroke HVDC link would represent two standard deviations of this uncertainty.

391 We have set the mean of this distribution to be consistent with our Gone Green business plan, and based the standard deviation on 50% of the cost of the Wylfa – Pembroke HVDC link. The spend profile for this scheme has been used to derive a distribution for each of the years of the RIIO-T1 period.

Management response

392 Ultimately the offshore integrated network that is implemented will be the result of detailed consultation between Government, Ofgem and Stakeholders. We will continue to take an active role in this process.

Risk sharing arrangements

393 There is a risk that a change to the offshore regime could have a significant impact on the balance between the level of offshore and onshore interconnection capability that is provided. This could invalidate the analysis that has been performed in developing the generation, demand and wider reinforcement works uncertainty mechanisms.

394 In our July 2011 business plan submission, we proposed a specific re-opener to deal with this risk, with the impact assessment that accompanied any change to the offshore regime being used as a trigger.

395 We have now completed further impact analysis of a change to the offshore regime on the uncertainty mechanisms described in the generation and demand section above.

396 These mechanisms will provide some protection against this risk since the change to a radial offshore solution is likely to manifest itself in a greater number of generation connections and higher transfers across wider onshore boundaries.

397 Based on this analysis, we have decided to withdraw this uncertainty mechanism and rely on the mechanisms described in the generation and demand section above. In finalising the detailed design of these mechanisms, we will ensure that the impact of changes to the offshore regime are accurately reflected.

398 This reduces the number of uncertainty mechanisms that we are proposing and therefore contributes to the simplification and increased transparency of the Price Control arrangements.

Network renewal volumes

What is it? *Uncertainty associated with the degradation of our assets*
How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £77m*
What are we going to do about it? *Continual review of intervention options; Increased level of proactive actions; Increased use of defect repairs, risk management and spares holding*
Risk sharing arrangements?
Corrections to RIIO-T2 allowances for underdelivery of network risk
Efficiency incentive rate for over/underspends

Context

399 The two principal sources of uncertainty around network renewal volumes are:

(a) Uncertainty associated with the forecasting of asset degradation;

(b) Uncertainty associated with unexpected type faults.

400 Asset degradation is inherently uncertain, and National Grid employs probabilistic modelling techniques to forecast future condition. This is combined with information on asset criticality to calculate a forecast of replacement priority. This modelling directly provides the standard deviation associated with the asset degradation uncertainty.

401 The specification of network risk as a secondary deliverable as part of the RIIO price control may increase National Grid's exposure to asset degradation uncertainty, given that a particular profile of network risk must be achieved at the end of the price control period.

402 Unexpected type faults cannot be forecast but can have a significant impact on network risk, cause significant costs and lead to disruption of the capital programme. It would not be sensible to model this risk probabilistically, and therefore we have estimated a standard deviation based on our recent experience.

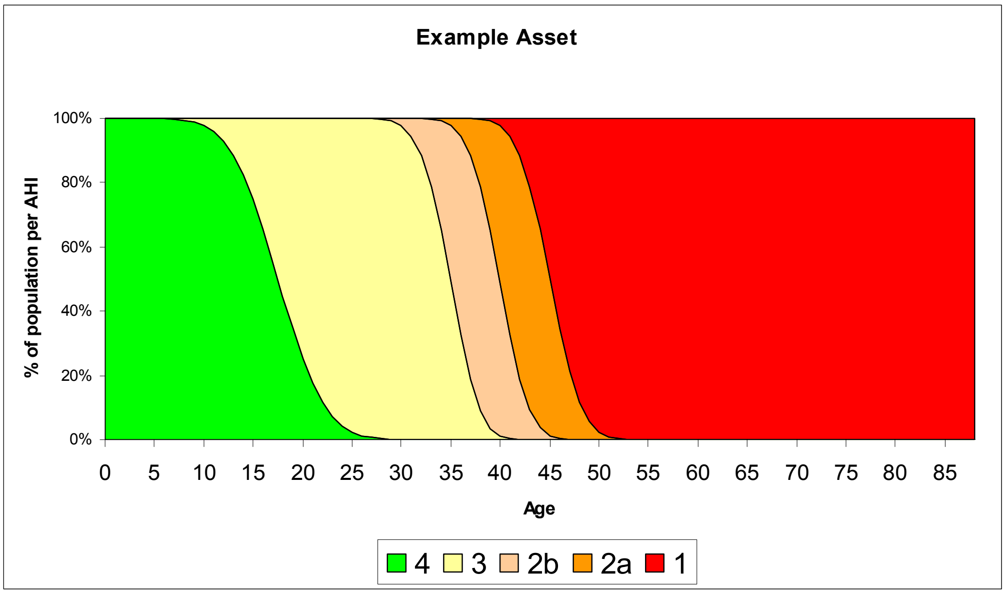
Asset Degradation Uncertainty

403 We actively develop our asset management capability and one of our most recent advances in our capability is the development of the risk and criticality approach to prioritising asset replacement. This targets asset replacement on assets in poorest condition with the highest consequences of failures. Throughout 2007 and 2008, we worked with Ofgem and the two Scottish Transmission Owners to develop the first version of the Network Output Measures methodology statement (Issue 1, 30 May 2008). Issue 4 of the statement was approved by Ofgem on 31st March 2010. The specific National Grid appendix in the Network Output Measures methodology statement contains information on how we have developed our asset management

capability to fully implement a risk and criticality approach to asset replacement.

404 One of the fundamental parts of this risk and criticality approach is our ability to forecast asset degradation. Distributions are defined for each Asset Health Index (4 being good condition and 1 being poor condition) based on the worst case experienced and best case deterioration predicted. The derivation of these deterioration curves is supported by extensive knowledge of the assets informed through R&D, failure investigations, forensic investigations, condition monitoring and assessment, family history, international experience and asset performance data.

405 The probability that the asset will progress to the next Asset Health Index at a particular age is calculated by modelling distributions defined by the Asset Health Index range. An example of these distributions for each Asset Health Index is shown in figure below.



406 Using the deterioration curve for each asset, from any age and starting Asset Health Index, a forward prediction for the future replacement priority of every asset can be modelled. A Monte Carlo simulation technique is used to predict the future replacement priority of each asset. This future replacement priority takes account of future planned replacement dates which when reached, reset the health of the asset to a replacement priority 10+ years. Summating the outputs across the simulations produces a distribution of the total number of assets in each replacement priority category. This distribution is used to calculate descriptive statistics of these distributions (e.g. the median, upper quartile and lower quartile reported to Ofgem in Table 4.28.1) and the mean and standard deviation numbers used in the uncertainty modelling.

Quantification

407 For the uncertainty associated with the forecasting of asset degradation, we have combined the standard deviations of the volume of assets in the 0-2 years and 2-5 years replacement priority categories for each asset category. We have assumed an 80% correlation between the 0-2 and 2-5 year

categories (that is, they mainly increase and decrease together) and this is because the cause of asset condition being better or worse than forecast for any particular asset category is highly likely to be equally applicable to the 0–2 years and 2–5 years replacement priorities. This gives a standard deviation for the uncertainty associated with needing to do more or less replacement work for each asset category.

408 The combined standard deviations for the 0-2 years and 2-5 years categories have then been divided by 5 to estimate an annual standard deviation. This is because an increase in the number of assets in the 0-5 year category would need to be addressed in a 5 year time horizon. This annual standard deviation data for each asset category is shown in the table below.

Asset category	Standard deviation of volume							
	2013	2014	2015	2016	2017	2018	2019	2020
Cables (km)	3	3.5	4	4.4	4.7	4.8	5.1	5.3
OHL conductor (km)	43.5	43.4	43.3	42.7	42	41.8	42	40
OHL fittings (km)	42	43.5	44.8	45.2	45.4	45.5	43.5	41.2
Switchgear (#)	2.3	2.3	2.2	2.2	2.3	2.3	2.3	2.3
Transformers (#)	1.3	1.5	1.7	1.8	1.9	2	2.1	2.2

409 These volumes have been converted into costs by multiplying by standard unit cost data for each of the categories. These cost impacts for each of the asset categories have then been combined to calculate a standard deviation for the annual cost impact of assets in all of the categories. This has been completed by assuming that the asset categories are independent (that is, the overall standard deviation for all asset categories has been calculated as the sum of squares of the standard deviations for individual asset categories). This is shown in the table below.

Asset category	Unit cost (£m)	Standard deviation of costs (£m)							
		2013	2014	2015	2016	2017	2018	2019	2020
Cables	4.5[24]	13.5	15.75	18	19.8	21.15	21.6	22.95	23.85
OHL conductor	0.4	17.4	17.36	17.32	17.08	16.8	16.72	16.8	16
OHL fittings	0.1	4.2	4.35	4.48	4.52	4.54	4.55	4.35	4.12
Switchgear	2.1	4.83	4.83	4.62	4.62	4.83	4.83	4.83	4.83
Transformers	3.5	4.55	5.25	5.95	6.3	6.65	7	7.35	7.7
All assets		23.38	24.88	26.47	27.66	28.60	28.97	30.09	30.40

[24] Per core per km

410 In addition to the asset degradation risk described above, we also need to consider the construction risk from the relevant section above. Since the unit costs used in this analysis have been established at the price control, we have used the probabilistic distribution associated with the original scheme estimate.

411 We have performed a Monte Carlo simulation to calculate the overall asset degradation risk for the RIIO-T1 period. The resulting distribution had a standard deviation of £70m.

412 For the uncertainty associated with unexpected type faults, we have considered our historical experience. Some notable recent examples are described further below.

FMJL / FMVG Instrument Transformers

413 During 2009 and 2010, four separate disruptive failures caused by FMJL / FMVG type Instrument Transformers (ITs) resulted in porcelain being projected over significant distances. In addition an FMJL owned by Connahs Quay Power Station failed disruptively in 2011. This failure resulted in a 10-20m fire ball and fragments of porcelain being projected over significant distances.

414 Extensive forensic analysis of all FMJL / FMVG related failures has determined that moisture ingress via the diaphragm or design / material defects is resulting in the disruptive failure of these units.

415 Following an extensive review during 2009/10, a replacement scheme was put in place to remove all FMJL/VG type ITs from the system within 10 years with the majority (80%) being removed within 5 years. Following the Connahs Quay failure we are accelerating the replacement of all FMJL and FMVG units and aim to have 70% removed by the end of 2012/13, with the remainder of the population removed by the end of 2013/14.

416 Following the 2009/10 failures, 75 metre (20m for FMVG 33 kV) Risk Management Hazard Zones (RMHZ) were applied across 143 sites on the Transmission network where FMJL/VG ITs are operational with high moisture levels, in order to protect staff, our contractors and the public. In December 2011 following the publication of the Connah's Quay failure report which identified design / materials defect as a second failure mode RMHZs were applied to the whole population of FMJL and FMVG 33 kV units. Due to additional protection devices on FMVG 132 kV units RMHZ remained only where units have high moisture content.

417 As a consequence, capex reprogramming costs of £2.7m were incurred across 20010/11 and 2011/12 together with the deferral of maintenance jobs which will have a subsequent impact on future years' maintenance plans.

418 The associated costs are described below.

(a) Capex costs: In 2009/10, £0.5m of additional capex costs were incurred as a result of scheme delays. A scheme has been sanctioned to replace 70 circuits of predominately FMJL type ITs at a cost of The FMJL / FMVG (the FMVG unit has an FMJL element) population is approximately 1300 which equates to a total spend of approximately [redacted] (based on an [redacted] capital cost for 70 circuits (3 per circuit)).

(b) Opex costs: We incurred £1.3m and £1.1m in 2009/10 and 2010/11 respectively on mitigation measures (ballistic screening, RFI, PD monitoring and thermovision), forensic and HV test costs. As we will be managing the impact of RMHZs around FMJL/FMVGs until they are removed from the system, it is anticipated that we will incur in the region of £4m over the next 3 years.

2005 SPL1A(C) SF6 High Duty Circuit Breaker

419 In 2005 shortly after closing there was a disruptive failure of an SPL1AI circuit breaker (CB). Despite forensic examination, the cause of failure could not be determined due to the limited evidence available.

420 In December 2009 and February 2010, a further two disruptive failures of SPL1A(C) CBs occurred. The second failure being less violent allowed evidence to remain for forensic analysis.

421 The third failure was extremely violent scattering porcelain fragments 70m. After forensic investigations it was concluded that the most likely cause of failure was mechanical component failure within the interrupter. Following cost-benefit analysis, the decision was taken to remove the population of 17 circuit breakers from the system.

422 Following the 2005 failure, a 50m RMHZ was established and entry prohibited for 30 minutes after closure. The RMHZ was extended to 75m after the failure in 2010.

423 The associated costs are described below.

(a) Capex costs: A scheme was developed at a cost of [redacted] to refurbish two CBs with one completed prior to winter 2010/11 for operational reasons. Following the cost benefit analysis, two further schemes have been developed with a cost of [redacted] to replace 6 CBs and provide a spare. All remaining CBs were either already in the capital plan for replacement or no longer operationally required.

(b) Opex costs: Minimal opex costs were incurred. With the advent of a 75m RMHZ, time was spent producing site specific risk assessments in order to ensure the safety of staff and the public.

Management response

424 National Grid has a wide range of options available to it to manage the uncertainty surrounding the volume of network renewal work.

Actions that we will take to avoid an adverse event

425 Throughout the eight year RIIO-T1 period, we will learn more about our assets as they age and experience new duty cycles. Further assets will enter the wear-out period of life which will allow collection of new condition information. In addition it is likely failures will occur which reveal new deterioration mechanisms which are currently unknown.

426 This new condition information and new deterioration mechanisms will feed into the deterioration modelling and technical asset lives. In addition, we will continue to seek new cost-beneficial intervention options to manage the evolving condition of the assets.

427 In some cases the new information and innovation options we develop will allow some life extension and in other cases this will cause life reductions. Circumstances where we already know this may occur have been highlighted in the 'Non-load related detailed plan' annex.

428 The likelihood of these changes will tend to increase as the period progresses. All the evidence we currently have has been included in our plans (i.e. the asset replacement schemes in the capital plan are based on current knowledge of condition and criticality). In the 'Non-load related detailed plan' annex, we have highlighted the assets which are not in the capital plan but which currently have a 10+ replacement priority and have a reasonable probability of deteriorating to and remaining in a 0-2, 2-5 or 5-10 replacement priority for at least a 5 year period during RIIO-T1. Our proactive asset management will tend to reduce the widening uncertainty range towards the back end of the RIIO-T1 period holding the uncertainty at similar levels to the front-end of the plan.

Actions that we will take to 'buy' an option to reduce the impact if an adverse event occurs

429 We will continue to forecast network risk using predicted replacement priorities as described above. To manage an increased network risk, we would increase the level of proactive actions that are currently undertaken to manage its impact. This would tend to increase both operational and capital expenditure.

430 Some examples of this are listed below.

(a) Re-prioritisation of asset replacement schemes in the capital plan if a less urgent scheme can be deferred. This incurs additional operational and capital expenditure caused by the scheme deferral and re-planning.

(b) Increasing inspection and condition monitoring on assets at risk of deterioration to enable early identification of emergency replacements. This requires additional operational expenditure incurred through additional inspections and fitting additional condition monitoring equipment if possible (e.g. on-line condition monitoring units for transformers).

(c) Increasing our capability to perform emergency replacements. This involves holding more spares and developing and maintaining the capability to undertake emergency replacements quickly and efficiently (e.g. having schemes partly developed which can be implemented quickly, having equipment and expertise available to undertake the emergency replacement). The spares would increase capital expenditure whereas developing the capability to undertake emergency repairs is a mixture of increased operational and capital expenditure.

431 The impact of these actions can usually have a positive impact within 1-2 years. The cost of these actions would be in the region of an additional £15m. These actions will have minimal impact on the credible uncertainty range compared to the proactive asset management approach described above.

Actions that will be taken when the adverse event occurs

432 If condition deteriorated more quickly than we expect, reactively we could defer asset replacement. This would inevitably lead to re-prioritisation in the plan to concentrate on assets in poorest condition with the greatest impact (e.g. type faults may be prioritised above asset replacement in the existing capital plan).

433 If this occurred we would look to undertake a higher level of defect repairs on some assets types to try to manage the asset to the end of life, we would employ a greater level of risk management (e.g. RMHZs to manage safety, enhanced demand at risk site activities to help manage energy not supplied risk) and we would also further increase spares holdings to decrease the time that failed assets are potentially out of service.

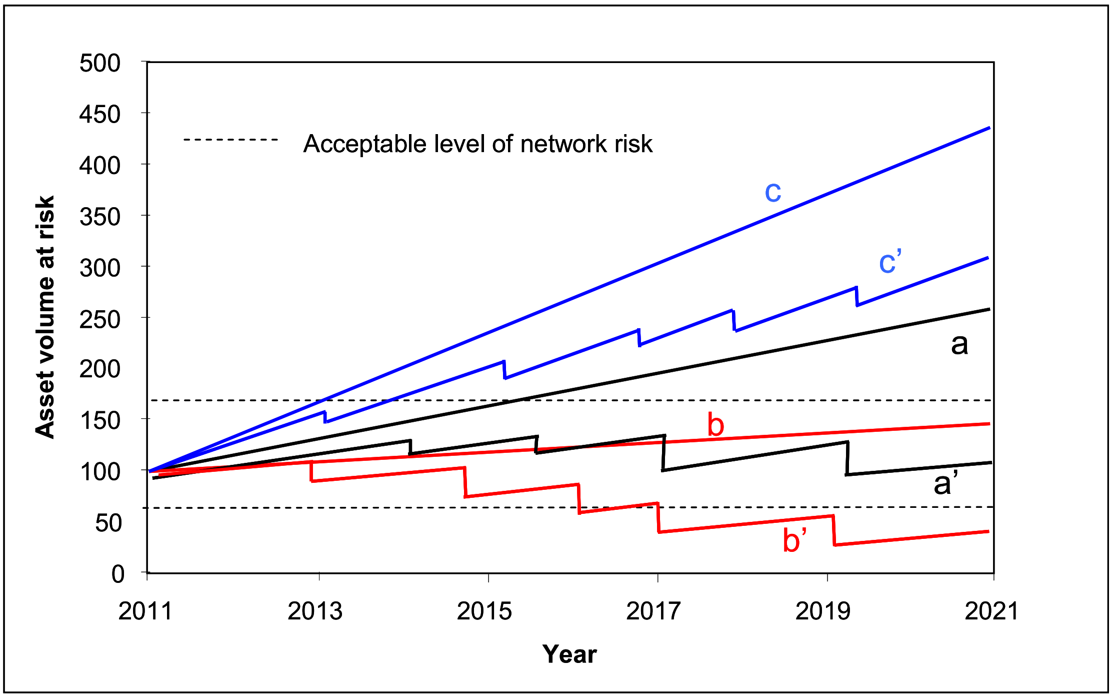
434 The overall cost of these actions is £20m. Whilst we could manage the immediate expenditure risk, this would lead to an increase in network risk. The impact on the uncertainty range could be managed to levels consistent with the capital plan using this approach but we would also be limited on what additional work we could actually achieve given outage and resource constraints which would limit our ability to manage network risk.

Risk sharing arrangements

435 Since our July 2011 business plan submission, we have considered the appropriate Network Output Measures secondary deliverable arrangements in more detail. These arrangements ultimately allocate the risk between National Grid and consumers.

436 A portion of the risk also falls on users to the extent that they signal their continued need for a service and pay cost reflective charges.

437 The key principles associated with our proposal for the Network Output Measures secondary deliverable arrangements are set out in the ‘Outputs’ annex. The diagram below illustrates why we are proposing a ‘network risk’ target rather than a ‘volumes only’ target.



438 The curves show the various uncertainties associated with the network risk position over the RIIO-T1 period.

a) Represents the natural deterioration of the assets without intervention

a') Represents the forecast network risk position taking into account the planned intervention (non-load related asset replacement, etc)

b) Represents a case where the network risk position is better than forecast by the end of RIIO-T1

b') Shows the effect of carrying out the planned interventions when network risk is better than forecast by the end of RIIO-T2

c) Represents a case where the network risk is worse than forecast by the end of RIIO-T1

c') Shows the effect of carrying out the planned interventions when network risk is worse than forecast by the end of RIIO-T1

439 Cases b' and c' highlight our concerns with a secondary deliverable target based on 'volumes only'. The Transmission Owner could deliver an agreed volume of asset replacement without delivering the expected network risk. In some cases this would lead to the consumer experiencing more risk (c') or not benefiting from the chance to reduce asset replacement volumes (b').

440 We propose that the network risk target for RIIO-T1 should be the forecast distribution of Replacement Priorities for each lead asset type at 2020/21 using the Network Output Measures probabilistic model and the business plan based on the Gone Green generation background. This network risk target for each lead asset category will be the sum of the 0-2 years, 2-5 years and 5-10 years Replacement Priorities, with a dead-band of ±5% to account for the

standard error of the forecast. The treatment of over and underdelivery against the network risk target and increased or reduced volumes compared to forecast is shown in the table below.

441 We propose that the overall network risk target would be described at an aggregate level i.e. when assessing overall network risk performance, overdelivery against one asset type could be traded against underdelivery of another (on a volume × relevant unit cost basis).

		Volumes replaced / refurbished		
		Increased volume	Ex ante forecast volume	Reduced volume
Network risk	Worse	Automatically exposed to additional costs for increased volume Apply penalty for volume difference between actual and target network risk	Apply penalty for volume difference between actual and target network risk	Automatically benefit from reduced costs from reduced volume Apply penalty for volume difference between actual and target network risk
	Within target dead-band	Exposed to additional costs for increased volume	No adjustment	Benefit from avoided costs for reduced volume
	Better	Exposed to additional costs for increased volume	No adjustment	Benefit from avoided costs for reduced volume

443 The arrangements described in the table above are symmetrical and would leave National Grid exposed to increased/reduced capex requirements to achieve the network risk target. This is consistent with the RIIO principles, with networks being exposed to higher incentive rates to achieve output-based targets. We have worked extensively with Ofgem, and the other Transmission Owners over the last few years to develop an outputs-based methodology for network risk, and this should be utilised as part of the RIIO price control.

444 We note Ofgem's concern that without a 'volumes only' target, TOs could receive capital allowances and subsequently deliver a reduced volume of asset replacement.

445 It should be noted that in order to deliver against a network risk target (and avoid the associated penalty) whilst reducing volumes, we would need to innovate in some way, for example, find a new strategy for the management of a particular asset type. Whilst we would share the benefit of this innovation with the consumer for part of the volume due for replacement in the RIIO-T1 period, we would not take a share of the consumer benefit from the consequent reduced asset replacement requirements and associated costs in future controls. The arrangements described in the table provide an incentive for networks to seek these innovations.

446 If we were unable to satisfy Ofgem that the reason for our reduced volume was genuine innovation delivering reduced costs in future controls, then an adjustment could be made at the start of RIIO-T2 such that we would only benefit from the avoided financing costs (multiplied by the efficiency incentive rate).

447 In order to achieve symmetry however, it would also be necessary to make a similar adjustment at the start of RIIO-T2 to reduce National Grid's exposure to increased volumes to achieve the Network Output Measure target. Our exposure should be limited to the additional financing costs (multiplied by the efficiency incentive rate) to ensure symmetry.

Interaction with load-related revenue drivers

448 There is a risk that load-related projects that deliver a non-load related benefit (i.e. their scope includes the replacement of assets with a high replacement priority) could be deferred by customers. Under these circumstances, we would be exposed to the additional costs of replacing these assets in order to meet our network risk target.

449 It should be noted that there is also the risk that other unanticipated load-related projects with a non-load related benefit will come forward and reduce the costs of meeting the network risk target.

450 We have considered two options to deal with the risk that changing customer requirements will mean that more or less non-load related work will be required to achieve the network output measure target:

(a) Adjust allowances at the start of RIIO-T2 on an NPV neutral basis such that National Grid is not exposed to this risk;

(b) Do not make any adjustments such that National Grid is fully exposed.

451 We are concerned that option (a) could lead to a perverse incentive to complete like-for-like asset replacement schemes instead of integrating load and non-load related schemes to deliver the most efficient overall solution. For this reason, we propose the treatment described in option (b). We propose that we should be incentivised to seek further opportunities to efficiently co-ordinate load and non-load drivers.

Impact assessment

452 As shown above, an initial analysis of the uncertainty associated with asset degradation highlighted a variation with a standard deviation of £70m. This is based on full exposure to differences between actual and forecast network risk at the end of the RIIO-T1 period.

Design standard changes

What is it? *Uncertainty associated with changes to the standards which specify the design of the transmission network, which cause an uncertainty in the level of transmission reinforcements that we need to complete*
How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £51m*
What are we going to do about it? *Formalisation of the governance arrangements for security standards;*
Risk sharing arrangements?
Mid-period review of outputs
Efficiency incentive rate for over/underspends

Context

453 The requirements of the security standards and Grid Code (and any subsequent European level documents that supersede them) underpin the design of the transmission system, and as such drive a significant proportion of National Grid's capital expenditure. Changes to either the security standards or the Grid Code during the RIIO-T1 period could have significant consequential impacts on our investment plans, either in a positive or negative direction. Potential changes can be separated into minor and fundamental changes. This categorisation will be based on the financial impact that the change will make to the total capital expenditure across the RIIO-T1 period, assessed as part of the impact assessment of any change proposal.

454 Examples of changes classed as 'minor' include:

(a) Minor changes to design criteria of the Main Interconnected Transmission System (MITS), such as a change to the definition of events that should be secured, for example changing the requirement to secure the network for any two outages (i.e N-2) at winter peak to securing for a double circuit fault (i.e N-D)

(b) Reduction in the local connection requirements to accommodate renewable generation

(c) Revised criteria for the main interconnected transmission system to accommodate wind generation

(d) A change to the Grid Code limit on Negative Phase Sequence voltages

(e) A change to the Grid Code limits on harmonics

455 Although these illustrative changes are described as minor, any of the changes identified above would still impact on National Grid's business plan and could cause, at the very least, a reprioritisation of work. Certain changes would still result in the need to change our capex plan, although it may be that

these changes would be covered by other uncertainty mechanisms (for example, the uncertainty mechanism for wider reinforcement works).

456 Examples of changes classed as ‘fundamental’ include:

(a) Specified secured event change from a two circuit outage (N-2) to a single circuit outage (N-1) at Winter Peak

“Some customers have grown to expect N-2 and they would not be happy about accepting a lower standard of service.”

Stakeholder comment, stage two workshop, 31st March, 2011

“Security of supply is an extremely important requirement. There may be circumstances where it may be possible to reduce to N-1 security in operational timescales, if it helps to alleviate a constraint. A decision to do this must however be in well defined circumstances and where the GBSO has assessed the risk to network reliability to be acceptable.”
EON response to May 2011 consultation

(b) Specified secured event change from two circuit outage (n-2) to a three circuit outage (n-3) in major towns and cities to provide improved security to critical areas.

457 Any of these fundamental changes could have a significant impact on the level of capex required during the RIIO-T1 period. It is also worth noting that this list of potential changes is in no way intended to be exhaustive and that a number of changes could have an additive effect on the level of capex required.

Quantification

458 In order to understand the credible range for this uncertainty, we have undertaken a high level assessment of the impact of some of the fundamental changes identified above. Specifically we have considered moving to:

(a) a specified secured event of (n-3) for London; and

(b) a targeted relaxation of the planning criteria secured event for the boundary between England and Scotland

459 Whilst any change to the security standards would apply nationally, we have assumed that the roll-out of fundamental changes would have to be phased and therefore we have limited our considerations to high impact local examples for RIIO-T1.

460 For the upper investment scenario, we have considered the impact of moving to a specified secured event of (n-3) for London. In order to achieve compliance with this requirement, we would need to construct a new route into London. The cost of this new route would be in the region of £200m to £500m, depending on the route chosen. In terms of timing, it is credible to assume that if this route were required then it is unlikely to be completed

before the final year of the RIIO-T1 period. We have assumed the spend profile shown below.

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
New London route: upper scenario	0	0	0	0	£125m	£125m	£125m	£125m

461 For the lower investment scenario, we have considered the impact of moving to a targeted relaxation of the planning criteria secured event for the England to Scotland boundary. If we reduced the planning requirement from n-2 to n-1 it would be possible to delay the (second) eastern HVDC link, deferring capital expenditure of £763m from the RIIO-T1 period. In reality, to achieve this saving it will be necessary to design a special protection scheme to protect the demand and generation from the consequence of a double circuit fault on this boundary, along with additional defence measures to ensure that the consequence of a double circuit fault is not propagated to the wider transmission system. These costs have been ignored for the purposes of this analysis, but in reality the cost of this scheme would need to be subtracted from the benefit.

462 The reduced capex associated with the lower scenario is shown in the table below.

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Deferral of HVDC link: Lower scenario	£4.6m	£151m	£228m	£228m	£151m	0	0	0

463 We have used the upper and lower scenarios to derive a distribution to represent this uncertainty. We have used our baseline plan as the mean and explored a number of different standard deviations. We have chosen a standard deviation of 10% of the range between upper and lower scenario as a reasonable representation.

Management response

Security standard governance

464 The security standard is currently subject to informal, voluntary governance arrangements managed by a review group comprising representatives of the three onshore Transmission Owners.

465 Our role in this process is to contribute to the development and justification of proposals for consultation and ultimately decision by Ofgem. Our proposals are aimed at keeping the standards up to date to reflect the latest technology, characteristics of user requirements and commercial opportunities. Whilst we have a responsibility to ensure that the impact of any change on transmission investment is identified, it would be inappropriate for us to use our role in this process to manage risk.

466 Formal governance arrangements already exist for the Grid Code, and a formalisation of the security standard arrangements is expected prior to commencement of the RIIO-T1 period. This will create greater transparency for the whole industry of any security standard change proposals.

Derogations

467 We could also apply to Ofgem for a derogation against the requirements of the security standards where alternative operational or technical measures are available to maintain customer service and reliability. This has the potential to allow this risk to be managed, provided sufficint alternatives to investment can be identified.

468 This management action is not currently included in our risk modelling, and we would welcome further discussion with Ofgem on its suitability.

Risk sharing arrangements

469 It is possible to manage the impact of minor increases in investment requirements through the risk sharing provided by the efficiency incentive rate and the re-prioritisation of capital schemes. Given the scale of the change in required expenditure with fundamental changes to the security standards or Grid Code (for either an increase or decrease in investment), we have concluded that an uncertainty mechanism will also be required.

470 In reviewing an uncertainty mechanism to deal with potential changes to the security standards or Grid Code, we have concluded that it is not possible to develop and calibrate a volume-driver during the price control review that is capable of dealing with the range of possible outcomes, given the potential scope of changes to these standards and the consequent impact on capital investment plans.

471 In our July 2011 business plan submission, we concluded that a specific re-opener would be the most efficient mechanism since it would not limit the scope of changes that could be covered.

472 In order to achieve a distinction between minor and fundamental changes to the Grid Code or security standards, we proposed a materiality threshold of £500m for the re-opener. This would be based on the total cost in the plan period determined by regulatory impact assessment. We proposed that this would apply symmetrically, i.e. if the impact assessment of any proposed security standard or Grid code change demonstrates either a reduction or increase in capital expenditure across the RIIO-T1 period of greater then £500m, then the re-opener would be triggered.

473 Following Ofgem's initial assessment of our July 2011 business plan submission, we have looked again at all our uncertainty mechanism proposals and sought to simplify them where possible.

474 We have looked again at the risks associated with design standard changes, including the potential for design changes that we are currently aware of, the management response options available and the opportunity afforded by the mid-period review of outputs.

475 Based on this assessment, we have decided to withdraw this uncertainty mechanism and rely on the mid-period review of outputs to adjust for design standard changes as necessary. This reduces the number of uncertainty mechanisms that we are proposing and therefore contributes to the simplification and increased transparency of the Price Control arrangements.

Critical National Infrastructure

What is it? *Uncertainty associated with the Critical National Infrastructure (CNI) sites identified by DECC, the requirements specified by the CPNI and the consequential works required by National Grid*
How big? *The cost risk over the RIIO-T1 period including real price effects has a standard deviation of £32m, which is reduced to £7m by the application of the proposed uncertainty mechanism*
What are we going to do about it? *Proactive engagement with DECC*
Risk sharing arrangements?
Specific re-opener for windows in 2015 and 2018 if materiality threshold is met, otherwise cost logged-up to RIIO-T2
Efficiency incentive rate for differences between design stage value for money audit and over/underspends

Context

476 There is uncertainty around the Critical National Infrastructure (CNI) sites identified by DECC, the requirements specified by the CPNI and the consequential works required by National Grid. These requirements change as frequently as on a quarterly basis.

477 There are currently [redacted] electricity transmission sites designated as CNI. We have developed cost forecasts by averaging the cost across a set of approximately [redacted] sites. The forecast for each site was set using a linear meterage calculation, and this was used to derive a CNI cost of [redacted] of fence length. For particularly large or small sites, the units have been adjusted. This gives overall unit costs of [redacted] for electricity sites.

478 Ofgem have proposed an ex ante allowance for schemes for which details and costs are certain, and value for money audits for all other CNI schemes, with changes to allowances that result from an audit or scope changes being handled with an uncertainty mechanism.

479 There remains some uncertainty over the scope and therefore cost of a majority of our CNI schemes. In developing this business plan submission, we have assumed that these schemes are not ‘certain’ and that they would therefore be subject to a design stage value for money audit.

[redacted]

[redacted]

[redacted]

Quantification

480 We have further developed our calculation of the credible range of this uncertainty since our July 2011 business plan submission. We have achieved this by separately considering the site scope, construction and volume risks.

481 For the site scope risk, we have based our credible range (plus or minus two standard deviations) on a site scope range of [redacted] around our baseline plan. The credible maximum of [redacted] has been estimated by considering the site scope range of a number of sites, and the credible minimum of [redacted]

482 These unit costs do not include an allowance for real price effects, and therefore we have calculated an adjustment by taking the appropriate project groupings from our Gone Green plan. This adjustment is summarised in the table below.

Unit cost allowance	Real price effect adjustment factor
CNI	[redacted]

483 For the construction risk, we have used the distributions described in the relevant section of this annex.

484 For the volume risk, we have calculated our credible maximum (plus two standard deviations) by estimating the number of additional sites that could be added based on our experience. We have assumed that this risk is symmetrical.

485 Since December 2010, [redacted] new sites have been added to the transmission CNI list (gas and electricity), and [redacted] have been removed. This is a net increase of [redacted] sites over a [redacted] period. DECC have indicated that this level of volatility is not expected to continue into the future. Based on this information, we have estimated an increase (or reduction) of [redacted] electricity CNI sites shortly after the start of the RIIO price control in April 2013 to represent a credible range (plus or minus two standard deviations). We have profiled this volume risk such that it is consistent with our baseline plan as shown in the table below.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

486 We have used probabilistic distributions to describe the site scope, construction and volume risks described above, and the resultant capex uncertainty is shown below.

487 We completed a Monte Carlo analysis to assess the resultant level of cost uncertainty. The resultant distribution has a standard deviation of £31m for the total spend over the RIIO-T1 period. When real price effects are added, the standard deviation increases to £32m. This is higher than the standard deviation of £19m reported in our July 2011 business plan submission, with the increase being primarily driven by the profiling of the volume uncertainty.

Management response

488 The main management response to this uncertainty is pro-active engagement with DECC on the priority assigned to each of the sites to ensure that the overall programme is deliverable.

489 As a result of this ongoing engagement, DECC have agreed to provide a letter of comfort to confirm that the need case for additional schemes will be robust such that the costs we incur ahead of a re-opener window will be justified in need case terms.

490 The result of this management action has already been factored into the credible range described above.

Risk sharing arrangements

491 We propose to use the uncertainty mechanism described in the Ofgem RIIO strategy documents.

Mechanism

492 The uncertainty mechanism would operate such that CNI cost changes that are consistent with the design stage value for money audit would be logged-up during the RIIO-T1 period (including an allowance for efficient financing costs). These would be considered during the preset re-opener windows during RIIO-T1.

Re-opener windows

493 The windows provide the opportunity for National Grid to request an increase to allowances during the RIIO-T1 period. If Ofgem agree to a request then National Grid's allowances will be increased during the RIIO-T1 period, instead of the costs being logged-up until the end of the control period (and therefore funding would be in the RIIO-T2 period).

494 In order to ensure that the use of re-openers is limited to significant changes, requests will be qualified against a materiality threshold. The windows will be in July 2015 and July 2018, leading to any adjustments being made in April 2016 and April 2019.

Materiality threshold

495 Ofgem propose a materiality threshold of 1% of annual revenue, where the calculation of annual revenue includes the application of the MOD term (which is derived from by the annual iteration of the Financial Model).

496 In order to satisfy the materiality threshold, the forecast cost increase over the RIIO-T1 period must be greater than 1% of annual revenue following the application of the efficiency incentive rate. This means that for an efficiency incentive rate of 50%, the cost increase would need to be 2% of annual revenue to breach the materiality threshold (or approximately £40m).

497 Basing the materiality threshold on annual revenue leads to a very high threshold which bears no relation to the category of cost being considered.

498 To address these issues, we propose a materiality threshold of 5% of the total forecast cost of Critical National Infrastructure cost for the RIIO-T1 period.

Impact assessment

499 As described above, the uncertainty associated with critical national infrastructure costs has a standard deviation of £31m. This represents the risk, for both consumers and ourselves, associated with an ex ante allowance agreed at the price control review to cover the cost of local the cost of meeting planning requirements.

500 The uncertainty mechanism described above would ensure that we were funded for costs consistent with the design stage value for money audit, and exposed to differences between our actual spend and this figure.

501 In order to show the impact of this mechanism, we have modelled a volume-driver to adjust allowances as volume and site scope requirements change. We repeated the Monte Carlo analysis with this mechanism and the results are presented in the table below.

Uncertainty mechanism	Standard deviation (£m)
No mechanism	£31m
Re-opener windows for material changes, otherwise logging-up to RIIO-T2	£7m

Summary

502 National Grid's uncertainty mechanism proposals for Critical National Infrastructure costs are summarised in the table below.

Trigger	Mechanism	Re-opener windows	Materiality threshold
Design stage value for money audit	Re-opener windows Utilised if materiality threshold is met Otherwise logged-up to RIIO-T2	2015 2018	5% of RIIO-T1 CNI cost forecast

Climate Change: Flood and Erosion Protection

What is it? *Uncertainty associated with requirements for contributions towards sea and river defences and other flood mitigation measures*
How big? *The cost risk over the RIIO-T1 period has a standard deviation of £2m*
What are we going to do about it? *Proactive engagement with the Environment Agency*
Risk sharing arrangements?
Specific re-opener for windows in 2015 and 2018 if materiality threshold is met, otherwise cost logged-up to RIIO-T2
Efficiency incentive rate

Context

503 As specified in Electricity Networks Associated (ENA) Engineering Technical Report 138 (Resilience to Flooding of Grid and Primary Substations), National Grid's baseline plan includes works required at transmission substations to achieve a target resilience of a 1:1000 year flood event by 2022. We are prioritising investment such that the flood risk mitigation works at sites at the highest risk (i.e. 1:100 year flood risk) are completed first, unless investment is delayed to co-ordinate with other major capital schemes.

504 In addition to these costs, we may also be exposed to contributions towards sea and river defences and other flood mitigation measures. Recent indications are that the Environment Agency and other flood management agencies will be required to seek contributions from beneficiaries towards the research, construction and maintenance of new and existing sea and flood defences.

505 National Grid have analysed the potential exposure to these costs in the future.

Quantification

506 In order to estimate National Grid's potential contribution towards the Environment Agency's (EA) flood defence costs, the recent Steart Peninsula contribution request of [redacted] has been assumed to be typical.

507 A similar request for funding has been made to our unlicensed interconnectors business, [redacted]

508 Whilst we do not know at present the full extent of the impact of changes to the EA's policy regarding flood mitigation, we have approximately 1900 overhead line towers within a distance of 250m from water (coast, river or flood plain). In addition, we know from recently issued EA documentation that 44 sites and associated overhead line routes are at risk from reservoir inundation flooding. We are currently seeking more information on the risks

to our sites. Costs to mitigate reservoir inundation are not currently included within our business plan.

509 Based on these examples, we have estimated a credible maximum of £2.58m per annum. This is based on receiving a contribution request of the magnitude of Steart Peninsula example every year, with an additional 30% added for contributions to maintenance costs. It should be noted that this would be an opex cost.

510 This represents initial analysis, and significant changes to the EA's policy could lead to a much higher credible maximum exposure.

511 We have assumed that this credible maximum represents three standard deviations, and therefore assumed that the standard deviation is £858k. We have modelled a distribution with this standard deviation in each of the years of the RIIO-T1 period.

512 Given that this work will be designed and delivered by the EA, we do not expect this to have any other impacts on the business plan.

Management response

513 We have responded to consultations in February of 2011 from the EA and Defra outlining our position and concerns into the future funding and working methodologies of flood river and coastal erosion schemes. National Grid has stipulated that Ofgem involvement is critical to this process.

514 National Grid will always investigate whether there is an alternative solution that could be completed at a lower cost to protect transmission assets and thus avoid the need for the EA works. Based on our experience, we consider this to be unlikely, however, and have therefore assumed that contribution to EA works will be the efficient solution.

Risk sharing arrangements

515 There is uncertainty surrounding the potential need for increased contributions to sea and river defence and mitigation projects in the future.

516 We will not be able to control these costs, and flood protection of substations will protect supplies to consumers during extreme weather events, therefore we propose the use of a specific re-opener with a materiality threshold.

517 As with the uncertainty mechanism proposed for Critical National Infrastructure projects, the mechanism would operate such that cost changes would be logged-up during the RIIO-T1 period (including an allowance for efficient financing costs). These would be considered during the preset re-opener windows during RIIO-T1. The windows provide the opportunity for National Grid to request an increase to allowances during the RIIO-T1 period. If Ofgem agree to a request then National Grid's allowances will be increased during the RIIO-T1 period, instead of the costs being logged-up until the end of the control period (and therefore funding would be in the RIIO-T2 period).

518 We propose the same re-opener windows as for the CNI uncertainty mechanism. We do not have a forecast of these costs which we can use as

the basis of a materiality threshold and therefore, based on our current knowledge of the likely costs, we propose a value of £10m.

519 Whilst we have assessed the materiality of this risk to be relatively low, the use of the same uncertainty mechanism as for Critical National Infrastructure is very simple and does not add additional complexity to the Price Control arrangements.

Summary

520 National Grid's uncertainty mechanism proposals for flood and erosion protection costs are summarised in the table below.

Trigger	Mechanism	Re-opener windows	Materiality threshold
Request for contributions from the Environment Agency	Re-opener windows Utilised if materiality threshold is met Otherwise logged-up to RIIO-T2	2015 2018	£10m

GB and EU Market facilitation

What is it? *Uncertainty associated with the opex and System Operator capex requirements to facilitate GB and EU market change*
How big? *The cost risk over the RIIO-T1 period has a standard deviation of £9m, which is reduced to £4m by the application of the proposed uncertainty mechanism*
What are we going to do about it? *Active engagement in relevant forums to clearly communicate the cost impact of decisions*
Risk sharing arrangements?
Specific re-opener with a materiality threshold of £1m
Efficiency incentive rate

Context

521 Changes to the GB and EU electricity markets often result in process changes which can impact on Transmission Owner or System Operator costs. If the changes require significant analysis or development to IT systems, they can incur material costs.

522 As we did in our July 2011 plan, we have included approximately £1m per annum of underlying costs in our SO IT capex March 2012 plan. This is a minimal forecast of our expenditure for the RIIO-T1 period, based on historical averages and does not take account of significant developments that will, or may, occur over the RIIO-T1 period such as Electricity Market Reform (EMR).

523 Also, we have not included any provision in our Transmission Owner or System Operator opex plans for significant analysis required as the result of a process change.

524 There is a risk that reviews currently underway, such as EMR, or currently unanticipated developments incur significant costs within the RIIO-T1 period as a result of required process or system changes. Projects currently underway such as EMR and the implementation of Network Codes as part of the Third Package[25] are not sufficiently developed for us to understand any implementation costs associated with them. We are therefore proposing an uncertainty mechanism that provides for a specific re-opener in the event that material costs are incurred as a result of GB or EU policy changes. We propose that the materiality threshold that would trigger this mechanism is +/- £1m which is proportionate to our baseline plan and comparable to the equivalent mechanism from the TPCR4 arrangements.

525 Our proposed mechanism aligns with the Third Package's acknowledgement that Transmission System Operators will shoulder the majority of costs associated with the development of pan-European energy markets and its direction to the national regulators to allow for increased expenditure in this area.

[25] The term 'Third Package' refers to a package of EU legislation on European electricity and gas markets that entered into force on the 3rd September 2009. The purpose of the Third Package is to further liberalise European energy markets. Network Codes framework guidelines are currently being developed which will set commercial rules and obligations governing access to and use of the European energy networks.

Quantification

526 There is a risk that GB and EU developments will diverge significantly from our current forecasts, or that new requirements will materialise over the RIIO-T1 period which are currently not anticipated.

527 There are a number of examples of current projects that could have a significant impact on our opex and SO capex costs, including Electricity Market Reform.

528 Based on our knowledge of these examples, we estimate that the annual risk will have a standard deviation of £3m, and we have modelled this with a log-normal distribution.

529 This gives an uncertainty for the full RIIO-T1 period with a standard deviation of £10m.

Management response

530 The main management response to this uncertainty is to continue our proactive involvement in EU and GB developments. This includes the roles that we already hold in ENTSO-E and the Connection and Use of System Code (CUSC) panel.

531 This provides the opportunity to influence the scope of potential developments, and ensure that network costs are reflected in any assessment of impact.

Risk sharing arrangements

532 There is uncertainty surrounding changes to Transmission Owner or System Operator costs that may result from changes to the GB and EU electricity markets resulting in process changes.

533 Whilst we can manage the cost of delivering process changes or the supporting analysis, the extent and timing of such change is ultimately beyond our control. We therefore propose that an uncertainty mechanism is introduced to deal with this uncertainty.

Mechanism

534 In reviewing an uncertainty mechanism to deal with this uncertainty, we have concluded that it is not possible to develop and calibrate a volume-driver during the price control review that is capable of dealing with the range of possible outcomes given the potential scope of changes.

535 We propose that System Operator or Transmission Owner cost increases required to facilitate GB or EU markets would be logged-up during the RIIO-T1 period (including an allowance for efficient financing costs). These would be considered during the preset re-opener windows during RIIO-T1.

Re-openers

536 The windows provide the opportunity for National Grid to request an increase to allowances during the RIIO-T1 period. If Ofgem agree to a request then National Grid's allowances will be increased during the RIIO-T1 period,

instead of the costs being logged-up until the end of the control period (and therefore funding would be in the RIIO-T2 period).

537 In order to ensure that the use of re-openers is limited to significant changes, requests will be qualified against a materiality threshold.

Materiality threshold

538 The materiality threshold will be £1m, which is proportionate to our baseline plan and comparable to the equivalent mechanism from the TPCR4 arrangements.

539 In order to satisfy the materiality threshold, the forecast cost increase over the RIIO-T1 period must be greater than £1m following the application of the efficiency incentive rate. This means that for an efficiency incentive rate of 50%, the cost increase would need to be £2m of annual revenue to breach the materiality threshold.

Impact assessment

540 As described above, the uncertainty associated with GB and EU market facilitation costs has a standard deviation of £9m.

541 The uncertainty mechanism described above would ensure that we were funded for costs greater than the materiality threshold of £1m.

542 In order to show the impact of this mechanism, we have modelled the re-opener with the associated materiality threshold. We repeated the Monte Carlo analysis with this mechanism and the results are presented in the table below.

Uncertainty mechanism	Standard deviation (£m)
No mechanism	£9m
Re-opener windows for material changes	£4m

Summary

543 National Grid's uncertainty mechanism proposals for GB and EU market facilitation are summarised in the table below.

Trigger	Mechanism	Re-opener windows	Materiality threshold
Opex or SO capex costs driven by EU or GB market change	Re-opener for costs above the materiality threshold	All years	£1m

Other uncertainties

Overview

544 There are a number of other uncertainties that National Grid will face during the RIIO-T1 period. We have not included a detailed assessment of these uncertainties in this annex but they are described briefly below for completeness.

Changes to safety and environmental standards

545 We are not aware of ongoing changes to safety and environmental standards that would impact us in the same way as changes to the design standards described above.

546 If fundamental changes to standards were to be introduced (for example, the introduction of revised limits for electro-magnetic field strengths) it is possible that the timing of such changes would mean that they would not have a major impact on our investment or costs over the RIIO-T1 period.

547 If the changes were to be implemented during the RIIO-T1 period, we would seek to address this issue either with a specific re-opener or at the mid-period review of outputs.

548 We would expect a specific re-opener for this uncertainty to be triggered by the result of an impact assessment and have a significant materiality threshold (for example, £500m).

Severe storms, vandalism and terrorism

549 There are a number of low probability, high impact events that could have a significant impact on our business during the RIIO-T1 period, including severe storms, vandalism and terrorism.

550 These risks are likely to impact on our primary reliability output of Energy Not Supplied. The Energy Not Supplied incentive scheme is to be applied via the efficiency incentive rate, and includes a cap on the penalty for unreliability.

Re-opener provision

551 In order to deal with uncertainties that are more difficult to quantify, we propose a specific re-opener facility with a suitably high materiality threshold, for example, £500m within the RIIO-T1 period.

Business Plan level management actions

552 In addition to the specific management actions described above, there are a number of actions that can be taken at an overall plan level. These actions are described in further detail below.

Defer capital expenditure

553 The issues surrounding the deferral of load and non-load related capex in response to adverse events is explored in the adaptability of our plans section of the 'How we will deliver' annex.

554 Our Gone Green baseline plan already includes a phasing adjustment applied to non-load related expenditure to avoid co-incident peaks between load-related and non-load related capex plans. We have constructed this phasing adjustment with reference to the forecast of our secondary deliverables for network output measures. These forecasts show that whilst we are managing increased risks through the middle of the RIIO-T1 period, by the end of the period, the same network risk profile is achieved.

555 The management actions described in the network renewal section above, including enhanced condition assessment and condition monitoring, could also be utilised to manage the risk associated with keeping assets in service for longer, although this would have an adverse impact on unplanned maintenance costs and average circuit unreliability.

Deferring non-load related expenditure

556 As described above, the option to defer non-load related expenditure has in effect already been taken in developing an efficient overall capital plan to deliver the peak in load-related expenditure associated with the Gone Green scenario.

557 Having explored the secondary deliverable consequences of this deferral in detail, we do not believe that there is any further scope for the deferral of non-load related expenditure from the first half of the RIIO-T1 period.

558 The scope to defer non-load related expenditure from the second half of the RIIO-T1 period will depend on the evolution of network risk. It is possible that a deferral with a similar magnitude to the phasing adjustment would be possible in the second half of the RIIO-T1 period with a temporary increase in network risk only.

559 Given the uncertainty regarding the availability of this option, we have modelled the impact of the deferral of £100m from each of the last four years of the RIIO-T1 period. This allows the sensitivity to this potential management action to be evaluated.

560 The definition of network output measures as a secondary deliverable under the RIIO price control has the potential to inhibit the option to defer non-load related expenditure by applying financial penalties for not achieving a particular profile of network risk at the end of the RIIO-T1 price control.

561 The deferral of non-load related expenditure is a valid and valuable management response to unexpected increases in capital expenditure in circumstances in which network risk can be managed. Since the definition of the incentive mechanism around the secondary deliverable has not yet been fully defined, we will work with Ofgem to ensure that the risks and benefits associated with this option are fully explored.

Advancing non-load related works

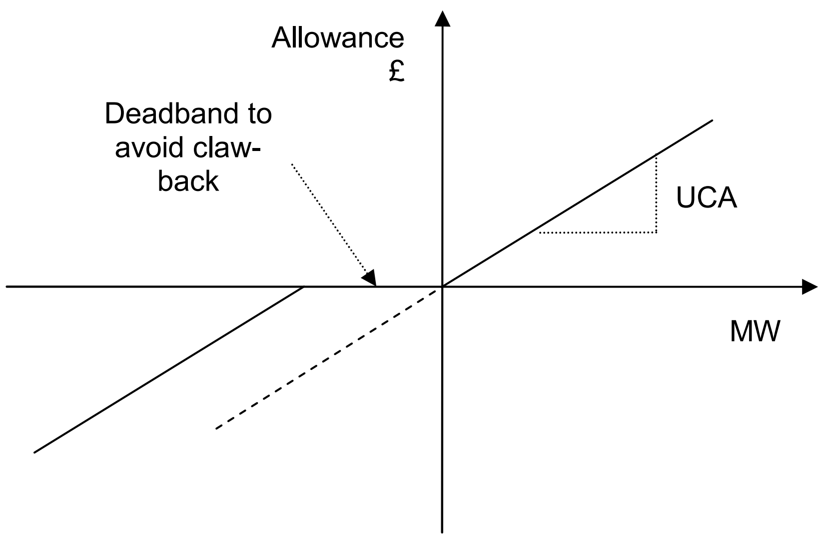
562 If the load-related investment in the Gone Green scenario was to be delayed, we would seek to undo the phasing adjustment and deliver our non-load related expenditure in line with our unconstrained non-load related business plan.

563 This will avoid the temporary increase in network risk and associated costs described above and may also keep the option to defer non-load related expenditure so that a delayed Gone Green style load-related peak could be delivered later in the RIIO-T1 period.

564 If the uncertainty mechanisms described in the generation and demand section above for local generation connection works and wider reinforcement works act to claw-back the allowances associated with these works without replacing these allowances, we will be exposed to the time value of money costs associated with the non-load related advancement.

565 Since the advancement of non-load related works would be an efficient response to a delay in the load-related expenditure associated with the Gone Green scenario, we propose that the load-related uncertainty mechanisms be developed to include a dead-band such that we are held whole.

566 This mechanism has not been fully developed at this stage, but its effect on the load-related revenue drivers is illustrated below for clarity.



Load-related capital expenditure

567 When considering whether load-related work can be deferred, we will not consider delaying customer connections. For wider works, we will consider the output consequences of a delay. These output consequences are likely to be constraints and Energy Not Supplied, and therefore an economic cost of

delay can be calculated for consideration. The availability of these options will depend on the economic costs of the options available, and we would look to defer the works with the least constraint cost impact, which will depend on the development of new generation and generation closures.

568 We will also consider the development of new SMART techniques as an alternative to transmission investment. Since many of these techniques rely on the provision of new services from customers, this will also involve the associated development of commercial arrangements and specialist service contracts with customers.

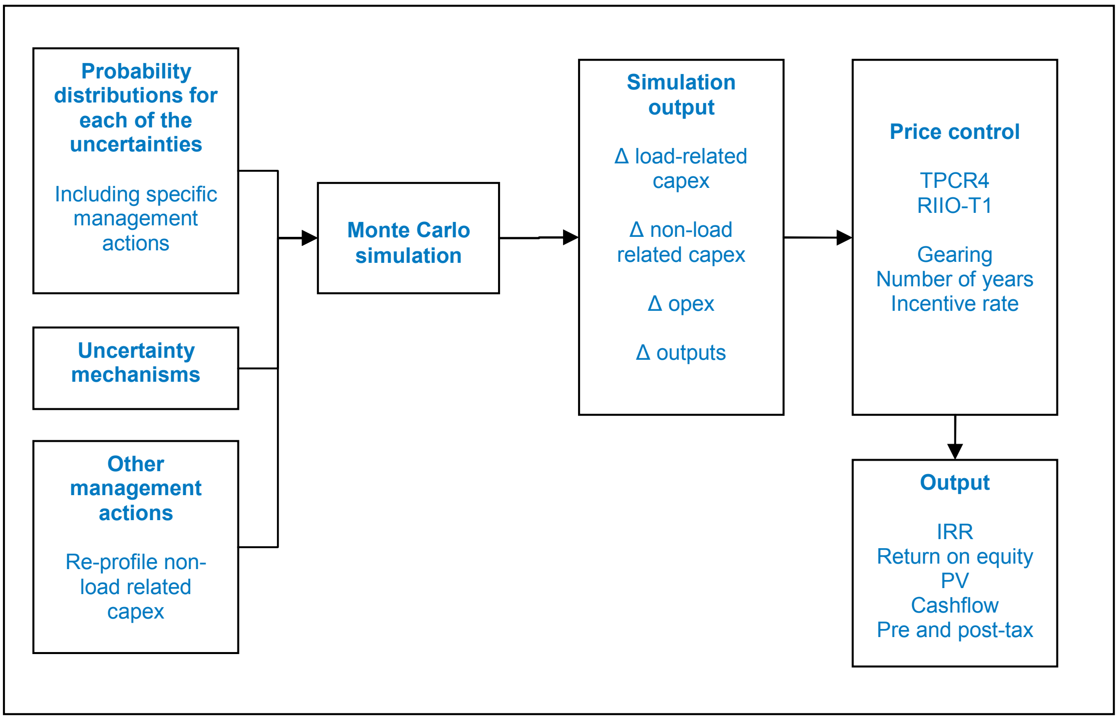
Risk Modelling

Overview

569 We have established a common framework for modelling the impact on returns of the risks that we accept. The aim of this work is to better understand the relationship between risks, management responses, uncertainty mechanisms and our financial performance.

570 Since our July 2011 plan, we have sought stakeholder views on our uncertainty mechanisms and our approach to risk modelling. This has included the development and publication of a simplified version of our risk model for stakeholders, one-to-one meetings, a detailed session at our November 2011 workshop and discussion of the potential charging volatility impact at the Transmission Charging Methodologies Forum.

571 A high-level overview of the risk model is shown in the diagram below:



572 A Monte Carlo simulation is performed with values for each of the uncertainties sampled from the credible range distributions described in this document.

573 These uncertainty ranges already include the effect of specific management actions, but plan level management responses such as the re-profiling of non-load related capital expenditure have been modelled separately. The uncertainty mechanisms described in this document have also been modelled, although in some cases it has been necessary to apply some simplification.

574 The simulation outputs are described as changes to load-related capex, non-load related capex, opex and outputs, where outputs cover the effect of the uncertainty mechanisms that have been modelled.

575 These outputs are then applied to the price control in order to understand the impact on internal rate of return, return on regulatory equity, present value and cashflow, both pre and post-tax. The main price control parameters, such as gearing, length of control and incentive rate are all defined by the user.

576 This allows the impact of the uncertainties that we face on both the TPCR4 and RIIO-T1 price controls to be compared. A comparison of the standard deviation of returns given by each of the price controls also allows the Sharpe ratio to be applied to give an indication of any necessary change in the allowed rate of return.[26] This analysis is presented in the 'Finance' annex.

Detailed description

577 Distributions for each of the uncertainties have been specified for each year of the price control.

578 In some cases, simple distributions of opex, load-related or non-load related capex have been modelled. Other more complex uncertainties (for example generation connections) have been modelled as a volume uncertainty multiplied by a unit cost uncertainty..

579 Correlations between years are not modelled. In most cases, the increasing uncertainty with time is reflected with increasing standard deviations. In some instances (e.g. flooding), the standard deviation is fixed across all years and therefore the increasing risk over time is modelled as a 'random walk', i.e. the outcome from year 1 is taken as the mean for the year 2 distribution, and so on.

Correlations

580 Whilst it has not been possible to conduct sufficient analysis to define correlations between different uncertainties, we have assumed a number of correlations based on our experience of the works required, and these are shown in the table below.

581 In order to understand the sensitivity of our risk modelling results to these correlations, we have also performed analysis with all correlation coefficients set to 0 (i.e. all uncertainties are assumed to be independent).

582 This demonstrated that the correlations did not have a significant impact on the standard deviation. This is because, unlike our July 2011 analysis, we have not modelled real price effects as a separate risk which is correlated with all others, but have instead modelled it across the other uncertainties more explicitly.

[26] The Sharpe ratio is a measure of the risk premium per unit risk in an investment asset. $S = \frac{R - R_f}{\sigma}$, where R = return; R_f = risk free rate and σ = standard deviation of returns

	Under grounding	Design standards	Wider works	Gen conn	Net renewal	CNI
Under grounding	1					
Design standards	0	1				
Wider works	30%	30%	1			
Gen conn	12%	0%	30%	1		
Net renewal	0%	12%	-12%	0%	1	
CNI	0%	0%	0%	0%	0%	1

583 As mentioned above, real price effects have already been split across the other uncertainties and therefore are not shown on the correlation matrix.

584 The correlation between design standards and wider works models the direct impact that a fundamental design standard change would have on the level of wider works required. A weaker correlation between design standards and network renewal models the impact that a fundamental design standard change would have on asset criticality, a key determinant of replacement priority.

585 Wider works and network renewal are weakly counter-correlated since deliverability issues are likely to mean that management actions are employed to ensure that peaks of activity in load-related and non-load related activity are not co-incident.

586 The correlation between both wider works and generation connections and undergrounding reflects the expectation that the new overhead line routes required during the RIIO-T1 period are associated with these two activities.

587 The correlation between generation connections and wider works reflects the expectation that the majority of wider works during the RIIO-T1 period will be required to accommodate the additional boundary flows caused by the connection of new generation.

588 The simulation results for each of the uncertainty distributions are summed such that the impact on load-related capex, non-load related capex and opex is calculated.

Management responses

589 The business plan level management responses have been modelled explicitly. The actions which involve the re-profiling of load-related and non-load related expenditure have been modelled as a capped and collared

range. When activated, these actions are automatically taken in each of the simulation results to minimise the impact of other uncertainties on returns.

Uncertainty mechanisms

590 The following types of uncertainty mechanism have been modelled:

(a) Specific re-opener with a materiality threshold – If the change in expenditure over the RIIO-T1 period is above the materiality threshold, then the uncertainty mechanism income matches the exposure. The sensitivity of the distribution of returns to the materiality threshold can be studied

(b) Volume driver – Changes in the volume of particular outputs are multiplied by unit cost allowances to calculate adjustments to allowances which are applied automatically during the price control period. The sensitivity of the distribution of returns to different combinations of unit cost allowance can be studied.

(c) Indexation with cap/collar and price rise lag – If the value of the index is outside the cap or collar for two years or more, then an allowance is provided to reset the baseline. The cap and collar are also aligned with any change in baseline. The sensitivity of the distribution of returns to the cap and collar levels and the time-lag can be studied.

591 The impact of the uncertainties, management actions and uncertainty mechanisms on both the TPCR4 and RIIO-T1 price controls are modelled, with each simulation output applied to both controls.

Price control modelling

592 The price control modelling includes base parameters, including regulatory gearing, price control length, base depreciation life and incentive rate, and simple tax assumptions that are applied to both price controls. There are also some base parameters that are specific to the TPCR4 (cost of debt, vanilla WACC, licence condition D9 WACC and depreciation) and RIIO-T1 (totex capitalisation rate) price controls.

593 A base scenario is then developed with a variable price control length. The cost of equity, cost of debt, weighted average cost of capital, operational expenditure and capital expenditure is presented for each year. A base scenario regulatory asset value calculation is performed for the TPCR4 price control, based on capital expenditure and depreciation, and the RIIO-T1 price control, based on capital and operational expenditure and the totex capitalisation rate.

594 Cashflows are then calculated for TPCR4 and RIIO-T1 separately, with the uncertainties, management actions and uncertainty mechanisms applied.

595 The TPCR4 cashflow calculation includes the adjustment to the RAV to be applied at the end of the price control period for efficiently incurred overspend, and the adjustments associated with licence condition D9, which applies a flat incentive rate to any over or under spend of capital expenditure based on a pre-tax weighted average cost of capital. This gives the pre-tax cash-flows and the internal rate of return, return on regulatory equity and present value are calculated. An approximate tax calculation is then applied to derive post-

tax cash-flows, and again the internal rate of return, return on regulatory equity and present value are calculated.

596 The RIIO cashflow calculation is based on the illustrative calculation provided by Ofgem. The allocation of any new allowances to customers based on the efficiency incentive rate was missing from the illustration and has been added for completeness.

597 The allocation of new allowance and overspend to customers is calculated based on the efficiency incentive rate. This is multiplied by the totex capitalisation rate and used to calculate the adjustment to the RAV to be applied at the end of the price control period. Fast and slow money adjustments are then calculated and applied two years later. As with the TPCR4 calculation, pre and post-tax cashflows, internal rate of return, return on regulatory equity and present value are derived.

Analysis

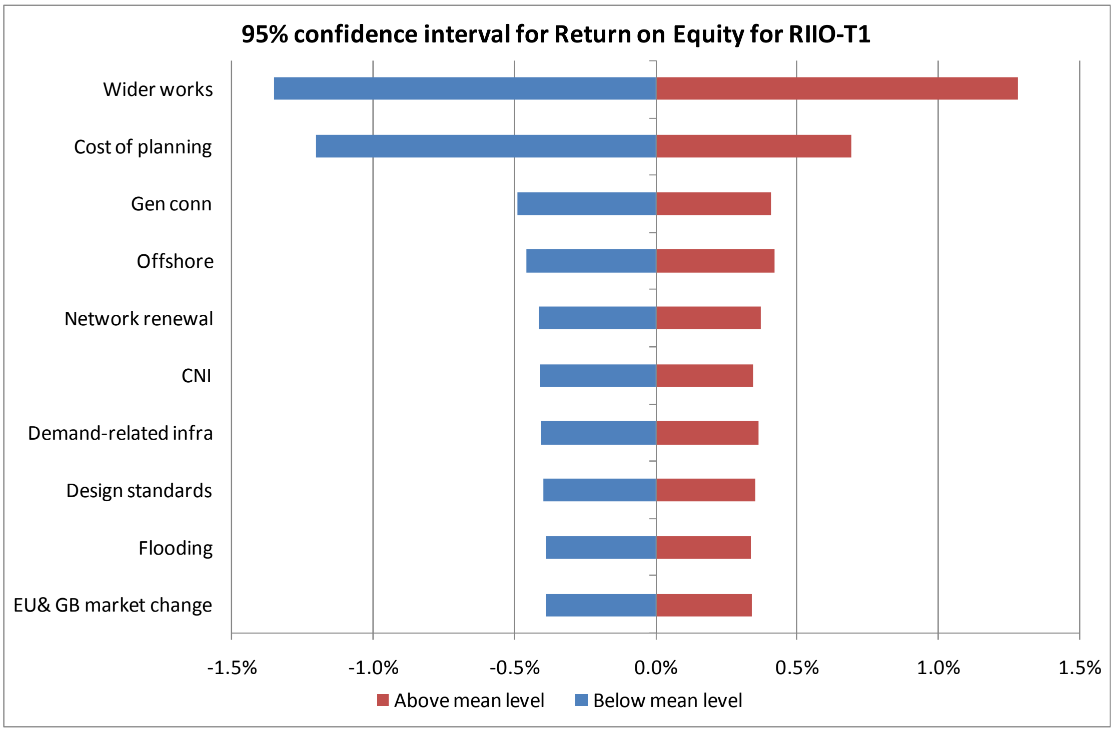
598 We have used the risk model to evaluate the impact of the uncertainties that we face, together with the impact of our proposed management actions and the uncertainty mechanisms proposed by Ofgem and ourselves.

599 For this analysis, a common set of base assumptions for the RIIO-T1 price control have been applied to ensure consistency. These assumptions are shown in the table below.

Base assumptions	
Regulatory gearing	55%
Control length	8 years
Base depreciation length	45 years
Incentive rate	50%
RIIO capitalization rate	87%
Cost of debt	3.2%
Cost of equity	7.5%

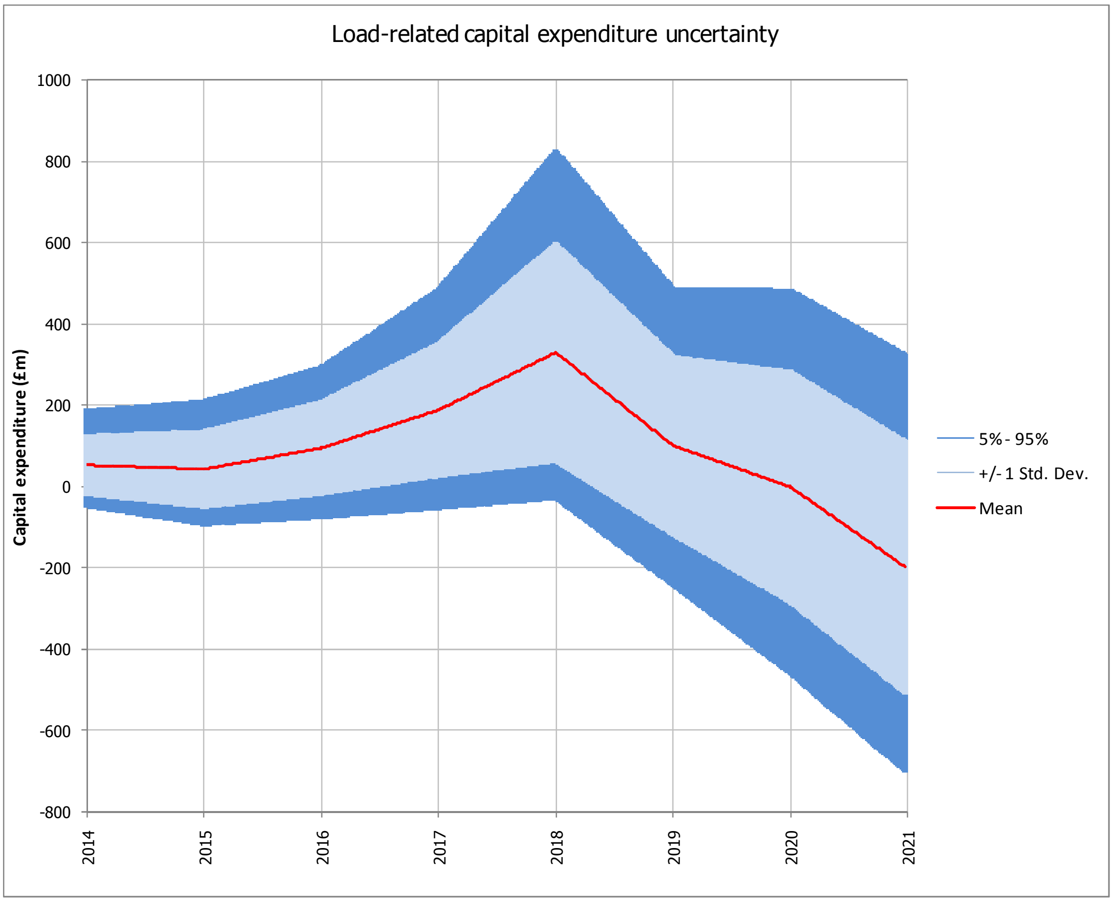
Uncertainties

600 The impact that each of these uncertainties has on the spread of our pre-tax return on regulatory equity for the RIIO-T1 price control is shown in the graph below.



601 The table shows that the most material volume uncertainties are wider works, and the cost of planning requirements. All plots include the impact Real Price Effects, and particularly the copper price on the baseline capital expenditure that is not subject to uncertainty mechanisms.

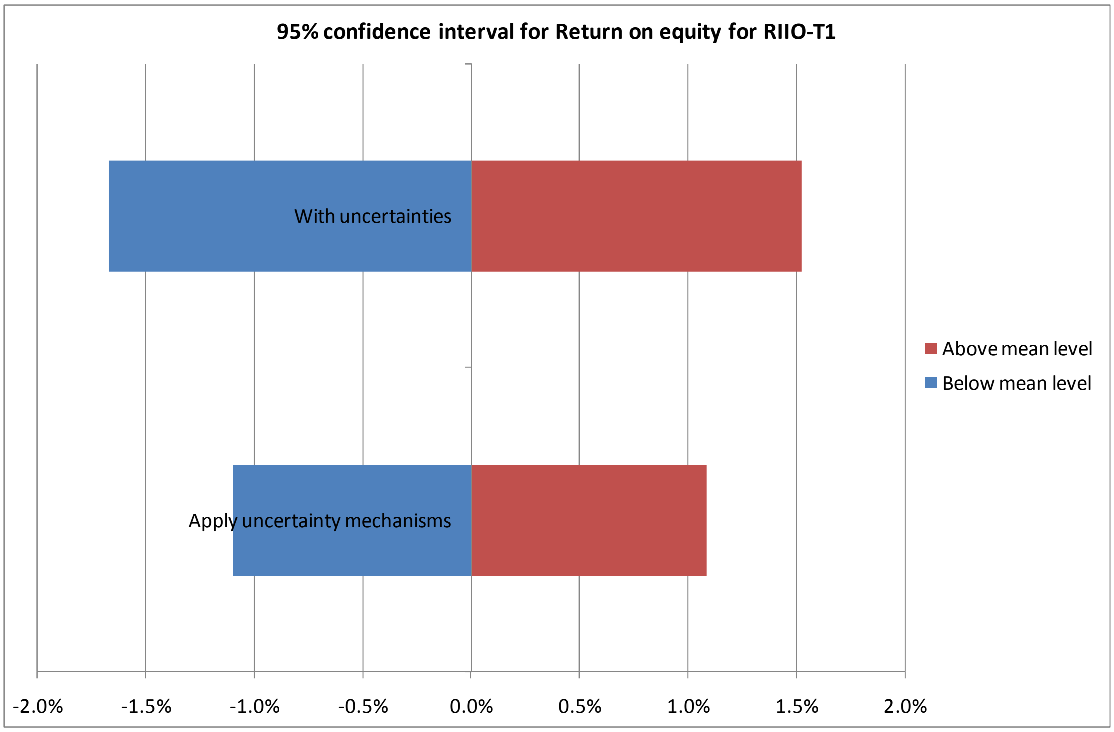
602 We have also used the risk model to assess the combined impact of all of these uncertainties. To illustrate this impact, the resultant load-related capital expenditure uncertainty is shown in the graph below. This is the most material uncertainty, followed by non-load related capital expenditure and operational expenditure.



Uncertainty mechanisms

603 We have also used the model to assess the impact of the suite of uncertainty mechanisms proposed by Ofgem and ourselves.

604 When our proposed uncertainty mechanisms are applied to the RIIO-T1 price control, the distribution of pre-tax return on equity is significantly reduced as shown in the graph below.



605 The graph shows the reduction in the range of returns following the application of the proposed uncertainty mechanisms. This reduction is achieved above and below the mean, demonstrating the reduced exposure to risk for both consumers and ourselves delivered by the proposals.

606 The implication of these results on our allowed cost of capital is covered in the 'Finance' annex to this submission.

Management response

607 As described above, the effect of specific management actions has already been taken into account in deriving the range of each uncertainty.

608 In addition to these specific responses, we have investigated the application of plan level management actions, including the deferral of non-load related expenditure. Although network risk has been defined as a secondary deliverable under the RIIO-T1 price control, it may be more efficient to defer asset replacement work in response to other external factors (for example, commodity prices).

609 As an example, the availability of an option to defer up to £100m of non-load related capex from each of the last four years of the price control did not have a significant impact on the distribution of pre-tax returns when compared to the impact of uncertainty mechanisms.

Conclusions

610 We have developed a risk model to better understand the relationship between risks, management responses, uncertainty mechanisms and our financial performance.

611 The model has been used to compare the impact of the uncertainties that we face on both the TPCR4 and RIIO-T1 price controls. A comparison of the

standard deviation of returns given by each of the price controls has allowed the Sharpe ratio to be applied to give an indication of any necessary change in the allowed rate of return and this analysis is presented in the 'Finance' annex.

612 The model has also been used to assess the impact of our management actions and uncertainty mechanism proposals. It has allowed any additional complexity associated with uncertainty mechanisms to be compared with the associated impact on risk, and for sensitivity analysis to be performed around the parameters associated with the uncertainty mechanisms.

613 The analysis presented in this annex demonstrates the impact that our uncertainty mechanism proposals have on our returns.

Appendix A: Uncertainty mechanism summary

Volume-drivers

	Baseline		Volume-driver	
	Allowance	**Output**	**Volume**	**Unit cost allowance**
	Local generation connections			
Substation costs	Forecast substation cost for gone green generation connections by year (£m)	Gone green generation connections by year (kW)	Actual annual connection volume (kW) – gone green generation connections (kW)	£23/kW (£24.7/kW with RPE)
Within-zone costs	Forecast within-zone cost for gone green generation connections by zone by year (£m)	Gone green generation connections by zone by year (kW)	Actual annual connection volume by zone (kW) – gone green generation connections by zone (kW)	Zonal £2.7/kW to £36.8/kW (£2.8/kW to £38.7/kW with RPE)
Overhead lines and cables	Forecast overhead line and cable cost for gone green generation connections by year (£m)	Gone green new overhead line and cable circuit lengths (km)	Actual annual new overhead line (and/or cable) length (km) – gone green new overhead line length (km)	**Overhead lines** £1.2m/cct km (£1.27m/ cct km with RPE) **Cables** Additional £10.91m/km to £21.2m/km (£12.1m/km to £23.6m/km with RPE)
	Demand-related infrastructure			
Substation costs	Forecast demand-related infrastructure cost by year (£m)	Gone green additional SGT volume by year (#)	Actual annual additional SGT volume (#) – gone green additional SGT volume (#)	£4.6m/ SGT (£4.96m/ SGT with RPE)
Overhead lines and cables	Forecast overhead line and cable cost for gone green demand connections by year (£m)	Gone green new overhead line and cable circuit lengths (km)	Actual annual new overhead line (and/or cable) length (km)	**Overhead lines** £1.2m/cct km (£1.27m/ cct km with RPE) **Cables** Additional £10.91m/km to £21.2m/km (£12.1m/km to £23.6m/km with RPE)

Boundary costs	Wider works			
	Forecast wider transmission reinforcement costs for gone green scenario by year (£m)	Gone green wider boundary capabilities by year (kW)	Gone green forecast required boundary transfer from year t-3 for year t (kW) - gone green forecast required boundary transfer at the price control for year t (kW)	Boundary specific; Above gone green; Below gone green
Under grounding costs	Costs of meeting planning requirements			
	Forecast based on 10% under grounding of new transmission routes across a mix of ratings (£m)	NA	Length of new underground cable (km) in particular year multiplied by relevant unit cost allowance (£/km) – forecast by year (£m)	Matrix of additional costs for under grounding from 31 January, 2012 IET report (+11.5% with RPE)
Cost of other mitigations	Forecast based on Gone Green generation background	Based on Gone Green background	Volume of distribution assets to be installed – forecast by year	Matrix of unit cost allowances for distribution works

Specific re-openers

Trigger	Mechanism	Re-opener windows	Materiality threshold
Critical National Infrastructure			
Design stage value for money audit	Re-opener windows Utilised if materiality threshold is met Otherwise logged-up to RIIO-T2	2015 2018	5% of RIIO-T1 CNI cost forecast
Flood and erosion protection			
Request for contributions from the Environment Agency	Re-opener windows Utilised if materiality threshold is met Otherwise logged-up to RIIO-T2	2015 2018	£10m
GB and EU market facilitation			
Opex or SO capex costs driven by EU or GB market change	Re-opener for costs above the materiality threshold	All years	£1m

Wider works qualification criteria

Project cost	<£150m	£150m to £500m	>£500m
Simplified volume-driver	All	High [>70% of boundary capability increase] user commitment; or Triggered by all scenarios before 2023	None

Copper price tracker

Feature	Value
Base month	Sept 2009
Base copper price	USD$6,212
Index	LME
Cap	+10% of base price plus ex-ante allowance
Collar	-10% of base price plus ex-ante allowance
Lag	One year
Trigger point	Rolling average needs to be above cap or below collar for one-year
Revenue change	Prospective from point of trigger

Appendix B: Insurable risk and National Grid's approach

Context

B1 This section covers how we use the placement of insurance as a management action to reduce the risk to the balance sheet and protect against cash flow volatility for some of the risks we face as a business.

B2 This section sits alongside the remainder of the insurance narrative which can be found in the various sections as follows:

(a) 'TPCR4 history' outlines the insurance coverage and premiums over the TPCR4 period to date.

(a) 'Detailed plan' documents cover the business metrics which drive our insurance costs and the forecast costs spanning the RIIO-T1 period.

(b) 'How we will deliver' explains the insurance strategy and how we utilise captive insurance companies to reduce overall costs and reduce premium volatility.

(c) The 'Efficiency and value for money' annex includes a section which outlines how the financial efficiency of the captive insurance placements is challenged and assessed for efficiency by comparing against the premiums which would otherwise be charged by the commercial insurance market.

B3 In order to understand how the insurance arrangements work, it would be helpful to refer to the how the 'How we will deliver' annex before reading this.

Insurance as a risk management tool

B4 As part of the overall risk management and risk financing methodology of an organisation, insurance is a mechanism for providing financial protection against a range of losses to its assets, revenues and people; and against its contractual and common law liabilities. Without insurance, the total cost of risk to a business would simply be the cost of all losses. This would introduce a higher level of uncertainty and volatility to the balance sheet.

B5 Where it is financially effective to do so, purchasing insurance can replace some of these potential claims costs with a less volatile premium charged year on year. The reduction in uncertainty permits the organisation to plan more effectively and efficiently for the future knowing that a proportion of future potential losses can be mitigated (albeit at a cost) and funds which would otherwise need to be held in the absence of insurance, to meet these liabilities can be diverted to more productive uses.

B6 Coverage offered by insurers will be dependent on the nature of the insured risk and how this is presented to the insurance underwriters. Focus will be on the organisation's overall risk management approach and the level and detail of the coverage sought.

B7 The types of insurance typically purchased by an organisation are as follows:

Coverage Type	Covers
Property Damage	Loss or damage to the insured property for example by flooding
Business Interruption	Loss of revenue arising from a property damage event
Property Terrorism	Loss or damage to the insured property and resulting loss of revenue arising from a terrorism event – this is typically excluded from a standard property damage policy
Third Party or Public Liability	Legal liability to third parties arising from contractual or common law for injury of physical damage
Employer's Liability	A statutory cover under UK law covering the employers legal liability to employees for injury or disease
Motor Third Party Liability	A statutory cover under UK law covering injury or damage to third parties from a motor accident
Personal Accident	Discretionary employer benefit for employees which pays out a lump sum in the event of serious permanent injury or death
Travel	Employees whilst travelling on company business
Directors and Officers Liability	Covers damages or defense costs in the event a Director (or Officer) suffers financial losses as a result of a lawsuit for alleged wrongful acts while acting in their capacity as directors and officers for the company
Professional Indemnity	Covers the company's legal liability arising out of negligent or wrong advise to third parties

B8 From this it is clear that insurance is only a partial risk management measure and that the business will retain an array of uninsured and traditionally uninsurable exposures.

National Grid's Insurable Risk Strategy

B9 Our insurance strategy is to maximise the use of a group owned captive insurance company wherever it is financially efficient to do so. This well embedded risk strategy provides stability of premiums, shielding the group businesses from dramatic price fluctuations experienced in the insurance market, whilst additionally allowing us to secure cover for certain risks that would otherwise be uninsurable with commercial market insurance companies.

B10 National Grid insures itself against the risks detailed above, with the exception of professional indemnity as there are no commensurate exposures.

B11 In terms of insurable risk, there tends to be three categories of expected losses, these sit comfortably with our risk management philosophy where the risk is best left with the party best placed to manage it:

(a) High frequency of low value losses – often known as attritional losses. In most cases insurers will set the policy deductible at a level that leaves these uninsured and therefore with the company to manage.

(b) Medium frequency, medium value losses. These form the core of an insurers actuarial assessment in determining an appropriate risk based premium as there is often a rich loss history on which to analyse expected future quantum and frequency of losses.

(c) Low frequency, high value losses. These high severity, low probability losses are harder to analyse actuarially due to the lack of loss data – insurers will assess the probability of loss and the premium required to fund a loss should one occur.

Jargon buster

*A **captive insurance company** is an insurance company which insures the risks of the businesses which are related to it through common ownership. 75% of FTSE 100 companies have a captive. National Grid has two captives:*

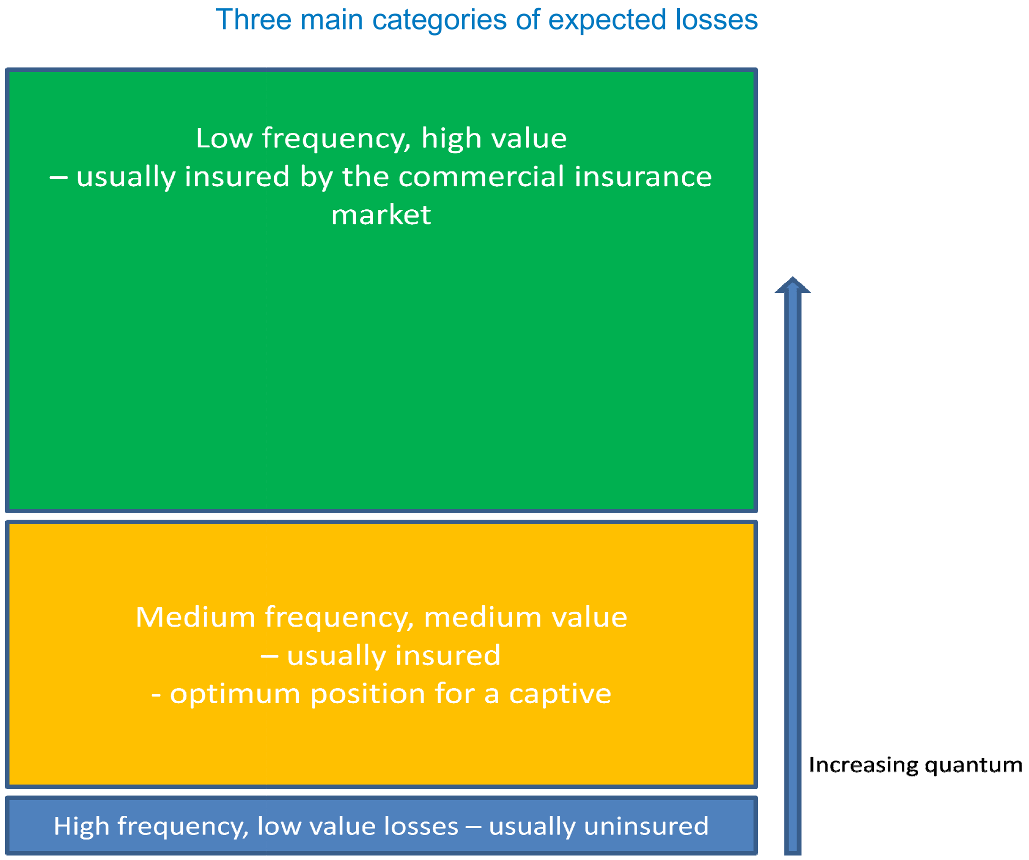
(a) National Grid Insurance Company (Isle of Man) Ltd. – NGICL

(b) National Grid Insurance Company (Ireland) Ltd. (NGICIL)

We explain in the how we will deliver annex to this submission, why we have two captives.

*The **commercial insurance market** consists of insurance companies and Lloyds of London syndicates. These are often international companies who will usually underwrite a whole range of insurance risks from domestic property or motor risks to property and legal liability risks of commercial companies on and offshore and across the world.*

B12 These categories of expected losses are illustrated in the figure below:



B13 Insurers will look to balance their costs against their income over their portfolio of business over the medium to long term. This may mean that individual policy holders' 'accounts' will run at a loss where losses have been heavy whilst others run in credit where losses have been minimal. Overall, however, the insurer will look to balance the overall underwriting account and deliver an element of profit in return for the risk to the capital that was exposed.

(a) Costs include insured losses they pay to policy holders and the cost of running their businesses which will include staffing costs, property costs and insurance they will buy to transfer some of the financial liability they have assumed to other insurance companies in return for a premium – or reinsurance as this is known. Commercial market insurance companies have a 'frictional cost' of operation at around 15-20% of their income level. A captive insurance company will have much lower 'frictional costs' due to reduced overheads at around 2-5%.

(b) Income will include premiums they receive from policy holders and investment income they receive from investing these funds.

B14 When setting the premium, the insurance company will use statistics and probability to approximate the rate of future claims based on a given risk. After producing rates, the insurer will use discretion in conjunction with historical loss data and historical premiums to reject or accept the risk of insuring the policy holder.

B15 In determining the optimum use of the captive, the probability of a loss hitting the captive is traded off against the cost of transferring the risk to the commercial market for a premium. This is assessed regularly to ensure the right balance of financial risk is retained by the company – through self-insured or captive losses against the cost of transferring the loss to the commercial insurance market.

Financial Risks to the Insurance Forecasts

B16 The insurance premiums are based on facts and knowledge today; in compiling these, assumptions have been made around variables such as the insurance market conditions, the legal regime for claimants, the expected changes in exposures. On the basis that they are compiled on a 'what we know today' basis, they will by definition not take account of events such as:

(a) A large loss on the programme beyond the scope of those actuarially forecast which would drive up reinsurance rates beyond forecast

(b) A 'Black Swan' or 9/11 type event driving up reinsurance rates across the insurance industry to levels above those forecast.

(c) A new claims exposure having a similar effect to asbestos related claims on Employers' Liability insurance depleting capital reserves and driving up future potential liabilities.

(d) Investments not performing as forecast leading to a reduction in investment income gains realised and transferred to Profit and Loss account.

(e) A material change to the group's overall risk financing strategy.

(f) A change in corporation or insurance premium tax regimes increasing overall the tax burden on the captive(s) reducing the level of profit retained to finance losses.

B17 These, amongst others, are financial volatility risks which are borne by the company.

Appendix C: Real Price Effects Reports