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Transmission Access Review – Initial Consultation on Enhanced Transmission Investment Incentives

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Target audience: Electricity transmission licensees, conventional and renewable generators, distribution network operators, suppliers and customers

Overview:

Ofgem is committed to playing a full role in helping to reduce carbon emissions to tackle climate change. As part of the joint Ofgem/Department for Energy and Climate Change Transmission Access Review we have proposed a range of measures designed to reduce or remove electricity transmission grid-related access barriers to connecting new generation. These measures will be vital in delivering our existing domestic renewable targets and the the UK share of the 2020 EU renewable energy targets. One of the most important changes is providing new financial incentives on the electricity transmission companies to anticipate future demand from generators and invest efficiently to meet that demand. This will help ensure that transmission capacity can be ready when new generation connects and to reduce the existing bottlenecks on the system. It can take between four and ten years to obtain planning permission and complete construction of major new transmission lines. Transmission companies therefore need to be able to invest sooner to make sure they have the capacity that generators require in future. But we also need to protect customers from having to pay for new capacity that isn't required or significant cost overruns on new infrastructure.

This document sets out, for consultation, our thoughts on new investment incentives that will allow transmission companies to earn higher returns for taking on more risk by investing sooner to expand capacity, and on our proposed work in the short term to address barriers to investing ahead of need. We would welcome views on our proposals.

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Context

Energy plays a critical role in the continued economic prosperity of Great Britain. The Energy White Paper 2007 set out the Government's international and domestic energy strategy to meet the long-term challenges we face in addressing climate change and maintaining the security of our energy supplies.

Increasing the contribution that renewable generation makes to meeting electricity demand in GB is a critical part of Government's energy policy goals. In the Energy White Paper, the Government announced a joint review of transmission access by the Department of Trade and Industry (DTI) (now the Department of Energy and Climate Change [DECC]) and Ofgem. The Transmission Access Review (TAR) focused on the framework for the delivery of new electricity transmission infrastructure, the management and operation of existing grid capacity, and the operation of the existing grid to ensure that they remain fit for purpose as the proportion of renewable generation grows.

The review was driven by the current delays that the large volume of renewable and conventional generation is facing when seeking connection to the transmission system and the potential effects these delays will have, if not removed, on achieving the Government's climate change targets and maintaining security of supply.

Following Ofgem and DECC's TAR Final Report in June 2008, a range of measures are being pursued which will improve access to the transmission network. An important element of these measures is our work to deliver, as soon as possible, the appropriate regulatory framework to allow the Transmission Owners (TOs) to take on the additional risk associated with investing in anticipatory investment, whilst protecting consumers from unnecessary and inefficient investment. The work of the Electricity Networks Strategy Group (ENSG) has identified a considerable amount of further system reinforcement in the run up to 2020.

We think that it is appropriate to review the current approach to regulatory funding and consider whether changes are needed to provide an appropriate level of reward through incentives to invest sooner in expanding transmission capacity. In this work, our focus is on projects which could be commenced within the current transmission price control period. We will take into account any relevant interactions with our RPI-X@20 review which is looking more fundamentally at the current approach to network regulation and developing recommendations for the way we regulate all of the energy networks in the future.

Associated Documents

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Transmission Investment for Renewable Generation – Initial Proposals. August 2004.
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/8008-19604_tirg_ip.pdf

Transmission Investment for Renewable Generation – Final Proposals. December 2004.
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Documents1/9139-28804.pdf

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http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080626_TAR%20Final%20Report_FINAL.pdf

RPI-X@20 project publications. March 2008 to date.
http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

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Summary

Overview

To help tackle climate change, Ofgem is committed to playing a full part in helping to reduce CO2 emissions from the energy industries we are responsible for. We proposed a range of measures with DECC through the Transmission Access Review (TAR) to reduce or remove grid-related access barriers for renewable and other low carbon generators. These are aimed at accelerating the connection of new generation helping to achieve the UK share of the 2020 EU renewable energy targets. A critical component of the TAR reforms is the delivery of enhanced financial incentives on the electricity transmission companies to encourage them to anticipate the future network demand of generators and to invest to meet this demand. This will help to ensure that we have the right amount of transmission capacity in the right locations when new generation wants to connect.

We asked the three transmission companies to carry out an investment study looking at the best options to expand system capacity to meet the 2020 targets. Initial findings from this study have identified a large number of major transmission system projects that may be necessary to increase capacity and reinforce the system to ensure the system has sufficient capacity to meet the needs of new conventional and renewable generation. This may include the need to invest in new, high voltage Direct Current (DC) cables that will run offshore from Scotland where much of the renewable generation may locate to England where electricity demand is concentrated. The transmission companies current forecast are that these projects could cost around £6 billion. This is in addition to the £4 billion of investment in new capacity and asset replacement allowed in the current electricity transmission price control that runs until 2012.

Typical lead times for constructing new renewable and non-nuclear generation are three to four years. Generators therefore typically seek to sign connection agreements for new capacity with National Grid three to four years before they need the capacity. The typical planning and construction lead times for new transmission capacity can be much longer than three to four years. The transmission companies need to be able to commence planning and work to expand capacity ahead of commitments from generators to make sure that transmission capacity is available when generators need it. If they do not, there is a risk that generators will face significant delays in connecting to the system or that of constraint costs on the system will rise significantly. This has happened in the last few years – constraint costs are forecast to be over £300 million next year and there is a long queue of generators waiting to connect to the system. But without financially firm contractual commitments from new generators to pay for new capacity there is a risk that transmission companies may invest in too much capacity or invest in additional capacity in the wrong locations on the network. These costs will ultimately fall to customers to pay under the existing arrangements.

This document sets out how we intend to strike a balance between the need to minimise delay and to protect customers. The document also invites views on how we propose to take this work forward, including how we propose to deal with interactions between this project, which is focussed on the arrangements which will apply to projects within the current price control period, and the RPI-X@20 project which is looking more fundamentally at the current approach to network regulation and will develop recommendations for the way we regulate in the future.

Proposed approach

We invited the transmission companies to make proposals for the new investment framework. Building on these proposals, we have considered how the current funding arrangements could be developed to enable the transmission companies to invest in a timely manner so that the capacity can be made available to meet the anticipated demands of future users, while protecting consumers from inefficient costs. In considering how to take this work forward, we have balanced meeting our commitment in the TAR Final Report to put in place revised arrangements in April 2009, and the need for a joined-up approach with the RPI-X@20 project.

We consider that the first step is to consider the extent to which the existing funding arrangements may create barriers to investing ahead of need, and to take appropriate steps to address such barriers as soon as possible. We have also identified a range of issues to consider in developing an appropriate framework which provides incentives to invest ahead of need, with appropriate risk/reward options and efficiency tests. There is a broad spectrum of possible approaches to designing such an incentive mechanism.

We think that work to address immediate barriers to investment – primarily associated with pre-works funding - could be undertaken by Spring 2009, but that a longer term process may be appropriate for the development of an enhanced incentive mechanism. We therefore propose to take forward work in two areas: first, measures that could be introduced quickly to address current barriers affecting known projects; and second, further measures that could be introduced in Winter 2009 to allow full funding of investments that could be commenced during the current price control.

Arrangements for investments in future price control periods will be considered as part of the next transmission price control review, building on any recommendations from the RPI-X@20 project. We think it may be important that we do not change arrangements which are put in place for investments in projects that commence during the current price control. We propose that any investments that commence during this price control period will be regulated on the same basis for the life of the project, such that any changes that come out of RPI-X@20 will not be retrospectively applied to them. We would also welcome comments on whether this approach is appropriate.

We also think it is important to give respondents an early opportunity to comment on the way we are planning to take matters forward. We are particularly interested to hear respondents' views on the proposed approach to address short-term needs, the need for measures to enhance investment incentives in the future, the appropriate balance between TO risk and reward and the appropriate timing of changes for these incentives. We would also welcome comments on the interaction between this review, the RPI-X@20 review and the next price control.

1. Introduction

Chapter Summary

This chapter sets out the background to this document. It also sets out a summary of the structure of the rest of this document.

Question box

There are no questions in this chapter.

Transmission Access review

1.1. Through the Transmission Access Review (TAR) project we and the Department for Energy and Climate Change (DECC) are working with industry to support the government's 2020 climate change targets. The TAR project began after the publication of the Energy White Paper in May 2007 that mandated Ofgem and BERR (now DECC) to review the present technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid. The motivation for the review was to ensure that the grid arrangements remain fit for purpose as the proportion of renewable generation on the system grows[1]. TAR is intended to help remove the barriers to access to the transmission system faced by generators, including renewable and low carbon.

1.2. The TAR Final Report published in June 2008 set out a package of measures that are targeted at helping facilitate the 2020 targets, by reducing or removing grid-related access barriers to connecting new generation. This is important in achieving the UK share of the 2020 EU renewable energy targets[2]. The conclusions of TAR described clear steps to remove these barriers and to create the appropriate regulatory and commercial framework and rules for the short and long term, in order to enhance the speed with which new generation (renewable and conventional) could connect to the transmission system. The TAR package includes individual workstrands targeted at helping facilitate the achievement of the 2020 targets; designing an efficient and enduring solution to transmission access; and speeding up connections in the short term before the other arrangements are in place through GB Queue management and an interim form of "connect and manage".

1.3. The TAR final report noted that potentially long lead times for expanding transmission capacity could prevent Great Britain from meeting its renewable targets - in addition to the considerable work currently being undertaken in relation to the transmission access arrangements, the planning and development of new grid infrastructure also needs to be accelerated if we are to reach our targets.

[1] For more information on TAR please visit the following link:
http://www.ofgem.gov.uk/NETWORKS/TRANS/ELECTRANSPOLICY/TAR/Pages/Traccrw.aspx
[2] These targets require 30-40% of GB's electricity requirements to come from renewable sources by 2020.

1.4. To address the longer-term investment planning challenges, we launched two workstrands: (a) we asked the three electricity transmission companies (TOs), namely NGET, SPT and SHETL, to explore what the transmission system would need to look like in the future and what investment would be required; and (b) to develop new financial incentives for the transmission companies to help deliver the necessary investment in a timely manner without exposing customers to excessive risk and/or inefficient costs.

Potential future investment requirements: 2020 investment study

1.5. The investment study will be brought together in January 2009 through the Electricity Networks Strategy Group (ENSG), which is jointly chaired by Ofgem and DECC. Early findings from the study are summarised below.

Methodology and approach

1.6. The 2020 investment study is looking at developments to the GB transmission system that would be required to accommodate the volume of renewable and nuclear generation needed to meet the 2020 targets, and the renewable nuclear and other forms of generation to meet the 2050 carbon targets. In undertaking this work, the transmission companies have developed a range of future scenarios. For the agreed scenarios and sensitivity studies, the TOs have assessed the required transmission capacity for the period 2015, 2020 and beyond to 2030 for all major network system boundaries.

1.7. Figure 1 below shows the key areas of investigation under the 2020 study. The initial focus of the analysis has been on the major transmission boundaries and those upgrades of existing routes that do not entail a high consent risk, nor rely unduly on unproven technology. Having established the scope for such incremental reinforcement, the study is then considering additional reinforcement options which may be required to meet 2020 renewable targets in an optimal way.

Categorising reinforcement options

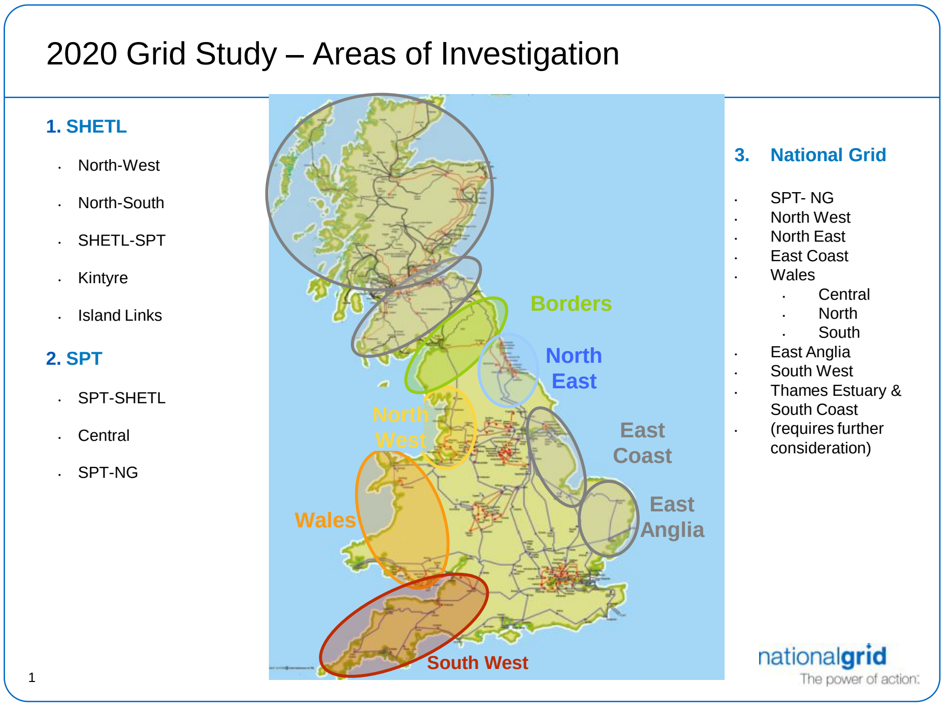
1.8. Following the completion of the 2020 investment study, it is envisaged that the reinforcements identified in the final report to be published in January 2009 will be allocated into the following categories:

1. Proposed **'no regret'** investments, where the analysis of the agreed scenarios and appropriate sensitivity studies has indicated a firm need by 2015, supported by cost benefit modelling.

2. Proposed **design/consent** only investments, where the analysis has identified strong need for 2015 or soon after, but not supported by all scenarios/sensitivity studies.

3. Proposed investments where reinforcements are driven by a limited number of scenarios and whose potential delays would not have a significant impact on meeting renewable targets.

Figure 1 - Transmission System Investment Study Areas of Investigation



Interim results

1.9. The 2020 investment study has so far identified a range of further reinforcements which are likely to be in the "no regret" category. This includes investment options both onshore and offshore to accommodate: increased transfer from Scotland to England and generation developments in North West; offshore generation connected to the East Coast and/or additional nuclear generation at Sizewell; and both renewable wind generation (onshore and offshore) and possible additional nuclear generation at Hinkley Point and/or Wylfa.

1.10. Overall, across the range of scenarios considered the current estimates of the scale of the investment to reinforce the system so it can cope with the increase in conventional and renewable generation are in the range of £4bn to £9bn, over and above the new investment already covered by the current transmission price control. To put that in context, this could more than double the existing Regulated Asset Value (RAV) of the GB transmission system, valued at £6.5bn in 2007/08.

1.11. To the extent that offshore reinforcements span territorial waters, consideration of this project will interact with the development of the offshore transmission regime, and with Ofgem's general policy of considering the most appropriate regulatory provision for large discrete projects. We have previously indicated that certain projects may be better suited to provision via a competitive tendering process rather than assuming that the existing TOs would be able to provide the project at the lowest cost, with the highest level of service.

Facilitating the achievement of the 2020 targets

1.12. Given the lead times associated with major transmission works, it is important to ensure that there are no regulatory blocks to the work that transmission companies will need to undertake in order to ensure that the transmission infrastructure can be put in place in time for when generators are ready to connect.

1.13. Under the current price control we authorised an unprecedented level of expenditure in new and replacement transmission investment, and introduced new flexible mechanisms to adjust the companies' revenue allowances, either up or down, in response to the emerging (and changing) needs of system users. The current arrangements assume that TOs only invest in their networks to accommodate new generation once there is firm commitment from the generators. The TAR Final Report concluded that, whilst full user commitment is desirable in ensuring an appropriate risk of disallowance/stranding, the transmission companies should have the freedom and incentives to invest ahead of signalled need, so that transmission capacity can be ready when new generation connects. This document represents the start of our consultation process on the arrangements for such anticipatory investment.

RPI-X@20 project

1.14. A key area of interaction with our work to develop arrangements for anticipatory investment under TAR is the 'RPI-X@20' review. This is a major two year project, initiated by Ofgem in March 2008, to review the workings of the current approach to regulating GB's energy networks and develop recommendations for future policy. The RPI-X@20 project[3] is looking fundamentally at the RPI-X framework, which has been used to regulate Britain's energy networks for nearly 20 years. Appendix 2 of this document provides further information on the RPI-X@20 project, including its rationale and guiding principles.

1.15. We recognise that stakeholders have discussed a number of issues relating to regulation of investment, including anticipatory transmission investment, at recent RPI-X@20 workshops. Our work under TAR is focussed on the arrangements to apply to projects within the current price control period, i.e. Transmission Price Control Review 4 (TPCR4), while the RPI-X@20 project, is looking more fundamentally at the current approach to network regulation and will develop recommendations for the way we regulate in the future. In Chapter 3 we set out and seek views on how we propose to deal with the interactions across the two projects.

Structure of this document

1.16. The remainder of this document is structured as follows: Chapter 2 describes the current funding arrangements for transmission investment and explains why change is needed to provide a framework for anticipatory investment. Chapter 3 discusses the development of a framework for anticipatory investment. Chapter 4 sets out our initial proposals for actions that could be taken in the short term. Chapter 5 sets out the way forward.

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[3] For more information see: http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

2. Transmission investment funding arrangements

Chapter Summary

This chapter describes the current funding arrangements for transmission investment and discusses why we think changes ares needed to provide a better framework for anticipatory investment.

Question box

Question 1: Do respondents agree that there is a need to put in place a framework for anticipatory investment in order to facilitate achievement of the 2020 targets? Do respondents agree that such arrangements should be developed for application to transmission projects commencing within the current transmission price control?

Question 2: Do respondents agree that this work should first focus on identifying and addressing barriers to investing ahead of need, before putting in place appropriate incentives to undertake investment ahead of need?

Price control and incentives overview

2.1. Under the transmission price control, each of the transmission companies is provided with a future level of revenue and associated incentives (that can vary this allowed revenue up or down based on performance or agreed triggers). Overall the companies are allowed a revenue that we judge to be sufficient for them to be able to meet all of their statutory duties and licence obligations. If a company thinks this revenue is insufficient they can refuse the settlement and ask us to refer the matter to the Competition Commission. The allowed revenues are recovered from generators, suppliers and (large, directly connected) customers through a variety of use of system charges. But all transmission charges are ultimately paid for by consumers.

2.2. The price control seeks to provide the transmission companies with a level of revenue that is enough to finance an efficient business. Under the price control, the companies are exposed to the risk and rewards of actual costs being different to those allowances. In relation to capital investments, the transmission companies earn returns at a level reflecting their assumed cost of capital[4]. By setting the allowed revenues in advance of costs being incurred, the transmission companies receive financial incentives to operate, undertake capital investment in, and finance their businesses efficiently; any cost savings during the incentive period can increase returns to their investors. Efficiency improvements will be passed on to customers in subsequent price controls when allowances are re-set.

2.3. A more detailed summary of the price control and incentives arrangements is set out in Appendix 3. In developing the current price control[5], which applies to the period 2007-12

[4] The cost of capital is the level of return required by the financial markets – both debt and equity - in order to provide capital for a firm.
[5] For more information on the current transmission price control, see the TPCR4 area of Ofgem's website at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/Pages/TPCR4.aspx

for all the transmission companies, Ofgem introduced a framework to strengthen these incentives, particularly in relation to capital investment. These arrangements include a range of mechanisms, discussed in more detail below, which were designed to provide stronger efficiency incentives to the transmission companies and flexibility to respond to changing needs. The arrangements under the current price control will be further reviewed as part of the RPI-X@20 review and in the next transmission price control review.

Funding for transmission investment under the current price control

2.4. Under the current transmission price control each of the three TOs is provided with investment funding through three mechanisms: ***baseline funding, revenue drivers*** and the ***Transmission Investment for Renewable Generation (TIRG) mechanism***.

2.5. The ***baseline level*** of funding is designed to provide a return on efficiently incurred past investment and to remunerate capex on relatively certain transmission works. The capex component includes "load related investment" required to accommodate anticipated changes in demand levels or, more particularly, connected generation, as well as "non-load related investment", such as asset replacement.

2.6. To accommodate uncertainty as to the level and timing of future investment requirements at the time the current price control was set, the baseline funding is supplemented by ***revenue drivers*** which provide automatic funding adjustments. These adjustments, which can be either upward or downward changes in revenue, apply in the situation that the generation connected and associated boundary flows turn out to be different from that assumed in setting the baseline.

2.7. In addition, the ***TIRG*** mechanism, introduced part way through the previous price control period, provides additional funding to all three TOs explicitly for connecting renewable generation. The ***TIRG*** mechanism covers expenditure which was not foreseen at the time the respective price controls were set and applies to specific investment projects.

Baseline investment

2.8. In establishing the revenue allowances for each transmission licensee, we formed a view of the level of costs we would expect an efficiently run business to incur. We also took account of depreciation and undertook an assessment of whether historical capital expenditure has been efficiently incurred. In establishing projected costs relating to planned investment we first formed a view of how generation and demand might be expected to develop over the price control period, then determined the efficient network investment which would be required to accommodate these developments. This included identifying deep reinforcement projects needed to accommodate the baseline level of connections and also any boundary flows considered highly likely to take place. We incorporated such investments into a fixed baseline capex allowance covering transmission investment projects which have been assessed and considered by Ofgem to be a likely scenario and suitable reference point for applying revenue drivers.

2.9. Setting a fixed capex allowance on an *ex ante* basis provides limited flexibility to deal with uncertainty. If actual demand for capacity, and associated investment requirements, differ from those assumed in setting the baseline, there is a risk that either the revenue allowances will be over-generous at the expense of the customers, or that they may be too low and may therefore fail to enable the transmission companies to undertake investment in a timely way. These uncertainties can be dealt with through either re-opening the price control to reflect the cost implications of material changes occurring within the price control period, or defining revenue drivers which provide revenue allowances which are contingent on specific events. The former approach, an example of which is the TIRG mechanism introduced under the previous price control, is typically used for significant changes which could not have been foreseen at the price control review stage, while the latter can be used to deal with known uncertainties. As described below, the current price control uses revenue drivers to provide flexibility to align the revenue allowances with the demand for connections to the transmission network.

2.10. The capex incentive seeks to provide a consistent strength of incentive over the control period. It takes the form of a profit-sharing incentive under which the transmission companies retain 25% of any underspend relative to their capex allowance, or bear 25% of any overspend, at the beginning of the next price control period. The current price control also introduced a safety net to protect customers against any substantial shortfall in investment against the companies' plans. If a company's investment falls over 20 per cent below the amount allowed under the control, this would automatically trigger a review and we would, if appropriate, reopen the price control.

2.11. In aggregate, the baseline allowances for the three transmission companies provide funding for c£3.8 billion of capital investment over the five year period 2007-12, representing a substantial increase in the authorised investment under the previous price control. The price control provides a 4.4% real post-tax rate of return on capital (6.25% real pre-tax) for all three transmission companies which, taking into account depreciation on existing assets, have a combined RAV of £6.5 billion in 2007/08.

2.12. Further, in addition to the baseline allowances and additional funding mechanisms described below, the capex provisions under the current price control introduce mechanisms for "logging up" specified items of uncertain costs for which we concluded it was not appropriate to set *ex ante* allowances but which we expected to be small relative to the baseline allowances. In our TPCR final proposals document we proposed that, subject to these costs passing our efficiency assessment, these costs should be included in the RAV from 1 April 2012 including an allowance for financing costs and depreciation incurred during the period of "logging-up"[6].

Revenue drivers

2.13. While the baseline capex allowances are fixed *ex ante* based on forecasts made at price control review stage, the revenue drivers provide flexible revenue allowances linked to actual demand for transmission capacity. The revenue drivers provide an automatic funding adjustment in line with the level or timing of transmission investment, relative to the

[6] For NGET, these "logging up" mechanisms apply to any necessary upgrading of NGET's operational telecom systems resulting from the introduction of BT's 21st Century Newtwork, the construction of tunnels to replace underground cables along certain routes, and security-related costs. For SHETL and SPTL, "logging up" is intended to cover 50 per cent of the potential expenditure relating to the provision of more secure (N-1) connections to wind generators up to 100MW in size and for potential expenditure on telecoms infrastructure arising as a result of the effects of BT21CN on tele-protection.

baseline. In developing the current price control we worked with the transmission companies to examine the likely range of requirements and the cost drivers for different types of load-related capex. Based on this analysis, the revenue drivers provide contingent allowances reflecting Ofgem's view of the efficient costs of such investments and the circumstances in which they might be expected to arise.

2.14. We developed separate revenue drivers to remunerate capex in the following areas:

- **Local connection and infrastructure** – for all three transmission companies, this applies to transmission reinforcement works local to, and triggered by, individual generators and is linked to the volume of generation connections.

- **Deep reinforcement works associated with generation connections** – for SPT and SHETL, this applies to specific reinforcement works, over and above the local works identified above, which would be triggered when the volume of generation connections in a given part of the network exceeds a given level.

- **Deep reinforcements associated with changes in boundary flows** – for National Grid, this applies to reinforcement works associated with the combined effects of changes in demand and generation, and is linked to changes in boundary flows across specific parts of the network.

2.15. For the local infrastructure works, the **local revenue drivers** for all the three TOs use unit cost allowances (UCA) based on forecast efficient unit costs (£m/MW) of connecting generation projects in the respective areas. The relevant UCA applies to the difference between the actual and assumed value of the volume of new generation connections for a given part of the network. This includes separately defined UCAs to reduce the revenue allowances in the event that the assumed volume of new connections does not materialise.

2.16. For deep infrastructure works in SPT and SHETL's networks, separate revenue drivers cover the more uncertain event that the additional generation connections trigger significant deep transmission reinforcement works. These **deep revenue drivers** are specified in the TOs' licence on a project-by-project basis, and use total cost allowances (TCA) based on forecast efficient project costs (£m) along with threshold levels of generation connections to trigger such funding. For National Grid, the **deep revenue drivers** use UCAs based on forecast efficient unit costs (£m/MW) which apply to changes in the level of export from or import to defined zones, relative to given baseline values.

2.17. The revenue driver mechanisms are in the form of profit sharing incentives which allow for 75% of the actual costs incurred from connecting generation and reinforcing the system to be "passed through", with the remaining 25% incentivised using *ex ante* allowances of efficient costs. This has the same effect as the baseline capex efficiency incentive, i.e. to allow the transmission licensees to retain 25% of underspend and bear 25% of overspend relative to the set UCA. The revenue allowances for this additional investment also reflect the same rate of return as the main price control.

2.18. The specific applications of the revenue drivers to each transmission licensee are described in more detail in Appendix 3.

Transmission Investment for Renewable Generation (TIRG)

Background

2.19. Following approval of the transmission price controls from 1999 and 2000 for Scotland and England and Wales respectively a considerable volume of new renewable generation expressed its intention to connect in Scotland and the North of England. The costs of connecting these generation projects and reinforcing the transmission system were not envisaged at the time of the price controls.

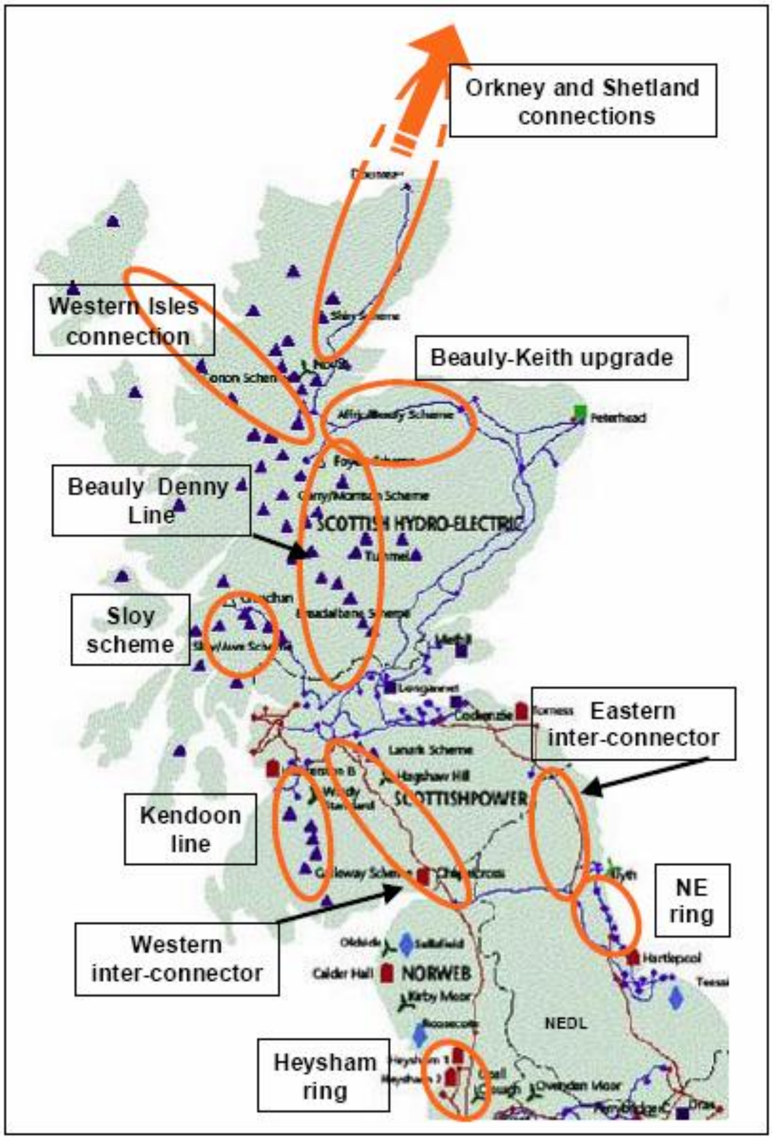
2.20. The three transmission owners were asked by Ofgem to conduct work to identify the necessary transmission system works, provide estimates of the costs involved, and identify how likely they were to proceed. The Renewable Energy Transmission Study (RETS) 2003 identified a range of major system reinforcements that might be needed to accommodate the increase in renewable generation, as set out below. Following publication of the RETS report Ofgem committed to look at the funding arrangements and incentives associated with connecting the new renewable projects, and deliver funding proposals. In so doing, the Transmission Investment for Renewable Generation (TIRG) project commenced, with a series of consultations, culminating in final proposals in December 2004.

Project categorisation and treatment

2.21. Eight investment projects put forward by the transmission licensees for consideration for inclusion in the TIRG mechanism. Each investment project was assessed to establish whether it could be justified in terms of reducing the cost of network constraints and transmission losses. We expected that this would help ensure that investment was carried out in a timely and efficient manner, protect consumers from the costs of stranded assets and lead to charges for generators that are no higher than is necessary. The projects put forward were as set out in map shown in Figure 2. On the basis of our assessment at the time, the investment projects put forward by the licensees were classified as follows:

- **Baseline investment** – investment projects which appear clearly justified in terms of savings in constraint and other costs. The Beauly to Denny, Sloy, Kendoon and Interconnector reinforcements meet this criteria.
- **Incremental investment** – investment projects where there is some uncertainty as to whether they would be justified in terms of savings in constraint and other costs. The reinforcement of the North East of England transmission ring falls into this category.
- **Additional investment** – investment projects where there is significant uncertainty and a relatively high probability that the investment could be stranded. The Heysham area reinforcement, Beauly to Keith reinforcement and links to the Scottish Islands fall into this category.

Figure 2 - Transmission licensees' investment proposals under TIRG



Nb "Western Inter-connector" and "Eastern Inter-connector" are included in the "Interconnector" project, and "Western Isles" and "Orkney and Shetland Connections" are included in "Beauly to Scottish Islands

2.22. Ultimately, the TIRG mechanism only covered projects identified as baseline projects. This provided funding for four network reinforcement projects, affecting all three transmission licensees, with total forecast costs of £560 million (in 2004 prices). The largest of these projects is the upgrading of the transmission line between Beauly and Denny in the north of Scotland, at an estimated cost of £332 million (in 2004 prices). However, despite Ofgem approving funding for this project in December 2004, it was subsequently referred to Public Inquiry by the relevant local authorities in 2006. This process has taken two years and the Inquiry Reporters are yet to make their decision on whether or not to grant planning permission for the project. An adjustment to the pre-construction and contingency costs for Beauly-Denny was requested for financial years 2006/07 and 2007/08 by SHETL, under the TIRG Income Adjusting Event provisions.

2.23. Given the relative uncertainty of the incremental and additional investment projects our policy was that these could be considered in subsequent transmission price control reviews. Following increases in the expected utilisation of the North East ring, the Transmission Price Control Review from 2007/12 approved this project for baseline funding, and via the revenue drivers also created flexible funding arrangements for Beauly to Keith.

2.24. Table 1 describes the eight TIRG projects, their status under the TIRG mechanism and forecast costs at the time of TIRG, and an update on the current funding status.

Table 1 - Summary of the classification of projects under TIRG final proposals and status under current price control

Transmission company	Project	TIRG Final Proposals status	Cost estimate during TIRG (£m)	Current funding status
SPTL/SHETL	Beauly-Denny	Baseline	£332 million	TIRG
NGC/SPTL	Interconnector	Baseline	£168 million	TIRG
NGC	NE Ring	Incremental	£140 million	Price Control
NGC	Heysham Ring	Additional	£65 million	Price Control
SPTL	Kendoon	Baseline	£40 million	TIRG
SHETL	Sloy	Baseline	£21 million	TIRG
SHETL	Beauly to Keith	Additional	N/A	Revenue Driver
SHETL	Beauly to islands	Additional	N/A	N/A

Project return

2.25. The financing arrangements for the TIRG projects (including interest during construction) were based on a cost of capital broadly equivalent to that used in the preceding price control review. For the four projects assigned to the baseline category, the pre-tax real cost of capital is 8.8%, equal to the average allowance used when we extended the Scottish transmission price controls. This level of return was intended to reflect the pre-tax real rate of return approved under DPCR4, which was 8.9% for SSE Hydro and 8.7% for SP Distribution. These values were carried forward for the 2 year price control extension for SHETL and SP Transmission, which average to the 8.8%. Comparing to the 6.25% pre-tax real cost of capital in the baseline allowances for the 2007/12 transmission price control allowances, the rate of return under TIRG contains a premium.

Limitations of current arrangements in delivering transmission investment to meet the 2020 targets

The need to anticipate investments

2.26. The combination of the baseline allowances and the revenue drivers provides fundings for the transmission companies which are closely linked with the amount of generation that actually turn out to connect. These conditions, whilst giving strong protection to consumers, do not encourage the transmission licensees to invest to anticipate future need. Instead, they tend. This was the intention of the revenue driver mechanism when they were designed given the uncertainty of the generation projects over the period of the price control. However, there may now be a stronger case need to take into account the difference in typical lead times between transmission and generation projects.

2.27. From the findings of the 2020 investment study it is clear that the challenges for the grid in accommodating the UK's 2020 renewables targets are considerable. Under the TAR project we recognised that the work to plan and develop new grid infrastructure also needs to be accelerated if we are to reach our targets. The current framework may create a barrier to progressing investment in a timely manner, given the lead times for investment and the fact that it is based on TOs investing based on user commitment. It is important that high priority projects are not delayed through a failure to invest in a timely way and equally that customers are protected from the risk of stranded investment

2.28. We have questioned whether the three transmission companies have the right commercial incentives to help address the challenges that government and EU renewable energy policy is placing on the transmission networks. We recognise that there is currently no strong financial incentive (although there is also no actual barrier) on the transmission companies to undertake anticipatory investment. There is no increased reward for undertaking such investment in an efficient manner, to counteract the arguably higher downside risk of investment being fully or partially disallowed.

2.29. We think that in order to address the challenges of meeting the 2020 targets we need to provide a framework which both allows and encourages the TOs to make for anticipatory investment. We consider that the first step is to consider the extent to which the existing funding arrangements may create barriers to investing ahead of need, and to take appropriate steps to address such barriers as soon as possible. The next step is to provide the right incentives to undertake investment ahead of need where it is more efficient to do so. These incentives would focus on investments commenced during the current regulatory period.

2.30. Our work on enhanced incentives interacts with the RPI-X@20 project discussed in chapter 1. The potential scale of investment to which the incentives might apply, and identification of projects which could commence within the current price control period, will be made clearer when the 2020 investment study reports its findings in January 2009. The initial findings of the 2020 investment study discussed in chapter 1 demonstrates a need for a framework to deal with major reinforcements over and above incremental upgrading of existing system, with such reinforcements potentially spanning multiple TO areas as well as potentially entering offshore territorial waters. This introduces further complexity into the development of enhanced transmission investment incentives, and may call for the application of a competitive approach. These and other issues relating to the development of a framework for anticipatory investment are discussed in more detail in the next chapter.

The need to incentivise timely delivery

2.31. When connecting new generation, the GBSO enters contracts with the users under which the connection is contingent on completion of any necessary infrastructure identified by the TOs. However the transmission companies do not provide firm connection dates or provide compensation if delivery of infrastructure is delayed. There is limited incentive on the licensees to deliver on time or early, in order to meet generator aspirations for an earlier connection date. Instead, the generators bear the risk of delay. We stated in the TAR Final Report that firm connection dates and appropriate incentives are vital in addressing the defects in the transmission access regime.

3. Developing a framework for anticipatory investment

Chapter Summary

This chapter summarises the proposals we have received from the transmission companies and our views, in the light of those proposals, on the relevant issues to consider in developing a framework for anticipatory investment. It also sets out how we propose to take this work forward, including how we will address interactions with the RPI-X@20 project.

Question box

Question 1: Do respondents have any views on the proposals received from the transmission companies? Do respondents consider that we have appropriately considered the impediments to anticipatory investment identified by the transmission companies?

Question 2: Do respondents consider that it is appropriate to take the current arrangements as a starting point for developing a framework for anticipatory investment? Have we identified the relevant issues to consider in taking this work forward, e.g. in relation to the definition of anticipatory investment and the design of an incentive mechanism? Do respondents have any views on the appropriate balance of risk and reward in relation to investment undertaken on an anticipatory basis?

Question 3: Do respondents have any views on our proposed way forward, including our proposal to separate short term work to measures address current and immediate barriers, from further measures, developed over a longer timescale, to allow funding for investments that could be commenced under the current transmission price control? Do respondents have any views on how we propose to address interactions with the RPI-X@20 project?

Introduction

3.1. This chapter discusses the issues we will need to consider to develop enhanced transmission investment incentives. The discussion starts with a summary of the proposals received from the transmission companies. It then sets out our proposed way forward, focussing on proposals for bringing forward investment in transmission projects that could commence during TPCR4.

3.2. The arrangements for investment in transmission projects commenced in the next transmission price control and beyond will be considered as part of the RPI-X@20 project and taken forward through TPCR5. The RPI-X@20 review will consider, as on option, retaining the arrangements introduced under the current price control, for application to future transmission projects. Ideas which come forward as a result of the the RPI-X@20 project will be considered in our work on enhanced incentives.

Proposals received from the transmission companies

3.3. The TAR Final Report concluded that in order to facilitate the 2020 targets the TOs should have the freedom and incentives to invest ahead of signalled need, so that transmission capacity can be ready for when new generation connects. We suggested that such incentives might include enabling the TOs to earn a higher return on efficient investments where they take on some of the risk of investing ahead of firm user commitment from generators, while ensuring they face some financial exposure when they make inefficient or poor decisions. Ofgem invited proposals from the three transmission companies on their willingness to accept a “different” incentive package for investments undertaken before user commitment is obtained, such as those that are likely to be required to meet the 2020 targets. The proposals we have received from each of the three transmission companies are outlined below. Table 2 compares the key features of the proposals and the current financing and incentive mechanisms and provides a summary of the current price control incentives.

National Grid

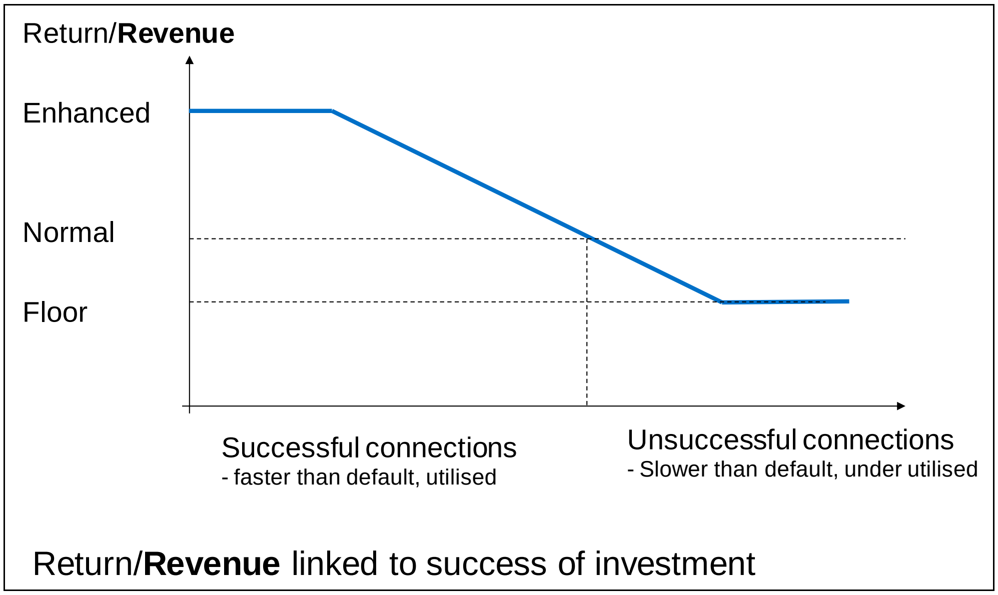
3.4. National Grid’s proposal covers both local and wider transmission investment. The proposal is based on revisions to the current price control revenue driver and capex efficiency incentive mechanisms. In National Grid’s view, the current capex incentives already include several aspects that are needed for anticipatory investments, including incentives on cost and delivery speed, as well as incentives for delivering greater utilised capacity than implied by the level contracted before construction. However National Grid note that these arrangements could be further developed to remove what it perceives as barriers to investing ahead of need, by:

- improving the incentive for undertaking pre-construction works;
- removing the requirement for evidence of user-commitment for the 75% pass-through of cost incurred;
- measuring utilisation by either generation capacity connected or level of actual usage, instead of by purchased long term access rights;
- dealing with economies of scale and lumpy investment, by setting UCAs with appropriate headroom for TOs to get reward from economies of scale associated with building larger schemes, together with clear procedure for updating UCAs, and
- setting a ceiling on returns of 300 basis points above the current price control rate of return for efficient investment and 100 basis points below the rate of return for less efficient investment. The overall capex will also be subject to safety net mechanisms. National Grid’s proposal of the cap and colloar arrangements on the incentivised rate of return depending on the utilisation of delivered capacity is illustrated in Figure 3 below.

3.5. National Grid also believed that the following areas are important for further consideration, but did not put forward its own proposals to address these areas:

- allocation of transmission consent risks in designing incentive for timeliness;
- treatment of write-off of pre-construction work costs in the event of a decision not to proceed with investment; and
- interactions with the offshore regime.

Figure 3 - National Grid proposed cap and collar arrangements



Scottish Power

3.6. Scottish Power's proposed incentive mechanism applies only to major shared-use transmission investment and is designed to operate on a project-by-project basis. The key features of the proposals are that:

- Pre-construction costs are treated as pass-through items;
- Ofgem would determine the project cost prior to construction[7]. The target completion date would also be agreed between Ofgem and the TO after all consents are obtained. Adjustments will be made in the event of circumstances which are beyond the control of the TO[8]; and
- The funding of a project consists of the following two parts: pass-through of a proportion (such as 75%) of the agreed project cost; and remuneration for an amount which will be added to the asset base. The asset value will be based on the remaining agreed costs, scaled by a utilisation factor[9]. The incentivised rate of return[10] will depend on the speed of delivery and the proportion of the built capacity that is anticipatory. Scottish Power's proposal would see a range of rate of return's between 89 basis points below the usual price control cost of capital for inefficient investment and 375 basis points above the price control cost of capital for the most efficient investments.

[7] With flexibility for "major unforeseen income adjusting events"
[8] Such as delays due to SO's decisions on circuit outages
[9] Which is the ratio between the capacity utilised and capacity constructed
[10] Scottish Power envisage that the incentivised rate of return will be fixed and apply to a 20-year depreciation period, but suggested that an alternative would be to front load the incentive to trigger investment.

3.7. Scottish Power provided the following example to illustrate the adjusted rate of return based on the timeliness and degree of anticipation of the investment projects. The last column, titled "built/contracted", means the ratio between the capacity built and that backed up by contracted generation when the TO decides to initiate the investment. In other words, it represent the degree of anticipation in the TO investment. The incentivised rate of return figures would only apply to the utilised proportion of the built capacity.

Table of Returns

LATE				AHEAD			Built v Contracted
<= 3 months	4 - 6 months	> 6 months	On time	<= 3 months	4 - 6 months	> 6 months	
7.70%	8.00%	8.30%	8.59%	9.06%	**9.53%**	10.00%	>125%
7.23%	7.53%	7.83%	8.13%	8.59%	9.06%	9.53%	120%
6.76%	7.06%	7.36%	7.66%	8.13%	8.59%	9.06%	115%
6.29%	6.59%	6.89%	7.19%	7.66%	8.13%	8.59%	110%
5.83%	6.12%	6.42%	6.72%	7.19%	7.66%	8.13%	105%
5.36%	5.65%	5.95%	6.25%	6.72%	7.19%	7.66%	100%

SHETL

3.8. SHETL's proposal also focused only on deep infrastructure works and is designed to operate on a project-by-project basis. Its key features are that:

- Pre-construction work should be funded in full;
- Once all pre-construction work is complete for a project, the TO would submit to Ofgem information on the project cost, delivery date and the current level of user commitment. After its own assessment, Ofgem would then set the efficient forecast project cost and the target completion date; and
- Regulatory funding would then consist of two broad parts: pass-through treatment of a proportion of the actual cost as it is incurred[11]; and a payment based on the predetermined £/kW cost applied to the utilisation volume[12].

3.9. SHETL identified funding for pre-construction works as a key issue, particularly for developing innovative designs for complex lumpy investment such as island links. SHETL noted the arrangements could apply to investments to reinforce the existing transmission system without user commitment, enabling "critical path" reinforcements to be undertaken in parallel rather than in sequence.

[11] In contrast to the current fixed 75% pass-through, the proportion for the new incentive mechanism could be varied on the basis of the degree of user commitment. Incentives for efficient cost and timely delivery could also be added to this part of the funding by adopting a sliding scale of regulatory return around the target cost and a reward/penalty payment for early/late delivery around the target date.

[12] The £/kW increment is set at a level such that there will be positive return to incentivise the TO to make anticipatory investment decisions. No details were provided in SHETL's proposal as to how this should be done.

Table 2 - Summary table comparing current revenue drivers and TO enhanced incentive proposals

Proposals	Funding independent of utilisation	Funding dependent on utilisation
Current Price Control		
Revenue driver £/kW (NGET local & deep, SPT & SHETL local only)	75% of actual cost pass-through subject to evidence of need case based on user commitment	25% based on actual utilisation of kW and pre-determined £/kW unit cost allowances (UCAs) - Incentive on cost: UCA set ex-ante - Incentive on timeliness: UCA based on NPV over typical construction profile, therefore come incentive on speedier delivery.
Trigger mechanism (SHETL & SPT deep only)	Once generation contracted in defined areas exceeds predefined thresholds, funding for specific projects will be allowed on basis of forecast costs	
TOs Proposals for Enhanced Incentives		
NGET	75% of actual cost pass-through	Funding based on utilisation kW and pre-determined £/kW UCAs
SPT	[75]% of actual cost pass-through	Separate RAV based on actual utilisation of kW and pre-determined £/kW UCAs - Incentive for anticipatory investment: higher rate of return for higher proportion of anticipatory capacity - Incentive on cost: UCA set ex-ante - Incentive on timeliness: higher/lower rate of return for earlier/later delivery than target date
SHETL	X% of actual cost pass-through, X based on degree of user commitment relative to capacity to be built - Incentive on cost: sliding scale return around target cost - Incentive for timeliness: reward/penalty for earlier/later completion than target date	Funding based on utilisation kW and pre-determined £/kW UCAs - Incentive for anticipatory investment: UCA to include positive incentives

Comparison of the proposals from the transmission companies

3.10. The proposals received from the transmission companies identify a number of immediate impediments to anticipatory investment, while setting out their views on the potential options for how this could be addressed by adapting the current framework. While the TO proposals share some common elements, which we discuss below, there are a number of important differences, driven in part by differences in the TOs' circumstances and the nature of investments to which they envisage the arrangements applying. For example:

- National Grid has approached the incentives in a different way because it wanted to ensure the incentives could be aligned with its System Operator (SO) incentives; the Scottish TOs' designs do not have any SO responsibilities.
- National Grid has focussed on adapting the current revenue drivers, e.g. in terms of the UCAs. The Scottish companies have focussed on the triggers for funding of major reinforcements under the deep revenue drivers, particularly in relation to pre-construction works.

Adapting the current framework

3.11. As discussed in the previous chapter, a key objective of the current funding arrangements is to ensure TOs can finance their activities and respond flexibly to user demand, while protecting consumers from inefficient costs through incentive regulation. The different funding arrangements introduced under the current price control seek to achieve this objective while reflecting the extent to which the (potential) need for, and associated costs of, the transmission works could be identified at the price control review. They also seek to provide a revenue stream with a rate of return consistent with the level of risk in undertaking the investment.

3.12. The range of the mechanisms under the current arrangements share the following common features, they:

- provide (in some cases conditional) funding for transmission investments occurring within the price control period;
- set revenue allowances for efficient investment;
- define an incentivised period and degree of exposure to incentivised costs;
- trigger revenue stream during the incentivised period;
- utilise rates of return which reflect the level of risk and cost of capital, and
- take account of the efficiency of investment in deciding whether to include in RAV after incentivised period.

3.13. The proposals for enhanced incentives which we have received from the TOs also share these features. We therefore think it possible to adapt the current arrangements to provide a framework for anticipatory investment. To take forward the work to develop such a framework it will be important to consider such factors as:

- Whether the issue creates an immediate impediment to investment;
- The level of uncertainty as to whether the investment will be required (a) at the time the incentives parameters are set and (b) at the time the decision is taken to invest;

- The materiality of the investment costs, and
- The respective risks to the transmission companies, customers the achievement of the 2020 targets of the transmission companies making the choice between investing ahead of need vs deferring investment until there is full user commitment.

3.14. In developing incentive mechanisms to encourage the transmission companies to undertake efficient anticipatory investment, we will need to consider the magnitude of the associated risk and return and trade-off and the extent to which each party should be exposed to these risks and the way in which the risk and return are influenced by the design of the incentive mechanism. In doing so, we will seek to ensure consistency with the risk and returns available in other contexts, such as the regulated returns under the price control or TIRG, or the returns expected from for investments in comparable circumstances. We will also take account of current capital market conditions, as these may have an impact on the ability of the transmission companies to finance substantial new capital investment. These issues are discussed in more detail below.

Current barriers to anticipatory investment

3.15. This section discusses in more detail the barriers to anticipatory investment highlighted by the TO proposals. We seek views on our assessment of the risks and tradeoffs relevant to the examples highlighted by the transmission companies' proposals.

Uncertainty over funding for pre-construction works

3.16. The Scottish companies in particular identified the treatment of pre-construction works as a key issue to be addressed. We agree that the treatment of pre-construction works could create a barrier to commencing work on anticipatory investments in projects for which the pre-construction costs are not included in the baseline revenue allowances. We think that for such projects, which potentially includes projects beyond those currently subject to deep revenue drivers, it may be beneficial to undertake pre-construction works early as this may facilitate identification and optimisation of design options and associated construction costs. In doing this it will be important to retain appropriate incentives on the transmission companies to minimise costs and undertake work in an efficient manner. We discuss the issues relating to pre-construction works in more detail in Chapter 4, where we also set out our proposals for how these issues could be addressed in the short term.

Revenue driver triggers require full user commitment

3.17. Another focus of the Scottish companies' proposal is the treatment of large lumpy investment which is only required under certain generation scenarios and for which a need case is not yet made due to lack of full user commitment. In this case, the risks are defined by two choices, either to:

- delay commencement of construction works until there is full user commitment, with a consequential impact on the connection timescales for contingent generation projects, or
- initiate construction ahead of need, which would potentially result in stranded costs if generation projects do not subsequently materialise.

3.18. We agree that the trigger conditions serve as a barrier to investing ahead of need in relation to deep revenue driver projects. This is consistent with their purpose in protecting consumers from the risks of stranded assets. However, we also agree that in some circumstances there may be benefits in allowing construction works on such projects to take place ahead of user need, given the respective construction timescales of transmission works and generation projects and the potential impact on achieving the 2020 targets.

3.19. We think that an incentive mechanism could be designed for construction works which would encourage the transmission companies, through appropriate risk/reward options, to undertake efficient anticipatory investment decisions while protecting consumers from inefficient investment decisions. We discuss this in more detail below. As highlighted by the proposals we have received from the transmission companies, a key parameter in such an incentive mechanism is likely to be the ratio between the capacity which is built and that which is contracted at the time of the investment decision.

3.20. The benefits of such a mechanism would be to provide appropriate incentives to the transmission companies to make the choice as to whether to undertake anticipatory works, while protecting customers from inefficient decisions. In the absence of such a mechanism, an alternative approach in the short-term could be design an *ex ante* efficiency test to replace the current trigger conditions, or for Ofgem to consider such investments on a case by case basis as to whether they should proceed ahead of the trigger conditions. We discuss this in more detail in Chapter 4.

Treatment of transmission works contingent on other reinforcements

3.21. A related issue, raised by SHETL, is the fact that some of the reinforcements are contingent on other reinforcements being completed, in particular Beauly-Denny, so that the transmission works can only be delivered sequentially. In this case the risks are again defined by two choices, to:

- Delay the commencement of construction works until completion of contingent reinforcements, with a consequential impact on the delivery timescales for the transmission works and connection timescales future generation projects, or
- Initiate construction ahead of need, resulting in stranded costs if the contingent reinforcements are not completed or the generation projects do not subsequently materialise, and potentially increased operational costs during construction.

3.22. We think that this example raises similar issues to those discussed above in relation to pre-construction works and construction works for projects currently subject to trigger conditions. In relation to the treatment of operational costs, given the magnitude of investments we think that in order to protect consumers such investment should only undertaken when it is economically efficient to do so, whether or not this is driven by the prevailing level of user commitment. In this context, it will be important to attach appropriate weight to the impact on operational costs during and after construction, taking into account the increased incidence of constraints as a result of the outages required to undertake parallel construction works.

UCAs don't reflect sizing options

3.23. National Grid's proposal highlights the potential situation where there is already a need for increased capacity and the TOs are faced with a choice: either to build on the basis of the requirement for which there is already full user commitment; or to build capacity which exceeds the requirement, in anticipation of the additional capacity being used by further connections in the future. This issue is particularly relevant in National Grid's area, where there apapears to be greater scope for economies of scale through different investment sizing options. In this case, the risks are defined by three choices, to:

- Construct on the basis of current user commitment, with risk of additional costs and time to increase capacity later for future generation connections
- Construct on the basis of anticipated future requirement, with risk of stranding/disallowance if future generation connections do not subsequently materialise
- Defer construction until there is more certainty as to user requirements, with consequential impact on connection timescales.

3.24. There may be benefits through economies of scale in investing on the basis of anticipated future requirements. It is unclear that the current arrangements create an actual barrier to taking account of such tradeoffs in investment decisions. However, we agree that there may also be scope to design an incentive mechanism to encourage efficient anticipitatory investment decisions while protecting consumers from inefficient investment decisions. As illustrated in National Grid's proposal, key elements of such an incentive mechanism are likely to be differential UCAs reflecting different sizing options.

Options for design of incentives for anticipatory investment

3.25. The examples highlighted above demonstrate that there is a range of potential applications for a framework for anticipatory investment, and the risks and tradeoffs may differ between these applications. However, the examples all share the following common elements which could be used to form a basis for a definition of anticipatory investment:

- The frameworks envisage that investment decisions, in terms of timing or sizing, are **based on anticipated (rather than contracted) demands**.
- Risks, compared to those under the current funding arrangements, relate to the **difference between anticipated and actual outcomes**.
- Key success criteria are: (a) whether the anticipated demands, on which the investment decision was based, ultimately materialise and (b) whether the investments are in place for when generation is ready to connect.

3.26. As highlighted by the TOs' proposals, there is a range of ways of varying the level of risk exposure under the current funding arrangements, and tailoring the design of the mechanism to the types of investment to which it might apply. This includes varying:

- The length of the incentive period;
- The level of incentivised costs during the incentive period;
- The conditions under which the revenue stream is triggered, and the way in which the level of the revenue stream varies over time;
- The proportion of pass-through vs. incentivised costs; and

- The range of returns allowed on capital costs and the triggers used to determine where in that range a company's return lies.

3.27. We also note that there is a degree of interaction between these design choices. For example, we note that increasing the proportion of pass-through reduces the risks to the transmission companies, which may have implications for the appropriate rate of return. Similarly, the risks to the transmission companies in undertaking anticipatory investment may be reduced for transmission projects for which the decision to commence work is taken with prior approval from Ofgem following an needs case assessment, compared to the situation where they make the choice to undertake anticipatory works following their own assessment of tradeoffs.

3.28. Another key consideration is the interaction between the funding arrangements for anticipatory investment and the other funding mechanisms already included under the current price control, specifically whether there is it would be appropriate to maintain the separation of these mechanisms or to secure greater integration. We note that a key feature of the proposals from the Scottish transmission companies is that specific projects would be nominated for inclusion in the enhanced incentives arrangements, thereby treated separately. In contrast, National Grid's proposal adapts the revenue driver mechanism to the reflect the extent to which the investment is anticipatory, while recovering the same outcomes as the current revenue drivers for investments based on prevailing signalled need. We seek views on the respective merits of these approaches and the implications for developing success criteria for gauging the efficiency of anticipatory investment.

3.29. We seek views on the above issues and on whether there are any other factors to consider in designing an incentive mechanism in relation to anticipatory investment.

Rate of return and risk/reward options

3.30. In considering arrangements providing different potential for reward to reflect different levels of risk, it is possible to distinguish between the following types of risk:

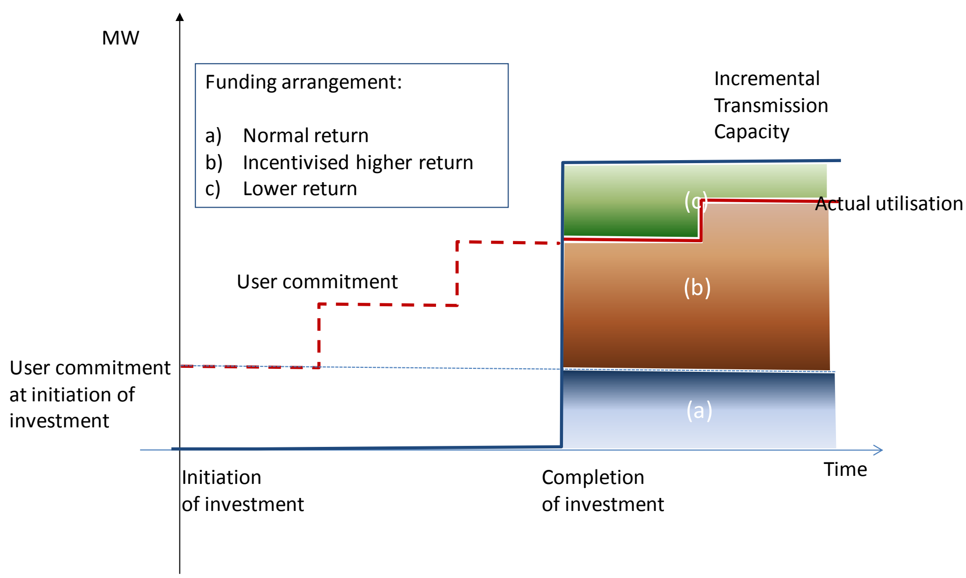
- **Asset utilisation risks** – the primary aim of the enhanced incentive is to encourage the TOs to bring forward the investment in assets which will subsequently be utilised. It might be appropriate to allow an enhanced rate of return to reflect asset utilisation risk. For this incentive to operate, we may need to make a commitment to a package of funding that is linked to the long-term use of the assets. In this way, some of the risk of under-utilisation would remain targeted on the transmission companies.
- **Construction/execution risks** – a number of the potential projects that have been identified by the TOs involve the use of new technology and new approaches. For example, the TOs have been considering the desirability and feasibility of offshore, high voltage direct current cables. It might be approapriate to allow an enhanced rate of return to reflect this risk. But it may then be appropriate, as these risks drop away (for example post construction), to taper rates of return back to normal levels. We would welcome views on this approach.
- **Delivery risk** - we note that the current revenue drivers already provide for increased reward, through an earlier revenue stream, for early delivery. We seek industry views on whether or not this same principle should similarly apply to anticipatory investment.
- **Cost risk** - we note that under the current funding arrangements, the transmission companies have some exposure to the risks that actual investment costs will differ from

regulatory allowances, with the extent of this exposure varying though the scheme parameters rather than through the rate of return. We seek industry views on whether or not this same principle should similarly apply to anticipatory investment.

3.31. In relation to asset utilisation risk, we consider that the following principles might apply, illustrated in Figure 4 below:

- For the proportion of the delivered capacity that there is full user commitment at the time of TOs initiating investment, then normal price control provisions would apply;
- For the proportion of the delivered capacity that were utilised in addition to the user commitment at the beginning of the TOs' investment, an incentivised premium reward eg in form of higher rate of return could be considered, and
- For the remaining proportion of the delivered capacity not yet utilised some minimum level of funding is provided, eg in form of lower rate of return.

Figure 4 - Potential incentive mechanism to reflect asset utilisation risk

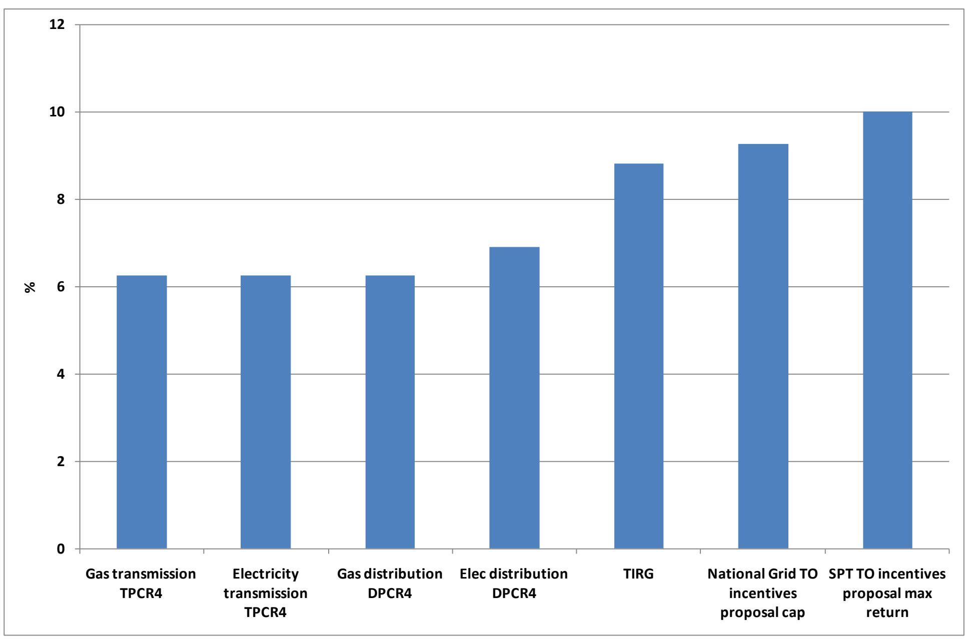


3.32. The differential rates of return, extent of exposure to incentivised costs, and other parameters of the funding mechanism could be designed to strike an appropriate balance of risk between the TOs and customers. It may be appropriate to consider a limited period of time for these differentiated rates of return to apply before all efficient costs are allowed to enter normal RAV and be allowed normal return for the remaining asset life. We seek views on this approach.

3.33. Both SPT and National Grid's proposal would see them earning a higher return on efficient, timely (or early) investments, than under the standard price control. Under SPT's proposal, delivery of investment that provides greater than 125% of the capacity requirements of contracted generation and greater than 6 months ahead of need, would see them earning a pre-tax rate of return of 10%, compared to the standard price control return of 6.25%. Similarly, National Grid's proposal would place a cap on earnings equivalent to a pre-tax rate of return of 9.25%. These levels of return exceed those allowed for in TIRG of 8.8%, albeit with specific tax adjustments which differ from the methodology used in calculating the current base price control of 6.25%. Figure 5 below indicates the rate of return employed in several areas of the regulatory regime to illustrate the relativities of the TOs' proposals. The differences between the regulated returns relate primarily to different assumptions rather than different levels of risk. Whilst there is a higher rate of return on TIRG assets, we stated in the TIRG Final Proposals that there is no compelling evidence that transmission reinforcement for renewable generation is at a higher risk of stranding than other transmission investment.

3.34. Whilst at this stage it is too early to give a view on the appropriateness of any rate of return figures set out in the TOs proposals, we think that any mechanism and associated returns should be commensurate with the level of risk to which the TOs are exposed. We would welcome views on the rates of return identified by the TOs, specifically in the light of current financial conditions, and taking into account the relative risks involved. We also seek views on whether the rate of return available should be subject to a cap and collar, and if so, the appropriate basis for setting these scheme parameters, e.g. in relation to the parameters used in setting the regulated rate of return under the price control. We would also be interested in respondents views as to whether there are any parallels with international examples in which an enhanced rate of return is available to regulated companies for taking on additional risk in undertaking network investments.

Figure 5 – comparison of pre-tax real WACC



Nb – whilst the same measure for the cost of capital is used in the chart above, there will be differences in the exact methodology used, for example in the treatment of tax.

Other considerations

3.35. The proposals we have received from the transmission companies show a wide spectrum of possible approaches. The most suitable approach may vary depending on the particular circumstances surrounding the investments to which the incentive mechanism will apply. It will also be appropriate to consider whether there are other approaches which could be adopted, and which take account of interactions with other areas, see below.

Competitive approach to major projects

3.36. Ofgem is committed to considering the merits of introducing greater competition into activities wherever this is practical and expected to result in significant customer benefits relative to the expected costs of introducing competitive processes. In this context, we will consider whether there would potentially be benefit in some significant new projects being opened up to competition, or subject to new incentive arrangements. Ofgem has already published its view that one of the options for building the connection infrastructure to the Scottish Islands is via a competitive tender. Similar approaches for discrete projects may yield benefits to the consumers.

3.37. As set out in Chapter 1, the current estimate provided by the TOs in relation to the amount of investment needed to deliver the transmission infrastructure necessary for 2020 is in the range £4bn - £9bn. There could be significant reductions in the costs to consumers in the event that this investment is secured at a lower rate of return. If total capex costs were to be £6bn, a 10 basis point (0.1%) decrease in the pre tax real WACC (for example, from 6.25% to 6.15%), over a 40 year lifespan would reduce the total cost to consumers by £120m (£60m in NPV terms). This is equivalent to savings of between £5m and £6m per annum for the first five years.

SHETL is developing proposals to build transmission connections out to the Western Isles and Shetland in order to connect planned renewable generation in those locations to the mainland network via submarine cables. As part of TPCR, it was agreed that SHETL could recover the efficient cost of pre-construction works (in the period leading up to the application for consents) for these proposed connections. Separately, Ofgem set out its initial views in June 2007 that it may ultimately be appropriate to adopt a competitive approach, similar to the offshore transmission regime, for delivering transmission connections to the Scottish islands. The scope for opening any projects to competition depends on several factors, not least the specification of the project and the potential for a competitive approach to result in a lower cost and higher level of service.

3.38. We would welcome views on whether respondents think that we should pursue a competitive approach to the investment required for 2020 and, if they do, what form this approach should take. We could, for example, limit the competition to existing licencees and ask the three existing transmission companies to submit competing offers under our proposed incentive framework. Or we could widen the arrangements and invite other companies to apply for transmission licences and bid against the existing companies.

Access reform and SO incentives

3.39. Establishing the right commercial incentives on the TOs, and to NGET in its role as GBSO, is vital to improving transmission access. When connecting new generation, the TOs do not provide firm connection dates, or provide compensation if delivery of infrastructure is delayed. Therefore there is no incentive on the licensees to deliver on time or early. Instead, the generator bears the risk of delay. We stated in the TAR Final Report that firm connection dates and appropriate incentives are vital in addressing the defects in the transmission access regime.

3.40. The introduction of enhanced transmission investment incentives could potentially support the implementation of a revised enduring access regime, targeted for April 2010. In the shorter term there may also be some synergies with the development of the next GBSO external incentive scheme, which is due to be implemented in April 2009.

RPI-X@20 project and TCPR5

3.41. In the above discussions we focussed on options for investments which commence during the current transmission price control period (TPCR4). Investment incentives, including those considered here, will also be reviewed as part of the RPI-X@20 review. The proposals from the RPI-X@20 review, which will be made to the Authority in Summer 2010, will be relevant for TPCR5. We think it is crucial that our work on enhanced incentives is consistent with our work on RPI-X@20. We will ensure that interactions between our work on anticipatory incentives and the RPI-X@20 review are taken into account. We will consider the appropriate timing of any suggested changes to incentives for future enhanced transmission investment. In particular, we consider that it may be important to give consideration to the definition of investment which would be covered by enhanced incentive arrangements and the investments that would be covered by other regulatory mechanisms.

3.42. There will be joined-up working across the two projects to ensure any interactions are identified and discussed. An initial consultation document regarding the RPI-X@20 review is planned for publication in Q1 2009. We will endeavour to ensure that issues associated with enhanced incentives are reflected in the RPI-X@20 consultation document. A further consultation document on RPI-X@20 is scheduled for publication towards the end of 2009 and we will take steps to ensure that the policy synergies with enhanced incentives are taken into account.

3.43. In the event that any changes are recommended under the RPI-X@20 review which could have implications for the incentives on the transmission companies, we would take steps to put in place appropriate arrangements to ensure effective transition from the existing arrangements. We think if may be important to ensure that the findings from the RPI-X@20 project do not disturb the arrangements established for anticipatory investment related to individual projects during the current regulatory period.

3.44. We would welcome views on the interaction between our work on enhanced incentives and the RPI-X@20 project. In particular, we would be interested to understand whether parties may have any concerns regarding the overlaps between the projects or the best way to take account of these linkages.

Proposed way forward

3.45. As set out earlier in this document, the initial results of the 2020 investment study highlight the need to put in place a framework for anticipatory investment. This applies to projects likely to arise under the current price control period as well as to projects that may be identified in the future. There are two broad areas of focus:

- Consideration of the extent to which current funding arrangements create barriers to investing ahead of need, and taking appropriate steps to address such barriers, and
- Ensuring that the TOs have appropriate incentives to invest ahead of need where to do so is more efficient than investing on the basis of user commitment.

3.46. The former issue is particularly pertinent in the short term as the current arrangements may not facilitate commencement of work on certain projects currently in the pipeline. There are a range of possible approaches to the complex issues identified above in relation to providing appropriate incentives to undertake anticipatory investment. We have also identified a range of issues to consider in developing an appropriate framework which provides incentives to invest ahead of need, with appropriate risk/reward options and efficiency tests. The potential scale of investment to which the incentives might apply, and identification of projects which could commence within the current price control period, will be made clearer when the 2020 investment study reports its findings in January 2009.

3.47. In the TAR Final Report we commited to put in place revised arrangements in April 2009. Having considered the proposals received from the transmission companies, and for the reasons set out below, we think that a longer process than that envisaged in the TAR Final Report may be appropriate for the development of an incentive mechanism. However, as discussed in Chapter 4, we also have identified work which could be undertaken in the short term, by Spring 2009, to address immediate barriers to undertaking anticipatory investment.

3.48. We therefore propose to take forward the work in relation to anticipatory investment in two areas: first, measures to address current and immediate barriers, specifically allowing funding to enable acceleration of known projects; and second, further measures to allow funding for investments that could be commenced during the current transmission price control period. Arrangements for investments which start after this period will be considered as part of the next transmission price control review, building on any recommendations from the RPI-X@20 project.

3.49. We consider that there are merits in splitting our work in this way. We think this will allow us to accelerate the delivery of arrangements to overcome short-term impediments – allowing us to ensure that there are no regulatory blocks to the urgent work that the TOs will need to undertake to develop a network which addresses the challenges of the 2020 commitment. It will also allow more time to develop and agree appropriate arrangements for additional projects under the current transmission price control as well as more fundamental reforms, and facilitate a joined up approach with the RPI-X@20 project. Our detailed rationale for this approach, on which we invite views, is set out in more detail below. Our proposed consultation process is set out in Chapter 5.

Measures to address short term barriers to anticipatory investment by spring 2009

3.50. We note that facilitating timely investment in potential future transmission projects to achieve the 2020 targets is the ultimate aim of the revised incentive arrangements. However, as highlighted by the proposals received from the transmission companies, there is a more urgent requirement to put in place arrangements to address current and immediate barriers to anticipatory investment, particularly for specific projects which are already in the pipeline. We consider that a key initial focus should be to consider what steps can be taken in the short-term to address the barriers to investing ahead of need for currently known projects. Chapter 4 sets out our initial thinking of the steps that could be taken in the short term to refine the current funding arrangements, by adapting the revenue drivers, to provide a framework for anticipatory investment in identified projects.

3.51. Given that these measures would involve relatively minor changes and have limited application, we consider that a relatively rapid consultation and development process would be appropriate for the short term scheme, to enable revised arrangements to be implemented by Spring 2009. We seek respondents' views on whether this is an appropriate approach. In particular, we note that respondents may consider that adapting the current revenue drivers may not be an appropriate way forward in the short term, and that efforts should be focussed on developing fundamental changes to strike an appropriate balance between risk and reward.

Further measures to be implemented by winter 2009

3.52. We also need to consider whether further measures are needed to the design of the incentives to encourage the TOs to invest ahead of signalled need. We will consider whether measures can be introduced by winter 2009 to facilitate additional investments that could commence during the current transmission price control period. We think that it would be appropriate to allow more time to consult on and develop such measures, than was envisaged in the TAR Final Report, for a number of reasons, as discussed below.

Current financial market uncertainties

3.53. Current financial market conditions are making it more difficult and/or expensive for network businesses to raise finance. At this stage it is not possible to predict whether this is a temporary, or more enduring, feature of the capital markets. We will keep this under review but think that given the significant (and unprecedented) capital market uncertainty, allowing more time to develop the longer-term measures we give us more time to assess the implications of recent financial market developments on our proposals.

Need to allow adequate consultation

3.54. Based on the preliminary work of the 2020 investment study described in chapter 1, the scale of investment which might be funded through the new incentive mechanisms, over and above projects already covered by the current funding arrangements, is considerable. Given the lead time for transmission reinforcements it is likely that work will need to commence on at least some of these projects within the current price control period. Development of appropriate incentive arrangements for such projects will be a major undertaking which will require a careful assessment of the risk and reward options. Given the potential scale of investment, and the broad spectrum of possible approaches, we consider our approach to consultation should be broadly consistent with the approach that might be expected to be adopted in a price control. It would not be possible to follow and complete such an approach by April 2009.

Complexity of potential interactions

3.55. It is likely that developments in access reform will, in some way, shape the design of appropriate future incentive arrangements. This is because the arrangements for providing user commitment are a key factor in assessing the extent to which the investment is anticipatory, as well as in measuring utilisation and assessing whether the investment is efficient. We also need to consider interactions with parallel work in other policy areas, including RPI-X@20 and TCPR5. We will ensure consistency across the projects and consider appropriate timetables for any changes in a holistic way across all relevant projects. Finally, some of the projects identified by the ENSG, such as offshore reinforcements, interact with other areas of Ofgem policy that have not yet been decided. This includes the treatment of Scottish islands connections, and the wider application of competitive tendering for onshore transmission projects. The scale of these interactions, and identification of relevant projects, will be made clearer when the ENSG reports its findings in January 2009.

Consideration of alternative options

3.56. We would welcome views on our proposal to allow longer to consider the design of an appropriate incentive mechanism. In developing this proposal, we have considered the alternative approach of seeking to fulfil our commitment in the TAR Final Report to introduce incentive arrangements in April 2009. We note that under this approach it would necessarily mean that there would be less time for industry consultation and engagement. We have also considered whether to take forward our our work on anticipatory investment through the RPI-X@20 project rather than through TAR. We note that under this approach it is unlikely that we would be able to introduce arrangements which could apply to projects commencing within the current price control period.

3.57. We think it is important that high priority projects are not delayed through a failure to invest in a timely way. Equally, it is important that there is appropriate protection to ensure that customers are not paying in the future for assets which are not needed. Further, given the potential scale of investment, and current issues relating to the GB queue, it is important that industry and other interested parties have an opportunity to express their views on the way forward. We seek views on whether our proposed approach strikes an appropriate balance between these considerations.

4. Addressing short term barriers to anticipatory investment

Chapter summary

This chapter summarises our views on the issues that the transmission companies are facing in the short term that could be barriers to anticipatory investment. We set out our views on the treatment of pre-construction costs, and our views on the scope and necessity of amendments to the existing regulatory funding arrangements in the short term.

Question box

Question 1: Noting the large allowances that have already been made, what measures could be taken to enhance the regulatory treatment of pre-construction costs, whilst protecting consumers from expenditure that turns out not to be efficiently incurred?

Question 2: Do you agree with our view that there is a less compelling case to revise the existing local works revenue driver provisions, and that short term improvements could be better focused on the funding arrangements for deep infrastructure works?

Question 3: What are your views on the enhancements that could be made to the funding arrangements for deep infrastructure works, and do you consider that we should focus our attention on delivering quick wins in the short term?

Introduction

4.1. This chapter outlines our initial thinking on the steps that could be taken to address current blocks to investment in projects that are either known and/or will be required in the short term. These short term measures focus on identifying potential amendments to the provision of funding for pre-construction and construction works to facilitate earlier investment in projects where work could potentially start within the next year or so, but which could be delayed under the current arrangements, because of a lack of signals from users, or lack of explicit provision within the revenue drivers.

Potential refinements to the current funding arrangements

4.2. In order to identify the need to enhance incentives or to remove blockages to timely investment, we have reviewed the current regulatory funding arrangements for projects, and have characterised them as follows:

- Pre-construction costs; and
- Construction costs, subdivided into:
    - Local works, and
    - Deep reinforcement works.

Pre-construction costs

Current treatment and associated blocks

4.3. In terms of investments for connecting generation, there are two funding arrangements for pre-construction costs in the current price control. For the majority of investments, the pre-construction costs are factored into the overall capex allowance either within the baseline or under the relevant revenue drivers. In either case, the allowed pre-construction costs are subsequently inserted into the RAV along with the efficient construction costs of relevant projects and earn a rate of return. For SHETL, recognising the importance of early execution of the pre-construction works for a number of significant potential investment projects, funding for the associated costs of these projects has already been included in the baseline allowance.

4.4. Where pre-construction costs are included within the same revenue allowance as the construction works, they are also subject to the same conditions. The TOs have suggested that the close linkage between revenue driver funding and outputs (generation connection or boundary transfer change) means that the funding for pre-construction costs is over-dependent on specific signals from connecting generators. In particular, for timely delivery of the necessary investment to enable generators to export its power, pre-construction costs may need to be incurred on schemes for which a sufficient need case may not be delivered for several years hence. We understand that this problem is more relevant in cases of large uncertain deep works projects.

4.5. In the longer term it may be possible to develop arrangements to resolve this issue in a holistic manner with more sophisticated risk and reward incentive design for pre-construction costs as well as construction costs. However, as discussed in chapter 3 we consider that in the short term there is a strong case for taking away immediate blockages for pre-construction works that are on critical path to deliver network solutions likely to be required for achieving the 2020 targets. We think this is appropriate given the relatively low materiality of costs for pre-construction works compared to construction works, and taking into account the potential benefits of undertaking pre-construction works early in certain cases.

4.6. The current revenue driver mechanism based on local generation connection volume and/or boundary flow does not incentivise the TOs to invest on an anticipatory basis because the signals they receive from generators are often not received sufficiently early.

Proposed short term measure – pre-construction costs

4.7. The transmission companies have informed us that there would be real benefit if they were able to conduct pre-construction works for certain projects, and if they were able to invest earlier to undertake feasibility studies and route investigations (in the case of new transmission lines). Whilst in some cases this would only reduce the process by a few months, for certain large investment projects, the ability to conduct pre-construction works early could result in significant reductions in the timescale for completion of the project, with a consequential impact on the connection timescales for generation projects contingent on the completion of the transmission works.

4.8. As we mention above, we have already allowed a considerable amount of funding in the baseline price control allowance for all three TOs. Therefore for us to propose freeing up additional funding, we would require from the TOs a list of which projects would be eligible. For projects already covered by current funding arrangements but proposed by TOs for separate funding without depending on the previously defined outputs, the revised treatment of pre-construction costs must avoid the potential for double counting, and this in turn may require amendments to the cost allowances under the current revenue drivers in order to separate out pre-construction costs. We envisage this list of projects will only include those for which pre-construction works would need to begin imminently.

4.9. In the short term, we consider that there are two potential approaches for providing earlier entitlement for pre-construction costs for specific projects. We consider that these can broadly be categorised as one of the following:

- **A mixture of pass-through and incentivisation.** This approach is essentially the same approach as that for the current baseline allowance. One variation could be that the pass-through proportion is provided on the basis of, instead of a pre-set time profile, a more dynamic linkage with a suitable trigger, for example, representative of a more realistic view of when costs may be incurred. Similarly for the timing of the incentivisation element, we consider this could relate to a defined trigger being met, such as consents for a project being achieved or upon completion. Our initial thought in this area is that any such combination of pass-through and incentivisation for pre-construction costs would benefit from being consistent with the incentive effect of the other provisions of the revenue drivers, and as such could be in the form of 75% pass through and 25% incenvitisation. The incentive part of this approach requires Ofgem setting the allowed costs ex-*ante*.

- **A "logging-up" treatment.** This option would be for the TOs to undertake pre-construction works without explicit *ex-ante* funding under the current price control. Expenditure would be "logged-up" and assessed at the end of the current price control period. Efficient spend will be remunerated from the beginning of the next price control, i.e. April 2012. This approach would not need *ex-ante* assessment of efficient costs. However, compared to the first option above, there may be concerns regarding the relatively weak efficiency incentive and/or potential lack of regulatory funding certainty. It is also possible that the mechanism may put company finances under strain.

4.10. We would welcome comments on these proposals and, at the same time, invite nominations of pre-construction works for relevant projects and forecasts of associated costs from the TOs, by the end of January 2009. We note that this might include projects not already covered by the current revenue drivers. Subject to the responses to this consultation and our assessment of TOs' submissions, we expect to include final proposals and statutory consultation for pre-construction funding arrangements in late February 2009.

4.11. It should be noted that for projects that are considered to be "imminent" by the transmission licensees, and are of the same inherent risk as those projects in the baseline and the revenue drivers, efficiently incurred pre-construction costs would earn the usual level of return based on the transmission price control review 2007/12 weighted average cost of capital. We would welcome views on this proposal.

Construction costs

Current treatment and associated blocks

Local works

4.12. While the generation connection volume remains within baseline levels, the revenue allowance for the TOs from the relevant capex allowance is fixed for the 5 years of the price control. When the generation connection volume exceeds the baseline levels, the UCA-based local revenue drivers provide additional funding allowances[13]. If the generation connection is short of the baseline, the revenue drivers described in chapter 2 will result in an adjustment at the beginning of the next price control such that the surplus revenue is taken back.

4.13. The revenue drivers, for both upward and downward revenue adjustments, link the TOs' income closely with the outputs in terms of connected generation. Together with the expectation of the review of efficiency including the need case of investment, such funding arrangements contribute to the caution exercised by TOs who normally would only carry out local works construction when there is sufficient user commitment. Given that local works tend to be only for the benefit for a single user or a small group of users, it could be argued that requiring user commitment before transmission investment represents an appropriate balance between renewable growth and consumer interests. We also note that the gap between the lead time of local works construction and the period between when a generator provides appropriate user commitment, and completion of the generating station does not appear to be as significant as the gap which is often experienced between deep reinforcement works and generation build times. In addition, the potential for there to be stranding of local works will increase if investment is delivered on an anticipatory basis for the benefit of either a single generator or a small number of generators, with limited potential for the connection assets to be reused.

4.14. On this basis, we do not consider that there is a need for immediate changes in terms of funding for local works. We would welcome views on this.

Deep reinforcement works

4.15. As with the local works, the baseline revenue allowance under the price control provides funding for a range of deep reinforcement works necessary to accommodate the assumed generation connection volume and boundary flow patterns for all three TOs in the period from 2007-12.

4.16. When the generation connection volume remains within baseline levels, the funding for deep works by the Scottish TOs are fixed without any negative revenue drivers. Any expenditure that was allowed within the baseline but are not subsequently justified would be assessed at the end of the price control period, and adjusted accordingly. In the case of

[13] In the case of the Scottish TOs, additional revenue allowances start as soon as the generation volume exceeds the baselines and the TOs commit to 25% of the total project spend. In the case of NGET, the total additional revenue allowance is calculated at the end of the price control and results in an adjustment at the beginning of the next price control.

NGET, this assessment uses the same £m/MW formulaic format as NGET's local works revenue drivers. The parameters were derived on the basis of costs and capacity delivered for a number of known projects. Lower outturn in flows across defined boundaries would result in a lowered allowance, trued up at the end of the price control, in the same way as the local drivers.

4.17. For deep works projects associated with material alterations in boundary flows beyond that assumed under the baseline, the deep revenue drivers provide funding subject to meeting defined flow patterns. In the case of NGET, again the same £m/MW formulaic format applies as its local works revenue drivers. For the Scottish TOs, the current funding arrangements are determined by total costs, triggered by the volume of generation connection in specified regions exceeding preset thresholds. The cost and trigger parameters were set on the basis of a number of known projects for SHETL only.

4.18. For National Grid, there may be additional projects that were not known when the revenue drivers were set that may need to be added to the scope of the existing provisions. In the event that this is the case, we would expect National Grid to come forward with details of the projects and the associated project costs. Given the effort that will be required, we do not consider that detailed project assessment work could be agreed between NGET and the Authority in time for April 2009. However, we are seeking industry's views on this issue.

4.19. For SHETL and SP Transmission, we consider that the deep revenue drivers may be contributing to them not being able to invest early enough to meet the needs of connecting generators. We consider that the main issue is the requirement for user commitment from generators that would enable the TOs to meet the relevant trigger conditions under the deep revenue drivers. In the absence of clear and sufficient signals from generators, such funding arrangements would not encourage the TOs to invest in anticipation, as they would not have the certainty of receiving funding for such investment. For example, in the event that there are a number of generators sited in the same vicinity that, when taken together, would justify a deep reinforcement project, the speed with which the user commitment can materialise may be affected by just one of those generators experiencing problems.

4.20. We also consider that the lead time for the construction of deep works will, in a number of circumstances, be significantly longer than the period between when a prospective generator can provide firm commitment and when it is completed, and is likely to result in wider reinforcement works being delivered considerably after the point when the generator is in a position to connect to the network. This is particularly the case for smaller projects with low lead times such as wind generation. The Beauly-Denny upgrade under the TIRG funding mechanism is a clear illustration of the mismatch between transmission and generation lead times. Ofgem originally provided funding for Beauly-Denny in December 2004, which, with a 3 year build profile could have seen Beauly-Denny completed in 2009. However, because of significant delays in planning consents, even if the project receives consent, work is unlikely to begin until the middle of 2009. There is a considerable volume of generation in northern Scotland that is dependent on Beauly-Denny that is being delayed or held off by the continuing delays to Beauly-Denny.

4.21. The transmission licence lists the deep revenue driver projects for SHETL and SP Transmission. For SP Transmission no entries were included as deep revenue driver projects as all relevant funding for known projects was provided for in the baseline. For

SHETL, there are four projects, each with a defined set of generation criteria and project costs. It might be appropriate to take forward work on some of these projects ahead of the materialisation of the currently specified triggering conditions. There are also likely to be additional projects that will need to be funded in the period up to the next price control. We do not consider however that it will be feasible to complete the detailed capex assessment work for such projects in time for Spring 2009. We therefore do not propose to consider this issue further as part of our work on short term measures, but will consider it as part of our work on further measures. We are seeking industry's views on this issue.

Proposed short term measures

4.22. We note in Chapter 3 that the enhanced mechanisms including fully developed risk and reward parameters for the TOs require more work that will take us beyond the short term implementation of Spring 2009. However we consider that there are some areas where enhancements can be made in the short term, and would welcome the industry's views.

4.23. At present what appears to be preventing the TOs from investing in construction works on deep reinforcements in an anticipatory manner is the linkage between funding provision and user commitment, in the form of either formulaic revenue drivers or MW trigger thresholds. Therefore one option in the short term would be to provide regulatory funding without explicit dependency on such outputs for a number of specific projects that need to proceed imminently, but there would need to be appropriate safeguards to avoid inefficient investment.

4.24. This approach would require detailed assessment by Ofgem of the need case and efficient construction costs for specific projects using the most up to date information arising from the pre-construction works process. We envisage this approach to be applied only to projects that can be justified for investment imminently and ahead of clear user commitment. Given the certainty of funding and similar incentive properties as contained in the current price control, we do not consider any further enhanced rate of return would be appropriate for such projects.

4.25. We welcome comments on the options that we are putting forward on short term measures, and in particular whether any aspects would be better considered over the longer term.

5. Way forward

Chapter Summary

This chapter sets out the way forward, including our proposed consultation process.

Question box

Question 1: Do respondents have any comments on our proposed approach?

Question 2: Do respondents have any views on our proposed consultation process for taking forward the development of our proposed short term measures and further measures?

Way forward and timetable

5.1. This document invites responses by 30 January 2009.

5.2. As set out in chapter 3, subject to the outcome of this consultation we propose to separate our work under TAR into:

- **short term measures** to be implemented in **Spring 2009**, addressing barriers to anticipatory investment in currently known projects, as discussed in chapter 4, and
- **further measures** to be implemented in **Winter 2009**, for application to additional projects commencing under TCPR4.

5.3. Measures relating to investments undertaken under TCPR5 and beyond will be considered as part of the next transmission price control review, building on the recommendations of the RPI-X@20 project. As set out in Chapter 3, we think it may be appropriate for arrangements put in place for anticipatory investments that commence during TPCR4 to be unaffected by any proposed changes coming out of RPI-X@20 project.

5.4. We would propose the following process for our proposed work under TAR:

- **Consultation on short term measures, February/March 2009** – following closure of the first consultation, we would be making final proposals and producing a statutory licence consultation to implement our proposed short term measures in Spring 2009.
- **Consultation on further measures, Spring/Summer 2009** – this document would set out our updated thinking, taking into account responses to this consultation, on further measures to be introduced for projects commencing under the current transmission price control. It would include an update on the findings of the 2020 investment study and on interactions with the RPI-X@20 project.

- **Potential further consultation, Autumn/Winter 2009** – depending on the views of respondents to the previous consultations, we may undertake a further consultation in before producing a statutory licence consultation to implement our proposed further measures in Winter 2009.

5.5. We invite comments on this proposed approach. We note that if the industry judges it appropriate to have a longer period of time to review potential short term measures, or would prefer to consider the development of a framework for anticipatory investment under a single workstream, it would be difficult to establish new arrangements in Spring 2009.

Further information

5.6. Appendix 1 sets out both the details for responding to this consultation and the appropriate contact details should you have any questions. It also sets out a list of all the key areas where we have sought respondents' views in this document. Respondents' views are also welcomed on any other aspect of this document.

Appendices

Index

Appendix 1 - Consultation Response and Questions

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

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

1.3. Responses should be received by 30 January 2009 and should be sent, preferably in electronic format by e-mail to:

transmissionaccessreview@ofgem.gov.uk

or alternatively by post to:

Cheryl Mundie
Senior Manager - Transmission
Ofgem
70 West Regent Street
Glasgow
G2 2QZ.

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

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

1.6. Next steps: Subject to the outcome this consultation, it is currently our intention to take forward the work set out in Chapter 5 of this document.

1.7. Any questions on this document should, in the first instance, be directed to Cheryl Mundie (e-mail: cheryl.mundie@ofgem.gov.uk, tel: 0141 331 6003) or David Hunt (e-mail: david.hunt@ofgem.gov.uk, tel: 020 7901 7429).

CHAPTER: One

There are no questions in this chapter.

CHAPTER: Two

Question 1: Do respondents agree that there is a need to put in place a framework for anticipatory investment in order to facilitate achievement of the 2020 targets? Do respondents agree that such arrangements should be developed for application to transmission projects commencing within the current transmission price control?

Question 2: Do respondents agree that this work should first focus on identifying and addressing barriers to investing ahead of need, before putting in place appropriate incentives to undertake investment ahead of need?

CHAPTER: Three

Question 1: Do respondents have any views on the proposals received from the transmission companies? Do respondents consider that we have appropriately considered the impediments to anticipatory investment identified by the transmission companies?

Question 2: Do respondents consider that it is appropriate to take the current arrangements as a starting point for developing a framework for anticipatory investment? Have we identified the relevant issues to consider in taking this work forward, e.g. in relation to the definition of anticipatory investment and the design of an incentive mechanism? Do respondents have any views on the appropriate balance of risk and reward in relation to investment undertaken on an anticipatory basis?

Question 3: Do respondents have any views on our proposed way forward, including our proposal to separate short term work to measures address current and immediate barriers, from further measures, developed over a longer timescale, to allow funding for investments that could be commenced under the current transmission price control? Do respondents have any views on how we propose to address interactions with the RPI-X@20 project?

CHAPTER: Four

Question 1: Noting the large allowances that have already been made, what measures could be taken to enhance the regulatory treatment of pre-construction costs, whilst protecting consumers from expenditure that turns out not to be efficiently incurred?

Question 2: Do you agree with our view that there is a less compelling case to revise the existing local works revenue driver provisions, and that short term improvements could be better focused on the funding arrangements for deep infrastructure works?

Question 3: What are your views on the enhancements that could be made to the funding arrangements for deep infrastructure works, and do you consider that we should focus our attention on delivering quick wins in the short term?

CHAPTER: Five

Question 1: Do respondents have any comments on our proposed approach?

Question 2: Do respondents have any views on our proposed consultation process for taking forward the development of our proposed short term measures and further measures?

Appendix 2 – More information on RPI-X@20 project

Introduction

1.1. A key area of interaction with our work to develop arrangements for anticipatory investment under TAR is the 'RPI-X@20' review - a major two year project, initiated by Ofgem in March 2008, to review the workings of the current approach to regulating GB's energy networks and develop recommendations for future policy. The RPI-X@20 project is looking fundamentally at the RPI-X framework, which has been used to regulate Britain's energy networks for nearly 20 years.

1.2. Our work under TAR is focussed on the arrangements to apply to anticipatory investments within the current price control period, i.e. TCPR4, while the RPI-X@20 project, which is looking more fundamentally at the current approach to network regulation and will develop recommendations for the way we regulate in the future.

1.3. This Appendix provides more information on the RPI-X@20 project.

The rationale underpinning RPI-X@20

1.4. While we recognise that RPI-X regulation has delivered significantly lower prices, better service quality and better network reliability since its implementation, we think that it is prudent to undertake a review now for a number of reasons. First, as a matter of good housekeeping, it is right that after 20 years we assess whether the approach remains fit for purpose. Second, the challenges faced by the energy industry have changed, with the emphasis now on facilitating efficient investment to achieve environmental targets and ensure security of supply as well as on the achievement of efficiency gains. Finally, over time RPI-X has become more complex and, if possible, it may be beneficial to simplify the framework to allow customers and companies to effectively engage in price control processes.

Guiding principles for RPI-X@20

1.5. We want to be clear from the beginning of the RPI-X@20 review that we don't intend to implement change for changes sake and amendments to the current regime will only be made where there are clear benefits for consumers. There are a number of further guiding principles to which we intend to adhere as part of the RPI-X@20 review including:

- Consultation: We intend to consult with stakeholders through a range of forums including informal stakeholder workshops, meetings and formal consultation documents as well as via the web forum we have developed which will provide stakeholders with the opportunity to post papers or thoughts regarding RPI-X@20 on the Ofgem website. We anticipate that the use of this range of consultative tools will allow stakeholders with ample opportunity to engage in and contribute to the overall review.

- Transparency: We will be transparent in the way we undertake this project and in how we arrive at conclusions and recommendations. Our consultative approach should help to facilitate this.

- Better Regulation: We will also seek to ensure that the process we follow and the recommendations that we present to the Authority are proportionate, consistent and targeted towards the issues in hand. We will remain accountable for the conclusions that are reached as well as the process that is followed.

- No surprises: Adopting a transparent approach to the RPI-X@20 review will ensure that stakeholders are aware of the direction of Ofgem's thinking and the rationale underpinning the recommendations that we take to the Authority. There should not therefore be any surprises for stakeholders.

- No retrospective action: We understand the importance of maintaining regulatory certainty and therefore are keen to make clear that RPI-X@20 will be focussed upon the framework for future regulation of energy networks rather than reconsideration of any decisions taken in the past.

- No stranding of efficient investment: Where efficient investment has been undertaken by network companies, suitable funding arrangements will be incorporated within any framework that may be adopted following the recommendations of the review.

Timetable for RPI-X@20

1.6. The RPI-X@20 project is set to report to the Authority in Summer 2010 and therefore there are clear linkages between this and TAR in terms of the timelines that are being faced. It will be important to recognise the overlaps between these projects and to ensure that the issues exposed in both projects are fed into considerations of the other.

1.7. An initial consultation document regarding the RPI-X@20 review is planned for publication in Q1 2009. Following the receipt of responses to this consultation, a series of RPI-X@20 workshops will be scheduled to discuss the issues identified in the initial consultation in further detail and it will be important to maintain appraised of the discussions that take place in these forums. A further consultation document on RPI-X@20 is scheduled for publication towards the end of 2009 and therefore, in considering arrangements for Winter 2009/Spring 2010, we will take steps to ensure that the policy synergies are taken into account.

Appendix 3 – More information on price control and incentives

Introduction

1.1. This Appendix supplements the information set out in Chapter 2 of this document by provding a more detailed overview of the price control and incentives, followed by further details of the revenue drivers introduced under the current transmission price control.

Price control and incentives overview

1.2. Under the transmission price control, each of the transmission companies is provided with a future level of revenue and appropriate incentives to be able to meet their statutory duties and licence obligations. The price control restricts the amount of money that a monopoly business can earn from its regulated business. The combined revenues allowed to the TOs under the price control are recovered by via charges on transmission users, and are ultimately paid for by consumers. The regulatory mechanism controls prices, not profits, and therefore encourages efficiency within the company, which in turn ensures consumers obtain good value for money. The price control also includes other incentive mechanisms to encourage companies to deliver what customers require. For example, companies can be rewarded or penalised depending on the quality of service they deliver. The combined allowed revenues across all TOs is [XX] in 2008/09, and the cost ultimately paid by consumers represents around 3% of a customer's bill.

1.3. The price control seeks to provide the company with a level of revenue that is enough to finance an efficient business, based on an estimate of the costs companies face in running their business. These costs include:

- Operating expenditure – covering the day-to-day costs of running the network, such as staff costs, repairs and maintenance, overhead costs, etc. An allowance is made to cover the amount of operating expenditure ("opex") which an efficient company would be expected to incur over the price control period.

- Capital expenditure – covering spending on assets, such as overhead lines, underground cables and other plant. A projection is made of the level of capital expenditure ("capex") that an efficient company would incur over the price control period. The benefits of capex are expected to last over several years so the companies recover these costs over the assumed lifetime of the asset rather than in the year of occurrence.

- Financing costs – covering the costs an efficient company may be expected to incur in providing a reasonable return to the investors who provide the capital and other financial liabilities it requires.

- Taxation – the price control must provide sufficient cash flow to cover the tax liabilities that an efficient company may be expected to incur, taking into account, for example, the current rate of corporation tax.

1.4. The revenue allowances seek to cover efficient costs, as determined during the price control review process. Under the price control, the company is exposed to the risk and rewards of actual costs being different to those allowances. The allowances take into account depreciation to reflect the extent to which assets are assumed to be used in any given year. The rate of return, which applies to the prevailing value of the regulatory asset base (the Regulatory Asset Value or "RAV"), is determined during the price control review process at a level reflecting the assumed cost of capital[14] for each licensee.

1.5. By setting the allowed revenues in advance of costs being incurred, the transmission companies receive financial incentives to operate, undertake capital investment in, and finance their businesses efficiently as any cost savings during the incentive period can increase returns to their investors. Such efficiency improvements will be passed on to customers in subsequent price controls. In addition, under the RPI-X formula, the level of revenue that the transmission companies can recover in any given year is linked to the rate of inflation represented by the retail price index, RPI, subtracted by an efficiency factor, X. The RPI-X formula and incentive regulation is at the heart of all monopoly price controls, although it has been refined and augmented in a number of ways over time[15].

1.6. In developing the current price control[16], which applies to the period 2007-12 for all the transmission companies, Ofgem introduced a framework to strengthen these incentives, particularly in relation to capital investment, in order to improve the incentives on the companies to run their businesses more efficiently. These arrangements include a range of mechanisms, some of which are discussed in chapter 2 of this document, which were designed to provide stronger efficiency incentives to the transmission companies and flexibility to be able to respond to the changing needs of network users. The arrangements under the current price control will be further reviewed as part of the RPI-X@20 review, discussed in chapter 1 of this document, and in the next transmission price control review.

1.7. In addition to its role as a transmission owner for the high-voltage network in England & Wales, National Grid, in its GB System Operator role, operates the high-voltage network over the whole of Great Britain. In this role, National Grid incurs

[14] The cost of capital is the level of return required by the financial markets – both debt and equity - in order to provide capital for a firm. It is calculated as a weighted average of the cost of equity and the cost of debt, for a given assumption about the proportion of investment that is financed by debt (i.e. the level of "gearing").
[15] For example this includes pass-through items, covering costs not fully within the control of the licensee, and excluded services for which there is no explicit revenue cap. It also includes the revenue drivers, capex incentives, safety net and logging up mechanisms described in this chapter. In addition, under the current price control the efficiency factor is only applied in relation to opex costs.
[16] For more information on the current transmission price control, see the TPCR4 area of Ofgem's website at:
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/Pages/TPCR4.aspx

external costs for operating the GB transmission system and for keeping the system in balance in real time by procuring balancing services from network users. These costs, which are also recovered by via charges on transmission users and ultimately paid for by consumers, are covered by the System Operator incentive scheme ("SO incentive scheme"), which encourages National Grid to operate the transmission system efficiently on behalf of all users. National Grid also incurs *internal costs* relating to its role as system operator. These costs are set for the same duration as the price control, and have historically been considered alongside the process.

1.8. We are currently undertaking a review of the SO incentive scheme. There is a potential interaction between operating costs and capital expenditure. We will take this interaction into account, as well wider interactions with the SO incentives review, as we take forward the development of enhanced transmission investment incentives.

Further information on revenue drivers

1.9. The revenue drivers introduced under the current transmission price control are outlined in Chatper 2 of this document, and described in more detail below17.

Application to SPT and SHETL

1.10. The revenue drivers for SPTL and SHETL are linked to the amount of generation that connects over the period 1 April 2005 to 31 March 2012. The key parameters of the scheme are:

- the volume of generation (MW) we assume will be connected in our baseline;
- the capex (£m) and unit cost (£ per kW) we consider to be consistent with this baseline volume; and
- the unit cost we consider to be appropriate for connected volumes of generation over and above the baseline amount

1.11. Once the baseline volume of generation has been connected, additional allowances will depend on the volume of extra generation connected, as well as a proportion (75 per cent) of the actual costs of work-in-progress for the more advanced new connection projects.

1.12. The local revenue drivers have been set using cost data for the range of generation projects that have applied for a connection in the respective areas. The differences between SPTL and SHETL reflect the different characteristics of the projects in the two areas rather than material differences in underlying unit costs. Table 3 sets out the scheme parameters.

[17] For more detail, see the TCPR4 documents.

Table 3 - Revenue drivers for SPTL and SHETL

	BASELINE			LOCAL REVENUE DRIVER
	Volume (MW)	Allowance (£m)	Unit cost (£m/MW)	Unit cost (£m/MW)
SPTL	1,734	94.4	0.054	0.052
SHETL	1,489	35.4	0.024	0.032

1.13. The baseline UCAs are used to adjust the revenues downwards in the event that the baseline volume of generation connected is not achieved over the period, while the revenue driver UCAs only apply once the baseline volume of generation has been connected, by increasing allowances within the period to allow depreciation and a rate of return on:

- 75 per cent of actual additional costs incurred; and
- a further capital sum based on 25 per cent of the estimated unit cost (i.e. the revenue driver) once generation is connected.

1.14. The UCAs are based on average unit costs over a large number of potential connection projects, most of which are relatively small, over the period, and excludes a small number of potential projects which have much higher than average unit costs.

1.15. In addition, under the deep revenue drivers, we specify a set of conditions (in terms of total MWs of generation in specified areas of the respective networks) which, if met, will trigger further revenue allowances, through TCAs set out in the licence. We established two sets of such conditions for SHETL, shown in Table 4, reflecting works that might need to be undertaken between Beauly and Dounreay and between Beauly and Blackhillock to accommodate increased flows across the North West boundary of SHETL's network. At this stage, we have specified no such conditions for SPTL, although the transmission licences makes provision for deep revenue drivers to apply.

1.16. The deep revenue drivers for SHETL relate to investment projects for which, at the time the price control was set, there was no perceived need in the short to medium term. The cost estimates are therefore based on indicative, rather than detailed technical designs. They also relate to projects for which the companies have not yet applied for planning consent. In these circumstances we think it is appropriate for SHETL to re-submit cost estimates as the need for actual investment schemes crystallises and planning consent for specific schemes is granted. This process will also enable us to extend the scope of the price control to new sets of circumstances.

Table 4 – SHETL's deep revenue driver projects and thresholds

c	**Conditions – relevant generation capacity and relevant embedded generation capacity in areas (as identified in Annex A to this condition)**	**Thresholds (MW)**	**DRDc (£m, 2004/05 prices)**
1	North of North West boundary	1850	52
2	North of North of Beauly boundary	300	47
3	South of Port Ann within the South West zone	85	89
4	North of Inverary within the South West zone	105	52

1.17. SHETL was explicitly allowed to recover the pre-construction costs associated with a number of capex projects that are deemed unlikely to commence construction but need to incur costs on pre-construction works such as design studies. Such projects include all "trigger–related" deep investments. This is discussed in more detail in chapter 4 of this document.

Application to National Grid

1.18. The revenue drivers for NGET are, like those for SPTL and SHETL, linked to the amount of generation that connects over the period 1 April 2005 to 31 March 2012. Because of the size of the NGET network, and the material differences in costs across it, we defined revenue drivers on a zonal basis.

1.19. For each zone we determine a profile of generation and demand which is consistent with our baseline capex allowances. We then use the revenue drivers to calculate adjustments, in effect, to our capex allowances to the extent that the actual profile of generation and demand by zone is different to the profile assumed in setting the baseline allowances. These adjustments are not made until the end of the price control period at which point we can observe how much generation has connected or closed, and where these new connections or closures have been. At that point we will make a one-off adjustment to future revenues to provide NGET with the revenues it would have received had we set the adjusted capex allowance at the start of the period.

1.20. The revenue driver adjustments to NGET's capex allowances will be calculated at two levels. First, the local revenue drivers reflect the local infrastructure costs incurred (or avoided) in connecting more (or less) MW of new connections than assumed in the baseline, and are a function of the volume of new connections and closures in each zone. Second, the deep revenue drivers reflect the wider network infrastructure impacts of changes in flows between each zone and the wider network, and are a function of changes in the extent to which there is surplus generation or surplus demand in each zone. The parameters for the scheme are set out in Table 5 below. A separate revenue driver applies to changes in the transfer capability across the network boundary between Scotland and England. If the Authority determines that a change has been made, then a revenue driver shall be activated for the consequent reinforcement works on NGET's network. This revenue driver shall take a value of £275,000 per MW.

Table 5 – NGET revenue driver parameters (£000 per MW)

	Local revenue driver	Deep revenue driver: Zonal Surplus	Deep revenue driver: Zonal Deficit
South & South West	15	0	20
Thames Estuary	15	60	0
London	60	0	250
South Wales	15	25	20
East of England & Home counties	10	65	15
West Midlands	5	0	40
East Midlands	5	55	10
North West & North Wales	30	45	0
Yorkshire & Lincolnshire	15	60	0
North East	15	50	0

Appendix 4 – The Authority’s Powers and Duties

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

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[18]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[19].

1.4. The Authority’s principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[20]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[21]

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

[18] entitled “Gas Supply” and “Electricity Supply” respectively.
[19] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[20] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[21] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[22] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[23] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[22] or persons authorised by exemptions to carry on any activity.
[23] Council Regulation (EC) 1/2003

Appendix 5 – Glossary

A

Access Rights

The rights to flow specified volume of electricity, usually from a specified location (node or zone) to an explicitly or implicitly defined destination (e.g. market hub), and for a defined period. For firm access rights, a failure to deliver access due to insufficient network capacity is associated with financial compensation. For non-firm access rights, the flow is terminated without compensation when capacity is unavailable.

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Balancing Mechanism (BM)

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the BSC.

Baseline

Baselines define the reference levels of capacity that the transmission licensee is to release. Baselines also determine the levels above (or below) which incremental capacity is defined.

Baseline Capital Expenditure

Baseline capital expenditure is the total amount of capex required in association with the baseline. It includes both load related capex and non-related capex.

British Electricity Trading and Transmission Arrangements (BETTA)

The arrangements for the trading and transmission of electricity across Great Britain which are provided for by Chapter 1 of Part 3 of the Energy Act 2004, which have replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales. BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system which came fully into effect at BETTA go-live (1 April 2005).

Balancing Services Use of System Charges (BSUoS)

The charges levied by National Grid in respect of the activities it undertakes to keep the transmission system in electrical balance at all time.

C

Capital Expenditure (Capex)

Expenditure on investment in long-lived transmission assets, such as gas pipelines or electricity overhead lines.

Connection Entry Capacity (CEC)

A measure of the maximum capability, expressed in MW, of a connection site and the associated generation units' connection to the transmission system.

Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the GB transmission system, parties connected to the GB transmission system and National Grid is relation to their connection to and use of the transmission system.

Consents

The process of obtaining Consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consents from landowners who will be affected by the construction of the new line. For a new line consent under section 37 of the 1989 Act will be required.

In addition to section 37 consent, the DNO/TO must also obtain consent from the landowners over whose land the line will run. If a voluntary agreement cannot be struck, then either the land will have to be compulsorily purchased, under the provisions of section 10 and Schedule 3 (which is usually used for substations), or a Necessary Wayleave obtained over it, under the provisions of section 10 (Schedule 4 paragraphs 6-8).

Constraints

In the event that the pattern of generation may exceed the safe operational limits of a particular line or transmission system equipment, the GBSO will take actions to reduce the output of generators at specific locations on the system. At present these actions are taken in the Balancing Mechanism in the form of bids, and also via ancillary services, such as Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs). Where a user's output is constrained down at a point on the system, the overall balance of energy will need to be retained, and costs will be incurred by the GBSO in bringing replacement energy onto the system.

Contracted background

This is the planning background against which National Grid assesses applications for connection and use of system. The contracted background includes all users that have entered into an (ongoing) agreement with National Grid for connection or use of system.

D

Deemed Transmission Entry Capacity (DTEC)

The deemed Transmission Entry Capacity allocated to certain generators under CAP148.

Deep reinforcement

Deep reinforcement refers to the works conducted on the wider transmission system in order to accommodate a change in the generation and demand pattern.

Directly Consequential Works (DCW)

The transmission works identified for a given generator which comprise local works required to connect a generator to the electricity grid.

G

GB System Operator (GBSO)

The entity responsible for operating the GB transmission system and for entering into contracts with those who want to connect to and/or use the GB transmission system. National Grid is the GB system operator.

GB Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain.

K

Kilowatt (kW)/Megawatt (MW)/Gigawatt (GW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts. A GW is a thousand megawatts.

Kilowatt hour (kWh)/Megawatt hour (MWh)/Gigawatt hour (GWh)

One kilowatt hour is the amount of electricity expended by a one kilowatt watt load drawing power for one hour. A MWh is a thousand kilowatt hours. A GWh is a thousand megawatt hours.

L

Load Related Capex

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

Long-run marginal costs (LRMC)

In the context of electricity transmission, long-run marginal costs are the marginal costs of establishing and using network capacity. They include, for example, marginal costs for network reinforcement, as well as resulting network losses and residual congestion costs.

Local works

Those works required to provide a generator with a connection to the transmission network that would enable it to export power.

N

National Grid Electricity Transmission (NGET)

The electricity transmission licensee in England & Wales.

Non-Load Related Capex

The replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

O

Offer

In the context of the Balancing Mechanism, an offer is a tool used by the GBSO, whereby a user submits data parameterising its willingness to increase generation or reduce demand. National Grid then decides whether or not to accept the offer.

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overhead.

R

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee’s regulated transmission or (as the case may be) distribution business (the ‘regulated asset base’). The RAV is calculated by summing an estimate of the initial market value of each licensee’s regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

Re-openers

A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances) under a price control before the scheduled next formal review date for the relevant price control.

Revenue Driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

S

Safety net

A mechanism that would trigger a review of allowances in the event of a major shortfall of investment relative to allowances.

Security and Quality of Supply Standard (SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Scottish Hydro-Electric Transmission Limited (SHETL)

The electricity transmission licensee in northern Scotland.

Scottish Power Transmission Limited (SPTL)

The electricity transmission licensee in southern Scotland.

Sliding scale

This term is used generically to describe incentive schemes which involve profit (and loss) sharing around a fixed target costs, such as the current form of SO incentives in gas and electricity.

T

Transmission Asset Owner (TO)

There are three separate transmission systems in Great Britain, owned by three Transmission Asset Owners, National Grid Electricity Transmission plc, Scottish Hydro Electric Transmission Ltd and Scottish Power Transmission Ltd. National Grid also has the role of system across the whole of Great Britain.

Transmission Entry Capacity (TEC)

Defines a generator's maximum allowed export capacity onto the GB transmission system. The holder of the TEC has the right to export the specified number of megawatts onto the transmission system at any one time, and is eligible for compensation if NGET cannot accommodate this export on the network.

Transmission Investment for Renewable Generation (TIRG)

In the context of this document, this means the regulatory mechanisms developed before the start of the next main price control in 2007, to fund a number of specific network enhancement projects required to provide transmission capacity for new renewable generation plants.

Transmission Owners (TO)

Companies which hold transmission owner licenses. Currently there are three electricity TOs; NGET, SPTL and SHETL. NGG NTS is the gas TO.

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, NGET, SPTL, SHETL and to the licensed gas transporter responsible for the gas transmission system, NGG NTS

Transmission Network Use of System (TNUoS) charges

Charges that allow National Grid to recover the costs of providing and maintaining the assets that constitute the GB transmission system.

U

Unit Cost Allowance (UCA)

A parameter of the revenue drivers for the three TOs. For SHETL and SP Transmission the local works revenue drivers uses a £ per MW funding allowance, and for NGET both the local and deep revenue drivers use a £ per MW funding allowance. Funding allowances that increase or decrease expenditure entitlements by a set amount for each MW above or below baseline assumptions are UCAs.

V

Vanilla Weighted Average Cost of Capital (Vanilla WACC)

The weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity.

W

Weighted Average Cost of Capital (WACC)

The weighted average of the expected cost of equity and the expected cost of debt.

Wider Works (WW)

The transmission works identified for a given generator which comprise deep reinforcement works required to provide capacity to support the additional generation coming online.

Appendix 6 - Feedback Questionnaire

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

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

1.2. Please send your comments to:

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