ofgem Making a positive difference for energy consumers

Consultation on a potential RIIO-T1 and GD1 mid-period review

Consultation

		Contact:	Geoff Randall (Electricity Transmission) and Mick Watson (Gas)
Publication date:	12 November 2015	**Team:**	MPR team
Response deadline:	12 January 2016	**Tel:**	020 7901 7000
		Email:	mpr@ofgem.gov.uk

Overview:

The RIIO-T1 and GD1 price controls allow for a mid-period review (MPR) of output requirements half way through the price controls. We are consulting on whether there is a need to initiate an MPR in Electricity Transmission, Gas Transmission and Gas Distribution. We present the potential issues that we have identified and our initial views on what should be taken forward under an MPR.

Our initial view is that there may be some issues in RIIO-T1 that could be addressed through an MPR. We have not identified any material issues for RIIO-GD1. We have also identified some areas of policy we think would benefit from further clarifications so as to avoid any potential uncertainty remaining until the end of the price control period. Based on feedback from stakeholders we will decide whether, how and when to take any such issues forward.

We are asking for stakeholder feedback on our initial views.

Context

RIIO-T1 and GD1 were the first price controls to reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The RIIO-T1 price control sets the outputs that the electricity and gas transmission network companies need to deliver for consumers and the associated revenues they are allowed to collect for the eight year period from 1 April 2013 until 31 March 2021. Similarly, the RIIO-GD1 price control sets these for gas distribution companies. We have since launched the RIIO-ED1 price control for electricity distribution which runs on a different timetable.

The RIIO framework is designed to promote smarter gas and electricity networks for a low carbon future. The RIIO price control placed much more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network that offers value for money to existing and future consumers. The RIIO framework allows for a mid-period review (MPR) of outputs halfway through the price control.

This is a consultation on the need for an MPR for RIIO-T1 and GD1. If an MPR is initiated it will start by examining the specific issues in more detail and any policy proposals would be set out in summer 2016 for a decision in late autumn 2016. Any associated licence changes would need to be in place by 1 April 2017.

Associated documents

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas

RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd

RIIO-GD1: Final Proposals – Overview

For Initial Proposals, strategy decisions and the RIIO Handbook, please see our dedicated RIIO pages:

- RIIO-T1 price control
- RIIO-GD1 price control

Contents

Executive Summary

Background

RIIO-T1 and GD1 are the first price controls under the RIIO model. They set the outputs that the electricity and gas transmission, and gas distribution network companies need to deliver for consumers and the revenues they are allowed to collect for the eight year period from 1 April 2013 until 31 March 2021.

When we developed the price controls we recognised that there were potential uncertainties that could affect the outputs companies would need to deliver and the expenditure requirements to deliver them. We also acknowledged, given the shift from a five year to an eight year price control period, the potential uncertainties could be greater. So to address this and to ensure the companies continue to deliver the outputs consumers will benefit from, various types of uncertainty mechanisms were included in the RIIO model. These allow changes to a network company's outputs and allowed revenues to be made in light of what happens during the price control period.

Mid-period review

A mid-period review (MPR) of outputs was one of the mechanisms we included in the price controls to help manage uncertainty. In our RIIO-T1 and GD1 Final Proposals[1] for the price controls we said we would consult on whether to have an MPR half way through the eight year price control period.

We said that any potential MPR would cover material changes to outputs that can be justified by clear changes in government policy and the introduction of new outputs that are required to meet the needs of consumers and other network users.

We made it clear that we would not use an MPR as an opportunity to re-open the price controls. We committed to not alter incentive mechanisms, other than as required to accommodate changes to outputs. We also ruled out making retrospective adjustments as part of the MPR,[2] for example, to 'clawback' gains made from delivering the outputs set at the price control at lower cost than expected.

This consultation

We have reviewed each policy area within the Transmission and Gas Distribution price controls. Our initial view is that there may be some issues in RIIO-T1 that could

[1] RIIO Final Proposals: T1 (link 1 and link 2), GD1 (link).
[2] https://www.ofgem.gov.uk/sites/default/files/docs/2011/03/t1decisionuncert_0.pdf paragraph 7.9.

be addressed through an MPR. We have not identified any material issues for RIIO-GD1. Through this consultation, we would like your views on:

1. The scope of an MPR for RIIO-T1 and RIIO-GD1, where we have tried to provide additional clarity on what we said in Final Proposals.

2. Whether we should:

    a. proceed with an MPR for RIIO-T1 for both Electricity and Gas Transmission

    b. not proceed with an MPR for RIIO-GD1.

If we do decide to proceed with an MPR, then there needs to be a balance between making changes to ensure outputs (and associated revenues) continue to reflect the needs of consumers and network users, and providing the regulatory stability associated with an eight year price control. With this in mind, we want to know whether you think that the issues we have identified merit being considered in an MPR, and are worth pursuing at this stage of the price control. We are also asking whether you consider there are any issues within the scope of an MPR that we have not yet identified.

We have also identified some issues that could benefit from being clarified. We are using this opportunity to consult on these. These issues might not be within the scope of an MPR as described in the RIIO-T1 and GD1 Final Proposals. But at this stage we think it is right to seek views from interested stakeholders on where clarifications should be made now.

Next steps

After this consultation, we will decide in spring 2016 on whether to initiate an MPR for each price control. If an MPR is initiated, it will start by examining the specific issues in more detail and any policy proposals would be set out during summer 2016 for a decision in late autumn 2016. Any associated licence changes would need to be in place by 1 April 2017.

1. Purpose and scope of an MPR

Chapter Summary

This chapter gives some background on the RIIO framework. We set out the scope and timelines of the mid-period review and the purpose and structure of the document.

Question 1: Do you have any views on the additional clarity we have provided on the RIIO-T1 and GD1 MPR scope?

Question 2: Do you consider the issues we have identified for RIIO-T1 and GD1 in this consultation fall within this scope?

Question 3: Are there any other issues within the defined scope that we have not included when assessing the need for an MPR for RIIO-T1 and GD1?

What is the mid-period review?

RIIO-T1 and RIIO-GD1

1.1. RIIO-T1 and GD1 were the first price controls to reflect the RIIO regulatory framework. They set out what the electricity and gas transmission, and gas distribution network companies are expected to deliver and details of the regulatory framework that supports both effective and efficient delivery for energy consumers over the eight years from 2013-2021.

1.2. RIIO-T1 and GD1 represent the first price controls which moved to an eight year period from five years. This move was designed to provide a longer period of settled price control arrangements, and to facilitate improved strategic planning and a long term approach to infrastructure management.

1.3. When setting the price control, we recognised that there will always be uncertainties about what will happen during the course of a price control period. During the control period, factors will change which can affect a company's outputs and expenditure requirements. We also recognised that risks are greater under an eight year price control than a five year price control. In order to retain the benefits that a longer price control period brings in terms of regulatory stability, we acknowledged that the regulatory arrangements needed to be adaptable in certain areas.

1.4. We put in place three types of **arrangements to help deal with uncertainty**:

- Uncertainty mechanisms (eg revenue drivers, area-specific reopeners)

- An MPR of output requirements

- Disapplication of the price control (in extreme circumstances).

1.5. The MPR represents an opportunity if needed to review the outputs of the price controls, part way through the price control period. Outputs are at the heart of the RIIO regulatory framework[3] and capture the key areas within which consumers expect the delivery of high quality services.

1.6. The outputs framework comprises both primary outputs (direct measures of performance that are visible to and valued by consumers, eg reducing energy not supplied) and secondary deliverables (indicators of performance used in support of the primary outputs, eg asset health and criticality). Appendix 2 outlines the various RIIO areas and associated outputs for RIIO-T1 and GD1. Any MPR for RIIO-T1 and GD1 will identify potential changes to existing outputs that the electricity and gas transmission, and gas distribution companies are expected to deliver or whether any new outputs are required. We further discuss the scope of the MPR below. When discussing 'outputs' in the context of scope we are not referring to the defined output categories (ie areas of delivery) but both the primary outputs and secondary deliverables.

Scope of the MPR

1.7. Across the various RIIO documents we have published for RIIO-T1 and GD1 (strategy documents, Initial Proposals (IP), and Final Proposals (FP)) we set out the purpose and scope of the MPR.

1.8. We provide more clarity on the scope below. We are seeking views on this, as well as whether the issues we have identified fall within this scope, as part of this consultation.

Definition of scope

1.9. In FP[4] we **defined the scope of the MPR** as: "*The scope of the mid-period review will be restricted to changes to outputs that can be justified by clear changes in government policy and the introduction of new outputs that are needed to meet the needs of consumers and other network users*".[5]

[3] The RIIO process identified key areas of delivery (or output categories) for network companies: safety and reliability, network availability, connections, customer (and stakeholder) satisfaction, environmental, wider works, and social.
[4] https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf paragraph 3.56.
[5] It is further set out in GD1 FP as relating to "*changes in outputs, or introduction of new*

1.10. On this basis we believe any MPR for RIIO-T1 and GD1 should seek to address the following types of changes if they are found to be needed.

1.11. **Changes to outputs driven by changes in government policy:** An eight year price control period is likely to see changes to policy that could affect outputs and the MPR would be an opportunity to reflect these on a one-off basis. This does not necessarily imply that a change in government policy will definitely result in a change in outputs. Some changes in policy could be dealt with through existing mechanisms/processes and some may not be material enough to justify making any price control changes.

1.12. **Introduction of new outputs driven by the needs of consumers or network users**: For RIIO-T1 and GD1, we don't think there is a meaningful distinction between the introduction of new outputs and changes to existing outputs. For example, new system planning obligations (such as those brought forward in Electricity Transmission from the Integrated Transmission Planning and Regulation (ITPR) project) could be viewed as a new output or a change to the existing outputs that already exist within wider works. If existing outputs are not adequately meeting the needs of consumers or network users then these outputs could be revised to address this. Alternatively, if consumer or network user needs change over the course of the price control then new/revised outputs to deal with these changing needs could be required.

1.13. The process for an MPR for RIIO-T1 and GD1 should be symmetric.[6] The changes to outputs driven by changing government policy or changing consumer and network user needs can result in increases or decreases in output requirements, which could have corresponding funding implications for the remainder of the price control. For example, if an output is no longer required then the companies may no longer need to deliver it and may also not need the corresponding funding associated with it for the second half of the price control.

1.14. We will consider materiality as part of our decision on whether to progress any issues under the MPR. As we said at FP, our view of materiality will be guided by responses to the consultation.[7]

---

outputs including changes to the Health and Safety Executive (HSE) iron mains programme, and asset integrity investment" and in T1 FP we proposed to consult on "*changes to outputs or the introduction of new outputs*". https://www.ofgem.gov.uk/ofgem-publications/48156/3riiogd1fpfinanceanduncertainty.pdf table 8.1 and https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 3.44.

[6] https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf paragraph 11.17.

[7] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 3.44.

1.15. In addition to the scope, in FP we also referred to specific areas in which new or changed outputs would be considered as part of any MPR, eg GB and EU market change, flood erosion and protection, network flexibility. For some of these specific areas we have identified potential changes that may be needed and we describe our initial thinking on these in the chapter relating to the relevant price control. For others we have not identified any changes are needed and we outline these in Appendix 3.

1.16. The network companies are also able to propose changes within scope of the MPR. Companies will need to justify that any proposed costs associated with requested changes in allowances are efficient. We will need to assess these on a case-by-case basis. Any MPR will also provide an opportunity for other stakeholders, not just the network companies, to propose changes.[8]

1.17. As stated in FP, we will consult on any changes to outputs or the introduction of new outputs, as well as on any consequential changes to cost allowances. As this is the first MPR conducted under RIIO, we are keen to understand your views and we have not yet reached a minded-to position on how, or whether, to proceed.

1.18. We said in previous RIIO documentation that "*if we consider that changes to outputs are necessary, we would not alter incentive mechanisms, the allowed return or other price control parameters other than as required to accommodate the change to outputs*" and also that if "*we deemed it necessary to change any of the existing price control parameters at the mid-period review, this will be based on consultation with stakeholders and will reflect the materiality of the issue being addressed*".[9]

1.19. Any changes to outputs or other parameters (such as incentives) that we might consider would need to be justified in meeting the needs of consumers or network users. There is a key distinction between outputs not meeting consumer and network user needs because they are incentivising the wrong behaviours from companies, and outputs which are being outperformed by the companies. We said clearly at the time of FP, and reiterate our position here, that the MPR should not be used to make changes to outputs to address outperformance. This is because we do not consider it to be in consumers' long term interests – clawing back outperformance may benefit consumers in the short term but could undermine the companies' development of long term efficiency strategies and also increase the cost of capital which could ultimately lead to higher costs for consumers overall.

1.20. We outline what we think is out of scope of the MPR further below. However, should stakeholders show that existing outputs are incentivising the

[8] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 3.47.
[9] https://www.ofgem.gov.uk/sites/default/files/docs/2011/03/t1decisionuncert_0.pdf paragraph 7.11.

wrong behaviours from companies, we may consider making changes to address this. We would remain mindful of the potential regulatory risk and uncertainty caused by making changes to these areas. We particularly welcome your views on this aspect of the MPR scope.

1.21. Finally, we have also identified some areas of RIIO-T1 and RIIO-GD1 policy we think would benefit from further clarifications, eg the treatment of outputs not delivered. We recognise that these clarifications are not within the scope of the MPR described above but think it would be of benefit to consumers, network users and the network companies for us to provide clarifications of policy alongside any MPR so as to avoid any potential uncertainty remaining until the end of the price control period. Based on feedback from stakeholders we will decide whether, how and when to take any such issues forward.

Out of scope

1.22. It is very important that the scope of any MPR does not effectively result in two four year price controls. We have committed through RIIO to an eight year price control and to long term strategies that will deliver efficiencies. As such we do not intend to re-open key aspects of the price control.

1.23. Changes to the key financial parameters (eg cost of capital) or to clawback outperformance are out of scope and we consider that any such changes could be harmful to consumers' long-term interests.

1.24. If we initiate an MPR for RIIO-T1 or GD1 and make changes to outputs, we are committed to not making retrospective adjustments, eg allowances related to previous years of the price control. We will also not make any changes to the cost of capital or change the totex (total expenditure) sharing factor.

1.25. As stated above, we think such issues are out of scope as they could potentially undermine the regulatory stability associated with an eight year price control and make companies less likely to commit to long term strategies that benefit consumers. Such changes could also increase the cost of finance from investors as they could perceive this as creating additional regulatory risk. We are therefore conscious of the need to balance the reduction of costs to consumers in the short term with the introduction of regulatory risk and uncertainty, which could ultimately lead to higher costs for consumers. When deciding which, if any, issues to take forward, we will be mindful of the potential risks and downsides of any changes being considered.

Electricity Distribution price control

1.26. The Electricity Distribution price control (RIIO-ED1) was launched two years after RIIO-T1 and GD1. This built on lessons learnt from the two first RIIO price controls. The RIIO-ED1 process also allows for an MPR of outputs. The scope, details and process of the potential RIIO-ED1 MPR presented in its FP are more detailed than the ones outlined for RIIO-T1 and GD1. The RIIO-ED1 FP set out more detailed parameters for the MPR. Whilst we have tried to ensure policy is joined up, the proposed scope outlined above for RIIO-T1 and GD1 should not be seen as setting a precedent for RIIO-ED1. The principles outlined in the ED1 documents still hold for that price control.

Timelines for any MPR

1.27. As per our website notice in July 2015[10] we have decided to bring forward our initial consultation as we want to ensure we have sufficient time to gather and consider stakeholder views ahead of implementing changes, if any, by April 2017.

1.28. The **indicative timeline** for each stage of the review is set out below – these dates may need to change depending on the issues that are identified and the nature of consultation responses. We will keep stakeholders informed as our plans develop.

- Phase 1: This consultation sets out potential issues that may be relevant for triggering a review. Based on responses, we will decide if there are grounds for initiating an MPR for RIIO-T1 or GD1 by the end of April 2016.

- Phase 2: If we decide to proceed and initiate an MPR, then the review would go into an assessment phase. During this stage we would work to develop any proposed changes as required.

- Phase 3: In July 2016 we would aim to consult on any proposed changes to outputs, on any consequential changes to allowed revenues and on any amendments to the licence to implement these. We would then issue our decision in late 2016 and make any necessary licence changes to take effect by April 2017.

Structure of the document

1.29. The consultation is structured as follows: each chapter presents our view on issues that could potentially be addressed through an MPR. We detail our views on issues specific to each of the sectors in turn: Electricity Transmission (Chapter 2), Gas Transmission (Chapter 3), and Gas Distribution (Chapter 4). For each area we present the issues we believe could be taken forward through an MPR and outline initial views on each of these. We also ask for stakeholder views on each policy area. In Chapter 5 we present further issues we have identified for potential consideration across one or several sectors.

[10] https://www.ofgem.gov.uk/publications-and-updates/potential-riio-t1-and-gd1-mid-period-review-timetable-and-next-steps

2. Electricity Transmission

Chapter Summary

Our initial view is that there may be some issues in Electricity Transmission that could be addressed through an MPR. In this chapter we present the issues we propose to examine further through a potential MPR in this area. We present each issue in turn and our initial views.

Question 4: Based on our current assessment there may be some issues in Electricity Transmission that could be addressed through an MPR. Do you agree with this assessment?

Question 5: We ask for detailed views, particularly from the TOs, on how the operability of the RIIO-T1 NOMs incentive mechanism could be improved. As part of this, we would like evidence on the manner in which any potential revisions may better facilitate the delivery strategy of outputs, in line with current needs of consumers and network users, and the materiality of such change.

Question 6: We are seeking views on whether the Environmental Discretionary Reward is driving the right business changes within the companies and providing the outputs that consumers and network users need.

Question 7: We are seeking views on whether the stakeholder incentives are driving the right behaviours to get the outputs that consumers and network users need.

Question 8: We have set out some initial thinking on the following issues: submission quality for Strategic Wider Works projects, further guidance on monitoring needs cases for projects in construction, the potential need for an availability incentive for Scottish island links, and potential funding requirements for NGET's enhanced SO function, as well as on onshore competition roles. What are your views on these?

Question 9: We wish to understand if there has been a material change in outputs due to the changes in government policy related to renewables subsidies. We ask that the TOs provide information on which connections and wider works are being taken forward compared to the ones that the unit costs were based upon and whether any variation is within the bounds of what was expected to be captured.

Question 10: We ask that the network companies provide information on any connections and wider works that are not easily correlated to a specific funding mechanism in the licence. We also ask that evidence is provided of the materiality of such issues as part of any response.

Question 11: We welcome views on whether there needs to be clarification of output requirements and treatment of activities (load related projects in particular), that sit outside of the revenue drivers, where they are no longer required or have been substituted.

Question 12: How material do you consider the RIIO-T2 outputs issue to be? Do you consider this is an issue that we should take forward?

Safety and reliability outputs

Network Output Measures (NOMs)

2.1. NOMs enable the evaluation of the condition of network assets and the associated risks to the reliability of the transmission system. They are used by licensees in relation to the development, maintenance and operation of their existing assets and in assessing future network expenditure. NOMs also provide us with a means to monitor and assess the present and future ability of the transmission assets to perform their function and each TO's asset management policy over the longer-term.

2.2. Under RIIO-T1, the network companies are set targets for the output of their investment programme in terms of network risks measured by quantities of assets remaining in 'replacement priority' groups. These in turn are based on the expected health and criticality of their assets at end of the price control period, taking account of their current investment plan, expected asset deterioration and other relevant factors. The licensees are subject to financial incentives depending on whether they deliver above or below such targets, and whether such over or under delivery is justified or unjustified.

2.3. The licensees are also obliged to have in place and maintain a NOMs methodology to facilitate the monitoring of their performance and the assessment of their expenditure. The electricity transmission licensees will soon publish a joint consultation on a revised common NOMs methodology and have committed to an ongoing workstream for continued development of the NOMs methodology. Amongst other things, the latest development of the NOMs methodology includes approaches for setting out the outputs of overall network risks in monetised terms.

2.4. While there is ongoing work developing the NOMs methodology, as part of the MPR we propose to assess how to operate the NOMs incentive mechanism within RIIO-T1 with sufficient clarity. This will assess in particular how over/under-performance against the specified targets is treated and consider if it is likely to deliver outputs in line with the needs of consumers and network users. As part of this process we will consider the need to clarify the definition of key parameters linked with outputs and associated incentives.

2.5. We ask for detailed views, particularly from the TOs, on how the operability of the RIIO-T1 NOMs incentive mechanism could be improved. As part of this, we would like evidence on the manner in which any potential revisions may better facilitate the delivery strategy of outputs, in line with current needs of consumers and network users, and the materiality of such change.

Environmental and stakeholder outputs

2.6. Having operated the incentives under the RIIO-T1 framework for two years, we are keen to make sure these are working as intended and delivering the right outcomes for consumers. We have identified some specific incentives relating to the environmental output and the customer and stakeholder outputs, in particular, which we are keen to get feedback on.

2.7. As detailed in Chapter 1 and set out in FP, we will only make changes to incentives as required to accommodate changes to outputs and to meet the needs of consumers or network users. In some cases the output is the behaviour that the incentive is trying to encourage and so the output and the incentive are intertwined, eg the stakeholder engagement/satisfaction outputs. We think it is important to distinguish between outputs not meeting consumer and network user needs because they are incentivising the wrong behaviours from companies and outputs which are being outperformed by the companies, which would be out of scope.

2.8. In any event, we are not concerned with systematic outperformance within these incentives at this stage. We have recently set the baseline targets for part of the stakeholder incentive and we believe these targets have been set at an appropriate level. Both of the incentives outlined below also have a discretionary element, within which performance is assessed annually by an independent panel.

2.9. We welcome your views on how these specific incentives have been working and whether they are driving the right behaviours from companies.

Environmental Discretionary Reward (EDR)

2.10. The EDR is a broad based environmental scheme for electricity transmission licensees and is part of their environmental output. The objective of the scheme is to encourage licensees to achieve high standards of environmental management as well as to facilitate the industry to move towards a low carbon system where it can do so effectively and provide value for money to consumers. Our design concept for the EDR was to complement and reinforce other environmental incentives included in the RIIO-T1 package. It should reflect activities that exceed licence requirements.

2.11. The scheme has been running since the start of RIIO-T1 and involves a reputational and financial reward based on a balanced scorecard, scored using an evidential submission and a review session with a panel. The combination of reputational and financial reward is designed to sharpen companies' focus on strategic environmental considerations and encourage corporate and operational culture change. In the first year no company achieved the standard required to receive an award but this year a reward has been determined and details of this will be announced shortly.

2.12. In implementing the scheme we have received feedback on aspects of the reward and made refinements. However, since setting up the scheme, an increasing amount of network company business is now already in the low carbon sector, eg connecting renewable generators, and has become business as usual.

2.13. We are interested in whether the scheme is driving the cultural, strategic and process changes within the companies that consumers and network users need, eg considering non-conventional alternatives to network development, or incorporating low carbon objectives in overall business strategies. We are also keen to get views on whether the focus of the incentive remains the most relevant focus for the environmental output. There are also elements of the reward that relate to innovation and stakeholder engagement which each have their own incentives. We would like to ensure that performance measured by the EDR is complementary and additional to other initiatives thereby ensuring it best meets the needs of consumers.

2.14. We are seeking views on whether the EDR is driving the right business changes within the companies and providing the outputs that consumers and network users need.

Customer and stakeholder outputs

2.15. For RIIO-T1 we introduced an incentive to cover customer and stakeholder engagement as part of the customer and stakeholder satisfaction output. The outputs/incentives include various elements.

2.16. **The customer and stakeholder satisfaction incentive** – a reward/penalty mechanism with a materiality of up to ±1% of annual revenue, which includes:

- The stakeholder satisfaction survey (all TOs)
- The customer satisfaction survey (does not apply to the Scottish TOs)
- Stakeholder key performance indicators (KPIs) (Scottish TOs only)
- Stakeholder external assurance (Scottish TOs only).

2.17. **The stakeholder engagement incentive** is a discretionary reward, across the electricity and gas network companies, which may reward up to 0.5% of base revenue depending on the quality of the company's stakeholder engagement. This decision is based on an assessment and recommendation by an independent panel.

2.18. In FP we said we would look at the customer and stakeholder satisfaction incentive again in 2016. We have recently set the baseline for the stakeholder satisfaction survey for all companies as well as the weightings for the various elements of the incentive.[11] As part of the incentive's defined two year review process for the KPIs we intend to look at these in conjunction with the companies. We want to ensure that the KPIs are aligned with stakeholder engagement/satisfaction and that they do not relate to areas where companies already have requirements, eg under the licence. We will be engaging with the companies as part of this KPI review as per our recent decision to set the parameters of the incentive.

2.19. As part of our June 2015 consultation[12] on setting some of the parameters, some of the responses mentioned concerns about the incentive driving the right behaviours and in particular that feedback from stakeholders and customers is not being considered and acted upon appropriately by the companies.

2.20. Our initial view is that the customer and stakeholder satisfaction surveys are providing reasonable measures of performance. However, we would particularly welcome views on the discretionary element of the output, on whether better clarity on the separation and roles of the incentive components would be beneficial. For example, evidence from other incentives (including stakeholder satisfaction survey scores, and engagement with parties on innovation competition projects) is currently used to demonstrate performance for the discretionary reward.

2.21. We are seeking views on whether the stakeholder incentives are driving the right behaviours to get the outputs that consumers and network users need.

Wider works

Strategic Wider Works (SWW) submissions

2.22. The SWW mechanism allows for the assessment and funding of large capital projects, within the price control period. Under this mechanism, the TOs must submit proposals to us to assess the needs case for the project, as well as the efficient design and costs.

2.23. We want to ensure that the TOs are required to submit the most economic and efficient proposal (having considered a reasonable range of alternatives) and note that there isn't currently a direct obligation in this area. We think that formalising such a requirement for future projects could be beneficial.

[11] https://www.ofgem.gov.uk/ofgem-publications/97454/decisiononvalueswithinthestakeholdersatisfactionoutputarrangements-pdf
[12] https://www.ofgem.gov.uk/sites/default/files/docs/2015/06/stakeholder_incentive_consultation_22_jun_15_publication.pdf

2.24. This could also help to ensure that any onshore competitive tendering is not undermined by submissions seeking to circumvent the criteria. We previously stated in FP that SWW projects could be subject to competitive tendering. We are now consulting[13] on arrangements so that projects which are new, separable and high value are tendered. Formalising this obligation could help ensure it is clear which projects meet the criteria for tendering.

2.25. We are considering strengthening either the relevant licence conditions or guidance document regarding the project proposals within SWW submissions, and are seeking views on this.

2.26. If doing this required guidance changes only, we would expect to undertake this separately from any MPR, via the normal routes for amending guidance.

Monitoring the needs case for projects in construction

2.27. For Incremental Wider Works (IWW) under its network development policy (NDP), NGET reviews each year whether it is prudent to continue spending on a project in construction. There is no clear requirement to do this under the SWW mechanism.

2.28. Following an SWW decision an output is included in the licence. There is no formal process/requirement/reporting around revisiting needs cases if circumstances change. For example, a change in a needs case could be driven by a change in generation background. We consider it may not be in consumers' interests for the TO to continue spending on a project where the needs case has since fallen away (though this needs to take into account costs already incurred and the benefits of completing the works). We therefore think there may be a need for additional formal reporting around this to mitigate the risk of stranded investments.

2.29. This could also be an issue for other wider works investments.

2.30. We think it could be beneficial to set out further guidance or strengthen the licence to mitigate this risk in the most appropriate/proportionate way. We envisage that any guidance/licence change would be supported by additional reporting (so that we can monitor that these assessments are taking place and the right decisions are being made). We are seeking views on this.

[13] https://www.ofgem.gov.uk/sites/default/files/docs/2015/10/ecit_consultation_v6_final_for_publication_0.pdf

2.31. If this required guidance changes only, we would expect to undertake this separately from any MPR, via the normal routes for amending guidance.[14]

Availability

Scottish island links

2.32. Most connections on the GB transmission system operate using at least a double circuit, making them more resilient to a fault/outage on one of the circuits. Due to the long distances involved, developers need to balance their consideration of capital cost of the links against their value of a secured connection. As such, links to the Scottish islands tend to use a single circuit connection, making these connections more susceptible to outages. As these connections do not have the same redundancy as required under the Security and Quality of Supply Standards (SQSS), generators would not be entitled to interruption payments for any outages on the links.

2.33. The incentives in place for TOs to ensure faults are addressed in a timely fashion may not be sufficiently strong. For example, the only direct financial incentive within the price control which aims to ensure a reliable and available network relates to energy not served. This is only relevant if demand is cut off and does not take into consideration instances where generation is isolated because of a network outage.

2.34. Additionally, subsea links are much harder to repair when there is a fault,[15] meaning that the likelihood of significant downtime is much higher than for a normal onshore connection. These circumstances combined could make it very challenging for the generators to form viable and financeable projects that could be in consumers' interests.

2.35. Offshore generators face a very similar situation. In order to mitigate impacts to offshore generators resulting from transmission failure, we introduced an 'availability incentive'[16] for Offshore Transmission Owners (OFTOs). This incentive sets a generic 98% availability target, with financial rewards and penalties for over and under-performance, respectively. Ultimately, the incentive aims to ensure the prompt restoration of the wind farm connection in the event of an unplanned outage and promote planned outages during periods less likely to result in adverse impacts to generators.[17] There is currently no corresponding

---

[14] https://www.ofgem.gov.uk/publications-and-updates/guidance-strategic-wider-works-arrangements-electricity-transmission-price-control-riio-t1-0

[15] Repair works generally require both specialised vessels and equipment to both find the fault and repair it. Any offshore works may be restricted by seasonal weather and/or environmental limitations.

[16] https://www.ofgem.gov.uk/ofgem-publications/51491/changes-offshore-transmission-owner-ofto-availability-incentive.pdf

[17] The OFTO availability incentive is weighted on a monthly basis, depending on expected

availability incentive for companies which operate (or will operate) transmission links between the Scottish islands and mainland networks.

2.36. We welcome views on whether the current outputs in this area are appropriate or whether for instance there is a need for an availability type incentive that should be explored further through the MPR process. Our initial view is that further exploration of the issue is warranted if the government's future direction on Contracts for Difference (CfD) suggests a reasonable likelihood of these links proceeding. Parallel to this consultation, we are also investigating the role of an availability incentive for Competitively Appointed Transmission Owners (CATOs) as part of our work on extending competition to onshore transmission assets.[18] We would take into account analysis and views on CATO and OFTO availability incentives in considering such incentives through any MPR process.[19]

2.37. We are considering the potential need for an availability incentive for Scottish island links. We welcome views on the need for such an incentive to be in place.

SO roles and associated impacts

2.38. In the Integrated Transmission Planning and Regulation (ITPR) project Final Conclusions, we created new responsibilities for NGET as System Operator (SO) and recognised that there were likely to be incremental costs associated with delivering these duties.[20]

ITPR enhanced SO role

2.39. The enhanced SO role for NGET involves a potential set of new activities which will impose additional costs not considered when determining revenue allowances for the current price control.[21]

---

generation revenues for the connected windfarm. This provides an incentive for planned outages to be scheduled during periods where the generation revenues are expected to be lowest.

[18] https://www.ofgem.gov.uk/sites/default/files/docs/2015/10/ecit_consultation_v6_final_for_publication_0.pdf

[19] Future island links that are proposed as SWW could be subject to competitive tendering and any incentives would then fall within the CATO regime.

[20] "*We are engaging with NGET on whether it should receive additional funding given its enhanced role. Our initial view is that where new outputs are to be delivered as a result of its new responsibilities these should be considered in the event of an MPR (allowed for in the RIIO-T1 settlement). We expect that any additional funding needed would be relatively small*." https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-final-conclusions paragraph 3.6.

[21] These activities and responsibilities include: delivering the initial 2015 Network Options

2.40. We believe that the MPR is an appropriate mechanism to assess and agree the costs associated with NGET's enhanced SO role. In order to achieve this, we require a detailed breakdown of the efficient costs associated with new SO functions that are currently not being remunerated through other means, and had not been anticipated during FP.

2.41. We are considering conducting an assessment of cost-efficient funding requirements associated with NGET's enhanced SO function as a result of the ITPR project conclusions. To facilitate this assessment, we request a detailed breakdown of activity-specific costs from NGET.

Onshore competition roles

2.42. In addition to enhancing the role of the SO, we decided in the ITPR Final Conclusions to competitively tender new, separable and high value onshore transmission assets. We are currently consulting on the arrangements for introducing competitive tendering to onshore electricity transmission projects, including proposals for what types of projects will be subject to tendering and how these will be identified.[22]

2.43. Our proposals for the competitive tendering arrangements include additional responsibilities for the SO. This will require new outputs to reflect the additional responsibilities and/or activities of the SO.

2.44. One such responsibility under the proposed late model[23] (whereby the CATO is appointed after the preliminary works phase of the project) will involve the SO undertaking a range of preliminary works for some tendered projects such as site surveys, environmental assessments and securing planning permissions and other related consents. These activities are currently conducted by the incumbent TO for projects it is going to build and own.

2.45. The October onshore competition consultation notes that the TO will continue to be responsible for pre-construction for projects that it is already

---

Assessment (NOA); developing the enduring NOA, enhancing the GB and offshore model for Electricity Transmission; developing a continental Europe model for interconnector welfare assessment; support to Strategic Wider Works (SWW) and offshore developer led wider network benefit investment (WNBI) gateways; power quality coordination; and the implementation of the ITPR licence requirements.

[22] https://www.ofgem.gov.uk/sites/default/files/docs/2015/10/ecit_consultation_v6_final_for_publication_0.pdf

[23] We are currently proposing to develop two models for tendering certain onshore transmission assets: i) the early CATO build model, and ii) the late CATO build model. Both models involve early SO inputs to identify a needs case for the work and recommend a preferred option. However in the late model, the SO will also be responsible for initial solution design, surveys and studies and obtaining relevant consents.

developing (and being funded for) under RIIO-T1. In practice, this means that incumbent TOs will be required to undertake all necessary works ahead of a tender for RIIO-T1 projects they are doing preliminary works on. We are also proposing that they will be required to undertake certain activities to support the tender process. Where these activities are above and beyond what the TOs are funded for under RIIO-T1, it would constitute a new output, and we would expect that TOs would be no worse off than they would otherwise be under RIIO-T1.

2.46. The onshore competition consultation process will help to inform our decision making in this area and we will consider whether there are any issues that need to be addressed through the MPR process.

2.47. We are considering investigating this issue alongside our work on introducing competition into Electricity Transmission. We are also seeking views on the materiality of this issue.

Revenue drivers

2.48. One of the uncertainty mechanisms incorporated into the RIIO framework was the introduction of revenue drivers. These mechanisms adjust baseline revenues each year to account for changes in scenario assumptions for generation and demand, throughout the price control period. For example if additional generation comes forward, the TO is funded through the revenue driver for the additional connection infrastructure.

2.49. Under the RIIO-T1 price control, the drivers include defined cost allowances for specific assets. Drivers were set up for new generation connections, new demand connections and new wider works, as well as for the cost of mitigation measures required to gain planning consent, related to visual amenity issues. The exact drivers are different for each TO however.

Assumptions behind renewable generation deployment

2.50. Forecasting assumptions underpin the revenue drivers. These were based on scenarios from NGET's future energy scenarios.[24] Over the price control we have seen a slower deployment of renewables than was expected at the time of the settlement. The RIIO-T1 business plans were based on NGET's 'Gone Green' scenario, eg at the start of the price control, NGET were forecasting the need to enable 33GW[25] of new generation in England and Wales across the price control period, this forecast has now reduced to 11GW[26]. Recent government

[24] National Grid produces a set of four energy scenarios – 'Consumer Power', 'Gone Green', 'Slow Progression', 'No Progression': http://fes.nationalgrid.com/
[25] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/ page 43.
[26] http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/results-centre/half-

announcements[27] on the diminishing and removal of renewables support has cast further doubt over the validity of these scenarios as compared to current observations and expectations.

2.51. We want to seek to understand the impact of this change in government policy. Whilst the revenue drivers will adjust revenues downwards automatically as fewer connections and associated reinforcements need to be delivered, we want to ensure that this is being done within the bounds envisaged and that there hasn't been a more fundamental change in connections (and other) outputs that the revenue drivers do not reflect.

2.52. We wish to understand if there has been a material change in outputs due to the changes in government policy related to renewables subsidies. We ask that the TOs provide information on which connections and wider works are being taken forward compared to the ones that the unit costs were based upon and whether any variation is within the bounds of what was expected to be captured.

Alignment of revenue drivers with solutions deployed

2.53. We are aware that there may be instances where the parameters of the revenue drivers do not align with the solutions that the TOs plan to deploy. In some cases, the TOs might not be funded for adopting, in their view, the most appropriate solution and this could incentivise inefficient behaviour (ie so that the TO can recover its costs). We set out two examples below:

- Some revenue drivers are based on unit costs for particular technologies (eg certain types of tower and/or standard substation) and the use of innovative solutions and/or new technologies to meet new needs may not align with the solutions in the licence text.

- How the revenue drivers manage upgrades to existing lines rather than the building of new lines. This is only an issue where the drivers are specified in terms of technology used, rather than capacity/capability – in these cases there is only a unit cost for new build, not for upgrading.

2.54. We want to understand whether the issues raised above are material and should be considered further as part of an MPR to ensure that the revenues are fit for purpose and help incentivise efficient output delivery.

---

year-results-statement-2015-16.pdf
[27] https://www.gov.uk/government/news/controlling-the-cost-of-renewable-energy and https://www.gov.uk/government/news/further-action-taken-to-prevent-energy-bills-rising

2.55. We ask that the network companies provide information on any connections and wider works that are not easily correlated to a specific funding mechanism in the licence. We also ask that evidence is provided of the materiality of such issues as part of any response.

Change of outputs for projects with baseline funding

2.56. As discussed in Chapter 5 we are keen to clarify the treatment of outputs that are no longer needed and also of outputs that are substituted to alternatives that meet similar needs. For Electricity Transmission this is particularly relevant for load related expenditure projects that sit outside of the uncertainty mechanisms (ie revenue drivers and SWW). These were assumed to be going ahead when RIIO-T1 was set but due to the changing generation background and system requirements some of these projects no longer need to be delivered within RIIO-T1 or have been substituted. The primary area that we have identified falling into this category is "Wider Works (General)" for NGET.[28] It may also be relevant to other areas of expenditure and also for the Scottish TOs.

2.57. We plan to examine how the need for these baseline projects has evolved in light of the changing network requirements. Because these projects are separate from the revenue drivers, associated revenue allowances are therefore not automatically adjusted. We therefore think there would be benefit in providing clarity ahead of RIIO-T2 about how non-delivery in RIIO-T1 or substitution would be treated. In some cases we gave an indication of how things might be treated and in others we did not. We want to ensure that the funding mechanisms remain fit for purpose and that the ability of network companies to report performance, and our ability to effectively monitor and assess performance, remains robust and transparent throughout RIIO-T1. To ensure this, we think it would be better, for the companies and consumers, to resolve this issue ahead of RIIO-T2 to assure that the regulatory settlement is well understood by all parties.

2.58. We welcome views on whether there needs to be clarification of output requirements and treatment of activities (load related projects in particular), that sit outside of the revenue drivers, where they are no longer required or have been substituted.

RIIO-T2 outputs

2.59. During the consultation phase of RIIO-T1 IP, some stakeholders noted that early grid development will play an integral role in overcoming barriers and uncertainties for renewable generation and managing long term network risk.[29] In

[28] https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/riio-t1-nggt-and-nget-cost-assessment-and-uncertainty_0.pdf paragraphs 4.180-4.187 – for description of the activities.
[29] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 4.65.

recognition of this, we decided to allow a future funding adjustment for NGET to cover expenditure associated with load related outputs (ie generation connections, demand related infrastructure and IWW) that will be delivered in the first two years of RIIO-T2. We placed this focus on NGET primarily due to outputs associated with IWW which do not apply to the Scottish TOs, and due to the fact that NGET was the only company to raise this issue during IP.

2.60. This funding adjustment could be triggered by NGET providing, in Year 6 of the price control (2018-19), evidence-backed forecasts of the load related outputs it will deliver in the first two years of RIIO-T2.

2.61. We did not propose any funding adjustment under RIIO-T1 for projects expected to be delivered later than the first two years of RIIO-T2. Uncertainty around whether a project will be delivered within our identified timeframe could create uncertainties regarding cost recovery and may not drive the right behaviours.

2.62. We recognise that generators pushing back connection dates could lead to delays for the corresponding grid reinforcements. As a result, there may now be more works than initially anticipated that will start in RIIO-T1 but will not be delivered until beyond the first two years of RIIO-T2. We wish to identify if such delays are occurring/likely to occur and how material this issue may be.

2.63. We have not received any evidence to suggest this is a material issue, but want to assess whether the current mechanism of recovering costs associated with RIIO-T2 outputs remains fit for purpose. We also want to understand whether this is an issue for the Scottish TOs where different funding arrangements currently exist for revenue driver outputs delivered in RIIO-T2.

2.64. How material do you consider the RIIO-T2 outputs issue to be? Do you consider this is an issue that we should take forward?

3. Gas Transmission

Chapter Summary

Our initial view is that there may be some issues in Gas Transmission that could be addressed through an MPR. In this chapter we present the issues we propose to examine further through a potential MPR in this area. We present each issue in turn and our initial views.

Question 13: Based on our current assessment there may be some issues in Gas Transmission that could be addressed through an MPR. Do you agree with this assessment?

Question 14: We are considering undertaking a review of the requirement and associated output to deliver an Avonmouth pipeline solution. Do you agree with this?

Question 15: We are considering reviewing how National Grid Gas Transmission (NGGT) is meeting its output to maintain its 1-in-20 obligation for Scotland. Do you agree with this?

Question 16: We are considering reviewing how NGGT is meeting its output to deliver specific compressor projects. Do you agree with this?

Avonmouth pipelines

3.1. NGGT proposed in its RIIO-T1 business plan to construct two pipelines (Easton Grey – Pucklechurch and Pucklechurch – Ilchester) by 2018. The proposal aimed to alleviate issues that would arise following the decommissioning of the Avonmouth Liquefied Natural Gas Storage (LNGS) facility. This related primarily to NGGT's ability to provide Operating Margins[30] (OM) and Transmission Support Services[31] (TSS).

3.2. In IP we proposed to fund NGGT to deliver the Avonmouth pipeline solution to alleviate concerns about security of supply. We set the solution as an output to maintain the capability of the network. More specifically, in IP we stated: "*Load*

[30] Gas used to maintain system pressures under specific circumstances including periods immediately after a supply loss or demand forecast change before other measures become effective.

[31] TSS are services rendered from either long run contracts at specific exit sites or from the constrained storage facility at Avonmouth. These are used as a substitute for capacity during periods of high demand to avoid constraints on the pipeline system to which this licence relates and allow the licensee to meet its 1-in-20 peak day obligation in the safety case it has in place from time to time pursuant to the Gas Safety (Management) Regulations 1996. https://www.ofgem.gov.uk/ofgem-publications/53600/2riiot1fpoutputsincentivesdec12.pdf

related investment relates to the Reliability and Availability output. Given NGGT's proposal for load related expenditure, we consider that the specific projects should be set as specific outputs".[32] We described the output for the Avonmouth decommissioning project scheme as a 'pipeline solution' with specified costs, and start and delivery dates.

3.3. In FP we included funding within totex of £165m (post information quality incentive (IQI)) for the pipeline solution as part of the Avonmouth decommissioning. To ensure the physical reinforcement of the transmission network took place ahead of the decommissioning we set a specific timeline for delivering the output: "*We note that the delivery date for the pipeline solution has been brought one year forward, compared to Initial Proposals, to 2018. This reflects commissioning of the pipeline solution in time, prior to the planned decommissioning of the Avonmouth LNG storage facility. Relevant funding to allow post-commissioning activities will be available to NGGT up to 2019 […]. Including the two pipelines in the baseline provides clarity to NGGT, compared to other projects subject to the Planning Act requirements. Therefore, we expect NGGT to expedite its activities and apply earlier than 2017, to warrant commissioning of the pipelines' operation in 2018. We will be reviewing the progress of these actions through the annual reporting progress and the mid-period review".*[33]

3.4. By proposing to review the progress in the MPR we intended to ensure that NGGT acted efficiently and delivered the pipeline solution in a timely manner.

3.5. NGGT has provided us with updates through its annual reporting as part of the Regulatory Instructions and Guidance (RIGs) submissions in 2013-14 and 2014-15. It has indicated that, following renewed analysis and engagement with relevant distribution networks and the Health and Safety Executive (HSE), it has identified a risk-based solution that removes the need for physical build.

3.6. NGGT's specific update in the 2014-15 RIGs was that: "*We have an output and associated allowance to manage the loss of the Avonmouth facility. Using efficient but low levels of our allowance throughout 2014-15, we have been able to invest in challenging the fundamental need case and undertake detailed risk analysis. As a result we have been able to find a solution which avoids the need for physical build and the significant additional cost to consumers. However, in the absence of any physical build we will be required to manage the increased capacity risk in the South West region of the network, once the Avonmouth facility closes*".

3.7. As explained later in Chapter 5 we think there may be benefits in clarifying our policy around non-delivery of outputs, where it is not currently clear, and

---

[32] https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/riio-t1-nggt-and-nget-cost-assessment-and-uncertainty_0.pdf paragraph 7.48.
[33] https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/3_riiot1_fp_uncertainty_dec12.pdf paragraphs 7.73 and 7.74.

assess whether the current policy is working in consumers' interests. In light of NGGT's position in relation to the Avonmouth pipelines, we consider that it may be in consumers' interests to review how NGGT is meeting the output to deliver a pipeline solution as part of the Avonmouth decommissioning.

3.8. We are considering undertaking a review of the requirement and associated output to deliver an Avonmouth pipeline solution. Do you agree with this?

Scotland 1-in-20 network flexibility projects

3.9. In IP and FP we allowed funding for projects to enable NGGT to maintain its 1-in-20 obligations[34] for Scotland notwithstanding diminishing UK Continental Shelf (UKCS) flows, especially from St. Fergus. These projects were aimed at enabling the National Transmission System (NTS) to reverse flows of gas from the South of the NTS towards Scotland.

3.10. We decided to fund the 1-in-20 projects for Scotland to alleviate concerns about security of supply, and set specific projects as outputs to enhance network capability.[35] Funding was set at approximately £23m (post IQI).

3.11. More specifically, we wanted to ensure that NGGT would deliver the resulting capability (to reverse gas flows between England and Scotland) in line with its proposed timetable for the projects. In FP we reiterated that we were maintaining our views and setting specific outputs in this area with specific costs and start and delivery dates.

3.12. Since the RIIO-T1 price control was set NGGT informed us in its RIGs reporting that it has reassessed the latest supply and demand information, its current network capability and the options available to manage the impact of the reduction in UK continental shelf flows. It has also engaged with its customers and stakeholders and in particular with Scotia Gas Networks (SGN). The aim has been to develop solutions that could increase the current capability of the network before progressing further with any investment in asset solutions. These conversations are expected to continue until May 2016. NGGT is planning to finalise the investment decision and the timing of any asset solutions following the conclusion of the discussions. Any such asset solution is expected to be delivered before the end of RIIO-T1.

[34] To meet the 1-in-20 peak aggregate daily demand, including but not limited to, within day gas flow variations on that day.

[35] https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/riio-t1-nggt-and-nget-cost-assessment-and-uncertainty_0.pdf paragraph 7.48.

3.13. As it is unclear when and if the Scotland 1-in-20 projects will be delivered, we consider that it may be in consumers' interests to review how NGGT is meeting its output to maintain its 1-in-20 obligation for Scotland.

3.14. Given further uncertainty since FP, we are considering reviewing how National Grid Gas Transmission (NGGT) is meeting its output to maintain its 1-in-20 obligation for Scotland. Do you agree with this?

Non-load related environmental outputs

Compressors

3.15. In RIIO-T1 we allowed funding for NGGT to deliver projects to replace specific compressor units to comply with environmental directives (specifically the Integrated Pollution Prevention and Control Directive (IPPCD) and the Industrial Emissions Directive (IED)). The IPPCD environmental legislation aims to reduce emissions at high utilisation sites. New units are installed to undertake the bulk of the operation, reducing the operation of older more polluting units. The IED environmental legislation requires compressor units to be compliant with specific emissions limit values (ELVs). Compliance with the ELVs can be achieved by different means.

3.16. NGGT requested £180m funding for three sites to:

- Install two new electric compressor units at Peterborough and Huntingdon
- Install a gas turbine driven compressor unit and a new electric compressor unit at Aylesbury.

3.17. We decided to allow funding of approximately £150m (post IQI) for these projects. To ensure delivery of the projects we set out the projects as outputs in IP and FP. In IP we specified the types of turbines that would need to be fitted for each site.[36] In FP we explained that we had set out our position to NGGT on the size of the compressor units (24MW for both stations) and specified that the funds were tied to the specific unit cost allowances (UCAs) set for electric and gas turbine driven units.[37]

---

[36] "*More specifically the outputs are set as follows: Appropriately sized electric Variable Speed Drives (VSD) in Peterborough and Huntingdon compressor stations, and rendering Aylesbury compressor station compliant with the IED requirements, via the installation of an appropriately sized VSD and a compliant gas turbine*." https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/riio-t1-nggt-and-nget-cost-assessment-and-uncertainty_0.pdf paragraph 7.89.

[37] https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/3_riiot1_fp_uncertainty_dec12.pdf paragraphs 7.80, 7.93 and 7.94.

3.18. The projects were set as outputs with specific time delivery for three reasons:

- To avoid projects being delayed (there have been delays to all projects from the previous price control).
- To mitigate the risk of NGGT receiving disproportionately high allowances by opting for other solutions, such as smaller units, catalysts etc, which were not reflective of the allowances set (at the time allowances were based on cost information for UCAs – cost information for other solutions was not available).
- To increase the network's capability by the installation of the additional new units.

3.19. Since the RIIO-T1 price control was set NGGT informed us in its RIGs reporting that it will be delivering projects at the three sites that are significantly different to the outputs specified in IP and FP. More specifically, for Peterborough and Huntingdon, NGGT has opted to install smaller gas turbine units instead of the larger VSD units that were specified in IP and FP and to which funding was tied. For Aylesbury, NGGT was funded for building two new compressor units specified as outputs in IP and FP but instead delivered a cheaper catalyst solution.

3.20. We consider that the projects delivered are not aligned with the outputs set in RIIO-T1. As mentioned the ex ante allowances reflect projects of different scope and size. In light of the above and current cost information, NGGT are expected to underspend by 30-50% on the allowances, ie by £50-75m.

3.21. In light of NGGT's reporting on the non-load related projects set as outputs, and as explained in Chapter 5 we think there may be benefits in clarifying our policy around non-delivery of outputs, where it is not currently clear, and assess whether the current policy is working in consumers' interests. We also consider that it may be in consumers' interests to review how NGGT is meeting the output to deliver the compressor projects.

3.22. Further to the above, in our IP we stated that during the MPR window we would be undertaking an additional evaluation of low utilisation sites which can opt for the '500 hours' derogation.[38] We still intend to carry this out as part of the MPR. We expect this will provide us with more evidence ahead of any decision for the industrial emissions reopener in 2018.

[38] The IED sets specific emissions limits with which gas turbines need to comply. The '500 hours' derogation refers to the exemption from compliance with the emissions limit values provided to gas turbines which operate below 500 hours per annum.

3.23. Given developments since allowances were set, we are considering reviewing how NGGT is meeting its output to deliver specific compressor projects. Do you agree with this?

Non-load related asset health expenditure

NOMs

3.24. In RIIO-T1 we acknowledged that NGGT was not relying on the NOMs tool to deliver its asset health expenditure. We are not considering reviewing the NOMs methodology for Gas Transmission within the MPR. However, we expect that NGGT will develop an appropriate and robust methodology which we will review in due course.

4. Gas Distribution

Chapter Summary

We have not identified any material issues for RIIO-GD1 which we think would require further examination through an MPR. In this chapter we focus on issues we had indicated in RIIO-GD1 FP we may consider through the MPR and specify why we do not think they need further examination.

Question 17: Based on our current assessment we have not identified any material issues for RIIO-GD1 which we think would require further examination through an MPR. Do you agree with this assessment?

Question 18: Do you agree with our current assessment that there is no need to review the risk reduction output associated with the iron mains risk reduction programme, as part of an MPR?

Question 19: Do you agree with our current assessment that we do not need to review the asset health and risk secondary deliverable as part of an MPR?

Safety

Iron mains safety risk reduction

4.1. One of the primary safety outputs, which Gas Distribution Networks (GDNs) have to deliver in RIIO-GD1, is iron mains replacement to deliver safety and environmental benefits. We expect GDNs to remove significant safety risk associated with iron mains during RIIO-GD1, and reduce gas transport losses. This output works in conjunction with the Health and Safety Executive (HSE) published enforcement policy for iron mains risk reduction.[39] This is known as the irons mains risk reduction policy (IMRRP).

4.2. In the RIIO-GD1 strategy decision[40] we identified removing risk associated with iron mains as a primary safety output. Removing this risk represented around 40% of total expenditure proposed by GDNs in their plans. Following a joint HSE/Ofgem review, the HSE changed their approach to IMRRP in May 2012 and adopted a 'three-tier'[41] approach. The new HSE approach provides greater flexibility for GDNs in managing the risk associated with iron mains.

---

[39] http://www.hse.gov.uk/gas/supply/mainsreplacement/enforcement-policy-2013-2021.htm
[40] https://www.ofgem.gov.uk/sites/default/files/docs/2011/03/gd1decision_0.pdf
[41] We summarised the action required by the GDNs in Appendix 4 of the RIIO-GD1 Annual Report 2013-14: https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/riio-gd1_annual_report_2013-14-final.pdf

4.3. Prior to the start of RIIO-GD1 the IMRRP required GDNs to decommission all iron mains within 30 metres of buildings within 30 years ('30/30' programme).

4.4. In FP we stated that the HSE would undertake a more fundamental review of the Pipeline Safety (Amendment) Regulations 1996 (PSR), regulations 13 and 13 (A) as they relate to iron mains, and had indicated to us that it would complete its review in 2015 in time for a potential MPR. Therefore, we stated in FP that we would address any changes to this primary output through an MPR. The trigger for reconsidering the output and allowed expenditure would be a change in the HSE iron mains policy.

4.5. The HSE notified us that in June 2013 they had consulted with GDNs on how best to approach the future management of risk from the gas distribution network and whether an approach based on reasonable practicability was justified. The GDNs responded in October 2013, unanimously rejecting any proposals to amend the regulation on the basis of reasonable practicability and stating that in their view the current system under IMRRP remained fit for purpose and cost effective. At the HSE's request the GDNs produced robust evidence supporting their views.

4.6. In June 2015 the HSE told us that, given the responses by the key industry stakeholders to their proposals to review the regulations and until the long term future of the gas networks is clearer, they are not proposing to amend the PSR.

4.7. Given the HSE have not changed their policy on PSR we do not think there is a need to review the risk reduction output and we are not intending to take this issue forward through an MPR.

4.8. Do you agree with our current assessment that there is no need to review the risk reduction output associated with the iron mains risk reduction programme, as part of an MPR?

Reliability

Asset health and risk

4.9. In the RIIO-GD1 strategy decision,[42] we identified three primary reliability outputs, these were:

- Loss of supply – measured by the number and duration of interruptions

[42] See footnote 40.

- Network capacity – providing capacity to meet a 1-in-20 peak day winter demand scenario

- Network reliability – defined as maintaining operational performance.

4.10. Maintaining operational performance is measured through six secondary deliverables. One of the secondary deliverables relates to asset health and risk.

4.11. The GDNs proposed significant increases in expenditure to maintain network reliability over RIIO-GD1. The GDNs justified these increased levels of expenditure on the basis of expected deterioration in asset reliability (eg in terms of asset health) in the absence of such expenditure. In RIIO-GD1 IP, we expressed concern about the quality of the asset health data supporting the proposed increase in expenditure, eg the assumptions in relation to current asset condition and deterioration rates, and whether these justify increased expenditure over RIIO-GD1. We proposed to only allow an increase in expenditure where the GDN has provided robust asset health data to support such an increase, and where the investment is justified in cost benefit terms. Our proposed approach meant that we suggested disallowing most of the GDNs' expenditure in relation to network reliability above historical levels.

4.12. We recognised that there may be a case for greater spending on asset health. However, in the absence of robust asset data it would not have been in the consumer interest to fund the proposed investment. Instead, for all asset classes, we proposed to allow GDNs to request a reopener at the MPR if they could provide more robust data (eg around deterioration rates) in support of higher asset integrity investment, and where the associated change in expenditure is material.

4.13. In our RIIO-GD1 FP we reiterated our RIIO-GD1 IP position on asset health and risk. We said that in order to reconsider the required improvement in asset health/risk secondary deliverable at the MPR we would require each GDN to demonstrate the following:

- It has improved asset health data and criticality for one or more asset classes, and the data is sufficiently robust to support a revision to the asset health/risk secondary deliverable for the specific asset class or classes.

- The improved data for the asset class or classes supports a material change to the corresponding asset health/risk secondary deliverables set at the price control. We defined materiality where the change in allowed costs exceeds 5% of allowed revenues.

4.14. There is ongoing work with the GDN Safety & Reliability working group to get to an agreed methodology for NOMs. We are currently consulting on the

GDNs' NOMs methodology,[43] which they submitted to us for approval. This methodology should allow us to assess the GDNs' performance on the asset health of their network. Following our approval of this methodology, GDNs will be required to submit their initial updated information to us by the end of July 2016. Therefore we consider that it is unlikely that the GDNs will be able to demonstrate that they have robust asset health data to support any increase in the allowed expenditure within the timeframe for MPR.

4.15. Therefore we do not consider we should take this issue forward as part of an MPR. We consider that an approved NOMs methodology would allow us to measure the performance of this secondary deliverable at the end of RIIO-GD1.

4.16. Do you agree with our current assessment that we do not need to review the asset health and risk secondary deliverable as part of an MPR?

[43] https://www.ofgem.gov.uk/publications-and-updates/gas-network-output-measures-methodology-consultation

5. Cross-sector issues

Chapter Summary

This chapter outlines some further issues we have identified for potential consideration across one or several sectors.

Question 20: Do you agree that we should clarify some areas where it isn't clear how late or non-delivery will be treated? If so, which areas do you consider would benefit from such clarification?

Question 21: How material do you consider innovation tax relief has been and is likely to be for the network companies? Do you consider this is an issue that we need to pursue as part of any MPR? We request that the network companies provide estimates of the benefits accrued so far due to this tax relief as part of their responses.

5.1. In this chapter we outline our views on potential areas of consideration that may involve more than one sector (Electricity Transmission, Gas Transmission and/or Gas Distribution). We outline our views for each of these potential issues and ask for stakeholder views on whether these are issues worth taking forward through an MPR.

Late delivery and non-delivery of outputs

5.2. One of RIIO's key components is that revenue should follow and be linked to outputs. We think there may be benefits in clarifying our policy around late and non-delivery of these outputs, where it is not currently clear, to help drive appropriate behaviours. This is potentially the most material issue we have identified.

5.3. We previously stated that network companies could be held accountable for non-delivery of outputs through enforcement action, but that this would also be managed through financial incentives.[44]

5.4. We also confirmed that revenues or allowances could be adjusted downwards if outputs were not delivered.[45]

[44] https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/2_riiot1_fp_outputsincentives_dec12.pdf paragraph 1.13.
[45] https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/2_riiot1_fp_outputsincentives_dec12.pdf, paragraph 1.14.

5.5. In our RIIO-T1 IP[46] we said that we would review National Grid Electricity Transmission's (NGET's) performance in delivering wider works, assess any late delivery and determine whether this constituted any breach of licence obligations (eg considering the reasons and potential mitigations put in place). We noted that in this event NGET could be subject to a financial penalty.

5.6. We consider there may be benefits in establishing up front the proposed basis of our assessment of completion of outputs, and our proposed principles for when and how we would intervene if outputs were not met, as well as clarifying how allowance adjustments would operate. We consider this would not remove the threat of enforcement action for licence breach where licence outputs have not been delivered, nor fetter our discretion in this area.

5.7. Whilst in some places, the rules are already clear, in others we could be clearer about how we might use our regulatory powers, separate to any enforcement action.

5.8. Moreover, we think being clearer upfront is consistent with best regulatory practice by being more transparent and reduces regulatory risk by providing network companies with the opportunity to mitigate or change their approach. It is also consistent with the RIIO principles.

5.9. We think it would be helpful to explain up front where possible how the ex ante rules for these adjustments could occur, as part of any MPR.[47] This will apply to various output categories:

- Outputs not delivered, but still needed
- Outputs not delivered and no longer needed
- Late delivery of outputs
- Substitution – projects that are no longer being delivered but other related projects are being delivered instead, which might meet the desired outcomes more efficiently.

5.10. An example is the Avonmouth gas pipeline (c. £165 million) which is no longer required and, as a result, National Grid is no longer delivering – we discuss this issue further in Chapter 3. Another example is the Western HVDC link (c. £1

[46] https://www.ofgem.gov.uk/sites/default/files/docs/2012/07/riio-t1-nggt-and-nget-cost-assessment-and-uncertainty_0.pdf, paragraph 1.44.
[47] There may also be a distinction between outputs which have been explicitly included in the companies' licences and those which have not.

billion) that will be delivered a year later than what the licence requires because of cable manufacturing difficulties.

5.11. Question: Do you agree that we should clarify some areas where it isn't clear how late or non-delivery will be treated? If so, which areas do you consider would benefit from such clarification?

Innovation and tax

5.12. We previously stated that "*The Treasury introduced tax relief for innovation spending in 2008. The innovation stimulus provides funding for companies to trial innovative techniques and approaches, and companies can pass through up to 90% of these costs to consumers (subject to the Network Innovation Competition and Network Innovation Allowance governance arrangements). We are mindful of companies receiving excessive gains through this tax relief, given this level of consumer funding. Therefore we intend to monitor its use during RIIO-T1 and may consider consulting on further action in the future*."[48]

5.13. This tax relief has the potential to provide windfall gains for the network companies. The extent of this relief depends on the nature and the volume of innovation projects coming forwards. Whilst we consider the innovation mechanisms themselves are working as intended, we are keen to identify the materiality of this potential tax relief benefit.

5.14. We consider this issue falls within scope of the MPR, as we identified it as a potential candidate for future action at the time of FP and intervention may be in consumers' interests. We also think we should try to resolve the issue now rather than leaving it until a later date.

5.15. Question: How material do you consider innovation tax relief has been and is likely to be for the network companies? Do you consider this is an issue that we need to pursue as part of any MPR? We request that the network companies provide estimates of the benefits accrued so far due to this tax relief as part of their responses.

[48] https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/2_riiot1_fp_outputsincentives_dec12.pdf paragraph 4.16.

Appendices

Index

Appendix 1 – Consultation response and questions

1.1. We 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 12 January 2016 and should be sent to:

Geoff Randall (Electricity Transmission) / Mick Watson (Gas)
9 Millbank
London
SW1P 3GE
020 7901 7000
mpr@ofgem.gov.uk

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

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

1.6. Next steps: Having considered the responses to this consultation, we intend to decide in spring 2016 on whether to initiate an MPR for each price control. If an MPR is initiated, it will start by examining the specific issues in more detail and any policy proposals would be set out during summer 2016 for a decision in late autumn 2016. Any associated licence changes would need to be in place by 1 April 2017. Any questions on this document should, in the first instance, be directed to:

Geoff Randall (Electricity Transmission) / Mick Watson (Gas)
9 Millbank
London
SW1P 3GE
020 7901 7000
mpr@ofgem.gov.uk

CHAPTER: One

Question 1: Do you have any views on the additional clarity we have provided on the RIIO-T1 and GD1 MPR scope?

Question 2: Do you consider the issues we have identified for RIIO-T1 and GD1 in this consultation fall within this scope?

Question 3: Are there any other issues within the defined scope that we have not included when assessing the need for an MPR for RIIO-T1 and GD1?

CHAPTER: Two

Question 4: Based on our current assessment there may be some issues in Electricity Transmission that could be addressed through an MPR. Do you agree with this assessment?

Question 5: We ask for detailed views, particularly from the TOs, on how the operability of the RIIO-T1 NOMs incentive mechanism could be improved. As part of this, we would like evidence on the manner in which any potential revisions may better facilitate the delivery strategy of outputs, in line with current needs of consumers and network users, and the materiality of such change.

Question 6: We are seeking views on whether the Environmental Discretionary Reward is driving the right business changes within the companies and providing the outputs that consumers and network users need.

Question 7: We are seeking views on whether the stakeholder incentives are driving the right behaviours to get the outputs that consumers and network users need.

Question 8: We have set out some initial thinking on the following issues: submission quality for Strategic Wider Works projects, further guidance on monitoring needs cases for projects in construction, the potential need for an availability incentive for Scottish island links, and potential funding requirements for NGET's enhanced SO function, as well as on onshore competition roles. What are your views on these?

Question 9: We wish to understand if there has been a material change in outputs due to the changes in government policy related to renewables subsidies. We ask that the TOs provide information on which connections and wider works are being taken forward compared to the ones that the unit costs were based upon and whether any variation is within the bounds of what was expected to be captured.

Question 10: We ask that the network companies provide information on any connections and wider works that are not easily correlated to a specific funding mechanism in the licence. We also ask that evidence is provided of the materiality of such issues as part of any response.

Question 11: We welcome views on whether there needs to be clarification of output requirements and treatment of activities (load related projects in particular), that sit outside of the revenue drivers, where they are no longer required or have been substituted.

Question 12: How material do you consider the RIIO-T2 outputs issue to be? Do you consider this is an issue that we should take forward?

CHAPTER: Three

Question 13: Based on our current assessment there may be some issues in Gas Transmission that could be addressed through an MPR. Do you agree with this assessment?

Question 14: We are considering undertaking a review of the requirement and associated output to deliver an Avonmouth pipeline solution. Do you agree with this?

Question 15: We are considering reviewing how National Grid Gas Transmission (NGGT) is meeting its output to maintain its 1-in-20 obligation for Scotland. Do you agree with this?

Question 16: We are considering reviewing how NGGT is meeting its output to deliver specific compressor projects. Do you agree with this?

CHAPTER: Four

Question 17: Based on our current assessment we have not identified any material issues for RIIO-GD1 which we think would require further examination through an MPR. Do you agree with this assessment?

Question 18: Do you agree with our current assessment that there is no need to review the risk reduction output associated with the iron mains risk reduction programme, as part of an MPR?

Question 19: Do you agree with our current assessment that we do not need to review the asset health and risk secondary deliverable as part of an MPR?

CHAPTER: Five

Question 20: Do you agree that we should clarify some areas where it isn't clear how late or non-delivery will be treated? If so, which areas do you consider would benefit from such clarification?

Question 21: How material do you consider innovation tax relief has been and is likely to be for the network companies? Do you consider this is an issue that we need to pursue as part of any MPR? We request that the network companies provide estimates of the benefits accrued so far due to this tax relief as part of their responses.

Appendix 2 – RIIO delivery areas and outputs

Electricity Transmission outputs

Area	Output
Safety and reliability	Safety (comply with legal safety obligations – HSE)
	Reliability (performance in relation to maintaining a low level of Energy Not Supplied)
	Other (suite of secondary output measures – asset health criticality, replacement of priorities, system unavailability, average circuit unreliability, fault and failures)
Network availability	Network Access Policy
Connections	New generation connections (sole use and shared use)
	Connections activity
Customer and stakeholder satisfaction	Customer satisfaction survey, stakeholder satisfaction survey, stakeholder key performance indicators, stakeholder engagement incentive, stakeholder external assurance
Environmental outputs	SF6 emissions
	Losses
	Business carbon footprint
	Visual amenity
	EDR scheme
Wider works outputs	Baseline wider works outputs
	Further areas of wider works
	Pre-construction outputs (routing, siting, optioneering studies, project design, environmental assessment, technical specifications for cost tenders, planning consents)

Gas Transmission outputs

Area	Output
Safety and reliability	Safety (comply with legal safety obligations – HSE)
	Asset health measures
	Other (suite of secondary output measures – asset health criticality, replacement of priorities, system unavailability, average circuit unreliability, fault and failures)
Network availability	Sufficient to deliver 1-in-20 winter peak
Connections	Process established
Customer and stakeholder satisfaction	Customer satisfaction survey, stakeholder satisfaction survey, stakeholder engagement, stakeholder engagement incentive
Environmental outputs	Business carbon footprint

Gas Distribution outputs

Area	Output
Safety and reliability	Major accident hazard prevention – GS(M)R safety case acceptance by HSE, COMAH safety report reviewed by HSE
	Repair – GS(M)R 12 hour escape repair requirement, Management of repairs (repair risk)
	Mains replacement – iron mains risk (based on MPRS), Sub-deducts networks off-risk
	Emergency response – 97% Controlled interruptions, 97% Un-controlled interruptions
	Reliability – Maintaining operational performance (see secondary deliverables)
Network availability	Number and duration of planned and unplanned interruptions
	Sufficient to deliver 1-in-20 winter peak
Connections	Guaranteed standards performance
	Introduce distributed gas entry standards
Customer and stakeholder satisfaction	Planned interruptions survey, emergency response survey, connections survey, complaints metric, stakeholder engagement
Environmental outputs	Leakage
	Business carbon footprint
	Provide biomethane connections information
Social	Fuel poor connections
	Carbon monoxide awareness
	Stakeholder engagement

Appendix 3 – Final Proposals issues

List of Final Proposals issues we are not at present planning on taking forward

Issue	Sector	Description	Comment
Disallowed tower flooding	Electricity Transmission	NGET forecast a total cost of £116m for weather related resilience covering flooding protection works for high risk sites at a total cost of £105m and tower flood protection works with an estimated cost of £11.1m. We disallowed funding for the flood protection works in our FP.	We stated in FP that we would revisit the disallowed cost of tower flooding protection during the mid-period review and may adjust the allowance for weather-related resilience if necessary. At this stage, we have not identified any relevant changes related to this issue, and are not currently considering to adjust allowances for weather-related resilience
Integrated network investment	Electricity Transmission	NGET submitted a request for funding through RIIO-T1 to undertake preliminary works related to potential integrated network investment off the east coast of England. In FP we provided a provision for NGET's 'East Coast' proposal by which additional funding could be potentially triggered. We stated "*For the avoidance of doubt, this process is only applicable for additional funding for the proposed East Coast project. Any further funding of preliminary works related to integrated network investment will be subject to review as part of the mid-period review*".[49]	We stated in FP that any adjustment would be, in part, subject to NGET's justification for these costs including evidence of the outputs that will be delivered. At this stage, we have not received any final evidence from NGET on this issue, and are not currently considering adjusting allowances to preliminary works related to the East-Coast Integrated Network. Further funding of preliminary works related to integrated network investment is being considered through our enhanced SO conclusions from our ITPR project.
Flood and erosion protection	Electricity Transmission, Gas	In NGET/NGGT FP we stated that we would look into costs for flood erosion and protection at MPR "*in the event that the Government requires NGET to*	The RIGs summarises work being undertaken to mitigate the risk of substation flooding. TOs must specify the number of assets in each risk category

[49] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 3.55.

	Transmission	*contribute to flood protection or erosion schemes*".[50] This would relate to changes in government legislation that require NGET/NGGT to pay additional contributions to schemes.	which have had, or are forecast to have, flood mitigation work carried out. RIGs submissions do not suggest costs associated with flood and erosion mitigation over and above what was expected. Consequently, we are not considering adjusting allowances in this regard at present.
EU/GB market change	Electricity Transmission, Gas Transmission	In FP, one area of uncertainty we proposed to consider as part of any MPR process was on the costs associated with new market facilitation roles/functions stemming from EU or GB legislative change.	We have not identified any relevant and sufficiently significant changes to EU energy market legislation to justify a new output or funding adjustment. Whilst there has been relevant and significant change to GB energy markets through the EMR, this was accounted for in Final Proposals through a reopener. We are not proposing to consider any further changes to outputs or revenue related to changes in GB energy markets.
Non-load related expenditure	Electricity Transmission	In IP we did not propose an uncertainty mechanism to review NOMs and adjust the baseline allowance for non-load related expenditure (NLRE). NGET commented that NLRE was largely dependent on the progress of Load Related Expenditure (LRE), and suggested slower than anticipated LRE could lead to financing costs exceeding the effective materiality threshold proposed for other uncertain costs. In FP we agreed to review this decision at any MPR, noting that "*If NGET can justify material changes to the delivery of NOMs and provide evidence to justify the changes in the best interest of*	We have not received any evidence to suggest that material change to the delivery on NOMs is in the best interests of consumers. As such, we are not currently considering adjusting baseline allowances for NLRE.

[50] https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf table 3.6.

		consumers, we will make necessary adjustments to its allowance to reflect financing costs".[51]	
Constraint management/buy-back	Gas Transmission	NGGT uses constraint management tools when insufficient capacity is available or investments are delivered late. We incentivise it to minimise its constraint management costs through a range of incentive mechanisms. In IP, we consulted on a proposal to combine existing incentives into a single constraint management incentive with no cap/floor, with an alternative proposal to continue with the existing arrangements. Based on stakeholder feedback to these proposals, we put in place a unified incentive but included a cap of £20m and a collar of £60m to protect NGGT from low probability, high impact costs.	In FP we said we would review the arrangements at the MPR or earlier if there are significant changes to the arrangements for providing incremental capacity. New arrangements for providing incremental capacity have been introduced but we have not received evidence to suggest that the overall risk of a constraint has materially changed. As such we are not proposing to revisit this issue as part of any MPR process.
Incremental capacity lead times	Gas Transmission	In IP, we proposed to keep current required lead times for providing incremental capacity and include an increased permits allowance for NGGT. NGGT expressed a need for further clarity on permits from 1 April 2014, onwards. In FP we said we would provide a permit allowance of £19m (in line with our IP) for Year 1 of RIIO-T1 and increase this to £40.2m for the next three years (ie up to the MPR point), based on evidence provided by NGGT. We also said we would review the requirement for permits for the remaining years of RIIO-T1 at the MPR.	In FP, we stated that any review of permit requirements would depend on the nature of any changes to the arrangements for providing incremental capacity that are introduced in the intervening period. Permits arrangements were terminated earlier this year and the licence has been changed to reflect this. The need to consider this issue further at the MPR has therefore been removed.

[51] https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf paragraph 5.54.

Appendix 4 – Feedback questionnaire

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

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

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk