Making a positive difference for energy consumers

Consultation on mid-period review parallel work

Consultation

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Contact: James Turnley

Team: RIIO Teams

Tel: 020 7901 7000

Email: mpr@ofgem.gov.uk

Overview:

In deciding to undertake our mid-period review (MPR) we identified areas we would like to look at further. We call this work stream MPR parallel work. MPR parallel work looks at both the transmission and gas distribution price controls.

We have looked at two outputs where it is unclear how we will hold companies to account. Our proposal is to focus on consumer outcomes rather than the output detail.

We have also identified two areas of the price controls where we think it is in consumers' interests to make adjustments. First, we intend to delay the allowances provided to National Grid Electricity Transmission and SP Transmission due to the late delivery of the Western HVDC, a £1 billion subsea link. We also intend to accept National Grid Gas Distribution's offer to refund consumers £53.9 million for medium pressure iron mains replacement work that has been delayed beyond this price control.

We are now seeking stakeholder views on our proposed approach.

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 put 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.

In deciding on the need and scope for the mid-period review and as part of our annual reporting process we identified a set of matters we decided to progress through a separate work stream: MPR parallel work.

We have reached a proposed position on these and are now seeking the views of stakeholders.

Associated documents

Consultation on the mid-period review (MPR) of RIIO-T1

Decision on a mid-period review for RIIO-T1 and GD1

Consultation on a potential RIIO-T1 and GD1 mid-period review (and associated responses)

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

For Initial Proposals, strategy decisions and the RIIO Handbook, please see our dedicated page for RIIO-T1.

Contents

Executive Summary

In deciding on the scope for our mid-period review (MPR) we identified areas we would like to look at further in parallel. We decided to progress these issues, which cover transmission and gas distribution, through a separate package: MPR parallel work.

MPR parallel work has two parts.

The first is to clarify how we will hold companies to account for output delivery. For two outputs, companies have proposed to deliver differently from what was envisaged:

1. National Grid Gas Transmission (NGGT) has an output to replace compressors to meet the Industrial Emissions Directive. NGGT has since identified more efficient solutions to meet these environmental requirements. For instance, at one location NGGT will retrofit a catalytic convertor to existing compressors instead of replacing them.

2. SP Transmission (SPT) has an output to provide voltage support to address the possible closure of Hunterston B nuclear power station. Hunterston B is now expected to stay open longer but changes elsewhere, such as the closure of the large Longannet power station, mean there is an ongoing requirement for voltage support.

Our proposed approach is to focus on consumer outcomes for these two outputs. This means we will consider the outputs to be delivered if they comply with the Industrial Emissions Directive and manage voltage control in a way that is in consumers' interests, ie economic and efficient. This may mean changing approach from what was originally envisaged. We think this approach promotes innovation and efficiencies by the companies which will benefit consumers.

The second part of the MPR parallel work relates to possible gaps (or imperfections) in the price control. Our proposed position is to make two adjustments:

1. **Delay allowances provided to National Grid Electricity Transmission (NGET) and SPT for delivering the £1 billion[1] Western HVDC subsea link late.**

   NGET and SPT report that the Western HVDC will be delivered late because of technical problems with the manufacture of the cable.[2] Although this will likely increase costs to consumers, the companies will likely receive a financial benefit by paying suppliers later than assumed in setting allowances. We consider that this represents a gap in the framework and that it is in consumers interests for us to delay allowances due to late delivery.

[1] All allowances are expressed in 2009/10 prices so that they are consistent with the RIIO-T1 final proposals.
[2] We have not yet evaluated the reasons for the delay.

2. **Accept National Grid Gas Distribution's (NGGD) offer to refund consumers £53.9 million for work to replace old medium pressure irons mains in central London which has been partly delayed to future price controls.**

   NGGD has identified that, due to unexpected engineering and stakeholder issues, only 29 km of the 69 km of work will be delivered in RIIO-GD1. We propose to accept NGGD's offer as the specific safety and reliability outcomes funded will not be delivered. This approach also ensures that consumers will not fund the same work twice in a future price control.

In addition to the above, we also looked at a range of other issues and propose to make no adjustments:

- **SPT's request to amend its connections volume driver such that it provides an additional £81 million in funding.** We do not think we should make the proposed changes as they are asymmetric. Making the change would provide additional funding where SPT overspends while leaving underspends elsewhere unchanged.

- **National Transmission System (NTS) Exit Capacity incentive.** British Gas raised a number of concerns including that the scheme encourages perverse behaviour that increases costs for consumers. Although we acknowledge that it has weaknesses, we think that overall the scheme is incentivising the desired behaviour and that the risks from making changes to the scheme outweigh any benefits.

- **Three gas distribution outputs not directly linked to allowances or incentive schemes.** This covers the safety repair risk, reliability loss of supply and maintaining operational performance outputs. After reviewing the mechanisms in place, we consider that no changes are required. We continue to expect companies to meet these outputs. Where this is not the case we will discuss performance with companies and expect them to take action to bring about improvements and, where appropriate, make redress to consumers.

- **SPT's trigger mechanism.** SPT requested funding for overhead line refurbishment works, which was originally set to be unlocked if works on the East Coast 400kv upgrade commenced. We do not consider that any adjustment to the price control is required as our Network Outputs Measures (NOMs) incentives will fund these works if they are justified.

- **Other electricity transmission outputs.** We have reviewed three specific outputs to determine how we would address non delivery. As all identified outputs are currently being delivered or have an appropriate mechanism in place, we consider no further action is required.

1. Background and scope

This chapter provides an outline of the background and scope of MPR parallel work.

➔ **Question:** Do you agree with the scope of the MPR parallel work?

1.1. We regulate energy networks companies with our RIIO (Revenue = Incentives + Innovation + Outputs) price control model. RIIO sets out up-front what outputs companies need to deliver for consumers and the associated revenues they are allowed to collect.

1.2. There are three RIIO price controls: transmission (RIIO-T1), gas distribution (RIIO-GD1) and electricity distribution (RIIO-ED1). RIIO-T1 and RIIO-GD1 apply from 1 April 2013 to 31 March 2021. RIIO-ED1 runs later from 1 April 2015 to 31 March 2023.

1.3. The RIIO price controls included a mid-period review (MPR) to address changes in government policy, and changes to consumers' and network users' needs. The MPR provides a mechanism to add, remove or adjust outputs to reflect these changes. The MPR recognises the forecasting difficulties of an eight year price control period.

1.4. In May 2016 we decided to launch an MPR for RIIO-T1 focused on three specific areas, relating to National Grid's electricity and gas transmission networks. We published our proposed approach in August 2016 and decision in February 2017. We decided not to hold an MPR for gas distribution.

1.5. As part of the MPR, and our annual review of company progress and performance under the price controls, we identified several issues that we considered would benefit from further consideration. To resolve these we began a project called 'MPR parallel work.'

1.6. We initially organised the issues into three categories.[3] We have since reframed and renamed each category and decided that some issues now fall more naturally into a different category.

1.7. We have decided to use the following categories:

- **Output accountability.** We clarify how and when we will consider an output delivered including where there have been changes in circumstance or the identification of better ways to solve problems.
- **Price control adjustments.** We look at making possible adjustments to the existing RIIO-T1 and RIIO-GD1 price controls to address certain gaps identified in the framework.

[3] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1*, p.5

1.8. In our May 2016 MPR decision we identified a number of actions we might take in response to the parallel issues identified. Having considered the matters further, we think it is appropriate for us to consider a wider range of responses. These potential responses include:

- Clarifying our approach to output delivery, such as when we will consider existing outputs delivered.[4] A potential response we are also considering is changing allowances to match changes in approach.
- Clarifying how we will treat outputs that are delivered late.[5] Potential responses include adjusting how payments will be shared with consumers, what information we expect to be provided and delaying allowances due to the late delivery of an output.
- Considering amendments to SP Transmission's connections volume driver.[6]
- Considering changes to the NTS exit capacity incentive that applies to gas distribution network companies.[7] We are also considering suspending the incentive.
- Adding existing outputs to licences.[8]
- Amending the gas distribution reliability loss of supply output targets.[9]
- Making changes to allowances mid-period and at close out.
- Making commitments about the provision of further allowances in future price controls.

1.9. In regards to the deferred replacement of medium pressure mains in London issue, we previously said that we would only consider action if it had an impact on delivery of other outputs. Having considered further, we now think it appropriate to consider action if this is not the case in order to protect consumers from the risk of funding the costs of a significant investment twice.

1.10. Lastly, we have excluded some matters that were originally included within MPR parallel work, because they are being considered by separate work streams. These are:

- Network Output Measures which is the set of output incentives that apply to the delivery of asset replacement and refurbishment works.

[4] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.15
[5] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.29
[6] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.30
[7] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.38
[8] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.36
[9] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1,* p.37

- The Environmental Discretionary Reward.

- The Stakeholder Engagement Incentive.

- Strategic Wider Works.

- Preparatory work on a gas transmission reopener related to the Industrial Emissions Directive.

2. Output accountability

In some cases, we set outputs in a fairly prescriptive way (eg solution specific). Changes in circumstance or the identification of better ways to solve problems makes it unclear when we will consider an output delivered.

Our proposed approach for the two issues we have reviewed is to focus on the output's purpose and whether it has been delivered in a manner which provides the greatest consumer value.

We will apply our proposed approach to two outputs, National Grid Gas Transmission's (NGGT) compressor output and SP Transmission's (SPT) voltage control output.

When should we consider an output delivered?

- ➔ **Question:** Do you think we are right to focus on the output purpose where there is ambiguity to decide when an output is delivered? If not, please explain why and provide evidence.
- ➔ **Question:** What do you think about our alternative options including focusing on the detailed output specification or output declassification? Will they achieve our purpose? Can you think of any other alternatives?

2.1. Outputs set out what network companies are required to deliver in return for earning the revenue set under the price control.

2.2. Our RIIO handbook provides the overarching outputs framework. This was further developed in our strategy decision for each price control.

2.3. Following the strategy decision, each company provided a business plan for the price control period. After considering their original (and subsequently revised) business plans, we set the outputs to apply in our final proposals.

2.4. Since the start of RIIO-T1 and RIIO-GD1, circumstances have changed. In some cases this makes it unclear when we will consider the outputs delivered. For instance, will we consider the output delivered only if exactly what we specified is delivered? Or will we consider the output delivered as long as the overall purpose of the output is achieved regardless of what method was used?

2.5. We have identified two outputs where it is unclear when we will consider the outputs delivered, which we discuss in detail later in this chapter.

2.6. We consider that we should address ambiguity of these two outputs by focusing on their purpose. We propose to consider the outputs delivered if they are delivered in a manner which provides the greatest value to consumers (both in the short and long term), ie are economic and efficient. This approach will encourage companies to find alternative ways of delivering and manage changing circumstances – it also avoids the risk of companies building things that are not needed.

2.7. In addition to our proposed approach above, we have considered two alternative options:

- We could hold companies to account for what was specified rather than the output's purpose.

  However, we are concerned that this approach will create incentives for companies to avoid considering alternative options. It will also encourage companies to seek changes to outputs if costs increase. We want to avoid creating these incentives.

- We could 'declassify' an output by removing the obligation to deliver but retain the original allowance provided. The main advantage of this is that it removes potential distortions.

  We think that declassification is unnecessary as we can avoid perverse incentives by holding companies to account for the purpose rather than detailed specification.

  It is also advantageous to retain the output, even if companies change their approach, as it allows us to remove funding if the output is ultimately not delivered.

2.8. We consider that this approach could be applied to other outputs. In each case we will need to consider the nature of the output and why it was set. Given the complexity of a price control, in some cases, our approach may provide outcomes that are not in consumers' interests. We will not apply our approach in these circumstances.

2.9. Further, we do not think that our approach applies to National Grid Gas Transmission's (NGGT) Avonmouth output, which we considered as part of the mid-period review. The Avonmouth pipeline was unambiguously defined as a pipeline solution and focused on the asset itself rather than the purpose of the output.

2.10. We note that it is sometimes appropriate to fund large, discrete projects in the terms of the asset being delivered rather than the objective. One advantage of this approach is that it lessens the risk that consumers will be funding works that are not required.

National Grid Gas Transmission’s compressors output

➔ **Question:** Do you agree with our proposed approach to hold NGGT to account if it complies with the IED requirements? If not, please explain why and provide evidence.

2.11. We specified an output for NGGT that included both an output purpose (complying with the Industrial Emissions Directive (IED)) and how this should be achieved (through installing new compressors).

2.12. NGGT has since identified more efficient solutions to meet the environmental requirements of the IED. At one location, NGGT will retrofit a catalytic convertor to the existing compressors and at another station install compressors of a different type than envisaged at the outset of the price control.

2.13. This change in circumstances and the ambiguous nature of the output makes it unclear whether we will focus on the output purpose or output specifics in holding NGGT to account.

2.14. Our proposed approach is to focus on the purpose: complying with the IED. We will consider the output delivered if NGGT complies with the IED in a manner that delivers the greatest value for consumers.

Background

2.15. Across the National Transmission System, compressor stations maintain pressure to keep gas flowing through the system.

2.16. In RIIO-T1 we allowed funding of £143 million for NGGT to install new compressors at specific stations to ensure compliance with the IED. The IED applies a new emission limit for carbon monoxide (CO) and a more stringent emissions limit for oxides of Nitrogen (NOx). It also removed the exemption that previously applied to NGGT’s compressors due to their age.

2.17. We provided funding for new compressors at Aylesbury, Huntingdon and Peterborough and added the following output:

> *Compressor replacement – changes for compliance with requirements of the IED.*

2.18. We provided further details of the output in the initial proposal:

> *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.*[10]

2.19. NGGT is delivering alternative solutions to what was originally envisaged. In particular, at Aylesbury an oxidation catalyst (catalytic convertor) was added to reduce emissions and comply with the IED rather than new compressors.

2.20. In Peterborough and Huntingdon, NGGT is installing smaller gas compressors than envisaged. NGGT has reported that the cost differences are not material due to other costs being incurred that were not included in the allowance.

2.21. The output is ambiguous because it is unclear what NGGT is required to deliver: the output purpose (compliance with requirements of the IED) or the output specifics (installation of specific type of compressor) or both.

Our proposed approach

2.22. Our proposed approach is to focus on the output purpose: compliance with the IED.

2.23. We will consider the output delivered if NGGT can justify that it complied with the IED in a manner which has delivered the greatest value to consumers. We expect NGGT to justify its approach, which would need to consider wider implications such as network capability.

2.24. We think this approach promotes innovation and finding new efficient ways of delivering. We think these benefits outweigh our previous concerns regarding project delays and high allowances.[11]

2.25. NGGT will share with consumers the benefit of any cost savings (and cost increases) through the total expenditure sharing mechanism. NGGT's latest forecast estimates that it will underspend by approximately £25 million against its allowance of £143 million. This is mainly due to the savings forecast at Aylesbury. Based on this projection NGGT and consumers will retain about £11 million each.[12]

2.26. We have considered the alternative of focusing on the asset specifics, rather than the output purpose. In this case we would focus on whether the original solution (compressor replacement) was deployed as envisaged.

2.27. Under this alternative we would adjust allowances to reflect the change in circumstances. This option could claw back savings from lower costs.

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[10] Ofgem 2012, *RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas,* Cost assessment and uncertainty Supporting Document, para. 7.89
[11] Ofgem 2015*, Consultation on a potential RIIO-T1 and GD1 mid-period review*, p.29
[12] This does not take into account the Information Quality Incentive (IQI) which will affect these amounts.

2.28. However, we would also have to consider whether we would apply this approach symmetrically. This could mean providing higher allowances when costs increase and transfer the risk of higher costs from companies to consumers. It would also remove the incentive for NGGT to identify alternative more efficient solutions. We are concerned that this would undermine incentives for network companies to identify and realise efficiencies.

2.29. We think that focusing on what consumers value, rather than the detailed output specification, will provide the greatest value for consumers in the long term. We propose taking no action if NGGT deviates from the approach envisaged as long as the new approach can be demonstrated to be in consumers' interests.

SP Transmission's voltage control

➔ **Question:** Do you agree with our approach to consider the output delivered if SPT manages voltage across its network efficiently? If not, please explain why and provide evidence.

2.30. Certain electricity generators assist in ensuring voltage stays within prescribed limits. Consequently, if generators close, a transmission owner may need to install additional equipment to ensure voltage is managed.

2.31. SPT's price control includes an output to provide voltage support to address the closure of Hunterston B nuclear power station. Hunterston B is now expected to close in 2023, which is in the next price control.

2.32. Although Hunterston B is expected to be operational for the remainder of RIIO-T1 there have been other changes in generation, such as the closure of the large Longannet power station. As a result, SPT Transmission still expects to provide voltage support, although in a different manner than forecast.

2.33. Our proposed approach is to focus on the purpose: voltage control. We will consider the output delivered if SPT manages voltage in a manner that delivers the greatest consumer value.

Background

2.34. One aspect of providing an electricity transmission service is voltage management. SPT is required to meet the requirements of the Grid Code and the National Electricity System Security and Quality of Supply Standard (NETS SQSS).

2.35. Voltage is generally controlled via capable generators or the use of specific network assets (such as capacitors or reactors). Voltage management can also be provided by changing how consumers use electricity.

2.36. Changes in the availability of generators to provide voltage support affect how system voltage can be managed. If a generator is decommissioned it may be necessary to install network equipment to ensure that voltage stays within prescribed limits.

2.37. SPT's RIIO-T1 business plan identified that network assets will be required to help manage voltage following the closure of Hunterston B in 2020/21.

2.38. To fund this requirement, an output and associated funding (£15.4 million) were included in RIIO-T1. The output is specified in SPT's licence as:[13]

> *Voltage support to comply with Grid Code and NETS SQSS on possible closure of Hunterston Power station and transmission system reconfiguration in the west coast.*

2.39. The closure of the Hunterston B power station has been delayed beyond the end of RIIO-T1. EDF Energy, the operator of Hunterston B, estimates decommissioning to occur in 2023.[14] No expenditure will therefore be required to address the closure of Hunterston B in RIIO-T1.

2.40. Elsewhere on the network, there has been a reduction in the availability of generators that can support voltage. In particular, the large 2,400 MW Longannet power station closed in March 2016. These changes were not foreseen by SPT in its RIIO-T1 business plan.

2.41. To address the reduced availably of generators, SPT proposes to deploy equipment (shunt reactors) across their network to help manage voltage. SPT forecasts this to cost £10.8 million.

2.42. SPT suggested that the change in circumstance could be addressed using the Output Amendment mechanism[15] included in its licence. However, the Output Amendment mechanism cannot make general changes to outputs. Rather, the mechanism only revises the capacity of an output where it is affected by changes in generation and demand.

Our proposed approach

2.43. Our proposed approach is to consider the output delivered if SPT deliver on the output purpose: to manage voltage efficiently and meet the requirements set out in the Grid Code and NETS SQSS. We will continue to monitor its performance against this output.

2.44. Although the closure of Hunterston B is later than envisaged, there is a continued need for SPT to provide voltage support on the network. Accordingly, we believe the output should be retained.

2.45. We note that SPT forecasted to spend £10.8 million, which is less than the £15.4 million allowance provided. The RIIO-T1 price control shares the risk of higher or lower costs between SPT and consumers via the total expenditure sharing mechanism. We see no reason to make an adjustment to alter the existing risk

[13] Special condition 6I, Table 1: Baseline Wider Works Outputs
[14] EDF Energy 2017, *Hunterston B power station,* available here
[15] This mechanism is specified in Part D of Special Condition 6I.

allocation and note that voltage control needs could increase or decrease in the remainder of the period.

2.46. An alternative is to reduce allowances due to the need decreasing. As with NGGT's compressors if we applied this approach symmetrically, we would also need to consider providing additional funding where the cost of meeting an output has increased. This approach will reduce incentives for companies to identify lower costs options and likely increase costs for consumers in the long run.

2.47. We will hold SPT to account for delivering this output in a manner that delivers the greatest consumer value. If voltage support is not efficiently provided we may take action such as removing associated funding.

3. Price control adjustments

The second part of the MPR parallel work relates to possible gaps in the price control.

We have identified two where we think it is in consumers' interests to make adjustments.

First, we intend to ensure that National Grid Electricity Transmission (NGET) and SP Transmission (SPT) do not benefit from their late delivery of the Western HVDC, a £1 billion subsea link.

Second we propose to accept National Grid Gas Distribution's (NGGD) offer to refund consumers for work it is unable to deliver. This relates to work to replace old medium pressure iron mains in central London which has been partly delayed to future price controls.

We also outline our assessment of a range of other issues where we think no change is required.

When should we address gaps in the price control?

3.1. Network companies make decisions based on how credible they perceive the regulatory framework to be. A credible regulatory framework allows companies to finance investment in their networks. Further, credibility strengthens the incentives we put in place to encourage companies to innovate and find new ways to improve the quality and cost of service to consumers.

3.2. To provide this credibility, we designed the RIIO model to provide certainty and transparency. We said we would seek to avoid any retrospective adjustments to the package agreed in final proposals.[16]

3.3. Accordingly, we have carefully considered the matters that were raised. We have considered first whether a gap exists and second whether it is in consumers' interests to address the gap mid-period.

3.4. We have identified two changes that we think it would be in consumers' interests to make: removing the timing benefit for the late delivery of Western HVDC and accepting the return of funding for deferred replacement of medium pressure pipes in London. We consider that making these changes would improve the RIIO price controls and will not have a detrimental impact on regulatory confidence.

3.5. In relation to all the other issues we have considered, we have either found no gaps or consider that it is in consumers' interests not to make any changes mid-period.

[16] Ofgem 2010, *Handbook for implementing the RIIO model,* para 5.6

Western HVDC

- ➔ **Question:** Do you agree with our proposed approach to delay allowances due to the delivery of the Western HVDC? If not, please explain why and provide evidence.
- ➔ **Question:** Do you have any views on how we should delay allowances? Please explain and provide evidence.
- ➔ **Question:** Do you have any view on how we should treat payments and in-kind benefits from suppliers paid to compensate for the delay? Please explain and provide evidence.

3.6. The Western HVDC is a £1 billion subsea link between Scotland and Wales, jointly developed by NGET and SPT. The link was intended to be delivered in 2016/17 but has been delayed to 2017/18. NGET and SPT report that the delay is primarily caused by technical problems with the manufacture of the cable.[17]

3.7. The delay in delivery is expected to increase costs to consumers by about £70 million as it will defer the reduction in constraint payments to generators. Despite this, NGET and SPT will likely receive a financial benefit from the delay. The financial benefit arises due to the timing difference between when funding was provided and when we expect the costs to be incurred. We expect costs to be incurred later as NGET and SPT may be able to pay their suppliers later, due to the delay.

3.8. We consider that allowing NGET and SPT to benefit from delivering a project late and increasing costs to consumers represents a gap in the regulatory regime. We propose to remove this benefit once the Western HVDC is delivered by delaying allowances.

Background

3.9. The Western HVDC is a £1 billion subsea link, jointly developed by NGET and SPT.

3.10. The objective of the Western HVDC is to provide additional capacity to allow electricity to be transmitted between Hunterston in Scotland and Deeside in Wales.

3.11. Transmission networks do not have unlimited capacity. In some cases there is a 'constraint' which limits how much energy can be transmitted at certain times and locations.

3.12. Network constraints can arise due to the connection of new generators. Where economic, the transmission network is reinforced to provide additional capacity. Until the new assets are installed and where it is not economic to build new transmission assets, National Grid, as system operator, manages these

[17] We have not yet evaluated the reasons for the delay. We will make this assessment on receipt of further information from the companies. Later in this section we set out what information we expect the companies to provide.

constraints. This is generally achieved by paying generators to limit how much electricity is produced.

3.13. The Western HVDC is expected to significantly reduce constraint payments in the order of £140 million per year.[18] Due to the delay, these costs will continue until the Western HVDC is delivered, after which costs will fall. As the delay will be about six months, we expect the cost of the delay to be around £70 million. Actual costs will differ based on when the Western HVDC comes online and the generation and demand patterns that occur. It is possible that constraint costs could be higher or lower than our rough estimate.

3.14. Due to the delay, we expect NGET and SPT to pay suppliers later. Funding was provided assuming that the Western HVDC will be delivered on time. As a result, NGET and SPT are able to hold onto the funding before it is spent. This provides a timing benefit. If we take no action, NGET and SPT will retain a proportion with the rest being shared with consumers through the total expenditure sharing mechanism.

3.15. In setting the price control we did not specify any penalties for late delivery of the Western HVDC. Instead we said we would review deviations from the agreed completion timescales to determine whether these constitute a contravention of the licence conditions.[19]

3.16. We also said we would consider whether or not the companies took reasonable and efficient steps to mitigate the impact of such events.[20] If the licence conditions are found to have been contravened then the Gas and Electricity Markets Authority (GEMA, the relevant decision-making body to whom Ofgem works) may consider taking enforcement action, which could result in the imposition of financial penalties and/or redress payments. Any decision to open a formal investigation, and, in the event subsequently a formal finding of breach is made, any decision as to possible penalty or redress, are matters for GEMA applying its enforcement guidelines[21] and penalty policy[22] respectively. Any GEMA enforcement processes and decisions occur independently of the processes set out in this document.

Our proposed approach

3.17. Our proposed approach is to delay allowances due to the late delivery of the Western HVDC. We believe that this action will remove a gap in the price control which allows companies to benefit from a project delay despite consumers likely being worse off. We think this approach better protects consumers.

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[18] National Grid 2015, *Connect & Manage Forecast Report,* April p.15
[19] Ofgem 2012, *Decision on funding arrangements for the Western High Voltage Direct Current link ("Western Bootstrap")*, p.10
[20] Ofgem 2012, *Decision on funding arrangements for the Western High Voltage Direct Current link ("Western Bootstrap")*, p.10
[21] Enforcement Guidelines
[22] Statement of policy with respect to financial penalties and consumer redress

3.18. In coming to this position we considered two options:

1. Doing nothing. This would allow the companies to retain the financial benefit from delivering the Western HVDC link late.

2. Delaying the allowances to remove the financial benefit.

3.19. We think that doing nothing fails to adequately protect consumers. Consumers have funded the companies to deliver an output by a specific deadline, which will not be met.

3.20. We are also concerned that the companies stand to receive a financial benefit arising from late delivery. We consider that this provides a perverse incentive that should be removed.

3.21. We think the second option of delaying the allowances better protects consumers. This option ensures revenues are better aligned with the delivery of outputs. It also removes the financial benefit that the companies may receive and the consequent perverse incentive.

3.22. We also consider that this approach is, at a high level, consistent with the approaches we employed elsewhere[23] where revenues only follow once an output is delivered.

3.23. Below we also set out

- Options for removing the timing benefit.

- Options on how we could treat damages.

- Information requirements for late delivery.

Proposed method for removing the timing benefit

3.24. There are several possible methodologies for delaying allowances. We are considering two options:

- Changing the profile of the allowances to match actual spend.[24] This option will remove only the timing gain achieved by the companies and no more or less. However this option weakens the incentives on the companies to defer expenditure when a project will be delivered late.

[23] Such as our Transmission Investment for Renewable Generation mechanism.
[24] We would do this by first working out what percentage of total spend was incurred each year. We would reallocate the allowances in line with these percentages. For instance if 20% of total costs were incurred in 2016/17 we would allocate 20% of the allowance to 2016/17.

- Shifting the allowances back in line with the length of the delay. The main advantage of this option is its simplicity. However the consequent timing benefit removed may be larger or smaller than the timing benefit actually achieved. This option also becomes more complex if we make more granular adjustments for how many months (rather than years) the project is delayed.

3.25. We are interested in views on each of these options or any alternatives.

Options on how we could treat possible damages

3.26. We understand that NGET and SPT may be able to recover or negotiate payments (or benefits in kind, such as extended warranties) from their suppliers in relation to the delay.

3.27. The total value of these payments may offset higher 'project costs' incurred by the companies (and in turn consumers) due to the delay. For instance, the companies may have been forced to break other contracts to reschedule work or incur costs to mitigate the impact of the delay. We note that both consumers and the companies are exposed to higher project costs, in the proportion set by the total expenditure sharing scheme.

3.28. It is also possible for the value of these payments to exceed the project costs incurred by the companies (and consumers). However, we note that consumers are exposed to higher constraint costs, to which the companies are not exposed.[25]

3.29. We are seeking views on what approach we should take in regards to these payments. We could:

- Pass these payments directly (wholly or partly) through to consumers.
- Allow the companies to share in the additional payments through the total expenditure sharing mechanism.

3.30. Allowing the companies to share in the payments has two benefits.

- It provides stronger incentives for the companies to maximise the size of the payments. Under this option consumers may receive a greater total benefit despite receiving a smaller proportion of the damages.
- It encourages companies to obtain insurance or insurance-like provisions in the future.

3.31. However, we are conscious that consumers face the majority of the constraint costs caused by the delay while the companies do not. This provides an

[25] The exception to this is National Grid who may be partly exposed through its system operation incentive scheme.

argument for passing through all payments to consumers which do not offset the ‘project costs’ incurred.

3.32. We welcome stakeholders’ views on our approach and any alternatives.

Information requirements for late delivery

3.33. We expect NGET and SPT to explain the late delivery. We expect a comprehensive submission from NGET and SPT once the link is operational. This should outline:

- What date the Western HVDC was originally intended to be operational.
- When the delay occurred.
- What caused the delay.
- What actions were taken (or not taken) to manage the risk of the delay. This should include evidence of the efficiency of the decisions made (or not made) and actions taken (or not taken).
- What actions were taken to mitigate the impacts of the delay. This should evidence the efficiency of the decisions made (or not made) and actions taken (or not taken).
- What the impact of the delay was on consumers. This assessment should form two parts:

  a) The impacts on the delivery of the Western HVDC project itself (such as changes in cost).

  b) The impacts on the price, quality, safety, reliability and security of supply on the electricity system as a whole (eg increases in constraint costs).

- Whether NGET/SPT will receive any benefit from the delay. We expect this to include (but not be limited to) paying suppliers later, payments (or in-kind benefits) from suppliers for late delivery.
- Anything else considered relevant.

3.34. We expect this submission to be in a form that can be published on our website. If there are any confidential elements we would also expect a redacted version that we can publish on our website, along with an explanation of why those elements should be considered confidential.

3.35. In the future we expect that companies will provide this information as soon as possible after they are aware that they will likely deliver a project late. Where the information is not yet known we expect the companies to set out when they will know and when the information can be provided. Should licence conditions be contravened then we may also consider taking enforcement action, which could result in the imposition of financial penalties and/or redress payments, in line with our enforcement guidelines.[26]

London medium pressure

➔ **Question**: Do you agree that we should accept National Grid Gas Distribution's (NGGD) proposal to return £53.9 million? If not, please explain why and provide evidence.

3.36. National Grid Gas Distribution (NGGD) is funded to remove or abandon medium pressure iron mains in London. Removing these iron mains will make the gas network more safe and reliable.

3.37. NGGD now reports that the majority of work cannot go ahead due to a combination of engineering and stakeholder challenges. NGGD intends to undertake the remaining work in future price controls.

3.38. NGGD has offered to return £53.9 million in funding for the work that will no longer be undertaken in RIIO-GD1.

3.39. Our proposed approach is to accept NGGD's proposal. We consider that as NGGD will not deliver the specific safety and reliability outcomes in RIIO-GD1, the right response is to return the associated funding to consumers.

Background

3.40. The medium pressure iron mains in London are up to 150 years old. The joints in these old mains contribute to gas leakage.

3.41. In its business plans, NGGD provided evidence that it was beneficial for some of the medium pressure iron mains to be abandoned. This work is in addition to work mandated by the Health and Safety Executive to abandon smaller mains with diameters up to eight inches (Tier 1).

3.42. For RIIO-GD1 we provided NGGD with £93 million to reduce the risk related to 69 km of medium pressure iron mains in London.

3.43. Combined with the smaller Tier 1 mains we funded NGGD to abandon in total 3,039.7 km of iron mains and to lower an associated risk score.[27]

[26] See paragraph 3.16
[27] All GDNs use a common model to determine the risk associated with particular iron mains. Our Final Proposals set the amount of risk that each GDN had to remove during the GD1 period. The risk being the likelihood of an incident occurring.

3.44. Since final proposals were accepted, NGGD reviewed the engineering and strategic options and engaged with stakeholders, such as local and highway authorities, the mayor's office, local businesses and residents. As a result of this work, NGGD identified that it was not possible to complete all of the work funded during RIIO-GD1. NGGD considers that it is only efficient to abandon 29 km in RIIO-GD1. NGGD plans to complete the remaining work in future price controls.

3.45. NGGD has offered to return £53.9 million which is proportional to the amount of mains not being replaced and asked us to lower the target lengths by 40 km.

Our proposed approach

3.46. Our proposed approach is to accept NGGD's offer to refund £53.9 million to consumers and lower the combined lengths target by 40 km.

3.47. We do not propose to make a change to the risk score as it is not materially affected by the reduction in medium pressure iron mains that are abandoned. Tier 1 iron mains are the main driver of the risk captured by the risk score.

3.48. As NGGD will not be able to deliver the work funded, we think it is appropriate that the allowances are returned to consumers. This is to ensure that consumers do not fund NGGD twice for the same work.

3.49. Funding for iron mains replacement was provided to achieve specific safety and reliability outcomes, which NGGD will not be delivering.

3.50. We consider that the amount of £53.9 million is appropriate, as it is based on the same unit cost per kilometre (£m/km) that was used in our final proposals.

3.51. We also note that iron mains targets are unlike the preceding NGGT compressor and SPT voltage outputs as there is no ambiguity in what we expect to be delivered.

3.52. All gas network companies have committed to meeting their targets for lengths of iron mains abandoned and reducing their risk score. We note that all gas network companies are largely on track to meet these targets.

3.53. We have also considered an alternative option of not accepting NGGD's proposed refund. In this case we would also not provide any further funding for NGGD to complete the works in future price controls to ensure consumers do not double fund NGGD for the work.

3.54. We have decided against this option for two reasons.

- We consider it is better to act now and recover costs for consumers given that NGGD will not be undertaking the work provided. This also ensures that NGGD does not benefit from a timing gain where funding is provided well in advance of when the work will occur.

- We have not decided the methodology for setting allowances for future price controls. Accordingly, we cannot be certain that the method used to set allowances will not double fund NGGD.

Connections volume driver

➔ **Question**: Do you agree with our proposed approach not to amend SPT's connections volume driver? If not, please explain why and provide evidence.

3.55. We included uncertainty mechanisms in RIIO-T1 to adjust revenue allowances for unforeseen circumstances. One type of uncertainty mechanism is a volume driver: a provision that automatically adjusts allowed revenue as a volume measure varies (eg number of new connections).

3.56. SPT's price control includes a connections volume driver that funds connections based on the specific assets installed from a menu included in its licence.

3.57. SPT requested that we change the volume driver by adding new assets to its menu. This change will provide funding for the use of these new assets, which are currently unfunded. SPT considers that these new assets should be added because there are now more connections than anticipated and in different locations.

3.58. We do not think we should make the proposed changes as they are asymmetric to consumers. Making the change would provide additional funding where SPT overspends while leaving underspends elsewhere unchanged.

Background

3.59. SPT is required to offer to connect generators to its electricity transmission network.[28] The number and cost of these connections is difficult to forecast. A volume driver was introduced to manage this uncertainty.

3.60. The price control splits funding for generator connections based on how many generators are connected. There are separate mechanisms to connect one generator at a time (sole-use connections) and another to connect multiple generators (shared-use connections).

3.61. SPT has a £112 million allowance to connect up to 1073 MVA[29] of shared-use connections. Any shared use connections above this threshold are funded through a 'connections volume driver' that provides a set amount of funding based on the assets used to make a connection.

3.62. SPT forecasts to deliver 1073 MVA of shared use infrastructure over RIIO-T1. SPT now forecasts to deliver 4229 MVA of shared use infrastructure to connect new generation to the network. Much of this increase has been seen in concentrated

[28] Ofgem 2016, *Transmission Licence Standard Conditions*, Condition: D4A
[29] MVA (megavolt amperes) measure the total capacity of the connections.

areas. For example, in the Coalburn/Linmill area over 800 MW is contracted to connect compared to the expected 70MW originally forecast.

3.63. SPT reports that due to the change in location and quantity of connections, different types of assets will be required. For example, increasing the capacity of existing lines rather than building new ones. These assets are not included in the current connections volume driver. This means that SPT will receive no funding if these assets are installed. Any costs that are incurred will be considered as an overspend and shared with consumers through the total expenditure sharing mechanism.

3.64. SPT has requested that we add the new asset solutions to the connections volume driver mechanism. This will provide funding for deploying the assets which SPT suggests are the most efficient solution.

3.65. SPT forecasts that adding assets to the volume driver would increase its allowance for shared use connections by £81 million.[30]

3.66. Another proposal by SPT was to fund each new asset installed based on the unit costs for its closest equivalent asset already included in the volume driver menu.

Our proposed approach

3.67. Our proposed approach is to not accept SPT's proposal.

3.68. We recognise that SPT may be required to spend more than the funds the connections volume driver provides. However, this is no different to SPT being required to spend more than what a fixed allowance provides. We also see this risk as being similar to SPT needing to do additional work that was not foreseen or the scope of a project expanding resulting in an overspend. SPT bears this risk in the price control settlement.

3.69. We consider that we should treat overspends the same as we treat underspends. If we make no changes in areas where SPT expects to underspend we should also make no changes in areas SPT expects to overspend. To do otherwise would be asymmetric and unfair to consumers. It would leave the risk of higher costs solely on consumers while allowing SPT to benefit from lower costs where they arise.

3.70. For example SPT has a £112 million allowance to connect up to 1073 MVA of shared-use connections, they forecast spending £72 million to reach this. We do not intend on clawing back this £40 million underspend. Similarly, we do not intend to increase allowances for overspends.

3.71. We also note that SPT could seek to build assets currently included in the connections volume driver mechanism rather than more efficient options, as these assets will receive funding. We expect SPT will install the most efficient assets and

[30] £81 million is SPT's forecast of the increase in the allowance if there is a licence change

focus on delivering long-term value for money for consumers as required by its licence.[31] If however, this is not the case we will consider conducting an ex-post review and may remove any inefficient expenditure.[32]

3.72. The alternative option is to add the new asset solutions to the volume driver as SPT requests. The advantage of this option is that it removes perverse incentives. However, this option could result in consumers potentially providing as much as £81 million additional funding. This transfers the risk of higher costs from SPT to consumers (while allowing SPT to retain the benefits from underspends). We do not think that adding new asset solutions to the licence would be in consumers' interests.

3.73. Lastly we do not think that SPT's alternative proposal to provide funding for the nearest asset options would be in consumers' interests. We consider that this has the same issues, in terms of transferring the risk of overspends to consumers while allowing SPT to retain the benefits from underspends, as adding new asset solutions to the volume driver. Further, it is not clear to us how the approach could work and could result in SPT recovering above efficient costs. We do not think this could be done without changing the current licence condition.

NTS exit capacity incentive

➔ **Question:** Do you agree that we should not make changes to the NTS exit capacity incentive? If not, please explain why and provide evidence.

3.74. The NTS exit capacity incentive scheme is a mechanism included in the RIIO-GD1 price control to encourage Gas Distribution Network companies (GDNs) to efficiently book exit capacity from the National Transmission System (NTS).

3.75. The scheme rewards GDNs for reducing capacity bookings. Reducing capacity at the points with the highest forecast exit charges provides the greatest financial rewards.

3.76. British Gas responded to our November 2015 MPR consultation raising a number of concerns about the scheme.[33] It said that the scheme is flawed as it encourages perverse behaviour that could increase costs for consumers.

3.77. Overall we think the incentive scheme is encouraging the desired behaviour and will lead to lower costs for consumers in the long term.

3.78. We acknowledge that the scheme has weaknesses. However, we think the risks from making changes to the scheme now outweigh any benefits. Making changes now could damage regulatory confidence and increase costs to consumers in the longer term. Therefore, we do not propose to make any changes to the scheme at this stage.

[31] Ofgem 2016, *Transmission Licence Standard Conditions,* Condition: B7
[32] Ofgem 2010, *Handbook for implementing the RIIO model*, p.88
[33] The consultation document and all non-confidential responses are available here.

Background

3.79. GDNs book capacity at NTS exit points to meet demand from end users on their network. Each exit point has a capacity charge associated with it, determined by National Grid Gas Transmission (NGGT) in accordance with its charging methodology.

3.80. Exit capacity costs incurred by GDNs are passed through to shippers as part of GDNs' own transportation charges. This means that GDNs are not exposed to higher or lower costs and do not gain financially from managing these costs efficiently.

3.81. The NTS exit capacity incentive was introduced to encourage GDNs to efficiently book capacity. The scheme rewards GDNs for using less capacity at an exit point relative to a baseline. The reward is based on the forecast charge at that exit point published three years ahead by NGGT. The higher the forecast price at a point, the greater the reward. For each GDN, the total reward each year is determined by aggregating rewards or penalties across all the exit points connecting to their network.

3.82. Collectively, GDNs earned rewards of £50 million under the scheme in the first three years of GD1. A full breakdown of these amounts by GDN and year is in Appendix 1.

3.83. British Gas responded to our November 2015 MPR consultation raising a number of concerns about the scheme. In particular, it said that:

- The scheme gives "incentives to book capacity at more expensive offtake points", because forecast prices may not be aligned with actual prices.
- GDNs are "benefitting through the incentive" by switching from flat capacity (which is covered by the incentive) to flexibility capacity (which is outside the scope of the incentive).[34]
- The incentive rates are too high because NGGT's forecast prices have been higher than out-turn prices. This means that incentive rewards have been higher than the cost savings achieved by the GDNs through lower capacity bookings in the short term.
- Baseline capacity targets used to calculate incentive rewards were too lenient, ie too high.

Our proposed approach

3.84. We think the incentive scheme has led to the right behaviour so far, in that it encourages GDNs to reduce exit capacity bookings at the most expensive exit points.

[34] Flexibility capacity is not guaranteed to be available when it is needed.

3.85. GDNs have generally responded to the incentive as intended. Aggregate exit capacity use (across all GDNs) has reduced from 4,454 GWh/d in 2013-14 to 4,242 GWh/d in 2015-16.

3.86. We have considered British Gas' concerns and acknowledge that the scheme could be improved.

3.87. Below we address each of the concerns raised by British Gas. We then outline the risks to maintaining and adjusting the scheme.

Alignment of forecast and actual prices

3.88. The differences between forecast and actual prices have not had a material impact on the operation of the incentive. There is broad alignment between the ranking of exit points based on forecast prices and those based on actual prices in the first three years of GD1 (see tables in Appendix 1).

3.89. The highest rewards under the scheme have been available at the most expensive exit points, whether measured by forecast or by actual prices. This means that the incentive has not been materially distorted by using forecast rather than actual prices.

Switching from "flat" to "flexibility" capacity

3.90. We have not been able to substantiate the view that GDNs have reduced their flat capacity bookings by unduly relying on flexibility capacity.

3.91. GDNs use flexibility and flat capacity as part of their normal operations. While flexibility capacity is not guaranteed to be available, GDNs have to book sufficient capacity to meet their 1-in-20 supply obligations. We have no reason to believe that GDNs are putting their compliance with these obligations at risk as a result of using flexibility capacity.

Incentive rewards are higher than the cost savings

3.92. We acknowledge that rewards earned under the scheme appear to be high relative to cost savings achieved.

3.93. In the first three years of GD1, we estimate that the incentive scheme has cost consumers approximately £15 million more in the short term than it might have in the absence of the scheme, assuming GDNs would have booked capacity in line with the baseline targets in their licences.

3.94. However, in the absence of an incentive scheme that rewards reductions, actual booked capacity may have exceeded baseline targets. This would in turn have cost consumers more in the short term through higher exit capacity charges and in the long term through increased investment in the NTS, which is also ultimately funded by consumers.

Capacity targets are too lenient

3.95. Baseline capacity targets were based on forecasts provided by GDNs at the time of setting RIIO-GD1. Actual demand growth has been lower than forecast in most areas, making some baseline capacities look high in hindsight.

3.96. We note that the risk to GDNs under the scheme is symmetrical, and GDNs are penalised if the actual capacity booking at an exit point is higher than the baseline.

The scheme going forward

3.97. While the incentive scheme has worked as intended so far, we acknowledge that there are risks going forward.

- Forecast prices and actual prices could become less aligned in the future. If that happens, the scheme might encourage GDNs to target their reductions at the wrong exit points – potentially reducing system efficiency and increasing overall costs to consumers.

- Forecast prices may be significantly higher than actual prices in future years, as they were in 2015-16. If that happens, rewards under the scheme would be high relative to cost savings from using lower capacity.

3.98. We have considered whether these risks and weaknesses can be addressed by changing the current scheme before the end of RIIO-GD1 or suspending the scheme for the rest of RIIO-GD1. However, there are a number of risks from changing or stopping the scheme mid-period:

- Any change that leads to lower or no rewards could weaken the incentive for capacity reductions. GDNs may then take a risk-averse approach to meeting their 1-in-20 supply obligations by increasing their exit capacity bookings. This could increase costs to consumers in the short term through higher exit capacity charges and in the longer term through additional investment triggered on the NTS.

- Changing an incentive scheme mid-period could lead to uncertainty about other schemes (across all RIIO sectors), and may have an impact on financing costs. This could adversely affect consumers.

3.99. On balance, we think that the risks from changing or stopping the scheme before the end of the current price control period outweigh any potential benefits. Therefore, we do not propose to make any changes at this stage.

3.100. We will review the exit capacity incentive arrangements as part of the overall package of incentives that would apply in the next gas distribution price control period.

Gas distribution outputs

3.101. In our May decision document on the scope of the MPR, we said we would look at several gas distribution outputs. In particular, the:

- **Safety (repair risk) output,** which measures the risk of gas escapes that do not warrant emergency action.

- **Reliability (loss of supply) output**, which measures the number and duration of planned and unplanned interruptions.

- **Reliability (maintaining operational performance) output**, which is composed of several leading indicators of operational performance.

3.102. Aside from one part of the Reliability (maintaining operational performance) output, there are no directly linked allowances to remove in the case of non-delivery, no incentive schemes apply and these outputs were not specified in licences.

3.103. We are considering whether we need to take any action to improve the accountability or effectiveness of these outputs, such as including the outputs in the licence or changing targets.

3.104. Our initial view is that the current arrangements are working to achieve their policy objectives. While we have considered introducing licence conditions, at this stage we do not believe this would be necessary. We do, however, propose to amend the targets for the reliability loss of supply output.

3.105. As outlined below, we continue to expect companies to meet these outputs (as amended). Where this is not the case we will discuss performance with companies. We will expect them to take action to bring about improvements and where appropriate to make redress to consumers.

Safety repair risk

➔ **Question:** Do you agree with our proposed approach to continue to monitor this output for the remainder of RIIO-GD1 and require companies to justify where they fail to meet this output? If not, please explain why and provide evidence.

3.106. Repair risk measures the safety risk presented by gas escapes that are individually assessed as not warranting emergency action. The repair risk output requires GDNs to maintain, as a minimum, their 2012-13 repair risk score. The repair risk metric takes into account factors such as proximity to buildings and duration of the escape. The output was initially developed by National Grid as a management tool to prioritise which gas escapes needed further repair.

3.107. Three of National Grid's GDNs (London, North West, West Midlands) failed to meet this output in two consecutive years: 2013-14 and 2014-15. In March 2016

National Grid acknowledged that it did not meet the output and donated £3 million to National Energy Action to help it tackle fuel poverty.

3.108. In the MPR decision document we stated that we would consider whether we needed to make changes to this output in order for it to encourage the right behaviour from the companies.

3.109. We considered the option of attaching a licence condition to this output as an additional way of holding companies to account for failing to meet the target. However, having reviewed this output we believe that it is operating as intended.

3.110. With regard to the safety aspects of gas escapes, we note this is not intended to be dealt with by this output, but rather is subject to the Gas Safety (Management) Regulations 1996 enforced by the Health and Safety Executive.

3.111. The output is driving the companies to improve their effectiveness at dealing with gas escapes. To meet the target level of performance, companies must consider effective ways to deal with all gas escapes, not just those that present a high safety risk.

3.112. Further, when companies have not behaved in the right way, they have taken action to improve their performance and have made appropriate redress to consumers.

3.113. Taking the above in to consideration, we think that consumers' interests will be best protected by the status quo and no changes are necessary in relation to this output.

3.114. We continue to expect any GDNs that do not meet this output to provide evidence of why they haven't and to work promptly to bring about improvements. We will also continue to monitor this output and publish performance against this output in our annual report. Additionally, we expect companies to engage with consumers and us in developing this aspect of their business plans for the next price control. We will consider putting it into the licence then if we think it will deliver a better outcome for consumers.

Reliability loss of supply

➔ **Question:** Do you agree that we should change the targets for the loss of supply output for the remainder of RIIO-GD1, continue to monitor performance and require companies to justify where they fail to meet this output? If not, please explain why and provide evidence.

3.115. This output measures the number and duration of planned and unplanned interruptions on the gas distribution network, over the eight years of RIIO-GD1. The aim of this output is to drive gas distribution companies to reduce the impact of interruptions on consumers. They can do this by minimising the duration and, where possible, the number of planned and unplanned interruptions. They should also proactively engage with consumers to minimise the inconvenience caused by interruptions.

3.116. This output was first introduced in RIIO-GD1. Before then, it was monitored by the companies, but was not part of a price control.

3.117. Although we stated in final proposals that we would review the output at the end of RIIO-GD1, we are concerned that some of the current targets are failing to drive the behaviour required to meet the aim of the output. This is why we have reviewed the output as part of MPR parallel work.

3.118. Three out of four gas distribution companies (SGN, Northern Gas Networks & National Grid Gas Distribution) are forecasting to fail at least one of the areas, mainly unplanned interruptions.

3.119. The main reasons for the forecast failures are errors in the data that was used to set the targets and that some uncertainties were not taken into account when setting targets. An example is not accounting for the number of multiple occupancy buildings (e.g. apartment complexes) in a network. If these contain internal risers (pipes) they can be difficult to access and interruptions, especially unplanned, are likely to be longer than average for other types of buildings.

3.120. When deciding on our preferred approach, we considered the two main issues associated with the output: the effectiveness of targets and the options for holding the gas distribution companies to account if they fail to meet them.

3.121. We recognise that at the time of setting the price control, neither Ofgem nor the companies had a deep understanding of appropriate targets in these areas. Following several years of reporting interruptions, the understanding has improved and errors that were included in targets have been identified.

3.122. We propose to amend the current targets so that they take into account factors not included in the targets set at the start of RIIO-GD1. This will make them more effective at driving the right behaviour.

3.123. We have asked the companies to produce targets that they are committed to delivering, which we will review following the outcome of this consultation. We will work closely with the companies to ensure targets are effective in driving the right behaviour. We have already had discussions with them on how this output could be developed in future and expect the companies to continue engaging with both us and consumers on this output.

3.124. We considered the option of attaching a licence condition to this output as an additional way to hold companies to account for failing to meet the new targets. However, we think we would benefit from continuing to monitor and evolve our understanding of this output before considering attaching a licence condition.

3.125. Therefore, our preferred way forward is to create more effective targets for the remainder of RIIO-GD1 that drive the right company behaviour. We will monitor performance against these new targets and report on it annually. We will take this performance into consideration for the next price control period and will consider putting it into the licence if we think it will deliver a better outcome for consumers.

Maintaining operational performance

➔ **Question:** Do you agree with our proposed approach to make no changes to this output for the remainder of RIIO-GD1, to continue monitoring this output and to require companies to justify where they fail to meet this output? If not, please explain why and provide evidence.

3.126. This eight-year output is a measure of network reliability. We set a number of secondary deliverables to act as leading indicators of performance. These give us a sense of how each company is performing and we can investigate further if required.

3.127. These deliverables are a combination of annual and eight-year targets. Every year, we monitor performance of each GDN against the deliverables and include this performance in our annual reports. Some of these deliverables are being reported on for the first time in RIIO-GD1.

3.128. We said we would assess performance against this output as part of an end of period review, as with a number of other outputs. However, given the similarities with the two issues described above we decided to review this output as well, as part of the MPR parallel work.

3.129. We have considered attaching a licence condition to this output as an additional way of holding the companies to account. However, we believe the output is operating as intended and do not propose to introduce a new licence condition.

3.130. Companies are forecasting to meet this output and are performing well. Any concerns with performance have been picked up by us during our annual reporting process and addressed by companies. For instance, SGN's Southern Network failed to meet the target for number/duration of telemetered faults[35] in the first two years. SGN has taken action to improve performance in this area, meeting the target in 2015-16. This output was intended to have an associated reputational incentive, through the publication of performance, and this is currently proving effective.

3.131. As such, we consider that consumers' interests are best protected by maintaining the current arrangements and that introducing the output into the licence would be a disproportionate level of change that is unnecessary.

3.132. We intend to continue to publish GDNs' performance against the deliverables on an annual basis in our annual report. We will determine whether the output has been met at the end of RIIO-GD1, based on performance against these deliverables and would expect each one to be met to achieve the overall output.

3.133. We will take this performance into account in our considerations for this output for the next price control and will consider putting it into the licence if we

[35] Telemetry provides the companies with continuous data on the operational state of the remote, unmanned outstations and report faults to the distribution control stations.

think it will deliver a better outcome for consumers. We also expect GDNs to engage with consumers and us on how this output can be developed for the future.

3.134. One of the deliverables was the demolition of gas holders, for which an allowance was given to the GDNs. Performance against this deliverable will be taken into account when determining the allowance given for this activity in the future. We will also consider removing allowances as part of this price control if delivery is under target.

SPT's Trigger mechanism

➔ **Question**: Do you agree with our proposed approach to this trigger mechanism? If not, please explain why and provide evidence.

3.135. At RIIO-T1 in its business plan, SPT proposed that it was more efficient to refurbish specific overhead lines at the same time as building the East Coast 400kv upgrade.

3.136. As it was uncertain when the East Coast 400kv upgrade would occur, we included a trigger mechanism to unlock funding for the overhead line refurbishment when the upgrade commenced.

3.137. The upgrade has now been delayed until the next price control. SPT reports that the overhead line refurbishments are still required in RIIO-T1. SPT is concerned these refurbishments will go unfunded as the East Coast 400kv upgrade will not occur.

3.138. We do not consider that any adjustment to the price control is required. Our Network Outputs Measures (NOMs) methodology will fund these refurbishments if they are justified.

Background

3.139. The RIIO-T1 price control for SPT included a number of uncertainty mechanisms.

3.140. One of these is a provision allowing revenue to increase/decrease by a specified amount if and when certain "trigger" events occur during the price control period.[36] The goal of the mechanism is to align funding with the investment needs of the network that change if a specific event occurs.

3.141. SPT's business plan identified that it would be efficient to conduct specific overhead line refurbishment projects alongside the East Coast 400kv upgrade. However, at the time it was uncertain when the upgrade would occur.[37]

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[36] Ofgem 2010, *Handbook for implementing the RIIO model,* pg.92
[37] SP Transmission, *RIIO T1 Business Plan Update Risk Management and Uncertainty Mechanisms*, pg. 10

3.142. To account for this uncertainty, we included a trigger mechanism that would award additional allowances, if the upgrade went ahead, to fund these overhead line refurbishments.[38] This is implemented through a licence condition (special condition 6H) in SPT's licence.

3.143. If the upgrade went ahead the overhead line refurbishments would have been subject to a within period assessment by us. If we considered that it was appropriate the refurbishments would be funded through a revenue adjustment during the price control.

3.144. The East Coast 400kv upgrade is now forecast to be delivered in the next price control. Despite this SPT considers that the overhead line refurbishment is required in RIIO-T1 because they are in poor condition.

3.145. SPT raised a concern that failure to trigger additional allowances would result in it incurring approximately £60 million expenditure on refurbishing the overhead line without receiving an allowance.

3.146. This type of work is usually funded through the NOMs incentive mechanism.

3.147. NOMs are designed to establish if the Transmission Owners are targeting investment in the right areas to manage network risk effectively. The NOMs incentive mechanism funds licensees that appropriately manage teir network assets.

3.148. The NOMs methodology excludes projects that have received funding elsewhere in the price control to ensure that projects are not double funded. SPT was concerned that these specific overhead line refurbishment projects were excluded from the NOMs incentive mechanism.

Our proposed approach

3.149. We consider that the NOMs methodology will apply to projects where the trigger event (such as the East Coast 400kv upgrade) has not occurred. This is in line with other asset replacement or refurbishment works that are not funded elsewhere. This means that the refurbishment projects will not be excluded from the NOMs incentive mechanism and will be funded if justified. Accordingly, we think that no further action is required.

[38] Ofgem 2012, *RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd,* p.48

Electricity transmission other outputs

➔ **Question:** Do you agree with our approach to these outputs?

3.150. In table 2 of our May MPR decision document[39] we said we would clarify what actions we would take for late or non-delivery of specific electricity transmission outputs.

3.151. We have reviewed each of the outputs and now consider that no further clarification is required. This is because each of the outputs has either been delivered, is being delivered or has a mechanism already in place.

Background

3.152. During our MPR scoping consultation, we identified some outputs where it was unclear how we would treat non-delivery. These are:

- The construction of a tunnel in Islington (categorised as 'Local enabling exit shared use').
- 4 Switch Mesh GIS Substation.
- Local enabling (exit sole-use), which is made up of:
  - a 275kv circuit breaker;
  - two super grid transformers; and
  - a grid supply point.[40]

Our proposed approach

3.153. The Islington Tunnel has been commissioned and the GIS substation is under construction and expected to be confirmed as delivered in 2016/17. This means there is no need for further action to deal with non-delivery.

3.154. Since May we have discussed the local enabling (exit sole-use) output with NGET. NGET highlighted that in final proposals this was part of 'excluded services.'[41] The RIIO-T1 close out will remove allowances for any undelivered excluded services'. No further action is needed now as we will consider these outputs at the end of RIIO T1.

[39] Ofgem 2016, *Decision on a mid-period review for RIIO-T1 and GD1*, Table 2, pg.29
[40] Ofgem 2012, *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Cost assessment and uncertainty Supporting Document,* Table 4.2 p. 27
[41] Ofgem 2012, *RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, Finance Supporting document*, pg.10

Appendices

Index

Appendix 1 – NTS exit capacity

1.1. The amounts earned by GDNs under the incentive scheme are set out in the table below.

All figures are in £m (nominal)	2013/14	2014/15	2015/16
NGGD - EoE	1.8	5.6	11.7
NGGD - Lon	1.3	1.5	5.3
NGGD - NW	0.9	1.5	5.1
NGGD - WM	0.4	1.6	2.5
NGN	0.0	0.6	3.0
SGN - Sc	0.1	0.0	0.0
SGN - So	2.5	1.2	2.0
WWU	0.4	0.4	0.5
Total	**7.4**	**12.3**	**30.0**
Total GDN expenditure on NTS exit charges	180.0	191.3	186.5

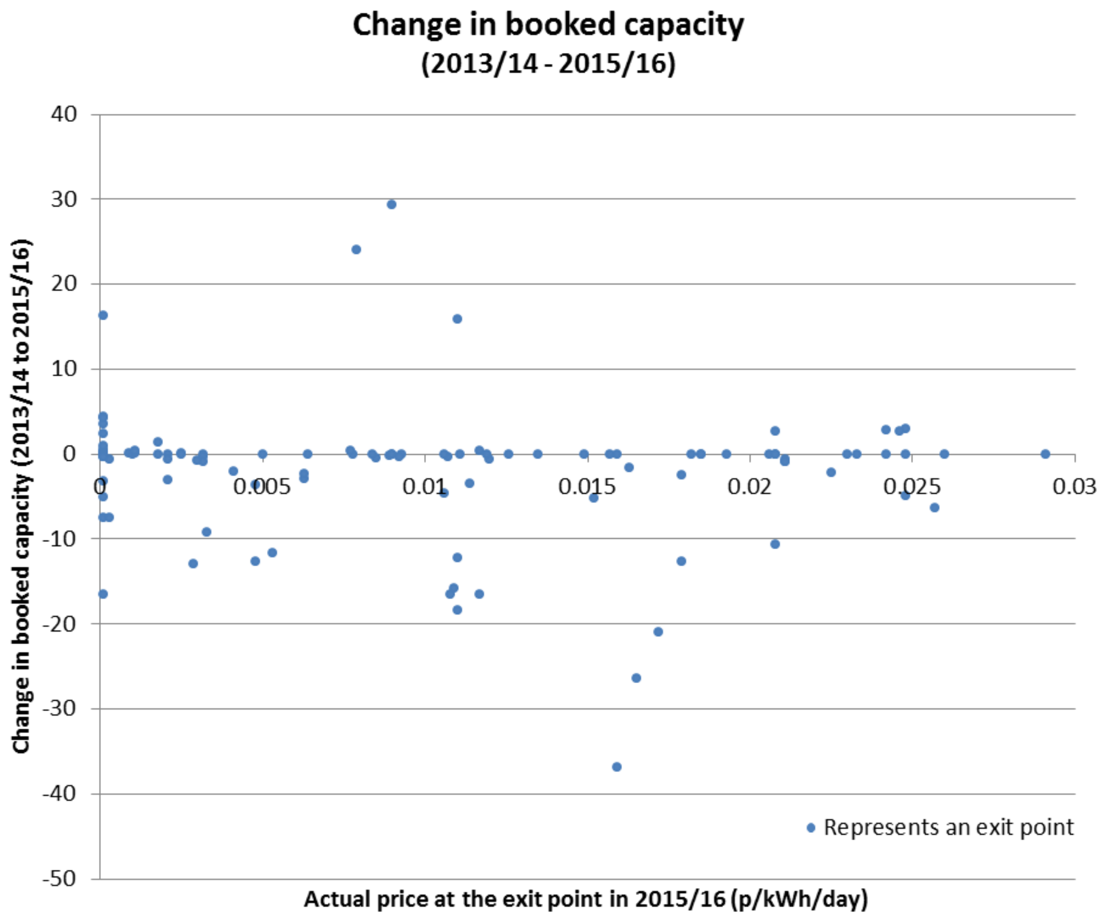
1.2. As part of our analysis, we ranked each NTS exit point by actual and forecast prices, both within each GDN area and also within each exit zone (each GDN area comprises several exit zones). The two tables below show the distribution of exit points based on the difference in their ranks (actual price vs forecast price). The vast majority of exit points show little or no change in ranks.

Difference in rank (within GDN)	2013/14	2014/15	2015/16	2016/17
No change	59	58	83	63
1-2	28	30	17	35
3-4	10	10	6	19
5-6	7	11	3	4

7-8	8	3	4	0
9 and above	9	9	8	0

Difference in rank (within exit zone)	**2013/14**	**2014/15**	**2015/16**	**2016/17**
No change	84	78	100	87
1	11	17	10	20
2	13	14	3	3
3	9	9	3	10
4	2	0	3	1
5 and above	2	3	2	0

1.3. The chart overleaf plots exit capacity booking changes since the start of RIIO-GD1 at every exit point against the actual price at that exit point in 2015-16. There is little evidence to support the view that GDNs have increased their bookings at more expensive exit points – indeed the chart shows reductions across the board, with very little increase at the more expensive exit points.


Change in booked capacity
(2013/14 - 2015/16)
Change in booked capacity (2013/14 to 2015/16)
40
30
20
10
0
-10
-20
-30
-40
-50
0
0.005
0.01
0.015
0.02
0.025
0.03
Represents an exit point
Actual price at the exit point in 2015/16 (p/kWh/day)

Appendix 2 - Feedback on this consultation

We want to hear from anyone interested in this document. Send your response to the person or team named at the top of the front page.

We've asked for your feedback in each of the questions throughout it. Please respond to each one as fully as you can.

You can ask us to keep your response confidential, by clearly marking it confidential and providing reasons, and we'll respect this, subject to obligations to disclose information such as the Freedom of Information Act 2000 or the Environmental Information Regulations 2004. However, we would like to publish as much of your response as we can. To help us achieve this goal we would appreciate it if confidential material could be provided in a separate appendix to your main response. This should also be clearly marked as confidential with reasons provided. Unless you mark your response confidential we'll publish it on our website, www.ofgem.gov.uk, and put it in our library.

If the information you give in your response contains personal data under the Data Protection Act 1998, the Gas and Electricity Markets Authority will be the data controller. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000.

General feedback

We believe that consultation is at the heart of good policy development. We are keen to hear your comments about how we've conducted this consultation. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send your comments to stakeholders@ofgem.gov.uk