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

Final decision

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Overview:

The RIIO-T1 and GD1 price controls have provisions for a mid-period review (MPR) of output requirements halfway through the price controls.

We have decided to launch an MPR for the RIIO-T1 price control looking at some specific issues in Electricity Transmission for National Grid Electricity Transmission and in Gas Transmission for National Grid Gas Transmission. We have not identified any issues within scope of an MPR in RIIO-T1 for either of the Scottish Transmission Owners. We have decided not to launch an MPR for the RIIO-GD1 price control.

However, for both RIIO-T1 and GD1 there are a number of important issues identified by us and stakeholders that we will be addressing through processes separate to the MPR. The separate work seeks to ensure effective output accountability by the licensees, fill in some gaps in the framework, and improve the operation of some of the mechanisms.

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. We consulted on the need for an MPR in November 2015.

Associated documents

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

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

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Executive Summary

Under the RIIO price control settlement, companies are required to deliver agreed outputs for consumers and are funded to cover the costs of delivering these. The eight-year price control settlement includes a number of uncertainty mechanisms to take account of the fact that some outputs and funding cannot be set with certainty at the start of the period. One of these uncertainty mechanisms is the mid-period review (MPR) of outputs. This mechanism was put in place to allow for material changes to outputs where there have been clear changes in government policy or consumers' and network users' needs. It enables the introduction of new outputs required to meet the needs of consumers and other network users and also for the removal of outputs no longer required.

Having considered responses to our November consultation, we have decided to launch an MPR for the RIIO-T1 price control focusing on three specific areas, all of which relate to National Grid's transmission outputs (both gas and electricity). The MPR decision at this stage sets out which outputs we will review. We will consult on proposals for any changes to outputs and associated revenues in the summer. We have decided not to launch an MPR for the RIIO-GD1 price control.

Importantly, alongside the decision on the issues we are reviewing as part of the MPR, we will be taking forward work in a number of related areas. In particular, we will review how we hold the companies to account for outputs; fill any gaps in the RIIO framework (relating particularly to Network Output measures (NOMs)); and improve the operation of some of the incentives (eg the focus of some of the discretionary awards). This work covers the transmission and the gas distribution price controls. Some of this work is already in train, and other parts cover issues which came to light as part of the MPR consultation process and annual performance monitoring.

Some stakeholders said we should widen the scope of the MPR and review RIIO outputs and revenues more fundamentally in light of network company financial performance. We do not think it is appropriate to change the scope of the MPR in this way. The RIIO framework lengthened the price control specifically with the intention to allow the companies to make longer term plans and react more effectively to incentives. Changing the framework by changing the scope of the MPR would damage confidence in the regulatory regime. Increasing regulatory risk in this way would lead to higher financing costs and costs to consumers. Given the significant sums invested in our energy networks, a small increase in the cost of capital would have a significant impact on consumers. We think this impact would outweigh any short-term gains to consumers by clawing back money from areas beyond our proposed scope.

We will be inviting views on how the RIIO price control framework is working when we consult on specific MPR proposals in the summer - in order to make sure it delivers for consumers in the current controls and make sure we learn any lessons for the next round of price controls. We will continue to monitor the performance of the regulated network companies and the drivers of this as part of the annual reporting process to satisfy ourselves that the RIIO framework is working as well as possible.

A Mid-Period Review for RIIO-T1

The three specific areas we will review through the MPR for RIIO-T1 are:

- **National Grid Gas Transmission's (NGGT) Avonmouth pipeline outputs**: these outputs were included in RIIO-T1 to help deliver security of supply. We now understand that these outputs (worth around £165m) may no longer be required so we will review them to assess whether any action is required.

- **Non-variant allowance outputs for National Grid Electricity Transmission (NGET)**: we will investigate changes to the output requirements relating to the Wider Works (General) category of load related expenditure. NGET has indicated changes to these output requirements, for example due to fewer generation connections than expected. The total value of these outputs is around £90m.

- **New enhanced system operator (SO) outputs for NGET**: as part of the Integrated Transmission Planning and Regulation (ITPR) project we introduced new obligations for NGET in its licence that it says will cost around £20-30m to deliver in RIIO-T1.

If we decide that outputs are no longer required then we may decide to remove the output requirements and the associated funding from the companies. As part of this we will consider whether the companies have delivered alternative/additional projects instead.

We have not identified any changes in output requirements for the gas distribution companies or the Scottish electricity transmission owners so are not proceeding with an MPR in these areas.

Work on other issues

While we are not re-opening the price controls, we believe it is important to ensure that all the elements of the regulatory settlement defined by the price controls are delivered and operated in a transparent and accountable manner by the companies. To that end, we are proposing to take forward additional work in three categories as set out below. This parallel work is not part of the MPR, but will be progressed in a similar timeline.

- **Ensuring output accountability**: we will review how we hold the companies to account for the outputs we have set them and for us to be clear about how/when we will do this. Providing clarity in this area is important to the successful functioning of RIIO. We think it is good practice to address this issue before the next price controls (as non-delivery of outputs could affect revenues) and also to influence the behaviour of the companies over the remainder of the price controls.

- **Filling gaps in the RIIO framework**: this category includes completing ongoing work important to the framework and also work to address circumstances that were not envisaged. The main area of focus in this category is Network Output Measures (NOMs). NOMs relate to asset replacement and refurbishment works (£15bn expenditure area across transmission and gas distribution) and are intended to give us assurance that the networks are being maintained to the required standard. In particular, there is work outstanding to develop the NOMs methodology.

- **Improving RIIO operation:** we will work to improve the operation of some of the RIIO mechanisms. This will consider improving the focus of some discretionary rewards and updating the guidance for some mechanisms.

Next steps

We will examine the MPR issues in more detail. Any policy proposals resulting from the MPR would be consulted on during summer 2016 for a decision in late autumn 2016. We would aim to make any associated licence changes to be effective from 1 April 2017.

We expect to consult on our proposals for ensuring output accountability in autumn 2016 and make a decision in early 2017. The timetables for the other items of work vary (some of this work is already ongoing) and we have provided further detail on how we will take these forward later in this document.

1. Introduction

Background

1.1. The RIIO-T1 and GD1 price controls were the first to implement our new RIIO approach. One of the key developments in the RIIO methodology is the lengthening of the price control period. Historically, price controls had been set for five-year periods but under RIIO we have moved to eight-year periods. The key aim behind lengthening the period was to encourage the companies to make longer term plans that would allow greater innovation and efficiency savings to be made that would ultimately benefit consumers. Another key part of the RIIO approach is the focus on "outputs" which are intended to capture the things valued and needed by consumers. In setting these outputs we hold the companies to account for their delivery and take action in cases where they are not delivered.

1.2. Within the RIIO-T1 and GD1 price controls we have a number of uncertainty mechanisms that adjust the revenues of the companies in response to changing circumstances. One of these uncertainty mechanisms was the introduction of a Mid-Period Review of output requirements. It was acknowledged in setting an eight-year price control that government legislation or consumers' needs could change, meaning that the companies could need to deliver different outputs. The MPR was therefore included to allow a focused review of these changes in output requirements and the associated funding needed to deliver any revised outputs.

1.3. When including the provision for an MPR we were very clear that it would not consider issues more broadly in a way that would undermine the aims of moving to an eight-year price control and the benefits that come from that. Instead we set out a clear intention that it would be narrowly focused on changes to output requirements and would not be used as an opportunity to claw back any outperformance or change any of the key financial parameters (such as the cost of capital). Similarly it would not be used as an opportunity to provide additional funding for areas where the companies were under-performing.

1.4. We consulted back in November 2015 on the need for a MPR and this document sets our decision to launch an MPR for RIIO-T1 only (ie not for GD1), focused on areas where we consider output requirements may have changed.

Structure of this document

1.5. The remainder of this document is structured as follows:

- Chapter 2 outlines areas we have decided to review through the MPR.
- Chapter 3 sets out the parallel work we propose to take forward. This work doesn't meet the scope of the MPR but we think it is important to take it

forward at this time. It focuses on ensuring output accountability, filling gaps in the RIIO framework, and improving RIIO operation.

- Chapter 4 outlines the areas that we do not propose to take forward at this time – either as part of the MPR or separately. These are either issues discussed in our November consultation or items raised in consultation responses.

1.6. There are also several appendices to the document providing further detail:

- Appendices 1-3 set out the parallel work we intend to undertake in Electricity Transmission, Gas Transmission, and Gas Distribution respectively.

- Appendix 4 gives a summary of responses to our November 2015 consultation

- Appendix 5 provides a high level impact assessment on why we don’t think it is appropriate to widen the MPR scope beyond an assessment of changes in outputs required.

2. MPR for RIIO-T1

Chapter Summary

The scope of the MPR is the same as we set out in our November 2015 consultation. We are planning to launch an MPR on three specific issues in the RIIO-T1 price control which we consider to be in scope. These areas are the non-variant allowance outputs for NGET, new outputs for NGET for the enhanced System Operator (SO) role, and the Avonmouth pipeline outputs for NGGT.

MPR scope and process

2.1. We confirm that the scope and approach of the MPR is as outlined in our November 2015 consultation.

2.2. We set out our view that it should seek to address the following types of changes if they are found to be needed:

- Changes to outputs driven by changes in government policy
- Introduction of new outputs driven by the needs of consumers or network users

2.3. We also made it clear the MPR for RIIO-T1 and GD1 would be symmetric, as per the intention of the MPR in the RIIO Handbook.[1]

2.4. For RIIO-T1 and GD1, we set out our position that we don't think there is a meaningful distinction between the introduction of new outputs and changes to existing outputs. One respondent disagreed with this aspect of our clarification on the scope. This respondent stated that removing the distinction between introducing new outputs and changing existing outputs widened the scope of MPR. This respondent did not elaborate on why it took this view. We still believe there is no meaningful distinction to make on this issue. In any event, we do not think any possible distinction that could be made would affect the issues that we have decided to explore further under the MPR.

2.5. Some respondents were in favour of a wider MPR that would go beyond a narrow assessment of changes in output requirements. They suggested that the MPR should look at value for money for customers and potentially make adjustments to company outputs and revenues on this basis.

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

2.6. We believe that widening the scope of the MPR in this way would have detrimental effects on consumers. The move to an eight-year price control under RIIO is driven by a desire to encourage the companies to adopt longer term strategies and innovate in order to deliver long term savings to consumers. It would be inconsistent to reopen the price control more widely as it would undermine the benefits of the eight-year price control and also damage regulatory confidence. Any damage to regulatory confidence would increase the cost of finance, which would increase consumers' bills in the future. For example, a 10 to 50 basis point increase in the cost of capital across the three RIIO sectors for an eight-year regulatory period could increase costs to consumers by £390m to £1.9bn. We think this impact would outweigh any short-term gains to consumers by clawing back money from areas beyond our proposed scope.

2.7. We have set out a high-level Impact Assessment (IA) on widening the scope, which explains our reasoning in more detail (see Annex 5).[2] We have, however, identified other areas of work that we propose to take forward separately from the MPR – we think they will deliver benefits for consumers by ensuring that we can hold the companies accountable for the outputs they have been set and improving the operation of RIIO. In addition, in our summer 2016 consultation on MPR proposals we will be asking for respondents' views on what aspects of RIIO could be improved for the next price controls – we think this is the most appropriate route to deliver the best value for consumers and take on board our learnings from RIIO-T1 and GD1.

2.8. Some respondents also voiced reservations about the approach and process taken to consulting on launching an MPR and suggested an alternative process. They suggested a presentation of company performance, identification of the drivers of performance against outputs and an assessment of these drivers against the scope of the MPR and the extent to which they deliver value for money to consumers.

2.9. We believe our process to date has been appropriate and provided stakeholders with opportunities to engage effectively. We began with an internal review of the RIIO outputs to identify changes in output requirements. The review also covered areas identified through our monitoring of company reporting and areas we stated would be considered by the MPR in Final Proposals (FP). We included these in our consultation on the MPR where appropriate. We also held a stakeholder forum during the consultation period to explain the process we had followed. At this forum we presented the areas that could be in scope and which we would consult on.

2.10. An important aspect of the RIIO framework is transparency and the companies now publish more information on their performance than under the previous regulatory regime. Stakeholders can use this information to develop their own views on company performance, eg by assessing company expenditure and output delivery forecasts. We also present company performance in our annual reports, which rely on the same information already made available by the

[2] We will publish a further IA alongside our consultation on our proposals for the MPR later this year. This will consider the impact of any options and proposals we present.

companies.[3] Given that reporting made available to date only covers the first 2 years of the price controls we don't think this should be used as the main tool to identify changes in output requirements for the eight-year period, which is the focus of the MPR.

An MPR for RIIO-T1 and parallel work on other issues

2.11. We have decided to launch an MPR for the RIIO-T1 price control focused on three specific areas for NGGT and NGET that fall into scope. We believe these issues are within the scope of the MPR and we provide further details on these below.

2.12. We have decided not to launch an MPR for RIIO-GD1 as we have not identified any relevant change in output requirements affecting the GDNs at this time. If there are outputs for the GDNs that we subsequently discover are no longer required (eg as circumstances change or new information becomes available) and are therefore not delivered then the treatment of these would be determined by our work on output accountability that we are taking forward separately from the MPR.

2.13. Our November 2015 consultation also sought stakeholder views on other issues that could be addressed or clarified that were outside the scope of the MPR. These included areas such as the provision of clarity for the treatment of late or non-delivery of RIIO outputs. In their responses, stakeholders were generally supportive of us taking action to address the issues identified or provide additional clarity. Respondents emphasised that these areas were best progressed using mechanisms other than the MPR.

2.14. We agree with stakeholders that these issues should be progressed separately from the MPR. While they do not fit the scope of the MPR we think it is important to resolve these now, in order for RIIO to work effectively for transmission and gas distribution. We are taking forward this parallel work in three workstreams: ensuring output accountability; filling gaps in the RIIO framework; and improving RIIO operation. This works covers Electricity Transmission, Gas Transmission and Gas Distribution. Chapter 3 and Appendices 1-3 describe these areas of work and what action we are taking (if any).

Electricity transmission MPR issues

2.15. We have identified two areas for Electricity Transmission that we will review through the MPR.

[3] RIIO Annual Reports: ET1 (link 1), GT1 (link 2) and GD1 (link 3).

Non-variant allowance outputs for NGET

2.16. NGET was awarded significant sums in non-variant allowances to cover certain load-related projects as part of the RIIO-T1 price control (in excess of £1.1bn). These works were identified as being needed to accommodate expected changes in generation and demand over the eight-years of the price control. These specific allowances fund projects that are not covered by any uncertainty mechanisms – ie the allowances do not adjust automatically depending on the volumes delivered. Some of the non-variant allowances relate to outputs that were specified in FP and we were clear at the time that NGET would be held accountable for their delivery.[4]

2.17. Because of lower than expected volumes of connections,[5] NGET's annual reporting information has indicated changes to the needs underpinning the outputs specified in the RIIO-T1 FP within the Wider Works (General) category of load related expenditure. For example, NGET had anticipated that the additional generation connecting to the system would see an increase of fault levels on circuit breakers. The FP for NGET specify the protection of nine sites against rising fault levels. NGET has since indicated in its annual report that the anticipated increase in generation has not transpired, which has resulted in lower than anticipated spend in this area. On the other hand, for shunt reactors, the FP for NGET specify the installation of 11 new reactors to the fleet connected to the transmission network. NGET has since indicated in its annual report that it currently plans to undertake additional investment to help manage the growing impact of embedded renewables on the operation of the network. We propose to investigate this output area as part of the MPR as we think the outputs are no longer required in the volume specified in the FP.

2.18. In the consultation we discussed this expenditure area as part of the section on "Outputs with baseline funding". We still think that clarification is required (see later in this document on output accountability) but also consider that some of the areas identified as outputs could meet the MPR criteria of being outputs no longer required and therefore warrant further investigation.

2.19. We are aware of views from NGET that these outputs should be viewed more widely rather than in isolation. As part of taking this work forward and our wider work on output accountability we will need to decide how to treat these taking into account all the relevant factors.

2.20. NGET also expressed views that it considered we should be focussing more on the outputs directly valued by consumers rather than "inputs", which some of these defined outputs relate to. We do not think this is a reason not to review the areas identified. We clearly specified them as outputs and said NGET would be accountable for their delivery. Part of the reason we included these items as outputs was that

[4] See paragraph 4.9 and table 4.2 of our FP Cost assessments and uncertainty for NGET https://www.ofgem.gov.uk/ofgem-publications/53601/3riiot1fpuncertaintydec12.pdf
[5] NGET currently anticipates around 23GW less generation will connect over RIIO-T1.

there was some uncertainty as to whether they would be needed. Therefore to protect consumers against the risk of them not being needed, we classified them as outputs. As they are outputs, we think they meet the criteria for the MPR and should be investigated further.

2.21. We may subsequently discover that the needs for other outputs associated with the non-variant allowances have changed as circumstances change and more information becomes available. These would be considered in our parallel workstream on output accountability. This work will set out our response to outputs not delivered (eg because they are no longer required) or with changing needs and we would expect this to be consistent with any action we would have taken under the MPR had the issue been identified earlier.

ITPR NGET enhanced SO role

2.22. In the Integrated Transmission Planning and Regulation (ITPR) project Final Conclusions,[6] we created new responsibilities for NGET as System Operator (SO). These new responsibilities primarily relate to system planning at the annual delivery of the Network Options Assessment report. This report will assess the need and timing of future reinforcements across GB and will also make assessment of cross border interconnector capacity requirements.

2.23. We recognised that there were likely to be incremental costs associated with delivering these duties that are not included in the revenue allowances for the current price control. We have already made the licence changes to require NGET to deliver these new obligations. NGET has suggested that the cost of delivering these new obligations in RIIO-T1 is around £20-30m.

2.24. We consider that the introduction of these changes has resulted in new outputs that are needed to meet the needs of consumers and network users. As such we think this issue is within scope of the MPR and should be investigated further as part of it. We note the points raised by stakeholders about the interactions between the enhanced SO role and onshore competition roles[7] and suggestions of delaying consideration of the enhanced SO role until there is further certainty on the costs involved as these are only starting to be incurred. We therefore need to consider the materiality of the costs involved and whether an adjustment to allowed revenues or the introduction of a focused reopener (to determine costs when there is more certainty) is appropriate to make as part of the MPR.

Gas transmission MPR issue

2.25. We have decided to proceed with reviewing how NGGT is meeting its output to

[6] https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-itpr-project-final-conclusions
[7] See Chapter 4 for further information on the onshore competition roles.

deliver a pipeline solution to ensure security of supply as part of the Avonmouth LNG storage facility's decommissioning through the MPR.

2.26. The pipeline output was set due to security of supply risks and we gave NGGT £165m to deliver this output as part of RIIO-T1. We had specified in FP that we would review progress at the MPR. We now understand from NGGT that this output is no longer required and that NGGT will manage the security of supply risks through other (much cheaper) means.

2.27. Some respondents to the consultation were supportive of reviewing the Avonmouth pipelines output through the MPR. In contrast, NGGT disagreed stating that the overarching safety and reliability outputs are still being met.

2.28. The output was set as the pipeline solution. Our understanding at the time based on the representations made to us by NGGT was that this was the only way to address the security of supply risks. It now appears that this specific output is no longer required and the justification for its need given at the time RIIO-T1 was set has also changed. For these reasons and the materiality of the issue, we have decided to investigate it further as part of the MPR to decide what action (if any) it is appropriate for us to take.

Next steps

2.29. We will examine the MPR issues in more detail, as part of the review process. Any policy proposals resulting from the MPR would be consulted on during summer 2016 for a decision in late autumn 2016. We would aim to make any associated licence changes to be effective from 1 April 2017.

3. Parallel work - overview and cross sector issues

Chapter Summary
We will be progressing a package of work in parallel with the MPR – it will cover both transmission and gas distribution. This work will ensure companies are fully accountable for their outputs, fill gaps in the RIIO framework and improve RIIO operation. This chapter provides an overview of this work and outlines the cross sector issues we will be looking at.

3.1. In addition to the issues being progressed through the MPR, we have identified additional work, which we think is important for us to take forward. These areas were identified through our November 2015 consultation and as part of our annual monitoring of the price controls. They apply to gas and electricity transmission and gas distribution. Many of the issues identified are already in progress. We do not think these areas fit the scope of the MPR but we think it is important to resolve any problems now in order for RIIO to work effectively. We will take these issues forward through separate processes and mechanisms. This parallel work falls into three categories:

- Ensuring output accountability,
- Filling gaps in the RIIO framework, and
- Improving RIIO operation.

3.2. This chapter sets out the issues we will progress in these areas that relate to all sectors (Electricity and Gas Transmission and Gas Distribution). Table 1 outlines the issues and sector specific issues are explained in Appendices 1-3.

Table 1: Summary of issues covered by our three workstreams

Issue	Description
Ensuring output accountability	
Clarifying how we hold the companies to account and how we will treat late/non-delivery of outputs (all sectors)	We want to clarify which outputs the companies will be accountable for; take any steps necessary to achieve this (eg include outputs from FP in the licence), and clarify how late/non-delivery and changing output needs will be treated to avoid storing up problems for RIIO-T2/GD2. Where we have already identified specific issues of this type, we have outlined these in the sector specific appendices (1-3).

Issue	Description
Filling gaps in the RIIO framework	
Network Output Measures (all sectors)	Network Output Measures are used to measure delivery of outputs relating to asset replacement and refurbishment expenditure. Currently the methodology used for measuring their delivery is at different stages of development across sectors. These need to be agreed and once they have been, we need to ensure that the incentive around them works as intended in FP. This is necessary to determine whether the companies are entitled to any reward/penalty for over/under-delivery and how we set funding in RIIO-T2/GD2.
Alignment of revenue drivers and solutions (electricity transmission)	Some companies are using solutions to connect new generation that are not covered by their revenue drivers. We need to determine how the revenue driver will treat these solutions that were not anticipated.
Change of projects with baseline funding (electricity transmission)	We have identified 2 further instances (both SPT) where unexpected circumstances have arisen and we need to decide how they will be treated. One is where SPT is proposing to substitute the delivery of one output for other works (Kilmarnock South project to be replaced by shunt reactor work). The other is to do with works that have funding triggered by certain circumstances arising – the works now need to go ahead for different reasons but the trigger condition has not been met.
Improving RIIO operation	
Environmental discretionary reward (electricity transmission)	We will look to remove overlaps with other incentives and target more on areas that are not business as usual.
Stakeholder engagement incentive (electricity transmission)	We will look to remove overlaps with other incentives and including more explicit consideration of how stakeholder engagement has influenced the companies' plans.
SWW submission quality (electricity transmission)	We will consider strengthening guidance on SWW submissions to ensure we get the most economic and efficient solutions proposed that can also best facilitate onshore competition.
SWW ongoing needs case monitoring (electricity transmission)	We will consider introducing reporting requirement on projects in development to ensure that impacts from changes in the generation background or in demand are considered.
500 hour utilisation compressor sites (gas transmission)	We will undertake work to inform any action we might take through the 2018 industrial emissions directive re-opener window.

3.3. Below we have set out some more detail on what each area will cover and the work on the key cross sector issues.

Ensuring output accountability

3.4. One of the key developments in the RIIO framework was the introduction of outputs, particularly the link between their delivery and the revenues that the companies are entitled to earn. We think there is a key piece of work to ensure that we can hold the companies to account for their outputs and for us to be clear about how/when we will do this. We think this is good practice to avoid storing up problems for RIIO-T2 and GD2 and also to influence the behaviour of the companies over the remainder of the price controls. This picks up from our discussion of the issue in our November 2015 consultation which respondents generally welcomed further clarity on.

3.5. In some areas, how we will hold companies to account is straightforward, eg where we have an incentive in the licence that automatically adjusts revenues up or down depending on delivery. However, in other areas it is more complex because we have not included all outputs in the licence and/or we have not set out how/when we will hold companies to account for late or non-delivery of outputs or how we would respond to changing output needs. Respondents to our consultation have different interpretations over what the companies will be held to account for and how. We think resolving this area is crucial to enable successful operation and closeout of RIIO-T1 and RIIO-GD1.

3.6. We will consider whether we need to make licence changes (eg include outputs that were specified in FP but were not transposed to the licence). We will also consider how we would assess delivery of outputs, what action we would take and when if the outputs are not delivered or delivered late and how we would treat changing output needs.

3.7. An example of the type of action we could take in this area is the recent redress payment made by NGGD following its failure to meet its repair risk commitment.[8] This was an output specified in FP but was not included in the licence. We identified that NGGD was not delivering the target through our annual monitoring work. Our work in the area resulted in NGGD making a payment of £3m to the National Energy Action charity. We are now planning to include these outputs in gas distribution network (GDN) licences to allow further action to be taken in future if the output requirement is not met.

3.8. An issue we are currently aware of is the late delivery of the Western HVDC link (£1bn subsea project) which will be delivered a year later than specified in the licence. This delay will have a detrimental impact on constraint costs. We need to decide what action it is appropriate for us to take in response to this, taking into account the reasons for the delay and the impact on consumers.

3.9. The sector specific appendices provide more details on the issues that we will look at under this workstream.

Filling gaps in the RIIO framework

3.10. This area of work relates to issues that ideally should have been addressed when setting the price controls, such as Network Output Measures (NOMs), and also

[8] https://www.ofgem.gov.uk/publications-and-updates/national-grid-agrees-pay-out-3m-after-failing-meet-gas-network-repair-targets

our response to unexpected issues that have arisen during the operation of the price control. We think that addressing these issues now will provide the needed clarity on how RIIO-T1 and GD1 will operate.

NOMs

3.11. The most material issue within this workstream is NOMs. NOMs cover the companies' asset replacement and refurbishment works – a £15bn expenditure area across the three sectors. NOMs are used to measure the long term condition and risk of the network.[9] It is relevant to all network sectors.

3.12. The NOMs targets have been set for each of the categories of network assets and are included in the licence, together with the arrangements for dealing with under/over-delivery. The network companies are able to decide how best to deliver an acceptable level of network risk taking account of the condition of the assets and their criticality. They can adjust their plans to deliver the appropriate level of network risk by the end of RIIO-T1/GD1 that provides best value to consumers.

3.13. The licence provides for a reward/penalty for any over/under-delivery depending whether it is justified or not. The licence also makes clear that cost savings from under-delivery will be excluded from the next price controls (RIIO-T2 and GD2). Equally any justified costs of over-delivery will be added to allowances for RIIO-T2 and GD2.

3.14. The methodologies to translate the individual asset category targets into an overall network risk level and to determine whether these NOMs targets have been delivered, are still under development. Gas distribution is further advanced but in all areas, we consider it important that this work is expedited.

3.15. The methodology will determine which works get prioritised by the companies and allow us to measure whether the targets have been delivered. Each sector's methodology is at a different stage of development. For gas transmission, we will work closely with NGGT to ensure that a robust methodology is developed within 2016/17. For electricity transmission, we published a decision letter in April 2016 that sets out modifications that we have asked the licensees to make to the NOMs methodology.[10] The electricity transmission licensees are required to submit a draft common methodology for review ahead of consultation no later than 31 December 2016. We will continue to work with the companies via the NOMs Working Group to ensure that these methodologies are developed so that the incentive can operate as intended and so that the companies can be held accountable. For gas distribution, the companies will submit their first data using the new methodology at the end of

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[9] NOMs also relates to issues explained in Chapter 4 and Appendix 3, namely asset health, London Medium Pressure and other issues raised by National Grid.
[10] https://www.ofgem.gov.uk/publications-and-updates/decision-direct-modifications-electricity-transmission-network-output-measures-methodology

July 2016. We will then assess this to see if it is meeting our requirements and can be used to assess GDN performance for RIIO-GD1. The final NOMs methodology will be submitted by GDNs in March 2017 following validation.

3.16. This NOMs work is a priority for us. We are committed to this programme of work and will be working with the companies to ensure it is delivered on time. We will be monitoring company progress and may take further action in the event that companies do not deliver. As work on the methodologies progresses, we will work to clarify operation of the incentive. Furthermore, this will inform our work ahead of the next price controls.

Improving RIIO operation

3.17. As the price controls have operated, we have identified potential improvements that could be made to specific elements. The main purpose of dealing with these issues now is to improve how RIIO works in practice. This area of work will consider two incentives, the Environmental Discretionary Reward (EDR) and the Stakeholder Engagement Incentive (SEI). It will ensure that they are appropriately focused and to reflect changes in what now constitutes business-as-usual activities for the companies.

3.18. Another area relates to Strategic Wider Works (SWW). We think that improvements could be made to the guidance for project submissions and that additional reporting requirements could be introduced for projects in construction.

3.19. These issues are discussed further in Appendix 1.

Next steps

3.20. We expect to consult on our proposals for ensuring output accountability in autumn 2016 and make a decision in early 2017. The timetables for the other items of work vary (some of this work is already ongoing) and we have provided further detail on how we will take these forward in appendices 1 to 3.

4. Areas not being taken forward

Chapter Summary

In this chapter we describe the areas where we have decided to take no further action at this time.

Electricity transmission – areas outlined by us in the consultation

Availability incentive

4.1. Proposed links to the Scottish islands would use a single circuit connection, which makes these connections more susceptible to outages. We sought views in the consultation on the potential need for an availability incentive for Scottish island links. We had concerns that the incentives in place for TOs might not be sufficiently strong to make the generation projects viable.

4.2. We do not currently have any evidence that the viability of any relevant RIIO-T1 projects would be affected by the introduction of an availability incentive in the RIIO-T1 period. Moreover, the developers for one of the affected island generation projects told us that they think there are better solutions available to manage the risks that we identified. We also note that there is currently uncertainty about whether any of the projects that would be affected by such an incentive will go ahead, as these projects are likely to be dependent on support from the Government's Contracts for Difference (CfD) auctions. As such, we do not consider that introducing an availability incentive is currently beneficial for consumers and network users.

4.3. Based on consultation responses, we have decided not to develop an availability incentive at this time. SHE Transmission is working closely with the developers to address their concerns and is seeking to provide the information and tools that developers need to mitigate the risks. As mentioned above, one of these developers has said it would be preferable to pursue these routes over an availability incentive. We encourage SHE Transmission to continue this process with all affected developers. Moreover, since our consultation there has not been any further clarification from government on CfD arrangements and timing for these projects so there remains uncertainty as to whether they would proceed. As such we do not think an availability incentive is needed at this time. We will keep the area under review and plan to reconsider as part of RIIO-T2.

Onshore competition roles

4.4. In the ITPR project Final Conclusions we decided to competitively tender new, separable and high value onshore transmission assets. We are currently developing the policy on the arrangements for introducing competitive tendering for onshore electricity transmission projects. Following our October consultation[11] and consideration of responses we will be publishing a document in May setting out further detail on the criteria and further consultation on other aspects of the regime.

4.5. We have decided not to specify new outputs and funding associated with the TOs' onshore competition roles through the MPR. We agree with stakeholders that as policy development is ongoing for onshore competition, it would be better to delay specifying new outputs and reviewing proposed costs until this is finalised.

Assumptions behind renewable generation deployment

4.6. Over the price control we have seen a slower deployment of renewables than was expected at the time of the settlement. Our consultation sought views on whether there had been a material change in outputs due to the changes in government policy related to renewables subsidies. Responses were mixed with some respondents calling for the area to be reviewed and others stating changes in government policy had not yet had a clear impact on outputs.

4.7. We do not consider that changes in government policy have materially changed the required outputs of the network companies. The largest changes in the generation background occurred before the 2015 general election and therefore could not have been due to recent policy announcements. Future developments in connections are still uncertain. The revenue drivers are intended to deal with this uncertainty. As such we do not think there is a strong basis on which to change the current arrangements. Further work is needed to understand the cost drivers for connections being progressed. We plan to do this as part of our work on annual reporting and in the development of RIIO-T2. We will keep this area under review.

RIIO-T2 outputs

4.8. When setting RIIO-T1, 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 incremental wider works) that will be delivered in the first two years of RIIO-T2. We recognise that generators delaying connection dates could lead to delays in the need for the corresponding grid reinforcements. As a result, there may now be more works than initially anticipated

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

that will start in RIIO-T1 but will not be delivered until beyond the first two years of RIIO-T2. Our consultation sought to identify if such delays are occurring/likely to occur and how material this issue may be.

4.9. Having considered consultation responses from the TOs we do not think that this is an issue that needs clarifying at this stage. There are provisions to review the matter later in RIIO-T1. We therefore don't propose to consider this issue further at this time.

Electricity transmission – areas suggested by respondents

European Network Codes

4.10. One of the TOs noted in its consultation response that it may have additional obligations and associated expenditure as a result of implementing European Network Codes.[12] It stated that there would not be sufficient clarity on the nature of any new outputs and associated funding for them to be considered within the MPR timetable. The two relevant codes are the Capacity Allocation and Congestion Management Code (CACM) and the Balancing Code. These codes are at different stages of development, with CACM currently being implemented in the UK and the Balancing Code being prepared for comitology.

4.11. We have not been presented with any evidence that any material new outputs have been set so we do not think the issue meets the scope of the MPR. The TOs were given ex ante funding for developing and implementing the European Network Codes when RIIO-T1 was set and we consider any risks are for the TOs to manage in line with the totex incentive mechanism. We plan to continue monitoring the development and implementation of European Network Codes.

Network Charging Volatility

4.12. Two suppliers commented on volatility in Transmission Use of System (TNUoS) charges. They suggested that the MPR consider steps to improve stability and predictability of TNUoS charges. However, as this does not relate to changing outputs for network companies we do not consider it to be within scope of the MPR.

4.13. We note that there is an ongoing Connection and Use of System Code (CUSC) modification proposal to increase notice periods of changes in TNUoS charges which would provide additional predictability of charges. We think that this route is the appropriate way to consider the issue ahead of RIIO-T2. We support the industry's work to address this area and will consider the proposed modification once it is

[12] European Networks Codes are part of the European Union's work to facilitate an internal energy market.

submitted to us for approval. We will not consider network charging volatility as part of the MPR but we will consider the impact of any changes to revenues that we make as part of the MPR in our summer consultation.

Separation of NGET's TO and SO functions

4.14. A generator suggested that the MPR should consider further separation of NGET's SO and TO function. The respondent suggested that an independent SO model be developed. It stated that this would help mitigate any conflict of interest that might exist for NGET acting as both SO and TO. We are working with DECC on whether there is a case for further separation of the SO. Subject to decisions arising from that work, there may be additional SO outputs and potential funding associated with these outputs at a later date. Given this work remains ongoing we do not consider it within scope of the MPR.

Gas transmission– areas outlined by us in the consultation

Scotland 1-in-20 network flexibility projects

4.15. In RIIO-T1 we allowed funding for projects to enable NGGT to maintain its 1-in-20 obligations[13] for Scotland. The challenge faced is that flows from the UK continental shelf into Scotland are projected to fall and flows on the network will therefore need to change direction in order to meet demand. In our November 2015 consultation we proposed to review how NGGT is meeting its 1-in-20 obligations for Scotland. NGGT has indicated that it will have further clarity on how it plans to meet the 1-in-20 output around May 2016. It has indicated it intends to progress with the solution that is in the best interests of consumers and meets the output of maintaining 1-in-20 compliance in Scotland. However, these timelines are uncertain.

4.16. We intend to carry out a review of how NGGT is meeting the output ahead of RIIO-T2 when further clarity will be available on how NGGT is meeting the 1-in-20 obligation. The issue does not relate to changing output requirements so it does not fall within the scope of the MPR.

Gas distribution – areas outlined by us in the consultation

Safety - iron mains safety risk reduction

4.17. We stated in FP that we would review the iron mains safety risk reduction output as part of an MPR, should the Health and Safety Executive (HSE) decide to review the Pipeline Safety Regulations (PSR) [14] by that time. We signalled in our

[13] To meet the 1-in-20 peak aggregate daily demand, including but not limited to, within day gas flow variations on that day.
[14] Pipeline Safety (Amendment) Regulations 1996 (PSR) 13 and 13(A).

November consultation that the HSE had decided not to review the PSR. As there has been no change in HSE iron mains policy, and therefore no change in resulting output requirements, we did not think there was a need for an MPR to review this output and associated expenditure. We sought views on this. Three GDNs agreed with our view. Other respondents, eg the Institution of Gas Engineers and Managers, also agreed. The HSE has also provided a response confirming that following its review there would not be a change in policy[15] relating to the PSR.

4.18. British Gas (BG) disagreed that there wasn't a need for an MPR to review this output. It considers that given the scale of funding required for this activity in comparison to actual spending, and the fact that stakeholders had a reasonable expectation that we would include this output as part of an MPR, BG believes it should be included in our review. BG's view is that the decision by the HSE not to review the regulations is as much of a policy change as deciding to amend them. It considers that FP was finalised with the expectation that this review was to be completed by HSE. In particular, it considers that the uncertainty mechanism for iron mains under RIIO-GD1 was expected to review changes arising in iron mains replacement, as part of the wider review expected by HSE.

4.19. In response to BG, the output and associated uncertainty mechanism were developed with the current and prevailing framework for this activity in place (which we updated in conjunction with the HSE in 2011[16]). This means that the allowed costs for GDNs, for a level of workload and risk removed, are based on the existing HSE policy. We therefore disagree with the view that there has been a policy change and that FP did not properly take account of the existing policy. It was always our intention that outputs and allowances would only have been adjusted if there was a change in output requirements from a change in policy - but this did not materialise.

4.20. We maintain our position that for safety - iron mains safety risk reduction - there is not a need for an MPR.

Reliability - asset health and risk

4.21. We said in FP that GDNs could submit proposals for any well-justified and material increase in expenditure for asset reliability, (specifically in relation to the asset health output), at the MPR. Given the NOMs methodology is still in development, we indicated in the November consultation that we did not think the GDNs would have sufficient information to submit a proposal in time for the MPR. We received six responses. All agreed that, given the ongoing work under the NOMs process and the lack of robust data available, there was no need for GDNs to use the MPR to consider spending under this deliverable. We will be pursuing the NOMs work as detailed in Chapter 3.

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[15] HSE response to stakeholder responses on Ofgem's MPR consultation
[16] https://www.ofgem.gov.uk/sites/default/files/docs/2011/06/note-on-repex-and-riio-gd1-timetable-for-website_0.pdf

4.22. We maintain our position that for reliability – asset health and risk - there is not a need for an MPR.

Gas distribution – areas suggested by respondents

4.23. We asked for views on whether there were any other material issues that should be considered under MPR for RIIO-GD1. We welcome and have reviewed the specific suggestions that respondents made for consideration under the MPR. These are outlined below.

Broad Measure of Customer Satisfaction (BMCS)

4.24. The BMCS is a new incentive for RIIO-GD1. Its aim is to incentivise network companies to improve and to maintain good levels of customer service.

4.25. The BMCS includes various customer satisfaction surveys, which incentivise network companies to meet and maintain defined levels of customer service. Where they meet these levels they are rewarded, if they do not they are penalised. When we designed the incentive for GDNs we took into account how electricity distribution network operators' (DNOs') performance has improved since this incentive was introduced. We anticipate similar positive effects should occur over time in gas distribution.

4.26. British Gas in its consultation response raised concerns that the current calibration of the customer satisfaction survey incentive may give an incentive to the GDNs to worsen performance. They also noted that this incentive was asymmetric.

4.27. In the first two years of RIIO-GD1, we have seen a general improvement in customer satisfaction scores and where GDNs' have not met the target they have been penalised through the incentive. We consider that if GDNs want to improve or maintain current levels of customer service this will require their continued monitoring and attention.

4.28. In addition to customer surveys, the BMCS has incentives relating to customer complaints and stakeholder engagement. These are both asymmetric. For complaints, GDNs face only a penalty for not meeting their target score and for stakeholder engagement only a reward, which can be flexed according to performance (ie a GDN can receive a lower score and lower reward). However, we still consider that the overall incentive (with all its component parts) delivers a symmetric benefit, ie at +/- one per cent of revenues.

4.29. We consider that the BMCS incentive has driven improved customer service and some progress in stakeholder engagement. The goal has always been to ensure improved and sustained levels across all the companies. Where customer service has not met targets or stakeholder engagement has not shown improvement, the GDNs are either penalised or rewarded less.

4.30. We think the incentive is encouraging the behaviours needed by consumers and do not think the overall desired output in this area has changed. We therefore do not think it would be appropriate to revisit this incentive - any outperformance has only been achieved by the companies delivering beyond the level expected when we set the price control.

Issues raised by National Grid

4.31. As part of its consultation response NGGD highlighted three issues: London medium pressure (LMP), multi-occupancy buildings (MOBs)[17], and shallow depth of cover for some pipelines. LMP is discussed in Appendix 3. For MOBs and shallow depth, NGGD considers it is having to deliver a higher level of intervention in these areas than assumed when the price control was set. It has argued that these areas of activity should be taken account of as part of the NOMs methodology so that these increased activity levels are recognised.

4.32. In NGGD RIIO-GD1 business plans, they highlighted an emerging risk with pipework feeding MOBs. They requested a volume driver uncertainty mechanism, but in FP we had concerns with the difficulty involved in setting an efficient unit cost, due to the large variance in costs between individual projects. We decided to allow ex ante funding as part of totex to manage their MOBs population.

4.33. Shallow depth of cover of pipelines relates to high pressure (HP) and intermediate pressure (IP) pipelines. The policy standard is for these mains to be buried by at least 0.6m. Where the depth of cover is less than this 0.6m, they need to take action (eg diversion or reburial). NGGD has identified that it needs to undertake additional work in this area; driven, for example, by the impact on land of intensive farming methods, ground movements caused by flooding and/or other environmental factors.

4.34. Both MOBs and shallow depth of cover are not output deliverables and we consider that these issues should fall under the output for reliability – asset health and risk. In NGGD's response, they were unable to demonstrate the materiality of these issues and given the NOMs methodology is still in development we consider that both issues are outside the scope of the MPR. There is an opportunity for NGGD to demonstrate how these issues could be considered as part of NOMs.

Smart meter roll-out

4.35. EDF states that a review of GDN spending and performance under the smart meter rollout should form part of the MPR. Smart metering has been provided with

[17] Buildings containing multiple individual dwellings (ie more than one dwelling within a single building). This excludes detached, semi-detached and terraced houses or bungalows predominantly occupied by a single family.

some funding and an uncertainty mechanism within RIIO-GD1 to allow for any changes that may be required.

4.36. When we published FP, we recognised that the impact of smart metering was uncertain for GDNs, but allowed some initial funding for set-up costs. We also put in place an uncertainty mechanism, which could be triggered at any time, where the GDNs could apply for additional revenue if they could demonstrate a material impact after the smart meter rollout. As with any uncertainty mechanism, we expect any application to also demonstrate their engagement with stakeholders. Because of this uncertainty mechanism we don’t think we need to review the issue separately.

Cross sector

Innovation and tax

4.37. In FP for RIIO-T1 and GD1 we indicated that we were mindful of companies receiving excessive gains through tax relief for innovation. The extent of this relief depends on the nature and the volume of innovation projects coming forwards. While we consider the innovation mechanisms themselves are working as intended, our consultation sought to identify the materiality of this potential tax relief benefit. Based on the information we received, we consider that this issue is of low materiality. For example for the three National Grid companies (NGET, NGGT, NGGD) the total relief is estimated to be less than £500k to date. Any action we take in this area is unlikely to change company outputs and as such is outside of the scope of the MPR. We will continue to monitor this and will further consider this issue as part of the next round of the RIIO price controls.

Appendices

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Appendix 1 Electricity Transmission – parallel work

1.1. We will be taking forward a number of important issues outside of the MPR. This appendix describes these areas, the views of respondents and what action we will take, if any, in these areas. The issues described in this appendix fall into the three workstreams we described in the executive summary. We have structured this appendix around these work headings.

Ensuring output accountability

1.2. As described in Chapter 3, one of the areas we intend to look at as part of the parallel work is output accountability. In Electricity Transmission we have identified some areas that require further clarity. These are listed in Table 2 below. One of these areas is being progressed through the MPR as we have identified that some of these outputs may no longer be required. With the exception of the late delivery of the Western HVDC, we have not currently identified any issues of late or non-delivery or changing output needs but we want to make sure the proper framework is in place to deal with this should it occur. Baseline wider works and strategic wider works are already included in the licence but further clarity is needed on what actions we would take for late or non-delivery. The other three categories Transmission system support, Local enabling (Exit - shared use), and Local enabling (Exit – Sole use) are not currently included in the licence.

Table 2: Electricity Transmission outputs where further clarity is needed

Output	Licence (Y/N)	Clarity needed for late/non-delivery (Y/N)
Baseline wider works and strategic wider works **(All TOs)**	Y	Y
Wider Works (General): 9 sites protected against rising fault level, 11 shunt reactors installed **(NGET only)**	N	Y (being progressed through MPR)
Transmission System Support: 1x4 switch mesh GIS substation **(NGET only)**	N	Y
Local Enabling (Exit – Shared Use): Completion of 1 tunnel **(NGET only)**	N	Y
Local Enabling (Exit – Sole Use): 1xGSP enabled, 275kV circuit breaker installed at 1 site, 2xSGTs installed **(NGET only)**	N	Y

Filling gaps in the RIIO framework

Alignment of revenue drivers with solutions deployed

1.3. One of the uncertainty mechanisms incorporated into the RIIO framework was revenue drivers for works associated with local reinforcement to accommodate shared-use generation connections. We are aware from consultation responses that SP Transmission in particular is using solutions that do not align with the solutions that are funded by the revenue driver – it forecasts that they will deliver £150m of connections using solutions not specified by the revenue driver. SP Transmission argues that these solutions deliver the connections in a more efficient way. Because of this misalignment between the assumed range of solutions to be delivered by the licence condition and what SPT is now delivering, it is not clear what revenues SPT can recover.

1.4. We will progress work in this area to clarify the appropriate treatment of these solutions under the revenue driver and therefore what revenues SPT is entitled to recover for delivering them. It is possible that licence changes might be required.

Change of outputs for projects with baseline funding

1.5. This area of work relates to resolving issues that were not anticipated when outputs and funding mechanisms were set. Clarifications are required to determine whether outputs have been delivered or how the funding mechanisms treat the issue. In particular there are two specific issues that we intend to look at further.

1.6. The first of these relates to substitution of projects. SPT has a licence condition (Special Condition 6I) which requires it to deliver an agreed set of baseline wider works projects. SPT has proposed to substitute one of its baseline wider works projects (£15m) for other works that are now needed. The licence currently precludes SPT from receiving an allowance for the proposed works.

1.7. The second issue relates to another of SPT's licence conditions (Special Condition 6H) and how the funding mechanism was set up. In this case, there is a provision for the award of additional allowances to fund specific schemes. The funding is triggered by certain circumstances arising – SPT has works (£69m) that need to proceed but due to unforeseen circumstances will not trigger the funding mechanism. We need to clarify how the licence condition will treat this.

Improving RIIO operation

Environmental discretionary reward

1.8. The Environmental Discretionary Reward (EDR) is a 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. The EDR should complement and reinforce other environmental incentives included in the RIIO-T1 package and reflect activities that exceed licence requirements.

1.9. We sought views on whether the EDR is driving the right business changes within the companies and providing the outputs that consumers and network users need. Respondents supported the scheme but noted that connecting low carbon generation (a key focus of the scheme) was becoming a normal business activity for TOs and that the reward could be more focused on environmental management rather than facilitating a move to a low carbon energy system.

1.10. We agree that connecting low carbon generation has now become a business as usual (BaU) activity for the TOs and we want to ensure that companies are incentivised and rewarded for the types of behaviour the incentive was established to encourage. We therefore propose to consider whether there is merit in focussing the incentive better to distinguish from BaU activities and also avoid overlaps with other schemes. We will aim to consider any changes to the EDR ahead of its operation in 2017.

Stakeholder incentives

1.11. The customer and stakeholder satisfaction incentive contains a range of mechanisms to incentivise effective engagement. One of these is the stakeholder engagement incentive. This 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.

1.12. Our November consultation sought views on whether the stakeholder incentives are driving the right business changes within the companies and providing the outputs that consumers and network users need. Responses to this question were generally supportive of the incentives but some respondents suggested improvements specifically to the stakeholder engagement incentive, such as removing overlap with other schemes and measuring the extent to which stakeholders are embedded within company decision making. We again propose to consider changes to the incentive ahead of its operation in 2017.

Strategic Wider Works (SWW) submissions

1.13. 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. In November 2015, we stated that we wanted to ensure that the TOs are required to submit the most economic and efficient proposal (having considered a reasonable range of alternatives).

1.14. We note stakeholder responses that TOs have existing obligations to run an economic and efficient network, but we want to ensure that only the most economic and efficient proposals are put forward. We think that such an obligation will assist in delivering consumer benefits through our work on competition in transmission to ensure that the right projects are brought forward and can be tendered where appropriate.

1.15. We propose to consider this issue through our next update to the SWW guidance which we expect to undertake in the summer.

Monitoring the needs case for SWW projects in construction

1.16. For Incremental Wider Works (IWW)[18] NGET reviews each year whether it is prudent to continue spending on a project in construction. Following a SWW decision, a new output for that project is included in the licence but there is no formal process/requirement/reporting around revisiting needs cases if circumstances change. We sought views on whether it would be beneficial to introduce additional reporting requirements for SWW projects under construction.

1.17. We think that there could be benefit in introducing such a requirement and plan to consider it for our next update to the Regulatory Instructions and Guidance. We consider that an explicit ongoing monitoring and reporting requirement for these large scale projects is in the interests of customers. This will ensure that the TOs are monitoring the needs cases for their large scale projects and further protect consumers.

[18] IWW are system boundary reinforcements that deliver additional transfer capability in England and Wales and cost less than £500 million (2009/10 prices). SWW are transmission reinforcement projects that deliver additional transfer capability across any of the system boundaries in Great Britain that are forecast to cost more than the threshold specified for each TO in the RIIO-T1 final proposals. The respective cost thresholds are: £500m for NGET, £100m for SPTL and £50m for SHE Transmission (all in 2009/10 prices).

Appendix 2 – Gas Transmission – parallel work

Ensuring output accountability

Non-load related environmental outputs - compressors

1.1. In RIIO-T1 we allowed funding (approx. £140m) for NGGT to construct compressor units to ensure compliance with environmental directives. We specified these projects as outputs. NGGT is complying with the directives by delivering projects that are significantly different to what was set out and funded in FP. In our November 2015 consultation we sought views on whether we should review how NGGT is meeting its obligations to deliver these compressor outputs.

1.2. Respondents to the consultation provided a range of views. Some argued that the issue is within the MPR's scope, as it relates to an instance in which the network company will be delivering different outputs to the specific ones set in FP (i.e. compressor units). NGGT argued that it does not see benefits in reviewing these outputs as it is delivering emission reductions and implementing a potential novel solution at different sites instead.

1.3. NGGT will deliver different outputs (e.g. catalysts instead of compressors) to the ones specified in FP. As such we intend to look at this as part of the parallel work relating to output accountability.

Improving RIIO operation

Evaluation of low utilisation sites which can opt for the "500 hours derogation"

1.4. Current environmental legislation, namely the Industrial Emissions Directive (IED) sets specific emissions limits with which compressors need to comply. The '500 hours' derogation refers to the exemption from compliance with the emissions limit values for compressors which operate below 500 hours a year. Hence, these compressors do not require investment to make them compliant in contrast to compressors with higher levels of utilisation. Within this context, NGGT can apply in 2018 under the IED reopener for funding towards upgrading compressors so they are compliant with the IED.

1.5. In our November 2015 consultation we said we are keen to proceed with undertaking an additional evaluation of low utilisation compressor sites which can opt for the '500 hours' derogation. This would enable us to assess which compressors require investment to comply with the IED. An evaluation would provide us with evidence ahead of any decision in the IED 2018 reopener for environmental compliance compressor projects. More specifically, if many of the compressors are found to be operating below 500 hours, i.e. do not need to comply, this would have an impact on the level of funding required by NGGT. We are already aware that the number of compressor units operating under 500 hours a year is higher than the number we considered during the RIIO-T1 price control assessment to estimate the provisional allowance of £269.3m.

1.6. We have decided to not proceed with reviewing the compressors' operation through the MPR as there hasn't been a change in output requirements. However, we intend to undertake further work in this area in 2017/18 ahead of the 2018 reopener window. We will review the data on compressor use ahead of the reopener to help us inform our decision on it.

Appendix 3 – Gas Distribution – parallel work

1.1. For RIIO-GD1, GDNs were set specific outputs, including outputs relating to safety and reliability. As part of our annual monitoring under RIIO-GD1[19] and the MPR process (through responses to the consultation) we identified that some GDNs are at risk of not meeting some of their agreed output commitments. We also need to ensure that we can hold companies to account for failure to meet outputs. We have decided to take work forward in four areas relating to output accountability under RIIO-GD1 and we will consult on any proposed changes. These relate to the following outputs:

- management of repair risk (safety)
- length of iron mains (safety secondary deliverable)
- loss of supply (reliability)
- maintaining operational performance (reliability).

Ensuring output accountability

Safety - management of repair risk

1.2. Repair risk measures the safety risk associated with gas escapes which have been individually assessed as not warranting urgent emergency action. The escapes are monitored until it is reasonable to carry out the necessary repair work. This enables the GDNs to risk assess escapes and prioritise repairs by factoring in considerations such as labour and material availability, and the public impact of completing the repair.

1.3. Annual repair risk is the total risk score associated with all gas escapes which require repair, recorded on a daily basis and totalled over a year. The repair risk primary output measure is based on maintaining, as a minimum, the total actual risk for 2012-13.

1.4. For the reporting year 2014-15 five networks (East of England, Northern, Scotland, Southern, and Wales and West) met their required output, but the remaining NGGD networks (London, North West and West Midlands) fell short. It is the second year running that these three networks failed to meet their required

[19] Please refer to our recent GD Annual Report 2014-15, for further background: https://www.ofgem.gov.uk/system/files/docs/2016/03/riio-gd1_annual_report_2014-15_final.pdf

output and their performance has deteriorated from 2013-14. Meeting the repair risk output for RIIO-GD1 is not currently part of the Gas Transporter licence.

1.5. We agreed with NGGD that they would make a redress payment of £3 million to a fuel poor charity (National Energy Action), as a result of not meeting their targets for repair risk. Additionally, we intend to introduce a new licence condition for this output. This, in principle, has been accepted by all the GDNs as a necessary step and we will take this forward as part of the output accountability workstream.

Length of iron mains - London medium pressure (NGGD)

1.6. When setting the price control, NGGD identified that the replacement of some of its medium pressure mains in London was a significant issue, termed London Medium Pressure (LMP). The LMP strategy is to manage risk by replacing high consequence mains in and around North London. This requires a number of large, complex engineering schemes to be completed. We provided an allowance for part of the submitted schemes for RIIO-GD1. NGGD has since then signalled a change to its planned targets and a significantly decreased workload for RIIO-GD1. In its response to the MPR consultation, it stated that it believes utilising the existing mechanisms (such as those related to delivering their NOMs utilising trade-offs between or within asset classes) will allow them to explore the right solution for their customers and minimise disruption to road users in London.

1.7. We think that it is appropriate for us to consider the impact that a significantly reduced workload in this area has on other outputs and secondary deliverables. We intend to look at this issue further, and need to assess how to address this whether through NOMs or through other means. If it does have an impact on delivery of other outputs then we would need to decide whether any action is required to protect consumers' interests. We intend on taking this work forward as part of the output accountability workstream.

Reliability - loss of supply

1.8. GDNs committed to the loss of supply output which aimed to minimise planned and unplanned supply interruptions. The measures for this output are the following:

- Planned supply interruptions
  - Number of interruptions
  - Duration of interruptions

- Unplanned supply interruptions
  - Number of interruptions
  - Duration of interruptions

1.9. Concerns have been raised that some of the interruptions targets (both planned and unplanned) may be unachievable or not challenging enough based on GDNs' first two years of performance. As a consequence the output might not be incentivising service levels that are in the consumer interest. This may have been due to errors in the calculation of the targets or a misunderstanding of the relationship between interruptions and other outputs. We are therefore reviewing this output and will consult with stakeholders on whether to amend the reliability (loss of supply) output for RIIO-GD1, with the objective of ensuring that the output meets the needs of the consumer and that the companies can be held accountable for its delivery.

1.10. We consider the current output may not be driving the right behaviour from companies as they strive to meet it. For example, the current interruptions target could influence companies when planning mains replacement and scheduling work. Sometimes it is in the interest of the customer to delay work to a more convenient time for the customer rather than to carry it out as quickly as possible, which could lead to shorter interruption durations but greater inconvenience for the customer.

1.11. There is currently no licence condition for the loss of supply output (relating to network reliability). We intend to introduce a licence condition in the Gas Transporter licence which will set out what standards we expect. We are also considering whether guaranteed standards (GSOP) for loss of supply should be improved. We will take this forward as part of the output accountability workstream.

Reliability - maintaining operational performance

1.12. Maintaining operational performance is measured through six secondary deliverables. These deliverables cover: number and value of offtake meter errors; duration of telemetry faults; pressure systems safety regulations (PSSR) fault rate; gas holder demolition; maintenance of network records; and health, criticality and risk metrics. Achievement of each of these deliverables confirms that the network is operating within agreed criteria; each must be met to achieve the overall primary output.

1.13. We said we would review to assess whether the GDNs had achieved this output at the end of the price control period, but have not specified how we would do this. We propose to set out how this review will be done and what action may be taken if the output is considered not to have been met. We will take this forward as part of our work on the output accountability workstream.

Improving RIIO operation

Exit Capacity

1.14. British Gas (BG) raised concerns relating the NTS exit capacity incentive. BG considers that the incentive encourages GDNs to book exit capacity at more expensive offtake points. It considers the GDNs have changed their approach to delivering their one in 20 peak day obligation and that the use of forecast prices can create inappropriate incentive rates. It also considers that the incentive delivers poor value for customers because incentive payments and actual cost reductions from reduced bookings, do not match.

1.15. In developing the thinking around RIIO-GD1 there was significant engagement in the development of the RIIO outputs, incentives and overall price control package.

Ofgem held a number of working groups and forums[20] during the period from the stakeholder consultation document through to final proposals to develop, propose and calibrate the RIIO incentives package. The exit capacity incentive was considered as part of this process.

1.16. The MPR was designed to take account of changes to output requirements that could not be predicted at the start of the price control, given the longer timeframe and potential for external factors to affect the delivery or need for certain outputs. The scope of MPR does not include the effects of calibration or design of individual incentives, like exit capacity, except where required to accommodate changes to outputs. Therefore, we consider that a review of exit capacity to be outside the scope of the MPR.

1.17. The GDNs have a licence obligation to design and operate their network to meet a one in 20 peak day obligation. This obligation is based on the level of aggregate demand of firm gas customers which is expected, as likely to be exceeded (whether on one or more days) only in 1 year out of 20 years.

1.18. The GDNs look to meet this obligation through a combination of capacity from the NTS, building on their network, and/or interrupting their customers in the event of meeting a growing demand. The NTS exit capacity incentive was introduced in 2005 at the time of GDN sales to encourage GDNs to book the capacity they take from the NTS in the most efficient way. In RIIO-GD1 we highlighted the need for good interactions between the NTS and GDNs and for GDNs to consider exit capacity as an option that potentially avoids investment based upon the idea that the delaying investment, whilst retaining the option to undertake it, was valuable especially where there is considerable volume uncertainty. This has encouraged the GDNs to look at the optimal way, within a number of baseline constraints, to utilise their NTS exit capacity.

1.19. GDNs have to balance their demands on the NTS across their region, and use specific selections of offtakes in an area to help them meet their demand requirement subject to physical flow constraints. When physically possible the incentive encourages the GDN to book capacity at the lowest cost offtakes and reduce bookings at expensive offtakes, which ultimately could signal investment in the NTS, which in turn could drive up costs to consumers.

1.20. We do not consider there is evidence that the GDNs are using the incentive to book capacity at more expensive offtakes and our initial view is that the incentive remains appropriate to incentivise the use of efficient offtake points.

[20] https://www.ofgem.gov.uk/network-regulation-riio-model/riio-forums-seminars-and-working-groups/riio-gd1-working-groups?page=1#block-views-publications-and-updates-block

1.21. Whilst the forecast prices might not align with actual price in all cases we think this is mitigated by the GDNs facing significant constraints on their choice of offtake points.

1.22. The one in 20 obligation referenced under exit capacity is set out in a specific licence condition which the GDNs must meet, there has been no change to this. It is for the GDNs to decide the most appropriate approach to deliver this using the options available to them. RIIO-GD1 has allowed GDNs to adopt a holistic totex approach to meet their licence obligations and output deliverables. Because of this we think it is too simplistic to only compare incentive payments and actual cost reductions from reduced bookings – there are other factors that would need to be taken into account, eg how other outputs are being delivered and developments to the network itself and its operation.

1.23. For the reasons above our initial view is that the incentive remains fit for purpose and does not need to be changed. However we want to explore further before confirming our position in order to ensure that it is incentivising the right behaviour and operating as intended.

Appendix 4 – Summary of responses

1.1. We received 23 responses to our November 2015 consultation, including one confidential response. Responses were received from the TOs, the GDNs, suppliers, renewable developers, industry organisations, a consumer group and other stakeholders. Not all respondents answered each of the questions set out in the consultation documents. We have published non-confidential responses on our website.[21]

1.2. The following is a summary of responses. We have summarised the views of respondents against each of the questions in the consultation.

Chapter one: purpose and scope of an MPR

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

1.3. All four GDNs were supportive of the clarity provided. One industry body noted that the additional information appeared consistent with RIIO-GD1 FP.

1.4. One supplier stated that the scope of the MPR should include whether changes to outputs were needed to ensure value for money for consumers, as this was in consumers' interests and a primary duty for Ofgem.

1.5. The TOs made several points. Two TOs agreed that some of the areas raised could benefit from clarification but said this is better provided outside of an MPR. Another TO welcomed the clarity provided in the consultation document and agreed that materiality should be considered in the decision to take forward an MPR. A third TO said the consultation was clear and asked Ofgem to produce a timetable for planning purposes if an MPR proceeds.

1.6. Two TOs did not agree with our clarification of the scope. One said that changing outputs to meet consumer or network user needs is not something it reasonably expected at the time of FP to be in the scope of the MPR. The other TO stated that a MPR should focus on whether outcomes rather than specific solutions have been delivered.

1.7. There was consensus among network operators that any MPR should avoid creating two four-year price controls.

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[21] https://www.ofgem.gov.uk/publications-and-updates/consultation-potential-riio-t1-and-gd1-mid-period-review-0

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

1.8. Stakeholders' responses to this question were mixed. Some agreed that the issues identified are in scope. Others agreed that issues could benefit from clarification or further consideration but outside of an MPR. .

1.9. The four GDNs agreed that an MPR was not required for RIIO-GD1. One agreed that the two issues identified for GD1 are within scope of a MPR, but they agreed that a MPR was not required. Another GDN stated that the primary issues for GD1 are the treatment of late or non-delivery of outputs and the innovation tax relief issue – it believes that neither of these issues are within scope of an MPR.

1.10. Two industry bodies agreed that the issues identified are within scope. One generator was supportive of launching a MPR. A Government Agency considered that some of the issues merit consideration but aren't of sufficient materiality to launch a MPR.

1.11. Two TOs stated that that the issues identified for their sectors aren't in scope of a MPR. Two other TOs stated that some issues are in scope and merit reviewed review but believed there are more appropriate mechanisms to address these issues.

1.12. One supplier stated the issues identified are in scope but proposed that a full review of performance is undertaken and presented to allow the identification of all issues. Another supplier agreed that the issues identified are in 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?

1.13. The four GDNs and two industry bodies stated that there were no additional issues within the defined scope for GD1. One GDN discussed additional areas (such as Multiple Occupancy Buildings (MOBs), shallow depth of cover for pipelines and London Medium Pressure (LMP) pipelines in its consultation response but concluded that these are out of scope.

1.14. One TO stated it had not identified any additional issues and noted that it was delivering additional outputs in relation to European activities but these additional costs are not material. Another TO stated there were areas that need to be managed in the second half of RIIO-T1 but that the uncertainty on their timing meant they should not be included in an MPR. Two TOs stated that there are no further issues.

1.15. Some respondents identified additional issues for consideration. One supplier and a consumer group suggested that we conduct an analysis of output delivery to allow stakeholders to identify further issues. The supplier also set out concerns in the GD1 price control relating to the exit capacity incentive and the broad measure of customer satisfaction.

1.16. Two other suppliers suggested that the MPR should also address volatility in Transmission Network Use of System (TNUoS) charges. A generator suggested that the MPR should consider increasing the separation of NGET's System Operator (SO) and TO roles. A TO noted that implementing European network codes may impose additional obligations and costs on it.

Chapter two: Electricity Transmission

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

1.17. Responses on this topic were mixed.

1.18. Six respondents agreed with our assessment. Six other respondents agreed that there are issues that could be addressed but disagreed with progressing these through an MPR. Views on the issues to be addressed varied by respondent, these are covered in response to the specific questions below.

Question 5: We ask for detailed views 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 a change.

1.19. Three TOs and an industry organisation noted the ongoing industry work to develop a common NOMs methodology. They considered that this is the most appropriate way to develop the incentive, as a different timetable might be needed from the MPR.

1.20. One supplier stated that it did not consider there was sufficient information available to respond to this question. It also stated that we should engage with all stakeholders, not just the TOs, if the incentive requires development.

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.

1.21. Respondents largely supported the Environmental Discretionary Reward. However, some respondents suggested areas for improvement. One supplier stated that connecting low carbon generation is becoming a normal business activity for TOs and that reward thresholds should be raised to reflect this. Two TOs stated that the reward could be more focused on environmental management rather than facilitating a move to a low carbon energy system.

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.

1.22. Two TOs supported the incentive. One believed it provides appropriate stimulus to drive the right behaviours. The other noted the year on year improvement in results and stated that we should allow recent changes to the baseline to 'bed-in' rather than make amendments through the MPR.

1.23. A third TO also supported the incentive but highlighted areas for further development. These included potential overlap with different aspects of the EDR and that the types of engagement the panel look for may be more appropriate for the SO than the TO.

1.24. A consumer group suggested that the incentive should measure the extent to which stakeholders are embedded within company decision making.

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?

<u>Submission quality for SWW projects</u>

1.25. Network companies did not agree that there should be an additional requirement in this area. The three TOs stated that existing obligations under the Electricity Act 1989 and transmission licence require them to operate economic and efficient businesses. They stated that these obligations extend to their submissions for Strategic Wider Works (SWW).

1.26. A supplier and two industry bodies agreed that TOs should be required to submit the most economic and efficient proposals for SWW projects. The supplier stated that it hoped this was already the case. The two industry bodies also stated that the transparency of the process could be improved.

1.27. One renewable developer agreed that TOs should submit the most economic and efficient proposal but noted that this assessment would take place against a shifting technical, regulatory and political background. The developer suggested that the needs case should process could be improved by providing greater clarity on the process and improved engagement with the TOs and dependent parties.

<u>Further guidance on monitoring needs cases for projects in construction</u>

1.28. The three TOs believe that such a requirement is not necessary. They noted that:

- they have monitoring arrangements in place for their investment projects:
- that the Electricity Act 1989 and their licence requires them to operate their businesses in an economic and efficient manner; and
- that inefficient expenditure can be disallowed.

1.29. Two of the TOs concluded that this requirement could be appropriately addressed outside of MPR through guidance updates.

1.30. A supplier stated that TOs should annually review expenditure on projects in construction. Three industry bodies and a renewable developer agreed that monitoring the needs cases was sensible as long as this did not delay projects and did not act as a barrier to project development. One government agency supported the introduction of an ongoing monitoring requirement as long as this did not increase the risk of project delays.

1.31. One consumer body agreed that extending needs case review to projects in construction was sensible.

Availability incentive for Scottish Island links

1.32. Four respondents were against introducing an availability incentive. One renewable developer welcomed consideration of the issue but stated it would be preferable to have the TO share information on design, construction, operation, and a stated availability objective, and to cooperate with generators to facilitate more tailored methods of compensation - such as insurance, and commercial contracts. A TO stated that adding an Availability Incentive could be seen as re-opening the price control. The TO stated that this topic was discussed and dismissed when the price control was set. The TO believes that it can meet the needs of developers without such an incentive.

1.33. One TO stated that this was outside of the scope of MPR and that the addition of a new incentive part way through the price control could undermine the stability of the price control. The TO noted there was merit in the incentive and stated that it should be considered further as part of RIIO-T2. Another TO stated that requests for derogations from the SQSS are possible and this arrangement is adequate to address the issue.

1.34. Other respondents were supportive in principle but did not put forward detailed responses. One renewable developer welcomed discussion and further investigation of this issue. One government agency supported the introduction of an incentive and noted that single cables have implications for project financing but that the offshore incentive had addressed these concerns in that sector. A consumer body and supplier agreed with introducing an Availability Incentive in principle. The supplier noted that such an incentive exists for offshore transmission operators. Two industry bodies supported the introduction of the incentive, as long as it did not lead to delays in project construction.

Potential funding requirements for NGET’s enhanced SO function and competition roles

1.35. One TO stated that it is now undertaking additional activities than when its business plan was submitted. It stated that while the enhanced SO role could be considered as part of MPR, it is linked to the ongoing onshore competition work and as such should be considered later once funding requirements are clear. It suggested this issue could be reviewed through a reopener like the one used for new roles it assumed in association with the Electricity Market Reform.

1.36. Another TO noted that considerable new activities could be imposed on TOs but these should be addressed outside of MPR. The TO suggested that this be done by ring-fencing costs and considered as part of RIIO-T1 closeout.

1.37. A third TO stated that additional funding and resources may be required for new roles associated with onshore competition by TOs and the SO and that it is currently assessing whether these lead to additional costs in its business.

1.38. One industry organisation stated that while these new roles could be significant, policy development is ongoing and that a review should be undertaken outside of MPR.

1.39. Two suppliers agreed that this should be reviewed through an MPR. They also suggested that the review identify any efficiency the new roles result in for TOs.

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.

1.40. Responses to this question were mixed. The TOs stated that changes in government policy had not affected their work programme beyond the realm of what was considered when the price control was set. One TO stated that there had not been a clear change in government policy and that reductions in the level of subsidies were expected as renewable technologies became more cost effective. The TO stated that generation connections are broadly within expected bounds and that there are increasing numbers of distribution generation connections.

1.41. One TO noted that changes in policy had created uncertainty in the renewable developer community but had not yet led to a change in contracted connection positions. This TO currently forecasts higher levels of generation connections than when it developed its business plan. The TO noted that it’s costs are sensitive to the types of connection that occur and if less offshore generation goes ahead than predicted then its average costs will increase.

1.42. The three TOs provided the data requested in the consultation regarding the projects being taken forward and their unit cost allowances.

1.43. One supplier stated that the consultation lacked sufficient information for them to provide a response. It suggested that an analysis of revenue drivers should be undertaken and Ofgem should consult with stakeholders if the mechanism requires improvements. One consumer organisation supported consideration of this issue and sought reassurance that these issues were monitored on an ongoing basis.

1.44. An industry body stated that it is not yet clear whether any changes in government policy would have a material effect on RIIO outputs. It noted that the UK is still committed to the carbon budget regime under the Climate Change Act 2008.

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.

1.45. All three TOs responded to this question. Two of the TOs stated that most of their works were closely related to the defined uncertainty mechanisms but a third noted that some of its schemes were not.

1.46. One TO stated that the majority of its connections works are directly correlated to defined uncertainty mechanisms. This TO notes that there are some areas that could be improved within these mechanisms but this is best addressed as part of RIIO-T2.

1.47. One TO identified one area where it did not have a specific funding mechanism, which was the provision of reactive compensation. It stated that for this area it had effectively substituted it by using its allowance for a baseline scheme that was no longer going ahead.

1.48. One TO outlined that it was expecting to connect more generation connections now than it had forecast in its business plan. The TO stated that this increase in generation connections meant that it was using a wider range of technical solutions than its unit cost allowance was based on. It estimates that about 60% of its schemes are aligned with the revenue drivers but the remainder (£150m) were not. This TO also stated that it believes clarity should be provided for baseline schemes whose need had changed or been superseded by developments.

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.

1.49. Respondents were largely supportive of clarification, but network operators argued that this should take place outside of MPR.

1.50. One supplier stated that it was important to clarify treatment of outputs no longer required or substituted. Another supplier stated that it is in customers' interest that activities no longer needed are not undertaken. It stated that the totex incentive is not suitable to prevent companies undertaking redundant activities. It suggested that totex expenditure and the IQI be reviewed as part of a more comprehensive MPR.

1.51. One TO stated that the majority of its expenditure on load related projects is aligned to revenue drivers. It stated that for RIIO-T1 complex revenue drivers were not included so a portion of expenditure was non-varying. It stated that it had no expectation that load related non-variant allowances would be reviewed and it expected these to be treated in the round and subject to the totex incentive mechanism.

1.52. One TO agreed that clarification would be helpful through amending existing guidance or new guidance documents rather than through an MPR. This TO highlighted a number of areas for clarification.

1.53. One TO stated that 94% of its load related projects were covered by specific incentive mechanisms and this had not materially changed from the business plan. It stated that there are other outputs that it is now required to deliver which were not identified when RIIO-T1 was set, such as diversions of existing infrastructure. The TO stated clarity should be given for schemes whose outputs do not align with a specific incentive and where it may be a material omission from the price control.

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?

1.54. Generally respondents did not consider this issue to be material.

1.55. One supplier stated that it did not have enough information to respond to the question. It stated that MPR should not fix anything ahead of the more rigorous assessment that would be done as part of setting RIIO-T2. It expects uncertainty to remain into RIIO-T2 and robust uncertainty mechanisms should be developed to protect customers.

1.56. One TO stated that it preferred to wait until 2017 to resolve the issue as it will have a firmer indication of which connections are going ahead then and this is the timing to address the issue specified in its licence. It stated waiting would allow for a more robust view of materiality and output requirements.

1.57. One TO recognised that some revenue driver schemes will begin in T1 but not be delivered until T2. It assumes appropriate allowances will be made through the T2 baseline plan. It stated that it did not believe this issue to be material but would welcome clearer guidance.

1.58. One TO forecasts £60m of investment in RIIO-T1 for outputs delivered in T2. It stated that it did not have a defined mechanism for treatment of these schemes and stated the need for guidance on these transition projects.

1.59. One industry body stated that there was not a consistent mechanism in this area. It stated that this should span a price control boundary and not be considered by MPR.

Chapter three: Gas Transmission

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?

1.60. Three respondents supported an MPR for Gas Transmission. A consumer body particularly support a review of how NGGT is meeting its output with regards to achieving the 1-in-20 obligation in Scotland.

1.61. NGGT rejects the need for an MPR, stating that the areas highlighted in the MPR consultation are not linked to changes in Government policy and are not new outputs.

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?

1.62. Three responses were received. One supplier supports an MPR of the Avonmouth pipeline solution, indicating non-delivery of specific outputs, is needed to protect the interests of consumers. Another supplier supports clarification of outputs no longer required or not delivered, but didn't mention Avonmouth specifically.

1.63. NGGT doesn't agree that an MPR is required for Avonmouth LNG. It said the allowance was set as a baseline allowance, and that the output was mis-specified in RIIO-T1. NGGT state that the output should have been to effectively manage the consequences in terms of Operating Margins and capacity reduction from the decommissioning of Avonmouth LNG.

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?

1.64. Two out of three respondents support a review of how NGGT is meeting its 1-in-20 obligation in Scotland.

1.65. One supplier agrees a review of this output is essential if NGGT has made any significant change in its approach to maintaining its 1-in-20 obligation. A consumer body supports a review, and isn't convinced that the level of outperformance in RIIO-T1 is justified. .

1.66. NGGT does not agree that a review is useful in the case of this output, as its investigations into the best way to meet this output are ongoing. NGGT is conducting investigations into how best to meet the output of maintaining 1-in-20 compliance in Scotland in response to changing flow patterns. NGGT states that it has already defined an asset build solution, but that it is also investigating more innovative and cost-effective solutions as per the RIIO framework. This includes collaborating with SGN to assess alternatives. This investigation is due to be completed in May 2016.

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

1.67. One supplier supports clarification of outputs no longer required / not delivered, but do not mention the compressor projects issue specifically. NGGT responded acknowledging its solutions differ from those agreed in FP, however it argues these solutions will deliver savings to the consumer. They also state that the specified output in FP at Peterborough and Huntingdon is to deliver emissions reduction at these sites.

1.68. NGGT states that they have undertaken BAT (Best Available Technology) assessments at Peterborough and Huntingdon which resulted in the decision to install smaller, gas units, compared to the allowance for 24MW electric units. NGGT argues that FP did not state that the allowance would be adjusted by the size and type of unit installed. NGGT states that costs its incurred due to exceptional circumstances offset the difference between the baseline allowance provided, and the current forecast costs. Hence it is not material.

1.69. NGGT states that at Aylesbury it has discovered an alternative, more efficient and cost-effective method to reduce emissions. It argues that such a solution adheres to RIIO principles.

Chapter four: Gas Distribution

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?

1.70. All four network companies agreed with our assessment that there weren’t any material issues necessitating an MPR for RIIO GD1. Two industry organisations for gas and electricity also agreed with this view.

1.71. Notably one GDN references that the feedback received from its customers or stakeholders indicated there wasn’t an appetite for a review of the outputs or any new outputs identified.

1.72. A second GDN considers that uncertainty mechanisms and end of period review were sufficient to protect customers and ensure delivery of outputs as well as flexibility eg when asset health issues arise. They also cite the NOMs process as sufficient to account for under or over-delivery during the period.

1.73. However, two suppliers as well as one customer group identified additional areas or an alternative approach necessitating the need for an MPR under gas distribution. Their comments are summarised below.

1.74. One supplier stated that a full review of all outputs is necessary for the MPR process and specifically for gas distribution. It questions the effectiveness and challenge of certain incentives, ie broad measure of customer satisfaction and exit capacity incentive. It considers that outperformance is an area that should be reviewed under MPR. Specifically for two incentives mentioned, it provided the following justification in support of inclusion under MPR:

- **Exit capacity:** This supplier considers that an appropriately structured exit capacity incentive would encourage GDNs to be efficient with their capacity bookings and if they beat targets, they would be able to retain a share of this outperformance, with the remaining share being passed to customers. However, the supplier believes that as currently calibrated, there is an incentive to book capacity at more expensive offtake points and that there has been a change in approach to delivering 1 in 20 obligation. It considers that the use of forecast prices can create inappropriate incentive rates and that in general, this incentive is delivering poor value for money for consumers.
- **Broad measure of customer satisfaction:** The supplier considers that the current incentive is set with an asymmetric calibration, leading to signals that encourage GDNs to worsen performance.

1.75. The supplier also commented on the limited amount of detail provided including any issues or results, in arriving at the views outlined in our consultation, and its potential impact on stakeholder engagement. The supplier noted that the GD Annual Report was not expected to be published until after our consultation had closed. Note: we received follow up responses to this supplier's comments-see below and full responses on our website.

1.76. A second supplier considers that a review of spending and performance of GDNs against the objectives of the smart meter roll out should be a consideration under MPR.

1.77. A consumer group believes a full review of delivery of outputs (and if rewards are appropriate), should form part of the MPR for gas distribution, rather than a selective review of specific outputs. Otherwise, given the current amount of information publically available, a decision on MPR is difficult; in judging what is contributing to companies' outperformance (eg government policy), and whether outputs are meeting customer need. It considers outperformance of outputs is in scope for MPR as it is within Ofgem's rights to alter the definition of those outputs found to not be meeting the needs of customers and network users. It is this consumer group's view that the MPR as likely the last opportunity ahead of devising GD2, to review outperformance and any information gathered may at least inform a more consumer-friendly settlement at GD2, (if it does not contribute to changes at GD1 settlement).

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?**

1.78. Three GDNs responded, agreeing with our view. Additional network respondents equally agreed that there was no need to review this output under MPR.

1.79. One supplier disagreed. Given the scale of funding required for this activity in comparison to actual spending, and the fact that stakeholders had a reasonable expectation that we would include this output as part of an MPR, it should be included in our review. The supplier said that the decision by the HSE not to review the regulations is as much of a policy change, as if they had amended them. The supplier stated that FP was finalised with the expectation that this review was to be completed by HSE. In specific, it considers the uncertainty mechanism for iron mains under RIIO GD1 was expected to review changes arising in iron mains replacement, as part of the wider review expected by HSE.

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?**

1.80. Six respondents provided views, including three of the GDNs. All responses agreed that given the ongoing work under the NOMs process, or the lack of robust data available, there was no need for GDNs to use the MPR to consider spending under this deliverable.

Follow up responses to stakeholder comments

1.81. HSE and three GDNs provided follow up comments to address some concerns raised by stakeholders, following our consultation. All of these responses are available on our website.

1.82. HSE provided a response regarding its decision not to review the PSR. In summary, HSE consider that discussions with the GDNs were held to inform HSE's policy formation, specifically whether or not there existed reasonable grounds for HSE to proceed with a full and open consultation on the matter of a potential amendment to PSR regulations 13 and 13A (eg through the publication of a consultation document). It did not consider that any other parties (other than GDNs) were directly affected by any changes it would have made to these requirements. HSE said it does not routinely place matters of policy formation in the public domain. Having been presented with evidence by the GDNs, that no economic benefit would accrue from a change to a 'so far as is reasonably practicable' standard, HSE has decided, at this time, not to proceed further.

1.83. One GDN responded to the comments around the possible favourable variance around RPEs as compared to the original allowances and comments about the availability of regulatory information for stakeholders. It considers that there has been no such favourable outcome with RPEs and it details the engagement and publication of regulatory information that it has completed for the benefit of stakeholders.

1.84. The three network companies all responded to stakeholder comments in support of the current arrangements for exit capacity and/or broad measure of customer satisfaction.

Chapter five: cross-sector issues

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?

1.85. Most respondents supported clarification of treatment of non-delivery of outputs. However many also stated that they considered such clarification to be outside the scope of MPR.

1.86. Respondents noted some specific areas for clarification. A GDN requested further clarity on treatment of newly introduced outputs, such as repair risk. It stated further work would be required to understand whether outputs should be consistent across all networks. Another GDN welcomed clarity on assessment periods and delivery of outputs with associated 2.5% penalties. It stated this work should occur over the remainder of the price control. A TO welcomed clarification of treatment of delivery for baseline wider works. Another TO stated that delivery of outputs should be considered on a category basis eg load vs non-load. A TO stated that clarification was not required except for treatment of the Western HVDC project. A GDN stated that the suite of RIIO-GD1 FP documents provided sufficient clarity and they did not expect any penalty or additional allowances for workload variances.

1.87. A supplier stated that it is in the interests of customers that activities no longer required are not carried out. It also stated that revenue allowances are considered alongside clarifications of outputs. The supplier stated that the sharing factor rewards companies for not completing activities to a greater degree than it rewards companies for completing activities efficiently.

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.

1.88. All network operators responded to this question. They largely concluded that this issue was not material and not within scope of MPR. Six companies provided estimates of the benefits that have been accrued so far due to this tax relief.

Additional comments

1.89. A supplier suggested an alternative approach to running the MPR. The supplier stated that the approach taken so far was limiting effective stakeholder engagement. It argued that by consulting on a range of pre-identified issues the consultation guides stakeholders to consider those issues in isolation. The supplier noted that limited issues were consulted on for the RIIO-GD1 price control. It suggested that company performance is presented, drivers for under/over performance are identified and an assessment of these drivers against the MPR criteria is undertaken. The supplier suggested some additional issues for consideration in RIIO-GD1 based on its own analysis.

1.90. A consumer body suggested that alongside the MPR, a wider analysis of how RIIO has functioned should be undertaken.

Appendix 5 – Impact Assessment

1.1. In FP, following extensive consultation throughout the RIIO process, we clearly defined the scope of any MPR as being limited to changes to outputs driven by changes to government policy or new outputs to meet the needs of consumers and network users. This was to mitigate the risk of the MPR acting as another price review, in effect creating two price control periods undermining the long term focus and associated benefits of RIIO.

1.2. In our November consultation, we re-iterated that the scope of any MPR would be as defined in FP; the consultation on whether any issue was in scope was firmly based on this defined scope and therefore implementing existing policy. As such, an IA was not merited at that early stage of the process.

1.3. In response to our consultation, some stakeholders suggested that the MPR should consider output and funding requirements more generally in response to company forecasts of strong financial performance and also consider value for money to customers. We consider that this would represent a change in scope for the MPR and constitute an important policy change. We have conducted a high-level IA outlining the reasons why we don’t think widening this scope is appropriate.

1.4. If we consider it appropriate, we will undertake a further IA when we have developed more specific policy proposals in the summer related to the issues that we are taking forward under the MPR.

A widened MPR scope

Options considered

1.5. Some respondents to our November 2015 consultation called for the scope of the MPR to be wider. Specifically, these respondents suggested:

- value for money for consumers should be a consideration when determining whether to make changes in the MPR; and
- we should revisit the role outputs are playing in delivering financial windfall for networks.

1.6. An MPR along these lines could allow scope to clawback some of the current and projected outperformance by the companies. For example, allowances considered with hindsight to be “too generous” and did not provide value for money to consumers could be reduced. Similarly, additional projects/schemes could be reclassified as outputs to allow a greater scope to take action (eg clawing back associated funding) if these schemes/projects were no longer needed or not delivered.

1.7. We set out below our views on what the impact of making such a scope change could be.

Impacts of a widened scope

Benefits

1.8. In the short term, if we were to claw back some of the projected outperformance or be more prescriptive in what we define as an output this would provide a benefit to consumers in the form of lower bills reflecting the sums clawed back. This would go beyond the savings that would be shared with consumers from the totex efficiency incentive that would operate in the absence of any further intervention.

1.9. We provide some illustrative figures below for how clawing back sums would affect consumers.

1.10. Under the normal operation of the totex efficiency incentive the incentive rate determines how much of any underspend is retained by the company after tax. For example an incentive rate of 50% would mean the company would retain half of any underspends. However the remaining 50% is not fully retained by consumers as there is an impact on corporation tax (ie the higher profits from the underspend). This means that in this example, roughly 40% of the underspend would be passed back to consumers and the remaining 10% would be paid in increased corporation tax.

1.11. Across T1 and GD1 the companies have different efficiency incentive rates so varying amounts are passed back to consumers. If we take an illustrative £100m underspend this would roughly result in:

- £44m being passed back to consumers under T1 using the average incentive rate
- £24m being passed back to consumers under GD1 using the average incentive rate.

1.12. This means that the impact of a one-off claw back of £100m in price control allowances would only benefit consumers by the amount not already passed back to them by the totex efficiency incentive. In the £100m illustration used, the clawback would therefore benefit consumers on a one-off basis by:

- £56m in T1
- £76m in GD1.

1.13. We don't think we can provide an estimate of how much would be clawed back if the scope were to be widened in the manner described as there would be a range of factors to consider including those discussed in the costs and risks section below. Moreover, it was the clear intention of RIIO to lengthen the price control and give the companies the ability to implement longer term plans. Broadening the scope as described would go against this intention and would damage regulatory confidence and increase regulatory risk.

Costs and risks

1.14. However, in the long run we would expect a number of detrimental impacts to consumers to arise from taking such action. These impacts would primarily stem from the fact that the action to extend scope would go against the stated intention of the MPR to be focused on changes in output requirements alone. Moreover, we have been explicit in previous documents that we would not use the MPR to reopen more widely and that we did not want the MPR to result in two four-year price controls. Widening the scope in this way would weaken confidence in our regulatory regime and the commitments that we make in future. These impacts would not be limited to just the transmission and gas distribution price controls but also other price controls we set for instance RIIO-ED which operates on a different regulatory timetable.

1.15. The key impact would be on perceived regulatory risk and would have a knock-on impact on future financing costs. Regulatory risk is generally perceived to be a key risk faced by the regulated network companies and affects their financing costs through an associated risk premium.[22] Changes to certain parts of the price control would undermine regulatory confidence and not deliver the long term best outcomes for consumers. To minimise the risk premium companies' face, investors must have confidence in the regulatory regime which is backed by a credible regulatory body.

1.16. We have been very clear on the scope of the MPR and the investment community reacted positively to the tightly defined scope. Changing our position now would harm regulatory confidence and likely increase the risk premium faced by companies. We believe that increasing perception of regulatory risk, for example by widening the scope of the MPR, could be to the detriment of customers by hundreds of millions of pounds annually through higher financing costs.

1.17. To illustrate the potential magnitude of this we have set out some illustrative impacts. Based on the current regulatory asset values in the 3 RIIO price controls (T1, GD1, ED1) a 10 basis point increase in the weighted average cost of capital would increase annual costs to consumers by around £65m per year. If such an effect were to last for the next price control period in each sector (ie the 8 year period), the discounted total value would amount to around £380m. If the weighted

[22] We are currently working with the UK Regulators' Network to ensure the most efficient financing costs for companies through the joint 'market returns and cost of capital project'. http://www.ukrn.org.uk/?page_id=429

average cost of capital were to increase by 50 basis points, this discounted total value would amount to around £1.9bn. The magnitude of the impact and its duration would depend on what precise action we took so could be within or outside of the 10-50 basis point illustration over 8 years but our expectation is that the effect would be significant and likely outweigh any short term savings.

1.18. Further detrimental impacts could also arise from a widened scope to the MPR:

- Companies will have less confidence to invest in significant projects that benefit consumers if we change *ex post* how historical expenditure will be treated (eg if we were to change historical allowances or allowances for the remainder of the control period).

- Companies will be less likely to invest in new processes/strategies with high upfront costs that could deliver efficiency savings if there is an increased risk that the benefits from such strategies will not be retained due to unexpected changed in the regulatory settlement.

- There could also be an impact on the market for corporate control. Some investors might be less likely to want to acquire energy network utilities which in turn could reduce the incentives on current management teams to deliver efficiency savings that would ultimately be shared with consumers.

1.19. There could also be other detrimental impacts from reclassifying some projects as outputs. In particular, it might weaken incentives for the companies to deliver the overall outputs that consumers really value in the most efficient way (eg delivering reliability improvements in a way not assumed by the baseline funding). Instead they might just deliver the assumed building block of their allowances meaning that there would be no efficiency savings to be shared with consumers and unnecessary assets might be built and solutions that are needed might be overlooked until the next price control. Adopting such an approach could also hamper innovation and the adoption of improved working practices and solutions.

1.20. There would be an expectation in future price controls that if the companies are underperforming the settlement (eg by overspending their allowances) that we would then make adjustments in their favour which we would want to avoid. This goes strongly against our position on ex ante price controls as it would weaken the incentives on companies to efficiently manage their costs and deliver savings for consumers.

1.21. 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. Based on this, we consider that the benefits of maintaining regulatory confidence and ensuring companies focus on the long term outweigh the potential short term benefits of widening the scope of MPR. For these reasons we think it is appropriate that the MPR remains focused on changes to output requirements as we have proposed.