# RIIO-ED1: Final determinations for the slow-track electricity distribution companies

## Overview

## Final decision


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**Overview:**

This document summarises our decision for the settlements (final determinations) for ten electricity distribution companies for the next price control (RIIO-ED1). This Overview is aimed at a wide audience, while the annexes are more technical.

In February 2014 we settled the price control of one group early (fast-track). The remaining (slow-track) companies submitted revised business plans in March. In July we consulted on our draft determinations, based on our analysis of these plans. Our final determinations take into account stakeholders' responses.

We will publish a statutory consultation on the licence conditions to implement these final determinations in December 2014.


**PLEASE NOTE THAT ON 17 DECEMBER 2014 WE PUBLISHED A LETTER DETAILING CORRECTIONS TO THE FINAL DETERMINATIONS SUITE OF DOCUMENTS. THIS OVERVIEW SHOULD BE READ ALONGSIDE THAT LETTER.**

# Associated documents

**RIIO-ED1: Final determinations for the slow-track electricity distribution companies – supplementary annexes**

- RIIO-ED1 business plan expenditure assessment
- RIIO-ED1 final determinations RPE methodology decision
- RIIO-ED1 final determinations Financial Model
- RIIO-ED1 final determinations detailed figures by company

The supplementary annexes are on our website:
https://www.ofgem.gov.uk/publications-and-updates/riio-ed1-final-determinations

**RIIO-ED1: Draft determinations for the slow-track distribution companies**
https://www.ofgem.gov.uk/ofgem-publications/89076/riioed1draftdeterminationoverview30072014.pdf

**Decision to fast-track Western Power Distribution**
https://www.ofgem.gov.uk/ofgem-publications/86375/fast-trackdecisionletter.pdf

**Assessment of RIIO-ED1 business plans and fast-tracking**
https://www.ofgem.gov.uk/ofgem-publications/84600/assessmentofriio-ed1businessplansletter.pdf

**Timing of decision on electricity distribution networks' revenue for 2015-16**
https://www.ofgem.gov.uk/ofgem-publications/86768/ed1revenuechangedecision.pdf

**Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls**
https://www.ofgem.gov.uk/publications-and-updates/decision-our-methodology-assessing-equity-market-return-purpose-setting-riio-ed1-price-controls

**Strategy Decision for RIIO-ED1 – Overview**
https://www.ofgem.gov.uk/publications-and-updates/strategy-decision-riio-ed1-overview

# Contents

# Executive Summary

These are our final price control determinations for ten of the electricity distribution network operators (DNOs).

We concluded the price control of one group (Western Power Distribution, WPD) early, based on the high quality of its business plan and the value it provided to consumers. All settlements will apply for the eight-year price RIIO-ED1 control period from 1 April 2015 to 31 March 2023.

**What our determinations mean**

Our decision results in a reduction in allowed revenues[1] of around 4.7% on average over the RIIO-ED1 period relative to the current price control (DPCR5). This translates into an underlying reduction of approximately £12 in the typical annual household bill over RIIO-ED1 relative to the current year.[2]

The final determinations allow for significant investment. Slow-track DNOs will be able to spend around £17bn to renew, maintain and operate their networks.

We expect the DNOs to meet tough targets to improve reliability, customer service, connections and their work with vulnerable consumers.

We believe they provide the basis for all DNOs to finance their activities during the course of RIIO-ED1.

**Our decision gives DNOs the funding they need to operate and develop the networks, to meet customers' needs at value for money.**

*Expenditure allowances reflect our view of efficient costs of delivering the required outputs and services.*

Overall we have slightly increased our view of DNOs' efficient costs compared to draft determinations. Following RIIO weighting (interpolation) of company and Ofgem forecasts, we have reduced companies' allowed total expenditure by £1.3bn over RIIO-ED1 from their forecasts.

We have revised our assessment of DNOs' cost forecasts based on further review and information provided. Our analysis still shows material differences between their proposals and our assessment of efficient costs. In our comparative assessment we judge DNOs could reduce their forecast expenditures by more than £700m.

We have also updated our forecast of the movement in DNO costs relative to the RPI measure of inflation. This gives a figure £728m lower than forecasts in the DNOs' plans.

[1] before inflation.
[2] The government's December 2013 measures to reduce energy bills accelerated the effect of the RIIO-ED1 savings.

Finally, we don't believe that the DNOs have sufficiently considered the potential savings they can make to the cost of running their networks by adopting smart grid solutions. It is important that consumers receive adequate returns on their investment in innovation trials and the roll-out of smart meters. We have reviewed the new evidence provided following draft determinations. The DNOs have included over £476m smart and innovative solutions in their plans. We think they can save a further £322m.

*DNOs are incentivised to deliver comprehensive outputs.*

The DNOs have strong incentives to provide a safe, reliable network while managing their carbon footprint and broader environmental impact. They are incentivised on how well they satisfy customers and engage with stakeholders. They also have strong incentives to provide a better service for connecting customers and to play a full role in identifying and assisting vulnerable customers and the fuel poor. They are incentivised to deliver these outputs at efficient cost.

DNOs have explained in their business plans how they will accommodate uncertain levels of low carbon technologies on their networks. The package of outputs and funding for innovation trials will ensure they do this efficiently, using smart grid solutions while providing good service to new and existing customers.

*The financial package means efficient DNOs can finance their activities.*

Our Weighted Average Cost of Capital (WACC) is the same as that for draft determinations. It includes an estimate of 6% for the cost of equity. The allowance for the cost of debt will be calculated using an extending trailing average index.

**Providing certainty on 2015-16 opening base revenue allowances**

We fixed the DNOs' base revenues for 2015-16 at the amounts in our draft determinations. This gave suppliers earlier confirmation of the DNOs' 2015-16 charges. We have spread the difference between draft and final determinations over the remainder of RIIO-ED1.

The revenues for the remainder of RIIO-ED1 are not fixed. There are a number of mechanisms which mean they will change over time. They are increased to recognise economy-wide inflation, DNOs get rewards and penalties depending on their performance, and there are some uncertain costs which can only be confirmed during the price control period.

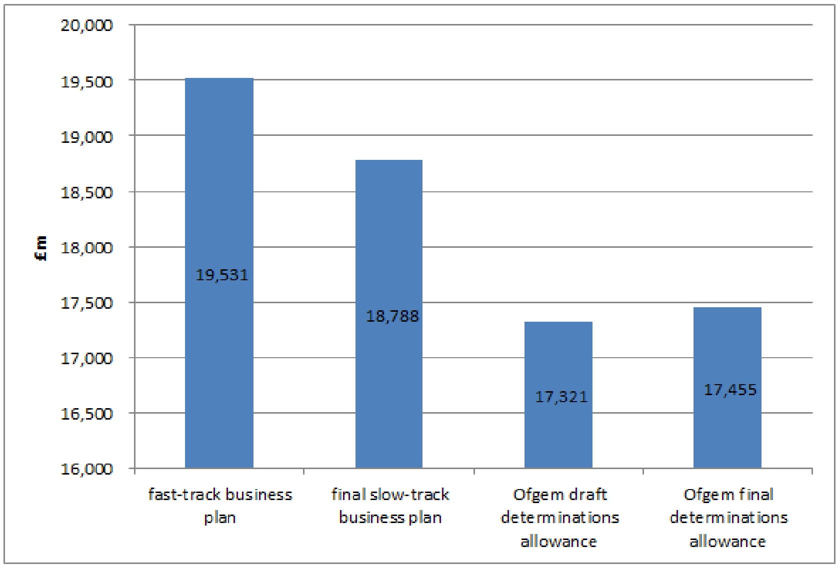
**Next steps**

We will publish a statutory consultation on the licence conditions to implement these final determinations in December 2014.

# 1. Final determinations at a glance

Our final determinations represent a £1.3bn (7%) reduction on the expenditure forecasts in the DNOs' slow-track plans. This is an 11% reduction from the fast-track plans and 1% high than our draft determinations. This is shown in Figure 1.1.

**Figure 1.1: Slow-track DNO forecast and allowed expenditures (2012-13 prices)**




This has resulted in small variations in revenues for the DNOs since draft determinations on a like-for-like basis. We have made capitalisation adjustments for two DNOs, which are explained Chapter 5. The revenue movements since draft determinations are shown in Table 1.1.

**Table 1.1: Slow-track DNO base revenues at draft and final determinations (£m, 2012-13 prices)**

| | ENWL | NPg | UKPN | SPEN | SSEPD | Total slow-track |
|---|---|---|---|---|---|---|
| draft determinations | 2,797 | 4,582 | 9,964 | 5,144 | 5,761 | 28,249 |
| final determinations *(pre capitalisation adjustments)* | 2,840 | 4,599 | 10,027 | 5,156 | 5,831 | 28,453 |
| Revenue difference | 42 | 17 | 63 | 12 | 70 | 205 |
| | | | | | | |
| Capitalisation adjustments | 52 | | | | 33 | 85 |
| Final determinations | 2,892 | 4,599 | 10,027 | 5,156 | 5,864 | 28,538 |

# 2. Introduction

**Chapter Summary**

Shows the purpose and structure of this document. We include a map of how this document links to the supplementary documents published at the same time.

## The RIIO-ED1 review

2.1. Britain's gas and electricity networks need significant expenditure over the next decade. This is so that consumers continue to receive safe, reliable network services and to meet environmental challenges. It is more important than ever that network companies can show consumers that they are getting value for money and that charges are contained.

2.2. The electricity distribution price control review (RIIO-ED1) is the first review in electricity distribution to use our new RIIO model (Revenue = Incentives + Innovation + Outputs). RIIO is designed to drive real benefits for consumers. It gives companies strong incentives to meet the challenges of delivering a sustainable energy sector at lower cost. RIIO makes sure companies prioritise sustainability and act in consumers' interests. It provides a transparent and predictable framework that rewards them for delivering on time.

2.3. In March 2013 we published our strategy decision on the key elements of the regulatory framework for RIIO-ED1. This included the outputs that we require companies to deliver, the incentive framework and financial parameters.

2.4. A key part of the RIIO model is for companies to develop a well-justified business plan. They should involve stakeholders in this development. The strategy decision provided the framework for the 14 distribution network operators (DNOs) to develop their business plans for the next electricity distribution price control (RIIO-ED1). They submitted these plans and published them on their websites on 1 July 2013.

*Fast-track*

2.5. Under RIIO, where a DNO steps up to the challenge of submitting a realistic and well-justified business plan that provides demonstrable value to consumers, we treat particularly high quality elements of a company's plan with lighter touch regulatory scrutiny. If a plan is sufficiently high quality and provides good value overall, we consider it for fast-tracking. This means we accept the business plan as submitted and conclude the company's price control review early.

2.6. We assessed the plans in the round, focusing on whether any were of a high enough standard to be accepted in their entirety. DNOs were expected to include all appropriate information and justifications within their plans.

2.7. The possibility of being fast-tracked inspired all DNOs to raise their game. However only WPD cleared our high hurdle. The other DNOs' plans showed areas of strength, but all had scope for improvement. In February we published our decision to fast-track WPD's four DNOs.

*Slow-track*

2.8. The remaining 10 DNOs submitted revised business plans in March 2014. These included improved justifications and output packages at lower cost – with a £700m reduction in forecast expenditures versus their fast-track plans. On July 28 2014 we published our draft determinations based on our assessment of these revised plans.

2.9. As at fast-track, we assessed the plans against five core criteria. These were process; outputs; resources (efficient expenditure); resources (efficient financing); uncertainty & risk. As part of our RIIO proportionate assessment, most DNOs did not change their business plans for elements we scored green at fast-track, unless we identified specific concerns. At slow-track, if a DNO does not satisfy a criterion, we make changes to its plan.

2.10. In draft determinations we scored all DNOs as green (acceptable) for process, outputs and uncertainty & risk. We scored UKPN green for resources (efficient financing), and the remaining DNOs amber. We have not changed these assessments for final determinations.

2.11. Our assessment of resources (efficient expenditure) in draft determinations was based on a comparative assessment of the DNOs' forecasts to determine our view of efficient cost using our benchmarking tools. In addition we assessed the DNOs' view of real price effects (RPEs) and smart grid benefits. These were two areas in which DNOs' costs were generally higher than our view. This meant that no DNO bettered our view of total efficient cost. We scored the DNOs based on the comparative assessment. For final determinations we have re-run all the analysis – using additional data and refinements to the models (this is explained in Chapter 4).

*WPD*

2.12. Some respondents to our draft determination claim that the differences between our fast-track and slow-track assessments mean we have over-rewarded WPD. Several see this as being discriminatory, and say WPD will have an unfair advantage at RIIO-ED2. We do not agree.

2.13. We calculate that the financial benefit to WPD of being fast-tracked is around £250m. It is worse than our slow-track efficiency benchmark for expenditures, but this is mainly volume inefficiency. WPD generally has some of the lowest unit costs. While we judge it would have been more efficient for WPD to deliver less over the RIIO-ED1 period it will not particularly profit from this additional work. It is committed to secondary deliverables that reflect these volumes. If it materially reduced its overall workload in RIIO-ED1 without justification it would be penalised.

2.14. If it had remained in the slow-track process, WPD would have had the opportunity to improve its expenditures and justifications. We would not have reduced its allowance to the efficiency benchmark above, since at slow-track we give weight to the companies' view. If WPD then spent according to its view rather than ours, customers would fund a share of the overspend.

2.15. In addition, WPD does not receive the revised cost of debt index.

2.16. We recognise that WPD still has a sizeable benefit from being fast-tracked. This is a predictable outcome of the fast-track process. We consider the benefits of fast-tracking (better initial business plans, further £700m improvement across the sector between fast- and slow-track, significantly better data for benchmarking DNOs at slow-track) are greater than the benefits available to WPD. We believe our fast-track process has unlocked substantial value for consumers that would not have been possible otherwise.

2.17. We do not agree that this gives WPD an unfair advantage for RIIO-ED2. The additional volumes we've described mean that WPD would be doing work that other DNOs should delay until RIIO-ED2. However, our cost assessment methodologies take account of historical workloads by looking at the current condition and criticality of the network. We can ensure that WPD does not benefit from this additional expenditure in our RIIO-ED2 assessment.

*Impact assessment*

2.18. We included an impact assessment (IA) in draft determinations. We did not receive any comments. We have included an updated assessment in Appendix 9.

## Stakeholders' role in RIIO

2.19. Stakeholders play a key role in RIIO. We assessed the quality of DNOs' engagement with their stakeholders, and how this was reflected in the business plans. This was not a one-off exercise. As part of the Broad Measure of Customer Service (BMCS), the DNOs are assessed annually on the effectiveness of their stakeholder engagement (see Chapter 3).

2.20. We have also ensured that all parties have had the opportunity to give their views during the RIIO-ED1 review.

2.21. We received 17 responses to our draft determinations. We considered them in making our decision. They are summarised in Appendix 1, and published on our website.[3] In general, the DNOs provided reasons why they believe our draft determinations were too tough. Non-DNO stakeholders tended to view our proposals as about right, or not tough enough.

2.22. We discussed our draft determinations at a Price Control Review Forum (PCRF). The PCRF is a broad range of stakeholder representatives who want to engage in the review without getting involved in detailed policy development.

2.23. Our RIIO-ED1 Consumer Challenge Group (CCG) also provided its views. The CCG is a small group of consumer experts which acts as a 'critical friend'. We want to ensure the price control settlement is in the best interests of existing and future consumers, and the CCG provides an external perspective. It advised us that we needed to design a package that squares financial and cost decisions with the needs of consumers.

## Future changes to allowed revenues

2.24. There are a number of mechanisms that automatically adjust the DNOs' allowed revenues during RIIO-ED1.

- Incentive mechanisms either where DNOs receive rewards for output outperformance (or penalties for underperformance) and the efficiency incentive which shares any expenditure over/under-performance with consumers.
- Base revenues are indexed by the Retail Prices Index (RPI) as the measure of economy-wide inflation.
- The cost of debt allowance is calculated each year based on an index. We have updated our forecast of the cost of debt in these final determinations. The actual index value will be included in DNOs' revenues every year via the annual iteration process.

2.25. There are also a number of elements which we will finalise after RIIO-ED1 begins, or we set independently.

- The price control settlements include uncertainty mechanisms where we recognise it is not appropriate to set allowances ex ante (see Chapter 6). We have included updated forecasts for many of these elements in the final determinations. This is in order to reduce revenue volatility when the mechanisms are applied.
- There are incentives and other adjustments relating to DPCR5 which cannot be finalised until DPCR5 has ended. This is so that we can use the reported data for the regulatory year from April 2014 to March 2015. We asked the slow-track DNOs to provide forecasts of these items in their plans, and in

[3] https://www.ofgem.gov.uk/publications-and-updates/riio-ed1-draft-determinations-consultation-slow-track-electricity-distribution-companies

some cases we have updated the forecasts based on more recent information. These numbers are indicative until we receive the final numbers in RIIO-ED1.

- The DNOs have pre-privatisation defined benefit pension schemes.[4] These have deficits which are funded through revenues. We set the funding every three years based on scheme valuations. This is explained further in Chapter 5.

## Implementing the price control

2.26. The DNOs' final determinations are implemented via conditions in their licences. The licence governs:

- the base revenue a DNO may collect from its customers
- the outputs it must deliver, and the rewards/penalties for over/under delivery
- uncertainty mechanisms.

2.27. We issued modifications to WPD's licence in May 2014 based on its fast-track final determinations. We published a draft consultation on the licence modifications for the slow-track DNOs in September. We will publish a statutory consultation in December 2014 and will issue the revised licences in February 2015.

## Monitoring the price control

2.28. We are developing our approach to monitoring DNOs' delivery under RIIO, building on the existing regulatory instructions and guidance (RIGs) and the electricity distribution Annual Report. We will consult on the RIGs in January 2014.

2.29. The DNOs have adopted our data assurance process developed for all network companies. This requires companies to demonstrate that they are managing the risk of reporting errors associated with different data elements.

## Overview of this and associated documents

2.30. In this document we describe how we reached our final determinations decisions. For each element we explain what our decision is, what our draft determination proposals were and stakeholder responses, and how we arrived at our decision.

2.31. We use the term 'fast-track assessment' to refer to the assessment process between the DNOs first submitting their business plans in July 2013 and when we published the assessment of those plans in November 2013. We use the term 'slow-track assessment' to refer to our assessment of the revised plans, between when they were submitted in March 2014, and this publication.

[4] which are closed to new members.

2.32. We use acronyms for the DNOs. These are:

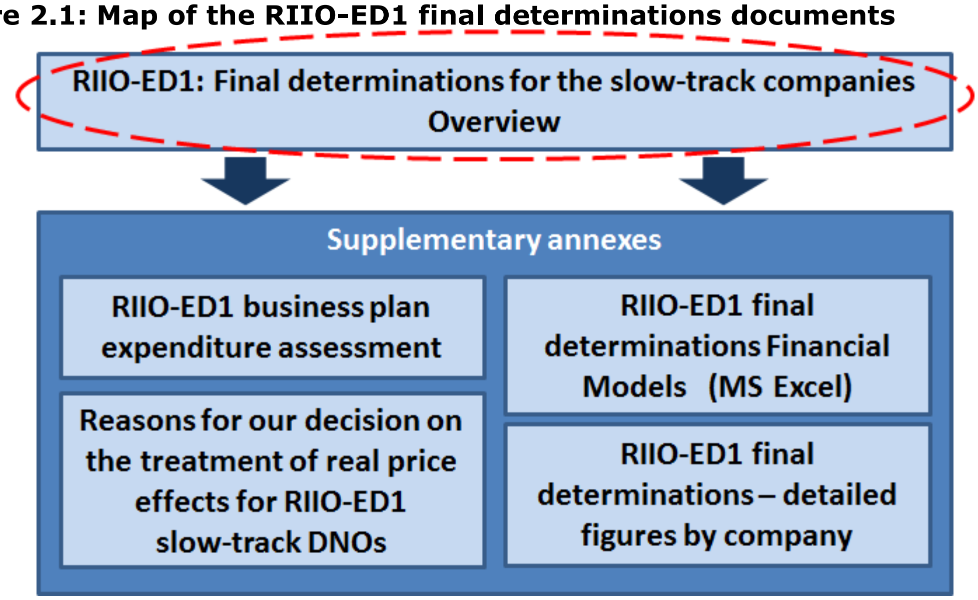
| **DNO Group** | | **DNO** | |
|---|---|---|---|
| ENWL | Electricity North West Limited | ENWL | Electricity North West Limited |
| NPg | Northern Powergrid | NPgN | Northern Powergrid: Northeast |
| | | NPgY | Northern Powergrid: Yorkshire |
| WPD | Western Power Distribution | WMID | Western Power Distribution: West Midlands |
| | | EMID | Western Power Distribution: East Midlands |
| | | SWALES | Western Power Distribution: South Wales |
| | | SWEST | Western Power Distribution: South West |
| UKPN | UK Power Networks | LPN | UK Power Networks: London Power Networks |
| | | SPN | UK Power Networks: South East Power Networks |
| | | EPN | UK Power Networks: Eastern Power Networks |
| SPEN | SPEN Energy Networks | SPD | SPEN Energy Networks: Distribution |
| | | SPMW | SPEN Energy Networks: Manweb |
| SSEPD | Scottish and Southern Energy Power Distribution | SSEH | Scottish and Southern Energy Power Distribution: Scottish Hydro Electric Power Distribution |
| | | SSES | Scottish and Southern Energy Power Distribution: Southern Electric Power Distribution |

2.33. This document is aimed at a wide range of interested stakeholders. We have also published a detailed supplementary annex on our cost assessment methodology. A second supplementary annex provides more detail on our decision on the treatment of real price effects for RIIO-ED1. These documents are more technical, and will be of interest to more specialist readers.

2.34. We provide all the data that we will include in the slow-track licences in the 'RIIO-ED1 final determinations detailed figures by company' document.

2.35. Figure 2.1 shows all the RIIO-ED1 documents we have published today.

**Figure 2.1: Map of the RIIO-ED1 final determinations documents**



# 3. Outputs

**Chapter Summary**

Explains our assessment of the outputs criterion in more detail.

3.1. Under the RIIO model, we committed to providing clear and comprehensive outputs that the network companies must deliver. These outputs, and the incentives to encourage the companies to deliver them, should ensure that the companies provide value for money for current and future consumers while playing a full role in developing a sustainable energy sector. Our six primary output categories are safety, environment, customer service, connections, social obligations, and reliability and availability.

3.2. For many of the outputs we set the level (or baseline) to be delivered, taking into account stakeholder views. However, the DNOs were able to justify alternatives. In some areas, they had to specify their own baselines (for example for the secondary deliverables, asset health and loading indices).

3.3. All of the DNOs have built on the outputs framework we described in our strategy decision. The quality of strategies and explanations for delivering these outputs varies across the DNOs. Most DNOs did not change the outputs sections of their plans significantly from those they submitted at fast-track. As at fast-track, we have considered the DNOs' historical performance in delivering the outputs as a guide to how plausible we think their future plans are.

3.4. We did not ask any questions on the outputs section of draft determinations. However we received comments on safety, environment and reliability. We summarise the comments and our responses, and update our view where appropriate.

**Safety**

3.5. The primary output for health and safety is compliance with the safety requirements set out in legislation and enforced and regulated by the Health and Safety Executive (HSE).

3.6. Secondary deliverables on asset health, criticality and composite risk include elements of safety performance. These will ensure that the DNOs do not risk their compliance with future safety requirements by decisions made in RIIO-ED1.

3.7. In their slow-track plans all DNOs commit to complying with legislative safety requirements.

3.8. One respondent had concerns over safety. While it recognised measures to improve the safety of assets, it believed this is undermined by the reduction in investment proposed in the business plans. We do not agree. Our cost benchmarking and assessment takes into account the need to plan, maintain, develop and operate the distribution networks safely. This requirement takes priority for all DNOs.

**Customer service**

3.9. The customer service outputs are designed to incentivise DNOs to think about how to best engage with their customers and understand their needs.

3.10. The Broad Measure of Customer Service (BMCS) comprises three elements: an assessment of the company's ongoing stakeholder engagement, a measure of how well the DNO resolves complaints, and a survey of customer satisfaction that incorporates the views of customers who have made a general enquiry, experienced an interruption or required a connection.

3.11. A DNO's performance in each component of the BMCS is subject to a separate financial incentive. Performance for the customer satisfaction survey and complaints elements is measured against absolute targets.

3.12. We consider that the DNOs' customer service proposals are acceptable.

**Conditions for connections**

3.13. Under the Electricity Act, DNOs have to offer a connection to any customer who wishes to connect to the network. A customer seeking connection has to pay for the cost of the connection and expects to get a good service. When customers are not connected in the timescales they need, the consequences can be considerable, both to individual customers and to society more generally.

3.14. Customers with smaller connections[5] are protected by the connection element of the BMCS and a 'time to connect' incentive. DNOs' 'time to connect' performance will be measured against a target (which increases over RIIO-ED1). This looks at the time taken from initial application to connection quotation and the time taken from quotation acceptance to connection completion.

3.15. The Incentive on Connection Engagement (ICE) will drive the DNOs to understand and satisfy the particular requirements of different types of larger connection customers.

3.16. We think the DNOs' connection proposals are acceptable.

[5] Typically at low voltages and up to no more than four properties.

**Environment**

3.17. The environmental outputs ensure DNOs play their role in achieving broader environmental objectives and reduce their own carbon footprint.

*Losses*

3.18. System losses are the largest component of a DNO's carbon footprint. They can be reduced through various actions by the DNOs.

Decision

3.19. Our assessment of DNOs' losses strategies and proposed measures has not changed from our draft determinations. In RIIO-ED1, DNOs will have a licence requirement to ensure that losses on their networks are as low as reasonably practicable, and to maintain and act in accordance with their published losses strategies. We do not approve these strategies. DNOs must satisfy themselves that they are compliant. Based on the evidence and strategies provided to us, we remain concerned whether the DNOs will be able to meet their licence requirement.

3.20. We expect all DNOs to revise their losses strategies, taking into account the questions and feedback provided during the assessment process and in our draft determination and considering best practice and each other's proposed measures. DNOs should do more work to identify potential loss reduction benefits and measures to achieve them, for example, through the use of smart metering data.

3.21. They should ensure their strategies are supported by robust, comprehensive and up-to-date cost-benefit analyses (CBAs). DNOs should demonstrate that they have evaluated all reasonably practicable losses-management measures and carried out CBAs of a full range of options. The CBAs should be clearly referenced in their strategies. The DNOs should describe their plans for reducing losses clearly enough that they can report against them annually, as required by their licence.

3.22. The DNOs were able to justify expenditure in their business plans in the context of the value of lost electricity including carbon reduction. For measures over the minimum legal requirements, costs and volumes have been allowed for proposed loss-reduction measures which were properly justified.

Responses and reasons for our decision

3.23. A non-DNO agreed with our assessment that the DNOs' losses strategies are poor. It was disappointed with the DNOs' lack of commitment to loss reduction.

3.24. Some DNOs highlighted measures in their plans which they believe have potential losses benefits. We have corrected the inconsistency in NPg's allowances for oversizing low voltage cables. We don't think the additional losses reduction measures cited in DNOs' comments were sufficiently justified and have not amended their costs or volumes for this.

3.25. One non-DNO said the licence requirement could result in DNOs doing things which could incur costs or increase system losses on the transmission network. While we agree that there is potential for actions on the distribution system to affect the transmission system, the respondent did not provide sufficient evidence to justify us changing our approach.

3.26. One non-DNO proposed that a proportion of DNOs' innovation strategies be dedicated to non-technical loss reduction. DNOs decide on their innovation priorities in consultation with their stakeholders. We encourage parties to propose ideas, which may include how they tackle losses for consumers' benefit.

*Other environmental impacts*

3.27. DNOs have to report and publish their business carbon footprint (BCF) annually. We will publish an annual league table of percentage change as a reputational incentive. There is an allowance for undergrounding overhead lines in National Parks (NP) and Areas of Outstanding Natural Beauty (AONB). DNOs will publish an annual Environmental Report[6] to address concerns about public accountability regarding broad environmental performance.

Decision

3.28. Our assessment of environmental activities remains the same as draft determinations.

3.29. We benchmarked sulphur hexafluoride ($SF_6$) mitigation costs and volumes as part of general asset replacement costs and volumes, as we were unable to separate out specific costs. We expect all DNOs to consider PFT[7] technology as an industry standard practice for leak detection from oil-filled cables.[8]

3.30. We were encouraged that all slow-track DNOs propose to spend their full allowance for the undergrounding of lines in NP and AONB. This scheme is stakeholder-led and the DNO's allowance cap is specified in their electricity distribution licences.

[6] Under standard licence condition 47 of the DNO's Electricity Distribution Licence. We recently consulted on the accompanying guidance document outlining the content this report should have. We are due to publish the final guidance document shortly. https://www.ofgem.gov.uk/publications-and-updates/consultation-draft-riio-ed1-environment-report-guidance-document-ergd
[7] Perfluorocarbons are injected into oil-filled cables. This improves the accuracy of leak detection. The Environment Agency has in place certain requirements for DNOs to mitigate any leakage of this fluid, which could contaminate local environment and groundwater sites.
[8] Otherwise known as fluid filled cables (FFC).

Responses and reasons for our decision

3.31. One non-DNO supported ENWL's and NPg's plans for undergrounding. It questioned if there is a conflict between kilometres to be undergrounded and proposed expenditure. It doesn't think DNOs should be constrained on timing. The cap for undergrounding is on the total RIIO-ED1 allowance. There is no restriction on timing or kilometres. DNOs should prioritise, assess and action schemes in consultation with stakeholders.

3.32. One DNO said we didn't take full account of its qualitative evidence on environmental improvements in our assessment. We have reviewed its evidence and our view has not changed.

3.33. We have made some changes to our cost assessment methodology, as described in Chapter 4. This results in an increase in allowed costs for environmental measures overall for the majority of DNOs. We expect DNOs to demonstrate environmental measures and benefits commensurate with these costs through their annual reporting.

**Reliability**

3.34. Customers want a reliable supply. The interruptions incentive scheme (IIS) drives DNO performance on the number of customer minutes lost and the number of customer interruptions against DNO-specific targets.[9]

3.35. There are also secondary deliverables for reliability which track the condition of the network to ensure the DNOs will deliver a reliable service in the future. These are: the asset health index, criticality index, asset risk metrics, the load index and secondary deliverables for High Value Projects (HVPs). The health index is a DNO-specific composite measure of age, asset condition and fault history among other things. Criticality measures the impact of asset failures. The asset risk metric measures combine both probability of failure with the consequence of failure to measure the level of asset risk on DNOs' networks. The load index is a DNO-specific measure of loading on their primary network. The secondary deliverables for HVP projects cover a range of different types of work. For some HVPs, they are aligned with the asset health, criticality and risk metrics. For others they are based on the load indices or other delivery based metrics.

3.36. All DNOs other than SSEH have a 'use it or lose it' allowance to address customers deemed to be worst served in terms of reliability. SSEH has several schemes relating to worst served customer performance funded as part of its ex-ante allowance. It does not therefore have the wider worst served customer mechanism.

3.37. Statutory regulations set out guaranteed standards of performance on reliability, under which a customer is entitled to claim a fixed payment from the DNO

[9] There are separate targets for planned and unplanned interruptions.

if their supply has been interrupted for a certain period.[10] We are reducing this period to 12 hours (from 18 hours currently)[11] and are removing exemptions so that all customers receive payments for being off supply irrespective of their location. We are doubling the payments DNOs make to customers following a prolonged period without supply caused by severe weather. These will be £70 after the initial period of interruption[12] followed by an additional payment of £70 for each successive period of 12 hours without supply. The cap per customer has been increased and is now £700. We will consult shortly on a new statutory instrument to introduce these arrangements.

3.38. In our strategy decision we recognised the potential impact of flooding on supply. The UK's climate is changing and this is likely to affect average conditions as well as the frequency and severity of extreme weather and flooding. Without good risk management this could harm the operation of DNO networks. We will monitor and publish DNO performance against secondary deliverables for network resilience.[13]

3.39. We described our methodology for setting the reliability targets in the strategy decision. SSEH and LPN have proposed tighter targets for their networks due to specific projects which will improve reliability. We have accepted them.

3.40. One respondent thought the targets will be too easily achieved. Its view is that DNOs have gained significantly from this over DPCR5. It proposed targets based on rolling averages to include historical improvements in performance. Our approach to benchmarking reliability performance includes historical performance and therefore sets challenging targets for RIIO-ED1. We have included improvement factors in the RIIO-ED1 targets to ensure the DNOs continue to be challenged by the IIS. We have also reintroduced the cap on upside performance to protect customers from DNOs making excessive returns.

3.41. We have reconciled the asset health, criticality and risk deliverables for RIIO-ED1 with our final determinations cost allowances. DNOs report health and criticality differently at present. More work is required to develop a common approach and we are including a timetable for this in the DNOs' licence. The DNOs have started this work and are making good progress. We are also designing the RIGs to ensure DNOs report asset loading using common definitions of load indices, according to our strategy decision. We will be carrying out further work with the DNOs on the load indices to take into account interactions with smart grid savings and the load-related re-opener.

3.42. We consider that 2 DNO groups have significant further work to do to improve the robustness of their condition-based risk management and the collection and

[10] The guaranteed standard penalties are paid by the DNOs. The increase in penalties arising from this change in standard will not affect customer charges.
[11] For interruptions that are classed as normal weather.
[12] The time period depends on the scale of the severe weather event, which is defined according to the number of related faults at high voltage and above.
[13] Flooding, Black Start and overhead lines.

reporting of information on asset health, criticality and risk metrics. We are switching on part F of standard condition 5D of the electricity distribution licence for SPD, SPMW, SSEH and SSES.

3.43. We will take into account DNOs' performance against outputs and secondary deliverables in our assessment for RIIO-ED2. For example, with respect to load indices, if DNOs fail to deliver the additional capacity they were funded for at RIIO-ED1, our starting point for RIIO-ED2 funding will be from the capacity they should have had in place.

**Social**

3.44. DNOs have an important role to play in helping consumers in vulnerable situations. Our Consumer Vulnerability Strategy[14] highlights the need for DNOs to maximise their role in this respect.

3.45. DNOs were required to include a strategy for realising this objective in their business plans. The Stakeholder Engagement element of the BMCS will ensure that the DNOs have an incentive to deliver these strategies.

3.46. At draft determinations we viewed all DNOs' social proposals as acceptable. We maintain this view.

[14] https://www.ofgem.gov.uk/ofgem-publications/75550/consumer-vulnerability-strategy.pdf

# 4. Assessment of efficient expenditure

**Chapter Summary**

How we have assessed the DNOs' expenditure forecasts and set the final determinations allowances. This includes the information quality incentive.

4.1. Our cost assessment is made up of four elements:

- comparative cost assessment
- smart grids/innovation benefits
- real price effects (RPEs)
- information quality incentive (IQI).

4.2. We explain our overall decision across all four elements. We then explain each of the elements in turn.

**Decision and results**

4.3. Our final determinations allowances for totex[15] are intended to be reasonable allowances for the DNOs in RIIO-ED1. We use a toolbox approach to assess efficient costs recognising that there are many ways of assessing what is appropriate. Similarly, our use of upper quartile benchmarking (rather than frontier) and IQI interpolation (where we use 75% our view and 25% DNO's view) recognise we do not have perfect information. We believe our final determinations are appropriate. We do not intend to make any further changes.

4.4. Table 4.1 below summarises our cost assessment. The figures in these tables are before IQI interpolation.[16]

[15] Total expenditure
[16] The DNO's RIIO-ED1 allowances are set after IQI interpolation. This is where we use 75% of our benchmark view and 25% of the DNO's forecast.

**Table 4.1: Results of our cost assessment by DNO (2012-13 prices)**

| DNO | Slow-track final submitted totex[+] | Adjustment result of cost assessment only | | Adjustment result of smart grid benefits | | Adjustment result of RPEs | | Our view of efficient costs | |
|---|---|---|---|---|---|---|---|---|---|
| | £m | £m | % | £m | % | £m | % | £m | % |
| ENWL | 1,876 | 17 | 0.9% | -8 | -0.4% | -77 | -4.1% | 1,808 | -3.6% |
| NPgN | 1,368 | -57 | -4.2% | -21 | -1.5% | -60 | -4.4% | 1,230 | -10.1% |
| NPgY | 1,805 | -46 | -2.5% | -21 | -1.2% | -80 | -4.5% | 1,657 | -8.2% |
| LPN | 1,970 | -164 | -8.3% | -29 | -1.5% | -73 | -3.7% | 1,704 | -13.5% |
| SPN | 1,872 | -105 | -5.6% | -22 | -1.2% | -71 | -3.8% | 1,673 | -10.6% |
| EPN | 2,775 | -160 | -5.7% | -53 | -1.9% | -106 | -3.8% | 2,457 | -11.5% |
| SPD | 1,563 | 60 | 3.9% | -55 | -3.5% | -64 | -4.1% | 1,505 | -3.7% |
| SPMW | 1,924 | -200 | -10.4% | -60 | -3.1% | -83 | -4.3% | 1,581 | -17.8% |
| SSEH | 1,210 | -68 | -5.6% | -14 | -1.1% | -37 | -3.1% | 1,092 | -9.8% |
| SSES | 2,425 | -6 | -0.2% | -39 | -1.6% | -76 | -3.1% | 2,304 | -5.0% |
| **Total** | **18,788** | **-728** | **-3.9%** | **-322** | **-1.7%** | **-728** | **-3.9%** | **17,011** | **-9.5%** |

[+] We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.

4.5. Since draft determinations a number of DNOs have identified errors in their submissions or have revised their forecasts for specific cost areas. These corrections and revisions increase DNOs' submitted forecast costs by £29m from draft determinations.

4.6. Table 4.2 below compares our view of efficient expenditure and our final expenditure allowances at final determinations (shown as fd in the table) with draft determinations (dd) and DPCR5.

**Table 4.2: Final expenditure allowances by DNO (2012-13 prices)**

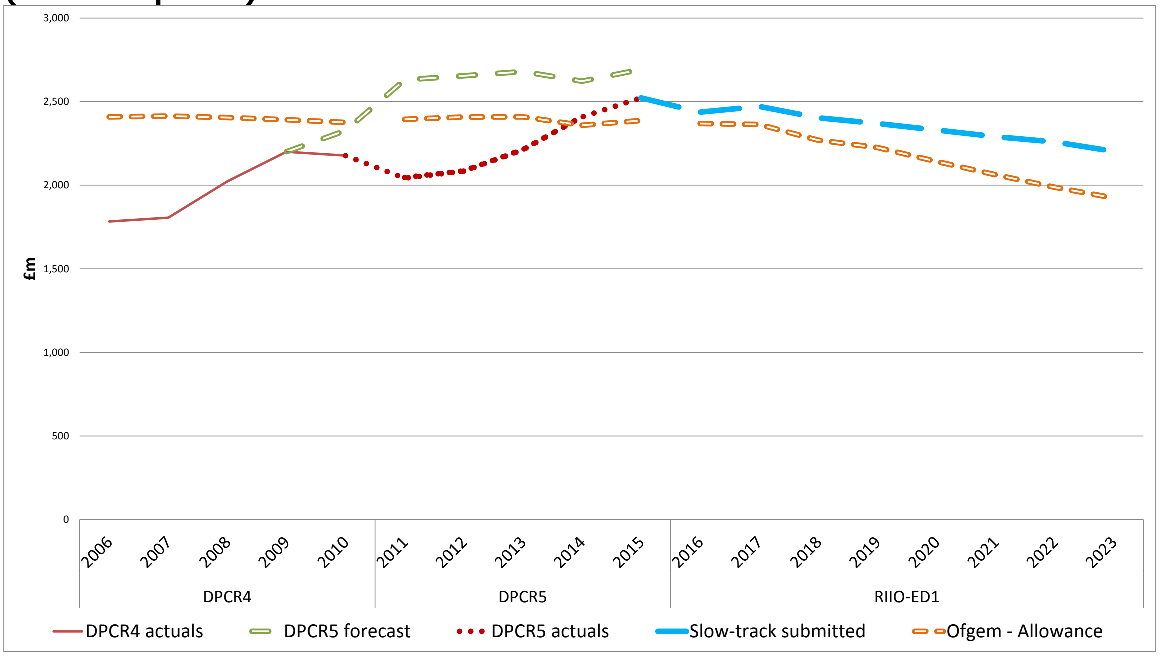
| DNO | DPCR5 totex** | Fast-track submitted totex | Slow-track final submitted totex+ | Slow-track dd allowance* | Ofgem's view slow-track fd | Slow-track fd allowance* | Difference between st submitted and fd allowance* | Difference between dd and fd allowances* |
|---|---|---|---|---|---|---|---|---|
| | £m | £m | £m | £m | £m | £m | % | % |
| ENWL | 1,949 | 1,900 | 1,876 | 1,794 | 1,808 | 1,825 | -2.7% | 1.7% |
| NPgN | 1,307 | 1,365 | 1,368 | 1,243 | 1,230 | 1,265 | -7.6% | 1.8% |
| NPgY | 1,771 | 1,859 | 1,805 | 1,685 | 1,657 | 1,694 | -6.1% | 0.5% |
| LPN | 1,762 | 1,968 | 1,970 | 1,749 | 1,704 | 1,771 | -10.1% | 1.3% |
| SPN | 1,827 | 1,897 | 1,872 | 1,710 | 1,673 | 1,722 | -8.0% | 0.7% |
| EPN | 2,753 | 2,861 | 2,775 | 2,537 | 2,457 | 2,536 | -8.6% | 0.0% |
| SPD | 1,581 | 1,740 | 1,563 | 1,519 | 1,505 | 1,519 | -2.8% | 0.0% |
| SPMW | 1,908 | 2,220 | 1,924 | 1,687 | 1,581 | 1,667 | -13.4% | -1.2% |
| SSEH | 998 | 1,230 | 1,210 | 1,097 | 1,092 | 1,121 | -7.4% | 2.2% |
| SSES | 2,264 | 2,490 | 2,425 | 2,301 | 2,304 | 2,334 | -3.7% | 1.4% |
| **Total** | **18,120** | **19,531** | **18,788** | **17,321** | **17,011** | **17,455** | **-7.1%** | **0.8%** |

+ We have excluded DNOs' submitted costs of Network Rail's electrification programme and of remediating link boxes that will be covered by re-openers.
* Allowances are after IQI interpolation ie 75% our view 25% DNO view.
** We have converted DPCR5 expenditure into an eight year total by multiplying the annual average (calculated from four years of actual data plus one year of forecast) by eight.

4.7. Figure 4.1 below shows the price control allowances against DNOs' actual and forecast expenditure over DPCR4 and DPCR5, and RIIO-ED1 forecasts.[17]

[17] We have used the DPCR5 and RIIO-ED1 post-interpolation allowances excluding IQI additional income. The DPCR4 allowance includes the sliding scale capex allowance. There are other differences between price control allowances, including activities treated as uncertain and those excluded from the price control. However, the differences between the allowances and actuals in each period reflect the magnitude of the difference.

**Figure 4.1: Slow-track DNOs - totex forecasts, allowances and actuals (2012-13 prices)**




4.8. DNOs' actual DPCR4 expenditure was well below our allowances. While DNOs' actual expenditure towards the end of DPCR5 is anticipated to be slightly above our allowances, over the whole period their actual expenditure is below. It is significantly below DNOs' DPCR5 forecasts. The profile for our allowances for the RIIO-ED1 period brings the DNOs' allowances towards the end of RIIO-ED1 back in line with their average DPCR4 actual expenditure (in real terms). We view this as reasonable as in DPCR5 the DNOs had high levels of network investment to replace assets installed during the investment peak in the 1950s/60s.

## Comparative cost assessment

4.9. We use a toolkit approach to assess the DNOs' expenditures. This includes quantitative and qualitative methods. It involves both comparative analysis and company-specific assessment. We use three models – a top-down totex model with high level cost drivers, a bottom-up totex model using drivers from our disaggregated analysis and a disaggregated activity-level model. We review DNO narratives and supporting evidence, including historical costs and performance data and DNO forecasts.

4.10. Our two totex models both use regressions. In the top-down totex model we use regression analysis to determine efficient costs. We use a composite scale driver (CSV) that is a combination of the modern equivalent asset value (MEAV) and customer numbers. We use statistical techniques to derive the weights to apply to each element. Our second model aggregates cost drivers used in our activity-level analysis into a single composite driver.

4.11. Our disaggregated, activity-level benchmarking incorporates a mixture of techniques that are appropriate to the activity in question. This includes regression analysis, age-based modelling, ratio analysis, trend analysis and technical assessment by our consultants.

4.12. We benchmark the efficient level of totex for each DNO using the upper quartile (UQ) of the combined outputs from the three models. This addresses the risk that the combination of three separate UQ benchmarks might result in a benchmark that is tougher than any of the DNO forecasts. We use UQ rather than the frontier to allow for other factors that may influence the DNOs' costs. The UQ level of efficiency (lower quartile level of costs) is the $25^{th}$ percentile in the distribution of efficiency scores.

**Decision and results**

4.13. We have used the same approach as we used for comparative cost assessment in draft determinations.

4.14. We have refined the data and models. Some DNOs provided revised forecasts in the supplementary question process. We, and the DNOs, also identified errors in the draft determinations modelling.

4.15. We have made a number of adjustments to take account of these issues. We describe the adjustments in more detail in our 'Business plan expenditure assessment' supplementary annex. A summary of the key adjustments are:

- We changed MEAV cost drivers (across all the models) to ensure that the costs we are assessing and the associated cost drivers are on a like-for-like basis. An example of this is where we have normalised the costs associated with certain assets in our analysis. Because they are atypical we have also removed them from MEAV.
- We excluded NPg's proposed costs for Network Rail's electrification programme from our assessment. These costs will be covered under an uncertainty mechanism.
- We took UKPN's representations for strategic and fault response investment in London into account. Strategic investment is investment made in network assets in anticipation that customers will request to use them in the future.
- We have considered UKPN's proposals to mitigate the risk of exploding link boxes. We have included a short-term allowance which reflects the importance of this issue, but also the limited data available. We discuss this in more detail in Chapter 6.

*Totex benchmarking*

4.16. In both models, as at draft determinations, we use 13 years of data (five years of DPCR5 and eight years of RIIO-ED1). We consider this better takes account of the scope for efficiency savings and likely pattern of costs during the RIIO-ED1 period which are reflected in the DNO data. Using 13 years' data is also consistent with our disaggregated activity-level benchmarking where we have made extensive use of both historical and forecast data.

4.17. We think it is right to exclude some costs from the totex benchmarking. This is where costs are not explained by the cost drivers that are being used or where there is a substantial change in the nature of the activity between the historical period we are using to estimate the cost models and RIIO-ED1. Following responses to draft determinations, we have reduced the number of excluded activities. We now think the cost drivers explain some of the activities that we previously excluded. The shorter list of excluded activities is in the 'Business plan expenditure assessment' supplementary annex.

*Disaggregated activity-level analysis*

4.18. We reviewed both our volume and unit cost assessments. As part of fast-track and draft determinations, we reviewed a large sample of scheme papers, health and criticality information, CBAs and narrative justification to consider whether higher volumes and/or unit costs were justified. We have since reviewed new evidence from the DNOs and have adjusted our modelled results where appropriate.

4.19. We have refined parts of our disaggregated activity-level analysis to take account of DNO comments on our draft determinations. We describe these refinements in more detail in our 'Business plan expenditure assessment' supplementary annex. Some of the changes are:

- Removing some of the ratchets. Ratchets constrain our modelled costs to the lower of our view and the company forecasts.
- Updating our approach to severe weather 1-20 to better reflect actual expenditure and the probability of a severe weather 1-20 event.
- Taking account of DECC's reclassification of a number of critical national infrastructure sites in August 2014.

*Combining the models*

4.20. When combining the three models we have maintained our draft determinations weighting of 25% for each of the totex models and 50% for our disaggregated modelling. We have applied the RPE and smart grids adjustments after calculating the UQ.

### Responses

4.21. Responses on our two totex models raised issues on our corrections to drivers, the number of exclusions we made, and our use of regressions. One DNO questioned whether our totex models are appropriate and argued for a different approach. One DNO felt that the models did not deal with differences in scope or volume of works arising from legitimate differences in investment cycles between DNOs. It argued that this led to totex reductions not sufficiently supported by evidence or robust modelling.

4.22. A number of DNOs questioned the size and scope of the adjustment we made for SPMW's network.

4.23. Two broadly agreed with our approach of excluding costs that are only incurred by some DNOs. One of these suggested that the costs of complying with the Electricity Safety Quality and Continuity Regulations should be excluded because changes to health and safety legislation affect some networks more than others. Another DNO was concerned how consistently we excluded costs across DNOs. It argued that we did not distinguish between costs being incurred by a small number of DNOs and costs incurred where DNOs have different approaches to delivery of the output. It proposed that only the former should be excluded.

4.24. A number of DNOs argued against the use of ratchets in the disaggregated model. They considered that it did not reward DNOs for being efficient in some areas.

*Combining the models*

4.25. Two DNOs disagreed with our change in weighting from the 12.5%, 12.5%, 75% we used at fast-track. One DNO suggested that we should place more weight on the totex models to avoid giving undue weight to specific points of detail and anomalies arising from boundary issues. Another suggested only using the totex models as a cross check for the disaggregated modelling.

### Reasons for our decision

4.26. We use a toolbox approach recognising that there is no definitive answer for assessing comparative efficiency. We expect the models to give different results. The different approaches each have their advantages and disadvantages. The advantage of totex models is that they internalise opex and capex trade-offs, are relatively immune to cost categorisation issues. They give an aggregate view of efficiency. The disaggregated model uses activity drivers that more closely match the costs being considered.

4.27. The concerns regarding investment cycles have been raised previously in the development of RIIO-ED1. Our consultants found that investment cycles across the industry were not significantly misaligned. We use data from the full 13-year period and DPCR5 was considered a peak for asset replacement. We think this provides a good approach for estimating costs for RIIO-ED1.

4.28. The disaggregated model shows SPMW as more efficient than the totex models indicate. We make a significant regional adjustment to SMPW for its interconnected network. SPMW provided substantial evidence supporting this adjustment which we reviewed with support from our engineering consultants. Without this adjustment the range between the totex models and disaggregated would have been even greater for SPMW. We continue to accept the majority of SPMW's case. We have corrected some errors in the application of this adjustment for final determinations.

4.29. We have excluded fewer activities in our final determination totex models from draft determinations. We reviewed the reasons for excluding each activity and concluded that the cost drivers we were using were sufficient to explain these costs. Using a 13-year period in the model means that timing issues and atypical costs are unlikely to distort the modelling. Almost all DNOs' report some atypical expenditure which is likely to even out across 13 years. The magnitude of the exclusions was also very high at draft determinations and we were concerned that this was, in part, due to DNOs' allocation approaches. This may have distorted the results of the modelling.

4.30. Following DNO representations, we concluded that we should remove some of the ratchets.

*Combining the models*

4.31. We consider the model weightings are appropriate given the better data quality since fast-track and the advantages and disadvantages of the models. The DNOs' proposals for different weights aligned with the models that favoured them.

4.32. Our model for comparative benchmarking, including the use of UQ, is well established and used by a variety of regulators including Ofwat in PR14. It does mean that a change in one company's costs can impact our assessment of the efficiency of some or all of the others. The changes we have made since draft determinations have improved several DNOs' efficiency scores. But this in turn has reduced the UQ, which makes it more challenging.

4.33. Using the UQ to benchmark the efficient level of totex works well for areas of costs where there are differences in efficiency across companies and forecasts reveal information about comparative efficiency across the DNOs. As we explained in draft determinations, it does not cater for instances where we consider all the DNOs to be above our benchmark. This is the case for RPEs and smart grids.

4.34. The figures below show the spread of efficiency scores (the difference between DNOs' submitted totex and our view) from the different models and the combined results. These do not include smart grid savings or RPEs.

4.35. The results for some groups' DNOs are quite different. The spreads reflect differences such as overhead cost allocations and DNO group forecasts.

**Figure 4.2: Difference between DNOs' submitted view and our view**

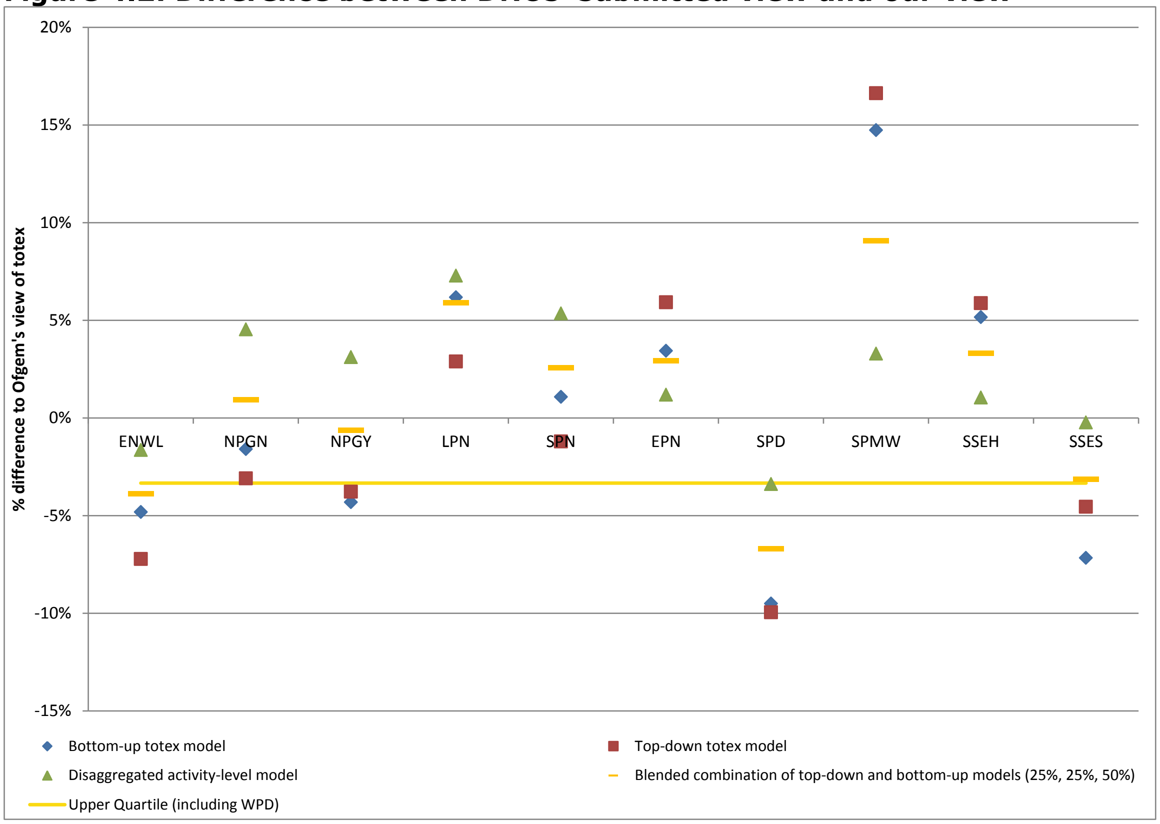
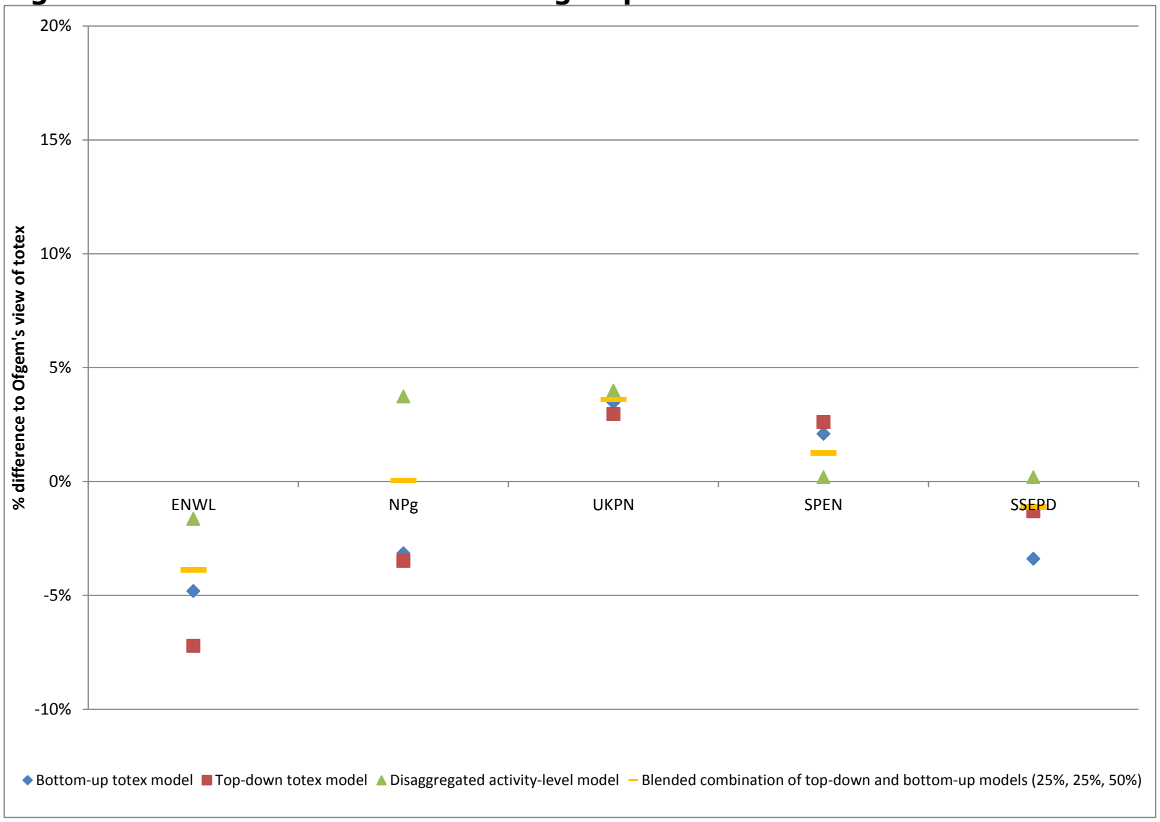


**Figure 4.3: Difference between DNO groups' submitted view and our view**




## Real price effects and ongoing efficiency

4.36. DNOs' allowances are indexed by RPI as part of the price control framework. We expect some of the costs faced by DNOs during RIIO-ED1 to change over the period at a different rate than the RPI measure of economy-wide inflation. These differences in cost changes are termed RPEs. Our cost allowances for DNOs include the forecast impact of RPEs.

4.37. Even the most efficient DNO should make productivity improvements over the price control period, such as by employing new technologies. These improvements are captured by the ongoing efficiency assumption which represents the potential reduction in input volumes that can be achieved while delivering the same outputs.

### Decision

4.38. We have decided to retain our existing approach to RPEs and include the expected impact of RPEs as an ex ante cost allowance for each DNO.[18]

[18] Further details on how we reached this decision are in the 'RPE methodology decision' supplementary annex.

4.39. We have retained our draft determinations methodology for calculating the RPE allowance, but updated certain input assumptions.

4.40. We derived an RPE assumption for each year from 2013-14 to 2022-23. The assumption is derived for different inputs and these are weighted together using an average of the weights submitted by the slow-track DNOs. The final determinations RPE assumption is in Table 4.3. We apply the same RPE assumption to all slow-track DNOs.

**Table 4.3: RPE assumption**

| | 2013-14 | 2014-15 | 2015-16 | 2016-17 to 2022-23 |
|---|---|---|---|---|
| **Totex** | - | -1.4% | -0.3% | 0.6% |

4.41. To get the monetary impact of RPEs, we multiplied each DNO's efficient cost allowance from 2015-16 onwards by the cumulative RPE assumption.

4.42. An ongoing efficiency assumption was included by all DNOs in the costs submitted in their business plans. We have not adjusted these assumptions because we considered them to be reasonable as they were in line with independent information we referenced. So, costs savings of between 0.8 and 1.1% per year are included in the cost allowances.

4.43. In summary, our efficient cost allowances are reduced due the inclusion of an RPE assumption and an ongoing efficiency assumption. The RPE assumption results in a positive addition to costs of £45m[19] (in total over eight years and all slow-track DNOs), but this is more than offset by productivity improvements.[20]

4.44. Our final determinations RPE assumption is £728m less than the slow-track DNOs requested in their business plans.

**Responses**

4.45. All slow-track DNOs considered that our draft determinations on RPEs were inadequate and wouldn't protect them against the risk of their costs increasing above economy-wide inflation. On the other hand, a supplier welcomed the cost reductions we proposed. Although it considered that introducing indexation would provide a better outcome for consumers.

4.46. Slow-track DNOs were particularly concerned with the labour RPE assumption we proposed. They considered that the assumption applied from 2012-13 to 2015-16 wouldn't adequately reflect the cost pressures they would face over this period because:

[19] before IQI interpolation.
[20] This is prior to smart savings.

- their historical wage costs have not followed the indices we used to set the assumption
- we applied an economy-wide wage growth forecast which did not reflect the fact that they are private sector organisations and have a more specialist labour force than the average private company
- in recent years, the data we referenced was skewed due to those not in continuous employment receiving lower wage growth than those in continuous employment and that this didn't represent their labour force.

4.47. The slow-track DNOs proposed an alternative way of setting the RPE assumption using a modelling technique known as ARIMA. In their opinion it would better reflect the expected return to the long-term mean growth rate from the current below-trend position of most cost indices. They also referenced differences between our approach and that taken by the Competition Commission (CC) in its determination for Northern Ireland Electricity (NIE). In their view, the CC approach would result in higher cost allowances. Some DNOs were also concerned that we had materially changed our approach to forecasting the impact of RPEs from that used at previous RIIO price control reviews.

4.48. In draft determinations we made an adjustment to the RPE assumption to account for the step change in RPI in 2010. The slow-track DNOs argued that either no adjustment should be made or it should be 0.15% per year rather than 0.4% per year as we proposed.

4.49. Some respondents highlighted the relationship between ongoing efficiency and RPEs. They stated that a negative net impact of the two was inappropriate. Some felt that assessing ongoing efficiency separately from RPEs fails to recognise that higher RPEs drives higher productivity. One DNO suggested that the RPI adjustment applied to RPEs should apply in an equal and opposite direction to the ongoing efficiency assumption.

4.50. A number of DNOs also raised concerns that including both smart grids savings and an ongoing efficiency assumption would result in a double count of the savings they could achieve. We discuss this point further in the smart grids section below.

**Reasons for our decision**

4.51. We have made some changes to the RPE assumption both in response to comments raised and to reflect more recent data.

4.52. We have not changed the data we used to derive our labour RPE assumption. The RPE assumption is not intended to match the DNOs' actual costs. Rather it is intended to reflect the external pressures on costs, relative to economy-wide inflation, that are outside of their control. We therefore don't think it's appropriate to use DNOs' own pay deals because these will have been influenced by DNO decisions.

4.53. We have included an addition of 0.15% to the labour RPE forecast applied in 2015-16 to reflect the fact that the forecast is for the whole economy whereas DNOs are private sector companies. We have not included an additional uplift to account for the specialist nature of some of their employees because there is no clear evidence that the premium will exist in 2015-16.

4.54. We recognise the benefits that ARIMA modelling could bring. However it also requires a level of subjectivity in the choice of assumptions you put into it. For this reason we don't think it would be suitable for us to change to using this approach at this stage in the price control review. Our approach is different to the CC's for NIE. We note that the CC has used different approaches for different reviews. It is not possible to say what the CC's approach for NIE would translate to for the DNOs, as multiple assumptions are required. We consider that the approach we've used is well justified and creates the right balance of risk between DNOs and consumers.

4.55. We still consider that accounting for the step-change in RPI is necessary and that the proposed magnitude is appropriate. Principally, the adjustment is needed because otherwise we would over-compensate DNOs for the impact of inflation in the cost of goods and services they purchase. The value of the adjustment relates to our estimate of the structural change in RPI inflation relative to real-world prices. We describe this in Appendix 8.

4.56. We have updated all data used to construct the RPE assumption since draft determinations. This means that the assumption for 2014-15 is now based on five to seven month's actual data that has since become available rather than applying a forecast or reverting to the long term trend. We have also decided to not apply an RPE assumption in 2013-14. We are using actual data for 2013-14 in our cost benchmarking and therefore consider that this is the most appropriate year from which to apply an RPE assumption.

4.57. Further detail on our reasons for making these changes is Chapter 12 of our 'Business plan expenditure assessment' supplementary annex.

4.58. We do not agree that higher productivity improvements can only be achieved by providing cost allowances that potentially over-compensate DNOs for the input price inflation they will face. The RPE and ongoing efficiency assumptions reflect our view of what an efficient DNO can achieve. We also don't agree that an adjustment should be made to the ongoing efficiency assumption to account for the RPI step-change. The information we have used to assess what an efficient DNO's productivity improvements could be over RIIO-ED1 is independent of RPI.

## Smart grids, smart meters and innovation savings

### Decision

4.59. We have reduced DNOs' allowances by £322m[21] to reflect additional cost savings DNOs should be able to achieve from using smart grid solutions and wider network innovation in RIIO-ED1. We have accepted more solutions as 'smart' or innovative. This has increased the savings included in the business plans to £476m. Therefore, at minimum, a total saving of £798m will be delivered to customers by slow-track DNOs. The DNOs are incentivised to find additional savings which they share with customers through the efficiency incentive.

### Draft determinations

4.60. In draft determinations we recognised £296m of embedded smart grid or wider network innovation benefits within the DNOs' business plans. We consulted on an additional cut to DNO allowances of 2.2% of totex for slow-track companies. This equated to £396m. It comprised £197m additional savings in reinforcement (including the savings achievable through the use of smart grid solutions) and £199m in 'Other' areas.

4.61. We used evidence from the DNOs' business plans and their Transform models[22] to determine a forecast of the potential smart savings achievable in reinforcement. We set a benchmark of 25% savings compared to a baseline of 'conventional' expenditure. The savings in 'Other' areas were based on extrapolating the savings achieved by the best performing DNO in areas other than reinforcement (ENWL). These savings were in ENWL's fault repair costs.

4.62. We added the relevant benefits from DECC's smart metering impact assessment to reflect potential network savings from smart metering in areas other than reinforcement. We recognised the potential for overlap between ENWL's benefits and the savings achievable from smart metering. We therefore scaled back the savings in other areas to £199m which amounted to around half of the embedded benefits in reinforcement. The total cut for both reinforcement and 'Other' was applied at a totex level for each DNO.

### Responses

4.63. Two non-DNOs supported our assessment of smart grid savings. One supported our approach and thought the evidence presented was the most robust available. It disagreed with the cut being applied pre-interpolation (where it is

[21] All numbers are before IQI interpolation.
[22] The Transform model was developed by DNOs and other stakeholders under the Smart Grid Forum (SGF). More information is on the SGF web page: https://www.ofgem.gov.uk/electricity/distribution-networks/forums-seminars-and-working-groups/decc-and-ofgem-smart-grid-forum

reduced by 25%) and said we should cut DNO allowances by a further 1% on the basis of additional savings which could be achieved in RIIO-ED1.

4.64. DNO responses can be grouped into four broad areas.

4.65. All DNOs commented that the 25% savings in reinforcement were based on inappropriate use of the Transform model. They were concerned that the Transform model was only designed to look at savings for LV-33kV reinforcement triggered by low carbon technologies, not all reinforcement. Therefore using the results of the model and applying a 25% cut to all reinforcement, including reinforcement driven by fault level issues and at 132kV, was not appropriate.

4.66. All DNOs questioned the savings outlined in DECC's smart metering impact assessment, particularly the savings on fault fixing costs. They commented that DECC's £89.5m of savings for fault fixing was far greater than the ENA had outlined in its 2013 report. DNOs and the ENA also commented that there remained double counting issues between smart grid benefits and smart metering benefits.

4.67. Most DNOs questioned why savings they had identified were not recognised when we assessed the savings embedded in their plans. In many cases, DNOs provided new evidence of why individual activities were smart or innovative.

4.68. Two DNOs commented that the allocation of savings at a totex level did not reflect the opportunity DNOs had to make savings in individual cost categories. They said it penalised those DNOs with a reinforcement allowance which made up a smaller proportion of totex.

4.69. A number of DNOs also raised concerns that including both smart grid savings and an ongoing efficiency assumption would double count the savings they could achieve.

**Reasons for our decision**

4.70. We continue to consider that there are substantial additional savings which DNOs can achieve through smart grids, smart metering and innovation in RIIO-ED1. We have not received evidence to convince us that DNOs have embedded sufficient savings in their business plans. By making an adjustment to the DNOs' allowances, we are ensuring consumers receive a fair return on their investments in innovation projects. We have made amendments to our methodology, where appropriate, in light of responses to the draft determinations.

4.71. Based on additional evidence provided by DNOs since draft determinations, we recognise an additional £180m of savings from the use of smart solutions in DNOs' plans. DNOs are forecasting savings in a range of activities including network reinforcement, asset replacement, and managing faults. For us to accept a solution as smart it had to either have been developed using innovation funding during

DPCR5 or be demonstrably smarter or more innovative than what other DNOs do as business as usual.

4.72. We benchmarked these savings, using only information provided by the DNOs. Reflecting on responses, we do not add a further stretch for smart metering to avoid the risk of double counting. We included the DNOs' forecast smart metering savings in the benchmarking together with smart grid savings. We continue to expect the DNOs to deliver all the benefits identified in DECC's impact assessment for the smart metering programme during RIIO-ED1.

4.73. Given the level of investment consumers have made in innovation projects and the smart metering programme, we would expect savings from these to be on top of historical levels of ongoing efficiency. We have no evidence that ongoing efficiency forecasts for RIIO-ED1 are significantly above those for previous price controls where these factors did not apply. DNOs identified smart grid savings and ongoing efficiency separately in their plans. The adjustment for smart grids and other innovation represents, on average, an additional frontier shift of 0.2% per year for slow track DNOs. The total smart savings (embedded and additional) are 0.6% per year, compared to the DNOs' ongoing efficiency assumptions of between 0.8 and 1.1% per year.

*Reinforcement*

4.74. Recognising the different opportunities for savings in different types of reinforcement, we disaggregated reinforcement into three areas: LV-EHV general reinforcement, 132kV general reinforcement and fault level reinforcement.

4.75. We set an UQ benchmark where possible to avoid cherry-picking and to acknowledge any residual potential risk of double counting with the cost assessment benchmarking. In LV-EHV general reinforcement we have enough data to calculate a robust UQ. In LV-EHV fault level reinforcement we do not, as only a small number of DNOs considered the potential for savings. In this case we use 75% of the best performing DNO as a proxy for an UQ. We include 132kV fault level reinforcement in the assessment as one DNO has demonstrated that savings are achievable in this area. We therefore expect all DNOs to be able to deliver these benefits. The weighted average benchmark savings as a percentage of expenditure is under 20%. This is less than is indicated by the DNOs' Transform models.

4.76. We do not apply a cut to the first two years' of 132kV general reinforcement expenditure as we accept these schemes may already be designed or in progress. We consider this to be a conservative assumption as it will also include a certain amount of expenditure for new schemes in RIIO-ED1.

4.77. The total cut to slow-track DNOs in reinforcement is £94m, which is about half of what we proposed in draft determinations. However, embedded benefits we recognise on the basis of additional evidence have increased to £283m for slow-track DNOs.

*Other cost areas*

4.78. Our assessment of savings in other cost areas[23] is based on the best-performing DNO across all these areas (rather than the best in each). This avoids creating a potentially difficult to achieve combination of savings across all areas. The proportion of savings to expenditure delivered by the best-performing DNO (ENWL) across these areas sets the benchmark for other DNOs. This is equivalent to £580m of savings.

4.79. The total cut to slow-track DNOs in areas outside reinforcement is £228m, which is similar to what we proposed in draft determinations. Embedded benefits we recognise on the basis of additional evidence have increased to £193m for slow-track DNOs.

*Allocation of savings*

4.80. In draft determinations we allocated the total savings we considered achievable between DNOs on the basis of totex. We acknowledge that this approach penalises companies with lower expenditure in areas where savings are possible as they have less opportunity to deliver these savings. In final determinations we allocate savings according to expenditure by each DNO in each cost area. This reflects the DNOs' opportunity for savings. We have scaled the DNOs' embedded benefits to make them proportionate to efficient expenditure, not DNOs' submitted forecasts.

4.81. As a sensitivity, we calculated what the adjustment would be if we separately benchmarked the best performing DNO in each cost area. In this case, the total cut to allowances would have been around £524m. We acknowledge it may not be appropriate to take the best performing DNO in each cost area and ask all DNOs to deliver against this. There may be good practical reasons why this might be difficult to achieve. Consequently, we have taken a more conservative approach by using UQ benchmarking in reinforcement and using the best performing DNO across all other cost areas as a whole as the benchmark.

*Reporting of smart grid savings in RIIO-ED1*

4.82. We assessed additional information provided by DNOs to determine the smart grid benefits embedded in their business plans. We recognise that there was an incentive on DNOs to overstate the value of savings in their plans. To mitigate this, we have only accepted benefits that are justifiably smart and that were referenced in the DNOs' business plans.

4.83. In addition, the DNOs will be required to report against their forecast embedded benefits from each solution identified during RIIO-ED1 in the

[23] We have considered in more detail: savings in managing faults and outages, operational IT and telecoms, asset replacement and refurbishment, and inspection and maintenance.

Environmental Report. Stakeholders will be able to hold DNOs to account and we will be able to ensure consumers receive sufficient returns from their investments.

## Information Quality Incentive

4.84. We use the IQI to encourage slow-track DNOs to create business plans that reflect the best available information about their future efficient expenditure requirements. The IQI provides additional financial motivation for companies to spend the time and resources to produce high-quality and well-justified business plans. It also deters DNOs from submitting inflated expenditure forecasts.

4.85. The IQI has three core elements:

- DNOs receive an up-front financial reward or penalty depending on their forecast relative to our assessment of efficient expenditure.
- DNOs that submit better forecasts (ie closer to our view of efficient cost) receive a higher efficiency incentive rate (sharing factor).
- Allowed expenditure is based 75% on our benchmark view and 25% on the DNOs' forecasts (called interpolation).[24]

**Decision and results**

4.86. As at draft determinations, we have included RPEs and smart grids in the costs included in the IQI. We have moved the break-even point in the IQI matrix so that the best-performing DNO groups receive a reward. The break-even point is an IQI score of 102.9 rather than 100. This means that a DNO group that forecasts 2.9 per cent above our efficient cost benchmark and achieves its forecast will earn its cost of capital but no additional IQI reward or penalty.

4.87. We have also adjusted the IQI calculation so that all components are now calculated post-tax. This increases both the rewards and penalties versus draft determinations.

4.88. Table 4.4 shows the IQI for each slow-track DNO group for final determinations.

[24] This recognises that we do not have perfect information.

**Table 4.4: IQI results for the DNO groups (2012-13 prices)**

| DNO | Final determinations | Upfront financial reward/penalty. Also total reward/penalty if DNO spends in line with final determinations allowance | | Total reward/penalty if DNO spends in line with its forecast | | Total reward/penalty if DNO spends in line with Ofgem's modelled view | |
|---|---|---|---|---|---|---|---|
| | IQI ratio | % | £m | % | £m | % | £m |
| ENWL | 103.8 | 1.1% | 20.2 | -0.5% | -9.5 | 1.7% | 30.4 |
| NPg | 109.9 | 0.1% | 2.7 | -4.0% | -115.2 | 1.5% | 43.1 |
| UKPN | 113.4 | -0.5% | -31.5 | -5.9% | -344.6 | 1.2% | 75.3 |
| SPEN | 113.0 | -0.5% | -14.2 | -5.7% | -175.1 | 1.3% | 40.7 |
| SSEPD | 107.1 | 0.6% | 19.7 | -2.4% | -81.8 | 1.6% | 54.4 |

4.89. A DNO group's total reward or penalty over RIIO-ED1 comprises an upfront reward or penalty, plus its share of the under/overspend in the period depending on how it spends versus its RIIO-ED1 allowance.

4.90. The second column shows a DNO's IQI ratio. This is the companies' forecast expenditure as a percentage of Ofgem's modelled view. A low ratio indicates a more efficient forecast/better quality forecast. The third and fourth columns show the additional upfront reward or penalty that the DNOs receive (as a percentage of totex and an absolute number) dependent on the quality of their forecast. This is also the total reward/penalty if a DNO spends in line with its final determinations totex allowance (after IQI interpolation).

4.91. The fifth and sixth columns show the total reward/penalty if the DNOs spend according to their forecasts. If they spend in line with their forecast they will overspend their totex allowance and will be penalised.

4.92. The seventh and eighth columns show the total reward/penalty if the DNOs spend in line with our modelled view of efficient cost. If they spend at this benchmark they will underspend their totex allowance and will be rewarded.

**Responses**

4.93. One DNO agreed with the calibration of the IQI matrix. The others raised issues with the design.

4.94. A supplier felt that there was no justification for adjusting the break-even point and that this should be reversed.

4.95. One DNO stated that the incentive properties fail to realise that the efficiency incentive rate is a post-tax value while the additional income is awarded pre-tax. It argued this will mean some DNOs are inappropriately rewarded for requesting more allowances than they need. Others thought that the scope of the IQI is too narrow and that it has weakened the incentive for future efficiency.

**Reasons for our decision**

4.96. While we received mixed responses, we consider that it is still appropriate to reward companies that had provided information that helped our comparative benchmarking. We therefore make no adjustment to the IQI matrix from draft determinations for the break-even point. We have, however, adjusted the IQI calculation so that all components are post-tax.

# 5. Assessment of efficient finance

**Chapter Summary**

Our decisions on the financial components of the DNOs' plans, and on changes to three components of financial policy.

5.1. We summarise the financial components of our final determinations in Table 5.1 below.

**Table 5.1: Summary of final determinations financial components**

| | ENWL | NPg | UKPN | SPEN | SSEPD | DPCR5 |
|---|---|---|---|---|---|---|
| Cost of equity | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.7% |
| Cost of debt index trailing average | 10-20 yrs | 10-20 yrs | 10-20 yrs | 10-20 yrs | 10-20 yrs | n/a |
| Notional gearing | 65% | 65% | 65% | 65% | 65% | 65% |
| Asset lives | 45 yrs | 45 yrs | 45 yrs | 45 yrs | 45 yrs | 20 yrs |
| Transition from 20 years asset lives | 8 yrs | 8 yrs | 8 yrs | 8 yrs | 8 yrs | n/a |
| Capitalisation rate | 68% | 70-72% | 68% | 80% | 64-70% | ~72% |

## Allowances for the cost of capital

5.2. Under the RIIO model, we set allowed returns using a weighted average cost of capital (WACC). The allowed return provides a fair return to investors in network companies, which underpins the long-term confidence necessary to facilitate efficient, low cost financing of this capital intensive sector.

5.3. The WACC comprises the cost of equity (which we set at the price control review) and the cost of debt (which is updated each year based on an index).

**Decision**

5.4. Our WACC for final determinations is the same as that for draft determinations.

5.5. It includes an estimate of 6% for the cost of equity.

5.6. The allowance for the cost of debt will be calculated using a trailing average of bond market indicators (using daily data for the unweighted average of iBoxx non-financial corporate 10+ year bond yields, deflated by forward inflation implied in gilt yields). This will extend by one year each year from a 10-year to a 20-year trailing average. The averaging period starts on 1 November 2004 and ends on 31 October 2014 for 2015-16 (10 years) and the end of the period will advance by a year each year, trombone-like, until the period length reaches 20 years. For 2025-26, the averaging period will start on 1 November 2004 and end on 31 October 2024 (20 years).

**Draft determinations**

5.7. In draft determinations we referred to our 17 February 2014 decision on our equity market return methodology. This said we were minded to set a cost of equity of 6% for the slow-track DNOs. We explained at draft determinations why we considered 6% was still appropriate.

5.8. Under RIIO, we set allowances for the cost of debt using an index derived from market evidence of benchmark bond yields. This helps ensure allowances are sensitive to changes in the interest rate environment that cannot be known at the time of a price review. At the start of this review, in our RIIO-ED1 strategy decision, we said we would use an index based on 10-year trailing averages. In our draft determinations we proposed a modified index, a trombone index extending from a 10-year to a 20-year trailing average. In developing this proposal, we tested a number of possible specifications by comparing forecast levels for the resulting index with DNOs' forecast interest costs.

5.9. Our testing showed that extending the trailing average period would better protect DNOs from exposure to market interest rate uncertainty. Recognising this advantage to DNOs, we considered a 10 to 20-year specification would provide a reasonable match with interest costs across the sector. It would not be a perfect match and our forecasts indicated that DNOs' actual debt costs might slightly exceed the allowance. Together with our cost of equity estimate and the reduced exposure to interest rate uncertainty, we considered the 10 to 20-year index would provide appropriate WACC allowances overall.

**Responses**

5.10. One non-DNO respondent agreed with our cost of equity. One thought it is generous and that there is scope for further reduction.

5.11. One DNO thought 6% is appropriate, but did not agree that it includes headroom. Other DNOs thought the cost of equity should be higher. Most suggested that a cost of equity of 6.4% would be more appropriate. Several DNOs commented that we have made errors in translating the Competition Commission's (CC) cost of equity decision for Northern Ireland Electricity (NIE) across to the DNOs.

5.12. Several DNOs welcomed the move to a 'trombone' cost of debt index but believe that trailing average periods should start at 15 years rather than 10, to be more closely aligned with average DNO financing costs.

5.13. Several respondents commented that our proposal would underfund the cost of debt and justifying this through headroom in the cost of equity would be invalid as that headroom doesn't exist. The DNOs, through the Energy Networks Association (ENA), commissioned a report by NERA economic consultants explaining why.

5.14. One non-DNO thought we should maintain our focus on the notional efficient company, and that actual debt costs should only be used to cross-check.

**Reasons for our decision**

5.15. We have reviewed the evidence submitted by respondents, in particular the detailed NERA reports on behalf of the ENA. While some of the points are well made, we find the evidence does not materially alter our overall assessment.

5.16. Respondents who criticised the way we translated the CC's decision for NIE did not correctly present the role of debt beta in the CC's calculations. They overlooked adjustments to the debt beta that the CC had made to reflect NIE's relatively low gearing, adjustments which need to be reversed to be applicable to higher-geared DNOs. Our calculations for our draft determinations followed the CC's own re-gearing methodology behind Table 13.13 of its final determination report. Our translation also recognised that the CC took into account a lower scored regulatory regime relative to Ofgem's in its beta assessment for NIE.

5.17. The DNOs presented evidence that replicated our own analysis that the 10- to 20-year trombone index could lead to allowances below the DNOs' projected out-turn debt costs, estimating the under-provision at 0.17%. However, there are uncertainties in these projections. In setting WACC allowances, we make wider judgements about how uncertainty affects the cost of capital overall, rather than trying to precisely match actual costs. We think our approach is consistent with our 'RIIO Handbook' which ensures the index should provide a reasonable estimate of the cost of debt.

5.18. Behind our cost of debt forecasts are assumptions about future inflation and its impact on the cost of embedded conventional debt. Inflation rates are uncertain and liable to depart from our forecast, but we noted in draft determinations that investors in the regulatory asset value (RAV), taking both debt and equity investors together, are fully protected from inflation risk. More recently, market movements have highlighted downside inflation risks over RIIO-ED1[25], which could increase real debt costs, but they also highlight downsides in the risk-free rate which, reflecting our equity market return methodology, would simultaneously reduce the cost of

[25] The new independent RPI forecasts in HMT's November 2014 'Forecasts for the UK Economy' suggest upside RPI risk compared with our forecast by the middle of the RIIO-ED1 period.

equity. These kinds of interactions mean we need to make our judgements around the WACC on a holistic basis.

5.19. We make our assessment of the cost of equity in light of considerable uncertainty around the longer term outlook for market returns, how our regulated businesses are exposed to systematic risk and the interest rate environment over the price control period. Our assessment is necessarily cautious.

5.20. Our judgement at the time of our draft determinations was that our WACC allowances would appropriately remunerate the DNOs' providers of capital. After reviewing the evidence, we believe they remain appropriate.

## Financeability

### Decision

5.21. We have accepted ENWL's proposal for a reduction in its capitalisation rate from 72 to 68%.

5.22. We have changed SSEH's capitalisation rate for the first four years of RIIO-ED1 to accommodate the change to our treatment of its interim cost of supplying energy in Shetland.

5.23. We believe our final determinations provide the basis for all DNOs to finance their activities during the course of RIIO-ED1.

### Summary of draft determinations

5.24. For our draft determinations we tested whether the underlying cash flows, profitability and indebtedness of the DNOs would remain consistent with supportive credit ratings. This was the same as in previous reviews and drew from the credit rating agencies' own methodologies. Our financial modelling took account of DNOs' embedded debt positions.

5.25. Our analysis indicated that our draft determinations should result in no more than a one-notch downgrade in the credit rating of any DNO. All DNOs would remain within investment grade.

5.26. We also considered how resilient DNOs would be to plausible downside scenarios. We identified that one DNO, ENWL, may have limited resilience to downside scenarios due to relatively high debt costs. We invited it to propose how it would improve this. We said we would consider adjustments to revenues provided they did not represent an increase in discounted present value terms.

**Responses**

5.27. A number of DNOs expressed concerns about reduced WACC allowances and a sector-wide deterioration of a key indicator, the Post Maintenance Interest Cover Ratio (PMICR, also known as the Adjusted Interest Cover Ratio). Some DNOs see PMICR levels of 1.4 as a necessary condition for financeability. One DNO submitted a calculation of its financeability that assumed it would under-perform against the totex allowance in its final determinations.

5.28. Most DNOs said our cost of equity allowance and cost of debt index have to be changed to maintain their financeability.

5.29. A supplier said it should be the responsibility of business owners to resolve financeability issues. It argued we should assess financeability in light of plausible outcomes, including expectations of financial outperformance.

**Reasons for our decision**

5.30. The change to ENWL's capitalisation rate has a neutral effect on the present value of allowed revenues over time. It improves the company's cash flows and gearing levels in RIIO-ED1 and we believe it provides a better foundation for any owner initiatives to reinforce its financial position further. Although this change means lower revenues after RIIO-ED1 it should mean less new borrowing at the end of RIIO-ED1 and better financial metrics thereafter. We think ENWL's proposal is in the consumer interest.

5.31. The changes to SSEH's capitalisation rate have a broadly neutral effect on the DNO's revenue requirement in the affected years. At the time of our draft determinations, interim costs associated with supplying energy on Shetland were assumed to be remunerated as fast money. In Annex 7 we explain our decision to fund these costs as part of totex. This means they are included in the capitalisation. Without any change, this would inappropriately defer the recovery of some of the costs. It would mean they are met by future consumers. We have reduced SSEH's capitalisation rate in the first half of RIIO-ED1 to avoid this anomaly.

5.32. We have reflected on the financeability concerns of respondents. After considering a wide range of evidence, including our financeability analysis, we think our WACC allowances are set at appropriate levels and are consistent with longer term financial sustainability. We believe any financeability issues would therefore be short-term and should be resolved primarily through management and owner action.

5.33. We make our assessment in light of the DNOs' licence regime and the way it protects consumers, lenders and bondholders. Among other protections, licences require DNOs to take all appropriate steps within their power to maintain an investment grade rating. We will enforce these protections if necessary. They do not guarantee financeability, but they do guard against imprudent financing decisions or inappropriate distributions to DNO shareholders. We believe the combination of these protections, with our approach of setting price controls so that a prudently-financed licensee is reasonably resilient to adverse outcomes, limits the risk of fundamental financeability problems. They help ensure that any company-specific issues can be corrected by the DNO and create a safe environment for debt finance providers.

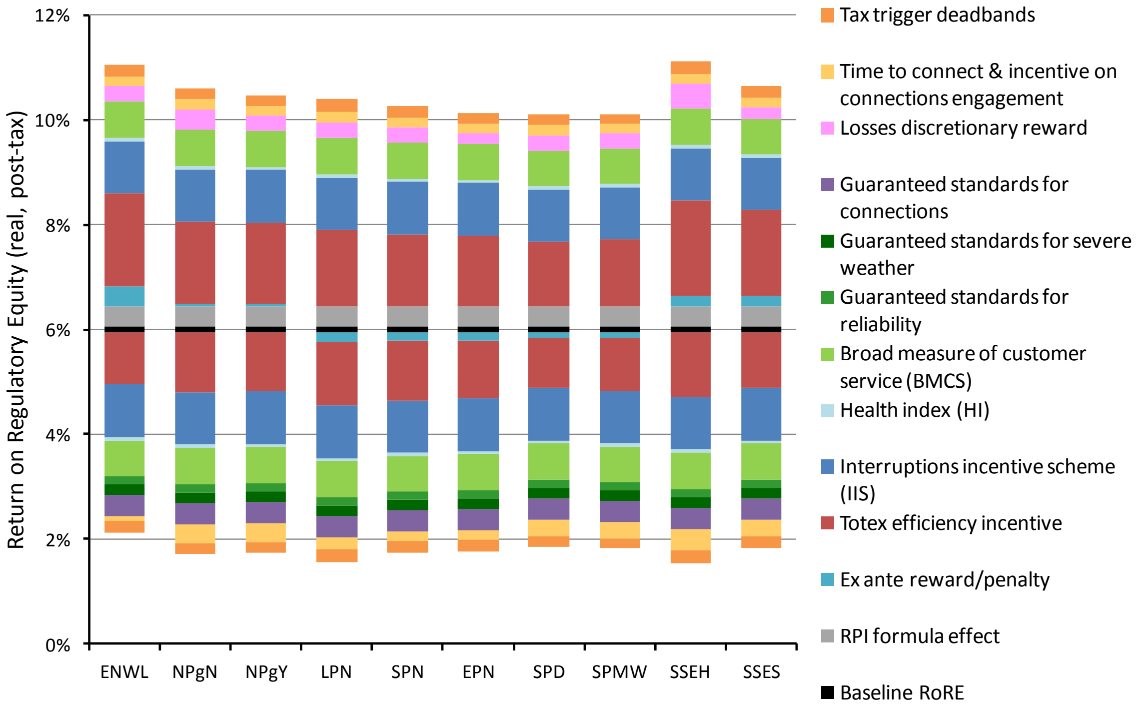
5.34. We have updated the analysis we carried out for our draft determinations.

5.35. For all DNOs, our projections indicate that, with the exception of the PMICR, conventional accounts-based financial indicators are positive and well above levels that would threaten investment grade. Taking PMICR into account, our simulations of Moody's methodology[26] suggest no more than a one-notch downgrade for any DNO, similar to our finding at draft determinations. We consider the published responses of the rating agencies to our draft determinations are broadly consistent with our assessment.

5.36. Our testing takes account of DNOs' embedded debt positions under a wide range of future market interest rate scenarios. We tested the underlying resilience of DNOs' capital structures to plausible downside scenarios. We set a threshold for this testing informed by our analysis of uncertainty in DNOs' returns on regulatory equity (RORE). We have calculated what we think are plausible ranges for RORE for each DNO over the RIIO-ED1 period, as shown in Figure 5.1.

[26] Moody's issued its revised rating methodology for regulated electricity and gas networks on 25 November 2014. We have reviewed the revisions. It has reduced its weighting on PMICR. We assess that the revised methodology will not adversely affect the credit ratings of the DNOs.

**Figure 5.1: Ranges for RORE over RIIO-ED1 period**



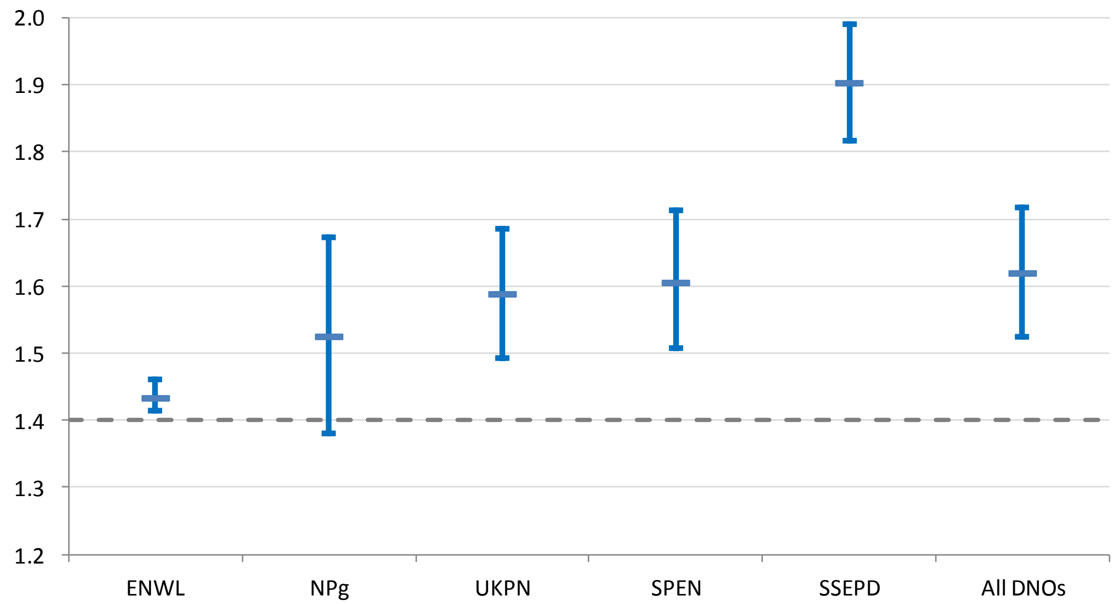

5.37. The RORE ranges shown in this chart are broadly consistent with our strategy decision that outperforming DNOs could have the potential to earn RORE above 10% while RORE for underperforming DNOs could be below the cost of debt. This indicates we have appropriately calibrated our package of risk and incentives.

5.38. In draft determinations we used an additional tool[27] to test the underlying resilience of DNOs' capital structures to plausible downside scenarios. We have used the same test for final determinations, consistent with plausible RORE downsides. Our view is that a threshold value of 1.4 remains appropriate.

5.39. Our analysis indicates financial resilience above our threshold under central interest rate scenarios for all DNOs, including ENWL. This is illustrated by the central bar for each DNO in Figure 5.2 below.

[27] We explained this measure, which we call $PMICR_G$ in the Financial issues supplementary annex to the draft determinations.

**Figure 5.2: Ranges for financial resilience over the RIIO-ED1 period**




5.40. NPg is slightly below the threshold under more extreme interest rate scenarios (sustained interest rates above 7.0% compared with about 4.5% now). It shows that substantial underperformance against its cost and output targets, in combination with sustained high interest costs, could leave the company with insufficient cash flows to maintain benchmark levels of gearing. NPg is forecast to start RIIO-ED1 with a relatively low level of gearing. Taking this balance sheet headroom into account, we consider it will be resilient to plausible downside scenarios.

## Proposed policy changes

**Our decision**

5.41. We have decided to implement the financial policy changes we proposed in draft determinations.

5.42. These are to:

- make a 100% RAV deduction for top-up and standby revenues that some DNOs treated as excluded services during DPCR5. This regularises the treatment of these revenues, which could be treated as excluded services in the DPCR5 licence.
- use DNO-specific attributions of qualifying expenditure to capital allowance pools (rather than developing a generic allocation method) and then roll forward regulatory tax pool calculations at the end of the RIIO-ED1 period. This ensures that consumers benefit from the capital allowances attributable to expenditure they are funding.
- treat the proceeds or fair value of asset disposals as deductions from

totex for the calculation of the efficiency incentive. This gives DNOs incentives to optimise their expenditure programmes as a whole, taking additions and disposals together.

**Responses**

5.43. A supplier disagreed with our proposals for top-up and standby revenues, arguing that we should return these revenues to consumers during RIIO-ED1. It is also concerned about DNOs benefitting from the disposal of assets that have been funded by consumers.

5.44. One DNO thinks only the slow money portion of top-up and standby revenues should be deducted from the RAV.

5.45. Other respondents broadly supported our proposals.

**Reasons for our decision**

5.46. We believe it is correct to make a 100% adjustment in relation to top-up and standby revenues that some DNOs treated as excluded services during DPCR5. The costs associated with these revenues were in our DPCR5 cost allowances. Adjusting for less than 100% would fund some DNOs twice.

5.47. Whether we should make adjustments to the RAV or to RIIO-ED1 revenues has a neutral effect on consumers overall, taking existing and future consumers together. It does affect the balance between different generations of consumers. It also affects DNOs’ shorter term cash flows and financial metrics. We think this is similar to other factors that have inter-generational effects, including our implementation of revised asset lives. We think our proposals keep an appropriate inter-generational balance and also facilitate efficient financing for the benefit of consumers in the long-run.

5.48. Our proposal to treat disposals of assets as negative totex recognises that these assets have been funded by consumers. On behalf of consumers, our objective is to minimise the resources needed to deliver desired levels of service. We believe it is important to encourage DNOs to optimise their assets, maximise the proceeds from asset disposals and minimise asset acquisition costs. We have built-in safeguards that mean DNOs require our consent before selling operational assets and must properly account for the arm’s length commercial value of disposals.

## Pensions reasonableness review

5.49. Network companies, including DNOs, have defined benefit pension schemes which were in place before the gas and electricity privatisations in the 1980s and early 1990s. These schemes are all currently in deficit. They have all been closed to new members.

5.50. We carry out a review of pensions deficit funding every three years following actuarial valuations prepared on behalf of the schemes' trustees. Our allowances for the funding of pension scheme deficits through regulated revenues is governed by principles already established in the financial handbooks for RIIO-T1 and GD1. We true-up for the deficit funding amounts companies actually pay to ensure companies cannot profit from these revenue allowances. We included our price control pension principles as Appendix 7 to our Financial Issues annex to our RIIO-ED1 strategy decision.

5.51. We have just completed our 2014 review for all network companies. We are publishing the results with our Annual Iteration Process 2014 for RIIO-T1 and GD1.

5.52. We asked DNOs to forecast pension deficit funding allowances in their business plans. Following our review, we have calculated revised allowances. We have applied these to the RIIO-ED1 base revenues, as per our strategy decision. The effect on base revenues is summarised in Table 5.2.

**Table 5.2: Summary of deficit funding allowances**

| £m 2012/13 prices | ENWL | NPg | UKPN | SPEN | SSEPD | Slow-track DNOs |
|---|---|---|---|---|---|---|
| Forecast at draft determinations | 131.8 | 208.4 | 649.4 | 353.7 | 363.1 | 1,706.4 |
| Allowances at final determinations | 126.6 | 170.1 | 712.8 | 446.1 | 360.4 | 1,815.9 |
| Movement | (5.2) | (38.3) | 63.4 | 92.4 | (2.7) | 109.5 |

# 6. Uncertainty and risk

**Chapter Summary**

Our decisions on uncertainty and risk in our final determinations.

6.1. There are always uncertainties about what will happen during the price control period. Factors can change a company's outputs and expenditure requirements.

6.2. In our strategy decision we presented a range of mechanisms (uncertainty mechanisms) which allow changes to the revenues the DNOs are allowed to collect in response to specified uncertainties. DNOs presented their proposals for managing the uncertainty and risk they could face over RIIO-ED1 in their business plans. This included proposing additional uncertainty mechanisms if DNOs thought they would help manage risk and bring benefits for consumers. We expect the companies to bear their own business risk. Therefore uncertainty mechanisms should only be used where action is required due to changes outside the companies' control which could significantly impact costs.

**Decision**

6.3. As we presented in draft determinations, we view the DNOs' consideration of risk and uncertainty as acceptable. Most DNOs' descriptions of residual risk were lacking, but that is not significant enough to change our assessment.

6.4. The DNOs developed their forecasts for low carbon technology take-up in many different ways. While all engaged with stakeholders, the plans generally lack detailed evidence. They all described how they will accommodate increases in penetration beyond their 'best view' forecast. However, not all considered the impact of different scenarios on their wider business or in the same level of detail. We think SPEN and SSEPD should consider this in greater detail to ensure they are in a position to manage it effectively and efficiently.

6.5. The RIIO-ED1 uncertainty mechanisms are listed in Table 6.1.

**Table 6.1: Uncertainty mechanisms in RIIO-ED1**

| Mechanism type | Name |
|---|---|
| Indexation | RPI indexation of allowed revenues<br>Cost of debt |
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC[28] fixed costs<br>Shetland (SSEH only) |
| Volume-driver | Smart meter roll-out costs |
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Rail electrification<br>Link boxes<br>Moorside (ENWL only)<br>Shetland (SSEH only)<br>Subsea cables (SSEH only) |
| Trigger | Tax |

6.6. We are accepting the majority of uncertainty mechanisms the slow-track DNOs included in their revised plans. We accept SSEPD's additional re-opener for the costs of diverting lines associated with Network Rail's electrification programme, and are applying it to all the slow-track DNOs.

6.7. SSEH still has a mechanism for the interim costs of supplying energy in Shetland. This is a combination of ex ante allowance, pass-through and a re-opener. Following a consultation in parallel to RIIO-ED1, we have changed the balance between these categories. More information on the issues in Shetland, our decision and reasoning is in Appendix 7.

6.8. Several issues have arisen since draft determinations.

*Enhanced physical site security*

6.9. In August 2014, DECC and the Centre for the Protection of National Infrastructure (CPNI) reclassified a number of sites. Sites some DNOs (UKPN, ENWL, NPg) had included in their plans for enhanced physical infrastructure are no longer classified, while others are now included. It is likely that some sites will be classified as Category 3 or above during the RIIO-ED1 period. The enhanced physical site

[28] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

security re-opener is designed to allow the DNOs to recover the costs of security for new sites at Category 3 or above. Because this is still under review by the CPNI, we have decided to remove the materiality threshold.

*Link boxes*

6.10. There have been recent high profile cases of link boxes exploding under pavements. These are a particular issue in UKPN's area. UKPN is working with the HSE on mitigation and resolution. This is an important safety issue. Based on its recent experience, UKPN has requested (after submitting its slow-track plan) an extra £95m to manage this risk. We are concerned that UKPN does not have sufficient evidence at this point to decide the best long term solution. We advocate a risk-based approach, to ensure safety at a reasonable cost.

6.11. We have decided to give UKPN an ex ante allowance for the first two years. This is so it can do short-term work on link boxes. We will have a re-opener after two years, at which point we may review the efficient expenditure for the first two years and will determine an efficient level of expenditure for the remainder of RIIO-ED1. In the meantime, we expect UKPN to work with other DNOs to look for the best solution for managing the link box risk and to gather detailed data on this issue so that it, and we, can assess it properly. We think it is appropriate to include a re-opener for the other slow-track DNOs. This will apply for the remainder of RIIO-ED1.

*Subsea cables*

6.12. As part of the approvals process for subsea cables, Marine Scotland[29] favours burying cables rather than laying them on the seabed. This significantly increases the cost – but could reduce the risks that the cables pose to third parties and of cables being damaged. SSEH has highlighted that, depending on the requirements, this could cost up to an additional £180m on their planned replacement programme for subsea cables.

6.13. We and SSEH are in discussions with Marine Scotland to discuss the cost-benefit of changing the approach. We think it is appropriate to have a re-opener in 2016-17, in case it is confirmed that the outcome of this is that the cables require additional protection.

**Responses**

6.14. Three DNOs agreed with our proposed acceptance of the DNO-specific uncertainty mechanisms. One suggested a new mechanism for link boxes (see below), and requested three windows for re-openers for High Value Projects (HVP) rather than two.

[29] Marine Scotland is responsible for the integrated management of Scotland's seas.

6.15. One DNO proposed a mid-period review of smart grid savings to set an adjustment to the DNOs' allowances for the remainder of RIIO-ED1.

6.16. A supplier thought uncertainty mechanisms should conform to principles of: minimising revenue/charging volatility, not weakening efficiency and performance incentives and symmetrical triggers for re-openers.

6.17. Another non-DNO asked if an uncertainty mechanism might provide the flexibility to cater for DNO costs associated with high system voltages where these could be more efficiently dealt with on the DNO system than on the transmission system.

6.18. Three DNOs and a supplier agreed with our proposal to give all DNOs an uncertainty mechanism for rail electrification. The supplier claims the alternative (as per WPD) would be windfall ex ante funding. A DNO thinks we should not have a materiality threshold for this mechanism as no baseline allowances have been included in the draft determinations and the proposed efficiency test should ensure that only efficiently incurred costs are remunerated.

6.19. One DNO stated it is not obvious that WPD could be more certain of the costs it will face. Another (which disagreed with our proposal) believes it represents a disproportionate treatment of the risk in favour of the fast-track DNOs.

**Reasons for our decision**

6.20. We think that two re-openers windows in RIIO-ED1 are sufficient to cover for any uncertainty related to HVP. We do not think a mid-period review of smart savings is appropriate. DNOs would have less incentive to make smart grids savings in the first part of RIIO-ED1, and would be less likely to make smart grid enabler investments before 2019. Our smart grids assessment is based on solutions that DNOs have proposed in their plans.

6.21. We have designed the uncertainty mechanisms according to the principles we explained in our strategy decision.

6.22. We have not received sufficient evidence to convince us that an uncertainty mechanism is required for high system voltages.

6.23. As we explained at draft determinations, there are questions about who will bear the costs to the networks of Network Rail's electrification programme. Some parts of the programme are more certain than others. We think an uncertainty mechanism is an appropriate solution. Re-openers generally have a materiality threshold, as we expect DNOs to manage cost variations up to a certain level. DNOs have funded costs from work undertaken by National Rail in the past. WPD's costs of Network Rail's rail electrification were accepted in the round as part of its business plan. We judged that the costs it included were efficient, and that there was a high degree of certainty around the particular schemes involved. Due to the uncertainty over who should pay, we amended WPD's licence so that if another party funds the costs they will be removed from WPD's settlement.

6.24. The need for the two new mechanisms for link boxes and burying subsea cables has been driven by external agencies. We are liaising with HSE and Marine Scotland, and are advocating a risk-based approach in both cases. We think it's appropriate to have a re-opener for both issues.

# 7. Network Innovation Allowance

**Chapter Summary**

Our assessment of the innovation strategies and the corresponding amounts we set for the Network Innovation Allowances.

7.1. In RIIO-ED1 (as with RIIO-T1 and GD1) we are introducing a time-limited innovation stimulus package consisting of an annual competition (Network Innovation Competition, NIC), a limited funding allowance (Network Innovation Allowance, NIA) and a mechanism to fund the roll-out of successful innovation trials (Innovation Roll-out Mechanism, IRM). A key requirement of these mechanisms is that the projects generate learning for all the companies and that this learning is shared. NIC and NIA projects will be part-funded, with the DNOs and partners providing at least 10% of the funding.

7.2. In our strategy decision we said that DNOs would receive a default NIA of 0.5% of base revenue each year. They could receive a higher allowance depending on our assessment of their innovation strategies. Our assessment is based on amended strategies submitted by DNOs as part of their slow-track business plans.

7.3. We published our assessment and proposed NIAs a supplementary annex to the draft determinations. We have included our decision in this Overview so that all our final determinations are in a single document.

**Decision**

7.4. Table 7.1 shows the NIA percentages for the slow-track DNOs versus the percentages they requested.

**Table 7.1: NIA percentages for the slow-track DNOs**

| DNO | RIIO-ED1 NIA request (% of base revenue) | RIIO-ED1 NIA amount (% of base revenue) |
|---|---|---|
| ENWL | 0.8 | 0.7 |
| NPg | 0.6 | 0.6 |
| UKPN | 0.5 | 0.5 |
| SPEN | 1.0 | 0.5 |
| SSEPD | 1.0 | 0.5 |

7.5. The RIIO-ED1 NIA amount is calculated each year taking into account any changes to the DNOs' base revenue as a result of the price control financial model annual iteration process.

**Draft determinations**

7.6. Our assessment of the innovation strategies and NIAs has not changed from draft determinations.

**Responses**

7.7. Three DNOs acknowledged that their proposed NIA is what they requested.

7.8. A supplier thought DNOs could benefit disproportionately compared to customers as a result of innovation funding. This is because customers fund the innovation but benefits flow to licensees through savings against the price control allowance or improved performance against output targets.

7.9. Three non-DNO respondents raised concerns regarding the levels of funding sought by licensees. These respondents also raised concerns over the subject areas that licensees intended to focus on. One argued that funding should be ring-fenced for studies on non-technical losses.

7.10. SPEN disagreed with its proposed NIA. It thinks our proposals were based on a relative assessment of all licensees' innovation strategies rather than reviewing SPEN's strategy against the criteria. It also notes that it has addressed the areas of feedback we provided in the draft determination.

**Reasons for our decision**

7.11. We do not agree that the DNOs get a disproportionate benefit from innovation. Our final determinations include significant savings from smart grids and innovation. This provides a direct benefit to customers that would not be possible without innovation funding. The efficiency incentive shares any further savings a DNO achieves against its price control allowance with customers.

7.12. Some respondents thought DNOs should, where their innovation strategy merits it, receive a NIA greater than they requested. The DNOs consulted their stakeholders and sought views on their priorities and willingness to pay for innovation. If a DNO thinks the allowance it has requested will allow it to deliver the learning and outputs it requires, then we do not think it appropriate to provide a larger allowance.

7.13. The price control mechanism incentivises DNOs to innovate in order to reduce costs and improve output performance. If they want additional funding they can submit projects to the NIC or fund the projects themselves. They can also partner with third parties.

7.14. We do not agree with SPEN's comments. Our assessment of innovation strategies involves an element of comparison. However, it was not a relative assessment. Each DNO's strategy was assessed against the criteria.

7.15. We noted in draft determinations that SPEN's revised innovation strategy was an improvement on its original strategy. However, our fast-track feedback was not meant to be exhaustive. It did not imply that if feedback was addressed we would automatically award the requested NIA amount.

7.16. Once a DNO fulfilled the minimum requirements we considered if it had sufficiently justified funding beyond the default amount (0.5%). Following the submission of the amended innovation strategies we asked SSEPD, SPEN and ENWL more questions. SSEPD's and SPEN's responses were not detailed enough to justify funding beyond the default amount. ENWL highlighted the areas that it would focus on if it received the default amount rather than the amount that it had requested. We have not awarded ENWL the full amount it requested. This is because while it justified some funding in addition to the default amount it did not justify an allowance of 0.7%.

7.17. After we received the responses to our draft determination and reviewed the innovation strategies again, we asked NPg to provide the same information as SPEN, SSEPD and ENWL. NPg explained what areas it would not invest in with a smaller allowance. This was sufficient for us to confirm our proposed funding of 0.6%.

# Appendices

# Appendix 1 - Consultation responses

1.1. We received 17 responses to our draft determinations consultation. Responses were received from DNOs, a transmission operator, a supplier, consumer groups and other stakeholders. Not all respondents answered each of the questions. Some made general comments. Non-confidential responses are published on our website as associated documents to the consultation.[30]

1.2. We summarise the responses below against each of the consultation questions.

1.3. We also summarise responses to the 'Assessment of the resubmitted RIIO-ED1 innovation strategies' document. This was published as a supplementary annex to the draft determinations. Our decision on innovation is in this Overview, so we include the responses too.

**Chapter 2 – Summary of assessment**

Question 1: Do you think our assessments for each of the five criteria are appropriate?

1.4. Two of the respondents agreed that our assessments were appropriate. One DNO broadly agreed but argued that complying with all our policy positions on financeability would not provide it with sufficient revenues to finance its activities.

1.5. Four DNOs did not agree with our assessments. Several were concerned about the basis of our conclusions on our assessments of efficient costs and efficient financing. One DNO and one non-DNO were particularly disappointed with the proposed reductions in planned investments in a particular distribution area.

1.6. One non-DNO was disappointed with the low priority given to safety, as it thinks we have not considered the long term benefit from investing in the health of assets.

**Chapter 4 – Assessment of efficient expenditure**

Question 1: Do you agree with our totex benchmarking?

1.7. There was a mixed response from the DNOs to this question. Three were broadly supportive while one believed that there are fundamental problems with total expenditure benchmarking and it should only be used to cross-check more effective cost assessment approaches.

[30] https://www.ofgem.gov.uk/publications-and-updates/riio-ed1-draft-determinations-consultation-slow-track-electricity-distribution-companies

1.8. A number of issues with the details of the benchmarking were highlighted by several of the DNOs. These ranged from concerns that we have not fully considered all DNO-specific factors when cross-checking the results of the modelling to noting specific calculation errors.

Question 2: Do you agree with our disaggregated benchmarking?

1.9. As with the previous question there were mixed views among the responses. One DNO agreed that disaggregated benchmarking is the most robust approach and another accepted the balance of our overall cost assessment approach. However, several respondents identified issues with our methodology, ranging from modelling discrepancies to concerns that the disaggregated benchmarking is skewed by cherry-picking.

1.10. One non-DNO noted the importance of ensuring that all allowed expenditure is linked to an appropriate output. Another was disappointed that the training allowance from DPCR5 has been removed and that our cost proposals do not account for specialist salaries to increase in line with inflation.

Question 3: Do you agree with our forecast of RPEs?

1.11. The majority of respondents to this question did not agree with our forecast of RPEs as they believe that changes to the methodology have not been fully justified. Several DNOs noted that our forecasts are more representative of periods of recession rather than growth and that this is inconsistent with the growth that is generally expected over the RIIO-ED1 period.

1.12. Several respondents disagreed with our short-term wage forecasts and our adjustment for the RPI formula effect. One questioned whether the approach we used to project forward from the totex index value for 2013-14 is appropriate.

1.13. One DNO said that while it agreed with us using 2013-14 data to inform our assessment of RPEs, we should also update the rest of our benchmarking to include the most recent data.

1.14. A supplier was supportive of several aspects of our approach, including the 0.4% adjustment to the RPI formula effect. It argued this is appropriate to ensure that DNOs don’t make windfall gains in RIIO-ED1.

Question 4: Do you agree with our assessment of potential smart savings?

1.15. Most respondents, including all DNOs, believe we have overstated potential smart benefits without providing sufficient justification for our assessment. Several disagreed with the level of savings in smart metering outlined in DECC’s impact assessment. One DNO commented that our approach to smart benefits has emerged very late in the process which has led to an unjustified difference between the fast- and slow-track processes.

1.16. Several respondents highlighted issues with the methodology we used to determine potential savings. For example, a few DNOs stated that we had used the Transform model inappropriately to calculate the cut to reinforcement. Several DNOs also considered there to be double counting between the smart metering benefits and the extrapolation of ENWL's performance in 'other' areas.

1.17. One non-DNO respondent raised a concern that the size of savings introduces a higher risk for the DNOs, as the review process for RIIO-ED1 doesn't seem to allow for adjustments if benefits are lower than our assessment.

1.18. Two respondents agreed with our assessment that potential smart benefits are higher than those included by the DNOs in their business plans. One of these (a supplier) argued that our estimates are conservative. Another non-DNO commented that there needs to be a more effective incentive process embedded if smart grid technologies are to be realistically trialled across any significant area.

Question 5: Do you agree with our approach to combining the cost assessment models?

1.19. Two DNOs agreed with our approach. One felt that the 50/50 weighting between the totex and disaggregated models is more consistent with RIIO principles than the fast-track assessment was, but does not agree with the way the results from models were used to determine final allowances.

1.20. The other DNOs raised concerns about the weightings having been changed and the difference this has caused between the fast- and slow-track assessments. A network operator commented that for future price controls it would be preferable if we indicated the likely approach in advance rather than after the results of the separate assessments are known.

Question 6: Do you agree with our design of the IQI?

1.21. One of the DNOs agreed that the calibration of the IQI matrix appeared to be appropriate. The others raised issues regarding the design. One DNO stated that the incentive properties fail to realise that the efficiency incentive rate is a post-tax value while the additional income is awarded pre-tax; it argues that this will mean that some companies are inappropriately rewarded for requesting more allowances than they need. Other DNO comments include that the design and scope of the IQI is too narrow and that it has weakened the incentive for future efficiency.

1.22. A supplier felt that there was no justification for adjusting the break-even point and that this should be reversed.

**Chapter 5 – Assessment of efficient finance**

Question 1: Do you agree with our cost of equity proposals?

1.23. One non-DNO agreed with our proposals and a supplier stated that our estimation is still generous and there is still scope for further reductions. One DNO accepted that 6% is an appropriate cost of equity but did not agree that it includes headroom.

1.24. The other respondents to this question believe that the cost of equity should be higher than our proposed 6%, which they argued does not include headroom. Most suggested that a cost of equity of 6.4% would be more appropriate. Several DNOs commented that we have made errors in translating the Competition Commission's cost of equity decision for Northern Ireland Electricity across to the DNOs.

Question 2: Do you agree with our cost of debt proposals?

1.25. Several DNOs welcomed the move to a 'trombone' cost of debt index but believe that trailing average periods should start at 15 years rather than 10. They think this would more closely align with average DNO financing costs.

1.26. Several respondents commented that our proposal to underfund the cost of debt through headroom on the cost of equity is invalidated as that headroom doesn't exist. A supplier believes we should maintain our focus on the notional efficient company, and that actual debt costs should only be used to cross-check.

Question 3: What are your views on our assessment of financeability?

1.27. Several issues were raised regarding our assessment. Most of the respondents to this question raised concerns about our use of our new credit metric in assessing financeability, given that ratings agencies do not use it.

1.28. One DNO's comments focused on its concern with the sector wide deterioration in interest cover observed. Another DNO stated that the assumption that DNOs finance 25% of their debt using index linked bonds is inappropriate.

1.29. A supplier agreed with the principles behind our financeability assessment but thought that some of adjustments we have made are not consistent with these principles.

Question 4: Do you agree with our proposals to modify the three financial policies?

1.30. One DNO made a general comment about its concern that our policies are overly responsive to short term issues and do not fully take the long term nature of networks into account.

1.31. Capital allowance pools: All of the respondents broadly agreed with our proposals on capital allowance pools, though one observed it would create a mismatch between the statutory tax computations and the regulatory tax allowance in future RIIO periods.

1.32. Directly remunerated services: Three respondents agreed with our proposal. One DNO agreed with the RAV adjustments for top up and standby revenues but said that we have not correctly reflected the adjustment for Value Added Services in our Price Control Financial Model. One DNO did not agree with the proposal as it believes that the current approach is correct. A supplier commented that revenues recovered from these services during DPCR5 over and above the costs of providing them should be returned to customers via an immediate rebate rather than through deductions from the RAV.

1.33. Disposals: Most respondents agreed with our proposal, with one DNO additionally asking for clarification as to whether the new policy would apply to the sale of non-operational assets and scrap as well as operational assets. A supplier was concerned with the proposal, arguing that monies recovered from disposals belong primarily to customers as they fund the assets.

**Chapter 6 – Uncertainty and risk**

Question 1: Do you agree with our acceptance of the DNO specific uncertainty mechanisms?

1.34. Three respondents agreed. Another agreed with the proposed scope of factors to be handled by uncertainty mechanisms and suggested principles for the design of each mechanism.

1.35. One DNO commented that there should be a volume driver adjustment and that there should be three reopeners for High Value Projects not two.

Question 2: Do you agree with our proposal to give all DNOs an uncertainty mechanism for rail electrification?

1.36. Five respondents agreed with our proposal, and one urged us to proactively engage with the relevant stakeholders to limit customers' exposure to the costs of rail electrification. One DNO disagreed. It believes that it represents a disproportionate treatment of the risk in favour of the fast-track companies. One of the DNOs who agreed stated that we have not justified why WPD's mechanism should be different from that of the slow-track DNOs.

**Other comments**

1.37. Several respondents raised concerns about the trade-off between short-term cost reductions and ensuring the necessary investment in long-term infrastructure. A few DNOs commented that there is a disproportionate gap between the fast- and slow-track companies. Several other respondents noted that the RIIO-ED1 framework is very complex and hard for non-DNOs to comment on. One suggested that we should implement a reporting regime that communicates performance clearly for all stakeholders. Another was concerned that the data used for our analysis has not been published so its robustness cannot be assessed independently.

1.38. Several respondents referred to the number of changes that we have made to our analysis. One DNO was concerned that the number of revisions has undermined the credibility of our conclusions, while another respondent thought our changes have allowed network revenues to increase in certain areas without being fully justified. National Grid suggested that we should re-run our models to demonstrate how all the DNOs, including the fast-tracked companies, perform against the new modelling approach.

1.39. Citizens Advice asked us to clarify the assumptions underpinning the headline figures, particularly the £12 saving for the average duel fuel customer over the course of RIIO-ED1, to enable consumers to make a more informed judgement about the draft determinations.

1.40. The Welsh Government commented that it is looking forward to seeing the impact of our proposed price control settlement on future charges in Wales. Friends of the Peak District repeated its support of two DNOs investing in undergrounding power cables in National Parks and requested that the licence conditions focus on financial expenditure rather than length targets.

**Assessment of the resubmitted RIIO-ED1 innovation strategies**

**Chapter 2 – Assessment of innovation strategies**

<u>Question 1</u>: Do you agree with our assessment of each DNO's innovation strategy?

1.41. Although mostly without comment, A supplier felt that licensees could benefit disproportionately from innovation funding, as customers are required to fund the NIA allowances and also the rewards for surpassing efficiency targets through methods funded by the allowances.

1.42. Another non-DNO did not fully agree. It suggested that some of the allowance should be ring-fenced to address non-technical losses.

<u>Question 2</u>: Do you agree with our draft determination of the NIA for each DNO?

1.43. Three DNOs agreed with the amounts they had been awarded as this was what they had requested. One DNO felt that it had been given benefit for addressing feedback provided in previous documents, and believed that a relative assessment had taken place rather than each strategy being assessed separately against the requirements.

1.44. One non-DNO respondent was disappointed with the level of innovation funding provided at a time of dramatic change in generation. Another suggested that 10-20% of each company's allowance should be ring-fenced to address non-technical losses.

**Other comments**

1.45. One respondent raised concerns that DNOs are not fully committed to innovation. It said this was evidenced by DNOs' approach to smart grids and losses and the fact that we are proposing to award just over half of the additional revenue that was available under the NIA. It also commented that the LCN Fund has suffered from the absence of a single consolidated and accessible source of information on projects and outcomes, which we should address for the new RIIO-ED1 innovation regime.

# Appendix 2 – ENWL final determinations

1.1. We summarise key elements of our final determinations for ENWL in Table A2.1 below. Figures are shown (unless indicated otherwise) as RIIO-ED1 totals and are in 2012-13 prices.

1.2. We provide further detail in the ‘Detailed figures by company’ supplementary annex. It contains the outputs targets that each DNO will be required to achieve for customer service, connections[31] and reliability, and the financial rewards or penalties they will receive depending on their performance. These values are not stated below.

**Table A2.1: Key elements of ENWL’s final determinations**

| | |
|---|---|
| Base revenue | £2,892m |
| *including updated pensions deficit funding* | *£2,887m* |
| Profiling[32] | Year 1: -20.1% followed by -0.78% pa |
| *including updated pensions deficit funding* | *Year 1: -20.1% followed by -0.81% pa* |
| Impact on the distribution charges included in domestic bills[32] | Year 1: -£20.47 followed by around -£0.64 pa |
| *including updated pensions deficit funding* | *Year 1: -£20.47 followed by around -£0.66 pa* |
| Outputs | |
| Safety | Compliance with the safety legislation enforced by the HSE |
| Customer service | Target: ENWL accepts our customer service targets. In order to perform well under this incentive it will need to deliver a level of service to all customers that is well above the current |

[31] We published the methodologies for setting the customer service and connections targets here: https://www.ofgem.gov.uk/publications-and-updates/decision-consultation-riio-ed1-customer-service-and-connection-incentives
[32] This does not include the impact of the government’s December 2013 measures to reduce energy bills.

| | |
|---|---|
| | industry average and will compare favourably against other industries where similar metrics are used.<br>Incentive: We will assess ENWL's performance using a customer satisfaction survey, a complaints metric and an assessment on the quality of stakeholder engagement. |
| Connections | Target: ENWL accepts our Time to Connect incentive targets (for smaller connection customers) and our approach to assessing its responsiveness to larger connections customers through the ICE.<br>Incentive: ENWL's performance will be assessed against the time it takes to issue quotes/make new connections and an assessment on the quality of its engagement with connection customers. |
| Environment | *Losses*<br>ENWL forecasts an 11 GWh annual reduction in losses by 2021. It will primarily achieve this by accelerating the replacement of pre-1970 transformers. We have allowed this in the cost assessment benchmarking as it was well-justified on loss reduction. We have also allowed ENWL's expenditure on electricity theft reduction initiatives as they are also well-justified. ENWL should update the supporting analysis for its losses strategy when further information on minimum standards becomes available and should clearly link the narrative to the analysis.<br>*Other environment*<br>ENWL has a good track record on environmental delivery, eg a 35% reduction in its BCF in DCPR5. It could be more ambitious in its BCF and $SF_6$ targets for RIIO-ED1 (10% BCF reduction by 2020 and $SF_6$ leakage rate reduction to 0.3% by leak detection and asset replacement). Its costs and volumes for $SF_6$ mitigation are embedded in asset replacement making its target and benefits for $SF_6$ difficult to assess. Therefore we have not specifically allowed for the costs and volumes for its $SF_6$ mitigation in the cost assessment benchmarking. ENWL intends to underground approximately 80km of lines in designated areas, spending its entire £9m allowance. There is evidence of best practice in its approach to stakeholder engagement, delivery and prioritisation for undergrounding and its ongoing commitment to a 30-year plan to phase out FFCs. We have allowed costs for its specific environment activities in the cost benchmarking where they have been |

| | | |
|---|---|---|
| | appropriately justified. | |
| Reliability | <u>Target:</u> ENWL accepts the reliability target setting methodology described in our strategy decision.<br><u>Incentive:</u> ENWL will be subject to the incentive rate setting methodology we described in the strategy decision.<br>ENWL's plan is generally strong across all aspects of reliability, in particular load modelling and asset health management.<br>We have reconciled ENWL's asset health, criticality and risk deliverables with our final determinations allowances. | |
| Social | ENWL's strategy for addressing social obligations is consistent with our strategy decision and it intends to align its work with the British Standard for vulnerability. It commits to using data better to understand who is connected to its network and how it can best serve customer needs. We consider that ENWL's focus on outputs, rather than financial expenditure, is appropriate and consistent with the RIIO approach to regulation. | |
| Expenditure | | |
| | | |
| Total expenditure (base totex) | £1,814m | |
| Financial parameters | | |
| Allowed return on equity (real post-tax) | 6.0% | |
| Allowed return on debt (real pre-tax) | Indexed using trailing average of 10 years in 2015-16; increasing by 1 year each year to 20 years in 2025-26. | |
| Notional gearing | 65% | |
| Depreciation | Straight line: 20 years on existing assets; 8-year transition to 45 years depreciation profile for new assets. | |
| Totex capitalisation rate[33] | 68% | |
| Efficiency incentive rate[34] | 58% | |
| Ex ante reward/penalty | £20m | |
| Uncertainty mechanisms | | |
| ENWL's uncertainty mechanisms are listed below. It accepted the mechanisms in the strategy decision but also proposed an additional mechanism. This is for the costs it might face depending on National Grid's chosen option to connect Moorside nuclear power station. We agree with this proposal. We have also given all slow-track DNOs an additional mechanism for costs arising from Network Rail's electrification programme and a re-opener for costs associated with managing link box risk. | | |
| Indexation | RPI indexation of allowed revenues<br>Cost of debt | |

[33] This is the proportion of totex that will be capitalised (added to the RAV).
[34] This is the share of any efficient under or overspend retained or borne by the DNO.

| | |
|---|---|
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC fixed costs[35] |
| Volume-driver | Smart meter roll-out costs |
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load-related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Moorside<br>Rail electrification<br>Link boxes |
| Trigger | Tax |

[35] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

# Appendix 3 – NPg final determinations

1.1. We summarise key elements of our final determinations for NPg in Table A3.1 below. Figures are shown (unless indicated otherwise) as RIIO-ED1 totals and are in 2012-13 prices.

1.2. We provide further detail in the 'Detailed figures by company' supplementary annex. It contains the outputs targets that each DNO will be required to achieve for customer service, connections and reliability, and the financial rewards or penalties they will receive depending on their performance. These values are not stated below.

**Table A3.1: Key elements of NPg's draft determinations**

| | NPgN | NPgY |
|---|---|---|
| Base revenue | £2,003m | £2,596m |
| *including updated pensions deficit funding* | *£1,976m* | *£2,583m* |
| Profiling[36] | Year 1: -18.2% followed by +0.08% pa | Year 1: -12.1% followed by +0.04% pa |
| *including updated pensions deficit funding* | *Year 1: -18.2% followed by -0.14% pa* | *Year 1: -12.1% followed by -0.04% pa* |
| Impact on the distribution charges included in domestic bills[36] | Year 1: -£18.31 followed by +£0.07 pa | Year 1: -£9.98 followed by +£0.03 pa |
| *including updated pensions deficit funding* | *Year 1: -£18.31 followed by -£0.11 pa* | *Year 1: -£9.98 followed by -£0.03 pa* |
| Outputs | | |
| Safety | Compliance with the safety legislation enforced by the HSE. | |
| Customer service | Target: NPg accepts our customer service targets. This means that in order to perform well under this incentive it will need to deliver a level of service to all customers that is well above the current industry average and will compare favourably against other industries where similar metrics are | |

[36] This does not include the impact of the government's December 2013 measures to reduce energy bills.

| | |
|---|---|
| | used.<br>Incentive: We will assess NPg's performance using a customer satisfaction survey, a complaints metric and an assessment on the quality of stakeholder engagement. |
| Connections | Target: NPg accepts our Time to Connect targets (for smaller connection customers) and our approach to assessing its responsiveness to larger connections customers through the ICE.<br>Incentive: NPg's performance will be assessed against the time it takes to issue quotes/make new connections and an assessment on the quality of its engagement with connection customers. |
| Environment | *Losses*<br>NPg has not identified any losses reduction expenditure or quantified benefits in its losses reduction strategy. However, it has forecast significant loss-reduction benefits from the roll-out of smart meters. We expect it to include these benefits in its updated losses strategy.<br>As part of its routine cable replacement, NPg has committed to installing oversized cables in excess of the minimum required standards, for the primary purpose of loss-reduction. NPg has clearly indicated it is driven primarily by loss-reduction and has provided CBAs with a positive NPV. We have allowed the costs associated with this in the cost assessment benchmarking. NPg highlighted an inconsistency in its cost allowances for oversizing LV cables for which we proposed to allow the losses-justified component. We expect NPg to include this initiative in its updated losses strategy. We have updated the cost allowances accordingly.<br>It stated that the costs of its EHV and 132kV transformers were higher than for other DNOs, in part due to higher losses-related specifications, and that its transformer costs should therefore be permitted. It did not confirm that the proposed transformers will exceed Ecodesign requirements.[37] We do not consider that these standards in respect of losses exceed those which will be required of other DNOs and therefore have not adjusted its allowance for these transformers based on losses.<br>*Other environment*<br>NPg's BCF strategy demonstrates best practice in reporting and monitoring of emissions from its contractors. Its RIIO-ED1 BCF target represents a |

[37] http://ec.europa.eu/enterprise/policies/sustainable-business/documents/eco-design/legislation/index_en.htm

| | | | |
|---|---|---|---|
| | reduced ambition compared to DPCR5 (10% reduction during RIIO-ED1 compared to 5% year on year in DPCR5). It intends to spend its entire £13.9m allowance undergrounding around 100km in designated areas. Like other DNOs, its plan lacks transparency on costs for activities which are embedded in other costs, eg FFC and $SF_6$ mitigation. So we have not specifically allowed for the costs and volumes of these activities in the cost assessment benchmarking. However, we have allowed costs and volumes directly for its environmental activities in the benchmarking, where they have been appropriately justified. NPg demonstrates best practice in its BCF contractor strategy and steps taken to improve transparency and accuracy on its $SF_6$ inventory, which informs its RIIO-ED1 target of not more than 112kg of $SF_6$ lost per year by 2023. | | |
| Reliability | Target: NPg accepts the reliability target setting methodology described in our strategy decision. It argues that it has greater risk than the fast-tracked group, WPD, since its historical under-performance on reliability means that it starts RIIO-ED1 behind its target. We do not view this as a risk issue as it merely reflects NPg's historical performance.<br>Incentive: NPg will be subject to the incentive rate setting methodology we described in the strategy decision.<br>NPg is forecasting some deterioration in asset health during RIIO-ED1, but states that its interventions will be more efficient. It provides plans to improve resilience. We have reconciled its asset health, criticality and risk deliverables with our final determinations totex allowances. | | |
| Social | NPg has a comprehensive strategy to address its social obligations. It recognises the important role that it can play in helping to address a range of social issues and commits to collaborating with relevant agencies to improve the service for vulnerable customers. | | |
| Expenditure | | | |
| | NPgN | NPgY | |
| Total expenditure (base totex) | £1,264m | £1,694m | |
| Financial parameters | | | |
| Allowed return on equity (real post-tax) | 6.0% | | |
| Allowed return on debt (real pre-tax) | Indexed using trailing average of 10 years in 2015-16; increasing by 1 year each year to 20 years in 2025-26. | | |
| Notional gearing | 65% | | |

| | |
|---|---|
| Depreciation | Straight line: 20 years on existing assets; 8-year transition to 45 years depreciation profile for new assets. |
| Totex capitalisation rate[38] | NPgN: 70% NPgY: 72% |
| Efficiency incentive rate[39] | 55% |
| Ex ante reward/penalty | £3m |
| Uncertainty mechanisms | |
| NPg's uncertainty mechanisms are listed below. It accepted the mechanisms in the strategy decision. We have also given all slow-track DNOs an additional mechanism for costs arising from Network Rail's electrification programme and a re-opener for costs associated with managing link box risk. | |
| Indexation | RPI indexation of allowed revenues<br>Cost of debt |
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC fixed costs[40] |
| Volume-driver | Smart meter roll-out costs |
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load-related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Rail electrification<br>Link boxes |
| Trigger | Tax |

[38] This is the proportion of totex that will be capitalised (added to the RAV).
[39] This is the share of any efficient under or overspend retained or borne by the DNO.
[40] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

# Appendix 4 – UKPN final determinations

1.1. We summarise key elements of our final determinations for UKPN in Table A4.1 below. Figures are shown (unless indicated otherwise) as RIIO-ED1 totals and are in 2012-13 prices.

1.2. We provide further detail in the 'Detailed figures by company' supplementary annex. It contains the outputs targets that each DNO will be required to achieve for customer service, connections and reliability, and the financial rewards or penalties they will receive depending on their performance. These values are not stated below.

**Table A4.1: Key elements of UKPN's draft determinations**

| | LPN | SPN | EPN |
|---|---|---|---|
| Base revenue | £3,140m | £2,754m | £4,133m |
| *including updated pensions deficit funding* | *£3,171m* | *£2,777m* | *£4,144m* |
| Profiling[41] | Year 1: -15.4% followed by +1.8%pa | Year 1: -13.4% followed by +2.1%pa | Year 1: -5.7% followed by +1.2%pa |
| *including updated pensions deficit funding* | *Year 1: -15.4% followed by +2.0%pa* | *Year 1: -13.4% followed by +2.3%pa* | *Year 1: -5.7% followed by +1.3%pa* |
| Impact on the distribution charges included in domestic bills[41] | Year 1: -£11.63 followed by around +£1.23 pa | Year 1: -£12.01 followed by around +£1.76 pa | Year 1: -£4.32 followed by around +£0.93 pa |
| *including updated pensions deficit funding* | *Year 1: -£11.63 followed by around +£1.35 pa* | *Year 1: -£12.01 followed by around +£1.88 pa* | *Year 1: -£4.32 followed by around +£0.96 pa* |
| Outputs | | | |
| Safety | Compliance with the safety legislation enforced by the HSE. | | |
| Customer service | Target: UKPN accepts our customer service targets. This means that in order to perform well under this incentive it will need to deliver a level of service to all customers that is well above the current industry average and will compare favourably against other industries where similar metrics are used.<br>Incentive: We will assess UKPN's performance | | |

[41] This does not include the impact of the government's December 2013 measures to reduce energy bills.

| | |
|---|---|
| | using a customer satisfaction survey, a complaints metric and an assessment on the quality of stakeholder engagement. |
| Connections | Target: UKPN accepts our Time to Connect incentive targets (for smaller connection customers) and our approach to assessing its responsiveness to larger connections customers through the ICE.<br>Incentive: UKPN's performance will be assessed against the time it takes to issue quotes/make new connections and an assessment on the quality of its engagement with connection customers. |
| Environment | *Losses*<br>UKPN has not identified any additional expenditure primarily driven by losses reduction benefits so we have not adjusted any of its costs or volumes in our cost assessment benchmarking because of losses. However, it has estimated a 229 GWh reduction in losses over RIIO-ED1 from an 'opportunistic' strategy, where it assesses losses reduction based on other network investment drivers or in selecting asset specifications in network design. This includes oversizing cables to reduce losses, but UKPN attributes no additional cost. We are particularly disappointed with UKPN's low estimate of losses reduction benefits from smart metering and it should refine its estimate of these benefits accordingly.<br>*Other environment*<br>UKPN demonstrates ambition by building on previous performance and good practice in some of its environmental activities. For instance, its leakage targets for FFC (supported by cost-benefit analysis), and plans for undergrounding are stretching but founded on good progress in DPCR5. Its targets for these are to underground 176km of lines in designated areas using its total £20.2m allowance and to reduce FFC leakage by 2% per annum in RIIO-ED1. This includes 37 specific FFC projects (supported by CBAs). It demonstrates good practice on tracking and monitoring of its contractors' BCF impacts and commits to a 2% reduction in BCF per annum. Other commitments, eg $SF_6$ mitigation, still lack clarity (it commits to minimising impact through exceeding international standard leakage rates) and so actual savings are less certain. We have allowed environmental costs and volumes in the benchmarking where they have been appropriately justified. |
| Reliability | Target: UKPN accepts the reliability target setting |

| | | | |
|---|---|---|---|
| | methodology described in our strategy decision. It proposes tighter targets for CI and CML in LPN which we have accepted.<br>Incentive: UKPN will be subject to the incentive rate setting methodology we described in the strategy decision.<br>Both LPN and SPN have relatively poor load indices in their plans, with EPN somewhat better. SPN and EPN have stronger health indices than LPN. We have reconciled its asset health criticality and risk metrics with our final determinations totex allowances. | | |
| Social | UKPN provides detailed information on how it will improve the service provided to PSR customers. It commits to developing partnerships during RIIO-ED1 to deliver positive outcomes for vulnerable customers. | | |
| Expenditure | | | |
| | LPN | SPN | EPN |
| Total expenditure (base totex) | £1,771m | £1,722m | £2,536m |
| Financial parameters | | | |
| Allowed return on equity (real post-tax) | 6.0% | | |
| Allowed return on debt (real pre-tax) | Indexed using trailing average of 10 years in 2015-16; increasing by 1 year each year to 20 years in 2025-26. | | |
| Notional gearing | 65% | | |
| Depreciation | Straight line: 20 years on existing assets; 8-year transition to 45 years depreciation profile for new assets. | | |
| Totex capitalisation rate[42] | 68% | | |
| Efficiency incentive rate[43] | 53% | | |
| Ex ante reward/penalty | -£32m | | |
| Uncertainty mechanisms | | | |
| UKPN's uncertainty mechanisms are listed below. It accepted the mechanisms in the strategy decision. We have also given all slow-track DNOs an additional mechanism for costs arising from Network Rail's electrification programme and a re-opener for costs associated with managing link box risk. | | | |
| Indexation | RPI indexation of allowed revenues<br>Cost of debt | | |
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC fixed costs[44] | | |
| Volume-driver | Smart meter roll-out costs | | |

[42] This is the proportion of totex that will be capitalised (added to the RAV).
[43] This is the share of any efficient under or overspend retained or borne by the DNO.
[44] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

| | |
|---|---|
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load-related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Rail electrification<br>Link boxes |
| Trigger | Tax |

# Appendix 5 – SPEN final determinations

1.1. We summarise key elements of our final determinations for SPEN in Table A5.1 below. Figures are shown (unless indicated otherwise) as RIIO-ED1 totals and are in 2012-13 prices.

1.2. We provide further detail in the 'Detailed figures by company' supplementary annex. It contains the outputs targets that each DNO will be required to achieve for customer service, connections and reliability, and the financial rewards or penalties they will receive depending on their performance. These values are not stated below.

**Table A5.1: Key elements of SPEN's draft determinations**

| | SPD | SPMW | |
|---|---|---|---|
| Base revenue | £2,720m | £2,436m | |
| *including updated pensions deficit funding* | *£2,762m* | *£2,488m* | |
| Profiling[45] | Year 1: +5.1% followed by +0.08%pa | Year 1: -26.2% followed by -0.01%pa | |
| *including updated pensions deficit funding* | *Year 1: +5.1% followed by +0.33%pa* | *Year 1: -26.2% followed by +0.34%pa* | |
| Impact on the distribution charges included in domestic bills[45] | Year 1: +£4.23 followed by +£0.07pa | Year 1: -£34.80 followed by -£0.01pa | |
| *including updated pensions deficit funding* | *Year 1: +£4.23 followed by +£0.29pa* | *Year 1: -£34.80 followed by +£0.34pa* | |
| Outputs | | | |
| Safety | Compliance with the safety legislation enforced by the HSE. | | |
| Customer service | Target: SPEN accepts our customer service targets. This means that in order to perform well under this incentive it will need to deliver a level of service to all customers that is well above the current industry average and will compare favourably against other industries where similar metrics are used.<br>Incentive: We will assess SPEN's performance using a customer satisfaction survey, a complaints metric and an assessment on the quality of stakeholder engagement. | | |

[45] This does not include the impact of the government's December 2013 measures to reduce energy bills.

| | |
|---|---|
| Connections | Target: SPEN accepts our Time to Connect incentive targets (for smaller connection customers) and our approach to assessing its responsiveness to larger connections customers through the ICE.<br>Incentive: SPEN's performance will be assessed against the time it takes to issue quotes/make new connections and an assessment on the quality of its engagement with connection customers. |
| Environment | *Losses*<br>SPEN's losses reduction strategy represents a significant improvement compared with that provided at fast-track. It forecasts a 163 GWh reduction in losses over RIIO-ED1 with losses reduction-driven expenditure focussed on accelerated replacement of pre-1962 transformers. We have allowed this volume of transformer replacement in the cost assessment benchmarking as it was appropriately justified. Since the rest of its transformer replacement is part of routine activities and will either not incur additional costs or not exceed Ecodesign 2015 standards we have not separately assessed these costs in the benchmarking. SPEN's revised losses strategy should relate more clearly to the supporting analysis.<br>*Other environment*<br>SPEN's slow-track plan provides clarity and justification of its environmental targets and some indication of stakeholder engagement and prioritisation for visual amenity projects. It clarified that it intends to spend its full RIIO-ED1 allowance of £12.2m to underground 85km of lines in designated areas. It notably shifted from its parent company BCF target, to its own (lower) target of 15% reduction through various actions. This represents one of the most ambitious targets across the DNOs. SPEN included more evidence of benefits around mitigation of $SF_6$ and FFC. It supports its FFC target of 50% reduction with additional justification. It also provides clarity on what its $SF_6$ target means, ie through procurement of lower leakage equipment it forecasts a reduction of 658 $tCO_2$ per annum. However, there is limited evidence whether the volumes for FFC reported in its data templates or the proposed targets for BCF and $SF_6$ are achievable, given its limited track record. We have allowed its costs for specific environment activities in the cost benchmarking where they have been appropriately justified. |

| | | | |
|---|---|---|---|
| Reliability | Target: SPEN accepts the reliability target setting methodology described in our strategy decision.<br>Incentive: SPEN will be subject to the incentive rate setting methodology we described in the strategy decision.<br>SPEN has submitted better developed criticality indices than it did at fast-track, but has not provided health or criticality information for low voltage assets. It was the only DNO to submit health and criticality indices for civil assets and is stronger in this area than in relation to its load indices. We have reconciled SPEN's asset health, criticality and risk secondary deliverables with our final determinations totex allowances. | | |
| Social | SPEN's Social Obligations Strategy provides more information about how it will improve services to vulnerable consumers. We consider that SPEN's slow-track social proposals are clearer and better structured. The slow-track business plan is more specific about how SPEN will provide support to vulnerable customers. Overall, we consider that SPEN's slow-track social outputs are acceptable. | | |
| Expenditure | | | |
| | SPD | SPMW | |
| Total expenditure (base totex) | £1,514m | £1,665m | |
| Financial parameters | | | |
| Allowed return on equity (real post-tax) | 6.0% | | |
| Allowed return on debt (real pre-tax) | Indexed using trailing average of 10 years in 2015-16; increasing by 1 year each year to 20 years in 2025-26. | | |
| Notional gearing | 65% | | |
| Depreciation | Straight line: 20 years on existing assets; 8-year transition to 45 years depreciation profile for new assets. | | |
| Totex capitalisation rate[46] | 80% | | |
| Efficiency incentive rate[47] | 54% | | |
| Ex ante reward/penalty | -£14m | | |
| Uncertainty mechanisms | | | |
| SPEN's uncertainty mechanisms are listed below. It accepted the mechanisms in the strategy decision. We have also given all slow-track DNOs an additional mechanism for costs arising from Network Rail's electrification programme and a re-opener for costs associated with managing link box risk. We will also give SPEN SSEPD's proposed change to extend the existing street works mechanism if new legislation is passed in Scotland. | | | |
| Indexation | RPI indexation of allowed revenues<br>Cost of debt | | |

[46] This is the proportion of totex that will be capitalised (added to the RAV).
[47] This is the share of any efficient under or overspend retained or borne by the DNO.

| | |
|---|---|
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC fixed costs[48] |
| Volume-driver | Smart meter roll-out costs |
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load-related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Rail electrification<br>Link boxes |
| Trigger | Tax |

[48] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

# Appendix 6 – SSEPD final determinations

1.1. We summarise key elements of our final determinations for SSEPD in Table A6.1 below. Figures are shown (unless indicated otherwise) as RIIO-ED1 totals and are in 2012-13 prices.

1.2. We provide further detail in the 'Detailed figures by company' supplementary annex. It contains the outputs targets that each DNO will be required to achieve for customer service, connections and reliability, and the financial rewards or penalties they will receive depending on their performance. These values are not stated below.

**Table A6.1: Key elements of SSEPD's draft determinations**

| | SSEH | SSES |
|---|---|---|
| Base revenue | £2,049m | £3,815m |
| *including updated pensions deficit funding* | *£2,059m* | *£3,803m* |
| Profiling[49] | Year 1: -18.2% followed by +0.64%pa | Year 1: -18.0% followed by +0.11%pa |
| *including updated pensions deficit funding* | *Year 1: -18.2% followed by +0.72%pa* | *Year 1: -18.0% followed by +0.06%pa* |
| Impact on the distribution charges included in domestic bills[49] | Year 1: -£26.95 followed by +£0.78pa | Year 1: -£17.84 followed by +£0.09pa |
| *including updated pensions deficit funding* | *Year 1: -£26.95 followed by +£0.88pa* | *Year 1: -£17.84 followed by +£0.05pa* |
| Outputs | | |
| Safety | Compliance with the safety legislation enforced by the HSE. | |
| Customer service | Target: SSEPD accepts our customer service targets. This means that in order to perform well under this incentive it will need to deliver a level of service to all customers that is well above the current industry average and will compare favourably against other industries where similar metrics are used.<br>Incentive: We will assess SSEPD's performance using a customer satisfaction survey, a complaints metric and an assessment on the quality of stakeholder engagement. | |

[49] This does not include the impact of the government's December 2013 measures to reduce energy bills.

| | |
|---|---|
| Connections | Target: SSEPD accepts our Time to Connect incentive targets (for smaller connection customers) and our approach to assessing its responsiveness to larger connections customers through the ICE.<br>Incentive: SSEPD's performance will be assessed against the time it takes to issue quotes/make new connections and an assessment on the quality of its engagement with connection customers. |
| Environment | *Losses*<br>SSEPD has provided more supporting analysis of its losses reduction approach than it did at fast-track. However, it has not provided a coherent losses strategy and its narrative is not clearly supported by robust analysis. It forecasts a losses reduction of 739 GWh over RIIO-ED1. This appears to be overestimated in comparison with the reductions forecast by other DNOs proposing similar measures. It has identified relatively low expenditure on losses reduction-driven activity. Its expenditures are primarily for cable replacement, for which we have not adjusted cost assessment benchmarking as SSEPD has not provided a robust supporting CBA.<br>As part of its routine asset replacement, SSEPD has committed to install transformers that exceed the minimum Ecodesign 2015 standards. We have allowed the costs associated with the increased specification of these transformers as they have been appropriately justified.<br>*Other environment*<br>SSEPD demonstrates a focus on stakeholder engagement for visual amenity and well-detailed (and now justified) benefits for its BCF target. SSEPD intends to underground 90km of lines using its full allowance of £15.1m. With no track record for undergrounding, there is limited justification for whether this target is deliverable. It is ambitious compared to other DNOs. Its BCF target, a 15% reduction over RIIO-ED1, is broken down into a set of individual targets by category. It targets reducing its rate of $SF_6$ leakage by 15% through asset maintenance and commits to specific replacement projects to reduce FFCs. Its target for FFC (ie oil leakage) is a 15% reduction for RIIO-ED1 relative to 2012-13 through these specific replacement projects. Its costs appear high (with limited rationale) for these FFC activities and therefore we have adjusted them in the cost assessment. In addition, there is some |

| | | | |
|---|---|---|---|
| | inconsistency between costs or actions and projected savings for $SF_6$ and FFC. We have allowed costs for its environmental activities in the cost benchmarking where they have been appropriately justified. | | |
| Reliability | Target: SSEPD accepts the reliability target setting methodology described in our strategy decision. It proposes tighter CI and CML targets for SSEH which we have accepted.<br>Incentive: SSEPD will be subject to the incentive rate setting methodology we described in the strategy decision.<br>For slow-track SSEPD has included criticality indices, which were missing at fast-track. SSES's load indices were stronger than SSEH's. We have reconciled SSEPD's asset health, criticality and risk secondary deliverables with our final determinations totex allowances. | | |
| Social | We were not convinced that SSEPD's fast-track business plan had a comprehensive strategy to address consumer vulnerability in both Scotland and England.<br>In its slow-track business plan SSEPD provides a new "Strategy for Customer Vulnerability". It commits to ensuring equal access to services for all consumers and improving the information that it holds on customers. Its slow-track social proposals also provide a more balanced approach across its SSEH and SSES regions.<br>Overall, we consider that SSEPD's slow-track social proposals are acceptable. | | |
| Expenditure | | | |
| | SSEH | SSES | |
| Total expenditure (base totex) | £1,202m | £2,330m | |
| Financial parameters | | | |
| Allowed return on equity (real post-tax) | 6.0% | | |
| Allowed return on debt (real pre-tax) | Indexed using trailing average of 10 years in 2015-16; increasing by 1 year each year to 20 years in 2025-26. | | |
| Notional gearing | 65% | | |
| Depreciation | Straight line: 20 years on existing assets; 8-year transition to 45 years depreciation profile for new assets. | | |
| Totex capitalisation rate[50] | SSEH: 2015/16–18/19 62%; 2019/20-22/23 70%<br>SSES: 70% | | |
| Efficiency incentive rate[51] | 56% | | |

[50] This is the proportion of totex that will be capitalised (added to the RAV).
[51] This is the share of any efficient under or overspend retained or borne by the DNO.

| | |
|---|---|
| Ex ante reward/penalty | £20m |
| **Uncertainty mechanisms** | |
| SSEPD's uncertainty mechanisms are listed below. It accepted the mechanisms in the strategy decision but also proposed three additional mechanisms. These are (a) a time-limited mechanism (part ex ante, part pass-through) for the interim costs of supplying energy in Shetland (b) to extend the existing street works mechanism if new legislation is passed in Scotland (c) a mechanism for costs arising from Network Rail's electrification programme. We agree with these mechanisms, although we have modified elements for Shetland (as explained in Appendix 7). We have given all slow-track DNOs a re-opener for costs associated with managing link box risk. | |
| Indexation | RPI indexation of allowed revenues<br>Cost of debt |
| Pass-through | Business rates<br>Ofgem licence fees<br>DCC fixed costs[52]<br>Shetland |
| Volume-driver | Smart meter roll-out costs |
| Re-openers | Street works<br>Enhanced physical site security<br>High Value Projects<br>Load-related expenditure<br>Innovation roll-out mechanism<br>Pension deficit repair mechanism<br>Rail electrification<br>Link boxes<br>Subsea cables<br>Shetland |
| Trigger | Tax |

[52] Smart meter Data Communications Company (DCC) fixed costs are costs/fees that will be charged to the DNOs for use of the DCC services.

# Appendix 7 - Shetland

**Appendix Summary**

Our decision on transitional arrangements for the cost of power on Shetland.

**Introduction**

1.3. The Shetland Islands distribution network is not connected to the GB mainland. It is supplied by energy generated on the Islands. SSEH runs the distribution network. It also operates generation assets and Power Purchase Agreements (PPAs) to meet demand on the Islands. While there are future plans for a link to the mainland, there are currently no transmission assets on the islands.

1.4. The cost of energy generation on Shetland is significantly higher than on the mainland, and the difference between this cost and the GB wholesale price is cross-subsidised by all northern Scotland customers.[53]

1.5. Shetland's main generator, Lerwick Power Station (LPS[54]), is reaching the end of its life. SSEH[55] also has a PPA with Sullom Voe Terminal (SVT) to supply most of the remaining demand. SSEH claims the availability of SVT is uncertain beyond 2017.[56]

1.6. In DPCR5 we required SSEH to develop an integrated plan for an enduring solution for the energy supply on Shetland. SSEH submitted a plan in July 2013. We rejected it on the basis of its costs, and instructed SSEH to run a competitive process to find a market solution for Shetland's energy supply.[57]

1.7. The competitive process will run in 2015. Once agreed, a solution is expected to be procured and commissioned by 2019. We need interim arrangements to recover the cost of the cross subsidy until this solution is in place.

1.8. SSEH currently recovers the Shetland energy costs through a combination of an ex ante allowance and pass-through mechanisms. There is currently no incentive for SSEH to reduce the pass-through costs.

[53] Currently the subsidy is paid for by SSEH's customers but a recent DECC consultation seeks to spread this cost across GB once the enduring solution is in place.
[54] LPS is a 67MW diesel fired power station owned by SSE generation which meets around 52% of demand
[55] through SSE Energy Supply Ltd
[56] SVT is a privately owned 100MW gas fired power station that provides supply of up to 22MW and meets around 41% of demand.
[57] https://www.ofgem.gov.uk/ofgem-publications/87381/ofgemdeterminationofshepdsubmissionundercrc18a.pdf

1.9. In August 2014 we received SSEH's proposals for recovering the costs of the cross subsidy for Shetland until the new energy solution is operational in 2019. We consulted on our proposals for the cost recovery mechanism in in October 2014.[58]

**Decision**

1.10. We agree that cost recovery arrangements are required for the interim period until an enduring energy solution is established on Shetland. However, we think changes to SSEH's proposed cost recovery arrangements are needed to incentivise efficient costs. These changes are consistent with our RIIO-ED1 policy to limit pass-through mechanisms.

1.11. We have decided on a multi-level arrangement which we summarise in the table below. SSEH will only be allowed to pass-through costs it has limited ability to influence. We are including a number of cost items in SSEH's ex ante allowance, which will encourage SSEH to make these costs efficient, as they will be subject to the efficiency incentive. Legacy provisions will allow SSEH to recover costs it incurred in DPCR5 that it has not yet recovered. Uncertain costs will be subject to a re-opener in 2017.

1.12. There will be two types of reopener. They will be triggered if costs exceed 10% of that portion of the ex ante allowance. We also note that there are two lots of NINES[59] project costs. Firstly, the remaining NINES project cost that will be recovered through the DPCR5 RAV Rolling Incentive.[60] Secondly, the additional NINES integration and operating costs that will be recovered as part of the Shetland Fixed Energy Allowance and subject to the efficiency incentive.

1.13. We have adjusted SSEH's totex capitalisation rate in years one to four to take account of the new cost recovery arrangements. This is now 62% for the four years. We have updated corresponding tax pools to derive the correct tax allowances.

**Shetland energy costs RIIO-ED1 cost recovery arrangements**

| Mechanism | Item | Description |
|---|---|---|
| Pass-through | Shetland Variable Energy Costs | • Fuel costs for LPS, including for any contingency arrangements (mobile generation)<br>• Environmental Permit |

[58] Consultation on Scottish Hydro Electric Power Distribution (SSEH's) Shetland Energy Costs recovery arrangements https://www.ofgem.gov.uk/publications-and-updates/consultation-scottish-hydro-electric-power-distribution-sseh%E2%80%99s-shetland-energy-costs-recovery-arrangements
[59] The NINES project is trialling a range of innovative solutions to deliver a secure, affordable and reliable energy system for Shetland.
[60] The DPCR5 RAV Rolling Incentive was superseded by the RIIO-ED1 Totex Incentive Mechanism

| | | |
|---|---|---|
| | | costs<br>• Less income from units purchased by suppliers.[61] |
| Legacy provision – (DPCR5 RAV Rolling Incentive) | NINES – Northern Isles New Energy Solutions | The remaining allowance for the NINES project. |
| | Integrated Plan Costs | Outstanding efficiently incurred costs of developing the Integrated Plan, submitted in 2013. |
| Ex ante allowance, subject to re-opener below (with 10% materiality threshold) | Shetland Fixed Energy Costs Allowance | • Costs of SVT PPA<br>• Contingency costs (excluding fuel), if applicable<br>• LPS capital and operating costs (excluding fuel)<br>• Cost of integrating and operating solutions from the NINES project.[62] |
| | Competitive Process Costs | Outstanding efficiently incurred costs of running the competitive process. |
| Re-opener (in 2017) for costs over materiality threshold | Uncertain Shetland Fixed Energy Costs | • Cost of the SVT PPA plus contingency costs (if applicable)<br>• LPS capital and operating costs<br>• Cost of integrating solutions from the NINES project |
| | Uncertain Competitive Process Costs | Outstanding cost of running the competitive process. |

**Our proposals**

1.14. Our proposals were broadly the same as our decision, other than:

- An uncertainty threshold of 20% was proposed for the Uncertain Shetland Fixed Energy Costs Allowance and the Uncertain Competitive Process Costs.
- We consulted on options for the reopener to be in 2016 or 2017.
- We included a combined ex ante allowance for the Integrated Plan and Competitive Process Costs, subject to a reopener.
- NINES remaining allowance was to be included separately ex ante.
- No allowance was provided for NINES integration and operating costs.
- We did not include capitalisation rate adjustments.

[61] SHEPD receives income for electricity units which are generated on Shetland and purchased by suppliers
[62] NINES project will continue to recruit additional customers under Demand Side Management (DSM)

### Responses

1.15. We received three responses. Two stakeholders commented on a new energy solution for Shetland. One thought a solution is needed that can easily integrate with the GB mainland in the event of a connection. The second had concerns over the high ongoing cost of electricity on Shetland and points to many potential alternative energy options.

1.16. SSEH was disappointed with the changes proposed to its cost recovery arrangements, particularly in relation to the SVT PPA costs and contingency costs. SSEH was concerned about the arrangements we proposed for the Integrated Plan and competitive process costs. It stated that the proposals affect its totex capitalisation rate compared to what it included in its business plan. It proposed a new rate.

### Reasons for our decision

1.17. We have had discussions and exchanged information with SSEH throughout the process of finalising its cost recovery arrangements. We have considered concerns it raised in its response. We believe our decisions adequately manage any of the risks highlighted by SSEH. Our objective is to provide the right incentives to SSEH to minimise the cost of the cross subsidy for Shetland while ensuring security of supply until the enduring solution is commissioned in 2019.

1.18. Pass-through items relate to uncertain costs that are not in SSEH's direct control, so it is reasonable that they are passed through to its customers. The pass-through costs that meet the criteria are LPS fuel costs (including fuel costs for any contingency arrangements), environmental permit costs and income from electricity units purchased by suppliers. These cost items will be subject to a two-year lag.

1.19. We are allowing the remainder of the NINES project costs to be recovered through the DPCR5 RAV Rolling Incentive.[63] We agree with SSEH's proposal with regard to the outstanding Integrated Plan Costs, and are also allowing these costs to be recovered as a legacy item through the DPCR5 RAV Rolling Incentive in two parts. Firstly we will provide an allowance for some of these costs, including externally procured staff costs. Secondly we will allow SSEH to make a proposal, with further evidence, for the recovery of efficient related party staff costs.

1.20. The Shetland Fixed Energy Costs item is made up of the SVT PPA costs, contingency costs, LPS capital and operating costs and NINES integration and operating costs. The SVT PPA is necessary to balance supply and demand on Shetland. These costs are somewhat driven by demand and system dynamics, but they are also subject to negotiated contracts with SVT. SSEH can influence the value

[63] As per our NINEs funding decision letter Decision on funding for the Shetlands Northern Isles New Energy Solutions (NINES) Project https://www.ofgem.gov.uk/publications-and-updates/decision-funding-shetlands-northern-isles-new-energy-solutions-nines-project

of these contracts. Contingency costs, LPS capital and operating costs and NINES ongoing costs are also in SSEH's direct control. These cost items can be forecast with some certainty. Therefore we are including an allowance for these costs in SSEH's ex ante allowance. This will be subject to the efficiency incentive, which will encourage SSEH to ensure costs are efficient.

1.21. We recognise some uncertainty with the Shetland Fixed Energy Costs and therefore they will be subject to a reopener. We agree with SSEH's response that the uncertainty threshold of 20% may leave it open to risk. We have reviewed the variability in the Shetland energy costs, excluding fuel costs, for DPCR4 and DPCR5. The standard deviation in these costs (as a proportion of the mean and median) suggests that a reopener threshold of between 10 and 15% could be justified. Given SSEH's response, we consider that a reopener threshold of 10% is appropriate. This negates the need to separately index SVT PPA fuel costs as proposed by SSEH. If SSEH submits a reopener, detailed evidence for all cost variations must be provided.

1.22. The Competitive Process costs are necessary to find an enduring solution for Shetland as described in our decision letter,[64] and are under SSEH's direct control. However these costs are currently uncertain, particularly the related party staff costs. We are setting an ex ante allowance for some of these costs, subject to a reopener with a 10% threshold.

1.23. We consulted on either 2016 or 2017 for the re-opener. We have decided on 2017, when SSEH will have a better understanding of its uncertain costs. We do not agree that another window is needed in 2019. In 2019, SSEH's cost recovery arrangements for Shetland will have to be modified in light of the new energy solution.

1.24. Both reopeners are symmetrical. The Authority can propose a reopener if costs decrease below the threshold amount.

1.25. We are changing SSEH's totex capitalisation rate for the first four years of RIIO-ED1. This is in line with its response. This change has a broadly neutral effect on SSEH's revenue requirement in the affected years. At the time of our draft determinations, the Shetland energy costs were assumed to be remunerated as fast money. As we have limited the amount of costs recovered by pass-through and now provide an ex ante totex allowance for some costs, these costs are now included in the totex capitalisation. Without any change, this would inappropriately defer some of the cost recovery. It would mean they are remunerated by future consumers. We have reduced the capitalisation rate to avoid this anomaly.

[64] Ofgem's determination of Scottish Hydro Electric Power Distribution plc's (SHEPD) submission required under Charge Restriction Condition (CRC) 18A, 22 April 2014 https://www.ofgem.gov.uk/ofgem-publications/87381/ofgemdeterminationofshepdsubmissionundercrc18a.pdf

# Appendix 8 – Financial

**Appendix Summary**

Further detail on three aspects of our financial assessment – the halo effect, distortion in forward inflation rates, rolling forward the cost of debt index and adjustments for a structural change in RPI inflation.

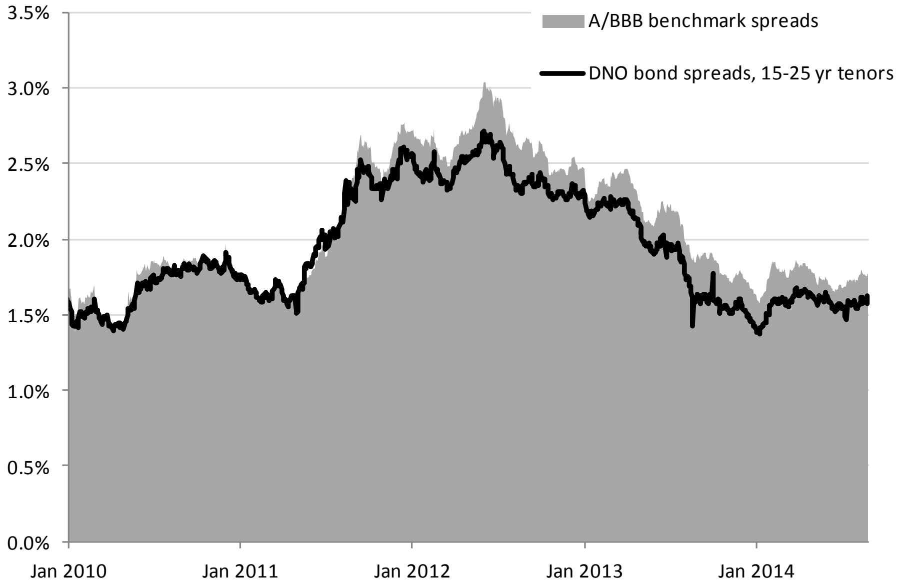
**Halo effect**

1.1. In our draft determinations, we presented a comparison between the daily yields implied by the market prices for traded DNO bonds and the benchmark yields used in our cost of debt index. It showed a sizeable difference which we attributed to what is known as the halo effect. The halo effect is the name given to an observed tendency for regulated network bonds to be priced at a premium by the markets. This could be a reflection of their relatively low risk status. Our view is that this halo effect gives companies an in-built tendency to beat the RIIO cost of debt index There is therefore no need for us to adjust the index to incorporate issuance costs and other fees. These costs represent about a further 0.2% cost to the DNOs.

1.2. Our draft determinations analysis of the halo effect did not account for differences in the tenors (the remaining term of each bond) between the population of DNO bonds and the bonds tracked by the benchmark. A number of DNOs claim that, after adjusting for tenors, there is no clear evidence of a halo effect.

1.3. We have revised our analysis to take account of tenors. We think it is appropriate to compare the yields on DNO bonds that have remaining tenors of between 15 and 25 years. This represents the bond terms DNOs might issue to be consistent with the RIIO-ED1 slow-track cost of debt index. The Figure A8.1 shows the results of our revised analysis. The value-weighted average tenor of the relevant DNO bonds remained close to 20.0 years during the period charted.

**Figure A8.1: Comparison of DNO to benchmark bond spreads**




1.4. Our analysis indicates that there is still a halo effect. The average difference in spreads since the start of 2012 is about 0.2%, although on this analysis the effect appears to be negligible in the period before. Our analysis in previous reviews, which considered differences at the dates of bond issues, found evidence of a halo effect.

1.5. These measures of the halo effect relate to DNOs' ability to issue debt at coupons lower than benchmark yields at the time of issue.

1.6. There are other opportunities for DNOs to outperform a cost of debt index. DNOs may, for example, time their debt issues to gain advantage against an index that weights all trading days equally. A supplier submitted a consultant report as part of their draft determinations response. The report states there is also significant scope for DNOs to lock in headroom by using the shape of the yield curve to good advantage. It describes how current debt portfolios have been influenced by this kind of treasury strategy.

1.7. While these other opportunities may be significant, they do not provide us with firm additional evidence of a halo effect that we can take account of in this review.

1.8. We think the analysis that informed our decisions at previous reviews and our updated analysis of bond spreads indicates that DNOs are able to issue debt at coupons lower than benchmark yields. We conclude that we do not need to adjust the cost of debt index to account for issuance and other fees.

**Distortions in forward inflation rates**

1.9. In draft determinations we described NPg's submission that the forward inflation rates we use to deflate nominal benchmark bond yields in our cost of debt index are distorted by market factors and an inflation risk premium. We acknowledged that there could be a significant inflation risk premium in nominal bond yields. The existing portfolio of DNO debt is predominantly fixed rate in nominal terms.

1.10. We also explained that, to the extent that a DNO is required to issue conventional debt and not just index-linked debt, it would suffer the additional cost of an inflation premium in its interest payments. However, the DNO is financing an asset, the RAV, which is mechanically indexed using the RPI. Investors in the RAV, taking both debt and equity investors together, are fully protected from inflation risk. Equity investors would be able to hedge away any inflation risk. This suggests there should be no inflation premium overall.

1.11. We concluded it would be inappropriate for us to impose additional costs on consumers by allowing for a higher overall WACC for any inflation risk in the financing of an inflation-proofed asset.

1.12. NPg argued in response that the regulatory process in RIIO-ED2 and subsequent reviews could reintroduce inflation risk and make an inflation risk premium appropriate. If RPI were to fall before the next price control review it would increase the DNOs' real cost of embedded debt. If we were to reflect this increase in the design of the cost of debt index for the next review, we would protect equity investors from inflation risk, but would re-introduce inflation risk for debt and equity investors taken together.

1.13. An investment in regulated network equity can be thought of as a hedge against inflation risk in fixed interest debt. Regulated network equity could therefore be especially valuable to investors in fixed interest debt, including investors in conventional gilts, as an inflation hedge. Such investors might reasonably ascribe a high value to any longer-term component of that hedge. A periodic re-calibration of the cost of debt index to adjust for changes in inflation could therefore have the effect of taking away that value.

1.14. This means we need to be cautious in adjusting our cost of capital allowances for changes in underlying levels of inflation. We noted in our decision on our equity market return methodology that we plan to examine a number of risk issues over the RIIO-ED1 period in preparation for future RIIO price controls. We expect to include inflation risk as one of those issues.

1.15. We therefore do not consider it necessary to provide for any component of inflation risk premium at this review.

## Rolling forward the cost of debt index

1.16. The RIIO-ED1 cost of debt index will transition to a 20-year trailing average index shortly after the end of RIIO-ED1. Consistent with our RIIO principles and the RIIO Handbook, we envisage retaining the same index specification for RIIO-ED2 and subsequent reviews subject to a check that the index still provides a reasonable estimate of the cost of debt.

1.17. We do not expect the index to diverge materially from the DNOs' cost of debt. If a divergence were material, we would make any change to the cost of debt index with caution. If DNOs maintain their general practice of issuing debt that matures after about 20 years, we would expect to maintain a 20-year trailing average principle.

## Adjustments for a structural change in RPI inflation

1.18. Our assessments of the cost of equity and of real price effects take account of a structural change in the measure of inflation using the Retail Prices Index (RPI) relative to real world prices. This arose from changes in how data on price changes are collected by the Office of National Statistics (ONS). We note that the RPI is no longer designated as a National Statistic.

1.19. We estimate that there has been an additional 0.4% per annum included in the measurement of RPI inflation as a result of statistical artefacts. We explained the background to this change in our November 2013 assessment of the RIIO-ED1 fast track business plans, our December 2013 consultation and February 2014 decision on our methodology for estimating the equity market return.

1.20. We explained in our February 2014 decision that there are three components to our estimate of the effect.

1.21. There are two components relating to differences in the statistical formulae used in the measure of RPI and the Consumer Prices Index (CPI). The first relates to the use of the Carli formula rather than the Jevons formula used in the CPI. The ONS recognises there is a fundamental problem with the Carli formula in that it has a propensity to create an upward bias in the measurement of inflation. The second relates to differences in the use of the Dutot formula, which RPI relies on more heavily than the CPI.

1.22. The third component relates to a structural change in the CPI measure. The changes in the ONS price collection guidelines were intended to improve the measurement of CPI inflation. Based on its review of ONS data on the impact these changes could have on CPI inflation, one DNO estimated that CPI will now be measured about 0.4 to 0.6 percentage points higher than it would have been previously.

1.23. A number of DNOs present analysis of the differences between the RPI and a new measure of inflation introduced by the ONS, RPIJ. The RPIJ is constructed in the same way as the RPI except that the Jevons formula is used in place of the Carli formula. It therefore avoids the main source of bias in the RPI.

1.24. A report by NERA on behalf of the DNOs estimates the structural difference between RPI and RPIJ to be no more than about 0.3%. With the prospect of routine changes to the RPI such as the annual update of the basket and weights, improvements to data validation and quality assurance, NERA considered an adjustment of 0.15% would be more reasonable.

1.25. NERA's analysis was based on differences between the RPI and RPIJ. We note that the RPIJ's scope, weights and use of the Dutot are the same as in the RPI, so the differences between the RPI and RPIJ do not capture all the differences between the RPI and CPI. Guided by our advisers for our February 2014 decision, we considered a reasonable adjustment for all of these formula effects would be 0.25%. A structural change in CPI adds to these effects.

1.26. We see no need to revisit our assessment in February that an overall adjustment of 0.4% was necessary.

**Ensuring financial resilience**

1.27. To gain insight into a network operator' financial resilience, we introduced a new interest cover ratio for our RIIO-ED1 analysis. It is a post-maintenance interest cover ratio, but not the same as the one used by rating agencies. We call it $PMICR_G$.

1.28. A number of respondents queried our use of this ratio in light of the fact that it is not used by the rating agencies.

1.29. Two of the credit rating agencies use a post-maintenance interest cover ratio (sometimes called an adjusted interest cover ratio) which calculates the funds from operations available after maintaining the value of capital and divides the result by interest payments. They use a real definition of value. The agencies believe it is a useful measure of liquidity. We give it full weight in our analysis of companies' credit rating metrics and our simulation of their ratings.

1.30. Our $PMICR_G$ measure is a longer term measure of financial resilience. Instead of a capital value maintenance concept, our new measure calculates the funds from operations available after maintaining the quality of capital. The quality of capital relates to a company's gearing ratio, the proportion of its capital represented by debt.

1.31. We believe it is a useful measure for us to forecast at the time of a price control review. It helps us ensure our decisions are consistent with the financial resilience of the regulated companies.

1.32. We calculate $PMICR_G$ as follows:

1.33. $PMICR_G = \frac{FFO + interest - NetRAVdepreciation - (1-\hat{g}) \cdot \Delta RAV_{Nominal}}{interest_{expense}}$

1.34. where $NetRAVdepreciation$ = regulatory depreciation of the RAV less indexation uplift of the RAV and $\hat{g}$ = our assumed notional gearing ratio

1.35. We calibrate a threshold for $PMICR_G$ to indicate resilience to what we think are plausible downsides for a licensee company, which we take to be overall RORE underperformance of about 4 per cent per annum. For RIIO-ED1, we used a threshold $PMICR_G$ of 1.4.

# Appendix 9 – Impact assessment

1.1. This appendix summarises our assessment of:

- the impact of our final determinations for the slow-track DNOs
- the impact of our changes to specific policies described in our strategy decision.

1.2. It consolidates and expands the discussion of impacts in the chapters of this document and the supplementary annexes. It is not a stand-alone assessment. These documents in their entirety form our assessment of the impacts of implementing RIIO-ED1 for the slow-track companies for the purposes of section 5A of the Utilities Act 2000.

1.3. We have previously published the impact assessments below, which are relevant to this appendix.

- the adoption of the RIIO regulatory regime[65]
- the RIIO-ED1 policy framework described in the strategy decision[66]
- our decision to fast-track WPD
- our draft determinations for the slow-track DNOs, including changes to certain policies in the strategy decision.[67]

1.4. In this impact assessment we consider the following factors:

- monetised impacts
- distributional impact
- hard-to-monetise impacts:
    - impact on competition
    - impact on sustainability
    - impact on fuel poverty and consumer vulnerability & impact on health and safety
    - impact on European internal market/third package.

1.5. We assess these final determinations against a base case of accepting the DNOs' slow-track plans as submitted.

1.6. We assess the proposed policy changes against a base case of no change.

[65] https://www.ofgem.gov.uk/ofgem-publications/51904/impact.pdf
[66] https://www.ofgem.gov.uk/ofgem-publications/47150/riioed1sconimpactassessment.pdf
[67] https://www.ofgem.gov.uk/ofgem-publications/84602/draftdeterminationsmaster.pdf

## Monetised impacts

1.7. Under the RIIO framework, the onus is on the DNOs to demonstrate that their business plans are cost efficient and give long-term value for money. All the slow-track DNOs revised their plans from those submitted at fast-track. This resulted in a reduction of more than £700m in expenditures and improved justifications and narratives.

1.8. We have reviewed and consulted on the slow-track plans (as described in the main section of the document), and considered the responses to our draft determinations. Our final determinations accept many elements that the DNOs have proposed during the course of this process, but in several areas our final determinations are different. The differences with the most monetary impact are our allowed total expenditures and the allowances for the cost of equity and cost of debt.

*Total expenditure*

1.9. Our allowed total expenditures are £1.3bn less than those in the DNOs' plans. We explain in Chapter 4 and the 'Business plan expenditure assessment' supplementary annex how we come to our view of efficient cost, and why we think our proposals are reasonable.

*WACC*

1.10. We explain in Chapter 5 and Appendix 8 why we remain of the view that the allowances for the components of the WACC in our draft determinations are reasonable. Our impact assessment at draft determinations explained the impact of this approach.

*Summary*

1.11. We think our final determinations will:

- ensure the delivery of the required network outputs at value for money for consumers
- enable DNOs to finance their regulated activities.

1.12. Our decision results in a reduction in allowed revenues[68] of around 4.4% on average over the RIIO-ED1 period relative to the current price control (DPCR5). This translates into an underlying reduction of approximately £12 in the typical annual household bill over RIIO-ED1 relative to the current year.[69]

[68] before inflation.
[69] The government's December 2013 measures to reduce energy bills accelerated the effect of the RIIO-

## Distributional impact

1.13. The final determinations and policy changes impact the allowed revenue which slow-track DNOs are allowed to recover from their customers. The amounts charged (via suppliers) to customers are calculated according to a common charging methodology for all DNOs. The charging methodology is not part of the price control review, and therefore not considered in this impact assessment.

## Hard-to-monetise impacts

**Impact on competition**

1.14. We do not consider that our final determinations and policy changes have any appreciable impact on competition.

1.15. The RIIO-ED1 connections outputs have been designed to reflect different levels of competition in the market to connect customers to the distribution networks. Under the existing price control (DPCR5), we have assessed the extent to which there is effective competition in the area of contestable connections (through the 'Competition Test' process). We are now in the process of reviewing the connections market to identify the steps that need to be taken to improve the arrangements for competition.[70] Any changes that may be required to further facilitate competition in connections are the subject of a separate process to this price control review and are not considered further as part of this impact assessment.

**Impact on sustainability**

1.16. In Chapter 3 we discuss our assessment of the slow-track DNOs' business plans with respect to delivering environmental outputs.

1.17. The slow-track DNOs have considered the actions that they can take to control and minimise losses in the network. Where they have fully justified additional expenditure for loss reduction actions, we have allowed this expenditure in the cost benchmarking. DNOs' licences for RIIO-ED1 will require them to ensure losses on their networks are as low as reasonably practicable, and to maintain and act in accordance with their published losses strategies. We expect all DNOs to improve their losses strategies, and have highlighted particular weaknesses in the main document.

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ED1 savings.
[70] https://www.ofgem.gov.uk/publications-and-updates/competition-electricity-distribution-connections-call-evidence

1.18. We required DNOs to explain in their plans how they will accommodate, and make best use of, the take up of low carbon technologies (LCTs). As part of this, DNOs had to forecast the number of LCTs they think they will connect over the price control period and provide evidence for this forecast. They also had to explain how they would flex their plans to accommodate differing take-up to their forecasts. We are satisfied with the DNOs forecasts and explanations.

1.19. We anticipate that the package of RIIO-ED1 outputs and incentives, alongside the innovation incentives, will provide significant benefits in the connection of LCTs in an appropriate time, at appropriate cost, without causing network problems. The innovation proposals will encourage the DNOs to further innovate and trial solutions to better accommodate the take-up of low carbon technologies and the connection of generation, particularly using smart grid solutions and customer response.

1.20. With respect to the other environment elements (eg undergrounding of lines in designated areas, business carbon footprint, reduction of $SF_6$ emissions and leakage from FFCs) we have assessed all the slow-track plans to be acceptable.

**Impact on fuel poverty and consumer vulnerability & impact on health and safety**

1.21. We detailed in our strategy decision what we expect DNOs to consider with respect to social and safety obligations. For the social obligations, this includes an emphasis on consumer vulnerability, as we believe that DNOs have an important part to play in assisting consumers in vulnerable situations.

1.22. As we explain in Chapter 3 we judge that all DNOs' business plans demonstrate a comprehensive strategy with respect to social obligations and that all DNOs have satisfactory safety outputs for RIIO-ED1. We have given UKPN an allowance and an uncertainty mechanism to mitigate the risk of exploding link boxes, and have provided the other DNOs with a similar uncertainty mechanism. We have given SSEH an uncertainty mechanism in the event Marine Scotland requires it to bury subsea cables. These provisions are designed to ensure that DNOs fulfil their safety obligations, but do so efficiently.

**Impact on European internal market/ third package**

1.23. We do not consider that our final determinations or policy changes have any appreciable impact in this area.

## Impact of proposed changes in RIIO-ED1 policy from our strategy decision.

1.24. Our strategy decision set the policy framework for RIIO-ED1. When submitting their business plans, DNOs had the opportunity to propose and justify alternative or additional outputs or uncertainty mechanisms.

1.25. We proposed specific policies in the strategy decision at draft determinations, as summarised in Table A9.1 below. We confirm those changes in our final determinations, and have also decided to make a small number of additional changes which we summarise in Table A9.2 below.

1.26. We explain these changes further in the following sections.

**Table A9.1: Confirmed changes**

| Proposed change | Summary | Change to all or specific DNO? | Further information |
|---|---|---|---|
| Information Quality Incentive (IQI) | Adjusting the break-even point in the IQI matrix so that the best performing slow-track DNOs receive a reward. | All slow-track DNOs | Chapter 4 |
| Financial - Redefined cost of debt index | Strategy decision set out the use of a 10-year trailing average for the cost of debt. Our allowance is now based on a trailing average which becomes progressively longer over the price control period. | All slow-track DNOs | Chapter 5 |
| Financial - Capital allowance pools | Strategy decision stated that we would retain the DPCR5 approach. We will now roll-forward regulatory tax pool calculations at the end of the RIIO-ED1 period. | All slow-track DNOs | Chapter 5 |
| Financial - Disposals | We will treat the proceeds or fair value of asset disposals treated as deductions from totex for the calculation of the efficiency incentive. In our strategy decision we stated that disposal proceeds are not included in the costs added to totex. | All slow-track DNOs | Chapter 5 |
| Financial - Directly remunerated services | We will now treat the majority of top-up and standby services as totex. | All slow-track DNOs | Chapter 5 |
| Uncertainty mechanism - Rail electrification | This additional uncertainty mechanism is designed to allow DNOs to recover costs of diverting electricity lines as a result of Network Rail's rail electrification programme. | All slow-track DNOs | Chapter 6 |
| Uncertainty mechanism - Moorside | Additional uncertainty mechanism to allow the recovery of electricity distribution network costs associated with development of a new nuclear power station. | ENWL | Chapter 6 |
| Uncertainty mechanism - Streetworks | Extending the existing mechanism should new legislation be passed in Scotland. | SSEPD and SPEN | Chapter 6 |

**Table A9.2: Additional changes**

| Proposed change | Summary | Change to all or specific DNO? | Further information |
|---|---|---|---|
| Uncertainty mechanism - CNI | Removing the materiality threshold in the light of site reclassification. | All slow-track DNOs | Chapter 6 |
| Uncertainty mechanism – Link boxes | Additional uncertainty mechanisms designed to allow DNOs to recover the efficient cost of mitigating health and safety risks associated with link boxes. | All slow-track DNOs | Chapter 5 |
| Uncertainty mechanism – Subsea cables | A mechanism to allow SSEH to recover the efficient costs of burying subsea cables should they be required to do so by Marine Scotland. | SSEH | Chapter 5 |
| Uncertainty mechanism - Shetland | Changed the balance between the components of SSEH's mechanism for the interim costs of supplying energy in Shetland. This is a combination of ex ante allowance, pass-through and a re-opener. | SSEH | Appendix 7 |

**Information Quality Incentive (IQI)**

1.27. The IQI is used to encourage slow-track DNOs to provide business plans that reflect best available information about future efficient expenditure requirements. It provides a financial incentive (both positive and negative) to encourage the submission of accurate expenditure forecasts.

1.28. As we explain in Chapter 4 we think that it is appropriate to reward companies that have provided good information that aided our comparative benchmarking. In light of this we have moved the break-even point in the IQI matrix from the position we stated in the strategy decision. By moving the break-even point the best performing slow-track DNO groups receive an ex ante reward.

1.29. The benefits of this proposed change include:

- ensuring DNOs that have provided good quality information which has aided our comparative benchmarking receive a reward – in line with the original policy intent of the IQI. It maintains penalties for those DNOs who have provided less robust forecasts
- preserving the incentive properties of the IQI for future price control reviews.

1.30. The potential downside of this proposed change is that it results in smaller overall penalties (and hence costs consumers more by approximately £290m).

However we consider that this cost is more than offset by the benefits of this change including the savings delivered through effective comparative benchmarking in this and future price controls. The slow-track benchmarking has delivered cost savings of nearly £700m. We consider that our proposed rewards and penalties are proportionate to the robustness of the information that the companies have provided.

**Financial changes**

1.31. Taken as a whole, we consider that the changes we have made to the RIIO-ED1 financial policy framework have positive benefits to both consumers and DNOs.

*Redefined cost of debt index*

1.32. We discuss the impacts of this change in the Monetised Impacts section.

*Capital allowance pools*

1.33. We think our change to the capital allowance pools is in the consumer interest. It will ensure that consumers enjoy the benefit of tax relief in respect of all expenditure they have funded through the RIIO-ED1 price control. We do not think there is any appreciable downside to making this change.

*Directly remunerated services*

1.34. We explain how we will:

- to resolve any double recovery of costs for affected DNOs that has occurred over the DPCR5 period
- to treat such costs over the RIIO-ED1 period.

1.35. We consider these changes are in consumers' interests overall, with no notable downsides. They ensure that there continues to be a reasonable incentive for DNOs to carry out these services for third parties but using a simpler, more transparent process.

**Uncertainty mechanisms**

1.36. When considering the addition of, and changes to, the uncertainty mechanisms in the strategy decision we have considered:

- the RIIO principles[71] on the needs for, and design of, these mechanisms

[71] See Chapter 11 of the RIIO Handbook - https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf

- the justification of any changes given by DNOs in their business plan.

1.37. We think that the uncertainty mechanisms in Tables 9.1 and 9.2 above are justified. They meet the RIIO principle that uncertainty mechanisms are only deployed where network companies are unable to manage the uncertainty they face, whilst preserving the ability of the network companies to finance their businesses and deliver value for money for consumers.

1.38. Each of the proposed uncertainty mechanisms:

- can only be triggered and approved at a set window or on specific events during RIIO-ED1. This provides suppliers and other stakeholders with advance notice of potential changes in DNOs' allowed revenue which would impact their network charges
- are subject to eligibility criteria (including materiality thresholds) and we will assess and consult on the proposals. This helps ensure that any additional allowed revenue is in the consumers' interest, well-justified and efficient.

## Follow up/ review

1.39. It is important for us to continually review the work that we do and the impact that it has on our stakeholders. We will undertake a lessons learnt exercise at the end of the RIIO-ED1 review. As part of this we will look at the process and any lessons we can learn for future reviews.

# Appendix 10 – DPCR5 performance

**Appendix Summary**

DNO performance over the first four years of DPCR5.

1.1. In this appendix we present data on the DNOs' performance in the current price control (DPCR5). This includes performance against output targets (ie reliability) and financial performance.

1.2. We have updated some of the information from that in our draft determinations. The data in this appendix is based on the DNOs' RIGs that were submitted in July 2014.

## Reliability

1.3. We incentivise DNOs' reliability against DNO-specific targets, in terms of the number and duration of interruptions. Tables A10.1 and A10.2 show the DNOs' performance for planned and unplanned interruptions against target.[72]

**Table A10.1: Customer interruptions (CIs), by DNO, over DPCR5 to date**

| | 2010/11 | | 2011/12 | | 2012/13 | | 2013/14* | |
|---|---|---|---|---|---|---|---|---|
| | Target | Performance | Target | Performance | Target | Performance | Target | Performance |
| ENWL | 52.9 | 47.8 | 52.7 | 45.9 | 52.5 | 46.6 | 52.4 | 43.1 |
| NPGN | 68.3 | 65.2 | 68.2 | 67.9 | 68.2 | 64.9 | 68.1 | 66.3 |
| NPGY | 75.3 | 69.9 | 75.3 | 69.3 | 75.3 | 72.2 | 75.3 | 67.8 |
| WMID | 109.9 | 102.2 | 109.9 | 73.7 | 109.9 | 81.4 | 109.9 | 75.8 |
| EMID | 75.7 | 61.7 | 75.7 | 52.9 | 75.7 | 48.1 | 75.7 | 49.7 |
| SWALES | 79.5 | 58.4 | 79.5 | 56.0 | 79.5 | 48.4 | 79.5 | 49.4 |
| SWEST | 73.6 | 61.5 | 73.6 | 53.9 | 73.6 | 60.3 | 73.6 | 52.9 |
| LPN | 33.4 | 24.4 | 33.4 | 27.6 | 33.4 | 25.0 | 33.4 | 21.6 |
| SPN | 85.0 | 76.9 | 84.2 | 53.3 | 83.3 | 54.9 | 82.5 | 55.5 |
| EPN | 76.1 | 86.0 | 75.9 | 63.2 | 75.7 | 56.7 | 75.5 | 59.4 |
| SPD | 60.1 | 50.7 | 60.1 | 52.6 | 60.1 | 51.6 | 60.1 | 53.1 |
| SPMW | 45.6 | 39.3 | 45.5 | 36.0 | 45.3 | 34.1 | 45.1 | 40.7 |
| SSEH | 77.0 | 74.0 | 77.0 | 70.1 | 77.0 | 68.1 | 77.0 | 74.8 |
| SSES | 73.8 | 63.6 | 73.2 | 69.8 | 72.6 | 61.8 | 72.0 | 68.8 |

* The 2013-14 numbers have not been finalised

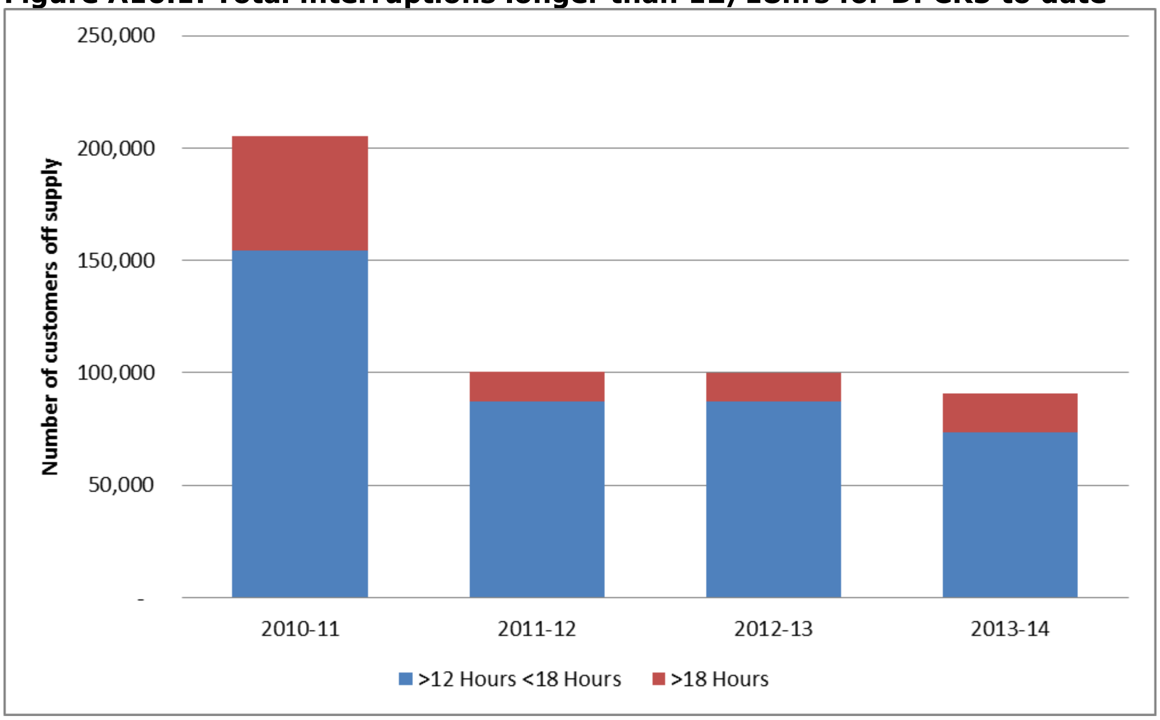
[72] Different types of interruption are weighted – this depends on the level of DNO control, and also reflects that planned interruptions cause less disruption than unplanned.

**Table A10.2: Customer minutes lost (CMLs), by DNO, over DPCR5 to date**

| | 2010/11 | | 2011/12 | | 2012/13 | | 2013/14* | |
|---|---|---|---|---|---|---|---|---|
| | Target | Performance | Target | Performance | Target | Performance | Target | Performance |
| ENWL | 55.6 | 47.3 | 55.6 | 47.6 | 55.6 | 49.3 | 55.6 | 42.6 |
| NPGN | 71.3 | 71.1 | 71.1 | 68.5 | 70.9 | 70.2 | 70.7 | 70.0 |
| NPGY | 76.0 | 68.2 | 76.0 | 65.0 | 76.0 | 62.8 | 76.0 | 67.2 |
| WMID | 97.0 | 89.5 | 96.3 | 49.0 | 95.6 | 44.8 | 94.9 | 38.6 |
| EMID | 69.0 | 54.9 | 68.6 | 37.0 | 68.2 | 30.2 | 67.8 | 26.0 |
| SWALES | 44.6 | 32.4 | 44.6 | 37.1 | 44.6 | 29.8 | 44.6 | 31.0 |
| SWEST | 51.0 | 42.6 | 51.0 | 39.7 | 51.0 | 46.0 | 51.0 | 40.6 |
| LPN | 41.0 | 42.4 | 41.0 | 31.2 | 41.0 | 33.8 | 41.0 | 29.8 |
| SPN | 87.6 | 73.2 | 82.9 | 42.8 | 78.1 | 47.0 | 73.3 | 54.3 |
| EPN | 71.1 | 72.4 | 69.7 | 47.4 | 68.3 | 49.6 | 66.8 | 50.1 |
| SPD | 65.5 | 49.4 | 63.5 | 48.8 | 61.5 | 45.7 | 59.5 | 44.0 |
| SPMW | 61.1 | 47.5 | 60.6 | 43.6 | 60.1 | 42.8 | 59.6 | 44.8 |
| SSEH | 75.1 | 78.4 | 75.1 | 71.4 | 75.1 | 67.0 | 75.1 | 70.1 |
| SSES | 69.1 | 64.1 | 68.3 | 60.3 | 67.5 | 65.2 | 66.6 | 67.3 |

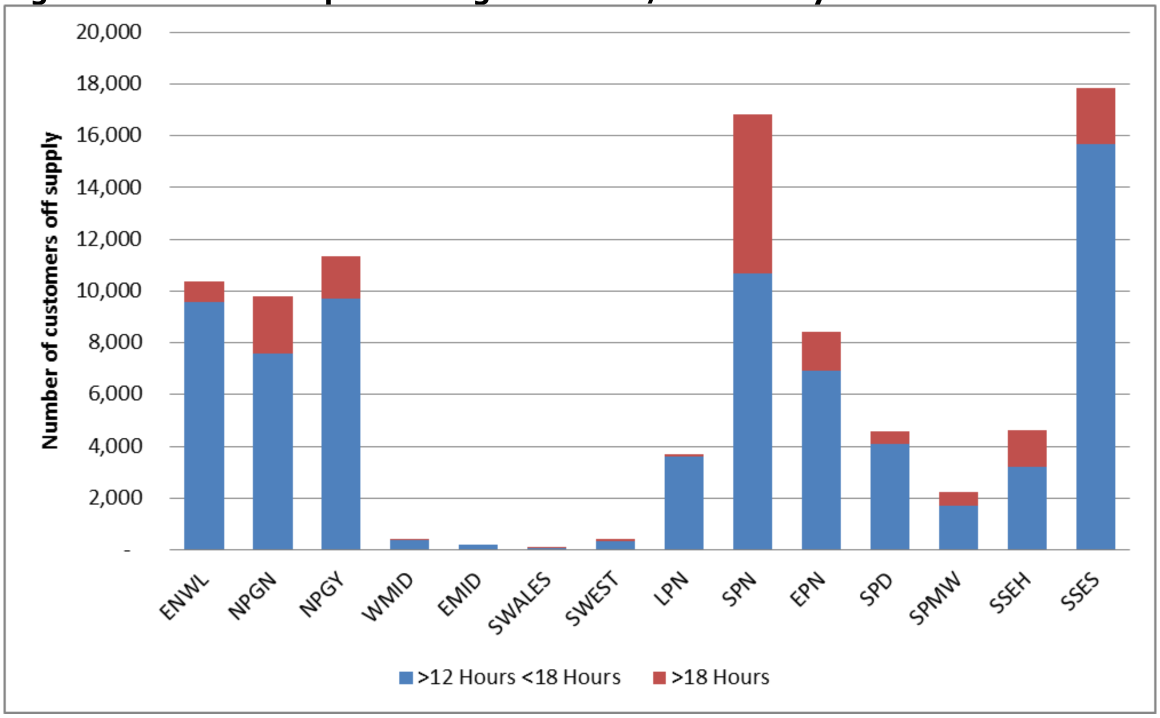
* The 2013-14 numbers have not been finalised

**Figure A10.1: Total interruptions longer than 12/18hrs for DPCR5 to date[73]**




[73] This has changed from draft determinations as there was an error in the 12 hour figures.

**Figure A10.2: Interruptions longer than 12/18hrs for year 2013-14[74]**



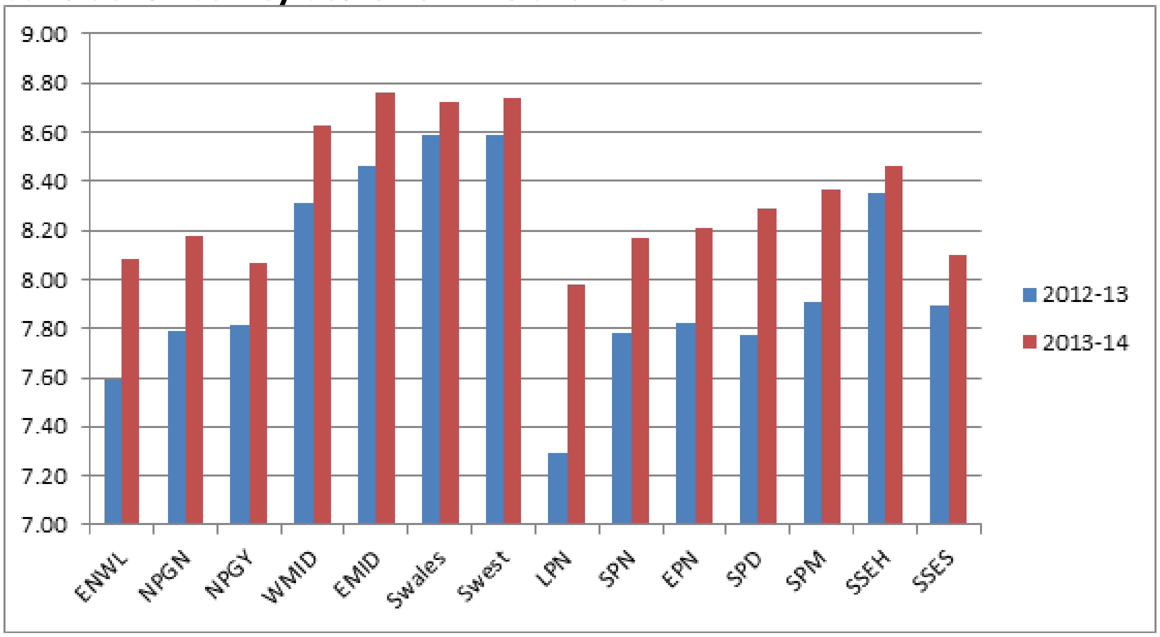

## Customer satisfaction

**Table A10.3: Broad Measure of Customer Service – Customer Satisfaction Survey Scores 2012-13 and 2013-14**

| | Overall Mean | | Interruptions | | Connections | | General Enquiries | |
|---|---|---|---|---|---|---|---|---|
| | 2012/13 | 2013/14 | 2012/13 | 2013/14 | 2012/13 | 2013/14 | 2012/13 | 2013/14 |
| ENWL | 7.59 | 8.08 | 7.77 | 8.31 | 7.62 | 7.83 | 7.14 | 8.09 |
| NPGN | 7.79 | 8.18 | 8.06 | 8.52 | 7.36 | 7.84 | 8.07 | 8.21 |
| NPGY | 7.81 | 8.07 | 8.04 | 8.21 | 7.48 | 7.73 | 8.01 | 8.43 |
| WMID | 8.31 | 8.63 | 8.39 | 8.76 | 8.21 | 8.54 | 8.34 | 8.52 |
| EMID | 8.46 | 8.76 | 8.48 | 8.82 | 8.42 | 8.69 | 8.53 | 8.80 |
| SWales | 8.59 | 8.72 | 8.78 | 8.83 | 8.33 | 8.61 | 8.71 | 8.73 |
| SWest | 8.59 | 8.74 | 8.58 | 8.76 | 8.57 | 8.73 | 8.65 | 8.71 |
| LPN | 7.29 | 7.98 | 7.56 | 8.14 | 7.23 | 7.81 | 6.87 | 7.98 |
| SPN | 7.78 | 8.17 | 7.92 | 8.18 | 7.47 | 7.85 | 8.11 | 8.77 |
| EPN | 7.82 | 8.21 | 8.11 | 8.29 | 7.34 | 7.89 | 8.23 | 8.67 |
| SPD | 7.77 | 8.29 | 8.13 | 8.57 | 7.41 | 8.08 | 7.79 | 8.15 |
| SPM | 7.91 | 8.37 | 8.29 | 8.54 | 7.33 | 7.93 | 8.33 | 8.89 |
| SSEH | 8.35 | 8.46 | 8.73 | 8.81 | 8.14 | 8.11 | 7.99 | 8.46 |
| SSES | 7.89 | 8.10 | 7.97 | 8.18 | 7.78 | 7.92 | 7.97 | 8.30 |
| Average | 8.00 | 8.34 | 8.20 | 8.49 | 7.76 | 8.11 | 8.05 | 8.48 |

[74] This has changed from draft determinations as there was an error in the 12 hour figures.

**Figure A10.3: Broad Measure of Customer Service – Overall Customer Satisfaction Survey Score 2012-13 and 2013-14**




## Secondary deliverables – health indices

1.4. Figures A10.4 and A10.5 show our estimation of the DNOs' delivery of their agreed HI deltas to the end of 2013-14. The delta is a measure of the difference in health indices with and without investment. Our charts show how much of each DNO's total DPCR5 agreed delta it appears to have delivered to date. This indicates whether the DNO is on track to deliver its agreed delta by the end of DPCR5.

**Figure A10.4: HI delta from refurbishment and replacement (as a percentage of total DNO deliverable) for DPCR5 to date**

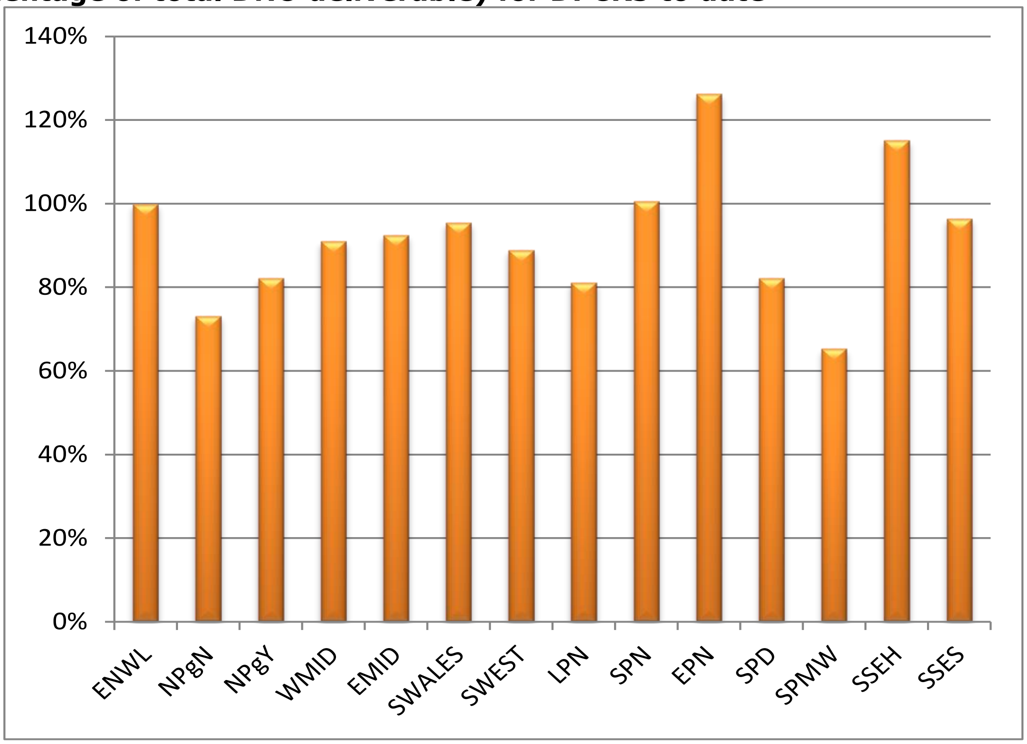
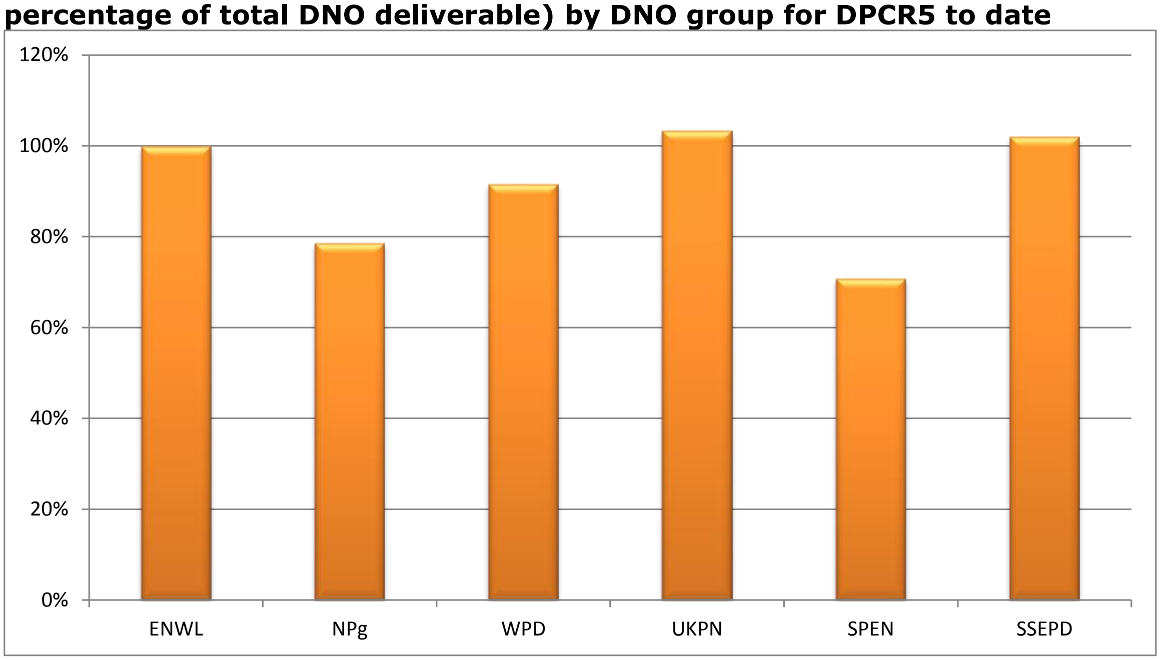



**Figure A10.5: HI delta from refurbishment and replacement (as a percentage of total DNO deliverable) by DNO group for DPCR5 to date**



## Returns on regulatory equity during DPCR5

### Background

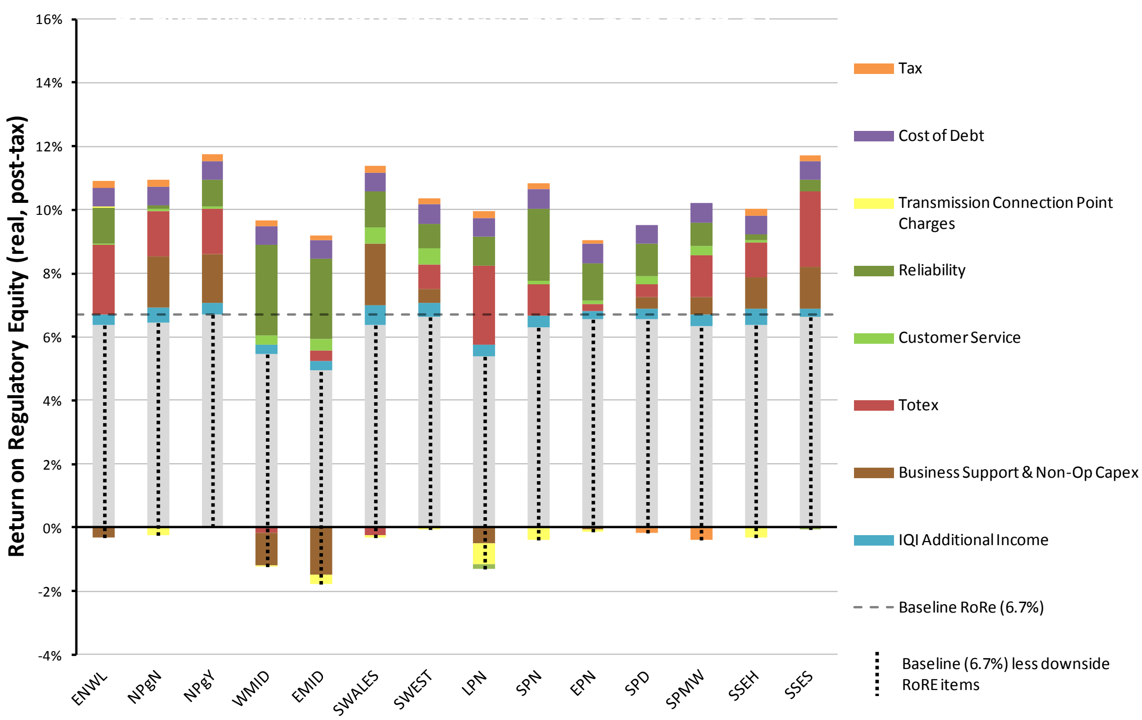
1.5. We introduced the concept of returns on regulatory equity (RORE) as a measure of regulatory financial performance for DPCR5. It is a measure of shareholder return.

1.6. We use RORE when setting a price control to test the range of equity returns that investors might earn from the package. We also use RORE to monitor DNO performance during the period.

### Performance during DPCR5

1.7. A chart of RORE earned by the DNOs in the first four years of DPCR5 is shown in Figure A10.6.

**Figure A10.6: DPCR5 historical RORE between 2010-11 and 2013-14**




1.8. The chart indicates that all DNOs have outperformed so far. This comes from three areas: cost savings, incentive rewards and savings on debt interest.

*Expenditures*

1.9. Most DNOs have made savings on their DPCR5 allowances to date (this is shown by the totex and Business Support & Non-Op Capex bars in the chart). These savings are probably overstated in the chart since we are not looking at the full 5-year period.

1.10. A number of DNOs have re-profiled their planned expenditures. They have reduced them in the first part of the period, but they forecast an increase. If this happens, it may mean that their savings across the five-year DPCR5 period are smaller.

1.11. DNOs share any savings with customers. We have reflected this in the chart, and customers will get the benefit after the end of DPCR5.[75] Customers also benefit from the fact that the DPCR5 costs are used (in part) to set the RIIO-ED1 benchmarks. Hence savings in DPCR5 are baked-in to RIIO-ED1.

1.12. In DPCR5 we set expenditure related outputs that the DNOs would have to deliver. We will assess the DNOs' performance in delivering these outputs once DPCR5 has finished. This means that if a DNO has reduced its expenditure by sacrificing these deliverables, we will be able to penalise it.

*Incentives*

1.13. Most DNOs have earned incentive rewards for reliability (power cuts) and customer service. Customers will have benefitted directly from this improved performance.

*Debt costs*

1.14. In DPCR5 we set an ex ante allowance for the DNOs' debt costs. Interest rates have been lower than we expected. This has significantly benefitted the DNOs. Had rates moved in the other direction, DNOs would have under-performed. We have a different mechanism in RIIO-ED1. Cost of debt allowances are calculated annually using an index, which tracks interest rates. This will largely eliminate the sector's exposure to interest rate uncertainty.

## Reporting RORE in RIIO-ED1

1.15. In RIIO-ED1 we will expect DNOs to explain their RORE performance to stakeholders. We plan to introduce a framework for RORE reporting in our reforms of regulatory accounting and our introduction of RIIO accounts.

[75] In RIIO these savings are reflected during the period.

## Innovation

1.16. In DPCR5, the Low Carbon Networks (LCN) Fund allows up funding to support projects sponsored by the DNOs. The projects trial new technology, operating and commercial arrangements.

1.17. Tier 2 of the LCN Fund provides DNOs with an annual opportunity to compete for funding for the development and demonstration of new technologies, operating and commercial arrangements. Funding is provided for the best innovation projects which help all DNOs understand what they need to do to provide environmental benefits, cost reductions and security of supply as GB moves to a low carbon economy.

1.18. Table A10.4 shows the projects funded in the first four years of DPCR5.

**Table A10.4: LCN Fund Tier 2 projects funded in the first four years of DPCR5**

| DNO | Project name | Year of funding | Year of completion | Funding awarded (£m) |
|---|---|---|---|---|
| **ENWL** | Capacity to Customers | 2011 | 2015 | 9.1 |
| | CLASS | 2012 | 2015 | 7.2 |
| | Eta | 2013 | 2017 | 8.4 |
| | FLARE | 2014 | 2018 | 4.4 |
| **NPg** | Customer-led Network Revolution | 2010 | 2014 | 26.8 |
| **SP** | Flexible Networks | 2011 | 2015 | 2.85 |
| | Accelerating Renewable Connections | 2012 | 2016 | 7.4 |
| **SSE** | New Thames Valley Vision | 2011 | 2017 | 22.8 |
| | Innovation Squared | 2012 | 2015 | 4.2 |
| | Solent: Achieving Value through Efficiency | 2013 | 2018 | 8.3 |
| | Low Energy Automated Networks | 2014 | 2019 | 2.7 |
| **UKPN** | Low Carbon London | 2010 | 2014 | 20.7 |
| | Flexible Plug and Play | 2011 | 2014 | 6.7 |
| | Smarter Network Storage | 2012 | 2016 | 13.2 |
| | Flexible Urban Networks - LV | 2013 | 2016 | 6.5 |
| | Vulnerable Customers and Energy Efficiency | 2013 | 2017 | 3.3 |

| DNO | Project name | Year of funding | Year of completion | Funding awarded (£m) |
|---|---|---|---|---|
| | Kent Area System Management | 2014 | 2017 | 3.4 |
| **WPD** | Low Voltage Network Templates | 2010 | 2013 | 7.8 |
| | Low Carbon Hub | 2010 | 2015 | 2.8 |
| | FALCON | 2011 | 2015 | 12.4 |
| | BRISTOL | 2011 | 2016 | 2.2 |
| | FlexDGrid | 2012 | 2017 | 13.5 |
| | Network Equilibrium | 2014 | 2019 | 11.5 |