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RIIO Electricity Transmission Annual Report 2014-15

Annual Report

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Target Audience: This document may be of particular interest to users of the transmission networks, licensees, and providers of finance and consumer groups.

Overview:

RIIO-T1 is the first electricity transmission price control that utilises the RIIO (Revenue = Incentives + Innovation + Outputs) price control model. This price control began on 1 April 2013 and runs for eight years, to 31 March 2021.

This report reviews the price control information received from the onshore electricity transmission companies for the second year of RIIO-T1 (2014-15). It reviews their performance against the outputs they committed to deliver and compares the actual costs they have incurred to date as well as forecast information across the whole price control period against their allowed revenues. In addition, the report outlines the performance of the electricity system operator (SO) company, whose role is to ensure that the electricity transmission system remains in balance.

All financial figures (including forecasts) are quoted in 2014-15 prices, unless stated otherwise.

Context

The electricity transmission network in Great Britain (GB) consists of the high voltage electricity wires and cables which convey electricity from power stations to local distribution networks and large customers directly connected to the transmission system. There are three onshore monopoly providers of electricity transmission services (transmission owners, or TOs):

- National Grid Electricity Transmission plc (NGET), which owns the high voltage electricity network in England and Wales
- Scottish Hydro Electric Transmission plc (SHE Transmission), which owns the high voltage electricity network in the north of Scotland and Scottish island groups
- SP Transmission plc (SPT), which owns the high voltage electricity network in the south of Scotland.

In addition to its TO responsibilities, NGET is the designated electricity and system operator (SO) responsible for day-to-day system operation and management.

Ofgem's principal objective is to protect the interests of consumers. One way we do this is by periodic price controls, which set the revenue that TOs are allowed to recover from users of the electricity transmission network and the outputs that they are required to deliver.

RIIO-T1 is the first period under the RIIO (Revenue = Incentives + Innovation + Outputs) model. The price control started in April 2013 and lasts for eight years. Our final proposals on the RIIO-T1 price control were published in April 2012 for the Scottish TOs and in December 2012 for NGET.

Outputs are at the heart of RIIO-T1. They capture the key areas within which consumers expect the delivery of high quality services. Network companies are provided with revenue allowances based on certain levels of outputs, but they are responsible for determining how best to deliver against these outputs. The revenue allowances can vary as the needs for the transmission system changes and/or if their performance exceeds or falls short of the pre-set targets.

RIIO-T1 also contains incentives for the network companies to deliver outputs efficiently. When a network company spends less than the allowance to deliver an agreed output, it retains around 50% of any efficiency gain and an allowance for the tax due on that incentive payment. The remainder is passed onto customers by reducing allowances to be recovered through network charges. The sharing is symmetrical if there is an overspend.

The second year of the price control period ended on 31 March 2015, and this report reviews how the electricity transmission companies have performed against the output based requirements. It also compares the costs incurred against allowances.

Associated documents

Price Control Documents

RIIO-T1: Final Proposals for NGGT and NGET - Overview

RIIO-T1: Final Proposals for NGGT and NGET – Outputs, incentives and innovation

RIIO-T1: Final Proposals for NGET and NGGT – Cost assessment and uncertainty

RIIO-T1: Final Proposals for NGGT and NGET – Finance

RIIO-T1: Final proposals for SP Transmission Ltd and Scottish Hydro Electricity Transmission

ET1 Price Control Financial Handbook

Transmission networks own reports on their performance

RIIO-T1: performance data

NGET's 2013-14 & 2014-15 performance report

SHE Transmission's 2013-14 and 2014 -15 performance report

SPT's 2013-14 and 2014-15 performance report

Contents

Executive Summary **5**

1. Revenue and Customer Bill Impact **7**
Electricity Transmission Revenues 7
Customer Bill Impact 12

2. Outputs & Incentives **14**
Outputs, measures and performance 14
Safety Output Measures 17
Reliability Output Measures 17
Energy not supplied (ENS) 17
Availability Output Measures 19
Network Access Policy (NAP) 19
Customer Satisfaction 20
Customer/stakeholder satisfaction survey 20
Connections and Wider Works Output Measures 22
Environmental Output Measures 24
Limiting sulphur hexafluoride (SF_6) emissions 24
Business carbon footprint (BCF) 26
Losses 27
Environmental discretionary reward 28

3. Innovation **30**
Network Innovation Allowance 30
Network Innovation Competition 30
Innovation Rollout Mechanism 31

4. Expenditure **32**
Introduction 32
Total expenditure (Totex) performance and forecasts 32
Load-related capex (LR capex) 34
Non load-related capex (NLR capex) 40
Network capital delivery 47
Non-operational capex 52
Operating costs (Opex) and forecasts 55

5. SO performance **60**

6. Financial Performance **63**
Regulatory Asset Value 63
Return on Regulatory Equity (RoRE) 65

7. Forward Look: 2015-16 Regulatory Reporting Year **67**

Appendices **69**

Executive Summary

In July 2015 the onshore electricity transmission licensees submitted their regulatory reporting packs covering the second year of RIIO-T1 (2014-15). We have now reviewed these packs and discussed them with the individual companies. In RIIO the focus of our analysis is on outputs, incentives and innovation as well as total expenditure (totex). Some of the required outputs will not be fully delivered until the end of RIIO-T1 (2020-21) and therefore this report considers forecast performance across the whole price control as well as actual performance over the first two years of the control period.

As part of the agreed initiative to make company performance more transparent in RIIO, the providers of onshore electricity transmission services (transmission owners, or TOs) have already published their own annual performance reports on their company websites at the end of September 2015. Rather than just re-presenting numbers which are already in the public domain, this report gives a combined picture of the results, as well as our analysis of the TOs' performance and, in the case of NGET, its performance as electricity system operator (SO). We also highlight areas where we will be focusing our attention in future years.

2014-15 Performance Headlines

TO Expenditure and Customer Bill Impact

Current forecasts by the TOs comprise expenditure of almost £18bn over the course of the RIIO-T1 control. If this is realised, the onshore transmission element of an average consumer electricity bill will increase by about 21% in real terms.

Financial performance

The financial performance of transmission companies is presented using the return on regulatory equity (RoRE) measure. Based on the latest forecasts from the TOs, all of them expect to exceed the allowed return of 7%, by 2-3 percentage points. These rates of return are in line with those achieved during the previous transmission price control. The forecast RoRE is dependent on future delivery of outputs, which is not confirmed at this stage, and so this should be seen as the TOs' best estimate of the outcome.

The regulatory asset values (RAV) of the electricity TOs are forecast to grow by over £8bn over the RIIO-T1 period, reflecting the necessary investment to accommodate new generation and other changes in the use of the network, as well as maintaining the existing network.

Output Performance

All TOs expect that output delivery will meet or exceed the targets set against five of the six output categories, namely: safety; reliability; availability; customer satisfaction; and environmental. So far, the TOs have earned just under £44m of incentive payments for exceeding targets on these output categories during the first two years of the control period.

For the remaining output category, 'connections and wider works', changes from the original baseline will result in volume adjusted revenue allowances.

Totex performance

In 2014-15 all TOs have spent less than their allowances.

All of the TOs are expecting to outperform their volume adjusted allowances (including Strategic Wider Works) over the entirety of RIIO-T1 by between 4-10%. Due to the revenue adjustment mechanisms within the price control, a proportion of these savings will be shared with consumers.

We have tried to identify the factors that are contributing to the companies' levels of underspend. Among these are changes in requirements for generation and demand connections and smaller increases in real price effects since the start of the price control, relative to the assumptions when setting the allowances.

Quality of regulatory reporting submissions

Having reviewed the reporting from the TOs in 2014-15 we have identified scope for improvements. These developments should help us to better understand and critically review TOs' performance during RIIO-T1 and improve the information within the annual report. We will be progressing these changes with the TOs over the coming months.

1. Revenue and Customer Bill Impact

Chapter Summary

This chapter explains how expenditure by the electricity TOs to improve GB's transmission infrastructure in RIIO-T1 impacts on customer bills.

Electricity Transmission Revenues

1.1. Over RIIO-T1, the onshore electricity transmission licensees expect to spend c.£18bn[1] reflecting the necessary investment to accommodate new generation and other changes in the use of the network, as well as maintain the existing network. If TOs' investment in the network proceeds in line with their forecasts, it will result in a c.21% increase in average transmission charges for consumers by 2020-21, as compared with the equivalent level of charges at the start of the price control period.

Allowed revenue

1.2. The TOs' licences include price control conditions which determine the maximum amount of annual revenue they can earn from their activities of maintaining, reinforcing and upgrading the transmission systems they are responsible for. The allowed revenues are recovered from users of the transmission network through Transmission Network Use of System (TNUoS) charges. These charges are levied and collected by NGET (in its role as system operator) on behalf of all TOs.

1.3. The maximum allowed revenue that each TO may recover is set by a formula in Special Condition 3A of its transmission licence. The main elements are as follows:

- Transmission Base Revenue: This includes a baseline derived from the TO's Business Plan, adjustments reflecting changes in requirements and a sharing mechanism for total expenditure (totex).
- Pass-through costs: Some costs that are both outside the TO's control and difficult to predict can be passed on to the consumer (eg licence fees).
- Incentive adjustments: These relate to the TO's performance under mechanisms set out in the licence.
- Innovation: These are costs associated with the Network Innovation Allowance (NIA) and Network Innovation Competition (NIC)[2].

[1] This represents actual total expenditure (totex) for 2013-15 plus six years forecast spend for 2015-21 based upon the TOs' latest published figures.
[2] See chapter 3 for further details on these mechanisms and allowances.

- Transmission Investment for Renewable Generation (TIRG): A mechanism from the previous price control specifically to fund transmission projects for connecting renewable generation.

- Correction factor: A revenue adjustment for under/over recovery of charges against allowed revenue in prior years.

Annual Process of Setting Revenue Allowances

1.4. RIIO-T1 includes an Annual Iteration Process (AIP)[3] which calculates the level of change to revenues in light of prevailing financial conditions, operational developments, and output levels achieved during the price control period. Revenues change as a result of TO performance following a two year lag. For example, the allowed revenue modification as a consequence of 2014-15 actual performance will impact allowed revenues for 2016-17. This reduces the need to log-up financial adjustments during the price control period and simplifies implementation of uncertainty mechanisms.

1.5. Table 1 below shows the value of the baseline base revenue set at the time of Final Proposals for 2013-14 and 2014-15 for each TO (row 1) and the updates we have made to these allowances to reflect the TO's actual outturn through the AIP and inflation (rows 2 and 3, respectively). The resulting base allowance is shown in row 4. Table 1 also summarises the other individual elements of the allowed revenue formula for each onshore TO in the first two years of the price control period (rows 5 to 11). The values in row 12 are the maximum allowed revenue[4] attributable to the onshore TOs. These values are produced by our Price Control Financial Model (PCFM) and will differ from previous published forecast values due to differences in the inflation forecast used.

[3] Further details on the workings of the AIP can be found in the ET1 Price Control Financial Handbook.
[4] Excluding the costs associated with pre-vesting connections.

Table 1: Breakdown of TO Allowed Revenues[5] for 2013-14 and 2014-15

£m, 2014-15 prices	NGET		SHE		SPT	
	2013-14	2014-15	2013-14	2014-15	2013-14	2014-15
1. Base Revenue Allowance	1597	1718	124	133	268	282
2. MOD determined in AIP	0	-7	0	10	0	7
3. True-up for actual inflation	0	-1	0	0	0	0
4. Adjusted Base Revenue (1+2+3)	**1597**	**1710**	**124**	**143**	**268**	**289**
5. Pass Through Items	3	3	0	0	0	0
6. Output Incentive Payments	13	0	0	0	1	0
7. Network Innovation Competition[6]	0	0	0	12	0	7
8. Network Innovation Allowance	6	9	1	1	1	1
9. TIRG	16	16	55	69	26	29
10. Other	-2	3	0	0	0	0
11. Correction Factor	3	0	3	0	1	0
Maximum Allowed Revenue (4+5+6+7+8+9+10-11)	**1630**	**1742**	**177**	**225**	**294**	**325**

1.6. The increase in TIRG revenues for both SPT and SHE Transmission reflects the work profile on the Beauly-Denny transmission line, with significant completion of construction work in 2015.

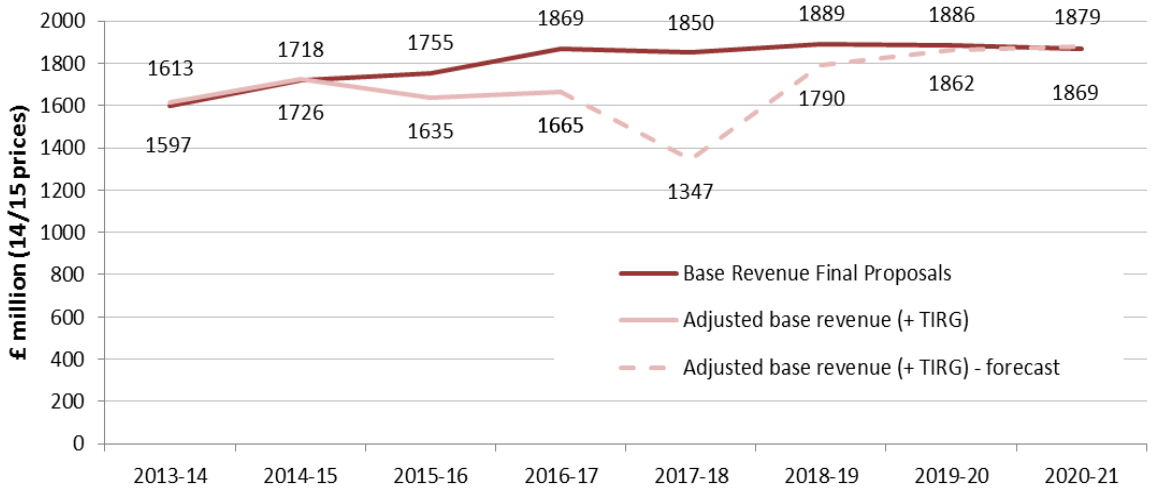
1.7. Output incentive revenues of zero in 2014-15 reflects the two year lag introduced in RIIO whereby incentive revenues 'earned' due to actual performance in the first two years of RIIO-T1 will only be collected as allowed revenues in 2015-16 and 2016-17 respectively. 2013-14 collected output incentive revenues were determined at Final Proposals.

1.8. Figures 1,2 and 3 below show the base revenue allowance against actual and forecast adjusted base revenues (based upon the TOs' forecast allowed expenditure[7]) for the remainder of the control period.[8] Note that the slight deviations in 2014-15 relate to changes to the cost of debt since Final Proposals and close out of legacy issues from the

[5] For comparison purposes Maximum Allowed Revenues for NGET have been adjusted to exclude revenues that are recovered on behalf of Offshore Transmission Operators and the Scottish onshore TOs through the pass through term and Network Innovation Competition.
[6] The values listed for SHE Transmission and SPT are for illustrative purposes only. The revenue is recovered by NGET on behalf of the Scottish TOs.
[7] Base revenues for 2017-18 onwards have been adjusted for the impact of uncertainty mechanisms based upon TOs' forecasts of the level of outputs that they consider will be required by their customers across the RIIO-T1 price control period.
[8] The difference between adjusted base revenues (plus TIRG) and maximum allowed revenues will be determined by the outturn values of the other elements of revenue presented in Table 1 (including output incentives, network innovation competition and network innovation allowance).

previous price control ('TPCR4', which ended on 31 March 2013). There is no impact from totex performance in the final year of TPCR4 (2012-13).

Figure 1: Final Proposal base revenue against adjusted base revenue (+ TIRG) – actual and forecast[9]: NGET TO

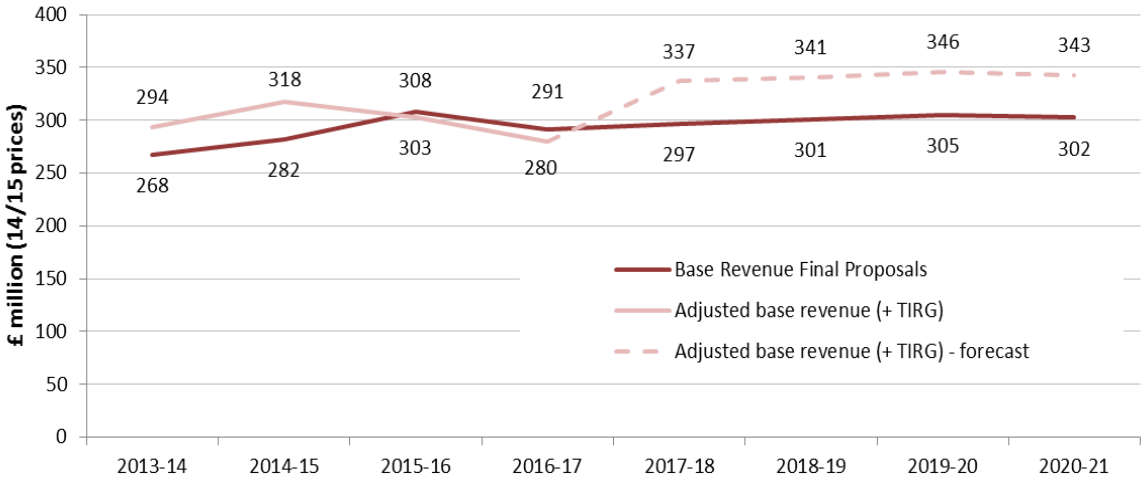


1.9. The reductions in NGET's revenue by c.£120m for 2015-16 and c.£204m for 2016-17 are mostly due to underspends against totex allowances in 2013-14 and 2014-15. The Totex Incentive Mechanism (TIM) allows NGET to keep 46.9% of any underspends it achieves. Consumers get the benefit of the remainder of the underspend, once taxation on the incentive payment has been deducted. This benefit takes effect by reducing allowances (after volume driver adjustments) for those years and carrying forward the revenue reductions to 2015-16 and 2016-17, respectively. NGET forecasts that after 2016-17 it will continue to underspend against totex allowances with a catch up in expenditure towards the end of RIIO-T1. Figure 1 above illustrates how NGET's adjusted base revenues may be affected going forward, as a result of those projected underspends (based upon NGET's forecast).

1.10. The sharp adjustment in the forecast adjusted base revenues in 2017-18 is driven by a revised allowance profile provided by NGET. This is reflecting a period of anticipated continual underspend until the latter part of the control period, when spending is forecast to increase above allowance. We will be exploring the underlying calculations with NGET so we can better understand this profile.

[9] Base revenue figures in 2009-10 prices are derived from Final Proposals and the Price Control Financial Model, updated for the November 2015 AIP determination and re-based to 2014-15 prices. Forecast maximum allowed revenues are estimated using the Price Control Financial Model for the base revenue element and are based upon TOs' latest forecast expenditure and forecast allowances expected to be achieved by 2020-21.

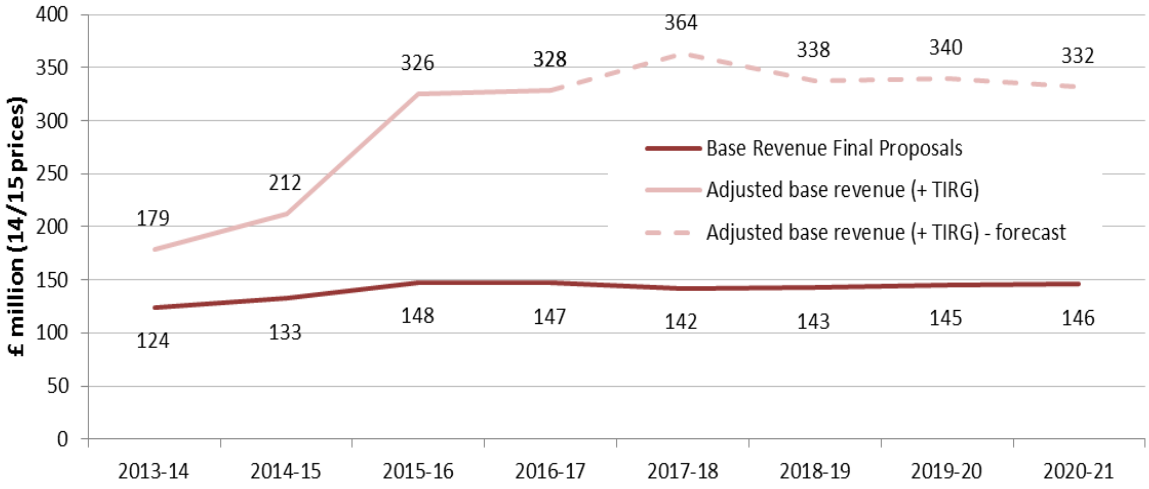
Figure 2: Final Proposal base revenue against adjusted base revenue (+ TIRG) – actual and forecast: SPT



1.11. The reductions in SPT's revenue by £5m for 2015-16 and £11m for 2016-17 are mostly due to moderate underspends against allowances incurred in the first two years of RIIO-T1. The TIM passes 50% of these underspends to SPT. Once taxation impacts are accounted for, consumers benefit by carrying forward the revenue reductions to 2015-16 and 2016-17. SPT forecasts that allowances due on generation connections from 2017-18 onwards will be greater than our current view of updated allowances under the volume driver. This is a result of additional expenditure on substations, overhead cables and undergrounding. Figure 2 above illustrates how SPT's adjusted base revenues may be affected going forward, based on SPT's forecast.

1.12. We note that SPT has made assumptions of how revenue drivers will be applied where there is no perfect match between the type of assets being installed and existing revenue recovery mechanisms. These assumptions will need further consideration during the course of the control period.

Figure 3: Final Proposal base revenue against adjusted base revenue (+ TIRG) – actual and forecast: SHE Transmission



1.13. The increases in SHE Transmission's adjusted baseline revenue by £178m in 2015-16 and £181m in 2016-17 are mostly due to the Caithness Moray Strategic Wider Works (SWW) determination in February 2015[10], which increased allowances across the eight years by £1,140m. This increase in allowances dominates the base revenue profile and outweighs the downward pressure on allowances driven by moderate underspends against totex allowances reported by SHE Transmission in the first two years of RIIO-T1.

1.14. SHE Transmission anticipates that from 2017-18 onwards updated allowances (ie following the inclusion of determined SWW funding) will continue to grow in line with the increase in delivered generation connections. SHE Transmission's latest eight year forecast of generation connections is 35% higher than the forecasts that have been incorporated into the volume driver and is driving the increase in allowances. Figure 3 above reflects how SHE Transmission's adjusted base revenues may be affected going forward, based on SHE Transmission's forecast.

Customer Bill Impact

1.15. The revenue allowances for the TOs to operate and maintain the transmission networks are directly paid by suppliers and generators through their transmission charges. Our bill impact calculations assume that both the supplier and generator TNUoS charges are passed through to customers' electricity bills.

1.16. At the beginning of RIIO-T1, the onshore TOs were set to recover £2,102m in transmission charges. This translated to an estimated £27.79[11] transmission element on

[10] SHE Transmission 2014 AIP was deferred until February 2015 to include Caithness Moray allowances.
[11] Re-based to 2014-15 prices from 2013-14 prices.

an average domestic electricity bill. TO forecasts for revenues in 2020-21 total £2,544m. This indicates that the onshore element of the transmission charge would increase by c.21% if investment occurs at the level projected by the TOs. It should also be noted that these forecasts anticipate significant spending on projects that are not yet agreed with Ofgem, but do not account for incentive payments, innovation funding or other adjusting items that may change these revenue projections.

2. Outputs & Incentives

Chapter Summary

This chapter examines the second year performance and forecast performance of the TOs in meeting their output commitments over the RIIO-T1 period. It also indicates the levels of incentive payments achieved by the onshore TOs in respect of their performance levels.

Outputs, measures and performance

2.1. As part of RIIO-T1, we set primary outputs the onshore electricity Transmission Owners (the TOs) have committed to deliver over the price control period. The following six outputs form the cornerstone of the RIIO price control framework[12]:

i. safety
ii. reliability
iii. availability
iv. customer satisfaction
v. connections/wider works
vi. environmental

2.2. This chapter considers delivery by the TOs. For outputs that have multiple metrics, we present some quantifiable measures for illustrative purposes; these are shown in table 2 below. If TOs achieve the targeted level of all measures satisfactorily we consider that they will have achieved the primary outputs.

[12] Further detail of the outputs framework in RIIO-T1 is available on the Ofgem website in the link: RIIO-T1: Final Proposals for NGGT and NGET – Outputs, incentives and innovation

Table 2: Outputs and measures

Primary Output	Measures	Incentive type
(i) Safety	Compliance with safety obligations set by the Health and Safety Executive (HSE). Supported by monitoring of secondary deliverables related to asset health, condition, criticality etc. which are assessed through Network Output Measures (NOMs). NOMs also has a link to reliability.	Statutory requirements (enforcement action under HSE legislation). No financial incentive. Financial incentive: Compliance with the NOMs targets impacts on RIIO-T2 funding through a penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs.
(ii) Reliability	Energy not Supplied (ENS) **2014-15 Targets** NGET: 316 MWh SPT: 225 MWh SHE Transmission: 120MWh	Financial incentive: • Incentive rate of £16,000/MWh which is based on an estimate of the value of lost load (VoLL)[13]. • A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues. Supported by monitoring through NOMs.
(iii) Availability	Implement the Network Access Policy (NAP) to ensure better planning of outages over RIIO T1 period	No financial incentive.
(iv) Customer Satisfaction	Customer/Stakeholder Satisfaction Survey Stakeholder engagement discretionary reward	Up to +/-1% of base revenue plus TIRG. Up to 0.5% of base revenue plus TIRG via a discretionary reward scheme.
(v) Connections/Wider Works	Generation connections & local Demand connections Baseline and Strategic Wider Works (SWW)	The timely meeting of existing licence requirements in relation to delivering connections. Financial incentives apply to Scottish TOs only. No direct financial incentive on NGET (general enforcement policy). Baseline and SWW outputs will be subject to timely delivery standards. Additional capacity to be funded through a flexible baseline (with volume driver to adjust allowances if delivery turns out to be different) and SWW.
(vi) Environmental	Limiting emissions of Sulphur Hexafluoride (SF_6) **2014-15 limits** NGET: 12,414.2 tonnes tCO_2e SPT: 591.8 tCO_2e SHE Transmission: 173.1 tCO_2e	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions.
	Environmental Discretionary Reward	Positive reward available if achieve leadership performance across different scorecard activities.
	Business Carbon Footprint	Reputational – publish annual progress

[13] VoLL represents the value that electricity users attribute to security of electricity supply and the estimates could be used to provide a price signal about the adequate level of security of supply.

	Losses	Reputational – publish annual progress
	Visual impact: to reduce the visual impact of transmission assets in designated areas.	Reputational incentive in the context of its performance in the utilisation of two mechanisms: (1) baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent of new infrastructure (e.g. undergrounding) (2) an expenditure cap of almost £600m allow all electricity TOs to work on mitigating impacts of existing infrastructure in designated areas from the beginning of RIIO-T1.

2.3. Table 3 below summarises the revenue rewards and penalties accumulated to date over the first two years of RIIO-T1 for the output incentive mechanisms with an associated annual revenue reward or penalty. There is a two year lag between a TO incurring a reward or penalty and the adjustment to its allowed revenue.

Table 3: Output incentive mechanisms – indicative cumulative revenue rewards and penalties for 2013-15[14]

Mechanism (14/15 prices)	Cumulative reward or penalty			
	NGET	SHE	SPT	Total
Energy Not Supplied	+£5.6m	+£1.2m	+£4.9m	+£11.7m
Customer and stakeholder satisfaction surveys	+£12.4m	+£3.2m	+£3.0m	+£18.6m
Stakeholder engagement discretionary reward	+£6.3m	+£0.7m	+£0.7m	+£7.7m
Sulphur Hexafluoride, SF_6	+£4.3m	-£0.4m	-£0.1m	+£3.8m
Environmental Discretionary Reward	+£2.0m	-	-	+£2.0m
Timely connections	n/a	0	-£0.1m	-£0.1m
Network Output Measures[15]	-	-	-	-
Total all mechanisms	**+£30.5m**	**+£4.7m**	**+£8.6m**	**+£43.8m**

2.4. The TOs' performances against the outputs and measures from Table 2 above are discussed in the following sections.

[14] Figures are based on indicative estimates.
[15] NOMs performance is assessed at the end of RIIO-T1 and financial rewards and penalties will be applied in RIIO-T2.

Safety Output Measures

Compliance with safety obligations

2.5. The output in this area is for each network company to be compliant with its legal safety requirements. These are requirements monitored by the Health and Safety Executive (HSE), as the safety regulator. We are not aware of any breaches of company safety obligations.

2.6. A suite of secondary measures inform both the safety and reliability of its network relating to asset health and condition measures known as network output measures (NOMs). These are discussed further below.

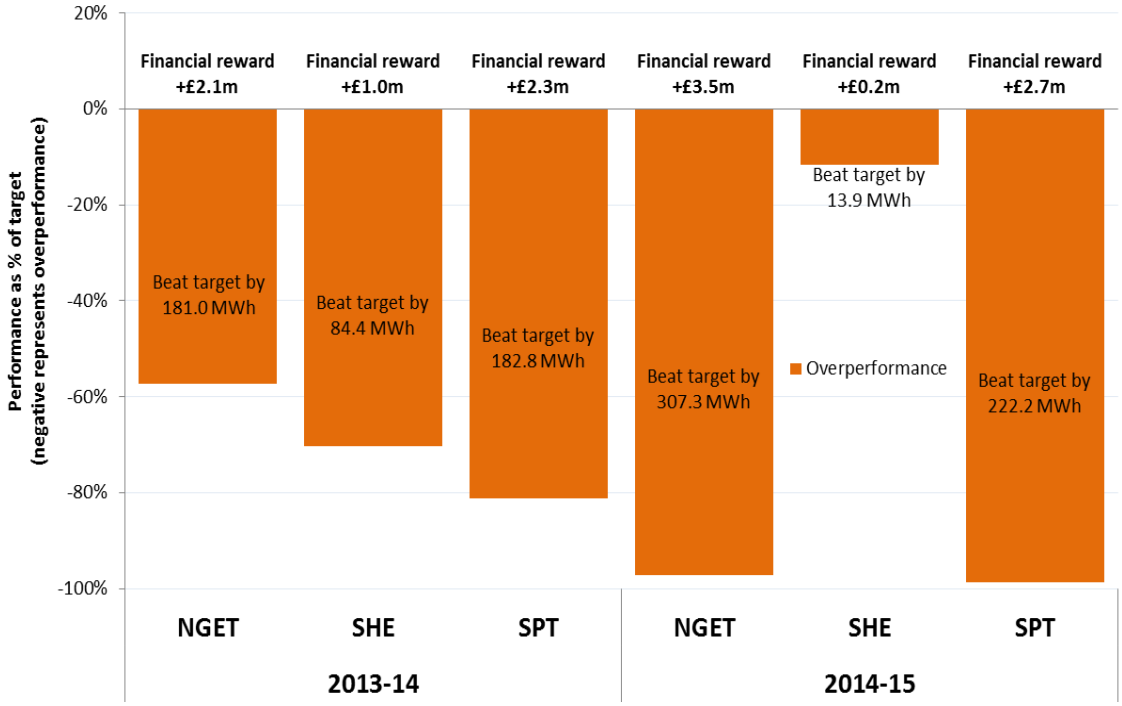
Reliability Output Measures

Energy not supplied (ENS)

2.7. ENS is the volume of energy to customers that is lost (not supplied) as a result of faults or failures on a TO's network. Each TO has annual targets for total volume (MWh) of ENS. A TO receives a financial reward if the actual volume of unsupplied energy is below the target volume, and a financial penalty if the volume is above target. An individual TO has the same target volume each year and these are set at 316 MWh for NGET, 120 MWh for SHE Transmission, and 225 MWh for SPT.

2.8. As was the case in year 1 (2013-14), all three TOs have significantly outperformed against their targets in year 2 (2014-15); see figure 4 below. The 2014-15 overperformance will be reflected in additional £5.4m in allowed revenue to the three TOs, but this is £0.9m down on their reward for 2013-14.

Figure 4: ENS Two year performance – volume of unsupplied energy above or below target as percent of annual target[16]



2.9. In July we published decisions determining that two incidents[17] (one for SHE Transmission and one for SPT) were exceptional events, and so the volumes of energy associated with them have been excluded from the reward/penalty calculation. The total value of the two exceptional events was £0.8m.

Network Output Measures (NOMs)

2.10. While we discuss the NOMs under the safety output, they also contribute towards the delivery of reliability and environmental outputs.

2.11. There are five NOMs defined under Special Licence Condition 2L. These are:

- The network assets condition measure
- The network risk measure
- The network performance measure
- The network capability measure

[16] A negative percentage indicates lower than target leakage volumes and hence overperformance.
[17] Authority Direction on SHE Transmission Energy Not Supplied Exceptional Event Claim: https://www.ofgem.gov.uk/publications-and-updates/authority-direction-she-transmission-energy-not-supplied-exceptional-event-claim
Authority Direction on SP Transmission Energy Not Supplied Exceptional Event Claim: https://www.ofgem.gov.uk/publications-and-updates/authority-direction-sp-transmission-energy-not-supplied-exceptional-event-claim

- The Network Replacement Outputs

2.12. Of these five NOMs, the final measure (the Network Replacement Outputs) is the only one with directly associated allowances and financial reward or penalty related to delivery. However, assessment of both the asset condition measure and the network risk measure are integral components of the Network Replacement Outputs.

2.13. Under Special Condition 2M, TOs have allowances totalling approximately £6.5bn over RIIO-T1 to deliver their Network Replacement Outputs (NOMs targets). The TOs' expenditure against these allowances is discussed in the 'Non-load related capex' section of Chapter 4. The NOMs targets are set for the end of the price control. If by that time a TO has delivered above or below its NOMs targets then it will receive a revenue reward or penalty in the next price control period. Any reward or penalty is dependent on whether the over or under delivery is justified or unjustified.

2.14. All TOs currently indicate that they will meet their end of period NOMs targets. TOs are currently developing their NOMs methodology and once this work is complete it will enable us to carry out a more informed assessment of TOs' performance than is currently possible. Further explanation of the NOMs development is given in Appendix 1.

Availability Output Measures

Network Access Policy (NAP)

2.15. The output in this area is for each onshore TO to produce and maintain a NAP document to contribute to better SO:TO interaction and cooperation in both short-term and long-term network outage planning. The aim of the NAP is to support improved communication and coordination between NGET, in its role as the SO across GB, and the TOs, to reduce overall costs to consumers (including constraint costs).

2.16. In June 2015 the Authority approved a single common NAP for Scotland, applicable to both SPT and SHE Transmission, and a separate NAP for England and Wales, capturing NGET's functions of SO for GB and TO in England and Wales.[18]

2.17. While we are confident that the network companies are operating consistently with NAP documentation, we believe there are some further activities that the TOs could undertake to develop this policy. These are discussed in Chapter 7.

[18] https://www.ofgem.gov.uk/publications-and-updates/authority-decision-approve-network-access-policy-nap

Customer Satisfaction

Customer/stakeholder satisfaction survey

2.18. The customer satisfaction output incorporates several component incentives:

- NGET operate customer and stakeholder satisfaction surveys, against which they are financially rewarded or penalised.

- SPT and SHE Transmission operate stakeholder satisfaction surveys, with associated financial incentives. Both also have key performance indicators[19] (KPIs) related to stakeholders around which they are rewarded or penalised financially.

2.19. These components together account for an incentive of +/- 1% of annual baseline revenue.

NGET

2.20. NGET reports both customer and stakeholder satisfaction surveys. NGET's scores are illustrated below in Table 4, against baselines.

Table 4: NGET stakeholder and customer satisfaction results

Company	Stakeholder Survey (0-10, baseline 5)		Customer Survey (0-10, baseline 6.9)	
	2013-14	2014-15	2013-14	2014-15
NGET	7.5	7.7	7.4	7.4

SPT and SHE Transmission

2.21. The two Scottish TOs record performance against stakeholder satisfaction surveys and against sets of KPIs. These KPIs were developed by SPT and SHE Transmission to cover their respective activities. Table 5 summarises their performance against baselines.

[19] SPT's KPIs are focussed around new connections-related activities but include measures relating to connected customers and broad interest stakeholders, while SHE Transmission's represent a diverse range of objectives, akin to a balanced scorecard for the business.

Table 5: Scottish TOs stakeholder satisfaction results

Company	Survey (0-10, baseline 5)		KPI (0-100, baseline 50)	
	2013-14	2014-15	2013-14	2014-15
SPT	7.40	7.10	68.00[20]	69.16
SHE Transmission	6.50	7.70	91.00	86.00

Stakeholder engagement incentive

2.22. All the TOs are eligible to participate in a discretionary reward scheme, the stakeholder engagement incentive, which is an annual panel assessment of stakeholder engagement.

2.23. TOs submit evidence to demonstrate that:

- A robust engagement strategy is in place with stakeholders.
- Outcomes of the engagement process are acted upon.

2.24. An independent panel, made up from experts from a range of backgrounds, assess the quality of the evidence and award each TO a score out of ten based on this assessment. The score is then used to derive the proportion of the overall incentive available to each TO. The incentive provides an annual award of up to 0.5% of annual revenues per TO where effective stakeholder engagement results in high quality outcomes.

2.25. All three TOs made submissions to our stakeholder engagement discretionary reward. The feedback for the companies was that they were improving (see Table 6), with a good level of resources committed to stakeholder engagement and they are progressing on embedding this work within the business.

2.26. However, the panel considered that there is still room for improvement: the companies could give more evidence on how the industry is working together and how their stakeholder engagement work relates to their day-to-day activities (and vice versa). More detail can be found in the decision letter concerning this year's stakeholder engagement discretionary reward.[21]

[20] The KPI submitted by SPT for the year 2013-14 in last year's RRP was incorrect. This has now been corrected so that it doesn't adversely impact the AIP.
[21] See https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/stakeholder_engagement_14-15_decision_letter_tos_1.pdf

Table 6: Stakeholder engagement discretionary rewards scores

Company	Score (out of 10) 2013-14	Score (out of 10) 2014-15
NGET	5.75	6.00
SHE Transmission	5.4	6.00
SPT	4.9	5.50

2.27. As noted in Table 3 previously, the cumulative incentive awards to date for the TOs' customer and stakeholder activities is just over £26m.

Connections and Wider Works Output Measures

2.28. We use a number of output measures in this category under the RIIO framework. All TOs have primary measures of wider works (baseline and strategic), entry connections and exit connections. NGET has additional output measures of incremental wider works, DNO mitigation and undergrounding provisions. For each of these measures, TOs were given allowances for delivery of a certain level of quantified outputs as derived from their business plans. We introduced mechanisms to flex allowances in accordance with changes to requirements for these outputs. NGET was also funded ex ante for significant 'general' wider works for which no quantifiable measures were set. We have considered the performance of the TOs against these outputs in the follow sections.

Baseline wider works connections[22]

2.29. Reinforcement works to the wider transmission system to accommodate existing and future generation and demand as projected in the TOs' business plans are known as Baseline Wider Works (BWW) outputs. BWW outputs are measured in terms of the additional transfer capacity across system boundaries.[23]

2.30. NGET's electricity transmission licence sets out each reinforcement project, the boundary it will affect and the amount of additional transmission transfer capability (MW) agreed as part of the BWW output. NGET has delivered on its BWW outputs in the first two years of RIIO-T1.

2.31. SPT's licence details the agreed BWW reinforcement schemes to provide additional boundary transfer capability in the south of Scotland. These works are due in 2015-16 and beyond. SPT has indicated that it expects to meet these outputs in time.

[22] These are set out in Special Condition 6I of each licence

[23] A system boundary splits the transmission network into two parts across which the capability to transfer electrical power can be assessed. For the avoidance of doubt, system boundaries are not network ownership boundaries and each TO's network could contain multiple system boundaries.

2.32. SHE Transmission's electricity transmission licence sets out the agreed BWW reinforcement schemes to provide additional boundary transfer capability in the north of Scotland. These are due from 2015-16. SHE Transmission is forecasting to connect all of its baseline wider works schemes on time.

Strategic wider works connections

2.33. In their RIIO-T1 business plans, the three onshore TOs identified transmission projects totalling approximately £9 billion that may be needed over the next decade, but there is significant uncertainty with some of these projects. RIIO-T1 put in place the SWW process for the approval of future major investments that were neither in the baseline nor captured by the volume drivers. These schemes are subject to a within-period determination by the Authority.

2.34. In 2013-14 we approved three projects proposed by SHE Transmission: Kintyre-Hunterston, Beauly-Mossford and Caithness-Moray. SHE transmission report that these projects are progressing according to schedule. Neither NGET nor SPT have any approved SWW schemes, but NGET expect a number of their proposed SWW schemes to go ahead in the future. SPT has one proposed SWW scheme to commence in RIIO-T1, which is currently under development.

General connection activity

2.35. TOs are required to deliver timely and effective connections to the network through their licences. SPT and SHE Transmission both face a timely connections financial incentive, by which their revenues are reduced if they fail to offer connection terms within the specified period. NGET has no financial incentive on timeliness of connection offers but needs to comply with its licence condition obligations.

2.36. SHE Transmission completed all 98 of its offers within time.

2.37. SPT failed, on two of its 88 offers, to meet the three month timescale as set out in its licence, although we understand that this did not result in an overall delay to the customers receiving the corresponding offers from NGET. The allowed revenue modification as a consequence of 2014-15 underperformance will have the impact of reducing SPT's maximum allowed revenue for 2016-17 in line with the provisions in the licence.[24]

2.38. NGET completed all 235 of its offers within the specified period.

[24] Set out in Special Condition 3G (Financial Incentive for Timely Connections Output) of the Scottish TO's electricity transmission licence.

Local Generation Connections (Entry)

2.39. Last year, NGET reported an approximate 21GW reduction from its baseline forecast for generation connections of 33GW. This year, NGET has further revised its generation connections activity forecast down to 11.15GW. We will continue to work with NGET to keep under review both its forecasts and the implications these have through the revenue adjustment mechanisms in the licence.

2.40. SPT has forecast an increase of 1GW in the generation connection output for sole-use infrastructure and 3.2GVA on shared-use infrastructure capacity above its business plan baseline (2.5GW and 1GVA respectively).

2.41. SHE Transmission is forecasting to significantly exceed its baseline generation output of 1.2GW for sole use connections and 1GVA for shared use. Its current forecast is at 2.1GW and 6.2GVA respectively.

Local Demand Connections (Exit)

2.42. NGET has seen a significant fall in terms of demand connections, reducing the required number of supergrid transformers (SGTs) from 72 to 48 and overhead line from 27km to 7.2km.

2.43. SHE Transmission is not forecasting to deliver any local demand connections for which it has allowances (Shetlands 132kV). Any unspent allowances will be shared with consumers.

Incremental wider works[25]

2.44. Incremental Wider Works (IWW) are transmission infrastructure works that deliver an increase in boundary transfer capability which NGET determines is required, in line with the implementation of its Network Development Policy.

2.45. NGET has a considerable number of IWW schemes. In the first two years of RIIO-T1, NGET has delivered on its baseline level of additional boundary capacity. Over the rest of the RIIO-T1 period, NGET is now forecasting a substantial fall in its IWW delivery against its baseline levels due to a fall in generation and demand connections.

Environmental Output Measures

Limiting sulphur hexafluoride (SF_6) emissions

2.46. SF_6 is an extremely effective electrical insulator and so is used in high-voltage switchgear and other electrical equipment. It is also a potent greenhouse gas with a

[25] Detailed in Special Condition 6J of NGET's licence

radiative forcing 23,900 times higher than Carbon Dioxide (CO_2). TOs are therefore subject to a financial incentive to limit their emission levels of the gas.

2.47. Both NGET and SPT outperformed against target emissions levels of SF_6 in 2014-15 and, based on the information we currently have, will receive a financial reward of £2.5m and £0.1m respectively. SHE Transmission exceeded its target emissions level and will therefore be penalised by £0.2m under the SF_6 incentive mechanism.

2.48. Both NGET and SHE Transmission have uncovered errors in their previously reported SF_6 figures. These errors affect both the SF_6 leakage and inventory figures reported to us.

2.49. The SF_6 performance figures reported in last year's annual report also assumed that two exceptional event claims from SPT that were awaiting the Authority's decision would be approved. The Authority has subsequently rejected both claims.[26]

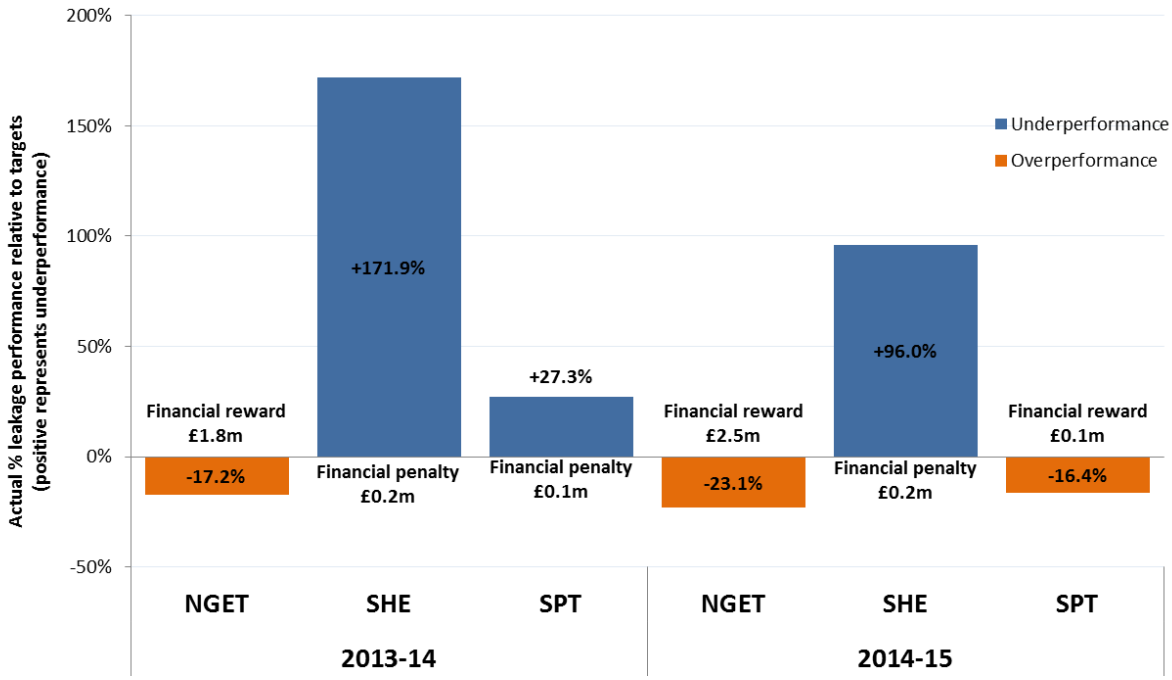
2.50. The performance figures in figure 5 below have been amended based on these updated leakage figures and Authority decisions. This has resulted in a £663k reduction in reward for NGET, an £139k increase in penalty for SHE Transmission, and a £199k increase in penalty for SPT. [27]

2.51. The net impact of these adjustments is that both SHE Transmission and SPT will, based on the information we currently have, be penalised by £0.2m and £0.1m respectively for their SF_6 leakage in 2013-14, while NGET will receive a reward of £1.8m.

[26] Authority decision on SP Transmission SF_6 Exceptional Event claim: https://www.ofgem.gov.uk/publications-and-updates/authority-decision-sp-transmission-sf6-exceptional-event-claim

[27] We have yet to confirm the impact of an error in NGET's SF_6 inventory. The effect of the error is likely to be a minor increase in its leakage target.

Figure 5: Two year SF_6 performance – leakage above or below target as percent of annual target[28]



Business carbon footprint (BCF)

2.52. The TOs must report annually on the transmission network BCF. The network BCF includes:

- Scope 1 emissions directly related to the day-to-day business activities of network business.
- Scope 2 emissions which arise from operating the network, including the CO_2 emissions from losses of electricity or shrinkage of gas that occur as a result of transporting energy on the network.
- Scope 3 emissions which are due to third party contractors carrying out business activities on behalf of the network.

2.53. Table 7 below shows the BCF reported in the first two years of the price control by the three transmission companies in terms of tonnes of carbon dioxide equivalent.

[28] A positive percentage indicates higher than target leakage volumes and hence underperformance.

Table 7: BCF in terms of tonnes of carbon dioxide equivalent per licensee in 2013-15

Year	NGET	SHE	SPT
2013 - 14	2,259,286	187,267	237,596
2014 - 15	2,552,420	346,176	252,944

2.54. Across all three TOs over 88% of their BCF can be attributed to electrical losses. These are heavily influenced by the ongoing changes in the characteristics of the network (eg connection of renewables far from areas of high consumption) and so year-on-year comparisons of BCF are not a suitable metric of efforts to reduce carbon emissions.

Losses

2.55. All onshore TOs have a reputational incentive to reduce transmission losses where they can do so and provide long term value to consumers. To date all three TOs have complied with the license condition by putting strategies in place to reduce losses on their networks and by reporting against these annually.[29]

Table 8: Historical annual losses from the GB transmission system[30]

Losses (%)	2008	2009	2010	2011	2012	2013	2014	2015
NGET	1.62	1.59	1.77	1.40	1.80	1.67	1.57	1.65
SHE	2.38	2.86	2.59	2.55	3.04	3.05	3.55	8.04
SPT	2.17	1.81	1.46	1.54	1.47	1.30	1.29	1.17
GB Total	1.75	1.73	1.82	1.49	1.92	1.72	1.70	1.84

2.56. Losses on the transmission network are affected by a number of factors including the volume of electricity transmitted, loading profile of circuits, the transmission distances between generation and demand, the level of reactive compensation, the type of transmission equipment (such as conductor) and the composition of circuits.

2.57. The SHE Transmission network, typically composing of generation units remotely situated and connected to the main interconnected transmission system with long transmission lines, is prone to incurring higher losses than those of NGET or SPT. However, the losses increase in 2015 is significant, even compared to its own historical levels. SHE Transmission is engaging with the system operator to understand the causes of this increase. We await the results of this investigation.

[29] Losses Reports
NGET: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=43615
SHE Transmission: https://www.ssepd.co.uk/WorkArea/DownloadAsset.aspx?id=6726
SPT:http://www.spenergynetworks.co.uk/userfiles/file/Transmission%20Losses%20Report%202015.pdf
[30] http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/transmission-losses/

Environmental discretionary reward

2.58. The Environmental Discretionary Reward (EDR) is a reputational and financial incentive for electricity transmission licensees. The aims of the scheme are to sharpen companies' focus on strategic environmental considerations and to encourage corporate and operational culture change to facilitate a growth in low carbon energy.[31]

2.59. A company must provide evidence of its activity in each category to show how it has met the required criteria. We score the evidence and assign a company to a performance band ('engaged', 'proactive', or 'leadership'). Only companies that achieve a leadership score can get a financial reward. The reward is related to their specific score and those of others that also achieve leadership performance. We indicate in the scheme guidance that to achieve leadership performance a company must show evidence of how it is looking beyond business as usual, takes a whole system perspective, and collaborates with a range of stakeholders to achieve outstanding performance across the scheme categories. Our assessment is reviewed at the strategic level by an independent panel of experts.

2.60. Last year, all three electricity TOs applied to the voluntary scheme but no rewards were made. In this scheme year (2014-15), all three companies applied but only National Grid Electricity Transmission was able to demonstrate leadership performance. As a result, it has achieved a reward of £2 million. All three companies have scope to make further progress on meeting the scheme's aims and we hope that the reward this year will encourage them to do so.

Table 9: EDR Performance in 2014-15[32]

Company	Performance Band	Financial Reward
NGET	Leadership	£2 million
SHE	Proactive	None
SPT	Engaged	None

Visual amenity[33]

2.61. We have made an allowance of almost £600m (2014/15 prices) available across the RIIO-T1 period to share with all TOs so that the visual impact of certain existing transmission infrastructure assets in designated areas can be reduced. To date, no schemes have been proposed and no licensee has reported expenditure in this category.

[31] The scheme covers activities in the following categories: Strategic understanding and commitment to low carbon objectives; Whole electricity system planning; Connections for low-carbon generators; Collaboration on innovation; Network development solutions that avoid the need to reinforce the network; Direct environmental impact; Business greenhouse gas emissions
[32] Ofgem's decision was published on 13 November 2015: https://www.ofgem.gov.uk/ofgem-publications/97538/edrdecision201415-pdf
[33] Special Condition 6G of the licences

2.62. We understand that NGET is developing technical plans to reduce the impact of electricity infrastructure associated with sections of high voltage lines in four areas, namely: Dorset (near Winterbourne Abbas), New Forest National Park, Peak District National Park and the Snowdonia National Park. NGET is also set to use part of the allocation for smaller localised visual improvement projects. This is expected to be progressed in Winter 2015-16. We will update on progress as part of next year's annual report.

2.63. No schemes to improve visual amenity have yet been proposed in the designated areas by the two Scottish TOs, although SPT have identified that 136km of overhead line is eligible for consideration under this mechanism. SHE Transmission have identified the potential for visual amenity works for 429km of overhead line and 13 substations across ten locations and is aiming to finalise its accompanying Methodology Statement in Autumn 2015.

3. Innovation

Chapter Summary

This chapter presents an overview of TOs' expenditure in relation to the various innovation incentives in RIIO-T1

Network Innovation Allowance

3.1. The Network Innovation Allowance (NIA) was established as part of the RIIO-T1 price control. The NIA provides each licensee with a 'use it or lose it' allowance to spend on innovation projects in line with the NIA Governance Document.[34] Both NGET and SHE Transmission have an allowance of 0.7% of annual base revenue; SPT's allowance is 0.5% of annual base revenue. In the second year of RIIO-T1 all licensees have begun NIA projects. If successful, these should bring a wide variety of operational, environmental and safety benefits.

3.2. Licensees have begun to develop useful learning from this investment. Details on all projects can be found on the Energy Network Association's (ENA's) Smarter Networks Portal.[35] While we are pleased that the NIA is working well and developing new learning we need to ensure this is shared effectively. We recently published an open letter encouraging the TOs to improve the quality of project reporting on the Smarter Networks Portal[36]. We encourage all licensees to consider how this can be improved. While we are concerned regarding the standard of project reporting we were generally pleased with the Annual Summary of NIA Activity published by licensees.[37]

Network Innovation Competition

3.3. The Network Innovation Competitions (NIC) is an annual competition to which transmission companies can apply. The competitions help to encourage Network Licensees to innovate in the design, build, development and operation of their networks.

3.4. The NIC provides funding to a small number of large-scale innovation projects. Trials financed through the NIC will generate learning for all Network Licensees and will be made available to all interested parties. This learning brings potential benefits and cost savings for current and future consumers. In 2014, two onshore electricity

[34] The Electricity Network Innovation Allowance Governance Document can be found here: https://www.ofgem.gov.uk/publications-and-updates/electricity-network-innovation-allowance-governance-document.
[35] http://www.smarternetworks.org/
[36] The letter can be found here: https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/open_letter_on_knowledge_transfer_0.pdf
[37] http://www.smarternetworks.org/Project.aspx?ProjectID=738#downloads

transmission projects were selected to receive a total of £9.7m. Funding for the electricity projects is being recovered across all electricity customers during 2015-16.

Table 10 – Onshore transmission projects selected for funding in the 2014 NIC[38,39]

Project Title	Lead company	Brief explanation	Funding request	Timescale
Enhanced Frequency Control Capability	NGET	The project will develop and demonstrate an innovative new monitoring and control systems. This will be used to send signals to both demand and generation customers to provide network services.	£6,911k	Project due to be completed in 2018
Modular Approach to Substation Construction	SHE Transmission	The project aims to evaluate the deployment of a permanent substation designed using a Modular Approach to Substation Construction.	£2,835k	Project due to be completed in 2020

Innovation Rollout Mechanism

3.5. The purpose of the IRM is to facilitate the rollout of proven innovations, which will provide long-term value for money to consumers, in advance of the next price control period. To qualify, rollouts must deliver carbon and/or environmental benefits and not provide a commercial return for the licensee within the price control period.

3.6. In May 2015 SPT applied for funding under the innovation rollout mechanism (IRM) to deploy a high temperature low sag conductor. This conductor will allow SPT to connect additional generation to its network without the need to completely rebuild circuits. We recently published our decision[40] to make £24.28m available to fund the project.

[38] More detail on the 2014 NIC and the progress of the projects can be found here: https://www.ofgem.gov.uk/publications-and-updates/2014-innovation-competitions-brochure
[39] The recently published results of the 2015 NIC can be found here: https://www.ofgem.gov.uk/publications-and-updates/2015-innovation-competitions-brochure
[40] https://www.ofgem.gov.uk/publications-and-updates/decision-sp-transmission-limiteds-submission-2015-innovation-rollout-mechanism-application-window

4. Expenditure

Chapter Summary

This chapter evaluates actual and forecast expenditure for onshore electricity transmission against the costs allowed in the RIIO-T1 settlement. The focus is on load and non-load capital expenditure, since those categories form the majority of TO spend.

Introduction

4.1. This chapter looks at the TOs' expenditure, and their forecasts of expenditure for the remainder of the control, against allowances. We firstly consider the overall expenditure (totex), then examine the two main components: load related capital expenditure (capex) and non-load related capex.

4.2. Load-related capex is the installation of new assets on the network to accommodate changes in the level or pattern of electricity supply and demand. Non load-related capex is expenditure to maintain the existing network including through asset replacement. Load and non-load related expenditure together make up approximately 87-96% of TOs' forecast totex, and therefore is an important focus of our analysis.

4.3. We present some high level analysis of the drivers of the deviation of TOs' capex from the allowances and assess the TOs' performance on capital delivery. We conclude the chapter with a look at non-operational capex[41] and operating costs (opex).

Total expenditure (Totex) performance and forecasts

4.4. A fundamental change between the previous price control and the RIIO framework is that companies are incentivised to deliver outputs based on total whole life costs, rather than being driven to preferring either opex or capex under different incentives. This enables the companies to select the best solutions and optimise costs and benefits.

4.5. The RIIO-T1 arrangements include setting a totex allowance, which is automatically adjusted to account for uncertainty in the volume of requirements. Underspend or overspend against this allowance is subject to a single incentive mechanism with a symmetrical sharing factor.

4.6. We monitor deviations from adjusted allowances both to allow us to correctly apply the totex incentive mechanisms and to better inform our understanding of how the TOs are achieving their performance levels. This understanding will also be an important element to input to the development of the RIIO-T2 framework.

[41] This covers expenditure on equipment not directly related to the transmission operations, for example, IT capital expenditure

4.7. The figures below show the performance to date and forecast expenditure for all three TOs against their baseline and adjusted totex allowances. These forecasts are based on TOs' calculations and are subject to our confirmation in due course.

Figure 6: Totex (actual & TO's forecast) against adjusted allowances[42]: NGET

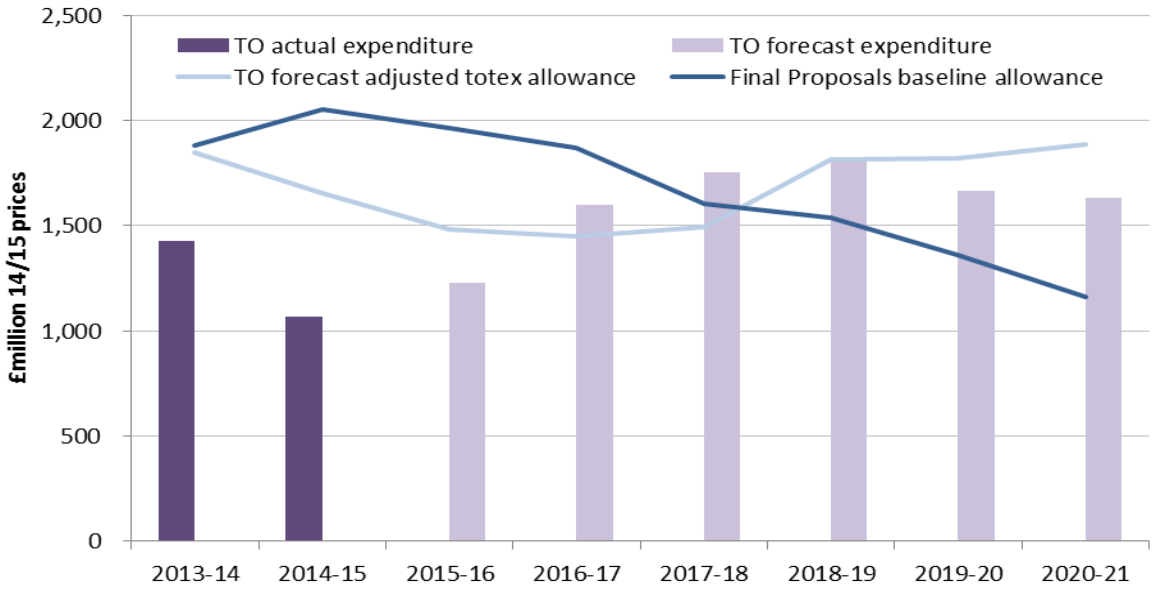
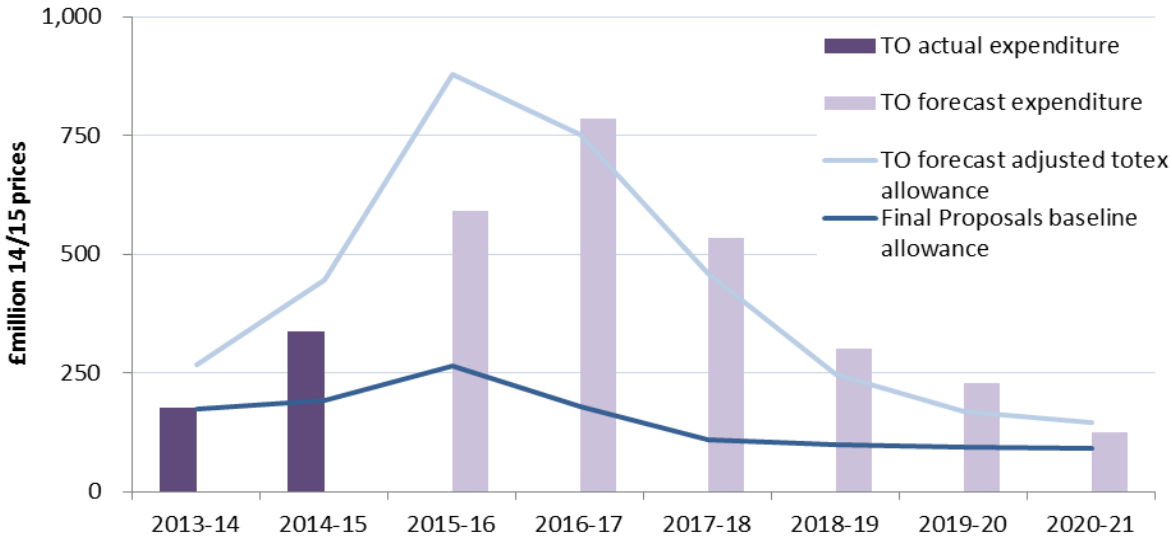
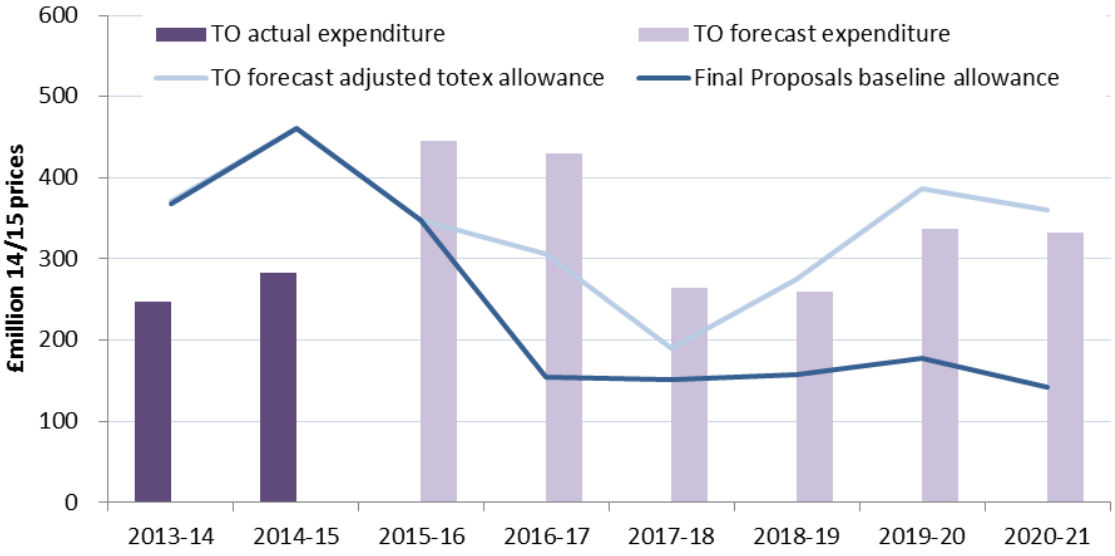


Figure 7: Totex (actual & TO's forecast) against adjusted allowances: SHE Transmission



[42]As NGET was not fast tracked, the costs were derived from the numbers that went into the price control financial model rather than the actual business plan as submitted in March 2012.

Figure 8: Totex (actual & TO's forecast) against adjusted allowances: SPT



4.8. In year two of the price control all TOs underspent against their adjusted totex allowances. The later sections of this chapter give more detail on the specific circumstances of each of the TOs' performances against their allowances.

4.9. All three TOs are forecasting to underspend against their totex allowance for the entire control period, though by varying amounts, as illustrated in Table 11.

Table 11: TOs' view of totex allowances and expenditures across RIIO-T1 period

£m, 2014-15 prices	NGET 2014-15	SHE 2014-15	SPT 2014-15
1. Final Proposals Baseline Totex Allowance	13,342	1,206	1,958
2. Volume Adjusted Totex Allowance: TO's view	13,453	3,362	2,700
3. Expenditure: TO's view	12,186	3,082	2,601
Difference in TO's view (2 and 3)	**10%**	**9%**	**4%**

Load-related capex (LR capex)

4.10. LR capex is the investment on the network to accommodate changes in the level or pattern of electricity supply and demand. This category can be split further into a number of funding mechanisms. The largest mechanisms are for (i) connecting new

electricity generation sources, (ii) connecting new demand sources, and (iii) 'wider works' which are associated reinforcements that facilitate these connections whilst maintaining network integrity. Lesser mechanisms include provisions for undergrounding cables and for mitigating works on the electricity distribution systems ('DNO mitigation').

4.11. The capex allowance for these elements comprises a baseline level, reflecting a 'best-view' business plan by the TOs, mechanisms to flex the allowance in accordance with the actual outturn demand and consequential system-wide requirements.

4.12. As part of the RIIO-T1 price control we put in place a mechanism to allow TOs to bring forward large investment projects – known as Strategic Wider Works (SWW) – where funding had not been awarded as part of the price control settlement. This mechanism allows us to consider the need and funding for these projects during the price control period, so that delivery of these outputs can be brought forward in a timely manner.

4.13. The transmission licensees have identified in their business plans a number of projects that they consider are suitable for future consideration under the Strategic Wider Works arrangements. To date, only SHE Transmission have gained approval for project funding under the SWW mechanism, but the other TOs have included some as yet unapproved projects in their expenditure forecasts. We have adjusted the TOs' expenditure forecasts to exclude such unapproved capex.

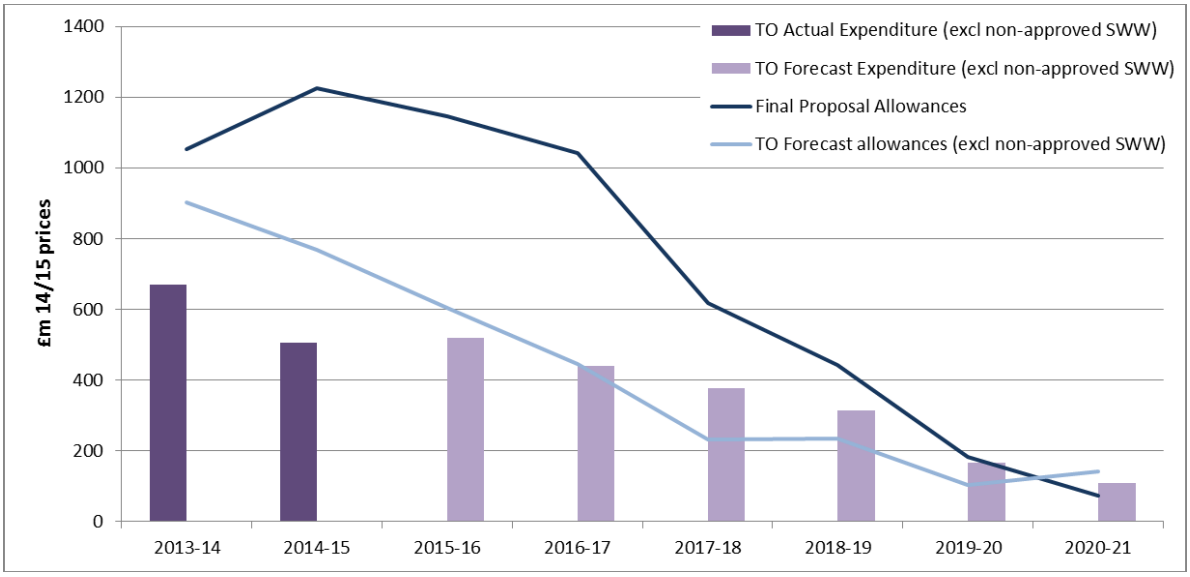
NGET

4.14. Since the start of the price control there has been a substantial shift in the forecast of load related works. At the time of setting the price control, NGET's business plan forecast connecting 33GW of new generation. Now in the second year of the price control, NGET's connection profile has fallen to a third of that anticipated (11.15GW). Demand connections have also fallen. These changes will lead to a downward adjustment to the allowances across the price control period.

4.15. In light of the reduction in volume of demand and generation connections, NGET currently anticipates that a large amount of wider works expenditure, required to maintain network integrity within and across network boundaries, has either become unnecessary or will be deferred beyond RIIO-T1.

4.16. This is reflected in its 2014-15 performance, where NGET has underspent on load-related capital expenditure by £268m against its forecast allowance. NGET's explanation is that this is in part due to a fall in the need for 'general' wider works for which there is no quantified outputs, and consequently no automatic allowance adjustment.

Figure 9: LR capex (actual & TO's forecast) spend for RIIO-T1 against adjusted allowances[43]: NGET



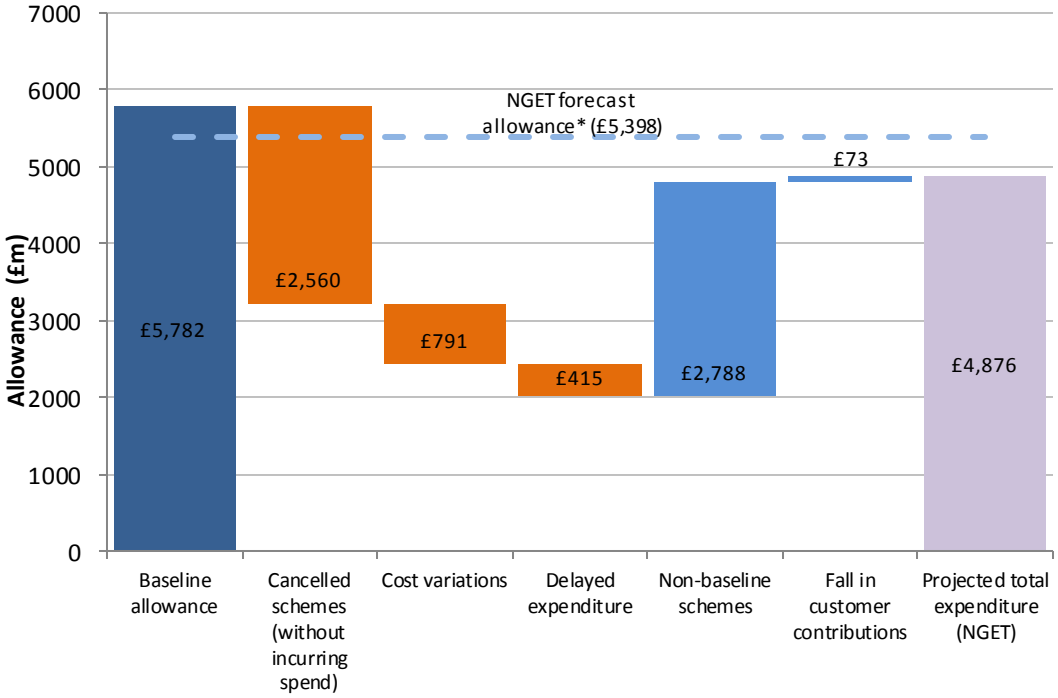
4.17. Figure 9 demonstrates the impact of the fall in LR workload across the price control period. Overall, NGET is forecasting a net LR expenditure[44] of £3.1bn. NGET estimates that LR allowances will scale downwards from £5.8bn to £3.6bn across the price control period as a result of changes in requirements. After accounting for 'true-ups' to account for customer contributions in excess of expectations, this represents an underspend of £332m against adjusted allowance over the RIIO-T1 period.

4.18. At a high level, the source of underspend is mainly driven through the cancellation/deferral beyond RIIO-T1 of some baseline and incremental wider works scheme expenditure, though this has been somewhat counterbalanced by an overspend on generation and demand connections.

4.19. To gain a better understanding of this underspend, we have looked more closely at how the allowances have adjusted for NGET's new work profile (figure 10). In setting the price control, Ofgem used a baseline allowance to reflect its expectation of some £1.4bn of fixed costs (eg for works that are needed but do not deliver a directly measurable output such as MW) and £4.4bn of varying costs (that change in proportion to measurable outputs). The parameters for varying costs according to relevant output levels were set on the basis of a list of projects proposed by NGET, although this is not meant to restrict the actual projects that NGET should take forward to deliver a certain output.

[43] These values include the capital costs of SWW pre-construction works and the annual 'true-up' estimated by NGET to account for customer contributions in excess of expectations, but exclude the value of other capital works associated with any non-approved SWW schemes.
[44] Once customer contributions and excluded services revenues are offset against expenditure

Figure 10: Comparison of load related expenditure allowances over RIIO-T1 with forecast expenditure: NGET



*Forecast total load related allowance pre Totex incentive adjustment

4.20. NGET expects that it will complete projects for which it received a baseline amount of £3.2bn, for £791m less than this allowance. A further £415m of this expenditure will be deferred to RIIO-T2 due to changes in delivery timing from the original plan. Since the original business plan submission does not associate the cancelled and non-baseline schemes with specific outputs, it is not possible to determine whether these are volume driven (which would attract further allowances) or from the fixed £1.4bn. This is an issue that we will be reviewing further with NGET.

4.21. There is a further issue to note that NGET's LR forecast allowances across the RIIO-T1 period are £329m less that the Price Control Financial Model (PCFM) predicts. Our understanding is that this discrepancy is due to the PCFM's current inability to project incentive payments beyond the end of the RIIO-T1 period, while NGET's modelling spreads these payments beyond RIIO-T1 period (in line with the two-year lag for incentive payments). We will be reviewing this issue with NGET over the coming months.

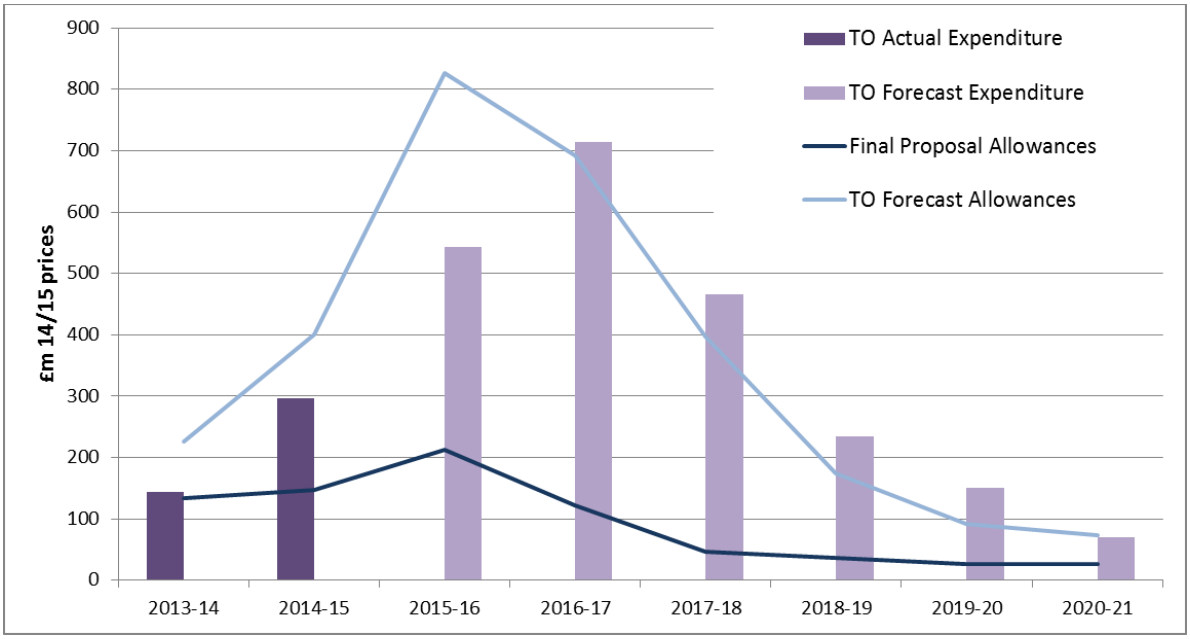
4.22. How the revised allowances scale against outputs and TO workloads is one measure of how the price control mechanisms are adapting to the new generation profile. Some elements of the allowances are non-varying, and do not scale with outputs delivered. Other elements of the allowances scale directly with outputs delivered. At the time of setting the price control the non-variant baseline amounted to £1.4bn whilst the anticipated volume-driver allowance amounted to £4.4bn. We will continue to work on evaluating how the allowances are adapting to the changing work demands by the TOs.

SHE Transmission

4.23. A number of significant changes within the first two years of the price control have affected SHE Transmission's RIIO-T1 workload. Generation connections have increased markedly and, in terms of expenditure, Ofgem has approved three Strategic Wider Works schemes; Caithness-Moray, Kintyre-Hunterson and Beauly-Mossford. SHE Transmission is forecasting to significantly exceed its baseline generation output (c.170% sole use and c.600% shared use, against respective baseline) and expenditure (£874m against a baseline of £216m).

4.24. In 2014-15, SHE Transmission has underspent on load-related capital expenditure by £103m against its revised allowance of £400m. Most significant is the £129m underspend for the sole use generation schemes.

Figure 12: LR capex (actual & TO's forecast) spend for RIIO-T1 against adjusted allowances[45]: SHE Transmission



4.25. Overall, SHE Transmission's RIIO-T1 net expenditure is forecast as £2,617m against an expected allowance of £2,882m. This indicates an outperformance of £265m for the total load-related balance over the RIIO-T1 period.

4.26. SHE Transmission reports that the entry baseline is forecast to be delivered by a different mix of schemes compared with those in the baseline. We are continuing to work

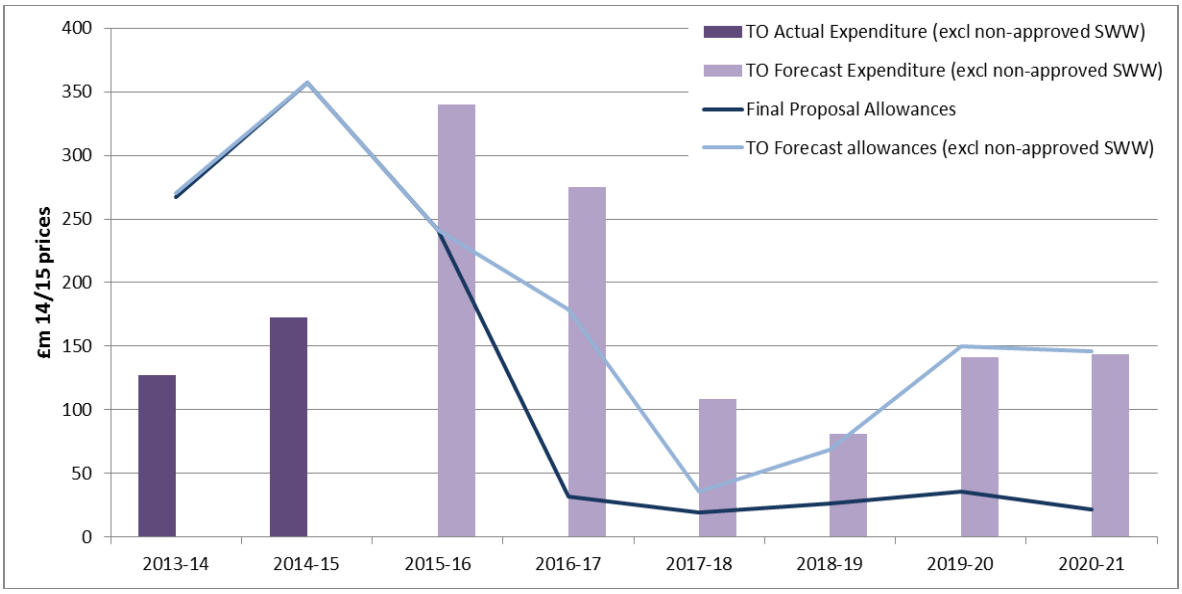
[45] These values relate to approved SWW schemes only.

with SHE Transmission to understand how this mix has led to underspend. In particular, we are looking to understand whether SHE Transmission has successfully underspent against its forecasts and our allowances for schemes in the business plans, or whether any underspend is driven by new schemes being progressed which are fundamentally lower cost than the volume driver allowances.

SPT

4.27. SPT has also seen a substantial shift in its work programme over the RIIO-T1 period, but in contrast to NGET it is now forecasting a far greater volume of connections (commensurate with customer requirements) than was in its business plan. However, it has had to undergo a re-profiling of its workload, with work such as the Western HVDC link being delayed, and other work being moved to later in the price control due to current planning and consenting issues. This has resulted in a £185m underspend over the current year. This can be seen from Figure 11, showing SPT's expenditure to date and its forecast of allowances and expenditure over the RIIO-T1 period.

Figure 11: LR capex (actual & TO's forecast) spend for RIIO-T1 against adjusted allowances[46]: SPT



4.28. SPT's forecast net expenditure (after calibrating to take account of customer contributions and excluded services) is £1,390m against its expectation of adjusted allowance of £1,448m, an underspend of £58m over the RIIO-T1 period. SPT is forecasting outperformance due to (i) innovation on the Series & Shunt Compensation (for Scotland-England interconnection) project, leading to savings of almost £50m, and

[46] These values include the capital costs associated with SWW pre-construction works but exclude the value of other capital works associated with any non-approved SWW schemes.

(ii) savings on the Installation of Mechanically Switched Capacitor Damping Networks (MSCDNs) to Upgrade Scotland – England Interconnection (circa £8m below allowance).

4.29. We estimate that SPT's forecast allowance includes c.£160m of works for which there is no perfectly matched asset type funding mechanism. We will be reviewing this with the company to determine the appropriate way forward.

4.30. SPT is not proposing substantial change in scheme composition from those that were in its baseline plan. On the exit connection side, SPT is planning to deliver the same schemes as those in the baseline, but at almost 10% lower cost.

Non load-related capex (NLR capex)

Overview

4.31. NLR capex is capital investment made by a TO to maintain its current network including through asset replacement. This investment covers mainly replacement and refurbishment of assets[47].

4.32. Non load related expenditure is split into lead asset[48] and non lead asset expenditure. Lead assets are the main assets comprising the transmission network that are required for the safe and reliable transfer of electricity from one point on the network to another. Non-lead assets include monitoring, telecommunications, protection equipment (except for switchgear), and any assets below 132kV (including assets in the lead asset category types). Non lead asset expenditure also covers cost incurred to maintain or improve weather related resilience.

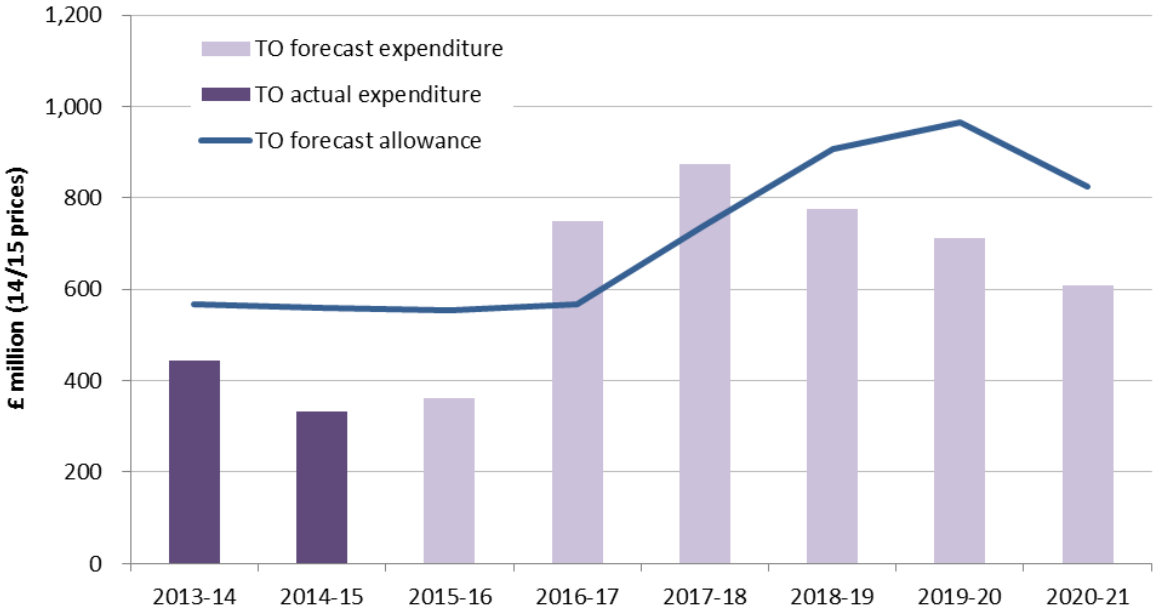
4.33. The Network Output Measures (NOMs) are the primary means of measuring outputs delivered by NLR expenditure. The NOMs relate only to lead assets and at the time that allowances were set it was assumed that about three-quarters of NLR expenditure would be on assets covered by the NOMs targets. As a consequence, our focus to date has been on NOMs outputs. As noted in Chapter 2, the development of the NOMs methodology (which is further detailed in Appendix 1), will better inform the assessment of such outputs. The latest information from TOs indicates that only around half of the three TOs' current RIIO-T1 total forecast NLR expenditure will directly contribute to the delivery of NOMs outputs. This proportional change raises the importance of our assessment of non-lead asset expenditure and we therefore intend to give it greater scrutiny in the future.

[47] The figures quoted in this section and in the Network capital delivery section of this chapter exclude NLR uncertain costs. NLR uncertain costs relate mainly to enhanced physical site security upgrade programme (PSUP). We published our decision on PSUP on 30th September 2015: https://www.ofgem.gov.uk/publications-and-updates/decision-tpcr4-cost-reviews-and-riio-t1gd1-uncertainty-mechanisms-enhanced-security-upgrades

[48] For reporting purposes the following asset categories are lead assets: circuit breakers, transformers, reactors, underground cables, over head line (OHL) conductors, OHL fittings, OHL towers (SHE transmission and SPT only).

4.34. The NLR allowances and actual and forecast expenditure for the eight years of RIIO-T1 for each TO are shown in figures 13-15. As illustrated below, all three TOs are forecasting an overall underspend on their NLR allowance of the eight years of RIIO-T1.

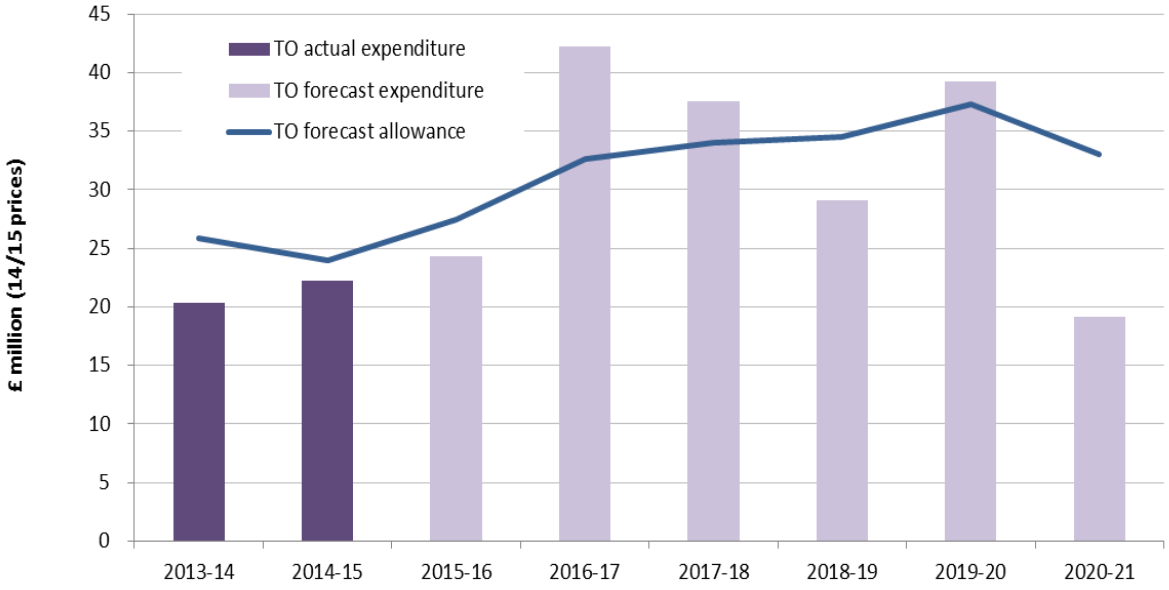
Figure 13 –NLR expenditure (actual & forecast) against TO forecast allowances: NGET



4.35. NGET is currently forecasting an underspend on lead assets of £783m with an overspend on non-lead assets of £100m. This results in a net underspend of £683m, or approximately 12% of NLR expenditure.

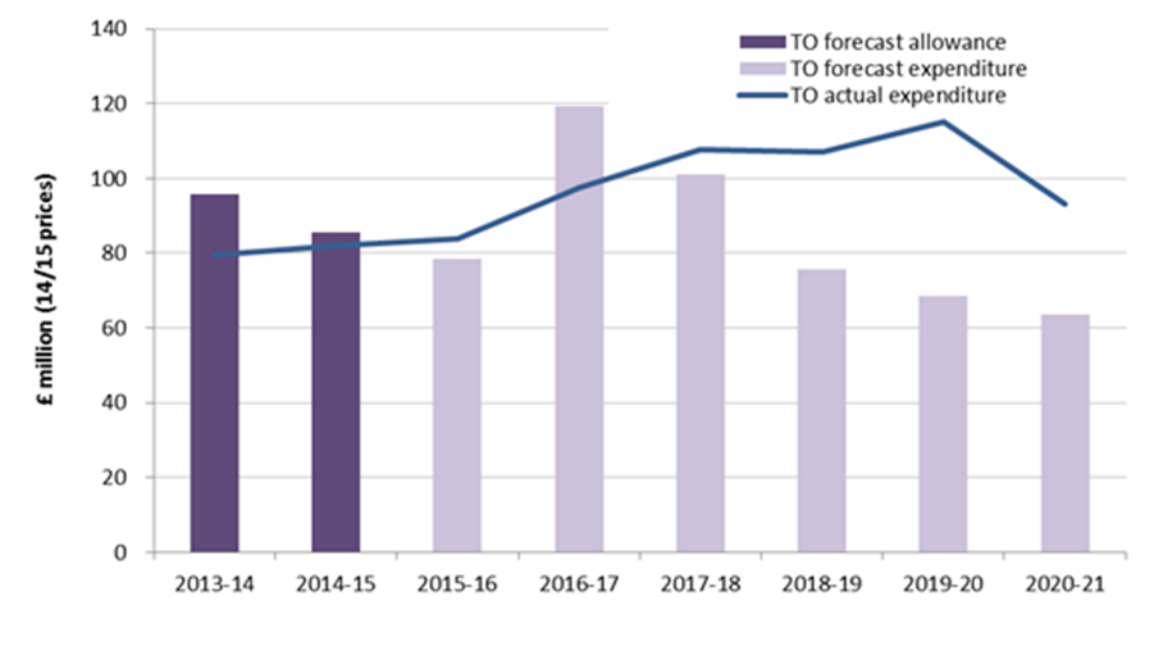
4.36. There are no defined outputs for non-lead assets and the majority of the overspend is in the 'Other TO Capex' and 'Substation Other' categories. These are two categories against which, to date, we have had little visibility over expenditure and over what that expenditure is delivering for consumers. We intend to carry out more detailed scrutiny of these categories in the coming year.

Figure 14 – NLR expenditure (actual & forecast) against TO forecast allowances: SHE Transmission



4.37. Overall SHE Transmission is forecasting that it will underspend its RIIO-T1 NLR allowances by about 6% (£15m). The most significant variation from allowances is on transformers where SHE Transmission is forecasting an underspend of £19m against an allowance of £56m, which equates to a 33% underspend. While SHE Transmission's condition reassessment has resulted in greater volume of transformer interventions it is achieving savings by refurbishing rather than replacing units and through negotiations on framework contracts.

Figure 15 – NLR expenditure (actual & forecast) against TO forecast allowances: SPT



4.38. Overall SPT's forecast non load expenditure is roughly 10% (£78m) below allowances. The underspend is driven by a combined £110m savings on overhead lines and underground cables. The savings are offset somewhat by overspend on switchgear and non lead assets. While the volume of switchgear has not changed from SPT's RIIO-T1 business plan, the unit cost has increased by approximately 15%. This is due, at least in part, to the carryover of schemes from TPCR4 adding to the costs in this category without increasing output delivery. The reason for this increase is not clear from the information provided by SPT. We intend to further investigate the overspend on both switchgear and non lead categories within the coming year.

4.39. SPT has stated that it is achieving efficiencies in its contracting by disaggregating contracts and leveraging the strong market position of its parent company, Iberdrola. In the past SPT's capital works contracts included the purchase of assets. This strategy relied on the contractor to purchase assets at lowest possible cost and to pass on any cost savings to SPT. By removing the purchase of assets from individual delivery contracts and purchasing in the greater volumes required to deliver its overall capital programme, SPT has been able to reduce the overall capital cost.

Analysis of variations from original plans

4.40. We have identified the key reasons for variation from the assumptions when setting RIIO-T1 as follows:

- Condition reassessment

- Data revisions
- Deferral of work delivering outputs in RIIO-T2
- Other factors

4.41. These are further discussed below.

Condition reassessment

4.42. We expect TOs to take reasonable measures to accurately determine the condition of the assets on their networks and to revise their investment programmes if necessary. Both NGET and SHE Transmission undertook a widespread condition reassessment programme during 2013-14.

4.43. NGET's condition reassessment resulted in changes to its asset replacement priorities and some replanning of its NLR programme. Using a consistent unit cost analysis we estimate that NGET's condition reassessment has added approximately £57m to its NLR lead asset costs over the RIIO-T1 period. NGET indicates that its revised NLR programme will deliver levels of network risk at the end of RIIO-T1 equivalent to its NOMs targets.

4.44. SHE Transmission has also revised its non-load related programme following condition reassessment of its assets. This has increased costs in some asset categories and reduced them in others. In our estimation, the condition reassessment has overall effectively increased the cost of SHE Transmission's non load related programme by approximately £9m when we compare using a consistent unit cost analysis. In addition, even when the same assets are worked upon, the content of the work has been adjusted. For example, the original estimates in SHE Transmission's RIIO-T1 business plan were based on the full reconductoring and reinsulation of overhead lines. Following condition assessment some circuits will now be refitting only, some will be earth wire reconductoring only, and some will additionally involve tower painting and steelwork replacement. These scheme changes give rise to further deviation in the cost from original plan in addition to the £9m estimated above.

4.45. SPT has not undertaken a widespread asset condition reassessment programme and has stated that it does not expect to carry out any such programme in RIIO-T1. SPT also stated that it assesses the condition of its assets at the time of replacement and as part of its routine inspection and maintenance programmes. To date the condition assessments have confirmed the assets were in need of replacement as assumed when SPT devised its non-load programme.

4.46. SPT's licence (Special Condition 6H) contains provision for the award of additional allowances to fund five overhead line replacement schemes. The additional allowances are only triggered if certain load related schemes go ahead. SPT states that replacement of the overhead lines will be required due to their age and condition. However, it is unlikely that the conditions required to trigger the additional allowances will be met. SPT has included the cost of these schemes (£69m) in its overall forecasts. We will consider

the appropriate treatment of these schemes in our ongoing work. These costs are not included in the figures quoted in this chapter.

Data revisions

4.47. TOs are expected to maintain robust quality of their asset data. Since the start of RIIO-T1, NGET's data assurance processes have uncovered some errors in its transformer and overhead line volume estimates and replacement priority categorisations. NGET reports that the financial impact of correcting these data errors is to add in the region of £17m to the cost required to deliver its NOMs targets.

4.48. Neither SHE Transmission or SPT have reported any financial impact of data revisions. However, this does not mean that their data is error free. In the case of SHE Transmission, it has identified data errors such as physical ownership of certain assets but without any financial impact. SHE Transmission is planning a significant programme of investment in its IT systems and processes associated with the gathering, management, validation, and reporting of its asset data. As well as transmission, this investment will include SSE's distribution businesses. SHE Transmission is not yet in a position to estimate the likely extent or impact of any data revisions arising from this programme.

Deferral of work delivering outputs in RIIO-T2

4.49. NGET's original RIIO-T1 business plan against which its allowances were set included a number of schemes where the outputs were to be delivered in RIIO-T2 but with proportion of forecast expenditure in RIIO-T1. While RIIO-T1 expenditure on these schemes was factored into NGET's RIIO-T1 NLR allowances, the expenditure would not contribute to the delivery of RIIO-T1 targets. Some of these schemes have now been cancelled or fully deferred to RIIO-T2. We estimate the impact of these deferrals and cancellations to be in the region of £300m in allowance not required. The majority of this (c. £220m) is coming from the deferral of underground cable expenditure.

4.50. Both SHE Transmission and SPT state that their original plans did not contain any lead asset schemes with forecast expenditure in RIIO-T1 and output delivery in T2.

4.51. We would expect that our discussions on the need for a Mid Period Review will consider how to take account of the deferral of work already funded under RIIO-T1.

Other factors

4.52. There are a number of other factors contributing to the variation in NLR expenditure from allowances. We have not attempted to individually assess the precise contribution of each these factors but may do so in the future. These include:

- Impact of changes in the load related plan, for example, requirements to replace assets that were previously assumed would be replaced as part of a LR scheme that has subsequently been cancelled.

- Replacement priority changes arising from changes in criticality assessment.

- Programme changes to achieve overall more efficient delivery of work, for example aligning work to minimise system outages or with DNO replacement plans.

- Delayed decommissioning of assets into the RIIO-T2 period, or earlier than planned decommissioning of assets prior to RIIO-T1.

- Condition driven changes to non-lead asset programme, non-lead asset data revisions, and other workload changes in non-lead asset programmes.

- Some movements between capex and opex either as a result of trade-off or accounting changes (which is further explained in the section on Opex later).

- Changes associated with schemes carried over from TPCR4. This is the main driver of cost increases for SPT's program of works.

- Efficiencies in implementing NLR works.

Summary of NLR variations from allowances

4.53. A proportion of the forecast underspend for each TO may be additionally explained by changes in input prices relative to assumptions when setting RIIO-T1 and by measures taken to mitigate risks and other delivery related efficiencies. These factors are discussed further in the Capital Delivery section below.

4.54. Table 12 below splits the TOs' forecast variation from allowances into our current estimates of the various contributory factors. The costs shown in this table are our best estimates to date.[49] These estimates may change considerably over time as we improve our estimates based on better information from the companies and externally and through refinement of our assessment approaches. Our final estimates will be used to inform our strategies and assessments going into RIIO-T2.

[49] Where no costs are shown, this does not necessarily mean that the factor is not relevant. It may mean that we have not yet been able to assess the impact of the specific factor.

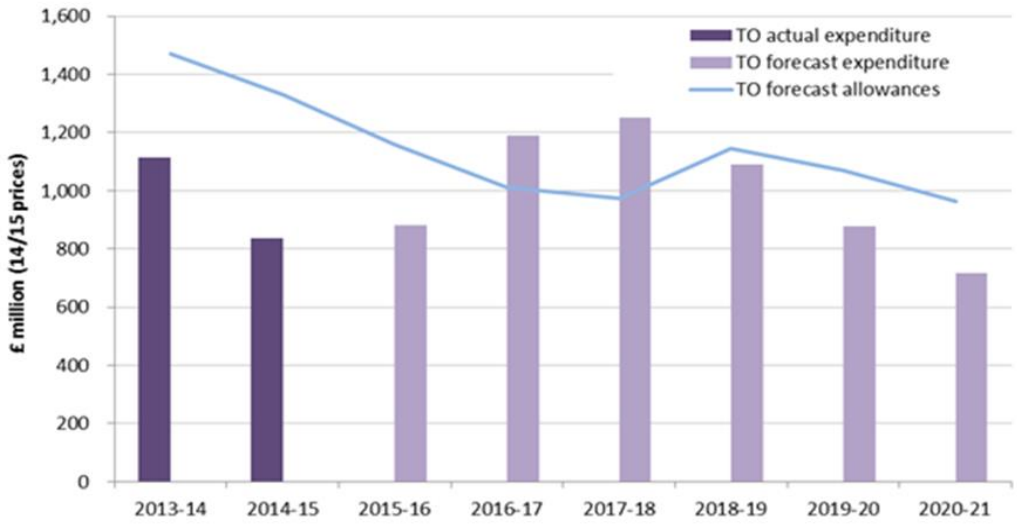
Table 12: RIIO-T1 non-load related variation from allowances – factors contributing to overall forecast underspend

	NGET	SHE	SPT
Allowance	**£5542m**	**£249m**	**£766m**
1. Condition reassessment (lead assets)	+£57m	+£9m	-
2. Data revisions (lead assets)	+£17m	-	-
3. Costs deferred	-£300m	-	-
4. Other NLR specific factors	+£30m	-£17m	+£48m
5. Market rates, risk mitigation, delivery efficiencies, etc. (discussed in Capital Delivery section)	-£486m	-£7m	-£126m
Total forecast underspend	**-£683m**	**-£15m**	**-£78m**
	-12%	-6%	-10%

Network capital delivery

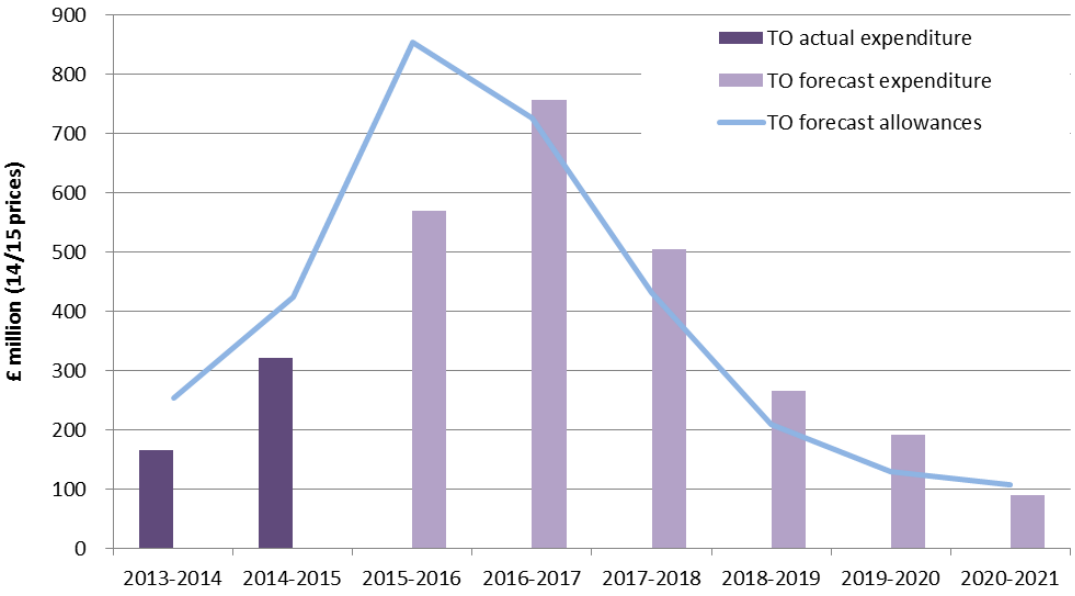
4.55. This section summarises our analysis to identify the main drivers for the companies' costs deviating from their allowances. The charts below summarise the TOs' actual and forecast capex against allowances (adjusted by relevant volume drivers) for the RIIO-T1 period.

Figure 16: LR and NLR capex performance (actuals and forecast) against TO forecast allowances: NGET



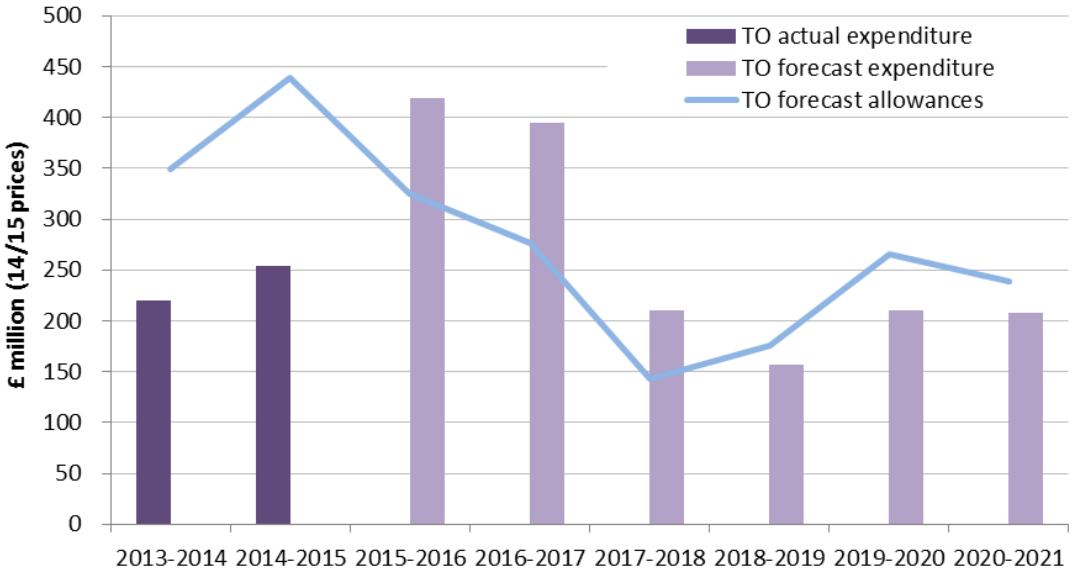
4.56. NGET will be spending approximately 87% of its total RIIO-T1 adjusted allowance, ie £1,160m below a total forecast allowance of £9,120m.

Figure 17: LR and NLR capex performance (actuals and forecast) against TO forecast allowances: SHE Transmission



4.57. SHE Transmission is currently forecasting to spend approximately 91% of its total RIIO-T1 forecast LR and NLR capex allowance across the price control period (£2,375m against a forecast allowance of £3,052m.

Figure 18: LR and NLR capex performance (actuals and forecast) against TO forecast allowances: SPT



4.58. SPT is currently forecasting to spend approximately 94% (£2,213m) of its total RIIO-T1 forecast capex allowance across the price control period (£2,086m), an underspend of approximately £128m from adjusted allowances.

4.59. As we can see, all TOs are forecasting an overall underspend between 6% and 11% over the RIIO-T1 period. The TOs highlighted operational and delivery improvements and technical innovation leading to cost savings, as well as changes to actual costs against their forecast. We have identified the following main drivers for over/under spend in addition to efficiency and technical improvement:

- Change of workload (volume) without impact on specified outputs;
- Input Price changes; and
- Delivery risks outturning differently from risk provisions

4.60. The first of these issues has been detailed in the load related analysis section. This section looks in further detail at the latter two points.

Input Price Changes

4.61. In our final proposals we have set ex-ante allowances for Real Price Effects (RPEs)[50] and leave it to the TOs to manage the actual fluctuation in commodity prices.

4.62. As the actual outturn and updated forecast of the input prices have changed significantly from the assumption behind the RPEs, we have carried out a high level analysis to allow us to better understand the impact on TOs' costs.

4.63. Over the past two years, input prices (actuals and forecast) have been lower than the ones set in our final decision. The lower prices for labour, materials and other elements should have enabled the TOs to achieve better rates in contracts. Some of these savings are already reflected in the actual spending of the companies (2014-2015), and some are reflected in their forecast for 2015-2017 as some of the contracts have been agreed at this point. We expect that the forecast expenditure beyond 2017 should also reflect those changes.

4.64. The information provided to us by the TOs has enabled us to conduct a high level analysis to understand the scale of underspending we would expect to be achievable due to the impact of lower input price rates. Our current view of the scale of the achievable savings for the three TOs are given below.

Table 13: Estimated savings related to changes in input prices (RPEs) forecast

Transmission Owner	NGET	SHE	SPT
Adjusted allowances incl. original assumed RPEs	8,975.3	3,130.8	2,254.6
Expected savings due to changes in input prices	237.3	129.2	95.8
Expected savings due to changes in input prices (%)	2.6%	4.1%	4.3%
Adjusted allowances incl. original provisional RPEs	7,346	2,523	1,815

4.65. NGET: We estimate that the potential scale of underspend due to lower input prices forecast should be approximately £237m for the period 2017-2021. This does not include any actual savings that the company has incurred in the first 2 years of RIIO-T1, or year 2016, as many of the contracts have already been agreed.

4.66. SHE Transmission: we have used forecast RPEs submitted by SPT to run the analysis for both Scottish companies. Based on that information we assess that SHE Transmission will be spending approximately £129m less than adjusted allowances due to changes in input prices only between 2016 and 2021. This does not include any actual savings achieved via lower input prices in years 2013-15.

[50] Allowed revenues are indexed by the Retail Price Index (RPI) as part of the price control. However, several key inputs (labour, material equipment/plant) do not necessarily change in line with RPI. To account for this differential, we provided an ex ante allowance based on the Real Price Effects (RPEs) forecast. The RPE values were different for each TO. More information can be found in the following document:
https://www.ofgem.gov.uk/sites/default/files/docs/2012/12/5_riiogd1_fp_rpe_dec12_0.pdf

4.67. SPTL: the updated forecast for RPEs and adjusted allowance (extended volumes compared to original forecast) used in the analysis show a potential underspending of £95.8m between 2016 and 2021 only.

4.68. It is important to note that we are still in the early years of the price control and market rates can still change significantly in the remaining years. TOs may lose or gain depending on how market rates change.

Delivery Risks Outturning Differently from Risk Provisions

4.69. The business plans that were submitted to Ofgem in 2012 included a variety of schemes. The forecast cost for them included some uncertainty costs in relation to project-specific risks, and costs to cover mitigation activities.

4.70. In its narrative of this year's report, NGET stated that some of the overall efficiencies are directly related to risk mitigation. As an example, it indicated that the London Power Tunnels programme has delivered £20m of efficiencies through risk mitigation only. While we note that such underspend will eventually be shared with consumers, we also note that we have not received sufficient information to conclude the extent to which the savings in this area are due to the uncertain nature of risks, caution in original provision, and efficiency initiatives taken by the company. We have been discussing, and will continue to discuss, this issue with NGET to reach a better understanding. The other two TOs have not indicated savings made due to delivery risks outturn lower than provision.

4.71. We intend to examine risk provisions, mitigation actions, and achievable savings in more detail over the coming year.

Generation connection allowance calculations

4.72. In our LR analysis we identified differences between our view of allowances and the TOs view. We noted that NGET is undercalculating its allowance relative to the PCFM by £329m, while SPT is overcalculating its allowance by c.£160m due to there not being a perfectly matching asset funding mechanism. There is also a slight overcalculation by SHE Transmission of £3.6m.

Residual (other) Effects

4.73. The variations from allowances described and quantified in this chapter do not explain the full extent of the variation from allowances. The following table summarises the factors that our analysis suggests explain the difference between allowances to current forecast/actual expenditure for each TO.

Table 14: TOs' Capex movements: adjusted allowances to actuals and forecast capex (£m)

Movements (£m)		NGET	SHE	SPTL
	LR allowance	**3,433.6**	**2,882.1**	**1,447.4**
LR specific factors	Volume driven changes (net of canceled/new schemes)	-1531.2	-	-
	Deferral of work delivering outputs in RIIO-T2	-415.3	-	-
	Cancelations and terminations (started schemes)	-50.9	-	-
	Exit connections	-	-	-57.2
	Technical innovation	-	-	-6.2
	Outputs not required - demand (exit)	-	-35.7	-
	Difference in allowance	-329.2	-3.6	+160.9
	LR expenditure	1,107.0	2,842.8	1,544.9
	NLR allowances	**5,687.2**	**248.7**	**765.7**
NLR specific factors	Condition reassessment	+56.7	+9.2	-
	Data revisions	+17.0	-	-
	Deferral of work delivering outputs in RIIO-T2	-300.0	-	-
	Other NLR	+29.6	-17.1	+48.4
Common factors	*Input price changes*	-237.3	-129.2	-95.8
	Risk mitigation	-20.0		
	NLR expenditure	5,233.3	111.7	718.3
	Other factors (Including delivery efficiencies)	+1,620.2	-95.1	-296.3
Total forecast expenditure	**LR + NLR forecast expenditure**	**7,960.4**	**2,859.4**	**1,966.9**

4.74. The 'other factors' may be explained to a greater or lesser extent by efficient delivery of work on the part of the TOs. The variations might include actual lower costs in the first two years of the price control due to lower input prices (lower RPEs) or may be due to actual efficiencies delivered via better overall management or other efficient drivers that were not captured in this section. They could also be related to one of the drivers that was mentioned in this section, but we were not able to quantify the exact cost impacts at this point.

4.75. It is important to note that some of the figures used are estimates and we intend to refine our analysis to improve the estimates as RIIO-T1 progresses.

4.76. Our analysis to date is based on the information provided by the TOs in their regulatory submissions and in response to supplementary questions. To better understand the savings that have been achieved we intend to continue looking into the subject in the coming year and throughout the RIIO-T1 price control period.

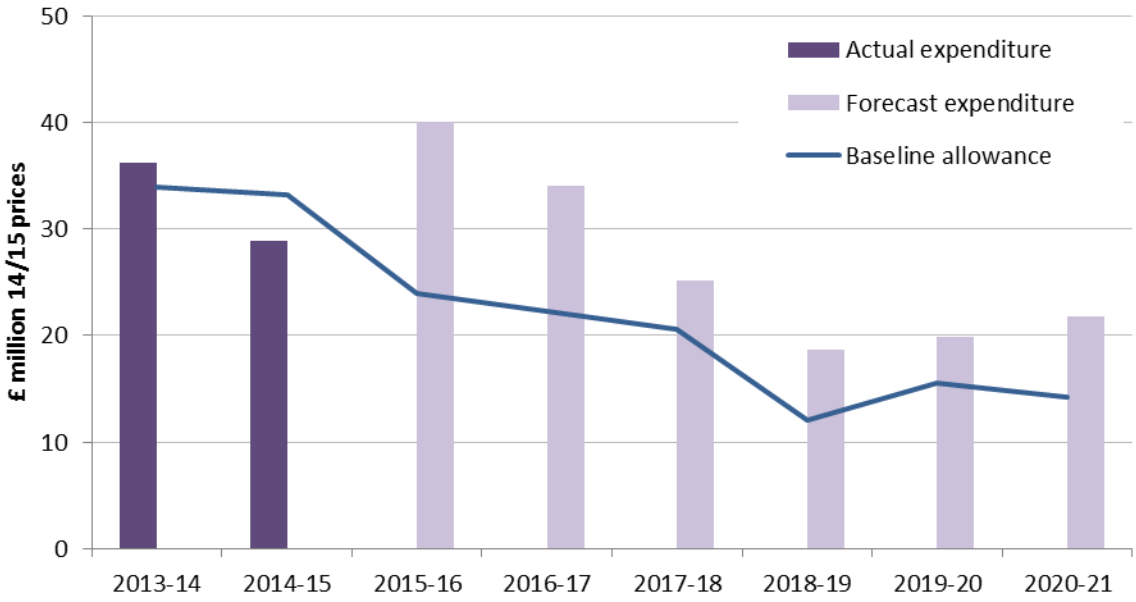
Non-operational capex

4.77. Non-operational capex is expenditure on non-network assets. The areas of expenditure are information technology (IT), land and buildings, vehicles and tools and

equipment. For all TOs the main type of this expenditure is IT, both hardware and software. This category of expenditure accounted for 4% (£29m) of NGET's total capex in 2014/15 and less than 1% of the total capex incurred by SHE Transmission and SPT.

NGET

Figure 19: Actual expenditure and forecast expenditure for the remaining RIIO-T1 period with baseline allowances: NGET



4.78. NGET has spent £4.4m below its non-operational capex allowance in 2014-15. NGET forecasts expenditure will be higher than its annual allowance for each of the remaining six years of the RIIO-T1 period. The total level of overspend is expected to be £48.9m against a total allowance of £176m across the price control period.

4.79. The increase in the forecast level of RIIO-T1 expenditure is primarily driven by a higher fleet costs over the period than expected, a change in the delivery strategy on specific information system (IS) investments and an increase in expenditure on weather related resilience measures. Further detail on these measures is set out below.

- IS investment: NGET have continued with development work to replace their core asset management system (Ellipse) and to install new network communication equipment (OPTEL) but have reprofiled the expenditure to allow time to undertake data preparation. Expenditure on the new systems are now expected to be incurred in the next couple of years of the RIIO-T1 period.

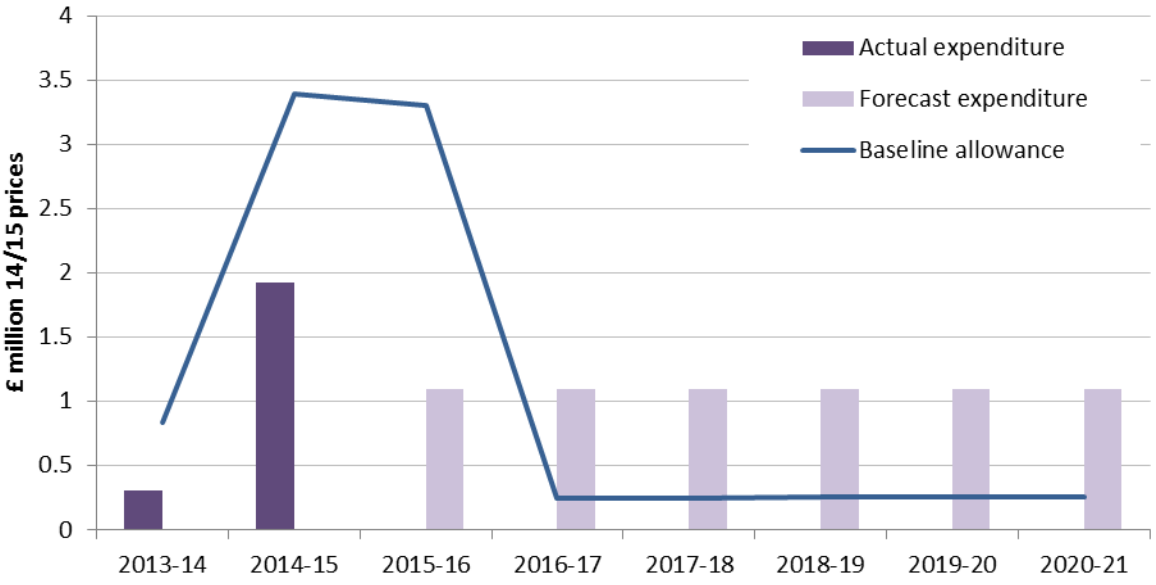
- Weather related investment: In 2014/15, the total expenditure on weather related resilience was £17.7m against last year's forecast of £11m. NGET's current capex forecast for this category over the RIIO-T1 period is £31m higher

than the opening allowances due to a significant increase in investment associated with the installation of mobile flood defence capability. This was in response to extensive flooding in the South West during winter 2013-14.

- Vehicle costs: NGET have explained that these were higher than typically expected in 2014/15 at £3.2m due to the inclusion of part of the build costs from the 2013/14 fleet order (as well as the 2014/15 fleet order).

SHE Transmission

Figure 20: Actual expenditure and forecast expenditure for the remaining RIIO-T1 period with baseline allowances: SHE Transmission



4.80. For SHE Transmission and SPT, non-operational capex expenditure is comparatively small with total allowances of £8.8m and £8.6m across the RIIO-T1 price control period respectively.

4.81. SHE Transmission have incurred £1.9m of costs in this area during 2014/15 and spent £1.5m less than its allowance. This is an increase on the level of underspend incurred in year 1 (£0.5m underspend).

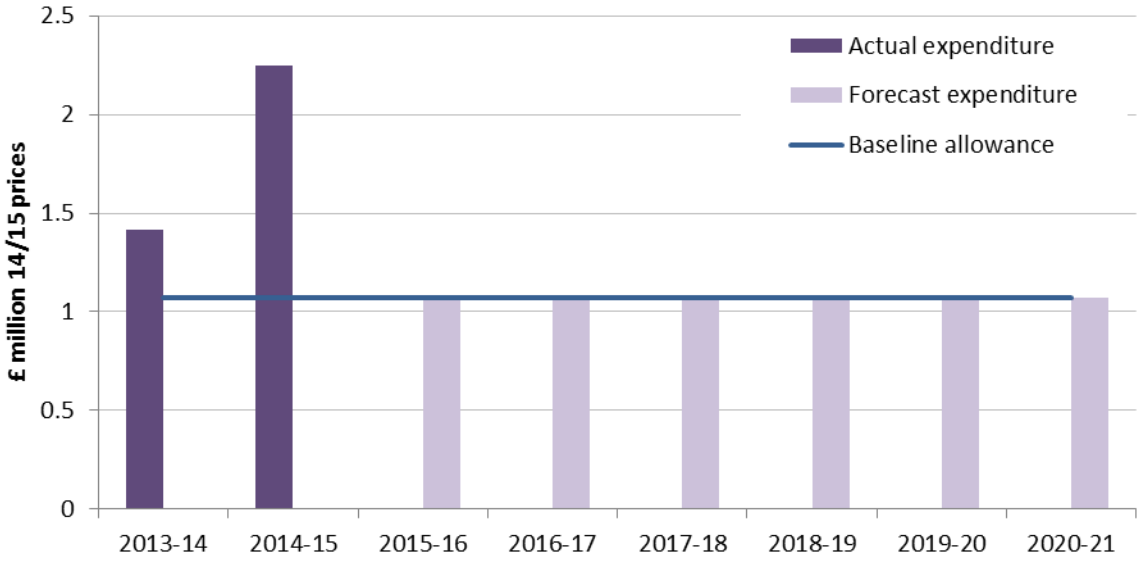
4.82. SHE Transmission explain that the bulk of the costs incurred in this category relates to the property upgrades to office space in Glasgow and Inverness (£1.1m), which is to accommodate increased staff numbers.

4.83. However, SHE Transmission is currently forecasting a catch up in expenditure for the remainder of RIIO-T1 with a constant overspend for the remaining five years of the RIIO-T1 price control period of £0.8m (a total overspend of £4.2m). This is expected to

offset the underspend in the first three years of price control period and bring total expenditure in line with allowances across the RIIO-T1 period.

SPT

Figure 21: Actual expenditure and forecast expenditure for the remaining RIIO-T1 period with baseline allowances: SPT



4.84. In 2014-15 SPT has spent approximately double its allowance level (£1.2m overspend). The reason for this overspend is unclear from the information provided. SPT currently forecasts that expenditure in this cost category will remain stable (at a level of £1.1m per annum) and in line with its allowance for the remainder of the RIIO-T1 price control period. SPT anticipate that the forecast profile of expenditure will result in an overspend of £1.5m across the RIIO-T1 period.

Operating costs (Opex) and forecasts

4.85. Opex are the costs incurred in the activities required to maintain and operate the transmission networks. Opex can be further split into:

- Direct Opex
- Business support costs
- Closely associated indirect costs (CAI)

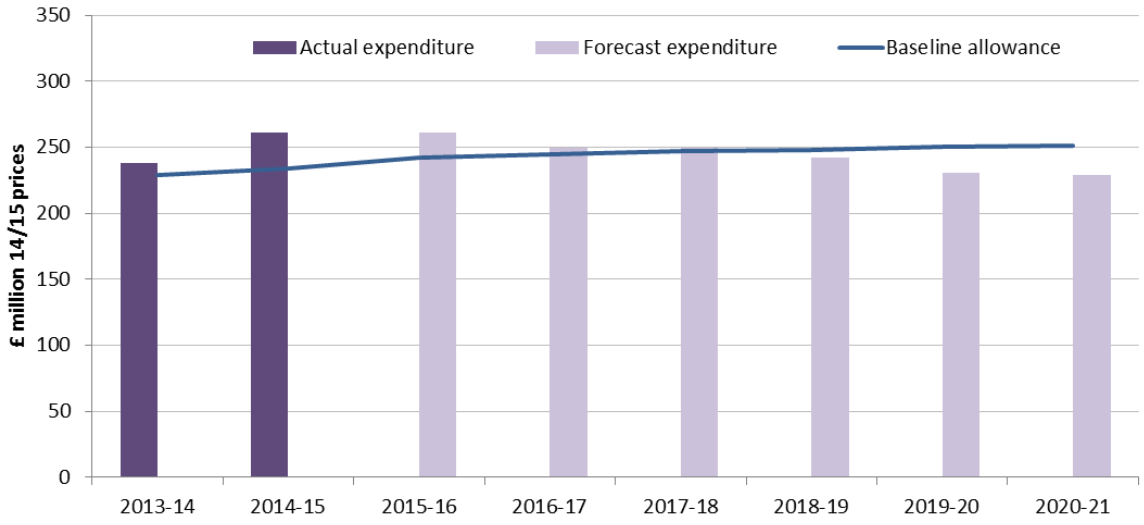
4.86. 'Direct Opex' can be divided into planned work largely associated with maintenance tasks that are driven by asset management policies and technical

standards, and unplanned work driven largely by faults on the network. 'Business support' refers to costs which support the overall company business such as IT[51], telecoms, property management and insurance. 'CAI' refers to costs which support the operational activities, but are not directly related to capex and direct opex activities. This includes operational training, IT equipment used exclusively in the real time management of network assets, tasks involved in the strategic planning of the network and engineering design of new connections, clerical support and project management costs.

NGET

4.87. Figure 22 below shows NGET's actual costs incurred in for the first two years of RIIO-T1 and the TO's forecast of expenditure for the remainder of RIIO-T1 compared to their allowance set under the RIIO-T1 price control.

Figure 22: Opex allowances compared with actual and forecast expenditure across the RIIO-T1 period[52]: NGET



4.88. NGET has spent £28m[53] (12%) above its overall opex allowance in 2014-15. The overspend is driven by the level of costs incurred in the category of business support costs. NGET has stated that this reflects both costs relating to several cost transformation initiatives and also is a recognition of the significant challenge to deliver against the level of opex allowances.

[51] This includes the costs associated with the development of applications before they are put into production and costs associated with implementing the systems. It does not include the costs of maintaining existing and operational systems.
[52] Figure excludes uncertainty mechanisms and decommissioning, but has been adjusted for movements in provisions.
[53] This value includes the smeared value associated with the adjustment for IAS 19 pension accrual (-£5.1m). Excluding this value, the overspend in 2014-15 is £33m (14%). Opex figures hereafter include the IAS 19 pension adjustment.

4.89. The costs incurred by NGET in the category of CAI have been broadly in line with allowances in 2014-15 (£2.7 m underspend against an allowance of £75.9m).

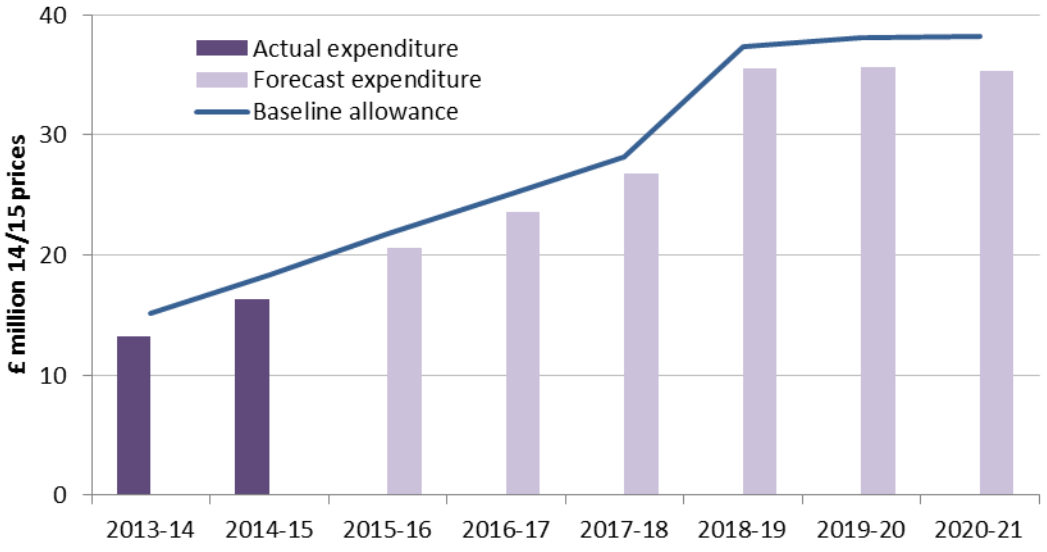
4.90. Direct Opex expenditure, the largest of the cost categories within the opex category, is broadly comparable to allowances for NGET in 2014-15 (£1.4m underspend). However, we note that there have been significant increases in the costs associated with tower painting year-on-year. During 2014/15 NGET has treated the steelwork in 1,700 towers using an enhanced paint coating system, instead of replacing them. This was 700 more than 2013/14 and resulted in £10m of the costs incurred being included in Direct Opex costs.

4.91. NGET is forecasting a £16m overspend over the RIIO-T1 period. This is driven by forecast overspend of £184m in the business support costs category and £168m underspend in the CAI and direct costs categories. Overall, NGET forecast that opex expenditure levels in the first five years of RIIO-T1 will remain above allowance due to the cost of reorganisation initiatives. Expenditure levels then fall below allowance levels towards the end of RIIO-T1 as a result of anticipated efficiency gains.

SHE Transmission

4.92. SHE Transmission has underspent its overall opex allowance by almost £2m in 2014-15.

Figure 23: Opex allowances compared with actual and forecast expenditure across the RIIO-T1 period: SHE Transmission



4.93. The majority of the underspend in 2014-15 (£2m) is due to costs incurred in the CAI category (£2.6m underspend). This is the result of greater than forecast capitalisation rate for costs, allied to delays in recruitment of support staff.

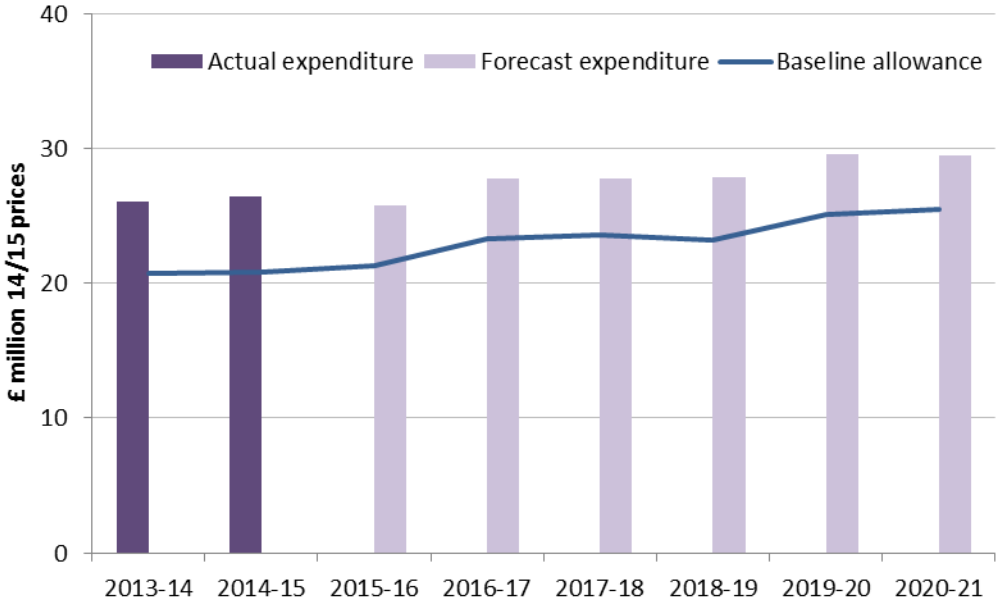
4.94. SHE Transmission has incurred a slight overspend in business support costs in 2014-15 (£0.1m), partly driven by additional property costs for offices in Inverness and Glasgow to accommodate increased staff numbers. Direct costs have also overspent by £0.5m against allowance. Factors in this increase were the network repair costs after the storm events experienced during December 2014 and January 2015 in the Western Isles additional tree-cutting undertaken by SHE Transmission in 2014-15.

4.95. SHE Transmission is projecting an overspend of £15m above its forecast allowance over the RIIO-T1 period. This is due to anticipated overspend in their CAI and direct costs categories across the price control period (totalling approximately £10.5m) being partly offset by an underspend forecast in business support costs over the same period (£4.6m).

SPT

4.96. SPT has spent £6m above its overall opex allowance in 2014-15.

Figure 24: Opex allowances compared with actual and forecast expenditure across the RIIO-T1 period: SPT



4.97. SPT has explained that the majority of this overspend is in the business support costs category, which have exceeded the RIIO-T1 allowance (of £2.6m) by £8.3m in

2014-15[54]. The main reason for this increase is due to a change of its accounting procedures for fixed assets, to bring it into line with the rest of the industry.

4.98. The level of overspend in business costs is partly offset by underspend in the CAI cost category (£3.1m). This underspend is due to the impact of delays in system availability, obtaining landowner agreements and necessary consents for wider works and other capex projects.

4.99. SPT has spent £0.5m above its direct opex allowance level in this cost area in 2014-15. It has provided a number of reasons for this overspend, including increases in minor cable defect repairs, greater levels of tower painting and increases in switchgear fault repair costs.

4.100. SPT is forecasting a total overspend on RIIO-T1 opex allowances of £37m. The main reason for this is due to a change in accounting approach. This will result in a reduction in capex project costs of approximately £60-65m during the RIIO-T1 price control period with a corresponding increase in business support costs above the original expenditure allowance level set at Final Proposals. We will continue to monitor this during RIIO-T1.

[54] This value includes the smeared value associated with the adjustment for IAS 19 pension accrual (-£0.3m) across opex cost categories. Excluding this value, the overspend in 2014-15 in the business support category is £8.4m. Opex figures hereafter include the IAS 19 pension adjustment.

5. SO performance

Chapter Summary

This chapter evaluates RIIO-T1 actual and forecast expenditure for NGET in its role as SO against the costs allowed to deliver the associated outputs. It looks at the various cost categories and activities which make up total expenditure. It also explains how we incorporate uncertain costs.

5.1. NGET is the designated electricity System Operator (SO) responsible for day-to-day system operation, including balancing supply and demand and constraint management. To do this NGET buys and sells electricity and procures associated services. The cost NGET incurs is recovered from users of the system via Balancing Services Use of System (BSUoS) charges.

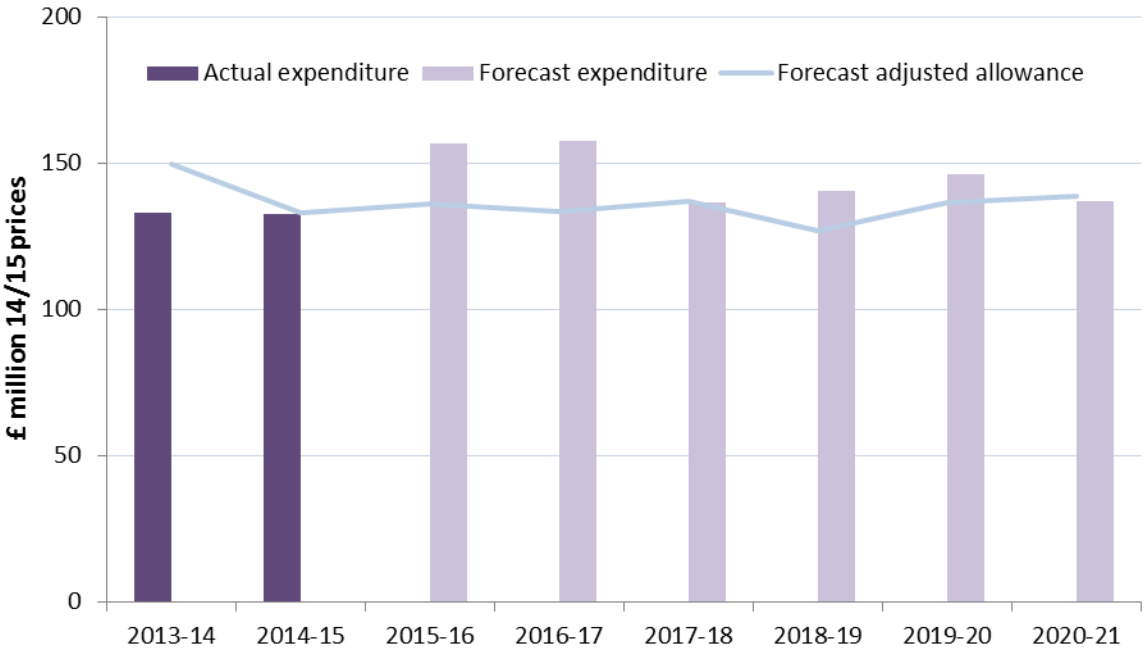
5.2. There are various costs that NGET incurs as SO and for which it seeks to recover revenue through its price controls. The RIIO-T1 price control for NGET SO includes allowances for capex (primarily related to investment in IT systems) and opex (covering the ongoing costs of running the business, including support for IT systems).

5.3. All SO cost allowances for system balancing are determined via a separate process outside the RIIO-T1 mechanism. The main incentive is the Balancing Services Incentive Scheme (BSIS) which incentivises NGET (SO) on actions it has to take to operate the GB electricity transmission system.

Performance

5.4. The figures below show the performance to date and forecast expenditure for NGET (SO) over the course of the RIIO-T1 price control period against its adjusted totex allowances. These forecasts are based on NGET's calculations and are subject to our confirmation in due course.

Figure 25: Actual & forecast expenditure against forecast adjusted allowance: NGET (SO)



Performance for 2014-15

5.5. NGET (SO) has outperformed against its totex allowance of £133.1m in year 2 (2014-15), as shown in the figure 25 above. The level of underspend is small (£0.5m) and comprises a marginal overspend in capex (£0.2m) and a larger underspend in opex (£0.7m). This capex overspend partly reflects investment in new systems to support NGET's role as EMR Delivery Body and the operation of new Supplementary Balancing Reserve and Demand Side Balancing Reserve products.

5.6. NGET explains it has introduced efficiencies in its ways of working through modified working practices, realignment of staff terms and conditions and reductions in waste (relative to the performance measures in place during the last price control). NGET believe these measures have led to a 41% increase in productivity to date. However, we have not been able to verify the value of these efficiency savings on the basis of the information provided. We will continue to monitor progress in this area.

Forecast performance for RIIO-T1 period

5.7. NGET forecasts that the required level of SO capital expenditure will be £67m above adjusted allowances (£290m) for the eight year RIIO-T1 period.

5.8. NGET has forecast controllable opex spend to be £19m lower than adjusted allowances (£802m) across the price control period. We have not been able to establish the specific detail of the strategic expectations and operating assumptions that drive this level of underspend. We will continue to monitor changes to NGET's operational expenditure profile and the impact on performance.

5.9. The figures include NGET's expectation of the additional costs needed to undertake the roles associated with EMR Delivery and the enhanced SO role under ITPR. Both of these areas are not yet currently funded in full[55] and as such expected costs are above allowances in some years. While NGET is forecasting to partially offset these costs through effective planning and delivering efficiencies from their business change activities, the expectation is that the costs of these additional requirements will drive an overspend across the RIIO-T1 period. NGET is currently forecasting to overspend against its adjusted totex allowances of £1,092m across the RIIO-T1 period to the value of £48m.

5.10. However, the forecast level of SO capex investment during the RIIO-T1 period is subject to change and will be dependent on future developments in the following notable areas:

- The level of additional investment required to deliver an efficient long term strategic solution to provide the required level of security and availability for Critical National Infrastructure systems and the development of NGET's data centre strategy. The costs included in NGET's submission reflect their current view of the long term capex strategy required to support the required level of security to safeguard the customer supply of electricity in the UK. This strategy drives a current expectation that required SO capex investment will exceed allowances over the RIIO-T1 period.

- The change to NGET's investment plan driven by the replacement of the 'Gone Green' scenario with the 'Slow Progression' scenario. The investment plan is therefore not progressing as rapidly as expected which has allowed certain investments to be deferred and allow NGET to offset some of the cost pressures resulting from its Market Facilitation activities and Operational Control improvements (eg replacement of the generation dispatch balancing model). We will continue to monitor changes to NGET's investment profile and the impact on efficiency savings.

5.11. NGET's submission reflects their current view on the additional funding requirement to accommodate various future enhancements to the SO's role, which will impose additional costs not considered when determining revenue allowances for the current price control. We will give further consideration to these uncertain events as part of our Mid Period Review process. Through this process we will seek to determine the appropriate level of adjustments to the SO totex allowances for the additional incremental costs we expect NGET to incur. Further consideration will also be given to the need for further uncertainty mechanisms to allow NGET to recover costs in respect of major changes to the scope of the work during the period or uncertain costs crystallising during the RIIO-T1 period.

[55] A document setting out our decisions on setting revenue, outputs and incentives for NGET's SO roles in EMR from August 2014 to March 2021 is available from our website: https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/decision_on_revenue_outputs_and_incentives_for_nget_plcs_roles_in_electricity_market_reform_0.pdf

6. Financial Performance

Chapter Summary

This chapter presents the opening and forecast closing position of the Regulatory Asset Value (RAV) for RIIO-T1 and estimates of the TOs' return on regulatory equity (RoRE) performance. It also identifies the contribution of each main element to the total RoRE

Regulatory Asset Value

6.1. Regulatory Asset Value (RAV) is financial balance representing the capitalised component of total expenditure on building and operating the network assets used to transmit energy. The opening RAV balance for each TO for RIIO-T1 comprises the closing RAV balance from TPCR4. Additions to the RAV during RIIO-T1 are based on the proportion of totex (i.e. the totex capitalisation rate) that we remunerate over the longer term. The relevant capitalisation rates for each TO were set at RIIO-T1 final proposals.

6.2. The price control allows licensees a return on RAV and return of money invested in the RAV, which comprises:

- A return on the RAV to compensate the risk and opportunity cost borne by shareholders and debt holders who fund the capitalised expenditure (the weighted average cost of capital or 'WACC'). The WACC is designed to encourage licensees to enter into long-term financing arrangements needed for efficient investment in the network.

- An allowance to reflect depreciation over the average useful life of regulated assets. Depreciation allowances are deducted from the RAV.

6.3. Table 15 shows an increase from the opening RAV at 1 April 2013 to the closing RAV at the end of the price control year 2014-15, alongside a forecast for the end of the price control period. The closing RAV is calculated as:

- opening RAV plus RAV additions (net of disposals) less RAV depreciation.

Table 15: RAV movement schedule for 2013-14 to 2014-15 and forecast RAV[56] at the end of RIIO-T1 (excluding TIRG)

Regulatory Asset Value (RAV)(£m)	NGET TO	NGET SO	NGET Total	SPT	SHE	Total
Opening RAV at 1 April 2013	10,339	88	10,427	1,301	811	12,539
RAV additions (after disposals)	2,545	80	2,625	581	423	3,629
Depreciation	(1,372)	(42)	(1,414)	(201)	(105)	(1,719)
Closing RAV at 31 March 2015	11,512	127	11,638	1,681	1,129	14,448
Forecast RAV at 31 March 2021	**14,977**	**153**	**15,130**	**2,706**	**2,817**	**20,653**

6.4. Major capital infrastructure projects for electricity transmission networks eg Strategic Wider Works and connecting new sources of generation have been planned for the RIIO-T1 price control. As such, the trend of substantial increases in electricity transmission RAV values is expected to continue until after the end of the decade.

6.5. Total forecast RAV for the sector at the end of RIIO-T1 is higher than the prior year forecast of c.£20.1bn. This is a result of: additional allowances granted to NGET in 2014-15 for enhanced security costs and the enduring solution for EMR; and, forecast increases in allowances for generation connections through the volume driver mechanisms for both SPT and SHE Transmission.

6.6. The RAV numbers in Table 15 exclude Shadow RAV[57], which primarily relates to TIRG projects. The position at the start of RIIO-T1 and the forecast end position for the Shadow RAV is given in the table below.

Table 16: Starting and forecast Shadow RAV movements through RIIO-T1

Shadow RAV (£m 14/15 prices)	NGET	SPT	SHE	Total
Opening RAV	119	171	371	661
Additions	0	130	256	386
Forecast RAV at 31 March 2021	0[58]	134	383[59]	**517**

[56]Forecast RAV has been calculated based upon the TOs' latest published view of forecast totex out-turns and allowances in their Annual Performance Reports. Closing RAV at 31 March 2015 is the provisional position based upon the 2015 AIP.

[57]Where investments are initially funded outside of the core RIIO-T1 price with a different allowed rate of return (WACC and depreciation) than set at Final Proposals the costs will be held outside of the main RAV in Shadow RAV. Once the normal allowed rate of return becomes applicable to the investments then the costs are transferred from Shadow RAV to the main RAV in the appropriate year.

[58] NGET's entire TIRG assets will transfer to the main RAV by 31 March 2017.

[59] The projected Shadow RAV closing balance for SHE is subject to change as a result of a funding determination to be made for the Beauly-Denny TIRG project in 2015/16.

Return on Regulatory Equity (RoRE)

6.7. Regulatory equity represents the proportion of average annual RAV that is funded by shareholders (also known as 'Equity RAV'). This is based upon the notional gearing set at Final Proposals which results in equity proportions of 40% for NGET, and 45% for both of SHE Transmission and SPT.

6.8. Returns on regulatory equity (RoRE) is the post-tax cost of equity set at RIIO-T1 final proposals (7%) plus the effect of revenue adjustments ie actual or forecast performance compared with the levels underlying the final proposals. We use RoRE analysis to estimate the financial impact on shareholders of the network companies from outperforming or underperforming the RIIO-T1 price control assumptions.

6.9. In summary the 8 year average RoRE can be calculated using the following formula:

$$\frac{\text{Average deviation from baseline revenue}}{\text{Average Equity RAV}} + \text{Baseline Cost of Equity (7\%)}$$

Where "deviation from baseline revenue" is the sum of:

- TO's share of the underspend (or overspend)
- IQI reward (or penalty)
- incentive reward (or penalty) from various outputs
- TIRG incentive revenue.

6.10. The values in Table 16 are based upon the companies' view of what investors could earn over the course of the RIIO-T1 price control period as a result of forecast expenditure and allowances, delivery of TIRG projects and earned output incentives. All figures are both net of tax and exclude the effect of any outperformance on interest and taxation.

Table 17: TOs' eight year average RoRE forecast for RIIO-T1[60]

Company	*Baseline (Post-tax cost of equity)*	*IQI income reward/ penalty*	*Totex*	*Output Incentives*	*System Operator*	*TIRG*	***Total***	*TPCR-4 achieved RoRE*
SHE	7.0%	0.3%	1.6%	0.2%	0.0%	0.6%	**9.6%**	*9.9%*
SPT	7.0%	0.5%	0.8%	0.3%	0.0%	0.2%	**8.7%**	*10.1%*
NGET	7.0%	0.2%	1.5%	0.3%	0.4%	0.0%	**9.4%**	*9.2%*

[60] The consolidated RoRE is calculated by taking total totex, IQI, output incentive and TIRG outturns for the three TOs and dividing by the total average 8 year RAV.

6.11. The output incentive performance shown in Table 16 considers earned incentives for year 1 (2013-14) and year 2 (2014-15) and assumes that the average level of performance will be carried forward for the remaining six years of RIIO-T1.

6.12. The estimated returns in excess of the baseline level of 7% are driven by material underspend[61] against totex allowances and the associated IQI incentives. For the Scottish TOs, a significant part of the RoRE increment is due to allowances related to efficient expenditure on TIRG projects (awarded a higher rate of return of 8.8% for the post-construction incentive period of 5 years before entering the main RAV and receiving baseline cost of equity of 7%).

6.13. Current levels of outperformance based on TOs' forecasts are moderate and broadly in line with the range achieved by TOs during TPCR4. These figures can change in subsequent years as a result of actual and forecast totex performance and delivery of volumes and outputs against targets.

[61] The totex underspend figure that feeds into NGET TO's RoRE calculation includes a deduction of £112.6m (14/15 prices) from expenditure for a legal settlement that relates to TPCR-4 and not underlying performance in RIIO-T1. The estimated impact of excluding this item from the 8 year average RoRE of NGET is -0.1%.

7. Forward Look: 2015-16 Regulatory Reporting Year

7.1. This report covers the 2014-15 reporting year, which started on 1st April 2014 and ended on the 31st March 2015. The purpose of this section is to give a brief overview of activities we expect to undertake in preparation for the receipt of data for 2015-16 performance year, and highlight areas of focus for next year's report.

Reporting packs and guidance

7.2. The analysis of company submissions is a resource intensive process, for both Ofgem and the TOs. It has become apparent in the course of this year's exercise that the regulatory reporting packs are not yet fully fit for purpose. The TOs have proposed various amendments to the current reporting packs and the associated guidance; Ofgem also has views on how the packs could be amended to facilitate a more informative and efficient process. We have already begun our engagement with the TOs to achieve this goal.

Data quality

7.3. Through the report we have noted a number of areas where there have been data revisions provided by the TOs, which have resulted in prior year adjustments.

7.4. While we welcome the TOs taking actions to uncover and report the errors, we remain concerned as to the lack of reliability of the originally reported data. Ofgem and the TOs have developed a Data Assurance Guidance methodology for introducing rigor into data review and reporting processes, to avoid these anomalies in the future. Now that this methodology is in place, we would expect any such misreporting to be dealt with in a more robust manner, including taking a view on whether enforcement action is appropriate.

Mid-period review

7.5. RIIO Final Proposals included provision for a potential mid-period review (MPR) during the eight year price control period with scope driven by:

- changes to outputs that can be justified by clear changes in government policy; and
- the introduction of new outputs that are needed to meet the needs of consumers and other network users.

7.6. In November 2015 we issued a consultation document on whether there is a need to initiate a mid-period review in Electricity Transmission. Depending on the outcome of the public consultation we may commence a mid-period review in July 2016.

Network Output Measures (NOMs)

7.7. We expect a final revised methodology to be submitted for Authority approval by early 2016. However, we expect that further work will be required throughout 2016 before the NOMs methodology achieves its objectives.

Network Access Policy (NAP)

7.8. One of the outputs required of TOs the licensees is that they should produce and maintain a NAP document to contribute to better SO:TO interaction and cooperation in both short-term and long-term network outage planning. This has been achieved, with the separate NAP documents for Scotland and England and Wales being approved by Ofgem in June, and we are satisfied that the network companies have been working increasingly closer in both the short and long term time frames. However we expect that continued progress to be made in developing the principles that the NAP sets out, including incorporating the issues identified in the consultation Ofgem held before making its decision to approve the NAP.

7.9. Special condition 2J of the electricity transmission licence requires the NAP to be regularly reviewed and updated as necessary. There is an ongoing governance process, in which Ofgem is an integral partner. We expect this process to facilitate evolution of future updates to the NAPs to incorporate any relevant changes arising from our conclusions on Integrated Transmission Planning and Regulation in March 2015 and other key events. Among other things, this decided on various future enhancements to the SO's role, including for the SO to be more proactive in supporting certain aspects of system planning. We therefore expect updates to the NAP documentation to be progressed in a timely manner and for the result of this work to be reported to the Authority in the first instance. We will continue to monitor progress in this area.

7.10. In keeping with the principal of transparency on which the NAPs are based we encourage licensees to ensure the NAP is applied in an open and transparent manner and appropriate stakeholder engagement is carried out ahead of any proposals to amend the NAP.

Appendices

Index

Appendix	Name of Appendix	Page Number
1	NOMs targets, performance and development of methodology	70
2	Glossary	75

Appendix 1 – NOMs targets, performance and development of methodology

1.1. The NOMs (Network Output Measures) are the defined output directly linked to Non-Load Related (NLR) expenditure. Each TO has end of period Replacement Priority (RP) targets under seven asset categories split across three voltage levels.[62] An asset's RP takes account of its health (condition) and criticality (impact of failure). The RP targets are set out in each TO's Special Condition 2M and in combination they are intended to reflect an overall acceptable level of network risk.[63] TOs are not required to deliver precisely the targets number of assets in each asset category but may trade-off between asset categories and voltages to efficiently deliver equivalent or lower levels of network risk.

1.2. The replacement priority for each asset is determined in accordance with the matrix shown as figure A1.1 below. There are four replacement priorities ranging from RP1, assets most in need of replacement or refurbishment, down to RP4, new or as new assets.

Figure A1.1 – Electricity Transmission Replacement Priority Matrix[64]

		Asset Health				
		AH1	AH2	AH3	AH4	AH5
Criticality	C4	RP4	RP4	RP4	RP3	RP2
	C3	RP4	RP4	RP4	RP3	RP2
	C2	RP4	RP4	RP4	RP2	RP1
	C1	RP4	RP4	RP4	RP1	RP1

	Replacement required in:
RP1	0-2 years
RP2	2-5 years
RP3	5-10 years
RP4	10+ years

[62] The NOMs asset categories are circuit breakers, transformers, reactors, underground cables, OHL conductors, OHL fittings, OHL towers (SHE Transmission and SPT only). These are split into 400kV, 275kV, and 132kV assets.

[63] The risks that we are concerned with are the economic risks to society that would arises as a result of the sudden unexpected loss of an asset and to the safety of people and the environment in the vicinity of the asset that would arise from the catastrophic failure of an asset.

[64] This is the replacement priority matrix for SPT and SHE Transmission. NGET's is similar but has AH4 split in two into AH4a and AH4b. However, the RP outputs RP1 to RP4 are the same.

1.3. The current NOMs targets and TOs' forecast position against them are shown in tables A1.1 to A1.3 below.[65]

1.4. The columns showing changes in totals are driven by a number of factors, the main ones being data revisions and decommissioning of assets. The implications of such changes for the incentive mechanism will be considered further in our ongoing work on NOMs.

Table A1.1: NGET – NOMs end of period replacement priority targets and expected delivery versus targets (all voltages combined)

Asset Categories		Units	Targets				Total
			Volume of assets in each RP				
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	73	134	129	2,589	2,925
2	Transformer	No.	38	31	84	626	779
3	Reactor	No.	38	34	10	63	145
4	Underground Cable	circuit km	86	6	99	450	640
5	OHL Conductor	circuit km	1,708	1,549	1,171	9,714	14,142
6	OHL Fittings	circuit km	1,753	992	1,137	10,277	14,159
7	OHL Tower (SHET & SPTL)	No.	-	-	-	-	-

Asset Categories		Units	Expected delivery versus target				Total
			Volume of assets in each RP				
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	- 47	- 24	+ 85	- 23	- 9
2	Transformer	No.	- 12	-	+ 9	+ 10	+ 7
3	Reactor	No.	+ 17	+ 4	- 9	- 11	+ 1
4	Underground Cable	circuit km	+ 24	+ 3	+ 6	- 32	+ 2
5	OHL Conductor	circuit km	+ 1,236	+ 712	+ 296	- 2,318	- 73
6	OHL Fittings	circuit km	+ 947	+ 44	- 162	- 902	- 73
7	OHL Tower (SHET & SPTL)	No.	-	-	-	-	-

[65] The comparison has been calculated by subtracting the target from the expected position. Positive numbers thus represent a forecast of more assets in that RP than in the targets (and vice versa).

Table A1.2: SHE Transmission – NOMs end of period replacement priority targets and expected delivery versus targets (all voltages combined)

Asset Categories		Units	Targets Volume of assets in each RP				Total
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	5	2	-	282	289
2	Transformer	No.	12	8	1	157	178
3	Reactor	No.	-	-	-	7	7
4	Underground Cable	circuit km	-	-	10	88	98
5	OHL Conductor	circuit km	56	124	187	4,449	4,816
6	OHL Fittings	circuit km	-	-	-	4,815	4,815
7	OHL Tower (SHET & SPTL)	No.	-	-	-	11,012	11,012

Asset Categories		Units	Expected delivery versus target Volume of assets in each RP				Total
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	- 14	-	- 8	+ 6	- 16
2	Transformer	No.	+ 6	+ 2	- 9	+ 1	-
3	Reactor	No.	-	-	-	-	-
4	Underground Cable	circuit km	- 3	-	+ 5	- 9	- 7
5	OHL Conductor	circuit km	- 98	- 174	- 813	+ 1,084	- 0
6	OHL Fittings	circuit km	-	-	- 482	+ 482	- 0
7	OHL Tower (SHET & SPTL)	No.	-	-	- 38	+ 38	-

Table A1.3: SPT – NOMs end of period replacement priority targets and expected delivery versus targets (all voltages combined)

Asset Categories		Units	Targets Volume of assets in each RP				Total
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	63	33	-	319	415
2	Transformer	No.	36	44	23	145	248
3	Reactor	No.	7	1	-	8	16
4	Underground Cable	circuit km	-	-	-	264	264
5	OHL Conductor	circuit km	200	1,258	473	1,754	3,684
6	OHL Fittings	circuit km	-	716	708	2,261	3,684
7	OHL Tower (SHET & SPTL)	No.	-	1,458	1,043	4,540	7,041

Asset Categories		Units	Expected delivery versus target Volume of assets in each RP				Total
			RP1	RP2	RP3	RP4	
1	Circuit Breaker	No.	- 30	- 65	-	+ 67	- 28
2	Transformer	No.	+ 21	+ 10	+ 16	- 76	- 29
3	Reactor	No.	+ 7	- 10	- 3	+ 2	- 4
4	Underground Cable	circuit km	-	- 7	-	- 13	- 20
5	OHL Conductor	circuit km	+ 100	+ 473	- 820	+ 136	- 111
6	OHL Fittings	circuit km	-	- 400	- 27	+ 316	- 111
7	OHL Tower (SHET & SPTL)	No.	-	- 485	+ 394	- 104	- 195

1.5. The TOs are required by their licence to develop their NOMs methodology to allow us to properly assess performance. The purpose of the NOMs is to show whether the TOs are managing network risk effectively and whether their NLR investments are providing consumers with long-term value for money. It should therefore enable Ofgem to administer the incentive mechanism. To do this, the methodology must be transparent and should enable the objective assessment of over and under delivery.

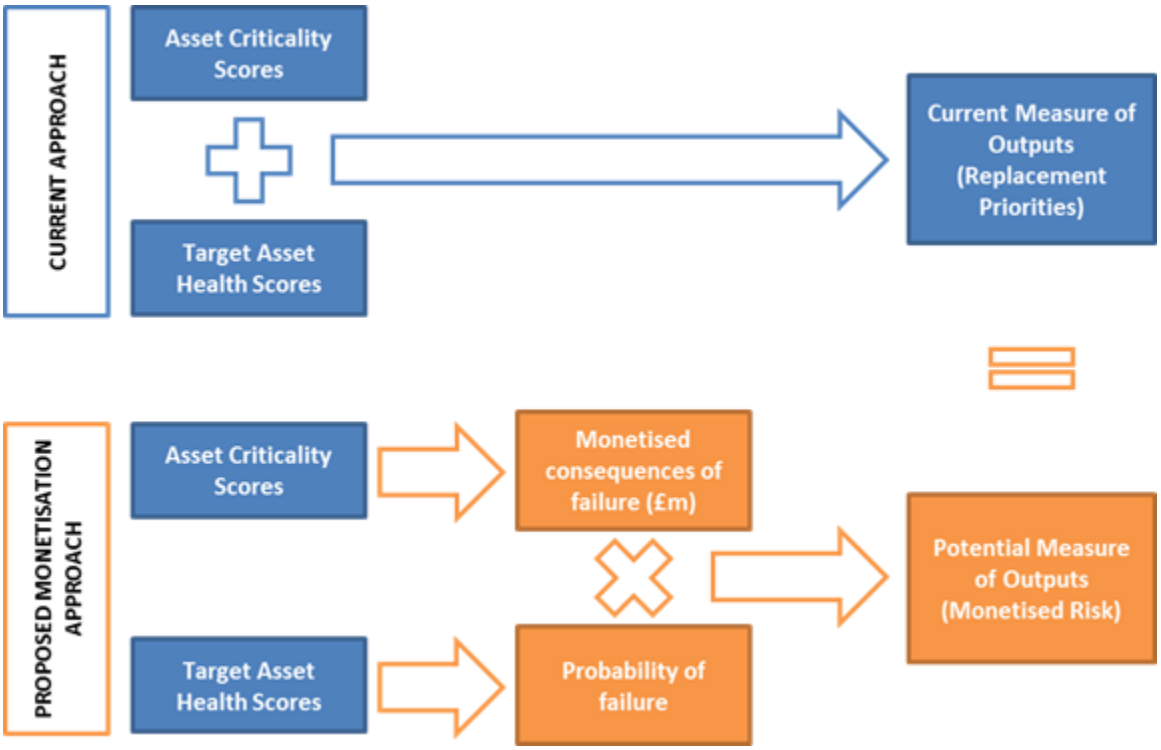
1.6. The approach taken by the TOs so far is to use a monetisation approach to quantify the risk of all individual assets. A monetisation approach would mean placing values on the expected consequences of individual assets failing and then weighting the consequences by the probability of them occuring. This would then give a monetised risk value for the risks carried by each asset. The individual asset risk values may then be summed to arrive at a single total network risk figure (expressed in £m).

1.7. The TOs published a draft methodology for consultation on 16th October 2015. The consultation has recently closed.[66]

1.8. In general terms, we see that the monetisation approach, once sufficiently developed, could faciliate better assessment of performance. At present we will need to exercise some judgement when assessing a spread of over and underdelivery in different asset categories' individual RP groups, as seen in the TOs' own expectation of performance at the end of RIIO-T1. Translating these into monetised values of risks should better inform that assessment, as illustrated in Figure A1.2 below.

[66] The NOMs consultation was published on each of the TOs' websites on 16 October 2015
NGET: http://www.talkingnetworkstx.com/current-consultations.aspx
SPT: www.spenergynetworks.co.uk/pages/tnoms
SHE Transmission: https://www.ssepd.co.uk/NOP/

Figure A1.2: Current and potential approach to assess NOMs performance



1.8. We are having ongoing discussions with the TOs to assess to what extent the TOs' draft methodology achieves the objectives set out in their licence.

Appendix 2 – Glossary of Terms Used in This Report

Annual Iteration Process

The annual iteration process is the process of annually updating the variable (blue box) values in the Price Control Financial Model (PCFM) and running its calculation functions in order to provide updated MOD and SOMOD values.

Base Revenue

Base revenue is the opening base revenue allowance, plus any incremental change to the opening base revenue allowance under the Annual Iteration Process.

MOD Term

The term of that name included in the formula for Base Transmission Revenue (System Operator Internal Revenue) set out in Special Condition 3A (or Special Condition 4A for SO) of the Electricity Transmission licence. It represents the incremental change to be applied to the licensee's Opening Base Revenue Allowance for the Relevant Year concerned. The value of the MOD term is calculated through the Annual Iteration Process for the ET1 Price Control Financial Model (see Chapter 1) and is specified in a direction given by the Authority by 30 November in each Relevant Year.

Pass through Costs

Costs passed through to the customer from the licensee.

RAV – Regulatory Asset Value

A financial balance representing expenditure by the licensee which has been capitalised under regulatory rules. The licensee receives a return and depreciation on its RAV in its price control allowed revenues.

TIRG

This is a mechanism for funding transmission projects specific to connecting renewable generation. The mechanism was implemented during TPCR4, outside of the price control allowance, to minimise delays.

Totex Incentive Mechanism (TIM)

TIM is the financial reward (or penalty) that companies are given in allowances for under or over spend on Totex. For RIIO-T1 Final Proposals Opening Base Revenue Allowances have been modelled on the basis that actual Totex expenditure levels are expected to

equal allowed Totex expenditure levels (allowances). If actual (outturn) expenditure differs from allowances, for any Relevant Year during the Price Control Period, the TIM provides for an appropriate sharing of the incremental amount (whether an overspend or underspend) between consumers and licensees.

WACC

The Vanilla Weighted Average Cost of Capital is Ofgem's preferred way of expressing the rate of return allowed on the Regulatory Asset Values (RAV) of price controlled network companies. The use of Vanilla WACC means that the company's tax cost is separately calculated as a discrete allowance so that only the following have to be factored in:

- the pre-tax cost of debt – ie the percentage charge levied by lenders, and
- the post-tax cost of equity – ie the percentage return equity investors expect to actually receive,

weighted according to the price control gearing assumption.

'Real Vanilla WACC' is used which gives a lower percentage than 'Nominal Vanilla WACC' would (when inflation is positive). This is because inflation isn't taken into account in the determination of the Real Vanilla WACC percentage.