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RIIO-ET1 Annual Report

2015-16

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Overview

RIIO-ET1 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 activities of the onshore electricity transmission companies in 2015-16. It also covers company progress in the first three years of RIIO-ET1 and company forecasts for the remainder of the eight-year period. It reviews company performance on the outputs we set and compares the costs incurred against allowed revenues.

In addition, the report outlines the performance of the electricity system operator (SO), whose role is to ensure that the electricity transmission system remains in balance.

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.

To ensure value for money for consumers, we regulate TOs through periodic price controls that limit the amount by which costs can rise, and that stipulate levels of performance.

To set our price controls we use the RIIO (Revenue = Incentives + Innovation + Outputs) framework. The current electricity transmission price control lasts for an eight-year period from April 2013 until March 2021.

We set the baseline revenues that TOs can earn at the start of the price control. There are mechanisms to adjust revenues year-on-year depending on TOs' performance against pre-set targets. There are outputs associated with baseline revenues that TOs must deliver either on an annual or eight year basis.

Using data and supporting information submitted by the TOs, this report reviews how they are delivering against the financial and output requirements of the price control.

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 2015-16 performance:

NGET:
http://www.talkingnetworkstx.com/general-performance.aspx

SHE Transmission:
https://www.ssepd.co.uk/TransmissionPriceControlReview/

SPT:
http://www.spenergynetworks.co.uk/pages/2015_2016_transmission_annual_performance_report.asp

Transmission networks 2015-16 performance data:

RIIO-T1: performance data

Table of Contents

Executive Summary

2015-16 was the third year of the RIIO-ET1 price control. In RIIO, the focus is on outputs, incentives and innovation as well as total expenditure (totex).

This report outlines our key findings of onshore electricity transmission sector performance under each of these areas to date and during 2015-16. It also outlines updated financial and output delivery forecasts for the whole RIIO-ET1 period.

Output performance

All TOs expect that output delivery will meet or exceed the targets set against five of the six output categories across the price control period, namely: safety; reliability; availability; customer satisfaction; and environmental. So far, the Transmission Owners (TOs) have earned £60m of incentive payments for exceeding targets on these output categories during the first three years of the control period.

For the remaining output category, 'connections and wider works', the licensees are meeting their requirement to provide these (where requested) in a timely manner. However, there have been significant changes from original expectations of connections levels. All TOs report substantial reductions in the total forecast generation capacity reported last year. Both NGET and SHET Transmission expects this to lead to downward adjustments in revenue; SPT currently anticipates a clawback of allowance through the operation of one of its licence mechanisms (see chapter 3 for more details).

TOs had good performance against the agreed output targets in 2015-16. Based on current information, only SHE Transmission will be penalised for underperformance against their agreed baseline target for SF_6 leakage in the environmental output category. When compared to last year, the leakage figure was a substantial decrease and suggests that SHE Transmission can meet the performance target in future years.

Expenditure performance

Transmission Owner (TO)

In 2015-16 all TOs have spent less than their allowances, continuing the trend of the previous two years.

All of the TOs are expecting to outperform their forecast allowances over the entirety of RIIO-ET1 by between 5% and 12%.[1] 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' underspend. At a high level, there has been a lower requirement for connections. There have also been smaller increases in prices, compared to what was assumed when setting the allowances. At a specific level, NGET have achieved significant savings through the re-conductoring of lines, where the allowances were based on more substantive work

[1] The figures are based upon the TOs' published values.

programs. NGET is also forecasting significant underspend in the Network Output Measures area, following reassessment of its assets' health (and other factors). SHE Transmission have achieved savings through the delivery of Strategic Wider Works projects and a reduction in connection assets in comparison to the original baseline plan. We will be investigating the drivers of this underspend throughout the control period.

System Operator (SO)

NGET, in its role as SO, underspent compared to their 2015-16 allowed totex by 3% in the reporting year 2015-16. NGET forecasts that the required level of SO totex will be 2% below allowance for the eight year RIIO-ET1 period.

Financial performance

The financial performance of transmission companies is presented using the return on regulatory equity (RoRE) measure. Based on our own assessment of TOs' forecast performance for the whole RIIO-ET1 period, we have calculated that RoRE will range from 9.4% to 11.5%[2]. This estimate depends on current forecasts and future delivery of outputs and may change during the remaining years of RIIO-ET1.

Customer bill impact

The financial and output performance of TOs affects the Allowed Revenue that they can collect through customer bills. The performance in 2015-16 will impact on Allowed Revenue, and therefore customer bills, in 2017-18. We estimate that the average GB customer will pay £38 per annum[3] in 2016-17 and 2017-18 to cover electricity transmission network costs. Charges differ depending on the region that a consumer resides in. For a typical consumer, 2016-17 charges are expected to range from £34 in the North East up to £41 in the South West.

Mid Period Review

Our review of these data submissions has run concurrent with the Mid-Period Review (MPR) for Electricity Transmission. Through that process, we have decided to reduce National Grid Electricity Transmission's (NGET) allowances by £16.6m (2009-10 prices). This reflects a reduced requirement to protect sites against rising fault levels (lowering allowances by £38.1m) (2009-10 prices) and new requirements relating to the new enhanced system operator role (increasing allowances by £21.5m) (2009-10 prices).

While we have acknowledged the impact of our MPR decision in our calculation of the RoRE (see chapter 2), the analysis presented in chapters 3-6 (inclusive) of this report does not include the impact of the MPR decision.

[2] We have used our own assessment of forecast spend, based on information provided by the companies for the entire control period. We have included the forecast impact of the Sole Use Exit Connections true-up which will occur at the end of RIIO-ET1. Our NGET numbers include the impact of our Mid Period Review decision.
[3] Nominal price base.

1. Introduction

1.1. Each year we report on how the onshore electricity transmission licensees have performed against the outputs and allowances set for the RIIO-ET1 price control. This is part of our annual process of monitoring network companies, and holding them to account for the money they spend and collect from consumer bills.

1.2. In July of each year each TO must submit information to us that outlines the actual costs they have incurred up to 31 March of that year and forecast costs to the end of RIIO-ET1. They also provide a written commentary with further detail behind the costs, including reasons for differences between costs, allowances and forecasts.

1.3. We analyse this information and examine any variances in TO performance against their annual and eight-year output targets. We also meet with the companies to discuss technical and financial aspects of their submissions.

1.4. This report outlines the performance of the licensees against their price control obligations and incentives for the third year of the price control. It also provides information on the licensees' updated forecast for the remaining five years.

1.5. The following chapters provide more detail:

- **Chapter 2: Expenditure** – explains the financial aspects of performance. This covers their total expenditure, allowed revenue, Return on Regulatory Equity (RoRE) and the impact on consumer bills.

- **Chapter 3: Outputs** – explains how the TOs have performed against their outputs during the reporting year and so far in the price control. It also gives information on forecast performance going forward.

- **Chapter 4: Innovation** – explains the costs incurred for the Network Innovation Allowance (NIA) and Network Innovation Competition (NIC).

- **Chapter 5: Analysis of expenditure** - explains reasons for variances between TO expenditure compared with what was allowed at the start of the price control.

- **Chapter 6: SO performance** – This chapter provides information regarding the performance and costs incurred by the SO.

1.6. Unless otherwise stated, all financial values in this report are in 2015-16 prices.

2. Expenditure, returns and customer bill impact

Chapter Summary

This chapter explains how we determine the annual allowed revenue of each onshore electricity transmission licensee that can be collected from network charges. It also contains an analysis of how expenditure by the licensee impacts on customer bills.

Introduction

2.1. For each network company we report

- their total controllable expenditure (totex[4]) on maintaining and improving GB's electricity transmission network infrastructure.
- their Allowed Revenue for these activities[5];
- the impact of Allowed Revenue on customer bills, and
- an estimate of the associated return on regulatory equity (RoRE) for investing in the electricity transmission network.

Total controllable expenditure (totex)

2.2. For each year of the price control we set network company cost baselines for each network company, which is their allowed totex. This is to enable investment to maintain the existing network and accommodate a new generation of network infrastructure, and to deliver agreed outputs. Network companies are required to report their actual totex, explaining their performance compared to the allowed totex and in relation to their agreed outputs annually.[6] They are also required to forecast their totex performance to the end of the price control.

2.3. Outputs are at the heart of the RIIO regulatory framework and capture the key areas within which consumers expect the delivery of high quality services. The outputs framework comprises both primary outputs - visible to and valued by consumers, e.g. reducing energy not supplied - and secondary deliverables - indicators of performance

[4] Includes only controllable costs, excluding uncontrollable costs such as business rates, and licence fees.
[5] Allowed revenues are recovered from users of the transmission network through charges levied and collected by NGET in its role as SO on behalf of all TOs.
[6] For RIIO-ET1 the reporting requirements have been consolidated in a single licence condition (Standard Condition B15).

used in support of the primary outputs, e.g. asset health and criticality. Chapter 3 gives more detail on the specific output categories.

2.4. As totex refers to total controllable expenditure, it comprises both of capital expenditure (capex) and operational expenditure (opex). Therefore, network companies are incentivised to deliver outputs based on total whole life costs, rather than being driven to preferring either opex or capex.[7] This better incentivises them to select the best overall solutions for customers.

Actual expenditure

2.5. Network companies are incentivised to outperform their totex allowance as part of the totex Incentive Mechanism (TIM). A better forecast (i.e. closer to our view of efficient cost) receives a stronger incentive rate, meaning a lower Sharing Factor. Through the TIM any underspend compared to the allowed totex is shared between the network company and its customers according to this Sharing Factor. Therefore, efficient spending leads to better returns for investors and lower network charges for customers. The sharing is symmetrical for any overspends; a network company is exposed to any shortfall and the remainder is passed onto investors and customers by increasing allowances to be recovered through network charges.

2.6. Table 1 sets out the values of allowed totex within the current financial model that are driving the allowed revenue calculations for each company. The values differ from the TOs' published values of allowed and actual totex values (see table 2 and chapter 5). This is because the published values are forecasts of the outcome of revisions to the allowed totex and reflect each company's own view[8] (see links on page 3) of the value of totex allowances at the end of the eight year price control period.

2.7. The combined allowed totex for the TOs in the reporting year 2015-16 is currently £2,940 million (note that this view is subject to ongoing revision). Actual expenditure was £2,042 million; an underspend of £898 million or 31%. NGET and SHE Transmission underspent compared to their allowed totex by 36% and 33% respectively and SPT overspent by 1%. NGET SO has a totex underspend of £1 million (<1%) in the reporting year 2015-16.

2.8. A forecast of allowed totex after revisions and equivalent revisions to 2013-14 and 2014-15 is provided in Table 2. The prevailing values set the value of the TIM for the purposes of 2017-18 Allowed Revenue, the forecast is considered to be a better measure

[7] Historically capex solutions have been preferred, as the cost was capitalised and increased their regulatory asset value (RAV). Under the Totex approach, when a company spends money on a solution, the same percentage is capitalised irrespective of whether that solution involves opex or capex. This means that companies are more likely to use the overall cost-effective solution.
[8] The figures published by the company contain no adjustments and are pre-true up.

of totex performance through the TIM mechanism. Revisions to allowed totex and therefore TIM performance will be reconciled in future revenue years.

Table 1: Pre-tax Totex in 2015-16

£m 2015-16 Prices	NGET TO	NGET SO	SHE Transmission	SPT
Allowed Totex	1,805	137	781	354
Actual Totex	1,161	137	524	358
Overspend / underspend	-644	-1	-257	4
Sharing Factor[9]	53.11%	53.11%	50.00%	50.00%
Allowed Totex after sharing[10]	1,463	137	652	356

Forecast expenditure

2.9. When the ongoing uncertainties in allowed totex for the years 2013-14 to 2015-16 are finalised, the outcome will affect TIM performance. Forecasts of the final outcome in the first three years and also forecasts of TIM performance for the remainder of the price control (2016-17 to 2020-21) have been conducted by the TOs based on their expectations.[11]

2.10. Each TO (after allowed totex uncertainties are resolved) is expecting to cumulatively outperform the totex allowance over the first three years of the RIIO-ET1 price control. The cumulative three year allowance for the TOs up to and including 2015-16 was £7,387 million, and actual expenditure £5,620 million; is forecast to have been £1,767 million underspend, or 24%, see Table 2.

2.11. The NGET SO has a cumulative out-performance of 5% relative to its allowed totex across the first three years of the price control (£428 million).

[9] This is the proportion of underspend / overspend the consumer receives (after accounting for tax).
[10] The allowed Totex after sharing is not wholly remunerated in the year it occurs. A minority of the expenditure is funded immediately through the Fast Money part of Base Revenue (see Appendix 1). The majority is added to the company Regulatory Asset Value (RAV), which is paid out over a period that is reflective of the average lifetime of long-term network assets (multiple decades).
[11] An important factor included in these forecasts is a c.£260 million correction (across the 8 year price control for all TOs) for excluded services income. The majority of this is associated with NGET TO.

Table 2: Company forecast of final allowed totex and expenditure[12]

£m 2015-16 Prices	*2013-14 to 2015-16*[13]				*Forecast: 2013-2021*			
	Allowed Totex	Actual	Difference		Allowed Totex	Actual + Forecast	Difference	
			£m	%			£m	%
NGET TO	4,791	3,683	-1,108	-23%	13,170	11,652	-1,519	-12%
SPT	1,190	891	-299	-25%	2,325	2,212	-113	-5%
SHE Transmission	1,406	1,046	-361	-26%	3,037	2,770	-267	-9%
TO Total	**7,387**	**5,620**	**-1,767**	**-24%**	**18,532**	**16,633**	**-1,899**	**-10%**
NGET SO	428	405	-23	-5%	1,156	1,138	-18	-2%

2.12. The cumulative TO allowed totex over the entire price control (after revisions) is expected to be of £18.5 billion. It is currently forecast that after all revisions that the TOs will underspend compared to this by £1.9 billion (10%).

2.13. The NGET SO is equivalently forecasting a total underspend of 2% relative to its allowed totex value across the RIIO-ET1 price control.

Allowed revenue

2.14. Consumers pay for network companies to operate and maintain the electricity transmission networks through their electricity bills.

2.15. Allowed Revenue is the total amount of money that TOs can collect from customers through Transmission Network Use of System Charges (TNUoS). Actual totex and the TIM are two of the factors that impact on the Allowed Revenue a TO can collect. This is further explained appendix 1

2.16. Allowed Revenue for 2017-18 is calculated following our price control Annual Iteration Process (AIP), which was completed on 30 November 2016. The AIP:

- determines the TIM reward/penalty based on the latest available actual expenditure information;
- accounts for changes to other factors that are updated, for example the allowance for borrowing associated with corporate debt, tax and updates through re-opener windows; and determines an annual modification term (the "MOD"), which modifies the Opening Base Revenue (set at the start of the price control).

[12] Totex values are adjusted for the current forecast "true up" to remove the gap between the allowance for excluded services income and the costs. The figures do not include the impact of the MPR decision.
[13] Values are forecasts of the outcome of revisions to these values therefore they differ from the currently reported 2015-16 allowed and actual Totex values shown in Table 1.

2.17. Table 3 shows Allowed Revenue we have determined may be collected during the price control so far. This is presented in a consistent price base and is exclusive of the reconciliation of the revenue collection correction factor to improve cross-years comparisons of the consumer cost for the services provided. Also provided are details of what comprises Allowed Revenue in 2017-18. Note that minor constituent parts of the Allowed Revenue are still subject to uncertainty or are not forecast in advance (these cases are indicated in the table).

Table 3: Allowed Revenue

	NGET TO	SHE Transmission	SPT[14]
Allowed Revenue[15]		**£m 2009-10 Prices**	
2013/14	1,372	152	246
2014/15	1,464	190	276
2015/16	1,427	280	257
2016/17	1,405	267	252
2017/18	1,304	164	271
2017-18 Allowed Revenue		**£m nominal prices**	
Opening Base Revenue	1,976	152	317
MOD	-322	67	-17
Non controllable Costs[16]	7	-7	-4
Incentive Payments	15	2	8
Innovation Funding[17]	21	1	17
TIRG[18]	-	84	31
Correction Factors[19]			
Revenue collection	97	-2	4
Inflation forecast true-up	-40	-7	-7
Corrected Allowed Revenue	1,754	290	348

[14] We note that SPT has made assumptions about 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 need further consideration during the course of the control period.
[15] Allowed Revenue values reported in this section of the table are exclusive of the "revenue collection" correction factor (licence term: k) and years are reported in a consistent price base, the method of calculation is otherwise identical to the method in the lower part of the table.
[16] Non controllable costs are cost items over which the company has no control. Examples include the charge levied on the company to cover the cost relating to Ofgem carrying out its regulation activities and; adjustments to business rates, such as tax, that a company cannot influence.
[17] Includes the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). The NIC revenue allowance is levied on users of the GB national transmission system. However, electricity network owners from distribution and transmission (onshore and offshore) all participate in the same competitive funding process. Transmission network users are liable for all associated funding costs.
[18] Transmission Investment for Renewables Generation (TIRG): a legacy revenue mechanism from the previous price control to fund projects that connect Renewable Generation to the network.
[19] These reconcile previous years' actual revenue to the Allowed Revenue of those years. These are the differences between actual inflation and our forecast; and revenue collection (it is not practical to collect the exact revenue allowed owing to tariffs being set before network usage is known).

Customer bill impact

2.19. We have used assumptions consistent with those that underpin our Supplier Cost Index (SCI)[20,21] to provide an estimate of the cost to typical domestic energy bills due to Allowed Revenues for each region of GB.

2.20. Actual customer costs are sensitive to geographic region, meter type, consumption volume and the timing and duration of contracts. Our methodology is based on typical domestic consumption values (the median domestic consumer in GB). Individual consumer costs may differ significantly from these values. We report costs on an annualised basis using our latest assumptions[22]. Bill estimates are reported in Figure 1 and Table 4; values are reported in nominal prices and so reflect the actual typical bills rather than the real terms cost to customers. The values we are reporting use our published typical domestic consumption values[23]. We have used these values uniformly for all reported years, with no correction made for recent trends in energy consumption.

2.21. We estimate that the typical GB domestic customer will pay £38 in 2016-17 (this financial year) for electricity transmission costs. This is estimated to remain the same in 2017-18. Charges differ depending on the region that a consumer resides in. For a typical consumer 2017-18 charges are expected to range from £25 in South Scotland and up to £45 in the South East, see Table 4 for details.

[20] SCI: https://www.ofgem.gov.uk/data-portal/retail-market-indicators
[21] SCI Method: https://www.ofgem.gov.uk/publications-and-updates/supplier-cost-index-methodology
[22] We used the January 2017 version of our Supplier Cost Index model. Note that the SCI uses a consistent view of a typical consumer for all years, in recent years this consumption has been reducing. This and future trends in consumption are not accounted for by this analysis.
[23] https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values

Figure 1: Estimates of typical GB consumer costs to meet Allowed Revenue.

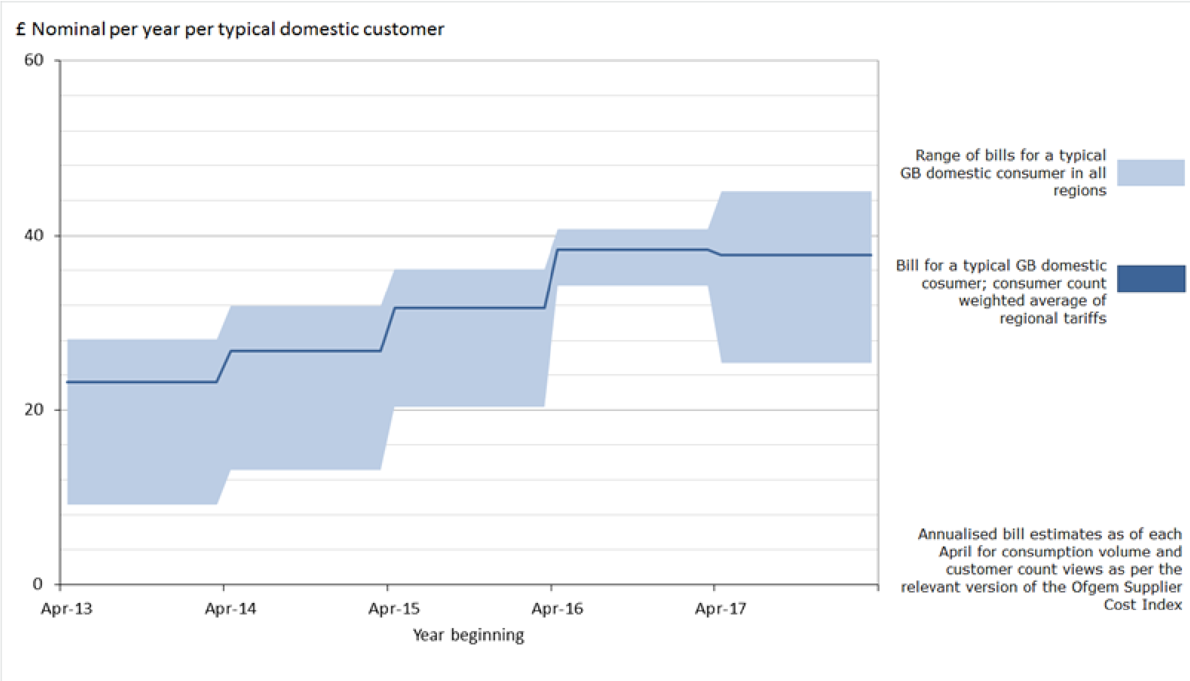


Table 4: Regional estimates of typical GB consumer cost to meet Allowed Revenue.

£ nominal prices per typical domestic consumer

Year:	Apr-13	Apr-14	Apr-15	Apr-16	Apr-17
GB consumer count weighted average	23	27	32	38	38
Region					
North West	22	25	29	34	36
North East	18	22	26	40	35
Yorkshire	21	25	31	39	35
Midlands	24	28	33	38	39
East Midlands	24	27	31	38	38
South Wales	22	25	31	38	34
South West	27	31	34	41	45
London	27	30	36	39	33
South East	27	31	35	40	45
East Anglia	25	28	33	38	42
South Scotland	14	18	22	37	25
Merseyside and N Wales	23	26	35	40	40
North Scotland	9	13	20	35	37
Southern	28	32	36	38	42

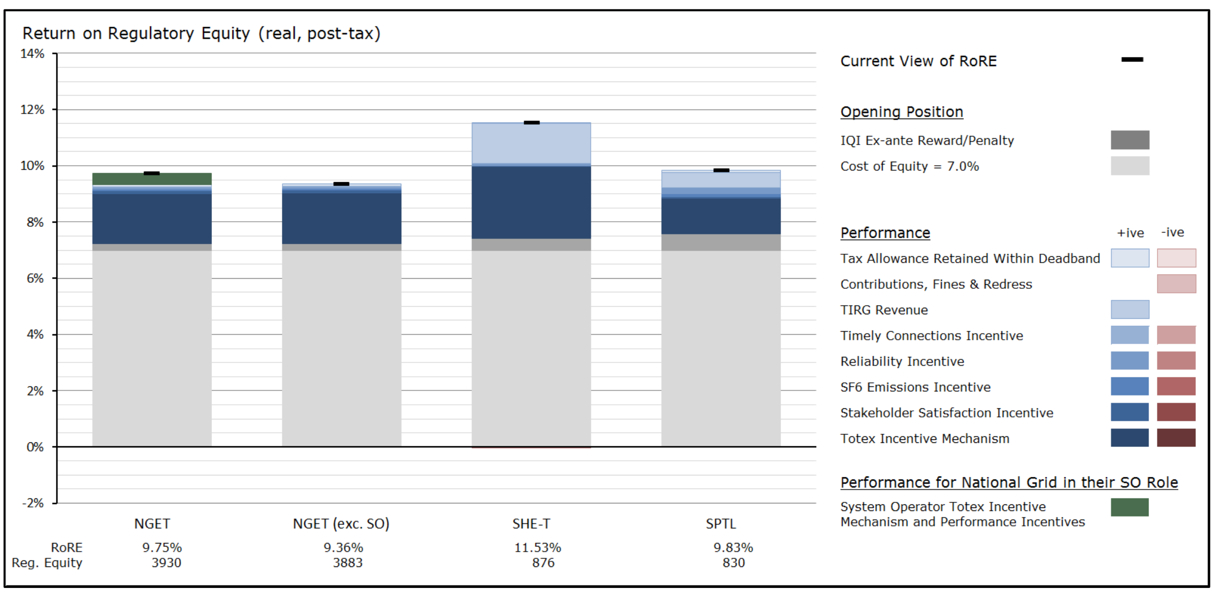
Return on Regulatory Equity (RoRE)

2.22. We assess the overall financial performance of network companies using a measure called the Return on Regulatory Equity (RoRE). RoRE is calculated post-tax and its estimation includes the use of certain regulatory assumptions, such as the assumed gearing ratio of the companies, to ensure comparability across the sector. To eliminate phasing impacts over the course of the price control, we use a mix of actual and forecast performance to calculate eight year average returns. These returns may not equal the actual returns seen by shareholders.

2.23. For the TIM component of RoRE, we have used our own assessment of forecast spend, based on information provided by the companies for the entire control period. We have included the forecast impact of the Sole Use Exit Connections true-up which will occur at the end of RIIO-ET1. Our NGET (SO) numbers include the impact of our Mid Period Review decision.[24]

2.24. For the incentive rewards we have used actual post-tax values where known[25]. We have assumed a simple average of known (pre-tax) rewards for the remaining years, taxed at future Corporation Tax rates. Note that in some cases, holding rewards constant assumes that the underlying performance will increase over time.

Figure 2: Eight year average RoRE



[24] Table A2.4 in appendix 2 summarises the allowed totex and expenditure values used in our calculation.
[25] Time value of money adjustments and forecast inflation effects have been stripped out of the value of incentives. They have been taxed at the actual Corporation Tax rate applicable to the year in which the company recovers the money, which is (usually) two years after the performance.

2.25. Our RoRE should be compared to the cost of equity allowed at the start of the price control. For Electricity Transmission, the cost of equity was set at 7.0%. Each company was also given an ex-ante reward or penalty based on business plan quality.

2.26. Underspending against allowed Totex and incentive outperformance (shaded blue) both increase companies' return, while overspending and penalties resulting from underperformance (shaded red) decrease their return.

2.27. Returns are predominately driven by all TOs forecasting underspends through the TIM. A large portion of SHE Transmission's and SPT's return comes from the Transmission Investment in Renewable Generation (TIRG) mechanism, where specified projects were incentivised at a higher pre-tax cost of capital, compared to current levels. The Scottish operators benefit from this scheme more than NGET, due to the concentration of TIRG projects in Scotland. Excluding TIRG Revenue reduces NGET's (SO & TO) return to 9.72%, SHE Transmission's return to 10.11% and SPT's to 9.28%. All TOs have also gained through the incentive mechanisms. Performance against each incentive is discussed in the remainder of this report.

2.28. Based on current forecasts, the highest performing company is SHE Transmission. The RAV-weighted RoRE across the sector is 10.1%. No companies are forecast to earn returns below their cost of equity.

2.29. There are a number of factors which are not reflected in our RoRE calculations, but which may impact the return realised by shareholders. The largest of these are the potential end of period clawbacks for under delivery on Network Output Measures. In the event companies fail to deliver their outputs the return calculation will need to be modified. The methodologies for over and under delivery of NOMS are in development. The current calculation assumes delivery of all RIIO outputs.

2.30. Our RoRE analysis also excludes companies actual debt costs relative to our regulatory assumption, innovation funding, legacy adjustments from prior control periods and unfunded pension deficits. We may include some of these items in the future as we continue to develop our methodology.

3. Outputs & incentives

Chapter Summary

This chapter examines actual and forecast performance of the licensees in meeting their output commitments over the third year of the RIIO-ET1 period. It also indicates the levels of incentive payments achieved by the licensees in respect of their performance levels.

Outputs, measures and performance

3.1. RIIO-ET1 was set as an outputs-based price control. On output delivery, our assessment is against expectations set at Final Proposals (FPs), including:

- targets which have associated rewards/penalty through incentives;
- targets (and associated allowances) which adjust automatically with changing needs; and
- other expectations against which we hold Licensees to account

3.2. In this Chapter, we are considering those targets which have associated rewards and penalties through incentives. The following six outputs form the cornerstone of the RIIO price control framework[26]:

i. safety

ii. reliability

iii. availability

iv. customer satisfaction

v. connections/wider works

vi. environmental

3.3. We are assessing delivery by the TOs. For outputs that have multiple metrics, we present some quantifiable measures for illustrative purposes; these are shown in table 5 below. If TOs achieve the targeted level of all measures satisfactorily we consider that they will have achieved the primary outputs.

[26] Further detail of the outputs framework in RIIO-ET1 is available on the Ofgem website in the link: RIIO-ET1: Final Proposals for NGGT and NGET – Outputs, incentives and innovation

Table 5: 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-ET2 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) 2015-16 Targets[27] NGET: 316 MWh SPT: 225 MWh SHE Transmission: 120 MWh	Financial incentive: • Incentive rate of £16,000/MWh which is based on an estimate of the value of lost load (VoLL)[28]. • 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 Satisfaction Survey (NGET only) and Stakeholder Satisfaction Survey (all TOs) Stakeholder engagement discretionary reward (all TOs)	Up to +/-1% of the sum of base revenue plus TIRG (Transmission Investment in Renewable Generation). Up to 0.5% of base revenue plus TIRG via a discretionary reward scheme.
(v) Connections/Wider Works	The timely meeting of existing licence requirements in relation to delivering new Generation connections & local Demand connections	Penalty of up to 0.5% of the sum of the licensee's base revenue plus TIRG. Financial incentives apply to Scottish TOs only; no direct financial incentive on NGET (general enforcement policy). The level of revenue reduction will be proportionate to the number of connections the licensee is unable to offer terms in accordance with the licence timetable.
	Timely delivery standards for Baseline Wider Works (BWW) and Strategic Wider Works (SWW)	BWW and SWW outputs specified in SpC 6I, tables 1 and 2. Additional capacity to be funded through a flexible baseline (with volume driver to adjust allowances if delivery turns out to be different) and SWW. Includes provision of baseline funding for pre-construction works undertaken to develop plans for a prospective SWW.

(continued on next page)

[27] These target values are applicable in each of the eight years of RIIO-ET1.
[28] 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.

(vi) Environmental	Limiting emissions of Sulphur Hexafluoride (SF_6) <u>2015-16 limits</u> NGET: 12,097.5 tCO_2e SPT: 618.9 tCO_2e SHE Transmission: 223.6 tCO_2e	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions.
	Environmental Discretionary Reward	Financial incentive: Positive reward available if achieve leadership performance across different scorecard activities. Annual funding of up to £4m will be available in each scheme year.
	Publish annual progress on Business Carbon Footprint	Reputational
	Publish annual progress on Losses	Reputational
	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 across all electricity TOs to work on mitigating impacts of existing infrastructure in designated areas from the beginning of RIIO-ET1.

3.4. Table 6 below summarises the revenue rewards and penalties accumulated to date over the first three years of RIIO-ET1 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 6: Output incentive mechanisms – indicative cumulative revenue rewards and penalties for 2013-16[29]

Mechanism (£m 2015-16 prices)	Cumulative reward or penalty			
	NGET	**SHE Transmission**	**SPT**	**Total**
Energy Not Supplied	10.3	3.0	8.5	21.9
Customer and stakeholder satisfaction surveys	22.4	1.6	1.8	25.8
Stakeholder engagement discretionary reward[30]	0.0	0.0	0.0	0.0
Sulphur Hexafluoride, SF_6	6.8	-0.4	0.1	6.5
Environmental Discretionary Reward	2.02	0.0	3.95	5.97
Timely connections	0.0	0.0	0.1	0.1
Network Output Measures[31]	-	-	-	0.0
Total all mechanisms (£m)	**41.5**	**4.2**	**14.5**	**60.2**
Amount earned in 2015-16 (£m)	**10.8**	**1.4**	**2.9**	**15.1**

3.5. The TOs' performances against the outputs and measures from Table 6 above are discussed in the following sections.

Safety output measures

Compliance with safety obligations

3.6. 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.

3.7. 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.

[29] Figures are based on indicative estimates derived from our price control model. The rewards/penalties 'earned' due to actual performance in 2015-16 will be collected as allowed revenues after a two year lag.
[30] The money awarded to the TOs under this incentive will form the Stakeholder Satisfaction Output term in the licence. The first year of running the scheme for the TOs was on a trial basis with no financial reward.
[31] NOMs performance is assessed at the end of RIIO-ET1 and financial rewards and penalties will be applied in RIIO-ET2.

Reliability output measures

Energy not supplied (ENS)

3.8. 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 have a constant annual target for total volume (MWh) of ENS, as follows: 316 MWh for NGET, 120 MWh for SHE Transmission, and 225 MWh for SPT. A TO receives a financial reward if the actual volume of unsupplied energy is below the annual target volume and a financial penalty if the volume is above target.

3.9. In a continuing trend from the first two reporting years of RIIO-ET1, all three TOs have significantly outperformed against their targets in 2015-16; see table 7 below. We estimate that the 2015-16 over performance will be reflected in a combined additional £8.5 million in allowed revenue to the three TOs (to be collected in 2017-18).

Table 7: ENS Three year performance – volume of unsupplied energy below annual target

	NGET	SHE Transmission	SPT
Target	**316 MWh**	**120 MWh**	**225 MWh**
2013-14	181 MWh	84 MWh	183 MWh
2014-15	307 MWh	14 MWh	222 MWh
2015-16	312 MWh	120 MWh	211 MWh

3.10. There has been no ENS events outside the TOs' control submitted for exception under this measure in this reporting year.

Network Output Measures (NOMs)

3.11. NOMs contribute towards the delivery of reliability and environmental outputs.

3.12. 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
- The Network Replacement Outputs

3.13. 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.

3.14. Under Special Condition 2M, TOs have allowances totalling approximately £6.5 billion over RIIO-ET1 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 5. The NOMs targets apply at 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.

3.15. The TOs have been developing their NOMs methodology to allow us to properly assess performance and to administer the incentive mechanism. They submitted a modified NOMs Methodology for approval on 16 February 2016. While we felt the modified methodology was a step in the right direction, we did not feel it fully facilitated the achievement of the NOMs Objectives. We therefore issued a Direction[32] to the TOs in April requiring the TOs to submit a further revised methodology for Ofgem's review by the end of 2016. We have given feedback on this and we have been working closely with the TOs to help ensure their development work proceeds in line with our expectations. We envisage the need for significant additional work in the coming year in order to further improve the methodology.

Availability output measures

Network Access Policy (NAP)

3.16. 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).

3.17. 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.[33]

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[32] "Decision to direct modifications to the electricity transmission Network Output Measures Methodology", Ofgem, 29 April 2016: https://www.ofgem.gov.uk/publications-and-updates/decision-direct-modifications-electricity-transmission-network-output-measures-methodology

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

Customer satisfaction

Customer/stakeholder satisfaction survey

3.18. 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[34] (KPIs) related to stakeholders around which they are rewarded or penalised financially.

3.19. These components together account for an incentive of up to +/- 1% of annual baseline revenue (plus TIRG).

NGET

3.20. NGET reports both customer and stakeholder satisfaction surveys. NGET's scores are illustrated below in Table 8, against baselines.

Table 8: NGET stakeholder and customer satisfaction results

	Stakeholder Survey (0-10)			Customer Survey (0-10, baseline 6.9)		
Company	**2013-14**	**2014-15**	**2015-16**	**2013-14**	**2014-15**	**2015-16**
NGET	7.53	7.74	7.53	7.41	7.40	7.54

SPT and SHE Transmission

3.21. The two Scottish TOs record performance against stakeholder satisfaction surveys and against sets of Key Performance Indicators (KPIs). These KPIs were developed by SPT and SHE Transmission to cover their respective activities. Table 9 summarises their performance against baselines.

[34] 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 9: Scottish TOs stakeholder satisfaction results

Company	Survey (0-10, baseline 5)			KPI (0-100, baseline 50)		
	2013-14	2014-15	2015-16	2013-14	2014-15	2015-16
SPT	7.40	7.10	6.90	68.00	69.16	73.10
SHE Transmission	6.50	7.70	8.20	91.00	86.00	76.00

Stakeholder engagement incentive

3.22. 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.

3.23. TOs submit evidence to demonstrate that:

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

3.24. 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.

3.25. All three TOs made submissions to our stakeholder engagement discretionary reward. The feedback for the companies was that they were improving (see Table 9), with a good level of resources committed to stakeholder engagement and they are progressing on embedding this work within the business.

3.26. 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.[35]

[35] See https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/stakeholder_engagement_14-15_decision_letter_tos_1.pdf

Table 10: Stakeholder engagement discretionary rewards scores

Company	Score (out of 10) 2013-14	Score (out of 10) 2014-15	Score (out of 10) 2015-16
NGET	5.75	6	6.25
SHE Transmission	5.4	6	6
SPT	4.9	5.5	6.25

3.27. As noted in Table 6 previously, the cumulative incentive awards based on performance to date for the TOs' customer and stakeholder activities is almost £26m.

Connections and Wider Works output measures

3.28. We use a number of output measures in this category under the RIIO framework. All TOs have primary measures of wider works (baseline, incremental and strategic), entry connections and exit connections. NGET has additional output measures of incremental wider works, Distribution Network Owner (DNO) mitigation and undergrounding provisions.[36] 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. We have considered the performance of the TOs against these outputs in the following sections.

Baseline wider works connections[37]

3.29. 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 (and Incremental) are measured in terms of the additional transfer capacity across system boundaries.[38]

3.30. The 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.

[36] NGET was also funded ex ante for significant 'general' wider works for which no quantifiable measures were set.
[37] These are set out in Special Condition 6I of each licence.
[38] 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.

NGET (TO)

3.31. NGET's electricity transmission licence details four reinforcement projects that were defined as BWW schemes. It has delivered the required BWW output in three schemes in accordance with the delivery date specified in the licence.

3.32. When taken together these three BWW outputs deliver additional transfer capacity of 2.8GW. NGET has delivered this capacity increase for £23m (or 16%) above the cumulative level of baseline allowance in the first three years of RIIO-ET1. This is driven by overspends in both the series compensation scheme (£13m) and Quadrature Booster scheme (£14m); which outweigh the small underspend (£3m) reported in the delivery of the re-conductoring project.

3.33. The fourth BWW scheme is the Western HVDC undersea cable link to facilitate an increased transfer of energy from north to south. This is a joint venture with SPT. This project has encountered technical problems with the cable manufacture process and the output is forecast to be delivered to a revised completion date within the 2017-18 financial year.

SPT

3.34. SPT's electricity transmission licence details five BWW reinforcement schemes in the south of Scotland. In the third year of RIIO-ET1 SPT has delivered one BWW output through the energisation of the subsea cable link between Hunterston and Kintyre (working jointly with SHE Transmission). This has reinforced the Kintyre peninsula with 240MVA of new capacity.

3.35. SPT has indicated that the delivery plan on schemes associated with other BWW outputs has been delayed due to uncertainty on timing of renewable generation and planning considerations. A phased completion has therefore been delivered in terms of two BWW outputs: the East-West upgrade (voltage uprating from 275kV to 400kV) and the Series and Shunt Compensation projects (installation of series capacitor units).[39] SPT currently expects to fully deliver both BWW outputs by the end of 2017-18.

3.36. Of the remaining two BWW schemes specified in SPT's electricity transmission licence:

- the Western HVDC link has a revised completion date of 2017-18 (delayed from 2016-17), and

[39] During 2015-16, three units – one at Eccles, plus Gretna and Moffat – were fully commissioned and available for service. A key element of the next upgrade is the addition of four series capacitors to the network at Eccles (2 units), Gretna & Moffat.

- voltage support at Kilmarnock South has been adversely affected by the subsequent announcement of life extension of the Hunterston 'B' generation plant. The BWW output is therefore not anticipated to be delivered. SPT's review of its network in that area has led it to propose a substitution of the baseline output to install shunt reactive compensation equipment at several sites including Kilmarnock South (to be delivered in 2020). This matter is being progressed through the RIIO-ET1 Mid-Period Review.

3.37. In the first three years of RIIO-ET1, SPT has incurred costs of £368m in the progression of BWW works; an underspend of £254m (41%). Across RIIO-ET1, SPT currently anticipates a totex expenditure of £563m in the delivery of the relevant BWW outputs. This is approximately 14% below SPT's current forecast of total allowance across the price control.

3.38. SPT explains that this expected level of outperformance is largely the result of efficiencies in the programme of upgrade work – mainly Series and Shunt compensation projects - and cost and delivery changes associated with an evolving profile of renewable generation connections. We will continue to work with SPT to keep under review both its forecasts and the progress of its BWW output delivery programme.

SHE Transmission

3.39. SHE Transmission's electricity transmission licence sets out two BWW reinforcement schemes to provide additional boundary transfer capability in the north of Scotland. Both schemes (Beauly Blackhillock Kintore (BBK) and the Beauly – Mossford substation) were delivered in line with licence requirements during 2015-16.

3.40. SHE Transmission has incurred totex of £48m in the first three years of RIIO-ET1 in the delivery of BBK and Beauly Mossford. This is 24% below the cumulative baseline level of allowance in the first three years of RIIO-ET1. This is comprised of a small overspend in the Beauly Mossford scheme (c.£1m) that is outweighed by a material underspend in the BBK scheme (c.£17m).

Strategic wider works connections

3.41. In their RIIO-ET1 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-ET1 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.

3.42. In 2013-14 we approved three projects proposed by SHE Transmission: Kintyre-Hunterston, Beauly-Mossford and Caithness-Moray. SHE Transmission reports an outperformance of £42m in relation to SWW projects, which mainly relates to the Kintyre Hunterston and Beauly Mossford projects both of which were successfully energised during 2015/16 ahead of schedule.

3.43. 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-ET1, which is currently under development.

General connection activity

3.44. 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.

3.45. SHE Transmission and SPT completed all offers during 2015-16 within the licence timescales. In both cases the offers being made were to a more diverse range of projects, including solar and hydro. Changes in the government financial support for onshore wind generation is expected to drive a reduction in the overall amount of new generation connecting across the period, and a consequential reduction in the total amount of additional capacity to be provided.

3.46. The allowed revenue modification as a consequence of 2015-16 performance will have the impact of increasing maximum allowed revenue of SHE transmission and SPT for 2017-18 in line with the provisions in the licence. Similarly, the impact of SPT's underperformance in 2014-15 will feed through to a reduction in next year's allowed revenue.[40]

3.47. NGET completed all 280 of its offers within the specified period.

Local Generation Connections (Entry): NGET

3.48. For NGET, an allowance was originally set on the basis of a baseline of 33GW of new generation connecting over the RIIO-ET1 period.[41] This year, NGET has revised its generation connections activity forecast up to 13.9GW, compared to the reduced forecast of 11.2GW made last year. This net increase (2.7GW) in transmission connected generation[42] is made up of some 7.5GW of increases and 4.8GW of decreases comprising new connections, deferrals, terminations or other changes over RIIO-ET1. We will

[40] Set out in Special Condition 3G (Financial Incentive for Timely Connections Output) of the Scottish TO's electricity transmission licence.
[41] Licence special condition 6F, table 1.
[42] 18GW of embedded generation is currently forecast by NGET to connect over the RIIO-ET1 period.

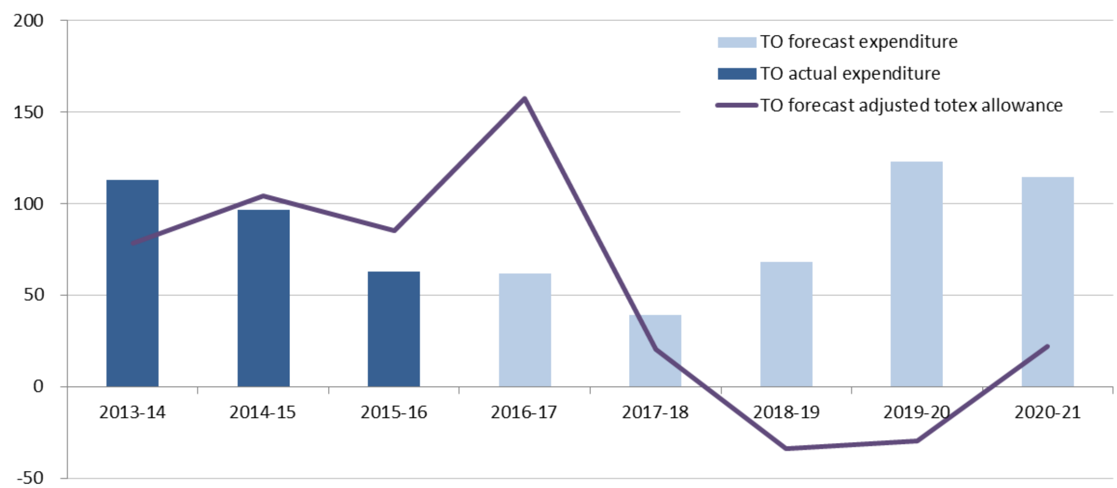
continue to work with NGET to keep under review both its forecasts and the implications these have through the revenue adjustment mechanisms in the licence.

3.49. On a cumulative basis, there was 5.4GW of generation expected to be connected in NGET's baseline during the first three years of RIIO-ET1. NGET has delivered 3.0GW, which is 2.4GW less than the baseline expectations. NGET has incurred £294m in connecting this 3GW; an overspend of £26m (or 10%) against NGET's updated view of the cumulative allowance over this three year period (£268m).

3.50. Changes in the numbers of customers connecting to NGET's network drive a reduction in the associated allowance through the volume driver mechanism. NGET's current view is that the mechanism will reduce their allowance from c.£1.2bn to c.£0.5bn across the price control.

3.51. As a result, NGET is currently forecasting to overspend against the adjusted totex allowance for entry connections across RIIO-ET1 by £296m (61%). Figure 3 highlights an expectation that the licence mechanism will clawback c.£60m of allowance in 2018-19 and 2019-20 (reflecting adjustment for the change in outputs).

Figure 3: Actual and forecast expenditure vs TO forecast allowance: NGET (TO)



3.52. NGET's electricity licence also requires it to report annually on the number of kilometres of overhead line (OHL) installed. The baseline expected 215.4km to be built across the price control (associated with the baseline forecast of 33GW of generation connections)[43]. NGET currently expects a significant reduction in the length of OHL to be commissioned across RIIO-ET1 from 215km to 41km; this compares to last year's forecast RIIO-ET1 figure of 118km. The reduction in new OHL (route/circuit) is largely the result of a delay of works associated with delayed generation projects.

[43] Zero km of underground cable was expected. This is unchanged.

Local Generation Connections: SPT

3.53. The price control for SPT and SHE Transmission splits funding for generators connections based on how many generators are connected. There are separate mechanisms to connect one generator at a time (MW of "sole use" [44] connections) and another to connect multiple generators ("shared use"[45] connections). The shared-use volume driver requires both Scottish TOs to report annually on the volume of infrastructure (MVA) to reinforce the capability of its network to accommodate generation connections.

3.54. Under SPT's baseline RIIO-ET1 package it will seek to complete the connection of 2.5GW of new, sole-use generation within the RIIO-ET1 period. A baseline allowance of £82m (2015-16 prices) was set to deliver this threshold target. A volume driver is applicable for the costs for sole use generation connections delivered by SPT during RIIO-ET1 in excess of the baseline target.

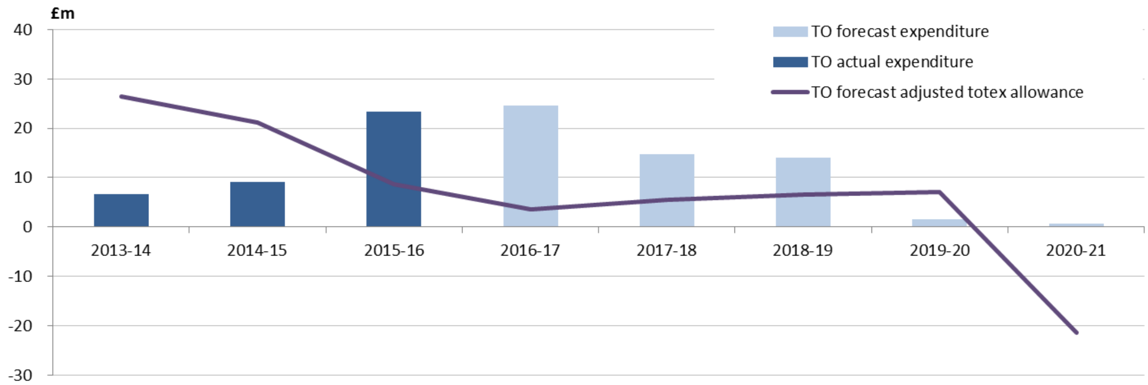
3.55. SPT is currently expecting to connect 2.1GW of generation requiring sole-use infrastructure across RIIO-ET1, at a cost of £94.4m[46]. This is below the baseline target level so SPT anticipates a clawback of c.£25m allowance through the operation of the volume driver mechanism (on the basis that the output target was set on the final year of the price control).

3.56. The current forecast of 2.1GW is a reduction to SPT's 2014-15 forecast of 3.6GW. SPT explains that this reduction has been driven by delays associated with the connection of a group of projects in the South West of Scotland, SPT's assessment that consenting issues with an offshore project is likely to defer connection and wider uncertainty driven by the changes to the financial support available to onshore wind generation.

3.57. Figure 4 illustrates SPT's forecast spend and allowance profile in delivering 2.1GW (below licence requirement). The net outperformance in the first two years of RIIO-ET1 (£32m underspend) has been followed by net overspend of £15m in 2015-16. This trend is forecast to continue for the next three years (cumulative £38m). An aggregate underspend of £37m (65%) is currently forecast (post clawback).

[44] "Sole Use" distinguishes between assets which are for the use of a single customer (covered by transmission connection charges) from assets which are shared by other users of the transmission network (covered by transmission network use of system charges).
[45] "Shared use" infrastructure relates to expenditure triggered by individual connection projects but only provides assets or reinforcements which are shared by users of the transmission network.
[46] In its original Business Plan submission, SPT identified a number of specific generation connection projects separately requiring Sole-Use and Shared-Use Infrastructure investment. Ofgem provided a baseline allowance in RIIO-ET1 for such investment - grouping it under, 'Local Enabling (Entry) Schemes not subject to uncertainty mechanisms'. Further development work is ongoing to improve transparency of reporting in these two key areas to better relate outputs and investment to the associated incentive mechanism.

Figure 4: Actual and forecast expenditure vs TO forecast allowance to deliver 2503MW (sole use generation capacity): SPT

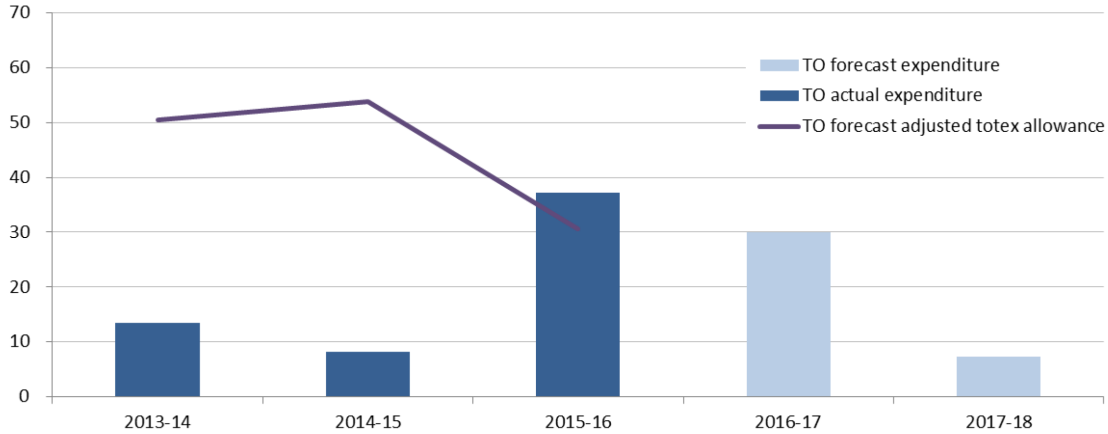


3.58. For shared use infrastructure, SPT's baseline package contains an output target to deliver 1073MVA of shared infrastructure capacity for generation connections. An allowance of £135m (2015-16 prices) was set to enable SPT to deliver this. A volume driver is applicable for the delivery of shared use connections infrastructure that exceeds the baseline capacity output.

3.59. SPT anticipates that the target will be met at some point during the 2017-18 reporting year; a delay of two years to the business plan estimate. SPT is currently forecasting to incur expenditure of £96m to deliver the target of new network capacity by 2017-18; an underspend of £39m (29%) against the baseline allowance.

3.60. Figure 5 below illustrates SPT's forecast spend and allowance profile in delivering the licence requirement. The net outperformance in the first three years of RIIO-ET1 (£76.2m underspend) is followed by a forecast £37.4m spend in the next two years (with no commensurate baseline funding).

Figure 5: Actual and forecast expenditure vs TO forecast allowance to deliver 1073MVA (shared use infrastructure): SPT



3.61. SPT currently expects to deliver 4.23GVA across RIIO-ET1; c.3.2GVA above the output target. This total reflects SPT's view of the investment relating to connections which it identifies as having the best probability of progressing. This is a slight increase to the forecast capacity reported by SPT last year (4.19GVA).

3.62. SPT currently forecasts it will earn an additional allowance of c.£275m through the volume driver mechanism for the delivery of this additional c.3.2GVA. The majority of the additional capacity is currently expected to be delivered during the final three years of RIIO-ET1. SPT currently forecast its total expenditure associated with the delivery of this capacity to be on a par with the additional allowance through the volume driver mechanism.

3.63. However, SPT's interpretation of what output is permissible to be reported under the licence mechanism and the associated value of the proposed increase in allowance is the subject of our minded-to MPR position.

3.64. The overall picture is also highly sensitive to the timing of connection energisation, which determines which mechanism the project costs are recovered against, and also the ultimate decision on the scope of the licence mechanism being taken forward through the MPR process. We will continue to work with SPT to keep under review both its forecasts and the implications these have through the revenue adjustment mechanisms in the licence.

Local Generation Connections: SHE Transmission

3.65. Under SHE Transmission's baseline RIIO-ET1 package it will seek to complete the connection of 1168MW[47] of new generation which includes sole-use infrastructure

[47] This comprises planned delivery of 1524MW typical cost generation capacity and 235MW of atypical generation connection capacity. Future sole use infrastructure schemes over the price control period have been

elements. The baseline package provided an allowance of £119m (2015-16 prices) associated with the delivery of "typical" generation connections which have a unit cost of less than £150k/MW (unit cost expressed in 2009-10 prices). Delivery of capacity in excess of the licence target (and 'atypical' connections with a unit cost greater than £150k/MW) will trigger additional allowances via the volume driver mechanism.

3.66. The business plan estimated that the 1168MW would be connected by 2017-18. SHE Transmission currently estimates that this level will be met in 2018-19 (a one year delay) and is anticipating to exceed the licence output by 639.9MW (total 1.8GW) by the end of the price control. This year's forecast of total capacity is a reduction on last year's 2.1GW forecast (a fall of 244 MW or 12%).

3.67. At the time of the business plan submission the output expected to be delivered within the 2015-16 reporting year was 559MW. SHE Transmission reports that a reduced level (125MW) of sole use connection was delivered by the end of 2016. This reduction is the result of terminations to some generation schemes and consenting delays with wind farm developments.

3.68. SHE Transmission has delivered a cumulative sole-use output of 491MW[48] during the first three years of RIIO-ET1, which is below the business plan forecast of 896MW. This reduced delivery is the result of the level of terminated schemes (c.560MW), where the infrastructure is no longer required, outweighing the amount of additional generation schemes delivered (c.150MW) during this period.

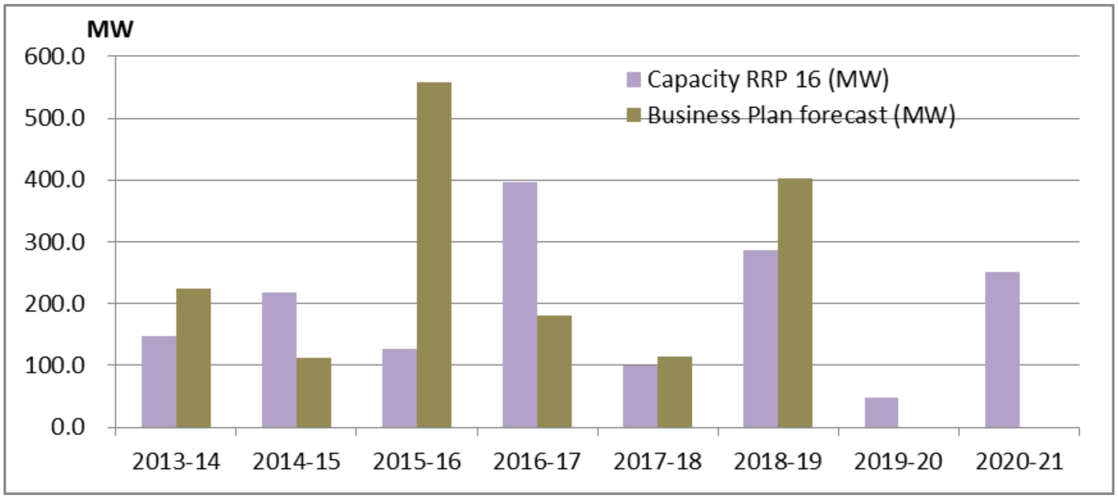
3.69. Figure 6 demonstrates the change in profile and volume of sole-use capacity by comparing the volume provided as part of the business plan submission with the volume that SHE Transmission currently projects to deliver over the RIIO-ET1 period. This represents the licence funding mechanism referred to as "LR5"[49].

included based on contracted best view forecast positions.

[48] 0MW of atypical sole-use connections was connected during the first three years.

[49] The profile of connection expected under the funding mechanism referred to as "LR6" (atypical sole-use connections) is not included in Figure 6. SHE Transmission currently expects to deliver 235MW in the next five years of the RIIO-ET1 period.

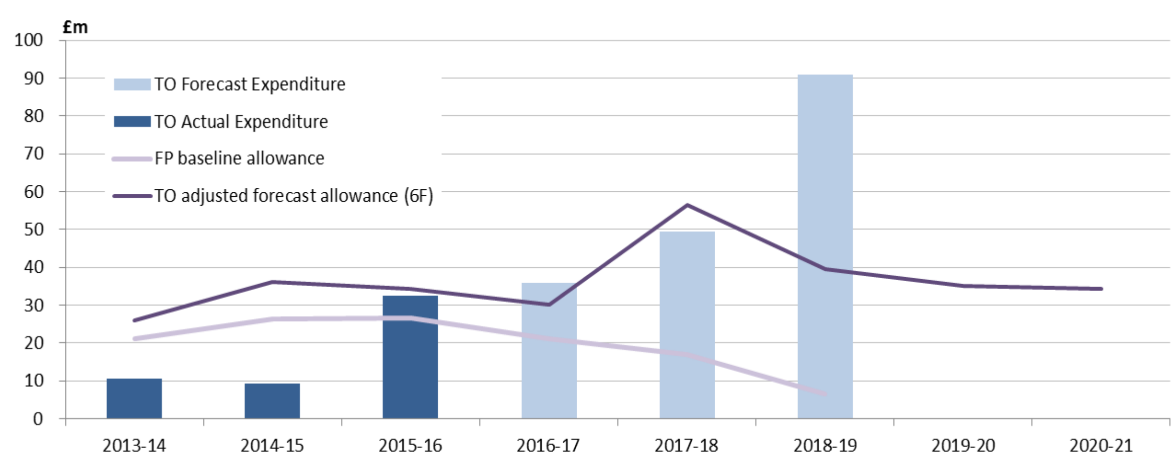
Figure 6: Comparison of actual and forecast sole use capacity volume delivery



3.70. SHE Transmission currently forecast £283m expenditure on generation connections with a sole use infrastructure element (2015-16 prices); this includes £129m on typical schemes and £154m on atypical schemes across RIIO-ET1. This forecast level of expenditure is broadly comparable with the forecast level of total allowance in the connection of generation with a sole-use infrastructure element.

3.71. Figure 7 below demonstrates the level of underspend SHE Transmission currently expects in the delivery of the sole-use generation connection licence target.

Figure 7: Actual and forecast expenditure vs TO forecast allowance to deliver 1168MW of sole use capacity[50]: SHE Transmission



[50] This is the cumulative spend and allowance for typical and atypical connections.

3.72. The baseline package also provided SHE Transmission with a level of funding for the construction of shared-use infrastructure (£100m in 15/16 prices) associated with the delivery of 'typical' schemes[51]. Delivery of capacity in excess of this threshold (and atypical schemes) will trigger additional allowances via the volume driver mechanism.

3.73. SHE Transmission currently estimates that the output threshold (1006MVA) will be delivered by the end of 2017, which is earlier than the licence expectation.

3.74. At the time of the business plan submission the expected shared use infrastructure output expected to be delivered during 2015-16 was 420MVa. SHE Transmission reports that an increased level (824MVa) of cumulative shared use infrastructure was delivered by the end of 2016.

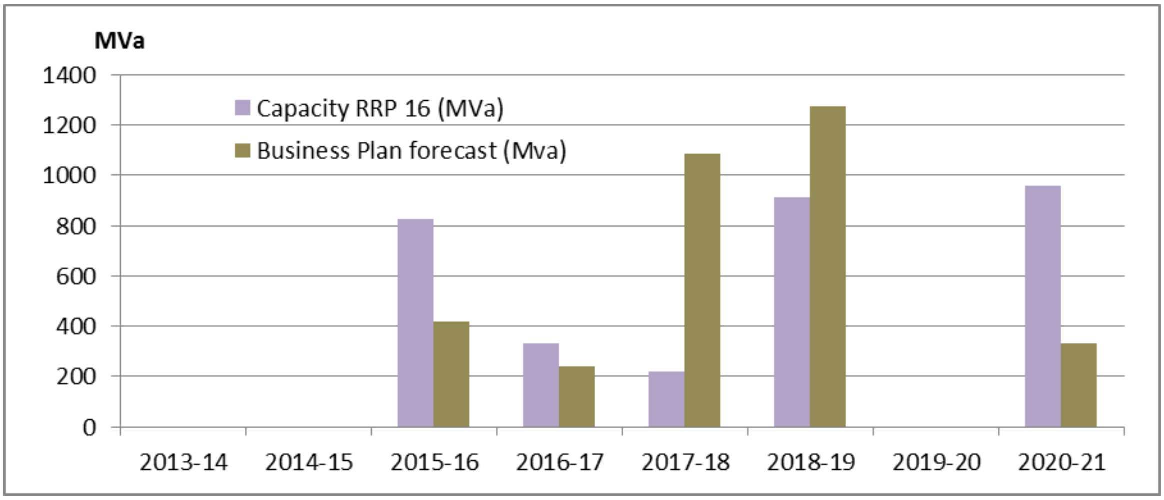
3.75. This increased delivery is the result of delivery of three schemes within the 2015-16 reporting year. Across RIIO-ET1, SHE Transmission anticipates the delivery of c.2.24GVA above the baseline threshold to be provided through the connection of typical generation schemes.

3.76. When taken together the expected shared use infrastructure output currently expected to be delivered across RIIO-ET1 is c.3.3GVA; 2.3GVA above the baseline. The total forecast capacity is a reduction on last year's RIIO-ET1 6.25GVA forecast (a fall of c.2.9GVA). This drop is driven by terminations, delays to customer infrastructure works and changes to the contracted position expected in the business plan.

3.77. Figure 8 demonstrates the change in shared-use infrastructure capacity by comparing the volume provided as part of the business plan submission with the volume that SHE Transmission currently projects to deliver over the RIIO-ET1 period. This represents the licence funding mechanism referred to as "LR7"[52].

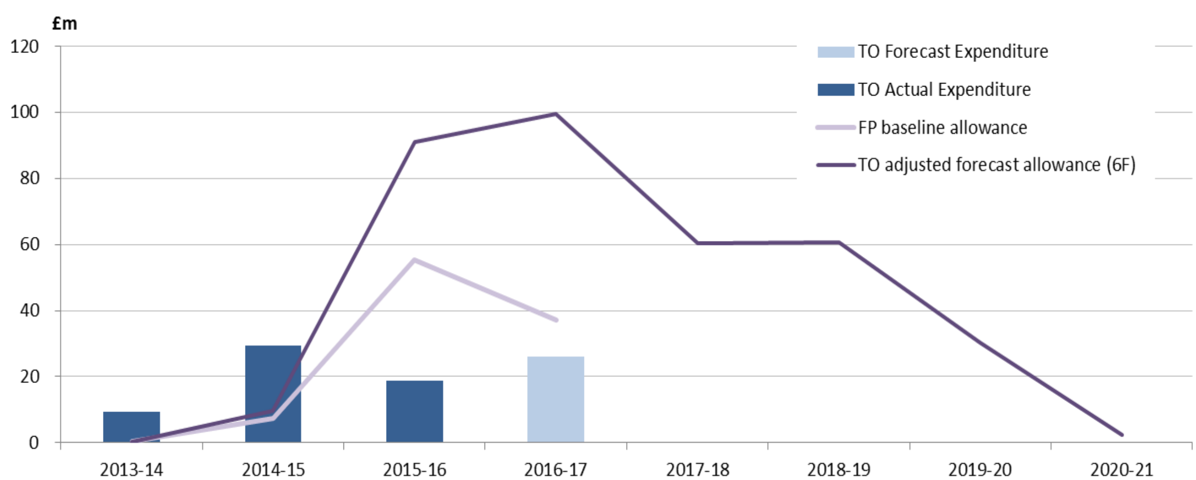
[51] Which have a unit cost of less than £166k/MW (unit cost expressed in 2009-10 prices).
[52] The profile of connection expected under the funding mechanism referred to as "LR8" (atypical shared-use) is not included in Figure 8. SHE Transmission currently expects to deliver 73MVa in the final year of RIIO-ET1.

Figure 8: Comparison of shared use capacity volume delivery



3.78. Overall expenditure on generation with a shared use infrastructure element is currently forecast to be £294m; of which the vast majority (£264m) is connected with the planned delivery of typical schemes. This forecast level of expenditure is 17% below the current estimate of funding SHE Transmission expects to receive across RIIO-ET1. Figure 9 below demonstrates the level of underspend SHE Transmission currently expects in the delivery of the 1006MVa threshold.

Figure 9: Actual and forecast expenditure vs TO forecast allowance to deliver 1006MVa of shared use capacity: SHE Transmission



3.79. SHE Transmission provides a view of the total adjusted allowances available under condition 6F. This view is formulated by assessing its "best view" of the contracted generation scenario and reflects the progression of schemes that it believes will trigger additional allowances through the volume driver mechanism. These allowances are based on a mixture of actual delivered schemes and forecast schemes to be delivered.

3.80. In aggregate, the total allowance under the licence based mechanism is estimated by SHE Transmission to be £647m across RIIO-ET1. SHE Transmission currently anticipates that it will underspend against the adjusted totex allowance by £71m (11%). We will continue to work with SHE Transmission to keep under review both its forecasts and the implications these have through the revenue adjustment mechanisms in the licence.

Local Demand Connections (Exit): NGET

3.81. NGET has seen a significant fall in terms of demand connections, reducing the number of supergrid transformers (SGTs) required across RIIO-ET1 from 72 to 48. This has been matched by a reduction in the length of OHL to provide local demand connections, from a length of 27km to 5.42km across RIIO-ET1 (all of which was commissioned by the end of 2015-16). NGET anticipates no new cable routes across RIIO-ET1 which is consistent with the business plan and forecast position.

3.82. Ten SGTs have been completed by 2015-16. The business plan forecast a total of 18 SGTs to be built between 1 April 2013 and 31 March 2016[53]. Expenditure in 2015-16 is £79m which is £40m higher than the level of baseline allowance for 2015-16. NGET overspent by almost £60m against the updated view of the allowance for 2015-16 (£20.5m). This overspend is largely driven by the costs of three schemes delayed from TPCR4 and new customer connections not foreseen at that time (network rail and DNO connections).

3.83. NGET's cumulative expenditure was £162.6m for the first three years of RIIO-ET1. This is 16% above the baseline allowance set at FPs (£139.9m) and 88% above NGET's updated view of the allowance for this period (£86.6m).

3.84. Overall expenditure is currently forecast by NGET to be £227.8m across the price control. NGET forecasts that the operation of the uncertainty mechanism will reduce its allowance by £84.2m to adjust for outputs in the RIIO-ET1 period that are no longer anticipated to be required by customers. NGET currently anticipates an overspend of 18%, or £35m, relative to NGET's forecast totex allowance across RIIO-ET1 (£193m).

Local Demand Connections: SHE Transmission

3.85. SHE Transmission is not forecasting to deliver any local demand connections for which it has allowances (the business plan included a £36.1m allowance for a demand

[53] Due either to delay (customer connection variations) or because the need case from the customer has been withdrawn.

scheme on Shetland that has since terminated). Any unspent allowances will be shared with consumers[54].

Local Demand Connections: SPT

3.86. On the exit connection side, SPT is planning to deliver the same schemes that were provided as part of the business plan submission (mainly Grid Supply Point reinforcement works).

Incremental wider works[55]

3.87. 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 (NDP).

Capacity delivered

3.88. NGET has a number of IWW schemes. NGET delivered 500MW of boundary capacity within the 2015-16 reporting year which is 3.1GW below baseline level of additional annual boundary capacity expected. The reduction in capacity has occurred because the driver for these investments has been delayed - in some cases beyond RIIO-ET1 - following successive iterations of the NDP.

3.89. The delivery performance in 2015-16 is in contrast to NGET's cumulative capacity delivery in the first three years of RIO-ET1; an additional 500MW of capacity has been delivered above the 6.4GW defined in the baseline.

3.90. Baseline allowances were set on the basis of NGET's expected delivery of 23.1GW of boundary reinforcements over the RIIO-ET1 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. NGET's latest forecast is that only 14.6GW of boundary reinforcements will be required across the price control (a reduction of 8.4GW).

Costs versus allowance

3.91. NGET has spent £36m within the 2015-16 reporting year, which is £282m (89%) below the level of baseline allowance set at FPs. Across the first three years of RIIO-ET1, NGET reports a cumulative underspend of 63% compared to the cumulative (unadjusted) baseline allowance for this period.

[54] SHE Transmission is forecasting to deliver £9.4m of reactors in place of the Shetland local demand schemes over next two years. The net underspend is currently forecast to be £26.7m.
[55] Detailed in Special Condition 6J of NGET's licence.

3.92. NGET anticipates that the licence mechanism will substantially reduce baseline allowances across the RIIO-ET1 period (by almost 60%) to take account of the outputs that are not being delivered due to changes in customer requirements. As a result, NGET is currently forecasting to spend £90m (19%) below NGET's updated view of the cumulative allowance in the first three years (£462m[56]) and £156m (18%) below the RIIO-ET1 allowance of £858m. 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.

Environmental output measures

Limiting sulphur hexafluoride (SF_6) emissions

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

3.94. Both NGET and SPT outperformed against target emissions levels of SF_6 in 2015-16 and, based on the information we currently have, will receive a financial reward of approximately £2.5m and £0.2m respectively. SHE Transmission slightly underperformed against its target emissions level and will therefore be penalised by £0.05m under the SF_6 incentive mechanism. All the three TOs are reporting an annual improvement in their scores against the targets over the first three years of the price control.

3.95. 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. 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.[57]

3.96. The performance figures in Table 11 below have been amended based on these updated leakage figures and Authority decisions. [58]

3.97. The net impact of these adjustments is that SHE Transmission will, based on the information we currently have, be penalised by approximately £0.4m for their SF_6 leakage in RIIO-ET1 to date, while SPT and NGET will receive a cumulative reward of £0.1m and almost £7m respectively.

[56] Excluding items associated with TPWW.
[57] 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
[58] We have yet to confirm the impact of errors in NGET's and SHE Transmission's SF6 inventory. The effect of the error is likely to be a minor increase in its leakage target.

Table 11: Three year SF_6 performance – leakage above or below target as percent of annual target[59]

SF6	NGET			SHE Transmission			SPT		
	2013-14	2014-15	2015-16	2013-14	2014-15	2015-16	2013-14	2014-15	2015-16
Target (kg)	11,933	12,035	12,097	151	173	224	573	592	619
SF6 leakage (kg)	10,110	9,544	9,502	335	339	272	730	495	441
Performance compared to target (negative number represents outperformance)	-1,823	-2,491	-2,595	184	166	48	156	-97	-178

Business carbon footprint (BCF)

3.98. 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 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.

3.99. Table 12 below shows the BCF reported in the first three years of the price control by the three transmission companies in terms of tonnes of carbon dioxide equivalent.

Table 12: BCF in terms of tonnes of carbon dioxide equivalent per licensee in 2013-16

Year	*NGET*	*SHE*	*SPT*
2013 - 14	2,259,286	187,267	237,596
2014 - 15	2,552,420	346,176	252,944
2015 - 16	2,270,683	306,158	204,884

3.100. 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 (e.g. connection of renewables far from areas of high demand) and so year-on-year comparisons of BCF are not a suitable metric of efforts to reduce carbon emissions.

[59] A positive number indicates higher than target leakage volumes and hence underperformance.

Losses

3.101. In order to help provide long term value to consumers, all onshore TOs have a reputational incentive to reduce transmission losses where they can do so. To date all three TOs have complied with the licence condition by putting strategies in place to reduce losses on their networks and by reporting against these annually.

Table 13: Historical annual losses from the GB transmission system[60]

Losses (%)	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16
NGET	1.62	1.59	1.77	1.4	1.8	1.67	1.57	1.65	1.17
SHE Transmission[61]	2.38	2.86	2.59	2.55	3.04	3.05	3.55	4.18	3.26
SPT	2.17	1.81	1.46	1.54	1.47	1.3	1.29	1.17	1.13
GB losses	**1.75**	**1.73**	**1.82**	**1.49**	**1.92**	**1.72**	**1.7**	**1.84**	**1.77**

3.102. 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.

3.103. 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. SHE Transmission reported losses at 8.04% in 2014-15, which even compared to its own historical levels, was far higher than expected. In its 2014-15 regulatory submission and in subsequent correspondence, SHE Transmission suggested that the increased losses were wholly attributed to increased generation in it transmission area associated with higher demand and export to the SPT transmission area. Following instructions from Ofgem to further investigate the cause of the reported increases, SHE Transmission engaged with the system operator and carried out system modelling to identify the precise causes of this increase and the specific circuits affected.

3.104. A separate investigation subsequently uncovered a metering error at the Arbroath bulk supply point (BSP) caused by an incorrectly wired current transformer that was installed in May 2014. This had resulted in the meter recording an export of energy instead of an import.

[60] http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/transmission-losses/

[61] The 2014-15 and 2015-16 figures for SHE Transmission are the corrected values.

3.105. ELEXON were made aware of this issue, and the metering error was corrected through normal and post-final settlement runs. The resolution of this incident also included a Trading Dispute (DA797) raised by ELEXON with an estimated materiality of £23.6m. Once the Arbroath BSP metering error is corrected for, the differences in energy losses between 2013-14 and 2014-15 are significantly reduced.

3.106. SHE Transmission has reported the findings of its investigation to us[62]. We will continue our dialogue with SHE Transmission to establish the lessons learned from this process and any other actions on its part to avoid a re-occurrence of such data discrepancies.

3.107. We are concerned there appears to have been a lack of engagement between SHE Transmission and the SO to discuss and resolve the anomalous losses figure reported for 2014-15. This is at odds with our understanding of the internal assurance process applied by SHE Transmission. Going forward, we would expect all companies to adopt a more pro-active approach to sense checking and resolving areas of discrepancy when they arise.

Environmental discretionary reward

3.108. The Environmental Discretionary Reward (EDR) is a reputational and financial incentive for electricity transmission licensees. It also takes account of National Grid's dual role as both TO and SO. 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.

3.109. 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.

3.110. In 2014-15, all three electricity TOs applied to the voluntary scheme but only National Grid were successful, and received a reward of £2 million. In this scheme year (2015-16) all three companies applied, but only Scottish Power Transmission was able to demonstrate leadership performance. As a result, it has achieved a reward of £4 million.

[62] The report can be found on SSEPD website: https://www.ssepd.co.uk/TransmissionPriceControlReview/

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 14: EDR performance in 2015-16[63]

Company	Performance Band	Financial Reward
SPT	Leadership	£4 million
NGET	Proactive	None
SHE Transmission	Engaged	None

Visual amenity[64]

3.111. We have made an allowance of c.£600m (2015-16 prices) available across the RIIO-ET1 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.

3.112. We understand that NGET is developing potential proposals to mitigate the visual impact of overhead lines in the 12 areas shortlisted (571km) and endorsed for the work by the stakeholder advisory group in 2014-15. Four locations have been prioritised for under-grounding sections of high voltage lines, namely: Dorset (near Winterbourne Abbas), New Forest National Park, Peak District National Park and the Snowdonia National Park. NGET currently expects to submit a funding assessment request to Ofgem in 2017, which will include cost estimates for each of the four schemes.

3.113. No schemes to improve visual amenity have yet been proposed in the designated areas by the two Scottish TOs, although SPT have initially identified that 136km of overhead line is eligible for consideration under this mechanism. SPT indicates that it is preparing a policy document during 2016-17, with proposals to be submitted thereafter.

3.114. SHE Transmission, under Special Licence Condition 6G, submitted a policy document to Ofgem in May 2016. A further review of the lines identified for visual amenity works has resulted in the total length of lines increasing from 429km to 505km; the number of substations remains the same, at 16.

[63] Ofgem's decision was published on 2 December 2016: https://www.ofgem.gov.uk/system/files/docs/2016/12/edr_decision_letter.pdf
[64] Special Condition 6G of the licences

4. Innovation

Chapter Summary

This chapter presents an overview of TOs' expenditure in relation to the various innovation incentives in RIIO-ET1

Introduction

4.1. The RIIO innovation mechanisms help to deliver our intention of making innovation core to how network companies facilitate the transition to a low carbon economy. We recently consulted on proposed changes to the governance arrangements of the Network Innovation Competition (NIC) and Network Innovation Allowance (NIA).[65] We will issue our decision in the coming months.

Network Innovation Allowance (NIA)

4.2. The NIA was established as part of the RIIO-ET1 price control. It is designed to fund small scale research, development and demonstration projects. The NIA provides each licensee with an allowance to spend on innovation projects in line with the NIA Governance Document.[66] This year all licensees have registered further NIA projects. If successful, these projects should bring a wide variety of financial, operational, environmental and safety benefits.

4.3. Licensees have already begun to develop useful learning from this investment. Details on all the registered NIA projects can be found on the Energy Network Association's (ENA's) Smarter Networks Portal.[67] We are pleased that the NIA is being used by the network companies, and have seen some improvement in the standard of companies' annual summaries, which provide information on how companies have used their allowance. We have provided links to them in table 15 below.

4.4. However, looking forward, we are keen to ensure that:

- We receive sufficient information from network companies on why their projects are eligible for NIA funding and would not be carried out under business as usual.
- Learning is being shared effectively across the sector.

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[65] https://www.ofgem.gov.uk/publications-and-updates/network-innovation-review-our-consultation-proposals
[66] 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.
[67] http://www.smarternetworks.org/

Table 15 – Company activity under the NIA

Company	Total number of projects since 2013	Expenditure £m/ % of allowance used	2013-14	2014-15	2015-16
NGET[68]	131	NIA Expenditure (£m)	6.1	10.0	9.6
SPT[69]	22	NIA Expenditure (£m)	0.6	0.7	0.8
SHE Transmission[70]	14	NIA Expenditure (£m) [71]	1.2	1.3	1.1

Network Innovation Competition (NIC)

4.5. The NIC is an annual competition to which both electricity transmission and distribution companies can apply. It provides funding to a small number of large-scale innovation projects. Its aim is to encourage network companies to innovate in the design, build, development and operation of their networks. If successful, these projects should bring a wide variety of financial and environmental benefits.

4.6. Trials financed through the NIC will generate learning for all network companies and will be made available to all interested parties. In 2015, three electricity transmission projects were selected by us to receive a total of £26.7m of funding.

68 NGET's Annual Summary of NIA Activity is available here
69 SPT's Annual Summary of NIA Activity is available here
70 SHE Transmission's Annual Summary of NIA Activity is available here
71 SHE Transmission do not have a cap on their annual NIA allowance – they have a cap on their allowance for the whole price control period. Their spending against the cap will be reviewed by us at the end of the RIIO-ET1.

Table 16 –Projects selected for funding in the 2015 NIC

Project Title	Lead company	Description	NIC funding awarded (£m)	Total project costs (£m)*	Project end date
Offgrid Substation Environment for Acceleration of Innovative Technologies (OSEAIT)	NGET	The project will convert an existing substation into a trial centre for innovation projects. 14 projects will conducted and provide learning to inform network licensees' RIIO-T2 business plans. The trials will develop unconventional technologies and practices, extend the operational life of ageing assets, and accelerate the implementation of innovation.	£12.0m**	£26.0m	2020
New Suite of Transmission Structures (NeSTS)	SHE Transmission	The project will create a new type of electricity transmission pylons that are smaller, better for the environment and could result in financial savings for customers.	£6.6m	£7.5m	2022
Future Intelligent Transmission Network Substation (FITNESS)	SPT	This project will create GB's first live digital substation. If successful, the project will reduce future costs associated with new and replacement substations while reducing environmental impact and land requirements.	£8.3m	£10.8m	2020

*Includes other contributions e.g. from project partners or the network company shareholders.

** The level of NIC funding required for this project is expected to be reduced, due to lower construction costs identified by NGET; savings will be returned to consumers.

4.7. Further information on these projects can be found in our funding brochure[72] and the companies' full submissions which are published on our website[73].

Innovation Rollout Mechanism (IRM)

4.8. 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.

4.9. In May 2015, SPT applied for, and was granted, £24.3m of funding under the IRM to deploy a high temperature low sag conductor[74]. This conductor will allow SPT to connect additional generation to its network without the need to completely rebuild circuits. This is expected to deliver savings to customers by reducing the cost of adding new capacity to the network. No expenditure has been reported as yet, as the associated expenditure will take place in 2016-17 and 2017-18.

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[72] https://www.ofgem.gov.uk/publications-and-updates/2015-innovation-competitions-brochure
[73] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition
[74] National Grid: https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition/national-grid-electricity-transmission
SPT: https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition/scottish-power-transmission-limited
SHE Transmission: https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition/scottish-hydro-electric-transmission-plc

5. Analysis of expenditure vs allowance

Chapter Summary

This chapter evaluates actual and forecast expenditure for electricity transmission against the costs allowed in the RIIO-ET1 settlement. The focus is on load and non-load capital expenditure, since those categories form the majority of TO spend.

Introduction

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

5.2. LRE relates to the installation of new assets on the network to accommodate changes in the level or pattern of electricity generation and demand. NLRE is to maintain the existing network including through asset replacement. Together, LRE and NLRE make up approximately 90% of TOs' forecast totex, and therefore is an important focus of our analysis.

5.3. We present some high level analysis of the drivers of the deviation of TOs' capital expenditure (capex) from their allowances from the price control agreement and assess the TOs' performance on capital delivery against the TOs' view of adjusted allowance. We conclude the chapter with a look at non-operational capex[75] and operating costs (opex).

5.4. Two scenarios of TOs' allowance are presented in our analysis: (i) their allowances from the price control agreement (Final Proposals baseline allowance), and (ii) the outcome of revisions that reflect each company's own view of the value of allowances at the end of the eight year price control period (TO forecast adjusted allowance). The TO forecast view is based on the baseline allowances, but with the changes applied through operation of the uncertainty mechanisms to reflect the current levels of outputs and the company's current forecast of future outputs in the remaining RIIO-ET1 period.[76]

5.5. The totex values summarised in this chapter are not adjusted for the current forecast "true up" of allowances to remove the gap between the allowance for excluded

[75] This covers expenditure on equipment not directly related to the transmission operations, for example, IT capital expenditure
[76] TO adjustments reflect changing circumstances. For example, downward adjustments may reflect a current view that certain outputs are no longer required or the licence target will not be met in the eight year period.

services income and the associated costs[77]. The numbers also exclude the impact of the MPR decision.

5.6. Appendix 2 sets out more detail on the potential impact of the true up using the TOs' estimate of the current gap that exists between allowances and costs included in the 2015-16 reporting pack forecast. Appendix 3 summarises the proposals for changes to RIIO-ET1 allowances as a result of our MPR decision.

Totex performance and forecasts

5.7. The combined allowed Totex for the TOs in the reporting year 2015-16 was £2,539m. Actual expenditure was £2,042m; an underspend of £496m or 20%. NGET and SHE Transmission underspent compared to their 2015-16 allowed Totex by 16% and 35% respectively and SPT overspent by 2%, see Table 17.

5.8. NGET, in its role as SO, underspent compared to their 2015-16 allowed totex by 3% (£4m) in the reporting year 2015-16. The SO performance is discussed in chapter 6.

Table 17: Company view of allowance vs actual expenditure in 2015-16 (£m)

£m 2015-16 Prices	NGET TO	NGET SO	SHE Transmission	SPT
Total allowed expenditure	1,377	141	811	351
Actual expenditure	1,161	137	524	358
Overspend (underspend) £m	-216	-4	-287	7
Overspend (underspend) %	-16%	-3%	-35%	2%

The figures are based upon the TOs' published values; pre true-up and exclude the impact of the MPR decision. Actual expenditure here has not been modified by underspend/overspend sharing and therefore differs to the actual Totex reported in table 1 in chapter 2.

Actual expenditure 2013-16

5.9. Each TO is reporting a cumulative out-performance relative to the adjusted baseline allowances across the first three years of the RIIO-ET1 price control. The TO's view of the cumulative three year allowance in 2015-16 was £7,598m, and actual expenditure was £5,620m; an underspend of £1,948m or 26%, see Table 18.

5.10. NGET, as SO, reported a cumulative out-performance of £23m (5%) relative to its published allowed totex value across the first three years of the price control (£428m).

[77] More information on the true up is available in this document: https://www.ofgem.gov.uk/ofgem-publications/53602/4riiot1fpfinancedec12.pdf (paragraph 2.17) and letter https://www.ofgem.gov.uk/ofgem-publications/53571/sptlshetplcupdateletter-21122012.pdf (page 3).

RIIO-ET1 company view

5.11. Based on the information provided to us through the 2015-16 regulatory reporting pack, over RIIO-ET1, the TOs currently expect to spend almost £17 billion. This represents actual totex for 2013-16 plus a five years forecast spend for 2016-21. The combined allowed Totex for the TOs across the period is currently forecast to be £18.8bn; a cumulative forecast underspend of 12% (£2.16 billion). All TOs currently anticipate a position of underspend across the price control.

5.12. NGET, as SO, currently forecasts a total underspend of £18 million (2%) relative to its published allowed totex value across the RIIO-ET1 price control (£1.16 billion).

Table 18: Adjusted allowance vs expenditure (£m)†

	Cumulative performance: 2013-16				*Current RIIO-ET1 Forecast: 2013-2021*			
	Allowance	Actual Expenditure	Difference		Allowance	Actual & Forecast Expenditure	Difference	
			£m	%			£m	%
NGET	4,930	3,683	-1,248	-25%	13,380	11,652	-1,728	-13%
SPT	1,197	891	-306	-26%	2,337	2,212	-126	-5%
SHE Transmission	1,440	1,046	-395	-27%	3,078	2,770	-308	-10%
Total	7,568	5,620	-1948	-26%	18,795	16,633	-2,162	-12%

† The figures are based upon the TOs' published values; pre true-up and do not reflect the impact of MPR. Actual Totex here has not been modified by underspend/overspend sharing..

5.13. Figures 10, 11 and 12 illustrate the annual profile of actual and forecast expenditure and allowance across the price control. The values show the performance to date and forecast expenditure for all three TOs against their current view of adjusted totex allowances. These forecasts are based on TOs' calculations.

5.14. However, there is significant uncertainty with some investment projects included in the price control information received from the TOs. RIIO-ET1 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. The values presented above include the TOs' current cost forecasts for such project.

5.15. The later sections of this chapter give more detail on the specific circumstances of each of the TOs' performances against their allowances under each cost category.

Figure 10: Actual and forecast expenditure vs TO forecast allowance[78]: NGET

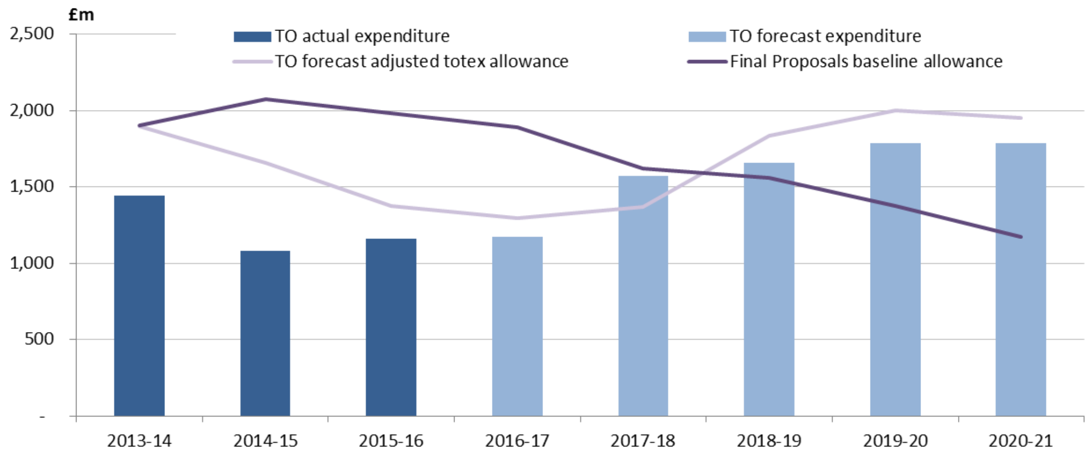
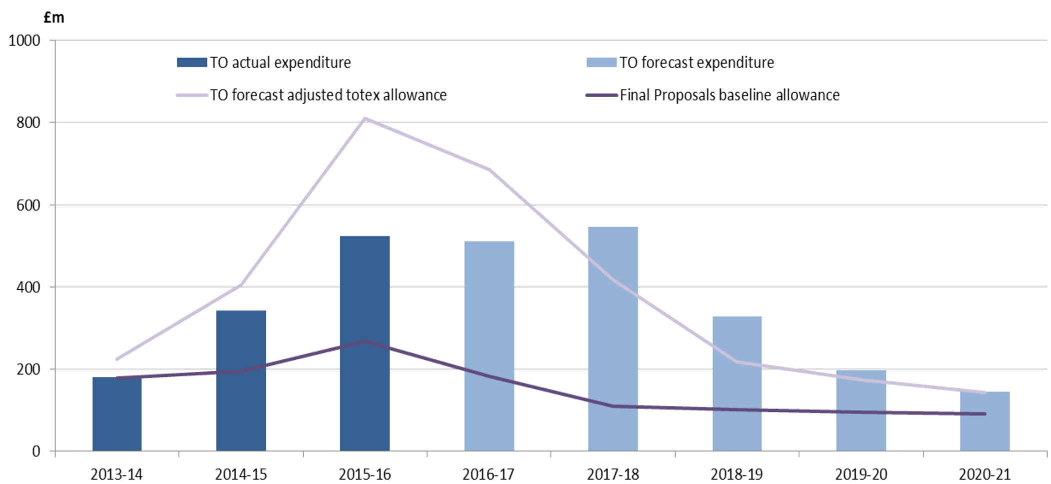
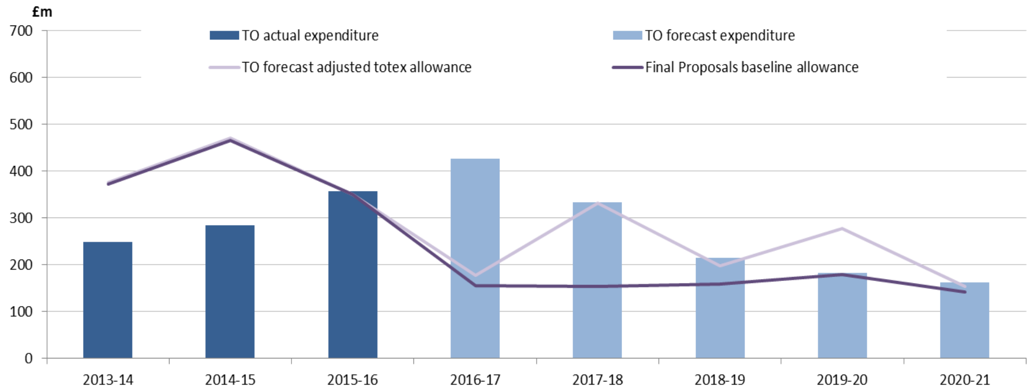


Figure 11: Actual and forecast expenditure vs TO forecast allowance: SHE Transmission



[78]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 12: Actual and forecast expenditure vs TO forecast allowance: SPT[79]



5.16. Appendix 2 updates the figures presented above to exclude the TOs' current forecasts for load-related investments which Ofgem have yet to approve; namely: SWW 'not yet approved' - applicable to NGET and SPT, and the term referred to as 'TPWW' - applicable to NGET only[80]. Appendix also includes further adjustments we have made to published values in the costs categories of non-load related, non-operational capex and opex.

Load-Related capex (LR capex)

5.17. LR capex is the investment on the network to accommodate changes in the level or pattern of electricity generation and demand. This is split further into a number of funding mechanisms, the largest of which 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. There are also mechanisms with provisions for undergrounding cables and for mitigating works on the electricity distribution systems ('DNO mitigation').

5.18. The capex allowance for these elements comprises a baseline level, reflecting a 'best-view' business plan by the TOs, augmented by mechanisms to flex the allowance in accordance with the actual outturn demand and consequential system-wide requirements. There are also 'non-variant' allowances that reflect envisaged general

[79] SPT's licence (Special Condition 6H) contains provision for the award of additional allowances to fund five overhead line replacement schemes. SPT has included the cost of these schemes (£36m) in its overall forecasts. These costs are included in this analysis. Appendix 1 updates the figures to exclude the cost of the schemes from its overall forecasts.

[80] Detailed in Special Condition 6J of NGET's licence, TPWW is a licence term that refers to the costs and income associated with wider works that are delayed by the implementation of the NDP. The licence terms TPG and TPD relate to costs and incomes that are associated with customer-driven terminations. This year is the first time that NGET is seeking to utilise the licence term TPWW. There are other schemes that have also been delayed, but the reconductoring scheme is the only one whose output was to be delivered in 2015-16.

system reinforcement to facilitate the achievement of specific outputs, but were mostly not associated with the delivery of specific outputs in their own right.

5.19. As part of the RIIO-ET1 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.

5.20. 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 been granted approval for project funding under the SWW mechanism.

NGET

5.21. In setting the price control, Ofgem used a baseline allowance to reflect its expectation of c.£4.5 billion of varying costs (that change in line with measurable outputs) and c.£1.4 billion of non-variant costs (for works that are needed but do not deliver a directly measurable output such as MW)[81]. Both allowances were set based on a list of projects proposed by NGET, but only a small proportion of the non-variant allowance was explicitly specified as outputs in order to maintain flexibility of the sources of load expansion.

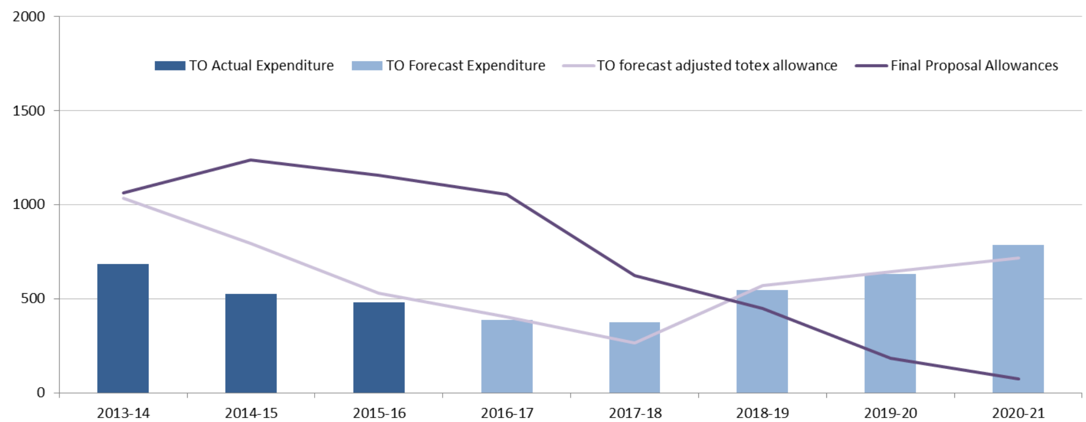
5.22. Baseline allowances were set on the basis of a baseline of 33GW of generation connecting over the RIIO period. Now in the third year of the price control, NGET's connection profile is estimated as 14GW. Demand connections have also fallen. These changes will lead to a downward adjustment to the allowances across the price control period.

5.23. 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-ET1. A significant proportion of these cancellations or deferrals are associated with the non-variant funding allowance.

5.24. In aggregate, NGET has underspent its revised LRE allowances over the first three years of the control by £663m, and is forecasting to underspend its revised allowances over the 8 year period by £544m. These values reflect the TO's published figures.

[81] A total load related baseline allowance £4,861m (2009-10 prices; £5,845m in 2015-16 prices) was set at Final Proposals. This value includes RPEs and is net of exit sole-use customer capital contributions estimate provided by NGET in 2012.

Figure 13: Actual and forecast expenditure vs TO forecast LR allowance: NGET



5.25. Figure 13 demonstrates the impact of the fall in LR workload across the price control period. Overall, NGET is forecasting a net LR expenditure of £4.4 billion. NGET estimates that LR allowances will scale downwards from £5.8 billion (set at FPs) to c.£5 billion across the price control period as a result of changes in requirements.

5.26. We have broken NGET's deviations from allowance into three categories:

- Delays/cancellation of work not subject to uncertainty mechanisms;
- Changing work scopes; and
- Additional works not originally funded.

Delays/cancellations

5.27. At the time of setting the price control the non-variant baseline amounted to £1.4 billion. We have reviewed the main elements of the NGET's expenditure against its original Business Plan (BP), to understand the key drivers for underspends against this element of NGET's LR allowance. These fall into two areas:

- Schemes in the BP that are no longer required
- Schemes in the BP that might be required during RIIO-ET1

5.28. Schemes in the BP that are no longer required: A total of 16 schemes that were identified as being necessary at FPs are deemed to be no longer required. These comprise £208m of the non-variant allowance. The majority of the BP was intended to accommodate a projection of renewable generation growth that has not materialised. Consequently, a number of schemes that were considered as essential for this system expansion are no longer required (e.g. London ring upgrade). We will further investigate the inclusion of schemes purely driven by the Gone Green (GG) scenario with NGET.

5.29. Schemes that might be required: This relates to two schemes, namely the Humber Smartzone and a rebuild of the Walpole 400kV substation. Since the generation that is driving these projects is delayed, NGET’s current assumption is that they will be delayed beyond the RIIO-ET1 period. This would result in underspend of £130m.

Changing work scopes

5.30. We have conducted a licence funding mechanism-by-mechanism review of expenditure and forecast allowances to assess whether scheme allowances are scaling directly with outputs delivered over the control period to date. This analysis has also considered whether there is any systemic over/underperformance between schemes that were in the BP and new schemes.

5.31. One area stands out in respect of this analysis; Incremental wider works excluding TPWW (referred to as “LR14”). Incremental wider works provide reinforcements to the major system boundaries; work under this mechanism is triggered by the system operator’s Network Options Assessment (NOA). On one of these schemes, NGET has chosen to reconductor the Fleet-Lovedean double circuit at a cost of £28m, but the volume driver allowance is £439m. The allowance is determined by a fixed UCA and the output (the volume) determined through the Network Development Process (now NOA). We note the requirement for these work remains subject to the NOA, to ensure economic decisions are made and this may change in the future.

Additional work not originally funded

5.32. NGET has chosen to proceed with work under the SWW program, although these have not yet been awarded specific allowances by Ofgem. The major expenditures under this category include preconstruction on the Hinckley-Seabank and Moorside schemes.

5.33. New schemes: There are eight small schemes that weren’t envisaged at the time of the BP but are now deemed necessary. This accounts for expenditure of just under £12m. Furthermore, NGET is now forecasting a higher need for voltage control due to a number of factors, including more embedded generation than expected. It plans to spend approximately £200m on shunt reactors; 65% of which is forecast to be incurred in the remaining five years of RIIO-ET1. The total cost includes £116m for shunt reactors at 25 identified sites and a further £84m provision for shunt reactors at as yet unspecified sites and to accommodate the growth in embedded generation.

Other factors

5.34. Deviations against allowance will also be driven through cost differences driven by a number of factors, e.g.:

- Efficiency/inefficiency
- Market movements
- Unit cost over/under-estimation when setting RIIO-ET1.

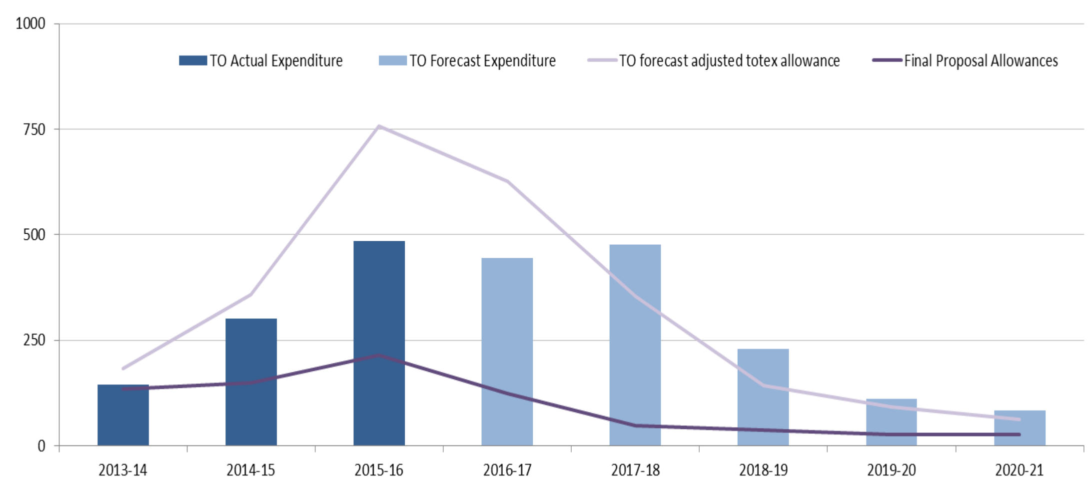
5.35. We discuss the impact of input price changes in more detail later on in this chapter. We have not been able to identify the material factors contributing to performance in the above categories and we will continue to improve our understanding and estimates of them through to the end of RIIO-ET1.

SHE Transmission

5.36. A number of significant changes within the first three years of the price control have affected SHE Transmission's workload. Infrastructure works have increased and, in terms of expenditure, Ofgem has approved three Strategic Wider Works schemes; Caithness-Moray, Kintyre-Hunterson and Beauly-Mossford.

5.37. In 2015-16, SHE Transmission has underspent on load-related capital expenditure by £273m against its revised allowance of £758m, see figure 14. Most significant are the c.£100m underspend for the delivery of Wider Works outputs, an underspend of c75m associated with generation connections with shared use infrastructure ('UM2' works) and a c.£50m underspend on the exit-connection side.

Figure 14: Actual and forecast expenditure vs TO forecast LR allowance [82]: SHE Transmission



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

5.38. Overall, SHE Transmission's RIIO-ET1 net expenditure is forecast as £2,278m against an expected allowance of £2,578m. This indicates an outperformance of £300m for the total load-related balance over the RIIO-ET1 period (pre true-up).

5.39. 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 with SHE Transmission to understand how this mix has led to underspend. In particular, we are looking to understand whether any underspend is driven by new schemes being progressed which are fundamentally lower cost than the volume driver allowances.

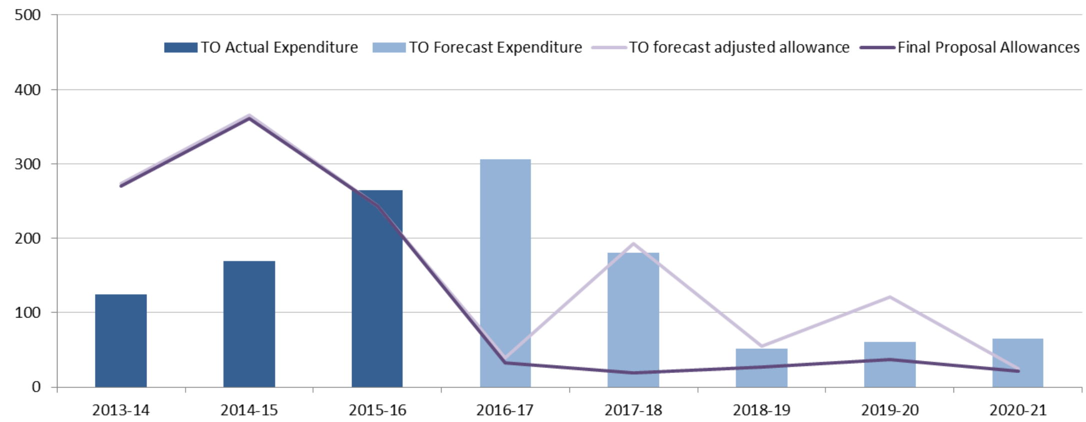
SPT

5.40. SPT has also seen a substantial shift in its work programme over the RIIO-ET1 period, and it is now forecasting a far greater volume of connections (commensurate with customer requirements) than was projected in its business plan. However, it has had to undergo a re-profiling of its workload, with some work being delayed beyond RIIO-ET1, and other work being moved to later in RIIO-ET1 due to current planning and consenting issues.

5.41. In 2015-16 SPT has overspent on load-related capital expenditure by £21m against its forecast allowance (£244m). In aggregate, SPT has underspent its revised allowances over the first three years of the control by £324m, and is forecasting to underspend its revised allowances across the eight year period by £92m.

5.42. This can be seen from Figure 15, showing SPT's expenditure to date and its forecast of allowances and expenditure over the RIIO-ET1 period (pre true-up). Appendix 2 updates figure 15 to exclude the value of capital works associated with any non-approved SWW schemes.

Figure 15: Actual and forecast expenditure vs TO forecast LR allowance [83]: SPT



5.43. SPT's forecast baseline allowance includes c.£80m (09/10 prices) of works for which there is no perfectly matched asset type funding mechanism. This value is currently included in SPT's forecast allowance calculations and reflected in our analysis. We have been reviewing this with the company to determine the appropriate way forward as part of our mid-period review parallel work. The MPR parallel work document is available from our website.

5.44. SPT is not proposing substantial change in scheme composition from those that were in its baseline plan.

Non Load-Related capex (NLR capex)

Overview

5.45. NLR capex is capital investment made by a TO to maintain its existing network. This investment relates mainly to replacement and refurbishment of assets[84] but also includes other capital expenditure directly related to maintaining a reliable network, such as investments to improve flood defences.

5.46. Non load related expenditure is split into lead asset[85] 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

[83] These values include the capital costs associated with SWW pre-construction and other capital works associated with any non-approved SWW schemes.

[84] 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

[85] 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).

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.

5.47. While Network Output Measures (NOMs) are the primary means of measuring outputs delivered by NLR expenditure, they directly measure only the effect of lead asset expenditure. There are no defined outputs for non-lead asset categories and therefore in order to gauge whether a TO is delivering what we expected them to deliver at the time of allowance setting, it is necessary to compare the scope of non-lead work the business plan was expected to deliver over the RIIO-ET1 period against their current forecast delivery.

5.48. The NLR allowances and actual and forecast expenditure for the eight years of RIIO-ET1 for each TO are shown in Figures 16, 17 and 18. Last year all three TOs were forecasting overall NLR underspends over RIIO-ET1. While NGET and SPT are still forecasting to underspend, SHE Transmission now expects an overspend due to what it claims will be an over delivery against its NOMs targets.

5.49. For each TO over-spend or under-spend against allowances may be attributable to a combinations of reasons. We have tried to identify and estimate the impact of as many of these as possible. In order to aid understanding of the reasons for over-spends and under-spends, when we have been able to do so, we have separated them into five broad categories. These categories are:

1. 'Work volume changes': changes in the total quantity of outputs for a given asset type that a company expects to deliver during the eight years of RIIO-ET1 (e.g. number of transformers replaced or refurbished)[86]. For example, a requirement for lower numbers of asset replacements due to better than expected condition of the assets will lead to a cost saving. In estimating the cost impact of work volume changes we calculated unit costs of carrying out the work implied by the companies' allowances (for each asset type) and assumed that the unit cost does not change over the course of the price control. The impact of any unit cost changes are reflected in the second category, 'work cost changes'.

2. 'Work cost changes': changes to the cost of delivering like-for-like outputs. For example if the average unit cost of replacing transformers decreases then this will lead to cost savings. However, if total transformer asset volumes increases

[86] Please note that outputs that were expected at the time of the RIIO-ET1 business plan submission to be delivered before the start of RIIO-ET1 but now subsequently delayed and carried over into RIIO-ET1 are not included in this category. These are included in category 4 (cost schedule changes) as RIIO-ET1 allowances assume these outputs have been funded in TPCR4 and the outputs are therefore assumed for these purposes to have been delivered in TPCR4.

(category 1 above) then, even though the unit cost has come down, we could see an overall overspend for the transformers asset category. Decreases or increases in this category could be attributable to efficiencies/inefficiencies on the part of a company or be due to external factors such as input price changes (as discussed later in this chapter), or a combination of both.

3. 'Work type changes': changes in the type of work used to deliver an output or desired benefit. For example if a company had been previously expecting to replace an asset and now discovers that the asset is no longer required and can be decommissioned, then the associated cost savings would fall within this category.

4. 'Cost schedule changes'. Costs are included in this category if:

   a. at the time of the RIIO-ET1 business plan an output was planned for delivery either in TPCR4 or RIIO-T2,

   b. there are changes to the timing of delivery but these timing changes do not impact RIIO-ET1 output volumes, or

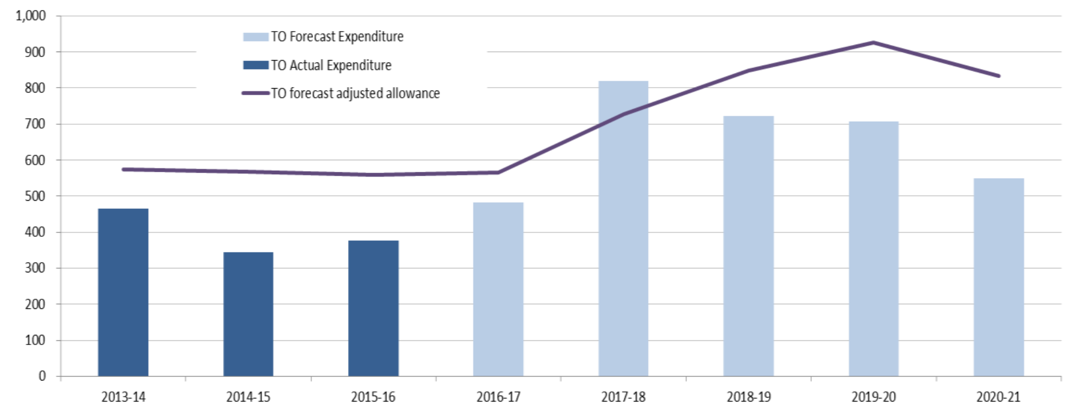
   c. timing changes impact RIIO-ET1 expenditure. For example, in its RIIO-ET1 business plan a TO was forecasting to start replacing underground cables in RIIO-ET1 but to deliver the final outputs RIIO-T2. If replacement of the underground cables is subsequently delayed and no expenditure is incurred in RIIO-ET1 then the associated cost savings will be included in this category.

5. 'Other factors': a balancing category and will include the impact of miscellaneous factors that don't fall into one of the above categories, any factors that we have not yet been able to identify or estimate, as well as the net impact of any inaccuracies in our estimates factors within the other categories. It is important to note that we have not been able to identify every material factor contributing to overspends or underspends and we will continue to improve our understanding and estimates of them through to the end of RIIO-ET1.

5.50. Tables 19, 20 and 21 below give our views of each contribution of each of the factor categories above to their overall lead, non-lead and total overspend or underspend. The paragraphs following each of the tables explain the main elements that we have identified to date within each category.

NGET

Figure 16 – Actual and forecast expenditure vs TO forecast NLR allowance: NGET



5.51. NGET's total NLR allowance over RIIO-ET1 is £5.6bn. It is currently forecasting to underspend by £1,137m over the eight years of RIIO-ET1, which equates to approximately 20% of its NLR allowance. This is comprised of a £694m underspend on lead assets and a £443m underspend on non-lead assets.

Table 19: NGET - Classification of factors contributing to RIIO-ET1 overspend or underspend

Overspend/Underspend Category	Lead Assets	Non-Lead Assets	Total
Work volume changes	-143.0	-5.3	-148.3
Work cost changes	-721.6	-	-721.6
Work type changes	-112.2	-43.0	-155.2
Cost schedule change	-225.4	-144.1	-369.5
Other	+508.5	-250.5	+258.0
Total RIIO-ET1 underspend, £m 2015-16 prices	**-693.6**	**-442.9**	**-1,136.5**

NGET: Work volume changes

5.52. We estimate that NGET is saving a net amount of approximately £143m on lead asset replacement and refurbishment due to workload volume changes. The main driver for the savings are revised condition assessments of their assets which lead to some assets in better than expected condition moving out of the RIIO-ET1 plan and others in worse than expected condition moving in.

5.53. In setting NLR targets and allowances for RIIO-ET1 the volume and cost of assets expected to be replaced or refurbished through load related schemes were excluded.

Load related programmes change over the course of the price control, for example to align with different assumed generation background scenarios, and therefore some assets which were expected to be replaced as part of a subsequently cancelled LR scheme now require replacement under NLR. Conversely replacement of other assets that were previously within NLR plan fall into scope of LR work. The estimated net effect on NLR expenditure over RIIO-ET1 of these interactions with the LR plan are an increase of £60m.

5.54. Deferral of current transformer / voltage transformer (CT/VT) units - under 'substation other' - to RIIO-T2 and scope changes on CT/VT replacement schemes have led to combined savings of £42m. However, NGET have indicated that some of the replacements deferred to RIIO-T2 may come back into RIIO-ET1 plan once condition is better understood.

NGET: Work cost changes

5.55. NGET carried out an exercise during the year to update its cost database, which it uses for forecasting project delivery costs. The update took account of the actual cost of projects completed to date as well as latest tender returns on planned load and non load projects. The current forecasts and unit costs utilise the updated database should therefore reflect current input price expectations as well as cost increases or savings attributable to any asset or intervention technological changes.

5.56. Unit cost changes on lead assets, including unit cost changes due to change type of intervention (e.g. refurbishing rather than replacing an asset), give rise to an estimated £721m total savings. The majority consists of savings on assets that were in the original RIIO-ET1 business plan (c.66%), the remainder is on assets brought into plan since the time of price control settlement. There has been unit cost reductions on all asset categories with the exception of reactors.

NGET: Work type changes

5.57. We highlighted in our 2013-14 Annual Report that NGET had identified savings through the use of an enhanced paint coating system as an alternative to replacing steelwork. Current estimates are that the enhanced paint coating system will avoid the need to replace approximately 8,000 tonnes of tower steelwork and lead to savings against allowances of approximately £179m at a cost of £6m for the tower painting work. While overall NGET is replacing less tower steelwork and is underspending by £111m, if the replacement volume changes are factored out then we see an effective increase in tower steelwork replacement volumes and a unit cost increase. The cost impact of these factors are reflected in the above 'work volume' and 'work cost' categories respectively.

Table 20: Summary of tower steelwork cost changes

		RIIO-ET1	
	Work Change Category	**2015 RIGs**	**2016 RIGs**
Allowance		216.4	216.4
Replacement volume reductions due to use of EPC System	Type	-179.4	-179.4
Other replacement volume changes	Volume	72.8	72.7
Cost of EPC System	Type	6.1	6.1
Unit Cost Changes	Cost	-6.4	-5.1
Revised forecasts RIIO-T1 expenditure		**109.6**	**110.8**

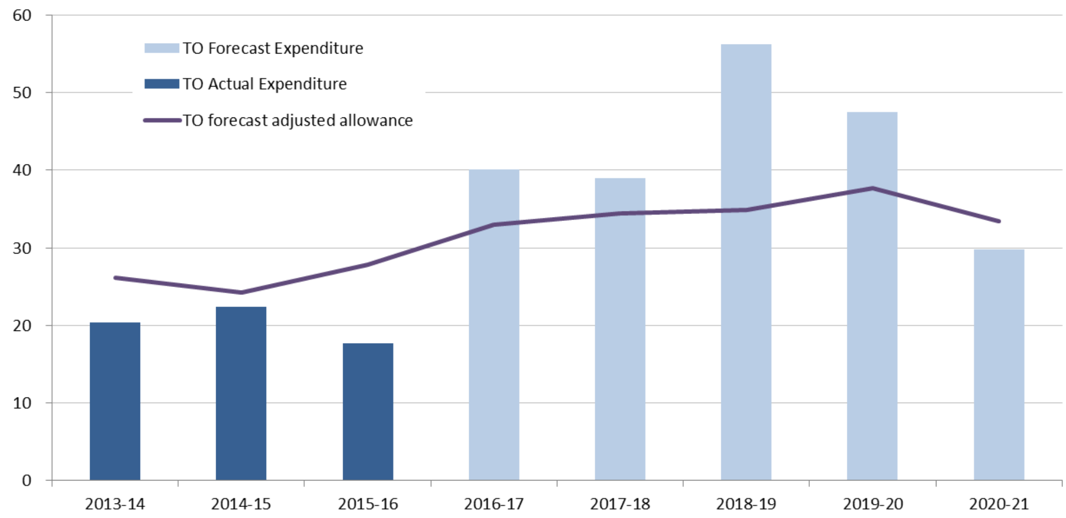
5.58. Through system modelling and negotiation with DNOs, NGET has identified that 22 transformers that were planned for replacement can be removed from the network instead of replaced and have similarly identified three reactors for decommissioning. The estimated total NLR capex savings achieved through these decommissionings is £116m. Additional opex of approximately £4m will be incurred to decommission the assets.

NGET: Cost schedule changes

5.59. NGET's NLR allowances included approximately £854m of allowances to cover RIIO-ET1 expenditure on schemes expected to deliver final outputs in RIIO-T2. There are therefore no RIIO-ET1 outputs to which these allowances can be linked. A number of these schemes have subsequently been either cancelled or fully deferred beyond RIIO-ET1. We currently estimate the value of cost savings attributable to these deferrals at £360m. As mentioned in last year's report the majority of these savings are on underground cable and cable tunnel schemes (£216m) and mainly relate to a change in NGET's view of network requirements in the Sheffield area. The remaining £144m saving is achieved through deferral or cancellation of transformer, reactor, and circuit breaker schemes.

SHE Transmission

Figure 17 – Actual and forecast expenditure vs TO forecast NLR allowance: SHE Transmission



5.60. SHE Transmission's total NLR allowance over RIIO-ET1 is £251m. Forecast increases in workload over the remainder of RIIO-ET lead SHE Transmission to estimate on overall RIIO-ET1 overspend on NLR allowances by about 9% (£21m).

5.61. In 2015-16, SHE Transmission underspent on NLR capital expenditure by £10m (36%) against its forecast allowance of £28m.

Table 21: SHE Transmission - Classification of factors contributing to RIIO-ET1 overspend or underspend

Overspend/Underspend Category	Lead Assets	Non-Lead Assets	Total
Work volume changes	+64.7	-	**+64.7**
Work cost changes	-42.3	-	**-42.3**
Work type changes	-25.2	-	**-25.2**
Cost schedule change	-	-	**-**
Other	+22.8	+1.6	**+24.4**
Total RIIO-ET1 overspend, £m 2015-16 prices	**+20.1**	**+1.6**	**+21.7**

SHE Transmission: Work volume changes

5.62. The discovery of data errors has to date not been identified as a material factor. However, asset data quality is still an issue for SSE across its network businesses. To address this SSE has instigated a major systems and process modernisation across its network businesses. This programme may uncover data errors that will affect work volumes for SHE Transmission in the remaining years of RIIO-ET1. It is still too early to precisely state the extent of any errors. However, SSEN views the potential for significant transmission data errors to be far less significant than for its distribution assets. We would therefore be surprised if the results of this modernisation programme were to necessitate significant change to replacement and refurbishment workload in future years.

5.63. SHE Transmission is forecasting that it will over-deliver on its NOMs targets. We estimate the total cost of replacing or refurbishing the assets that SHE Transmission is claiming over-delivery on at £88m over RIIO-ET1. The increased workload has arisen mainly due to changes in priority of asset replacement and refurbishment caused by revised condition assessments of assets elsewhere on SHE Transmission's network. The bulk of the increase is from transformers, which contribute approximately £58m additional costs.

5.64. Factors such as better than forecast condition assets no longer requiring replacement offset the additional costs associated with workload changes. We estimate these factors to have a value of approximately £65m.

SHE Transmission: Work cost changes

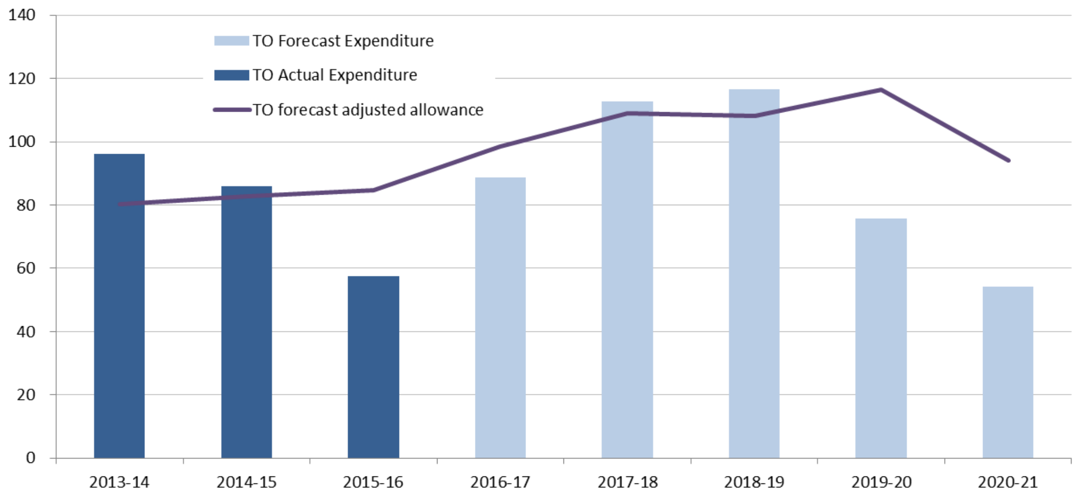
5.65. SHE Transmission has increased the volume of its transformer replacement work the unit cost of the work has come down and is now estimated to save £71m over RIIO-ET1. The transformer unit cost savings, and smaller savings on circuit breakers and underground cables, are offset somewhat by increased overhead lines unit costs, which add approximately £48m over RIIO-ET1.

SHE Transmission: Work type changes

5.66. Where overhead line (OHL) work was forecast to be required, SHE Transmission's business plan assumed that the work involved the replacement of both the OHL conductor and the OHL fittings. It has since emerged that for some OHL circuits only the conductor or the fittings require replacement. This has led to savings of approximately £25m.

SPT

Figure 18 – Actual and forecast expenditure vs TO forecast NLR allowance: SPT



5.67. SPT's NLR allowance over RIIO-ET1 is £773m. Overall SPT is forecasting that it will underspend its RIIO-ET1 NLR allowances by about 11% (£86m).

5.68. In 2015-16, SPT has underspent on NLR capital expenditure by £27m (32%) against its forecast allowance of £85m.

Table 22: SPT - Classification of factors contributing to RIIO-ET1 overspend or underspend

Overspend/Underspend Category	Lead Assets	Non-Lead Assets	Total
Work volume changes	+113.1	-	**+113.1**
Work cost changes	-247.3	-	**-247.3**
Work type changes	-0.2	-	**-0.2**
Cost schedule change	+93.1	-	**+93.1**
Other	-63.4	+18.3	**-45.1**
Total RIIO-ET1 underspend, £m 2015-16 prices	**-104.7**	**+18.3**	**-86.4**

SP Transmission: Work volume changes

5.69. Revised condition assessments has led to increased volumes of circuit breakers and underground cables requiring replacement and a consequent £26m increase in expenditure.

5.70. Changes in load related programme have meant consequential changes assets requiring replacement through NLR programmes. This has led to net increased requirement for NLR OHL work and decrease in circuit breakers. The net cost increase associated with this load related interaction is estimated at £10.5m.

5.71. In addition, £36m has been added to SPT's forecast NLR costs due to OHL replacement work where additional NLR allowance would have been triggered (under Special Condition 6H) had certain specified load related projects gone ahead. The additional allowances will now not be triggered but SPT's view is that the OHL work is still required to be carried out in RIIO-ET1.

5.72. Various strategy changes, for example substitution of Windyhill 275kV Switchgear Replacement (deferred to RIIO-ET2 Inverkip 400kV due to deliverability issues) and Inverkip 400kV Switchgear Replacement (cancelled due to planned closure of Inverkip Power Station meaning the network can be reconfigured instead), with schemes of greater scope increases costs in RIIO-ET1 by £40m.

SP Transmission: Work cost changes

5.73. Changes in unit cost for replacement and refurbishment has led to a forecast saving of £247m. All lead asset categories have decreased unit costs, with overhead lines contributing the largest proportion of the savings with £174m in total estimated savings over RIIO-ET1.

SP Transmission: Cost schedule changes

5.74. Projects that were due for delivery in the previous price control period (TPCR4) but delayed to RIIO-ET1, due to for example consenting or operational issues, add £16m to RIIO-ET1 costs[87]. These include Bonnybridge 132kV switchgear replacement, Neilston to Windyhill OHL modernisation scheme, Kaimes to Whitehouse 275kV cable replacement schemes.

Network Output Measures (NOMs)

5.75. We explained in last year's annual report that we were working with TOs to develop their NOMs Methodology to enable us to objectively assess whether they over-deliver or under deliver against their targets and to ascertain whether current and future NLR investments provided consumers with long-term value for money.

5.76. We received a revised NOMs methodology from the TOs in February 2016 and in April 2016 we issued a Direction[88] requiring the TOs to further develop their

[87] The figure of £93.1m given in table 21 is because we calculate the impact based on work volumes and constant unit cost figures. The difference between the two figures (£77m) is reflected as a saving within the Work Cost Changes category.
[88] https://www.ofgem.gov.uk/publications-and-updates/decision-direct-modifications-electricity-

methodology. Since then we have been working closely with the TOs on development and a revised methodology that meets the Direction requirements is expected in April 2017. TOs will be conducting a public consultation on their draft methodology prior to the April submission.

5.77. While we expect TOs to deliver a methodology that complies with the Direction it is likely that further development work will be required before the methodology and related implementation plans are fully complete and fit for purpose.

Input Price Changes

5.78. As previously highlighted, all TOs are forecasting an underspend over the eight year RIIO-ET1 period against their view of allowed Totex. The TOs highlighted operational and delivery improvements and technical innovation leading to cost savings, as well as changes to actual costs against their forecast. In our previous annual report, we identified changes in input prices as a potential driver for some of the underspend.

5.79. To understand how the changes in input prices could potentially affect the companies, it is necessary to understand our FPs.

Background

5.80. The current measure of inflation used across the RIIO price controls is the Retail Price Index (RPI), and network companies' allowances are adjusted annually to reflect actual RPI changes.

5.81. In our FPs we acknowledged that several key inputs (labour, material equipment/plant) do not necessarily change in line with RPI and will not match main components of network companies' costs. 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. It was then left to the network companies to manage any actual above inflation input price fluctuations

5.82. The RPE's were set by extrapolating mainly historic indices, and applying specific weights to those indices that match the different work stream categories (i.e., LR work, NLR work, Opex etc).

5.83. The Scottish TO's were fast tracked and therefore their business plan, including their view of RPE's, was used as the basis of the ex-ante allowance set in FPs. For NGET we carried out our own analysis on its view and derived an updated view of RPEs. The RPEs allowance for NGET consisted of both Ofgem's and NGET's view (weighted 75%:25% respectively).

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transmission-network-output-measures-methodology

Updated analysis

5.84. Over the past three years, actual outturn input prices have been significantly lower than the assumptions used to set the ex-ante RPE allowance; the TOs' updated forecast of the input prices have also changed. A proportion of this input price movement should theoretically enable the TOs to achieve better rates in contracts and to deliver some of the work below allowances, but the ability to secure these benefits depends on the contracting structure and associated obligations.

5.85. We have carried out analysis to allow us to better understand the impact of the movement in input price assumptions on TOs' costs. We asked for the TO's updated view of actual RPEs in the first three years of RIIO-ET1 (2013-2016) and an updated forecast of RPEs for the remaining years of the price control.

5.86. For the Scottish TOs, the actual and forecast indices are translated into RPEs based on the same methodology as used in their business plans in 2011/12. NGET used a different approach to the one used in their own business plan submission.

5.87. Additionally, we have updated our own analysis carried out in 2012 to come up with our own view of RPEs[89] (actual and forecast). For the forecast we used three different scenarios:

- based on average till 2010 (used here for comparison)
- based on an average till 2016
- constant linear growth from year 2016.

5.88. Over the past three years, input prices have been significantly lower than those used to set the RPEs in 2012. The input prices are also forecast to remain lower over the remainder of the RIIO-ET1 price control. As a result, the actual RPEs are also significantly lower than anticipated. The forecast based on the TO's view shows a slight increase in input prices anticipated towards the end of the price control. However, the current forecast view is that in total the RPE's will not reach the levels that were forecast in any of the TO's business plans, or in Ofgem's own forecast at the FP stage.

[89] As some of the indices that were originally used have been rebased/modified by ONS methodology or are no longer published, we used some assumptions to maintain as close as possible to the original methodology.

Methodology

5.89. We calculated the difference in allowance based on four sets of RPEs: TO's BP view, FPs view[90], TO's updated view (provided as part of the 2015-16RRP) and Ofgem's updated view.

5.90. We calculated the potential savings for NGET in two ways: (i) based on their business plan view of RPE, and (ii) based on what we used as the basis of the ex-ante allowance in FPs.

5.91. We applied each of the TOs view of RPEs to calculate the potential saving for all the TOs to sense check their submission, including our own updated view.

5.92. In our analysis we took into account differences in volume and changes in actual workload.

Results

5.93. We noticed that even though the TO's used different methodologies to derive their view of RPE's from the indices, the results were broadly comparable. We found that NGET's view was the most conservative. At this stage we did not use our own forecast for RPEs.

5.94. The cumulative difference between the level of ex ante allowance in the FPs (based on the view of RPE's available at the time) and the level of allowance that would be established if we were to base this on the TO's updated view of RPEs (a 'perfect hindsight' approach), is approximately £1.5bn across RIIO-ET1. This comprises £1.2bn for NGET, £0.18bn for SPT and £0.11bn for SHE Transmission. As mentioned, this includes variations in work and general allowances.

5.95. We found that if NGET's BP estimated RPE had been applied without revision, the potential difference produced by lower actual outturn input prices would be £1.67bn, instead of £1.20bn (2015-16 prices).

5.96. We also found that the majority of the potential difference due to changes in input price is related to the first few years of the price control. The forecast as reflected in the TO's submission is showing recovery of the market and rising input prices in the second half of the price control.

[90] As mentioned above, both Scottish TOs were fast tracked and their BP view of RPEs was used to establish the ex ante allowance set in FPs. The case is different for NGET; the ex ante allowance was instead based on our revised view of NGET's RPE submission.

Non-Operational Capex

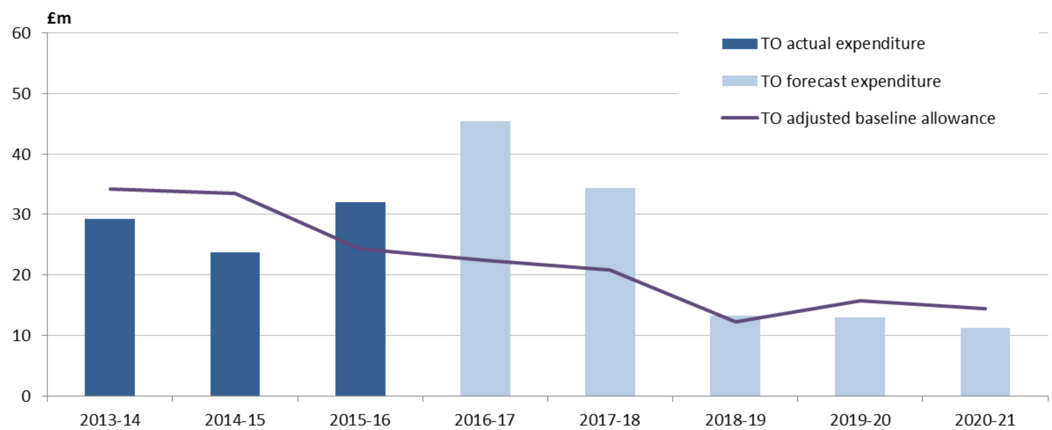
5.97. Non-operational capex is expenditure on non-network assets. The areas of expenditure are information technology (IT), land and buildings, vehicles and tools and equipment. For all TOs the main type of this expenditure is IT, both hardware and software.

5.98. This category of expenditure accounted for 4% (£38m) of NGET's total capex in the 2015-16 reporting year and less than 1% of the total capex incurred by SHE Transmission and SPT in the same period.

NGET

5.99. To ensure consistency with last year's reporting pack submission, the annual profile of non-operational capex allowance in figure 19 below excludes the value attributed by NGET to Optel network asset renewal and BT21 migration works. The associated expenditure has been deducted from the category of non-operational capex and classified as non-load related.

Figure 19: Actual and forecast expenditure vs TO forecast Non-op capex allowance: NGET



5.100. NGET spent c.£8m above its non-operational capex allowance in 2015-16 (£24.2m). This is a reduction in the level of performance observed in year 2 (£9.8m underspend).

5.101. NGET outperformed relative to the adjusted baseline allowances across the first three years of the RIIO-ET1 price control; an underspend of £7m or 14%. NGET forecasts expenditure will be higher than its annual allowance for the next two years of the price control (c.£37m). The anticipated overspend is driven by the adjustment to the non-operational expenditure to account for the costs incurred in the Optel migration process.

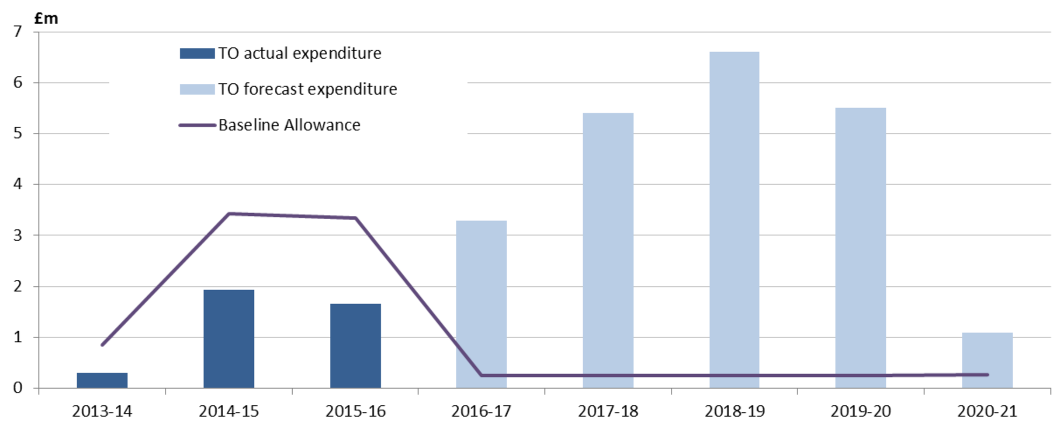
5.102. Overall, NGET forecasts that it will overspend by 14% across RIIO-ET1.[91] The forecast eight year overspend reported by NGET is principally driven by two factors:

- 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-ET1 period.

- Property capex: NGET has constructed a new switch room at National Grid House in Warwick to replace aged electrical infrastructure and has incurred increased property costs as a result of Project RUMES. However, we have not been able to verify the value of these costs on the basis of the information provided. We will continue to monitor progress in this area.

SHE Transmission

Figure 20: Actual and forecast expenditure vs TO forecast Non-op capex allowance: SHE Transmission



5.103. For SHE Transmission, non-operational capex expenditure is comparatively small with total allowance of £8.9m across the RIIO-ET1 price control period.

[91] Without the expenditure adjustment to account for the recategorisation of Optel/BT21 costs, NGET currently expects to incur costs of £257m over the eight year period, which is 7% above the combined allowances of £177.7m for non-operational capex and £62.8m for Optel/BT21.

5.104. SHE Transmission incurred £1.7m of costs in this area during 2015-16 and spent 50% less than its allowance. This is an increase on the level of underspend incurred in year 2 (43% underspend).

5.105. However, SHE Transmission is currently forecasting a catch up in non-operational capital expenditure for the remainder of RIIO-ET1 with a constant overspend for the each of the remaining five years of RIIO-ET1. This is expected to offset the underspend in the first three years of price control period and bring total expenditure more in line with allowances across the RIIO-ET1 period. A total overspend of £16.9m is currently forecast.

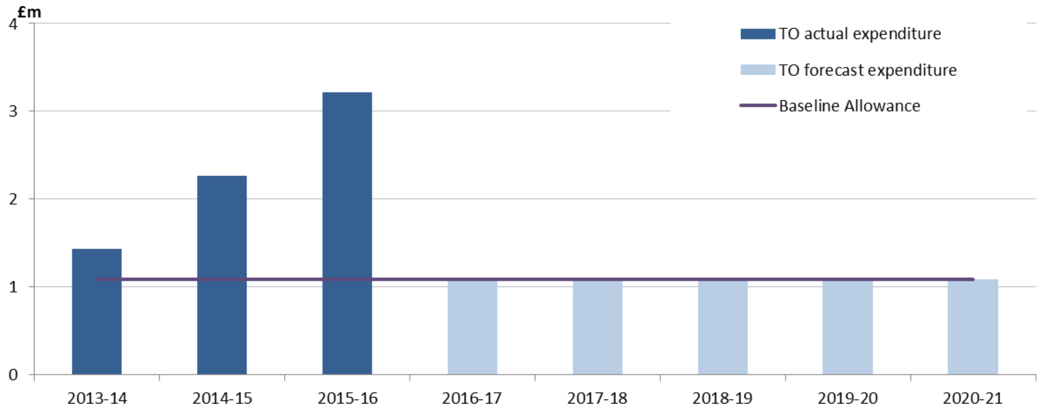
5.106. SHE Transmission explain that the bulk of the costs it expects to incur in this category relate to its IT Transformation Project - a large programme of work to upgrade and replace the whole IT system environment of the SHE Transmission and two Distribution Businesses. The figures reported in the 2015-16 RRP forecast were, at that point in time, the best available cost estimate.

5.107. During the course of 2015-16 and the current financial year the programme of work has been evolving and a revised timeframe and programme developed. It has now resulted in a number of specific projects being designed which are due to be implemented over the next 18 months.

5.108. The latest view of the anticipated cost to SHE Transmission over the remaining RIIO-ET1 period is currently c.£22m. The cost is being split between the three networks based on the requirement and utilisation of each system; the overall SSEN cost from 2017-2021 is potentially c.£130m. This cost estimate is still subject to change as the programme develops and evolves over the next few years.

SPT

Figure 21: Actual and forecast expenditure vs TO forecast Non-op capex allowance: SPT



5.109. In 2015-16 SPT spent approximately double its allowance level (£2.1m overspend), continuing the trend observed last year. The reason for this overspend is due to expenditure on IT projects (primarily the Network Asset Management System project to integrate regulatory reporting into the SAP system) and because the depreciation of non-system assets have increased due to investment in prior years.

5.110. 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-ET1 price control period. SPT anticipates that the forecast profile of expenditure will result in an overspend of £3.7m (42%) across the RIIO-ET1 period, an increase on the eight year overspend forecast as part of the 2014-15RRP (£1.5m).

Controllable Operating Costs (opex)

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

- Direct Opex – which comprises 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 costs – which refers to costs which support the overall company business such as IT[92] , telecoms, property management and insurance

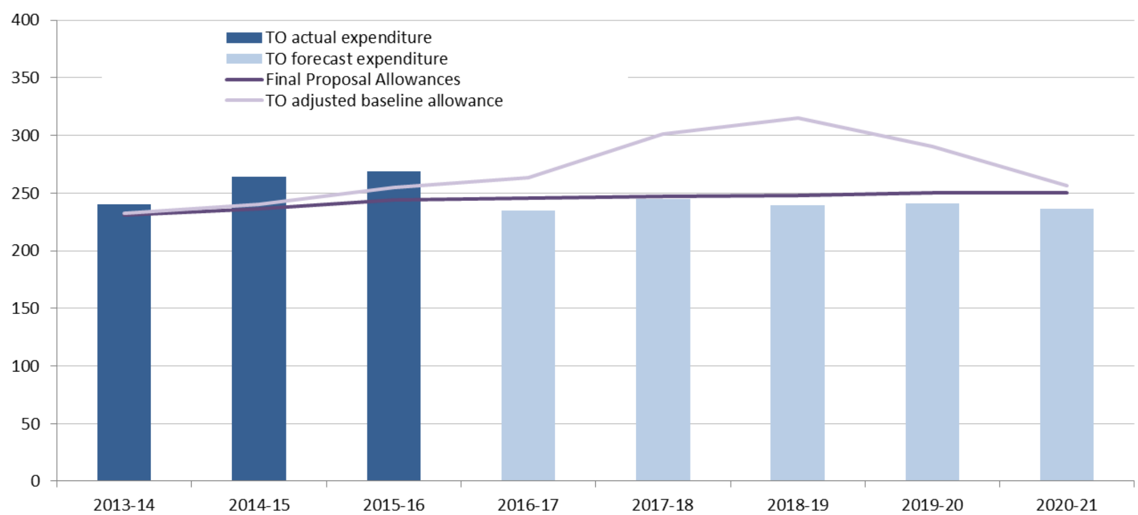
[92] This includes the costs associated with the development of applications before they are put into production and costs associated with implementing the systems. It does not include the costs of maintaining existing and

- Closely associated indirect costs (CAI) - costs which support the operational activities, but are not in the previous two categories, e.g. operational training, IT equipment used exclusively in the real time management of network assets.

NGET

5.112. Figure 22 below shows NGET's actual costs incurred in for the first three years of RIIO-ET1 and forecast of expenditure for the remainder of RIIO-ET1 compared to their baseline allowance and its updated view of allowance across the period.

Figure 22: Actual and forecast expenditure vs TO forecast opex allowance [93]: NGET



5.113. NGET spent 5%[94] above its view of adjusted opex allowance in 2015-16. The overspend is mainly driven by the level of costs incurred in the categories of business support costs (an overspend of £32m) and planned inspections and maintenance (an overspend of £6.5m) which outweighs the underspend reported in direct costs, CAI and fault categories (£7.1m, £4m and £13.5m respectively). Overspend across the first three years of RIIO-ET1 was £46m or 6%.

5.114. Direct Opex expenditure, the largest of the cost categories within the opex category, is £14m below allowances for NGET in 2015-16. However, we note that there have been significant increases in the costs associated with tower painting year-on-year.

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operational systems.

[93] The allowance values include the ISS allowances which were provided as part of the ISS reopener uncertainty mechanism.

[94] This value includes the smeared value associated with the adjustment for IAS 19 pension accrual in 2015-16 (-£8.5m). Excluding this value, the overspend in 2015-16 is £5.4m. Opex figures hereafter include the IAS 19 pension adjustment.

During 2015-16 NGET has treated rather than replacing the steelwork, in £4.8m of additional costs incurred.

5.115. Increased decommissioning work and expenditure on site care/safety drove £6.3m in Direct Opex costs.

5.116. Business support costs have increased year on year. This is mainly driven by the decision to insource the Service Management Integration of the information systems. This increased costs by £3.5m year on year.

5.117. The costs incurred by NGET in the category of CAI during 2015-16 have been broadly comparable with allowances in 2015-16, with only a small (5%) underspend against an allowance of £77.9m.

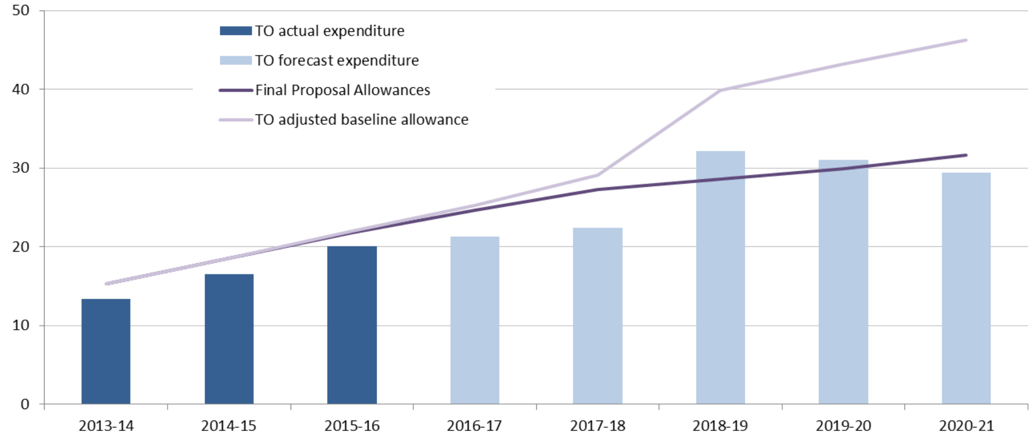
5.118. NGET is currently forecasting to underspend against adjusted allowances by 9% across the entirety of RIIO-ET1. This is driven by a forecast underspend in the CAI and direct costs categories of £352m that is only partially offset by a forecast overspend of £168m in the business support costs category. Overall, NGET forecast that opex expenditure levels in the first five years of RIIO-ET1 will remain above allowance due to the cost of reorganisation initiatives. Expenditure levels then fall below allowance levels towards the end of RIIO-ET1 as a result of anticipated efficiency gains.

5.119. Although the numbers align with NGET's published values, the opex allowances may be overstated as they include the additional allowances for Physical Site Security (referred to as "ISS") that are allocated in the PCFM to the 'other capex' cost category. Applying this recategorisation has the impact of reducing NGET's forecast total allowance for controllable opex. Appendix 1 updates the above analysis to include the capex ISS expenditure in NGET's opex analysis and sets out the corresponding impact on NGET's performance position.

SHE Transmission

5.120. SHE Transmission underspent against its adjusted baseline opex allowance by 9% in 2015-16. Underspend across the first three years of RIIO-ET1 was 6%.

Figure 23: Actual and forecast expenditure vs TO forecast opex allowance: SHE Transmission



5.121. Direct costs incurred are broadly comparable against allowance in 2015-16, this is despite additional tree-cutting undertaken by SHE Transmission in 2015-16 following a review of their expenditure over the last 3 years.

5.122. SHE Transmission has incurred an overspend in business support costs in 2015-16 (£0.5m), partly driven again this year by additional property costs for offices in Inverness and Glasgow to accommodate increased staff numbers.

5.123. The majority of the underspend in 2015-16 is due to costs not being incurred in the CAI category (£2.5m underspend). This is a result of the company still being in a period of capital growth and the delay in the CAI costs associated with this. As the capital projects become operational, there will be an increase in the CAI to provide the necessary support for these assets. Year on year, the costs in the CAI having increased by £1.1m, this is as a result of SHE Transmission's network increased growth and complexity.

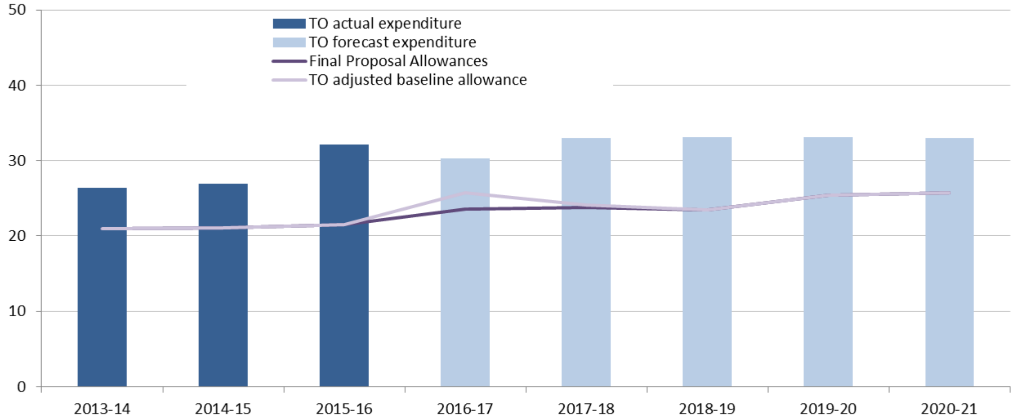
5.124. SHE Transmission is projecting an underspend of 22% (£53m) below its view of adjusted allowance over the RIIO-ET1 period (6% below its original baseline allowance). This is due to anticipated underspend across all cost categories across the price control period; largest in the CAI cost category.

SPT

5.125. SPT spent 49%[95] above its opex allowance in 2015-16 and 35% above its cumulative allowance across the first three years of RIIO-ET1.

[95] This value includes the smeared value associated with the adjustment for IAS 19 pension accrual (-£0.1m) across opex cost categories. Excluding this value, the overspend in 2015-16 in the business support category is £10.5m. Opex figures hereafter include the IAS 19 pension adjustment.

Figure 24: Actual and forecast expenditure vs TO forecast opex allowance: SPT



5.126. SPT explain that the majority of the 2015-16 overspend is in the business support costs category, which have exceeded the RIIO-ET1 allowance (of £2.9m) by £11.8m in 2015-16. The main reason for this increase as in previous years is due to a change of its accounting procedures for fixed assets, to bring it into line with the rest of the industry.

5.127. During 2015-16, SPT has carried out a review of their group corporate cost recharge model and this increased business support costs in comparison to the prior year by £2.5m. This reflects SPT's group policy and tax transfer pricing rules.

5.128. In addition to this review, a detailed analysis was carried out to all budget areas to determine each shared department / cost centre allocation from SPEN. This has the effect of increasing the percentage of SPEN costs allocated to SPT from c14.8% to 20%. This reflects the increase in activity of the SPT business and has increased business support and CAI costs by a further £2.1m.

5.129. SPT has spent £0.1m above its direct costs allowance level in 2015-16. It has provided a number of reasons for this overspend, including increases in site care costs and support costs for a specific gas insulated transformer. Year on year the direct costs have reduced, mainly due to a reduction in tower painting costs.

5.130. SPT is forecasting a total overspend on RIIO-ET1 opex allowances of £60m or 32% (c.£20m increase from the total forecast position in 2014-15). The main reason for this is due to the previous change in accounting approach. As in previous reviews, it is noted that this will result in a reduction in capex project costs of approximately £60m during the RIIO-ET1 price control period with a corresponding increase in business support costs. This is above the original expenditure allowance level set at FPs. This is now compounded by the business support allocation reviews that have been carried out in 2015-16. This may require further investigation for the justification of the new allocations to SPT. We will continue to monitor this during RIIO-ET1.

6. SO Performance

Chapter Summary

This chapter evaluates RIIO-ET1 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

Introduction

6.1 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.

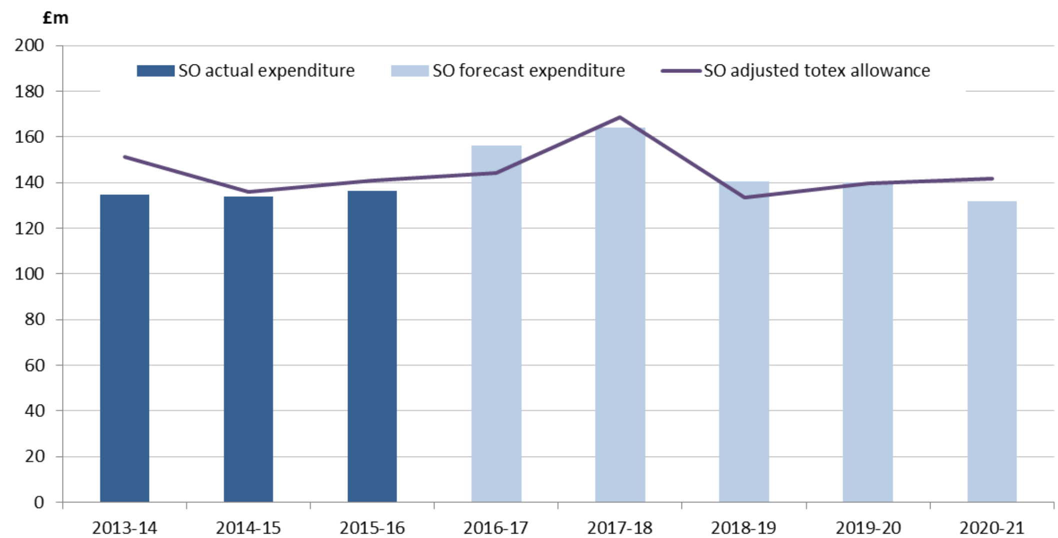
6.2 There are various costs that NGET incurs as SO and for which it seeks to recover revenue through its price controls. The RIIO-ET1 price control for NGET SO includes allowances for capex (primarily related to investment in IT systems) and opex (covering the ongoing costs of running the business, including support for IT systems).

6.3 All SO cost allowances for system balancing are determined via a separate process outside the RIIO-ET1 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.

Totex Performance

6.4. The figures below show the performance to date and forecast expenditure for NGET (SO) over the course of the RIIO-ET1 price control period against its adjusted totex allowances. These forecasts are based on NGET's published figures.

Figure 25: Actual and forecast expenditure vs SO forecast allowance



Performance for 2015-16

6.5. NGET (SO) has outperformed against its totex allowance of £141m in the third year of RIIO-ET1 (2015-16), as shown in the figure 25 above. The underspend is relatively small (£4.5m) and comprises a small overspend in non-operational capex (£3m) and a larger underspend in controllable operational costs (£7.5m). 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.

6.6. The underspend in controllable operational costs is despite costs having increased in 2015-16 from £92.7m to £96.3m. This is £7.5m below the 2015-16 level of allowance (£103.9m, an increase of 9% on the 2014-15 allowance). NGET explains this year on year increase reflects costs incurred as a result of change activities within the SO (e.g. security of supply), the marketing campaign and activity around its Power Responsive product and incremental support and maintenance costs associated with new investments including EMR. Inflationary pressures also account for a £1m increase in the annual costs.

Cumulative performance for the first three years (2013-16)

6.7. NGET reports that the actual cumulative level of SO total expenditure is £23.2m below allowances (£428.4m) for the first three years of the RIIO-ET1 period (5%). The level of underspend comprises a large underspend in non-operational capex (£21m) and a small overspend in direct costs (£1.5m). The wider costs incurred to date by NGET in supporting the overall company business such as IT, telecoms, property management and insurance (Business Support) has been broadly comparable with the cumulative allowance (underspent by £3.8m, or 3%).

6.8. The capex underspend (£21m) is driven by deferral of capital investment associated with progressing the Integrated Electricity Management System (iEMS) refresh (the asset investment will probably complete in the RIIO T2 period), and projects under the Transmission Analysis Road Map Programme (TARmap).

6.9. NGET explains that the savings to allowances reflect lower IS support costs due to savings and less IS investment than forecast in the RIIO submission. This reduction is partly offset by additional costs for its enhanced role under ITPR and security of supply. At the time of submission, these areas were not funded in full and as such expected costs are above allowances in some years. Appendix 3 sets out more detail of the impact of the MPR decision.

6.10. The marginal overspend in direct costs in the first three years of RIIO-ET1 is attributable to lower IS support costs due to savings and less IS investment than forecast in the RIIO submission. This reduction is partly offset by additional costs for our enhanced SO activities, the funding of which is the subject of the MPR decision and is discussed further in appendix 3.

Forecast performance for RIIO-ET1 period

6.11. NGET forecasts that the required level of SO total expenditure will be £18m below adjusted allowances (£1,156m) for the eight year RIIO-ET1 period.

6.12. NGET has forecast controllable opex spend to be £777m, which is £78m lower than adjusted allowances (£854m) across the price control period. NGET explains that the majority of this underspend is the result of the categorisation of allowances agreed at the time of the original business plan submission which, in NGET's view, is no longer consistent with the treatment of spend in some areas. NGET has therefore restated the allowances to improve the comparability of allowances to forecast totex. This is discussed further in the paragraphs below and in appendix 2.

6.13. NGET is currently forecasting to overspend against its non-operational capex allowances (prior to re-statement) of £301m across the RIIO-ET1 period by 20% (£60m).

6.14. However, the forecast level of SO capex investment during the RIIO-ET1 period is subject to change and will be dependent on future developments in the following 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 strategy, and the costs associated with its delivery over the remaining years of the price control period has changed over the course of the last year. The costs included in NGET's submission reflect their updated 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. NGET believe that £60m of data centre and cyber security allowances should be recategorised from SO Capex to SO Opex to be consistent with its spend allocation. Applying this reclassification will not change the total position versus allowances (£18.2m underspend) but will effectively remove the forecast overspend in the SO capex category and substantially reduce the forecast underspend in controllable costs.

- NGET is assuming receipt of additional allowances under uncertainty mechanisms (to the value of £53m). It is NGET's intention to make a submission within the May 2018 re-opener window to seek approval of this additional funding. 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 RIIO-ET1.
- 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 (e.g. replacement of the generation dispatch balancing model). We will continue to monitor changes to NGET's investment profile and the impact on efficiency savings.

6.15. The above numbers align with NGET's published values. NGET did, however, submit 're-stated' SO totex allowances as part of its reporting pack submission. This provided an alternative interpretation of cost categorisation and was intended to facilitate a better understanding of the underlying position of spend versus allowances. Applying the proposed recategorisation has no impact on NGET's forecast total allowance or expenditure across RIIO-ET1 but did recategorise certain allowances (Data centre and cyber security) from SO Opex to SO non-operational capex to be consistent with its spend allocation. The restatement therefore has an impact on the SO's current forecast of performance in these two categories (but not the total forecast level of performance). Appendix 2 provides a brief explanation of the impact of the proposed restatement on the annual performance profile of the SO.

Appendices

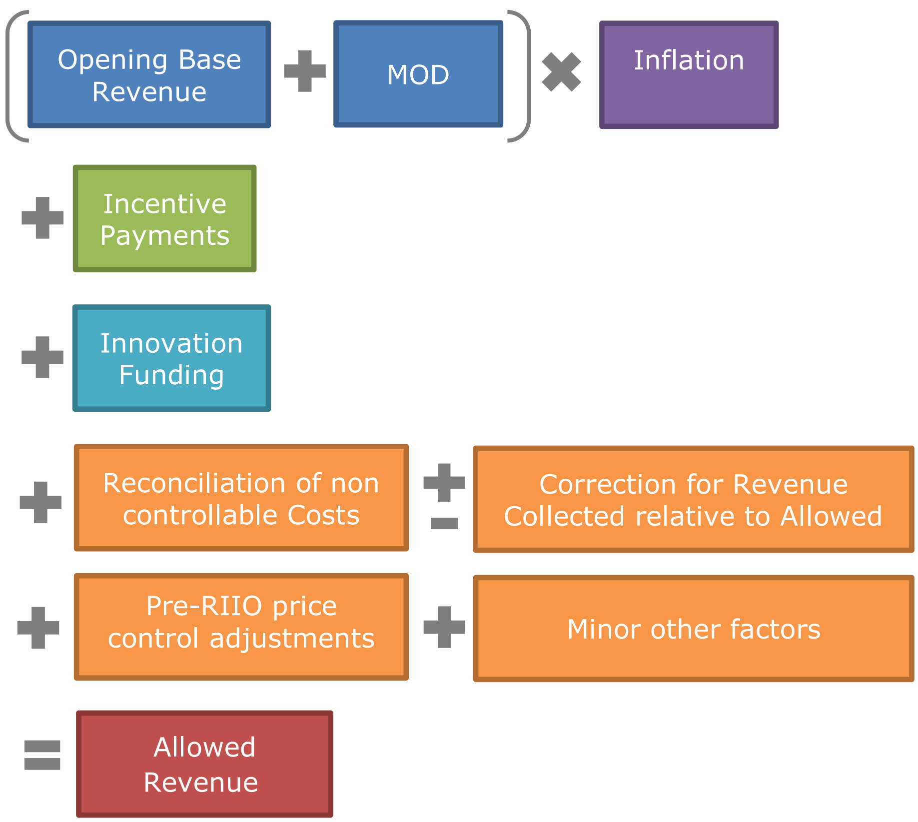
Index

Appendix 1: How we determine allowed revenue

This appendix describes how Allowed Revenue values are determined. This includes an explanation of how Totex performance relates to Allowed Revenue; a breakdown of the Allowed Revenue, showing the components that relate to pre-RIIO and RIIO spending; the use of Regulatory Asset Value (RAV) as a tool to spread revenue collection associated with Totex and; a history of the MOD directions that we have made under RIIO.

A1.1. Allowed Revenue is the amount of money that a network company can earn on its regulated business.[96] Figure A3.1 sets out at high-level, how we determine the Allowed Revenue in any given year of the price control.

Figure A1.1: Constituent parts of Allowed Revenue



[96] Due to the timing of receiving actual expenditure data and that customer tariffs are set in advance of regulatory years Totex spending assessments only begin to impact Allowed Revenue with a minimum two year lag. Therefore, Totex performance in 2015-16 will first impact Allowed Revenue in 2017-18. Detailed calculations are contained in the Price Control Financial Model (PCFM), which is available on our website: https://www.ofgem.gov.uk/network-regulation-riio-model/price-controls-financial-model-pcfm

A1.2. Of all constituent parts of Allowed Revenue, Opening Base Revenue comprises the significant majority. Opening Base Revenue is a best view of the amount of money a network company needs to earn on its regulated business to recover the efficient cost of carrying out its core activities. It is determined through ex ante forecasts conducted by Ofgem and the licensee.

A1.3. Opening Base Revenue is modified annually during the price control by the "MOD" term from the licences. This takes place as part of our Annual Iteration Process (AIP). The AIP process takes account of uncontrollable market uncertainties as they become known, such as the cost of debt and changes to taxation rules. It also measures financial performance against pre-determined output incentives. Where a company under / over performs relative to the ex-ante expectation a percentage of the difference is shared with consumers through the MOD.

A1.4. The MOD term is the difference between the updated Base Revenue (recalculated using the latest available performance data, including revisions to that data for previous years) and the Opening Base Revenue. Two key variables to the MOD value are Totex performance and Regulatory Asset Value (RAV), discussed below.

A1.5. Allowed Revenue is also adjusted for outputs incentive payments, innovation funding and other costs such as differences between previous years' Allowed Revenue and the actual amount that has been collected. True up of non controllable costs, and the correction factor are explained in the main body of the report.

A1.6. The remaining items included in Base Revenue are an allowance for taxation, legacy factors, pension deficits, equity issuance costs, costs that cannot be controlled and other minor adjustments.

A1.7. Table A1.1 displays MOD values from all the AIPs to date. Across these, total Base Revenue has decreased by £402m relative to the forecast at FPs. For all TOs a reduction in the cost of debt allowance has made a significant impact to MOD for 2017-18.[97]

Table A1.1: MOD values.

£m 2015-16 Prices	*2013-14*	*2014-15*	*2015-16*	*2016-17*	*2017-18*
NGET TO	-	-7	-138	-223	-305
NGET SO	-	5	7	25	11
SHE Transmission	-	11	102	105	63
SPT	-	7	-24	-26	-16
Total	-	16	-52	-119	-246

[97] The cost of debt allowance changes the WACC value. The cost of debt allowance itself is derived from the average of two indices (with serial numbers DE000A0JY811 and DE000A0JZAF5 as provided by IHS Markit) that report historic borrowing costs for GB non-financial "A" and "BBB" rated bonds. A 10 year rolling average of these costs is determined. The average currently includes periods that predate the 2008 financial crisis, during which time borrowing costs were greater than they are today (borrowing costs that are newly entering the calculation period are lower than these older costs that are exiting it).

Allowed Totex and Other Factors that Impact Base Revenue

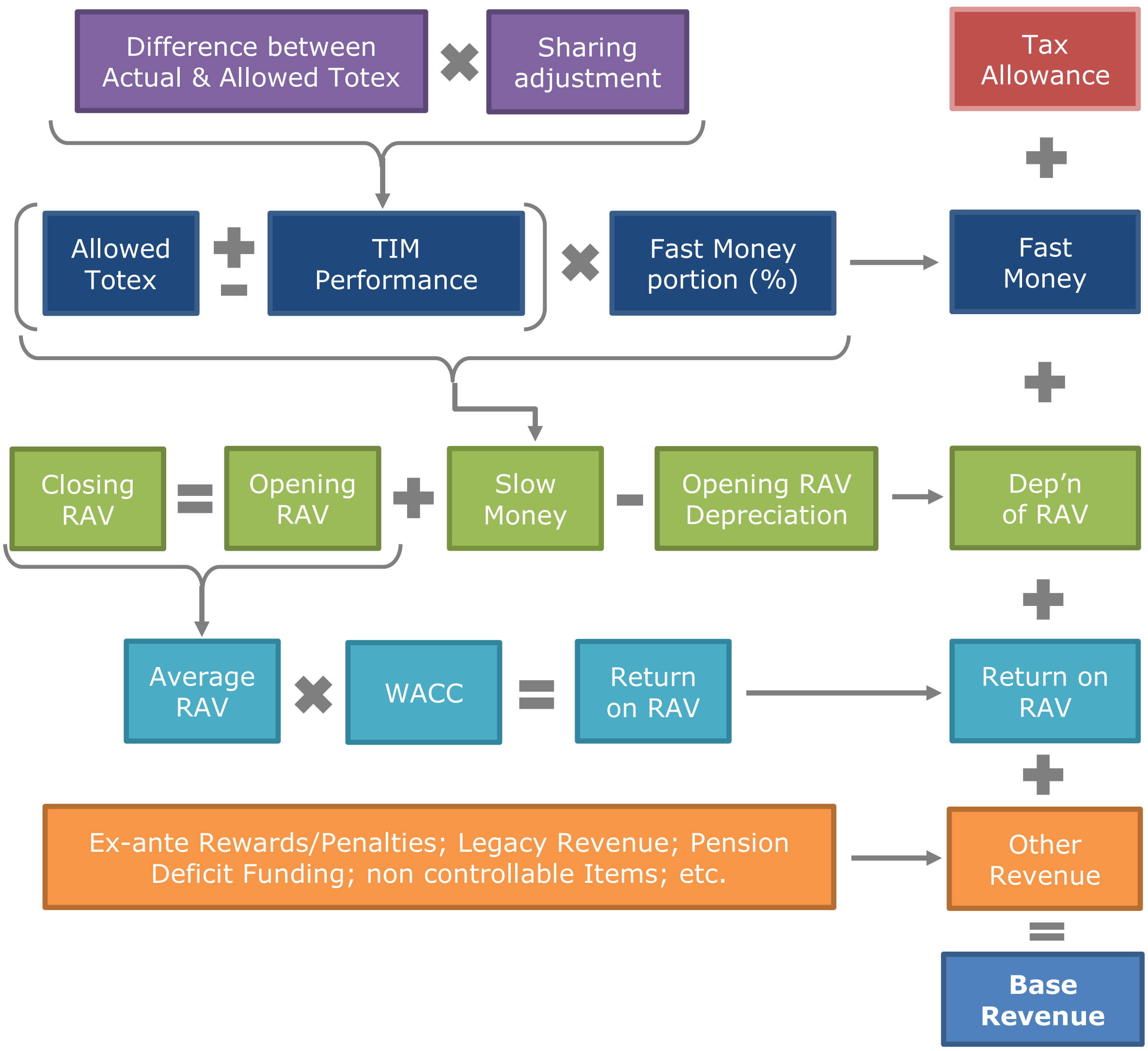
A1.8. The difference between actual Totex and Allowed Totex (whether the actual Totex is an underspend or overspend) is shared between the company (via modifying to Base Revenue) and with consumers and tax obligations. This process forms the TIM (explained in Chapter 2). To change company Base Revenue there is a revision to Allowed Totex that takes into account the sharing. As illustrated in Figure A1.2, this revised Allowed Totex is used in place of the original value. The revised Allowed Totex and the calculations that follow (described below) revise the Base Revenue that the company is allowed to recover as part of its overall Allowed Revenue.

A1.9. For Base Revenue calculations a portion of Allowed Totex is directly added to the Base Revenue (this is known as Fast Money as the company is allowed to collect revenue equal to this value during the next Allowed Revenue year).

A1.10. The remainder of allowed totex (known as Slow Money) is added to the opening Regulatory Asset Value (RAV). RAV is the long-term financial value of the capital employed in the regulated business

A1.11. RAV is based on the initial market value of the regulated asset base at privatisation, plus all subsequent additions. In accordance with established regulatory methods, RAV is gradually reflected in Base Revenue over multiple decades, reflecting the average lifetime of network assets. Amounts are deducted annually from opening RAV (this is depreciation). The depreciation value is then added to Base Revenue in the next Allowed Revenue year. The average of opening and closing RAV for the year also earns a return (at the Weighted Average Cost of Capital (WACC)).

Figure A1.2: Determination of Base Revenue



A1.12. As TIM performance becomes known, the RAV is recalculated using the updated Slow Money value. The latest view of RAV positions are shown in Table A3.2.

Table A1.2: RAV Balance

£m 2015-16 Prices	NGET TO	NGET SO	SHE Transmission	SPT
Total RAV at 1st April 2013	**10,574**	**89**	**1,177**	**1,452**
RAV at 1st April 2013	10,450	89	820	1,315
Transfer from Shadow RAV to RAV[98]	-	-	15	-
RAV Slow Money	3,698	119	1,016	906
RAV Depreciation	-2,122	-69	-174	-321
RAV at 31st March 2016	12,026	139	1,677	1,901
Shadow RAV[99] at 1st April 2013	124	-	358	137
Transfer from Shadow RAV to RAV	-	-	-15	-
Shadow RAV Slow Money	-	-	298	161
Shadow RAV Depreciation	-22	-	-75	33
Shadow RAV at 31st March 2016	102	-	565	332
Total RAV at 31st March 2016	**12,128**	**139**	**2,242**	**2,233**

A1.13. Total RAV has been increasing during the price control. Spending is rewarding the companies with Slow Money, which is added to RAV. These RAV additions are being gained at a greater rate than the rate at which the RAV is depreciating. A significant reason for this is that the RAV depreciation duration is being extended from 20 to 45 years by the end of the price control. The consequence of this change is that there is less depreciation (and therefore revenue) in the near term, but this is balanced by revenue through depreciation being returned for more years after expenditure takes place.

A1.14. The NGET Shadow RAV was for the England-Scotland Interconnector TIRG project. At the opening of the 2015-16 year (5 years after commissioning) the remaining RAV of this project transferred from Shadow RAV to RAV.

A1.15. The SHE Transmission Shadow RAV has been from two TIRG projects, Sloy and Beauly-Denny. Sloy was commissioned in 2011 and so has completed its 5 years of depreciation, therefore before the opening of 2016-17 its remaining Shadow RAV transferred to core RAV. The Beauly-Denny project is still being commissioned and so it continues to be accounted for as Shadow RAV.

[98] Includes a true up between the PCFM (where transfer values are as forecast at Final Proposals) and actual expenditure. This true up will only be reconciled in the PCFM at the end of the price control.
[99] Investments that are initially funded outside of the core of the RIIO-ET1 price control RAV. These have a different WACC and depreciation for 5 years compared to the main RAV. Once the normal return becomes applicable for a project its remaining Shadow RAV is transferred to RAV.

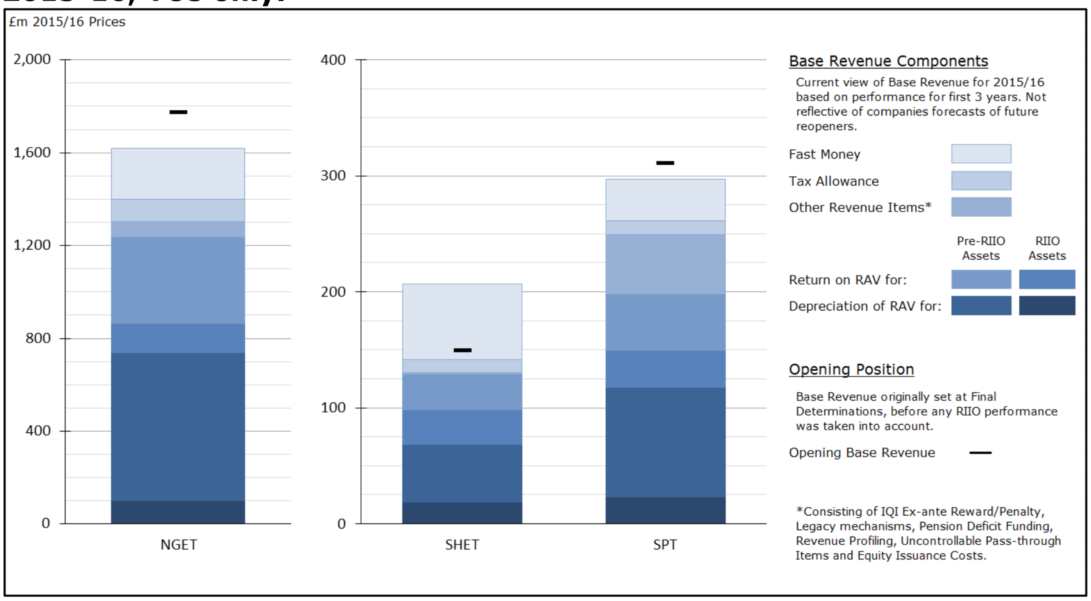
A1.16. The SPT Shadow RAV is comprised of five TIRG projects. The first of these that are expected to transfer to core RAV are Sloy and the England-Scotland Interconnector, this will take place at the opening of the 2017-18 year. The South West Scotland and Beauly-Denny project are still under construction.

Recalculated Base Revenue

A1.17. We recalculate Base Revenue taking into account items in Figure A1.1.

A1.18. Figure A1.3 shows the constituent parts of recalculated Base Revenue (stacked blue bars). The black lines are Opening Base Revenue.

Figure A1.3: Recalculated Base Revenue using actual performance data up to 2015-16, TOs only.



A1.19. Return on RAV and its depreciation of pre-RIIO assets continue to comprise the largest share (c. 60%) of all of Base Revenue. This is expected to decrease with successive years, meanwhile returns from RIIO-ET1 (Electric) investments will increase.

A1.20. For NGET a significant driver of change to Base Revenue is the reduction to Fast Money due to the sharing with consumers of their Totex underspend.

A1.21. For SHE Transmission Base Revenue has increased, despite sharing its Totex underspend with consumers. This is because a portion of its allowed Totex is treated as a variant whose value is revised during the price control. The SHE Transmission variants are being determined to be larger than the best view of their value as at FPs, increasing the overall expenditure allowance that SHE Transmission is spending.

A1.22. For SPT there has been comparably little change to Base Revenue and their actual Totex has been close to their allowed revenue.

Appendix 2: Totex analysis post "true-up" category

A2.1. The RIIO-ET1 control included forecasts for the allowances for load-related expenditure (less a forecast of the capital contributions expected to be received from customers) on exit connections to single users. The net expenditure for these connections is funded directly by the customer over the life of the asset in accordance with a pre-determined charging methodology. This income is not treated as part of the allowed revenue that TOs are permitted to recover through network charges (it is treated as "excluded services" income). The network companies net the forecast income from the total allowed revenue.

A2.2. FPs clarified that the position would be "trued up" at the RIIO-ET2 Price Control. This will entail resetting allowances to mirror the actual net capex and to reflect the removal of actual excluded service income from total allowed revenue, and the expectation that the monies received through customer contributions will be paid back.

A2.3. The table below illustrates the performance position of each TO in the reporting year 2015-16 adjusted to reflect the current estimated impact of the end of period (i.e. post "true up").

Table A2.1: Network company view of Totex in 2015-16 post true-up

£m 2015-16 Prices	NGET TO	SHE Transmission	SPT
Total allowed expenditure	1,324	808	345
Actual expenditure	1,161	524	358
Overspend (underspend) £m	(163)	(284)	13
Overspend (underspend) %	(12%)	(35%)	4%

A2.4. The combined allowed Totex for the TOs in the reporting year 2015-16 was £2,477 million. Actual expenditure was £2,042 million; an underspend of £435 million or 18%. NGET and SHE Transmission underspent compared to their 2015-16 allowed Totex by 12% and 35% respectively and SPT overspent by 4%.

Cumulative expenditure 2013-16 post true up

A2.5. Each TO is reporting a cumulative out-performance relative to the adjusted baseline allowances across the first three years of the RIIO-ET1 price control. The cumulative three year allowance for the TOs reported in 2015-16 was £7,387 million, and actual expenditure was £5,620million; an underspend of £1,767 million or 24%.

A2.6. NGET, as SO, reported a cumulative out-performance of £23m (5%) relative to its published allowed totex value across the first three years of the price control (£428m).

RIIO-ET1 forecast post true up: network company view

A2.7. Based on the information provided to us through the 2015-16 regulatory reporting pack, over RIIO-ET1, the TOs currently expect to spend £16.7bn. This represents actual totex for 2013-16 plus a five years forecast spend for 2016-21. The combined allowed Totex for the TOs across the period is currently forecast to be £18.5bn; a cumulative forecast underspend of 10% (£1.9bn). All TOs currently anticipate a position of underspend across the price control.

Table A2.2: Adjusted allowance v expenditure post true up (£m)†

	Cumulative performance: 2013-16				*Current RIIO-ET1 Forecast: 2013-2021*			
	Allowance	Actual Expenditure	Difference		Allowance	Actual & Forecast Expenditure	Difference	
			£m	%			£m	%
NGET (TO)	4,791	3,683	-1,108	-23%	13,170	11,652	-1,519	-12%
SPT	1,190	891	-299	-25%	2,325	2,212	-113	-5%
SHE Transmission	1,406	1,046	-361	-26%	3,037	2,770	-267	-9%
Total	7,387	5,620	-1,767	-24%	18,532	16,633	-1,899	-10%

† This table is identical to table 2 in Chapter 2. The figures are based upon the TOs' published figures.

Totex Analysis: Further Ofgem Adjustments

A2.8. As noted in chapter 5, there is significant uncertainty with some investment projects included in the price control information received from the TOs. The most notable example is the Strategic Wider Works (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.

A2.9. To overcome the uncertainty around the actual amount and timing of certain categories of expenditure over the price control period, the network companies agreed to populate the reporting pack by assuming a neutral performance. This means that the level of indicative allowance set by the company is the same as the level of forecast costs expects to incur. The costs will be subject to a within period assessment by Ofgem at some future date and only the TO will receive funding for efficiently incurred costs. This approach applies to areas of the price control other than SWW. [100]

A2.10. It is therefore possible to remove the impact of costs that we have not yet assessed or agreed from the performance analysis.

[100] An example is the Non Load Works under Special Condition 6H for SPT.

A2.11. Further adjustments can also be made to exclude expenditure in areas where we think it is unlikely that the conditions required to trigger the additional allowances will be met and/or where funding is likely to be available through another route (e.g. NOMs).

A2.12. The text below provides a high level explanation of the adjustments made. It is important to note that by removing such costs from our analysis we are not indicating that the company values submitted as part of the reporting pack are not an accurate forecast of the required activities or suggest that the activities they are associated with are inefficient. The adjustments have been made only to reflect the uncertain nature of these costs and the associated within period assessment that has yet to take place or has not yet concluded.

Load related

A2.13. We have made adjustments to the totex allowance and expenditure values to remove the impact of works that have not yet been assessed or agreed in two load-related areas: SWW 'not yet approved' (currently applicable to NGET and SPT) and the licence term "TPWW" (applicable to NGET only).

A2.14. In terms of TPWW, NGET has submitted a claim for the Hackney - Tottenham - Waltham Cross uprating scheme. This project is detailed along with the other baseline IWW schemes in Special Condition 6J. In November 2013 the NDP analysis signalled the investment is not now in consumers' interest to proceed and the investment has been delayed indefinitely. NGET is currently seeking to recover the costs of works incurred as a result of the output not being delivered. The total TPWW claim is £33.2m. This claim is currently being analysed to understand if it was efficiently incurred as well as whether it is reusable to deliver a different output.

Non-load related

A2.15. We have made further adjustments under the costs categories of non-load related, non-operational capex and opex to remove the impact of costs that we have not yet agreed[101] or we think are outside the scope of RIIO-ET1.

A2.16. The adjustments made in the category of non-load related expenditure reflect our general analytical approach that considers Asset Replacement Capex and Other Capex together.

A2.17. We have not adopted the allowance recategorisations in the NLR category proposed by NGET[102]. However, we have moved the associated expenditure from Non-operational capex to Other Capex. We have removed the impact of the capex spend in 2015-16 and forecast costs for visual impact projects (Other capex); with a forecast

[101] For example, assumptions of recovery for spend through allowances that will be the subject of a claim in a future reopener window.
[102] Optel & BT21 allowances recategorised from Asset Replacement Capex to Non Operational Capex, and Metering, Protection and Control, substation Other, Cable Tunnels and other non load related allowances recategorised from Asset replacement Capex to Other capex.

value of £348m. NGET's NLR expenditure has also been adjusted to reflect other exceptional items associated with specific legal costs.

A2.18. The adjustments made to NLR costs for SPT follows the same principle as NGET. The most material adjustment that we have made relates to special condition 6H. This condition 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 has included the cost of these schemes (£36m) in its overall forecasts.[103] We have excluded the forecast costs in the figures quoted in this chapter.

A2.19. Only one minor adjustment has been made to the forecast costs of SHE Transmission: removal of £6m associated with physical site security works (Other capex).

A2.20. The impact on allowed totex and expenditure is highlighted in tables A2.3 and A2.4 below. The values presented are adjusted to reflect the current estimated impact of the end of period (i.e. post "true up").

Table A2.3 : Allowance vs actual expenditure in 2015-16 (£m): Ofgem view

£m 2015-16 Prices	NGET TO	SHE Transmission	SPT
Total allowed expenditure	1,263	808	344
Actual expenditure	1,120	524	356
Overspend (underspend) £m	-143	-284	12
Overspend (underspend) %	-11%	-35%	4%

A2.21. The combined underspend in the reporting year 2015-16 is £415 million or 17%. NGET's estimated underspend is reduced by £20m under this analytical approach. There is no material change to the performance position of SHE Transmission or SPT (compared to table A2.1).

103 More detail on this issue and our minded to position is available from our consultation on MPR parallel work. The consultation is available from the Ofgem website.

Table A2.4: Adjusted allowance v expenditure (£m): Ofgem view

	Cumulative performance: 2013-16				*Current RIIO-ET1 Forecast: 2013-2021*			
	Allowance	Expenditure	Difference		Allowance	Actual & Forecast Expenditure	Difference	
			£m	%			£m	%
NGET (TO)	4,587	3,602	-985	-21%	11,035	9,606	-1,428	-13%
SPT	1,186	887	-299	-25%	2,233	2,130	-103	-5%
SHE Transmission	1,406	1,046	-361	-26%	3,037	2,763	-274	-9%
Total	7,179	5,536	-1645	-23%	16,304	14,499	-1,805	-11%

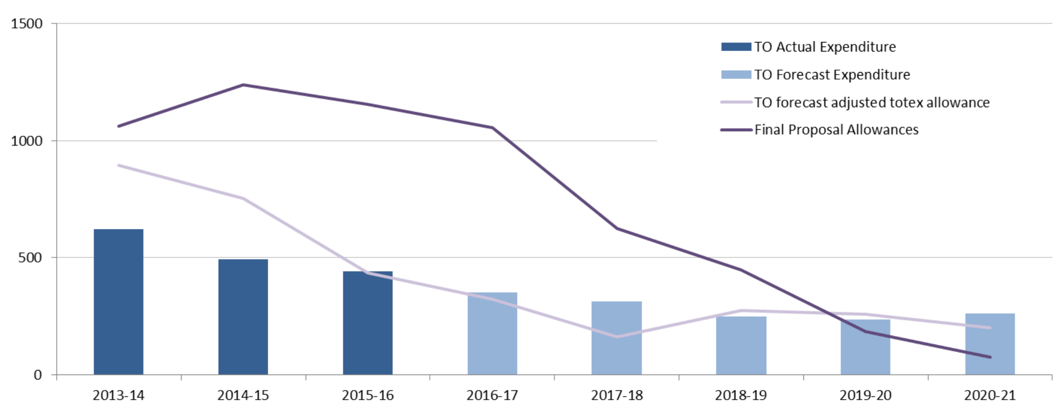
A2.22. The combined allowed Totex for the TOs across the period under this approach is currently forecast to be £16.3 billion; a cumulative forecast underspend of 11% (£1.8bn). The TOs underspent by £1.65 billion (23%) in the first three years of RIIO-ET1 (a £122m reduction in total underspend compared to table A2.2).

A2.23. This following sections set out the impact of the adjustments made in each of the cost categories that comprise allowed totex: load related, NLR, non-operational capex and opex.

Load related capex

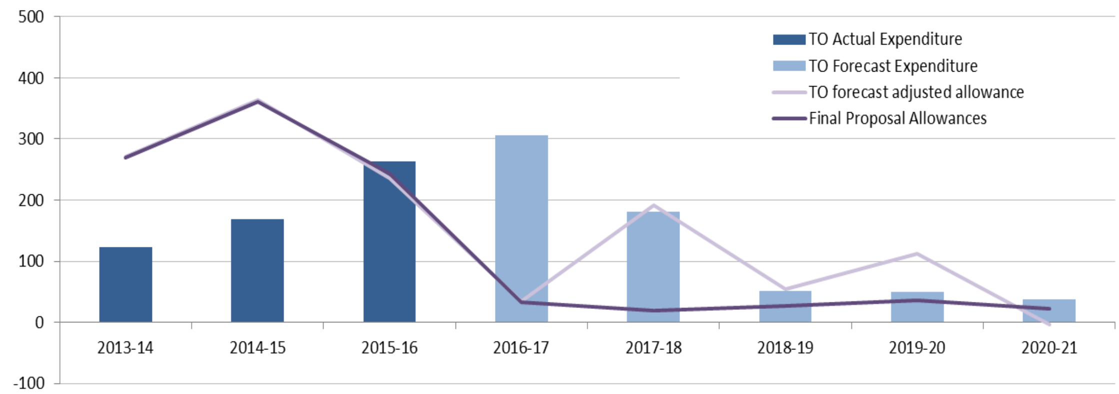
A2.24. Figures A2.1 and A2.2 demonstrate the impact of the fall in LR workload across the price control period.

Figure A2.1: Actual and forecast expenditure vs TO forecast LR allowance: NGET



A2.25. Overall, NGET is forecasting a net LR expenditure of £2.9bn. Applying our adjustments, we estimate that NGET's LR allowances will be £3.3bn across the price control period as a result of changes in requirements; and underspend of £334m or 10%.

Figure A2.2: Actual and forecast expenditure vs TO forecast LR allowance [104]: SPT



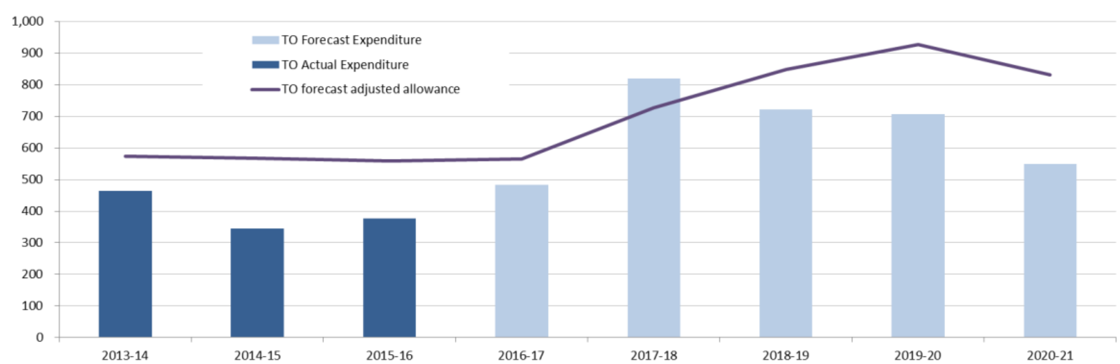
A2.26. SPT is forecasting a net LR expenditure of £1.18bn, which is £80m below the adjusted total LR allowance of £1.26bn across the price control period; an underspend of 6%.

A2.27. SHE Transmission's RRP submission contained no investments in the category of SWW not yet approved.

Non load-related capex

A2.28. Figures A2.3, A2.4 and A2.5 demonstrates the NLR workload across the price control period across each transmission area.

Figure A2.3: Actual and forecast expenditure vs TO forecast NLR allowance: NGET

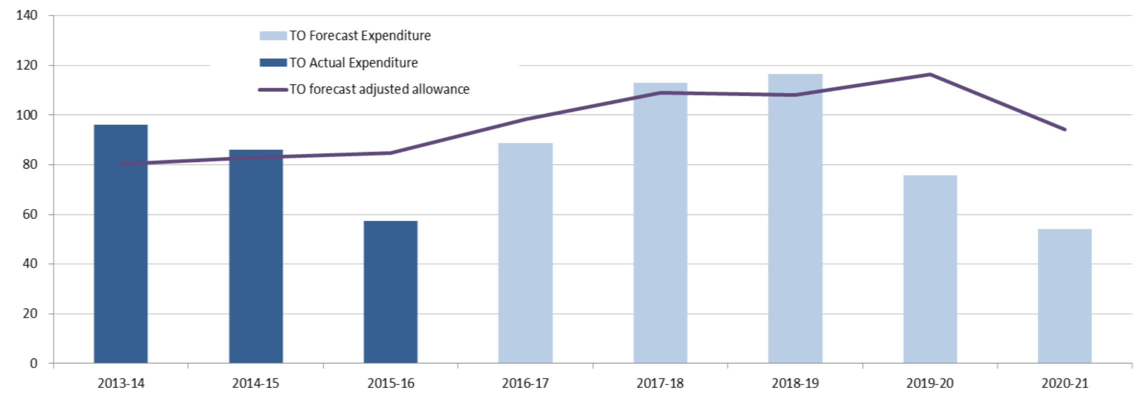


[104] These values exclude the value of capital works associated with any non-approved SWW schemes.

A2.29. NGET is forecasting a net NLR expenditure of £4.5bn. Applying our adjustments, we estimate that NGET's LR allowances will be £5.6bn across the price control period as a result of changes in requirements; and underspend of £1.1bn or 20%.

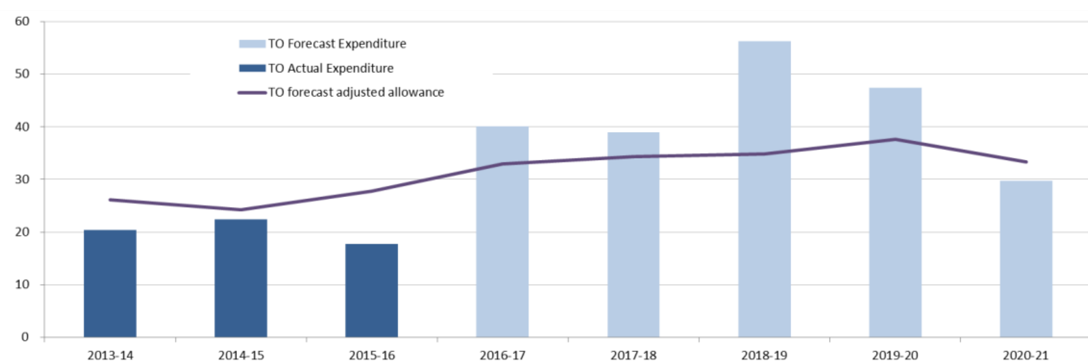
A2.30. We have made further adjustments totalling £14m that remove the impact of future allowances forecast to be triggered through uncertainty mechanisms associated with asset replacement and other capex cost categories.

Figure A2.4: Actual and forecast expenditure vs TO forecast NLR allowance: SPT



A2.31. SPT is forecasting a net NLR expenditure of £688m, which is £86m below the adjusted total LR allowance of £774m across the price control period; an underspend of 11%.

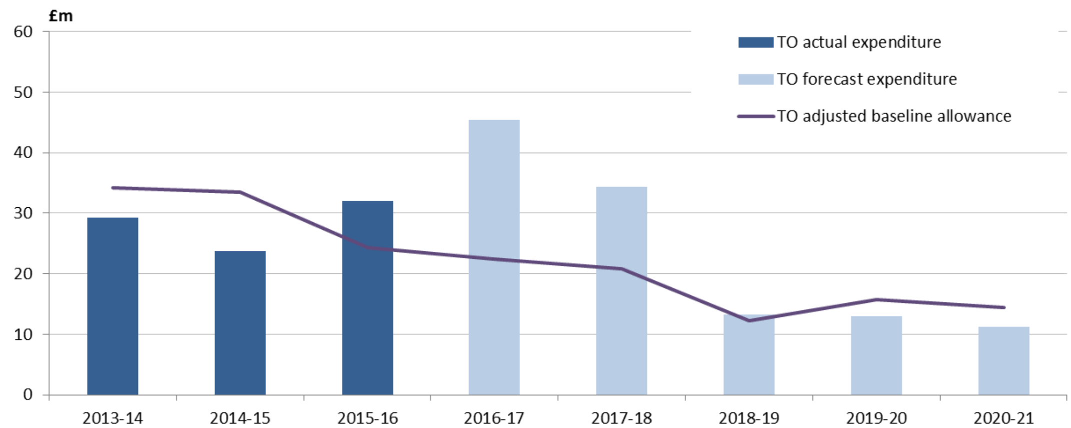
Figure A2.5: Actual and forecast expenditure vs TO forecast NLR allowance: SHE Transmission



A2.32. The above figures reflect SHE Transmission's published figures and demonstrates that it currently anticipates an outperformance of 9% across RIIO-ET1.

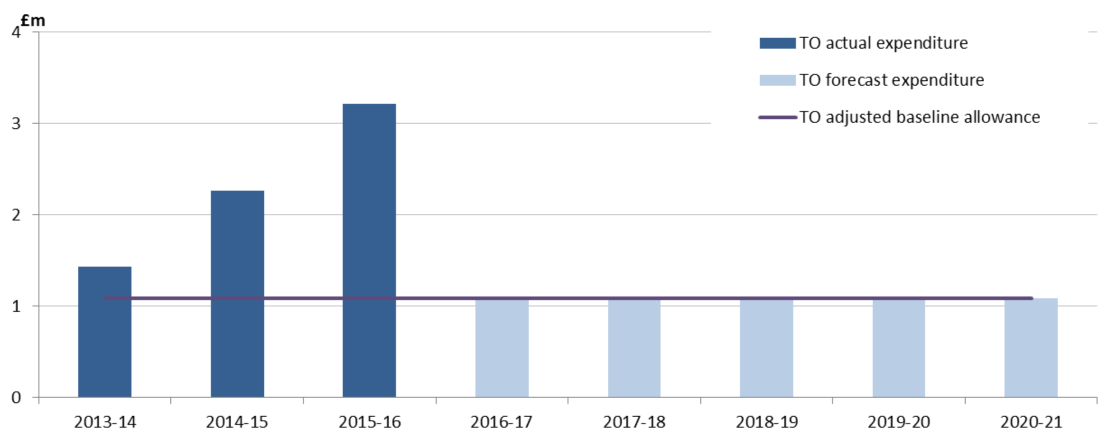
Non-operational capex

Figure A2.7: Actual and forecast expenditure vs TO forecast non-op capex allowance: NGET



A2.33. NGET is forecasting a net LR expenditure of £202m. As noted in chapter 5, NGET's total expenditure includes costs associated with the Optel/BT21 works (which NGET's RRP16 submission had recategorised as Other Capex). NGET's non-operational allowances will be £178m (with no reopeners) across the price control period as a result of changes in requirements; and overspend of £25m or 14%.

Figure A2.8: Actual and forecast expenditure vs TO forecast non-op capex allowance: SPT



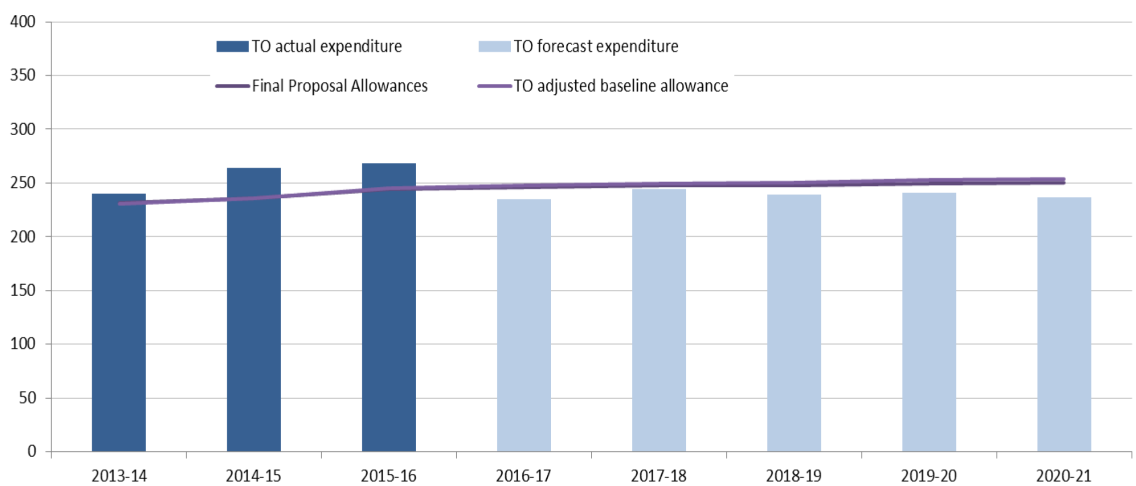
A2.34. SPT is forecasting a net expenditure of £12.3m, which is £3.6m above the adjusted total allowance of £8.7m across the price control period; an overspend of 42%.

A2.35. We have made no adjustments to SHE Transmission's non-operational capex analysis.

Controllable opex

A2.36. As noted in Chapter 5, NGET's published values may overstate the performance position with regards to controllable opex as the forecast allowances include the capital expenditure associated with the ISS project. We have removed the capital ISS expenditure from the forecast opex allowance values to be consistent with how NGET is currently treating this spend. The impact of this change is to bring the level of forecast expenditure (£1.97 billion) more in line with the adjusted forecast allowances across the price control (£1.95 billion).

Figure A2.9: Actual and forecast expenditure vs TO forecast opex allowance: NGET



A2.37. Under this approach, the level of overspend reported by NGET in the first three years of RIIO-ET1 is £62m (or 10%) above its cumulative opex allowance for this period. NGET forecast that opex expenditure levels in the next five years of RIIO-ET1 will fall below forecast allowance (between 1 and 5%) as a result of the cost recategorisation as well as anticipated efficiency gains. Overall, an overspend of 1% is currently forecast across RIIO-ET1.

A2.38. No changes were made to the controllable opex forecasts of SHE Transmission or SPT[105].

[105] Our adjusted analysis did not adjust for the additional directed funding with regard to the IRM decision in September 2015 (c.£2.4m).

SO Performance

A2.39. As noted in Chapter 6, NGET's published values do not include cost recategorisations applied by NGET to reflect the treatment of spend (and submitted as part of the "restated" submission). The text below provide our analysis of the performance position of the SO in light of the restated values it has provided.

2015-16

A2.40. NGET (SO) has outperformed against its totex allowance of £141m in the third year of RIIO-ET1 (2015-16). The underspend is relatively small (£4.5m) and comprises a small underspend in non-operational capex (£0.6m) and a slightly larger underspend in controllable operational costs (£3.9m).

Cumulative performance for the first three years (2013-16)

A2.41. NGET reports that the actual cumulative level of SO total expenditure is £23.2m below allowances (£428.4m) for the first three years of the RIIO-ET1 period (5%). The level of underspend comprises a large underspend in non-operational capex (£26.4m) and a small overspend in direct costs (£3.2m).

A2.42. The wider costs incurred to date by NGET in Business Support is unchanged (underspent by £3.8m, or 3%).

Forecast performance for RIIO-ET1 period

A2.43. NGET forecasts that the required level of SO total expenditure will be £18m below adjusted allowances (£1,156m) for the eight year RIIO-ET1 period. The component elements of the underspend change as a result of NGET's recategorisation. The non-operational capex underspend decreases from £60m to £0.5m and the underspend in controllable operational costs is seen to decrease by an equivalent amount (to £17m).

Appendix 3: MPR decision

A3.1. Our review of these data submissions has run concurrent with the Mid-Period Review (MPR) for Electricity Transmission. One of the areas that we decided to include in the scope of the MPR was the development of new outputs for NGET to reflect enhancements to its System Operator (SO) role. The enhanced activities reflect developments in three areas:

- the implementation of the Integrated Transmission Planning and Regulation (ITPR) licence requirements in 2015
- delivery of two new balancing services products: Demand Side Balancing Reserve (DSBR) and Supplementary Balancing Reserve (SBR), and
- a new programme of activities aimed at encouraging and facilitating increased participation in demand-side response (DSR).

A3.2. The following table sets out our proposed allowances for each of these outputs areas covered by its enhanced SO role.

Table A3.1: MPR changes to NGET TO Non-variant allowed load related capex expenditure

Output area	Our proposed allowances (2009-10 prices, £m)
ITPR activities	15.00
SBR/DSBR	4.50
DSR	2.02
TOTAL	21.52

A3.3. Our MPR process also considered changes to outputs in two areas relevant to NGET's role as TO in England and Wales, summarised below.

- **Protecting nine sites against rising fault currents**. The need for this was driven by NGET's forecast of increases in transmission connected generation over the T1 period. We had included an allowance of £39.5m (09-10 prices) for this output.
- **Installing 11 shunt reactors**. The need for this was driven by falling reactive power demand across the transmission network leading to an increased need for voltage control measures. We had included an allowance of £53.3m (09-10 prices) for this output.

A3.4. We have decided to lower NGET TO non-variant allowance by £38.1m; from £1.159 million to £1,121 million (09-10 prices). This reflects a reduced requirement to protect sites against rising fault levels. (2009-10 prices). On shunt reactors, we have decided to declassify this as an output and make no adjustments to allowances.

A3.5. The impact on NGET's allowed totex and expenditure is highlighted in tables A3.2. The values presented are adjusted to reflect the current estimated impact of the end of period (i.e. post "true up") and include the impact of the MPR decision.

A3.6. Based on the information provided to us through the 2015-16 regulatory reporting pack, over RIIO-ET1, NGET currently expects to spend £10.7bn. The combined allowed Totex across the period is currently forecast to be £12.2bn; a cumulative forecast underspend of 12% (£1.4bn).

Table A3.2: Adjusted allowance v expenditure (£m): Ofgem view

	Cumulative performance: 2013-16				*Current RIIO-ET1 Forecast: 2013-2021*			
	Allowance	Expenditure	Difference		Allowance	Actual & Forecast Expenditure	Difference	
			£m	%			£m	%
NGET (TO)	4,544	3,602	-942	-21%	10,989	9,606	-1,383	-13%
NGET (SO)	435	405	-30	-7%	1,182	1,138	-44	-4%
Total	**4,980**	**4,007**	**-972**	**-20%**	**12,171**	**10,745**	**-1426**	**-12%**

Appendix 4: Glossary of terms

Allowed revenue
The amount of money that a network company can earn on its regulated business.

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.

Capital expenditure (capex)
Expenditure on investment in long-lived assets, such as overhead lines.

Capitalisation policy
The approach that the regulator follows in deciding the percentage of total expenditure added to the RAV (and thus remunerated over time) and the percentage of expenditure remunerated in the year it is incurred.

Cost of capital
This is the minimum acceptable rate of return on capital investment. It includes both the cost of debt to a firm, and the cost of equity.

Cost of debt
The effective interest rate that a company pays on its current debt. Ofgem calculates the cost of debt on a pre-tax basis.

Cost of equity
The rate of return on investment that is required by a company's shareholders. The return consists both of dividend and capital gains (e.g. increases in the share price). Ofgem calculates the cost of equity on a post-tax basis.

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.

Opening Base Revenue
The best estimate at the start of a price control on the amount of money that a network company can earn on its regulated business.

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overheads.

Pass through Costs
Costs passed through to the customer from the licensee.

Regulatory Asset Value (RAV)
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.

Return on Regulatory Equity (RORE)
The financial return achieved by shareholders in a licensee during a price control period from its out-turn performance under the price control.

Sharing Factor
It represents the percentage that the licensee bears in respect of an overspend against totex allowances or retains in respect of an underspend against totex allowances.

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.

Total expenditure (Totex)
Totex consists of all the expenditure relating to a licensees regulated activities with some specified exceptions. See the RIGs for a list of these exceptions.[106]

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-ET1 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 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.

[106] https://www.ofgem.gov.uk/publications-and-updates/notice-modification-relation-riio-t1-electricity-transmission-price-control-regulatory-instructions-and-guidance-version-3-0-0

Appendix 5: List of figures and tables

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