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Transmission networks: Report on the performance of Transmission Owners during the regulatory periods TPCR4 and TPCR4RO

2007-08 to 2012-13

Information

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

Overview

We regulate Great Britain's transmission owners (TOs) and the GB system operators to protect existing and future energy consumers. We conduct price controls where the TOs earn revenues from consumers in return for delivering certain outputs.

This report summarises the outputs, incentives, Regulatory Asset Value, revenue allowances and company expenditure during Transmission Price Control Review 4 (TPCR4) and the subsequent rollover year. TPCR4 covered the period from April 2007 to March 2012, with a rollover year from 1 April 2012 to 31 March 2013. This report, therefore, covers the performance of the companies in the six years before the current price control, RIIO-T1, which started in April 2013.

In addition, the report outlines the performance of the system operator companies, which provide balancing services to the entire gas and electricity systems.

Context

We regulate the monopoly and some of the competitive segments of the gas and electricity markets. The competitive segment broadly encompasses the wholesale markets and the supply of electricity and gas. The monopoly segment is the network that transports the gas and electricity between the wholesale and supply markets. These are monopolies because the high costs of building and maintaining the networks would make it inefficient and costly for consumers to have multiple networks run by competing companies. The network is made up of transmission owners, whose large pipes and cables connect the generators and gas suppliers to the next element of the network, the distribution companies. These, in turn, connect to the supply segment.

There is one gas TO and three electricity TOs:

- National Grid Gas plc (NGGT)[1], which owns the high pressure gas transportation system across Britain
- National Grid Electricity Transmission plc (NGET), which owns the high voltage electricity network in England and Wales
- SP Transmission Limited (SPTL), which owns the high voltage electricity network in the south of Scotland
- Scottish Hydro Electric Transmission plc (SHE Transmission), which owns the high voltage electricity network in the north of Scotland.

In addition to their TO responsibilities, NGGT and NGET are the designated gas and electricity System Operators (SOs). They therefore have responsibility for day-to-day system operation, including balancing of the system and constraint management. The price controls for NGGT and NGET include allowances for the internal SO costs for NGGT SO and NGET SO, and some external costs for NGGT SO. All other external SO cost allowances are determined via a separate process.[2]

The electricity transmission network consists of the high voltage electricity wires which convey electricity from power stations to local distribution networks and large customers directly connected to the transmission system. The gas transmission network consists of high pressure long distance gas pipelines and compressors which transports gas from offshore, storage and LNG facilities to local Gas Distribution Networks. They are owned and operated by privately owned companies who have territorial monopolies. To protect the interests of consumers, we regulate these companies using price controls.

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[1] National Grid Gas plc also covers other businesses, including its system operator business and its distribution operations. The term 'NGGT' is used to distinguish the transmission network business.
[2] We develop SO incentive schemes that are designed to encourage NGET and NGGT to manage the costs of operating each system effectively. The SO incentive schemes establish cost targets that NGET and NGGT are expected to achieve in performing their SO roles.

Associated documents

- Transmission Annual Report 2010-11, 30 March 2012: https://www.ofgem.gov.uk/ofgem-publications/54015/transmission-annual-report-2010-11-final.pdf
- Transmission Price Control Review: Final Proposals, 4 December 2006, Ref: 206/06: https://www.ofgem.gov.uk/ofgem-publications/56158/16342-20061201tpcr-final-proposalsinv71-6-final.pdf
- Transmission Price Control Review 4 (TPCR4) Rollover: Final Proposals, 28 November 2011, Ref 162/11: https://www.ofgem.gov.uk/ofgem-publications/53953/tpcr4rolloverfinalproposals.pdf
- RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas – Overview, 17 December 2012, Ref 169/12: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf
- RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd, 23 April 2012, Ref 58/12: https://www.ofgem.gov.uk/ofgem-publications/53746/sptshetlfp.pdf
- Gas System Operator incentive schemes from 2013 Final Proposals, 17 December 2012, Ref 171/12: https://www.ofgem.gov.uk/ofgem-publications/39922/gas-so-incentives-2013-final-proposals-consultation.pdf
- National Grid Gas System Operator Incentives from 1 April 2013, 31 January 2013: https://www.ofgem.gov.uk/ofgem-publications/39913/gas-so-cover-letter.pdf
- System Operator incentive schemes from 2013 Initial Proposals, 27 July 2012, Ref 106/12: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/IP%20SO%202013.pdf
- National Grid Electricity Transmission and National Grid Gas System Operator Incentives from 1 April 2007, 2 October 2006, Ref 179/06: https://www.ofgem.gov.uk/ofgem-publications/40146/15613-17906.pdf
- A glossary of terms for all the RIIO-T1 and GD1 documents is on our website: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisiongloss.pdf

Contents

Executive summary

The Transmission Price Control Review 4 (TPCR4) set the revenues the transmission companies were able to recover from consumers over the period 1 April 2007 to 31 March 2012. TPCR4 was extended for an additional year from 1 April 2012 to 31 March 2013 to enable the RIIO price control principles to be incorporated into the current transmission price control (RIIO-T1).[3]

Over the course of the six years of TPCR4 and the rollover year, the TOs have between them operated and maintained the network of 24,000 km of electricity transmission wires and 7,600 km of gas transmission pipeline, improving the reliability of the networks, reducing harmful environmental emissions and improving stakeholder engagement.

Outputs performance

Reliability

The overall reliability of the electricity transmission system has remained consistently high over the six years and in 2012-13 was well over 99.99% for all three electricity TOs.

Additional electricity generation capacity

The price control recognised that the future supply and usage of electricity is changing. Moving to a low carbon future drives the ongoing need for new sources of renewable electricity generation which ultimately need to be connected to the grid. Various mechanisms were introduced to facilitate this. Over the period the connected generation capacity has risen by 25% to 95.6 GW. There are also many schemes in the course of construction which, on completion, will connect additional generation capacity to the system.

Customer satisfaction

Over the six year period we have observed increased stakeholder engagement and a willingness of the TOs to engage fully. The TOs have worked well with us towards developing a new framework in RIIO-T1 to measure and further improve their performance in this area.

Environment

The price control arrangements have incentivised the TOs to reduce their environmental footprint, in particular we have seen reductions in sulphur hexafluoride (SF_6), carbon dioxide, nitrogen oxide and nitrogen dioxide.

SF_6 is a particularly potent greenhouse gas commonly used in high voltage switchgear. National Grid Electricity Transmission (NGET) and SP Transmission Limited (SPTL), have

[3] See associated documents for information on RIIO-T1

both made large reductions (NGET 41%, SPTL 49%) for which they were rewarded under the incentive schemes in place for them. Scottish Hydro Electric Transmission plc (SHE Transmission) were not targeted to reduce SF_6 emissions in this period.

Revenue and customer impact

During TPCR4 and the rollover the estimated average annual network charge per household increased from £13.96 to £21.24 for electricity transmission. For gas transmission, the average annual charge per household increased from £12.28 to £16.22.

The main reason for these increases has been the unprecented growth in the network as it expands to meet the challenge faced by the industry in the country's target to reduce carbon emissions.

TPCR4 was established in December 2006, at a time when forecast investment was expected to increase by 100 per cent in comparison to the previous price control. The six years saw considerable growth in the asset bases of the TOs, driven by the need to connect new forms of generation to assist in the move to a more carbon neutral energy system for Great Britain. This was required to be delivered whilst at the same time maintaining a safe, secure and affordable system for existing and future consumers.

The total cost of achieving this was £11bn over the 6 years, some £0.7bn below the total allowances over the period with the companies looking for more efficient ways to maintain, operate and extend the networks. Under the capex incentive mechanism 75 per cent of the £0.7bn saving has been passed onto consumers. The allowances included investment of more than £9bn in new assets in Britain's gas and electricity transmission systems.

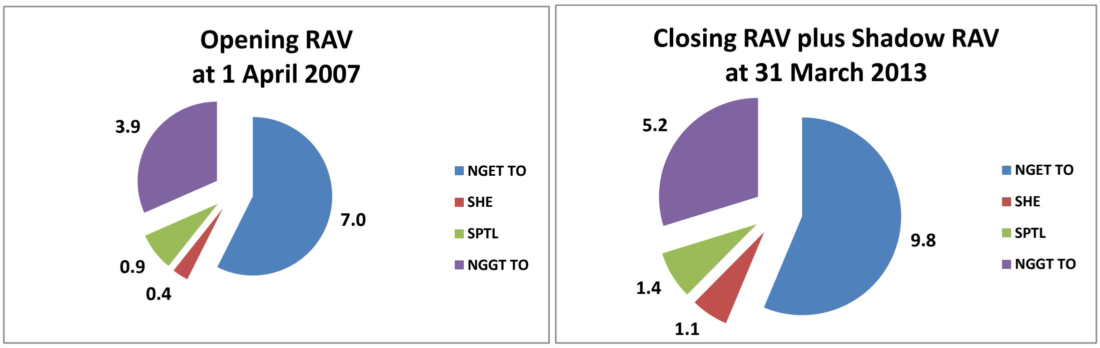
This report gives an explanation of the expenditure, revenue and outputs over these six years of large scale investment. In particular, we note the following key points on performance during TPCR4 and the rollover:

- Across all TOs and SOs total expenditure (totex)[4] was £11bn, of which £9bn was invested in new assets during the six years. This resulted in growth in the TOs' regulatory asset value (RAV)[5]. The average growth of which was 41 per cent over the period, and the largest was an increase of 154 per cent for SHE Transmission. The TO RAVs are expected to continue to grow substantially over the RIIO-T1 period. Figures 1 and 2 illustrate the growth in RAV.

[4] Operating expenditure (opex) plus capital expenditure (capex).
[5] RAV is the total regulatory value of, in this case, the transmission assets.

Figures 1 and 2: Change in RAV (£m)

- In terms of the main expenditure items:



- The electricity TOs spent around £3.9bn on new assets, to connect new electricity generation capacity to the network.

  - £1.4bn of this was funded through scheme specific allowances (TIRG or TII)[6]

  - Other connections capacity was funded through allowances set before the start of TPCR4 and its rollover. Where TOs have been able to supply connections for less than assumed the saving is shared with consumers.

  - NGET spent £574m less than its price control allowances in building new connections. This 24 per cent saving reflected efficiency in delivery of the required connections.

  - SPTL spent £203m less than its price control allowances. This 46 per cent saving reflected planning delays and less growth than anticipated, but also efficiency. Where delayed, these connections will need to be delivered in RIIO-T1.

- NGGT spent about £1.3bn on additional capacity.

  - National Grid Gas plc (NGGT) would have spent less than allowed, but spent £300m more than expected on the major pipeline from Milford Haven. We will be reviewing the efficiency of this project during 2014-15.

[6] These schemes are explained in Appendix 3.

- The TOs spent around £3.3bn on maintaining the electricity and gas transmission networks.

  - NGET spent 10 per cent less than we allowed (primarily by extending asset lives). The volumes of replacement were lower than the company business plan and our modelling, especially in first five years (between 30 per cent and 50 per cent lower in some cases).

  - SPTL initially deferred some maintenance activity and did not succeed in making up the backlog. This resulted in expenditure 24 per cent less than allowed, although with no discernible impact on the performance of the assets.

  - SHE Transmission spent slightly more than allowances. However, it is not clear where the benefits of this overspend can be seen in terms of improved asset health.

  - NGGT spent broadly in line with allowances on maintaining their asset base.

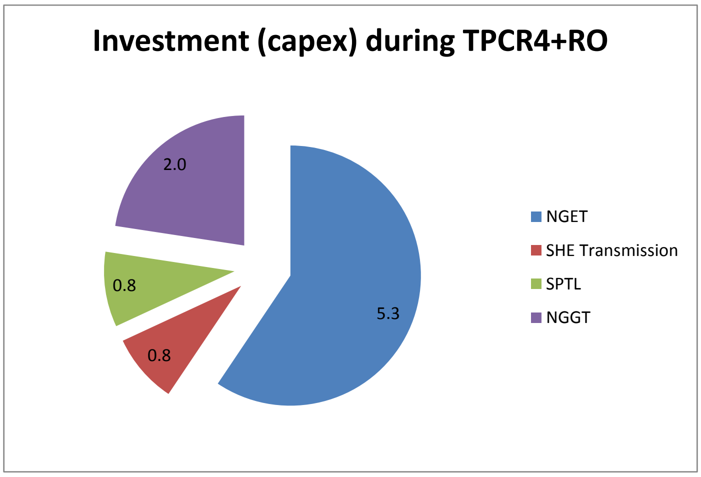
  - In RIIO-T1 the development of network output measures (NOMs) will enable us to track performance in this area and if necessary challenge underinvestment or failing asset health. Where NOMs targets are not met there will be financial implications for the RIIO-T2 price control.

- Where TOs have spent less capex than allowed, a sharing mechanism enables them to retain 25 per cent of the underspend, returning 75 per cent to consumers.

- Forecasting by the TOs has been poor. For the rollover year the capex forecasts were considerably overestimated with, for example, companies overstating load forecasting by 43-54 per cent. We challenged these forecasts and revised allowances down to set them at more realistic levels.

  In RIIO-T1 TOs will publish company forecasts annually and we will comment on their accuracy. This accuracy of forecasting will help inform our decisions for RIIO-T2.

Figure 3: TPCR4 and rollover investment (capex) by company (£bn)



1. Introduction

Chapter summary

Outlines the purpose and structure of the report. Provides additional context for the transmission network, its regulation, and the price control mechanism.

Purpose of the report

1.1. This report gives stakeholders important information on the performance of the transmission networks during Transmission Price Control Review 4 (TPCR4) and the rollover year.

1.2. The key output areas include connections, the environment, and network reliability and safety.

1.3. The report also reviews transmission owners' (TOs') important revenue and expenditure across TPCR4 and the rollover year.

1.4. While TPCR4 was not an output focussed regime, we consider the performance against those outputs that were identified.

1.5. Unless stated otherwise, all prices in this report are in 2012-13 terms.

Understanding this report

1.6. Here is some useful information to help understand this report:

- One of our primary goals is to protect the interests of consumers. Our role is to ensure the network companies earn only fair amounts of money to effectively run their networks, and to allow them to build new assets when necessary. We scrutinise all the business plans submitted by these companies to ensure their spending is efficient and aligned with the interests of consumers

- Our assessment approach depends on the nature of the costs. The main categories are:

    - Capital expenditure (capex): this is spending on assets, such as cables and pipes. This spending is further divided into load-related capex (LRE), and non-load-related capex (NLRE). LRE is spending motivated by changes in the use of the system (such as new wind farms needing to be connected to the electricity transmission system). NLRE is spending on renewing the current system

    - Operating expenditure (opex): this is spending on inspecting and maintaining the assets. For example, staff to operate the network

- In this report, for each of the TOs and system operators we look at the spending in these areas to check whether it has been efficient and whether it delivered the outputs consumers need. For example, we look at whether the system is more or less reliable.

1.7. The Transmission Price Control Review 4 (TPCR4) and its rollover year were the fourth price control of their kind. For April 2013 to March 2021 we are taking a new approach to price controls, known as RIIO-T1[7]. This changes how companies are funded to better ensure that the interests of consumers are protected. RIIO aims to promote smarter gas and electricity networks for a low carbon future and puts sustainability of supply to customers at the heart of what network companies do. The network companies now have to seek outside views from stakeholders when developing their long-term business plans and must show how they have responded to stakeholder views.

1.8. To better inform stakeholders we have agreed with the TOs that they will publish an annual report each September (initially). This will detail outputs and expenditure and forecast performance. We will produce an annual RIIO-T1 report that gives our overview of the sector's performance. The new format will focus on TOs' delivery of the primary and secondary deliverable outputs.

1.9. This report discusses the performance of the four TOs and two SOs over TPCR4. This ran from 2007-08 to 2011-12, and was extended by a rollover year to cover 2012-13[8]. This report covers the entire six-year period and draws conclusions on the TOs' performance. It also outlines many of the areas we will be monitoring under RIIO-T1.

[7] RIIO is a new performance based model for setting price controls. It stands for Revenue = Incentives + Innovation + Outputs.

[8] Rollover Final Proposals

2. Revenue and customer impact

Chapter summary

This section of the report contains an analysis of the revenue collected by the electricity and gas transmission networks and the impact this has on consumers' bills. The latter part of the chapter presents the return earned on regulatory equity during TPCR4 and the rollover year.

Overview

2.1. Consumers pay for licensees to operate and maintain the transmission networks through their gas and electricity bills. The gas transportation charges make up around 2 per cent of an average customer's gas bill. The electricity transmission charges make up around 4 per cent of an average customer's electricity bill.

2.2. During TPCR4 and the Rollover the estimated average annual network charge per household increased from £13.96 to £21.24 for electricity transmission. For gas transmission, the average annual charge per household increased from £12.28 to £16.22.

2.3. We set an assumed 'base' level of revenue that TOs can collect at the price control but certain mechanisms can allow this base level to change. Where a difference arises in allowed revenues, it is passed on to the suppliers through adjusted charges. Suppliers, in turn, pass the increase or decrease on to consumers through their bills.

2.4. Allowed revenue for 1 April 2007 to 31 March 2013 exceeded the base revenue amount determined at the beginning of the price control by £687m, or 3 per cent.

Table 1 – TPCR4 and rollover base revenue vs allowed revenue

	Maximum allowed transmission revenue £m	Transmission Base Revenue £m	Change in base revenue £m	Change in base revenue %
TOTAL for Electricity Transmission	15,497	15,064	433	3%
TOTAL for Gas Transmission	6,305	6,051	254	4%
TOTAL for TPCR4 and the Rollover	21,802	21,115	687	3%

2.5. The differences between base revenue and maximum allowed revenue can be broadly categorised as additional investment project allowances, pass through costs, cost adjustments and incentive revenue. The key reasons for the changes in base revenue during TPCR4 and the rollover year are explained in the rest of this chapter. Appendix 2 breaks down these differences by licensee.

Investment Project Allowance – electricity transmission

2.6. Investment Project Allowances in transmission relate predominantly to Transmission Investment for Renewable Generation (TIRG). This mechanism is explained in Appendix 3.

2.7. For Scottish Hydro Electric Transmission plc (SHE Transmission) and Scottish Power Transmission Ltd (SPTL), Investment Project Allowances were the main source of additional revenue during TPCR4 and the rollover, as compared to base revenue allowances set in final proposals. These differences accounted for more than 70 per cent of additional revenue for both TOs.

2.8. With National Grid Electricity Transmission (NGET), the value of additional revenues from Investment Project Allowances was similar to the other TOs. NGET received more Incentive Payment Adjustments which accounts for the difference to base revenue (see paragraph 2.15).

Investment Project Allowance – gas transmission

2.9. The negative Investment Project Allowance for gas transmission relates to Milford Haven. During TPCR3 National Grid Gas (NGGT) sold gas transmission capacity at Milford Haven, effective from October 2007. Incentive revenues for this project are paid to the System operator (SO), whereas the capex was added to the shadow Regulatory Asset Value attributable to the Transmission Owner (TO).[9]

2.10. At the start of TPCR4, we reviewed the Milford Haven funding and decided that the accumulated shadow RAV should be transferred to the TO's actual RAV. Revenues for the TO were reduced to reflect the income being received by the SO during TPCR4. An annual reduction of £9.5m was made to NGGT's revenues to avoid duplicating annual returns on RAV balances. This arrangement has been reviewed for RIIO-T1 and will cease when the remaining SO incentive period payments come to an end.

Pass-through adjustments

2.11. Pass-through costs[10] also contributed to differences between base revenue and maximum allowed revenue. By nature, pass-through costs are costs which the licensee has little control over.

2.12. Most of the pass-through costs for NGGT were in relation to the recharge of pension deficit costs (£145m). These costs relate to pension costs of the National Transmission System (NTS) and also employees of gas distribution networks before the sale of independent networks in April 2005. Of the remaining pass-through costs, these largely relate to the conveyance of liquefied petroleum gas to independent systems (£52m); and additional security costs incurred during the price control (£58m).

2.13. In electricity transmission, pass-through costs were mainly due to actual network rates being above forecasts at final proposals. Network rates refer to the tax rates applicable to the valuation of network assets. These costs were higher than forecast for all three licensees, but the increase was most significant for SPTL and SHE Transmission due to the timing of the review in Scotland.

2.14. In 2010, the Scottish assessor proposed an initial revaluation. This resulted in an increase of £5m to £10m in annual rates for SHE Transmission and SPTL for the remaining two years of the TPCR4. These rates are expected to be lowered for subsequent years.

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[9] Refer to Appendix 1 for an explanation of shadow RAV.
[10] Costs which are generally regarded as outside of TOs control and are therefore allowed as incurred.

Any rebates offered as part of this revision will be realised during the RIIO price control and passed back to consumers.

Incentive payment adjustments

2.15. Incentive payment adjustments are changes to base revenue which encourage efficient operation. The electricity incentives include:

- Transmission Network Reliability Incentive: a mechanism which pays NGET to minimise interruptions to the supply from its networks while ensuring that demand is met. A similar incentive is available to NGGT for the gas transmission network. A significant portion of the adjustment to allowed revenues is attributable to the Transmission Network Reliability incentive.

- Innovation Funding Incentive: a mechanism which pays transmission owners to invest in appropriate research and development.

- Sulphur Hexafluoride Incentive: a mechanism encouraging reductions in the emission of sulphur hexafluoride gas (See Chapter 3). This gas is used as an insulating and arc-extinction medium in electrical equipment.

Capital expenditure incentive revenue adjustments

2.16. At the start of TPCR4, to encourage the gas and electricity transmission licensees to incur capex efficiently, we established a "capex incentive". Under this, TOs were exposed to 25 per cent of any capex underspend or over-spend as compared to their capex baseline.

2.17. This adjustment was applied for all TOs during the rollover year. However, given the magnitude of the adjustment for NGET (more than £200m), the revenue adjustment was smoothed over several years. NGET was allowed £48m (2012-13 prices), or 20 per cent, in the rollover year.

Other adjustments

2.18. There are other adjustments to base revenues, but they are smaller and are essentially used to account for any one-off events. These adjustments included income adjusting events (SHE Transmission and SPTL); differences in services (NGET); and net under-recovery of allowances, which is also known as the "K factor" in the licence.

Return on regulatory equity (RoRE)

2.19. RoRE represents the percentage of returns earned by shareholders as a measure of equity regulatory asset value (RAV)[11].

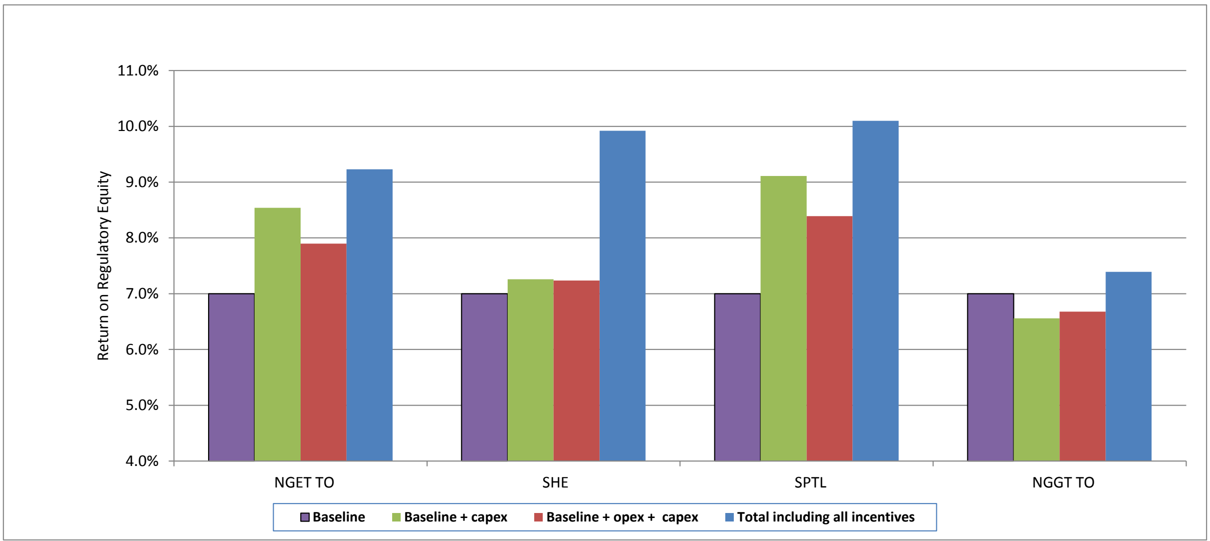
2.20. The cost of equity for both TPCR4 and the rollover year was set at seven per cent. This was in line with the long-run average total equity market returns observed at the start of the price controls. It also reflected the assessed systematic and non-systematic risks that the networks face under the terms of the price control.

2.21. We measure the TOs' RoRE performance against the baseline equity return[12] as illustrated in Figure 4. The chart demonstrates that all TOs earned a return on their notional regulatory equity in excess of the 7 per cent cost of equity assumed in the TPCR4 final proposals.

2.22. This document does not report on RoRE performance for SOs. This is because the SOs do not hold material equity RAV balances on which to calculate returns.

Figure 4 – Return on Regulatory Equity for TPCR4 and the rollover

	Total including all incentives	Baseline + opex + capex	Baseline + capex	Baseline	Opex	Capex	Interest	TII	TIRG	Revenue incentives	Tax
NGET TO	9.2%	7.9%	8.5%	7.0%	-0.6%	1.5%	0.5%	0.1%	0.1%	0.4%	0.2%
SHE	9.9%	7.2%	7.3%	7.0%	0.0%	0.3%	0.5%	0.9%	1.1%	0.2%	0.1%
SPTL	10.1%	8.4%	9.1%	7.0%	-0.7%	2.1%	0.5%	0.0%	0.9%	0.1%	0.2%
NGGT TO	7.4%	6.7%	6.6%	7.0%	0.1%	-0.4%	0.5%	0.0%	0.0%	0.1%	0.1%



2.23. Other contributors to the additional return outperformance for TOs, were incentive payments and the change in underlying interest rates compared to those assumed in setting the price control. SHE Transmission generated the majority of their additional returns from investments in large projects under the Transmission Investment Incentive

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[11] Equity RAV is derived in two steps. First, calculate the average of opening and closing RAV for each year. Then multiply this result by the equity portion of RAV (1 – gearing level assumed in the model).
[12] Baseline equity return is based on the assumption that cost under performance or over performance is converted into returns to shareholders.

(TII) and Transmission Investment for Renewable Generation (TIRG) schemes (1.9 per cent). The TIRG mechanism allows a pre-tax return during construction and for the first five years following completion. Beyond this incentive period the assets enter core RAV and receive the standard (lower) return paid on the core RAV.

2.24. Capex was the main source of additional return outperformance for NGET and SPTL (1.5% and 2.1% return respectively). This reflects capex performance discussed in Chapter 4. In contrast, NGGT overspent capex allowances in each year of both price controls, but underspent opex allowances.

2.25. It is important to note that the RoRE for NGGT does not show the full return. This is because income from gas revenue drivers is reported in the SO, while the capex sits in the TO. Thus in calculating RoRE for NGGT TO performance is understated.

2.26. There was little impact on RoRE of opex performance for most TOs. The exceptions were NGET and SPTL, both of whom overspent the allowed opex in each year of TPCR4. This is discussed in opex costs performance in Chapter 4.

3. Outputs, incentives and innovation

Chapter summary

Here we outline the outputs, incentives and innovation mechanisms under Transmission Price Control Review 4 (TPCR4) and the rollover year. Incentive schemes across the networks include the Innovation Funding Initiative, Capex Incentive and Reliability Incentive. This section also covers the outputs and incentives specific to electricity or gas transmission owners (TOs) or system operators (SOs).

This section should be understood in the context of the RPI-X regime[13], in which the TOs and SOs were primarily encouraged to increase efficiency and reduce costs. Operating expenditure (Opex) allowances were set to include efficiency improvements of 3 per cent per year. In our TPCR4 final proposals[14] we recognised the need to work with the TOs during the price control to identify suitable outputs to gauge performance against. These output measures were developed during TPCR4 to inform clearer targets for the new RIIO-T1 regime.

Electricity-specific outputs and incentives

TO system performance and the reliability incentive

3.1. There were two specific output targets in electricity: system performance or reliability incentive as one output, and the targets for reductions in sulphur hexafluoride (SF_6) emissions.

3.2. The overall reliability of the transmission system has improved over the price control. A total of 767 MWh of energy was unsupplied (0.00025 per cent of total demand) for 2012-13 compared with 1,675MWh in 2007-08 (0.0005 per cent of total demand).

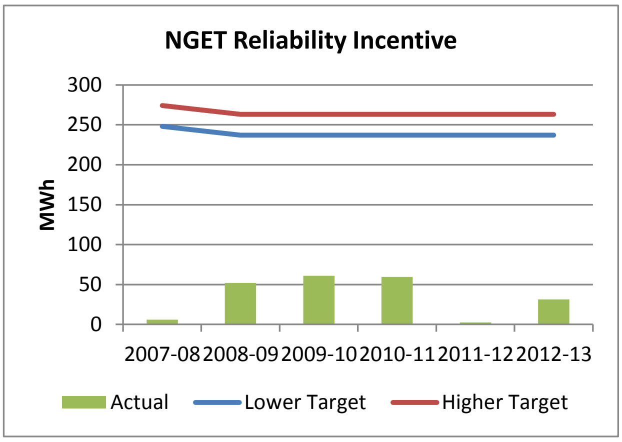
3.3. The system reliability target was defined differently between the companies; for National Grid Electricity Transmission (NGET) it was based on a loss of energy (in MWh), while for Scottish Power Transmission Ltd (SPTL) and Scottish Hydro Electric Transmission plc (SHE Transmission) the basis was the number of loss of supply events. Under RIIO-T1, system reliability will be measured using energy not supplied for all companies, akin to that already used for NGET under TPCR4.

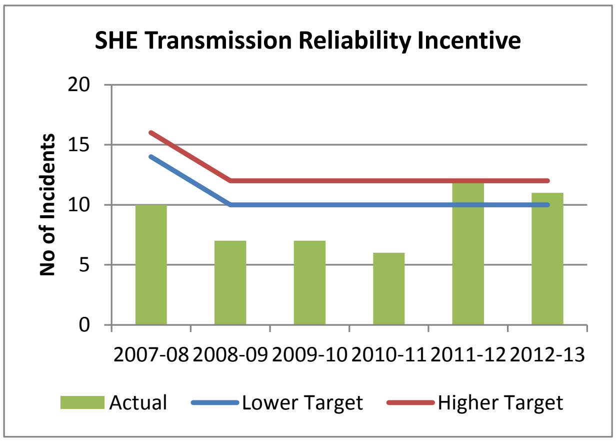
3.4. NGET has performed particularly well, with loss of MWh significantly lower than target (Figure 5). SPTL has also beaten its target (Figure 7). SHE Transmission initially performed well but saw an increasing trend of loss of supply events. This may partly reflect the two recent colder winters where SHE Transmission's overhead lines were more exposed to those weather events.

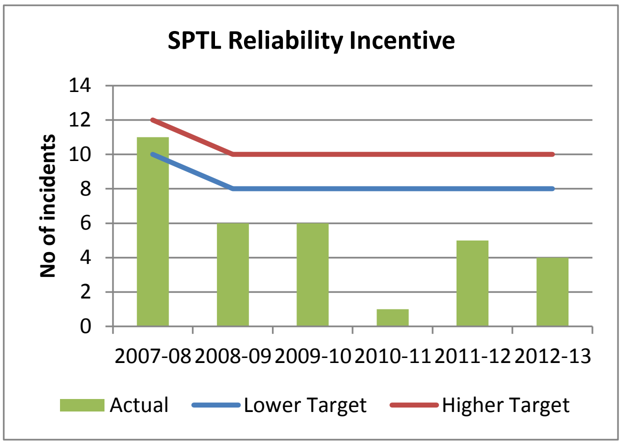
[13] RPI-X was the regulatory regime used for TPCR4 and other price controls before we introduced RIIO in 2010.
[14] Transmission Price Control Review: Final Proposals, 4 December 2006, Ref: 206/06.

3.5. The band between the upper and lower targets was set to provide a 'deadband' in which the TOs receive no incentive reward or penalty.

Figures 5 to 7: Reliability incentives







TO sulphur hexafluoride (SF_6) emissions

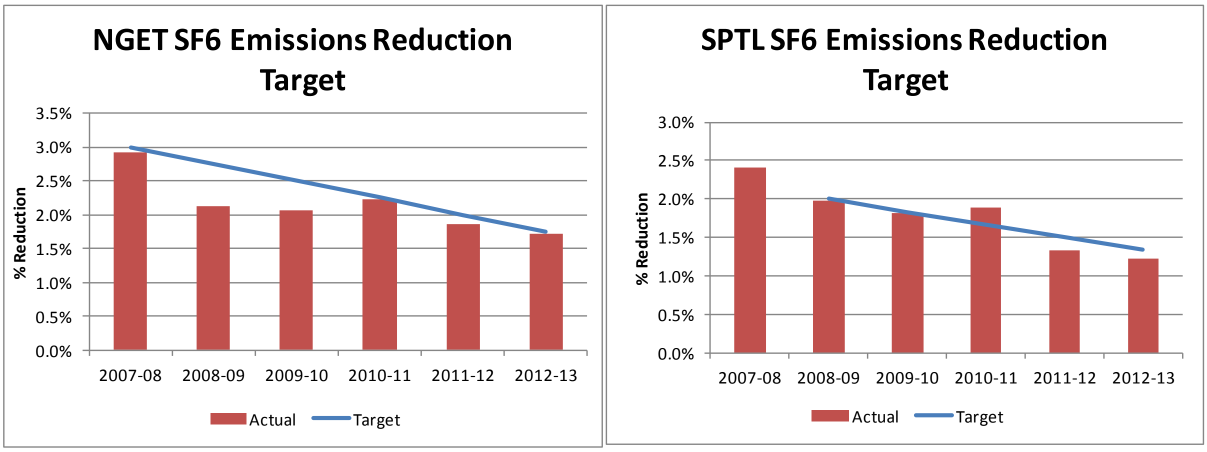
3.6. SF_6 is a potent greenhouse gas, with a global warming potential of 23,900 times that of CO_2 over a 100-year lifecycle. Its use has been banned in the EU in many applications, including refrigeration. In the transmission network, however, it is still used in high voltage switchgear where it enables useful options for more compact storage.

3.7. At the beginning of TPCR4 only CO_2 was covered by the EU Emissions Trading Scheme, meaning there was no financial incentive to reduce SF_6.

3.8. TPCR4 introduced incentives for NGET to reduce SF_6 emissions. For SPTL a target was set from March 2008. The delayed implementation of SPTL's target, and the lack of a target for SHE Transmission, is due to the difficulties these TOs faced in separating SF_6 emissions information between their transmission and associated distribution assets at the time. However, there are now clear targets set for RIIO-T1.

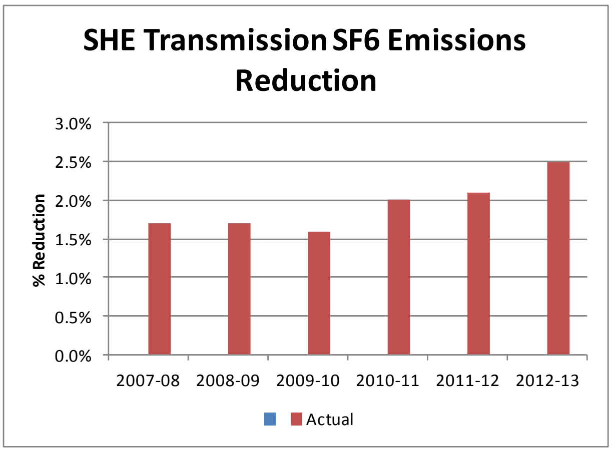
3.9. Incentives to reduce SF_6 leakage lead to good progress from NGET and SPTL. For NGET the target reduced over the period from 3 per cent of the gas in use at the beginning of TPCR4 to 1.75 per cent in the rollover year (Figure 8). For SPTL from 2 per cent to 1.34 per cent (Figure 9). Both companies met their targets over this period.

Figures 8 and 9: NGET and SPTL SF_6 performance



3.10. For SHE Transmission, SF_6 only reduced in 2009-10 to 1.6% from 1.7% in the previous 2 years. SF_6 emissions then started to increase (Figure 10).

Figure 10: SHE Transmission SF_6 performance



3.11. SHE Transmission explained that the increase in SF_6 emissions was due to a small proportion of circuit breakers that were older than average circuit breakers. It is a concern that SHE Transmission had not identified and replaced these earlier. SHE Transmission said that these particular assets started to perform poorly and they expect to remove them from the system by 2013-14. In parallel, more modern equipment has also reduced leakage. We will be following up this issue with SHE Transmission on receipt of their 2013-14 regulatory performance submissions.

3.12. In RIIO-T1 we have provided an incentive regime that should encourage all TOs to reduce SF_6 even further against a baseline target. This reflects the ability for new equipment put on the network to show lower leakage.

Gas-specific outputs and incentives

Emissions

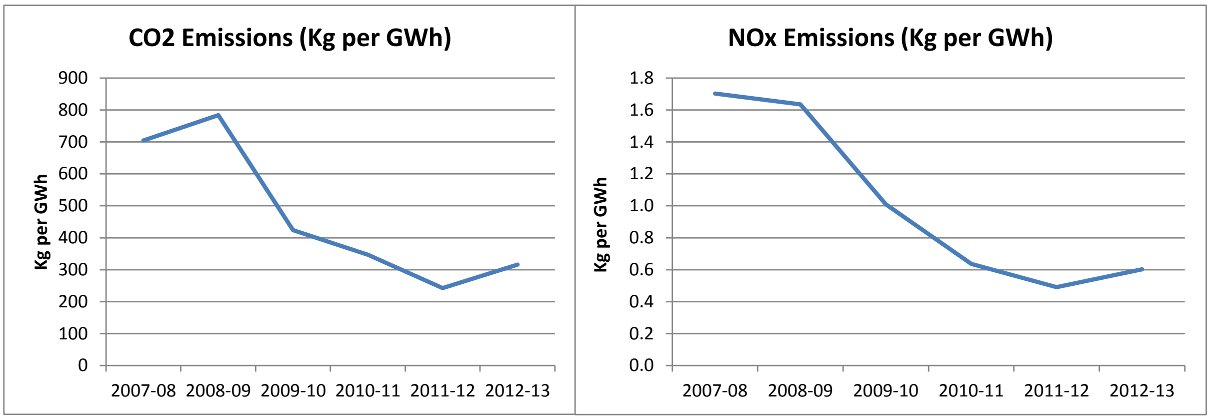
3.13. Carbon dioxide (CO_2) is a greenhouse gas, known to contribute to climate change. CO_2 is released during the operation of compressor stations on the gas transmission network. Reducing CO_2 is an important way the energy industry, and network companies, can address GB's climate goals.

3.14. Nitrogen oxide (NO) and nitrogen dioxide (NO_2), together known as NO_X, are air pollutants that cause acid rain. Acid rain has adverse effects on the environment, particularly forest ecosystems.

3.15. While we set no specific outputs for gas transmission, we monitored the performance of NGGT in reducing (CO_2) emissions (Figure 11) and NO_X (Figure 12) during TPCR4 and RO. Measured in kg per GWh of output, the reductions in CO_2 and NO_X emissions were achieved by, where possible, reducing the use of compressor stations. Another way TOs are cutting emissions is by replacing gas compressors with electric ones. Over the six years, they spent a total of £250m on installing electric compressor units. The operation of the electric compressors is expected to reduce emissions, as they will perform most of the compressor activity at the relevant sites instead of the gas compressor units.

3.16. Emissions of CO_2 and NO_X per GWh of gas transported increased slightly in 2012-2013 due to an increase in the requirement for compression. This was caused by the long winter to April 2013 which meant that additional gas was pumped from a variety of gas entry point locations. This was combined with extended running to support the flow of gas from continental Europe.

Figures 11 and 12: CO_2 and NO_x emissions



SO performance

3.17. NGGT performed well in minimising the energy costs associated with shrinkage[15], reducing greenhouse gas emissions caused by venting[16], minimising the costs of residual

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[15] Gas lost from the transmission system due to leakage, theft and gas used for operational purposes.
[16] Operational emissions from the gas compressors for the purposes of maintaining system pressure.

balancing, and improving website timeliness and availability. It had a mixed performance with its operating margins and demand forecasting (Appendix 5).

Buyback incentives

3.18. In gas transmission NGGT is obliged to buyback capacity where they are unable to meet contracted capacity requirements. This may happen when there are physical constraints on the network at a particular point in time.

3.19. The TPCR4 package contained buyback incentives for NGGT to address new obligated capacity and all other capacity. These schemes encouraged NGGT to minimise the costs of buyback.

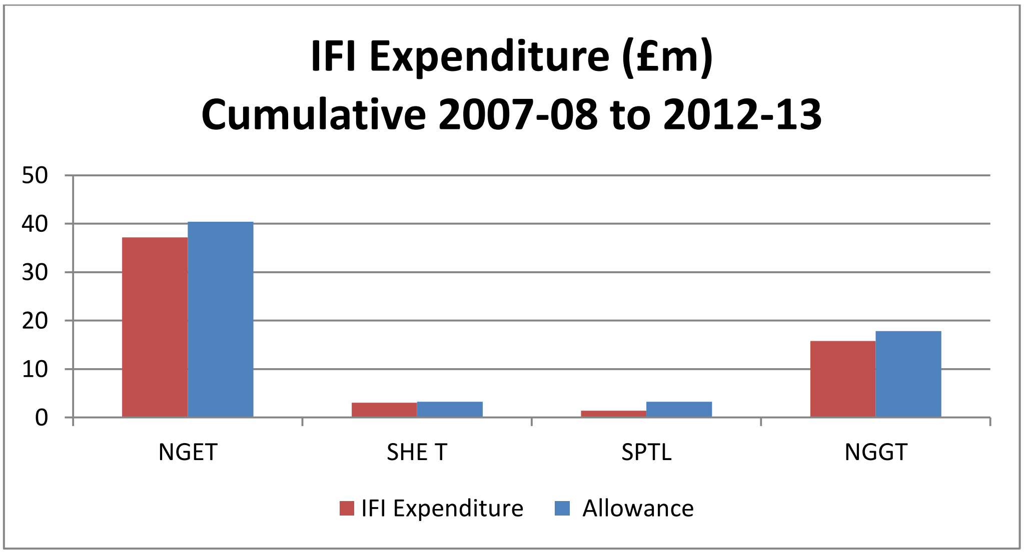
Gas and electricity transmission innovation

Innovation Funding Initiative

3.20. Under the Innovation Funding Initiative (IFI) companies were encouraged to undertake research and development to improve network operations. These projects are paid for by the licensee and undertaken by external parties (eg universities). In total, over the TPCR4 and rollover period the four transmission companies invested £58m in such schemes. Here are some examples of IFI projects:

- improved transformer thermal monitoring
- alternative tower construction
- ageing critical valve research
- alternatives to venting from the National Transmission System (Gas)

Figure 13: Total IFI Expenditure (£m) 2007-08 to 2012-13



3.21. Figure 13 indicates that NGET, SHE Transmission and NGGT were more active in their IFI spending, while SPTL spent less than 50 per cent of its allowance.

Other gas and electricity incentive mechanisms

Capex Incentive Mechanism

3.22. For both electricity and gas transmission a capex incentive mechanism shared overspend and underspend with consumers. It had a 25 per cent sharing factor (ie TOs kept 25 per cent of underspend and lost 25 per cent of any overspend). This encourages TOs to deliver their capital investment more efficiently, to the benefit of both TOs and consumers.

3.23. As detailed in Chapter 4, the TOs capex varied considerably over the period resulting in payments of £240m to NGET, £1m to SHE Transmission, £13m to SPTL and £6m to NGGT.

SO performance

3.24. The incentives on the SO are summarised in Appendix 5.

4. Expenditure

Chapter summary

We describe the cost performance of the companies by comparing expenditure with the allowances. Expenditure is divided into several different areas: load and non-load related (LRE/NLRE) capital expenditure (capex), and operating expenditure (opex). In some cases the accuracy of company forecasts is also illustrated through comparisons between forecast and actual expenditure.

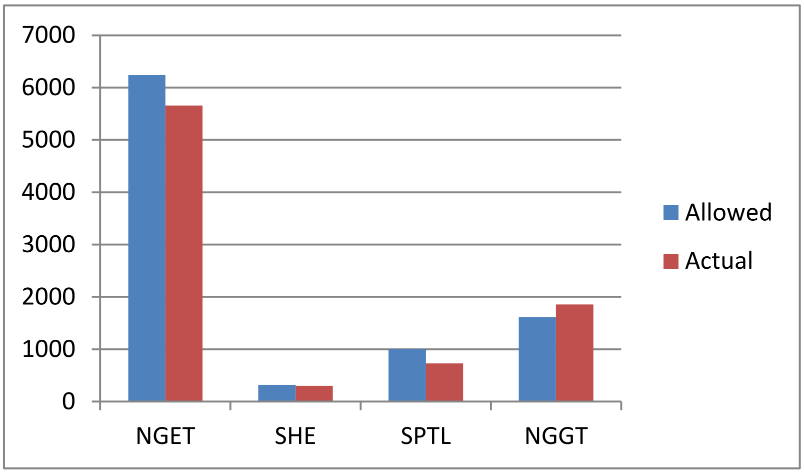
We present the figures for the TOs followed by those for the SOs. For the TOs we show the LRE and NLRE capex, and opex. We present this expenditure separately for TPCR4 and RO, but for areas such as load related capex the two periods of the price control are merged (because of the timing of spending and delivery of the schemes).

Overview

4.1. Figure 14 shows the opex and capex over the TPCR4 and rollover period for all TOs. This summarises the allowances the TOs were given, and their actual spend. Capex is further divided into load-related expenditure (LRE) and non-load related expenditure (NLRE).[17]

4.2. Overall, the electricity TOs spent less than their allowances whereas NGGT spent slightly more. This is primarily because of the continuing construction of the Milford Haven pipeline, which cost much more than NGGT had originally planned.

Figure 14: Overall Expenditure (opex and capex) in TPCR4 and rollover (£m)



[17] LRE is the installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand. NLRE is the replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

4.3. The table below compares the allowances and actual expenditure for each of the network companies. Capex is shown aggregated as well as split into LRE and NLRE. Non operational capex is categorised as opex.

Table 2: Comparison of expenditure against allowances

		Allowance	Actual	Difference (%)
NGET (TO)	Controllable Opex	1161.9	1318.0	13%
	Capex: LRE	2379.8	1805.7	-24%
	Capex: NLRE	2697.8	2425.8	-10%
	Total capex	5077.6	4231.5	-17%
	Non operational capex (Opex)	89.1	105.6	19%
SHE Transmission	Controllable Opex	48.9	50.4	3%
	Capex: LRE	182.3	154.9	-15%
	Capex: NLRE	86.6	97.6	13%
	Total capex	268.9	252.5	-6%
	Non operational capex (Opex)	0.1	0.7	547%
SPTL	Controllable Opex	129.5	154.3	19%
	Capex: LRE	436.5	233.9	-46%
	Capex: NLRE	435.3	332.8	-24%
	Total capex	871.9	566.7	-35%
	Non operational capex (Opex)	4.6	7.0	53%
NGGT (TO)	Controllable Opex	422.6	412.2	-3%
	Capex: LRE	699.6	951.7	36%
	Capex: NLRE	460.1	466.4	1%
	Total capex	1159.7	1419.3	22%
	Non operational capex (Opex)	34.3	27.3	-20%
NGET SO	Controllable Opex	371.8	402.5	8%
	Total capex	84.8	127.4	50%
NGGT SO	Controllable Opex	193.4	205.1	6%
	Total capex	98.0	77.3	-21%

4.4. Any deviation in capital expenditure between allowances (for TOs or SOs), whether underspends or overspends, is shared between consumers and TOs 25:75. There is also a sharing ratio in opex for the SOs. This is 25:75 in electricity and 40:60 in gas.

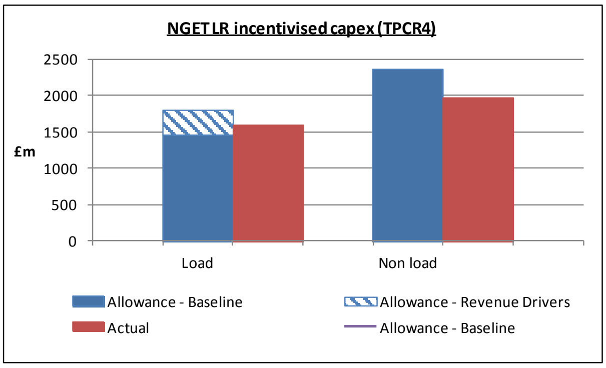
4.5. The profiling of this expenditure over the six year period is shown in Appendix 4

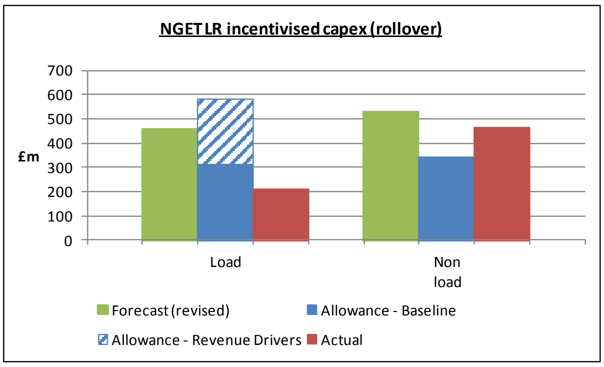
Electricity expenditure

1. National Grid Electricity Transmission (NGET)

4.6. An overview of NGET's capex during TPCR4 and the rollover is shown in Figures 15 and 16.

Figures 15 and 16 – NGET capex compared to allowances

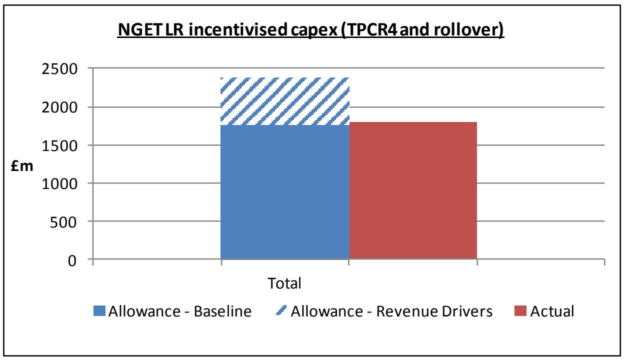




Load related capex

4.7. This expenditure delivers new connection capacity on the transmission network. During TPCR4 NGET was funded on the basis that it would produce an assumed level of connection capacity. Variations in this level of capacity were funded through a 'revenue driver' mechanism which reflected an increase (or potentially a decrease) in allowances as new capacity was created. This mechanism therefore varies the revenues allowed under the price control. Since additional funding is reflected only on output delivery, but projects may spend over three to four years to deliver the increased output, we have to consider the six years as one period (figure 17).

Figure 17 – NGET load related capex compared to allowances



4.8. Over the period NGET spent £1.8bn (excluding £244m of capex that had yet to deliver outputs which we refer to as work in progress on load related capex. The volume of connections was greater over the period than assumed in our final proposals (which the revenue driver mechanism was devised to recognise). NGET spent £574m, or 24 per cent, less than its allowance. This reflects efficiencies in creating these new connections, 75 per cent of which is returned to consumers.

4.9. An additional £610m of allowances were made available to NGET under the revenue driver mechanism (shown with hatched shading).

Non load related capex

4.10. NGET spent £2.4bn over six years on non load related capex (this is capex to maintain the capability of the existing network). It spent £272m (10 per cent) less than its allowance. This was predominantly because NGET refined the approach to assessing which assets were in need of replacement and chose to extend asset lives and refurbish assets rather than replace them. One effect of this has been increased spending on maintenance. This contributed to an overspend of opex allowances.

4.11. While we encourage the use of this kind of innovative approach it should not increase the risk of system failure for consumers. We have seen no evidence of increased asset deterioration for NGET, but we will monitor the approach closely under RIIO-T1 as we further develop our Network Outputs Measures (NOMs).

4.12. Non load volumes were lower than NGET's business plan submission and our modelling had indicated, particularly in the first five years (between 30 per cent and 50 per cent lower in some cases). Following the introduction of NOMs in RIIO-T1 we will be able to more effectively understand and challenge any cases of unexpected deterioration in asset health.

Other capex expenditure

4.13. NGET spent £648m on schemes outside the baseline revenues set for TPCR4. These schemes are Transmission Investment for Renewable Generation (TIRG) and Transmission Investment Incentive (TII) and further details can be found in Appendix 3. Some of the largest spends were the TIRG project Anglo-Scottish Interconnector (£140m) and £508m on TII projects, particularly Anglo Scottish incremental, East Anglia and Western HVDC.

4.14. These projects will be assessed on completion in accordance with each scheme's framework to check on the efficiency of the delivery process.

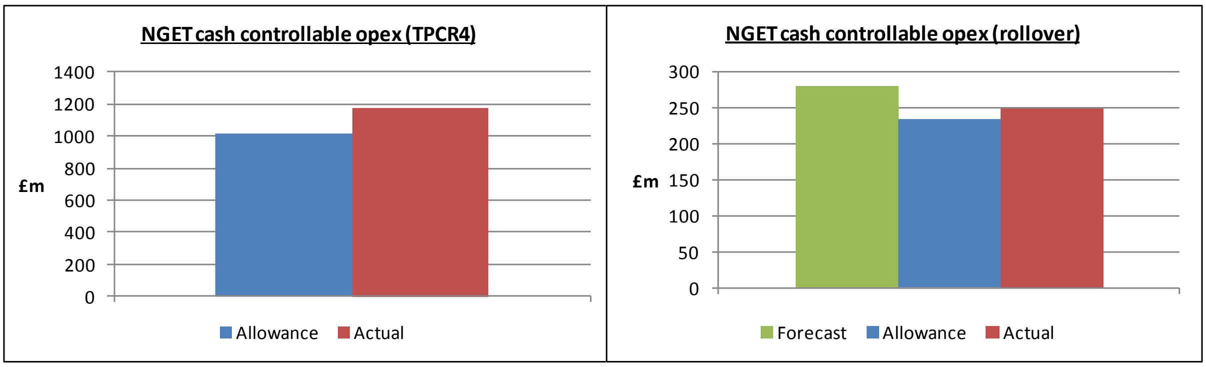
Opex

4.15. For NGET, there was an opex overspend in all five years of TPCR4. Despite efficiencies, there were significant additional costs, such as reorganisation of the business (£39m), recruitment of apprentices (£34m), and higher maintenance (£22m).

4.16. It seems likely that the change in approach to network management, extending the lives of assets rather than replacing them immediately, may have caused maintenance costs to rise.

4.17. In the rollover year, the actual opex £16m was higher than the £234m allowed, but it including £16m for reorganisation costs. The actual spend was 11 per cent below NGET's original forecast of £280m.

Figures 18 and 19: NGET opex compared to allowances



2. Scottish Hydro Electric Transmission plc (SHE Transmission)

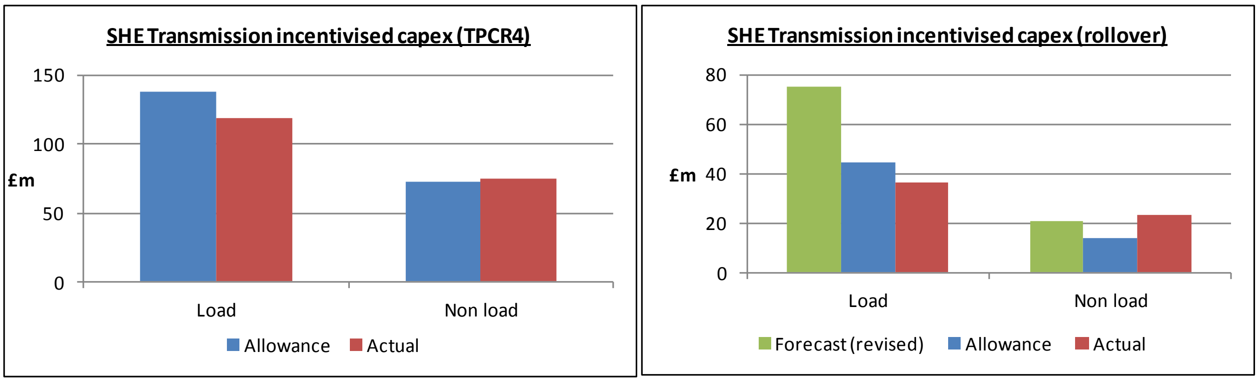
Capex

4.18. There was a load related underspend of £27m (15 per cent) compared with allowances. SHE Transmission has said these reflect efficiencies as well as some delays in obtaining planning consents. The underspend of £8m (19 per cent) in the rollover was 52 per cent less than forecast, raising questions about the robustness of SHE Transmission's forecasting capability. We made significant reductions in our assessment of their forecast for projects which we considered were not well advanced through the planning consent process.

4.19. There was a non load related overspend of £11m (13 per cent).

4.20. SHE Transmission spent £523m on TIRG and TII schemes (see Appendix 3 for full details). Significant schemes were the Sloy and Beauly Denny TIRG projects which have incurred costs to date of £367m. SHE Transmission spent £156m on four TII projects in the Beauly and Dounreay areas.

Figures 20 and 21 – SHE Transmission capex compared to allowances

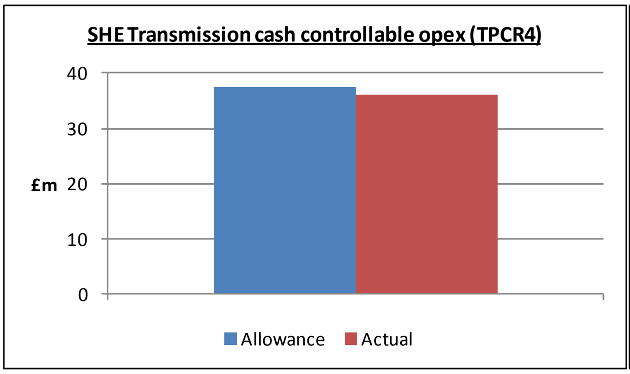


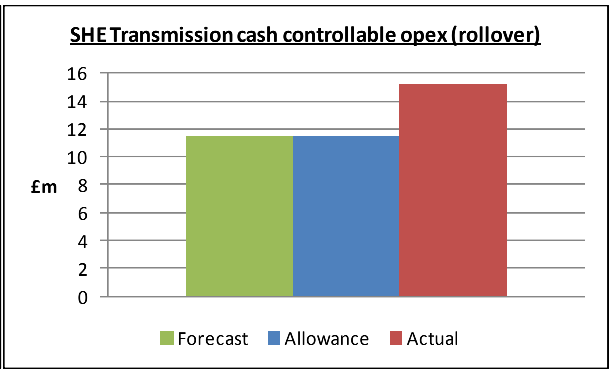
Opex

4.21. SHE Transmission's opex was broadly in line with allowances during TPCR4, despite having grown throughout the period (reflecting the growth in the overall business). However, during the rollover spending was 32 per cent higher than forecast and allowances. The £3m increase was entirely due to the exceptional weather in the winter of 2012-13.

4.22. The transmission business was reorganised during TPCR4, with many roles transferred in from other group companies. Overall this led to a growth in opex costs. SHE Transmission now employs 333 direct staff (compared to 73 people in 2008) but this also partly reflects the growth of the SHE Transmission business as a whole.

Figures 22 and 23: SHE Transmission opex compared to allowances





3. Scottish Power Transmission Ltd (SPTL)

Capex

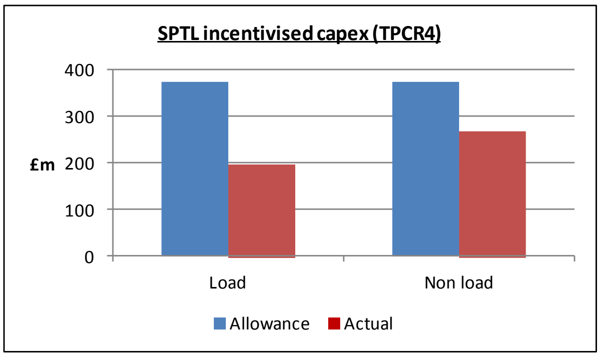
4.23. The load related capex was £203m (46 per cent) lower than the six year allowances. While SPTL cites delays with developers gaining planning consents, the generation capacity connected was slightly higher than had been assumed in setting allowances.

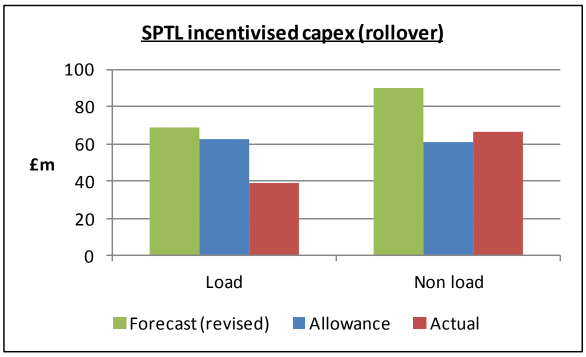
4.24. While we understand that planning can cause delays, we are disappointed by the quality of SPTL's load forecasting, which has been poor even one year ahead. TOs will publish forecasts during RIIO-T1, and we will be using evidence of accurate forecasting in any fast track decision for RIIO-T2. We will also comment on the accuracy of these in future annual reports and we expect to see this improve.

4.25. Over the period there was a £102m (24 per cent) underspend in non load capex. SPTL deferred some maintenance projects in the early years of TPCR4 and failed to catch up the backlog in expenditure compared to allowances. Whilst we have no evidence that this has added to the probability of system assets failure we will continue to monitor the asset data carefully. Following the introduction of NOMs in RIIO-T1 we will be able to more effectively understand and challenge unexpected deterioration in asset health.

4.26. Where TOs spend less than their capex allowances the benefits of this efficiency are shared with consumers; with TOs retaining 25% and the remainder benefitting consumers.

Figures 24 and 25 – SPTL Transmission capex compared to allowances





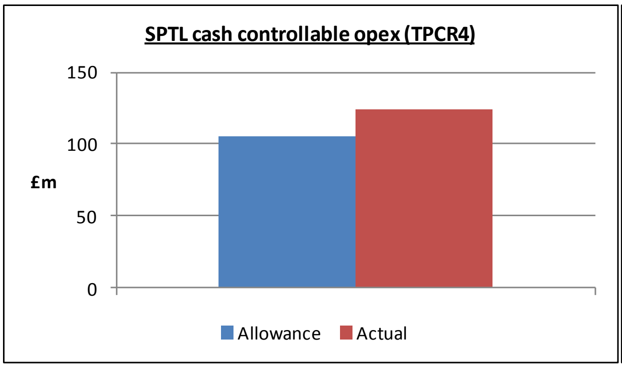
4.27. SPTL also spent £252m on TIRG and TII schemes (see Appendix 3 for full details). Total expenditure on TIRG projects in the six years was £156m. The largest projects were Beauly-Denny, Sloy, and the Strathaven-Harker Interconnector.

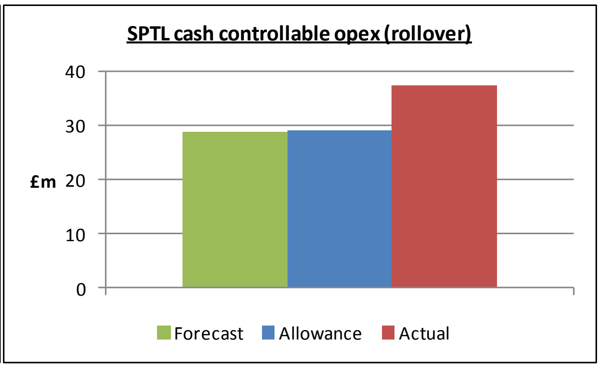
4.28. Total expenditure on TII projects in the six years was £96m. The major projects were Western HVDC and the East-West Upgrade.

Opex

4.29. During TPCR4 there was a £19m (18 per cent) overspend compared with allowances due to higher support costs. This purely reflects a greater level of capitalisation of overheads (around £38m) than we had estimated in the allowance (and which we therefore treat as opex). There was also a £9m (29 per cent) overspend in the rollover (adjustment £15m).

Figures 26 and 27: SPTL opex compared to allowances





Gas expenditure

4. National Grid Gas Transmission plc (NGGT)

Load related capex

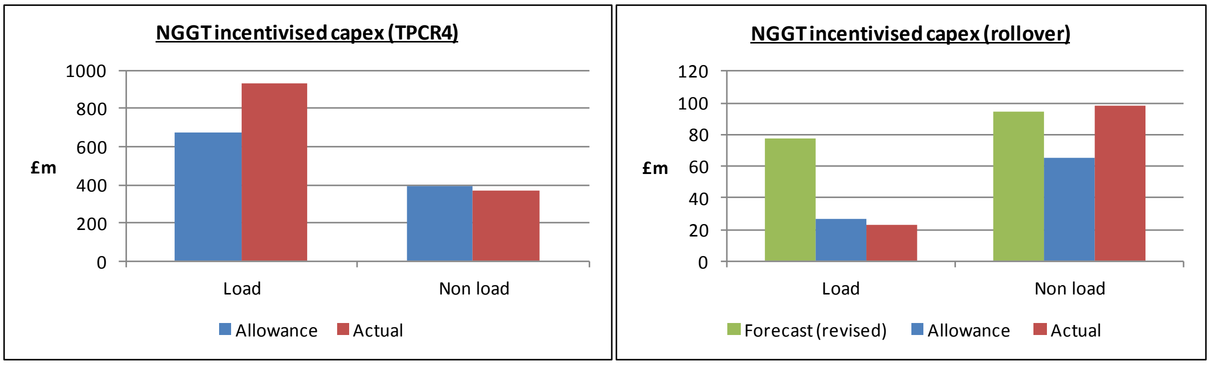
4.30. Despite a slow down in gas transmission connections activity there was an overspend of £252m (36 per cent) in load related expenditure during TPCR4 and the rollover. This was primarily because of additional costs in delivering the Milford Haven project. To provide context, the Milford Haven project was expected to cost £1bn, but has cost £1.3bn. Of this, £750m was incurred in the TPCR4 and rollover period, making up 80 per cent of all NGGT's capex load in this time. We will review the efficiency of this project in 2014-15.

4.31. The Milford Haven project is one of the largest schemes delivered by the TOs to date. NGGT began it after recognising that additional capacity was needed to connect new import terminals to the gas network.

4.32. Apart from the Milford Haven project, NGGT spent only £200m over the price control period (60 per cent of its £340m allowance) on new connection activity. Apart from activity falling, NGGT has identified efficiencies, with underspends in some projects.

4.33. As with the other TOs we have some concerns about the quality of NGGT's forecasting capability. For 2012-13 the load related capex spend was forecast at £77m, with actual spending coming in at £23m and mostly related to Milford Haven.

Figures 28 and 29 – NGGT Transmission capex compared to allowances



Non load related capex

4.34. The non load related expenditure during the price control was similar to allowances. Asset expenditure mostly occurred from the third year of TPCR4, leading to an underspend (54 per cent in the first two years of TPCR4) early in the price control, and overspend later (£33m (49 per cent) in the rollover).

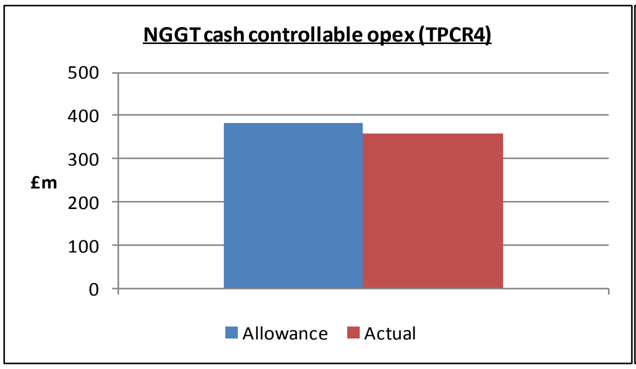
4.35. Unfortunately we have seen limited NGGT engagement on emissions abatement. Expenditure was less than anticipated, leading us to set measures to avoid similar problems during RIIO-T1.

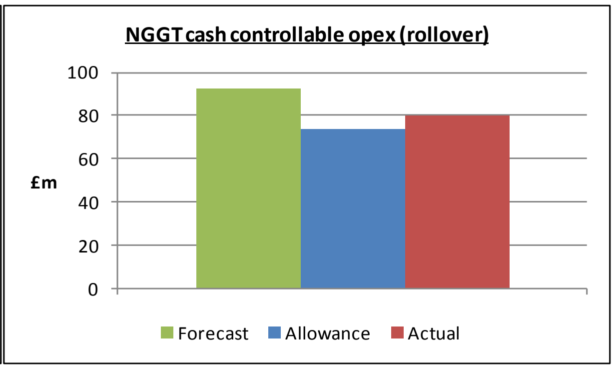
Opex

4.36. There was an underspend of £24m (6 per cent) during TPCR4, including a £7m (20 per cent) underspend of non operational capex (mainly IT). While the underlying trend continued into the RO, there was an overspend of £7m due to the cost of a reorganisation.

4.37. In the rollover opex was 13 per cent below NGGT's forecast. While the forecast included increases for work force growth and renewal, NGGT says it scaled these back due to reduced allowances. We note, however, that NGGT indicated it would be cutting staff at the start of RIIO-T1.

Figures 30 and 31: NGGT opex compared to allowances





NG System Operator

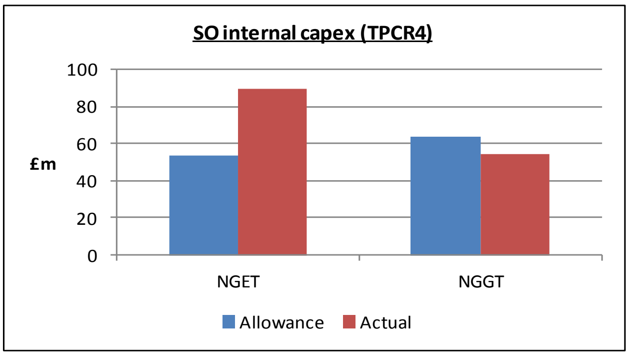
SO capex: NGET and NGGT

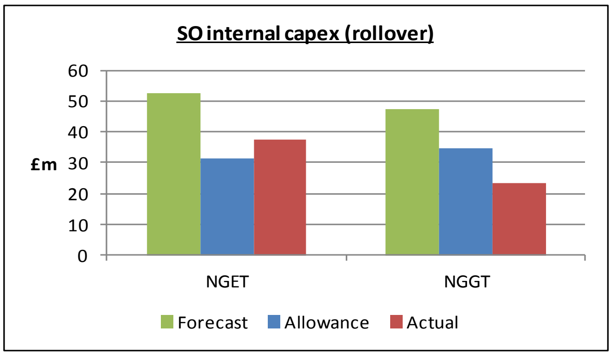
4.38. The capex of the SOs is almost entirely spent on IT systems to manage the flow of gas and electricity through the TO networks.

4.39. During TPCR4, NGET overspent by £36m (68 per cent). It attributed this to the need to replace critical systems to support increased wind generation, decarbonisation, access reform and increased security risks. NGET did not foresee these when we set the allowances. The £6m overspend during the rollover was due to higher costs of the electricity balancing system.

4.40. NGGT spent £9m (14 per cent)18 less capex than allowed in TPCR4. There was also an underspend in the rollover year of £11m (33 per cent below allowances and 51 per cent below forecast).

Figures 32 and 33: SO capex compared to allowances



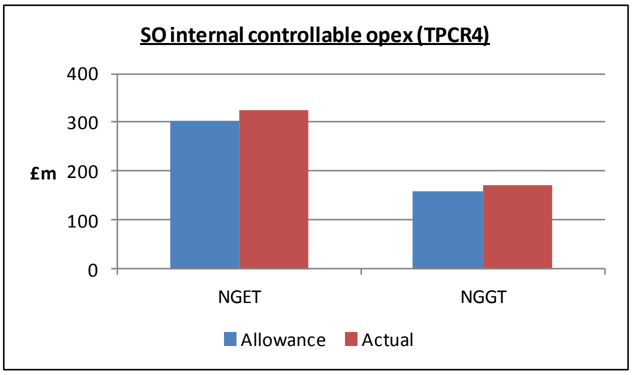


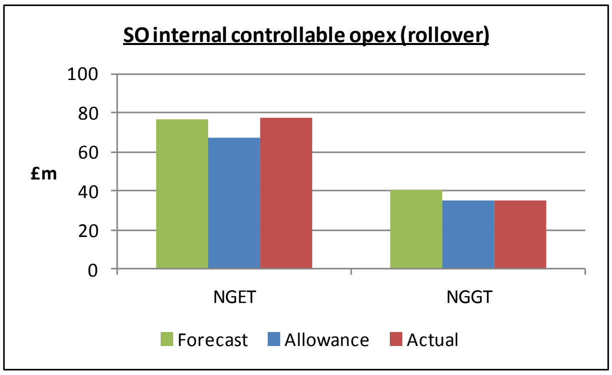
SO opex: NGET and NGGT

4.41. During TPCR4 NGET overspent on opex by 7 per cent due to additional costs of recruiting control staff, and additional costs of bringing critical system support in house.[19] There was a further overspend in the rollover year (£10m) which NGET said is due to growth in resources for more EU and market driven work, Information System costs, and exceptional reorganisation costs of £5m.

4.42. NGGT also overspent (8 per cent) during TPCR4 on opex due to higher costs in attracting control room staff, and in the sourcing of critical systems. In the rollover year NGGT spent as allowed despite incurring £4m of reorganisation costs.

Figures 34 and 35: SO opex compared to allowances





[18] Excluding Xoserve costs, which are treated as pass-through costs
[19] NGET Opex excludes £3.7m of EMR costs paid for by a DECC grant.

Index of Appendices

Appendix 1 – Regulatory Asset Value changes

1.1. Regulatory Asset Value (RAV) is the value of capital investment in GB gas and electricity networks. We allow licensees to obtain funding for both return and asset depreciation each year based on the size of the RAV. The return allowance is designed to encourage licensees to enter into the long-term financing arrangements needed for efficient investment in the network. Similarly, the depreciation allowance provides licensees with the funding required to maintain network assets throughout their useful lives.

1.2. Closing RAV is calculated as: Opening RAV + net additions - depreciation

1.3. We also recognise that in TPCR4 there were some schemes where the capex did not immediately enter RAV. Until this capex enters the main RAV we refer to it as shadow RAV. The shadow RAV at the end of the TPCR4 and rollover period consists of TIRG capital investment and some gas entry and exit spend (under the TPCR3 and TPCR4 gas revenue driver schemes).

1.4. The numbers quoted remain provisional pending final confirmation of the values. In particular we will be reviewing the efficiency of the Milford Haven project (see para 4.29) and the review of certain physical site security upgrade projects.

Change in RAV during TPCR4 and the rollover

1.5. RAV balances have substantially increased for all of the Transmission Owners (TOs) in the years from 1 April 2007 and 31 March 2013.

Table 1: Movements in TO RAV: 1 April 2007 and 31 March 2013[20]

£m [2012-13]	Movement in RAV				Shadow RAV information			Increase in RAV plus Shadow RAV
	Opening RAV at 1 April 2007	Net additions (after disposals)	Depreciation	Closing RAV at 31 March 2013	TIRG yet to transfer into RAV	Gas revenue driver	Closing RAV plus Shadow RAV at 31 March 2013	%
NGET	7,028	5,860	-3,234	9,654	113	N/A	9,767	39%
SHE Transmission	401	444	-160	686	334	N/A	1,020	154%
SPTL	947	723	-482	1,188	163	N/A	1,351	43%
NGGT	3,868	1,625	-854	4,639	N/A	518	5,157	33%

1.6. As a result of the move to a low carbon economy there has been unprecedented investment in the TO electricity networks. Over the TPCR4 and Rollover period, RAV and Shadow RAV balances held by Electricity TOs increased by 45 per cent. This reflects increases to RAV balances to National Grid Electricity Transmission (NGET) of 39 per cent; Scottish Hydro Electric Transmission plc (SHE Transmission) of 154 per cent; and 43 per cent for Scottish Power Transmission Ltd (SPTL). In this same period, RAV balances (including Shadow RAV) in gas transmission increased by 33 per cent.

[20] The movement in RAV includes 'legacy' adjustments made in RIIO-T1 price control as part of the first annual iteration of the Price Control Financial Models, which took place on 29 November 2013.

1.7. Major capital infrastructure projects for the gas and electricity transmission networks have been planned for the RIIO-T1 price control. As such, the trend of substantial increases in RAV values is expected to continue until after the end of the decade.

1.8. The RAV balances for the two SOs also showed marked increases during TPCR4 and the rollover year. By their nature these assets (generally IT related) will have a shorter useful life and we therefore allow depreciation over shorter periods than for the main TO RAVs.

Table 2: Change in SO RAV during TPCR and the rollover

	NGET SO £m [2012-13]	**NGGT SO** £m [2012-13]
Net additions (after disposals)	124	83
Depreciation	(40)	(24)
Closing RAV at 31 March 2013	84	60

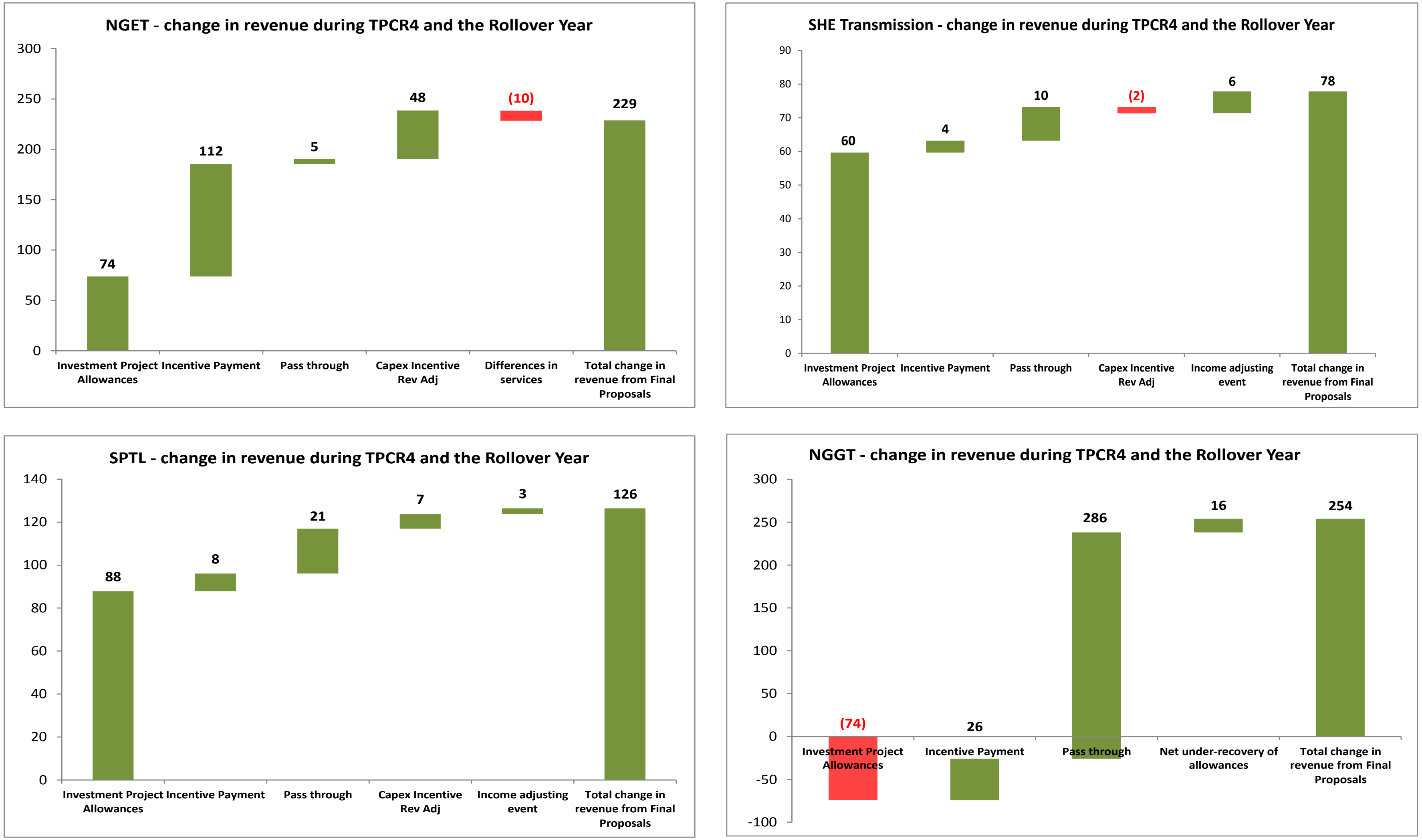
Appendix 2 – Revenue

Table 1: Comparison of maximum allowed revenue to base revenue

	TPCR4 and RO		
Electricity Transmission Entity	**Maximum allowed revenue** £m (2012/13 prices)	**Base Revenue** £m (2012/13 prices)	**Change in base revenue** £m (2012/13 prices)
NGET TO	8,280.6	8,051.9	228.7
SHE Transmission	487.7	409.8	77.8
SPTL	1,316.1	1,189.7	126.4
NGET SO	5,412.4	5,412.4	-

	TPCR4 and RO		
Gas Transmission Entity	**Maximum allowed revenue** £m (2012/13 prices)	**Base Revenue** £m (2012/13 prices)	**Change in base revenue** £m (2012/13 prices)
NGGT TO	3,875.2	3,621.2	254.0
NGGT SO	2,429.9	2,429.9	-

Figure 1: Disaggregation of changes in base revenue for all four TOs



Appendix 3 – TIRG and TII

Transmission Investment for Renewable Generation (TIRG)

1.9. At the time of the 1999 (for SHE Transmission and SPTL) and 2000 (for NGET) price controls, there was considerable uncertainty regarding the likely level and pattern of emerging renewable generation, which meant it was not practical to include allowances for transmission investment. Following the start of the price controls, there was an increase in demand for transmission capacity by renewable generators.

1.10. We put the TIRG mechanism in place in 2004 to provide the Transmission Owners (TOs) with revenue allowances to connect renewable generation that was not forecast at the time the relevant transmission price controls were set. It includes explicit expenditure allowances and output obligations for specific projects for each of the TOs. Given the uncertainty around the design and cost of these projects, we provided flexibility in the mechanism for us to consider amending the revenue allowances up or down under defined circumstances. These include:

- TIRG income adjusting event (IAE) - an event or circumstance that has occurred or is expected to occur which has materially increased or decreased the forecast preconstruction and contingency costs for the relevant years. The TO must notify us and provide supporting evidence where it considers that an IAE has occurred.

- TIRG asset value adjusting event (AVAE) - where a relevant amendment to the scope of construction work is expected to cause additional costs or savings to be incurred. In order to vary their ex ante revenue allowances during the construction period through an AVAE, the TO is required to give notice of such an event to us as soon as is reasonably practicable after it has occurred and in any event prior to the TIRG relevant year when construction of the project commences.

1.11. During TPCR4, four TIRG projects were underway:

- Beauly Denny, a project jointly delivered by Scottish Hydro Electric Transmission plc (SHE Transmission) and SP Transmission Limited (SPTL);

- Sloy, a joint project between SHE Transmission and SPTL;

- The Anglo Scottish Interconnector, a joint project between SPTL and National Grid Electricity Transmission plc; and

- South West Scotland, a project to be delivered by SPTL which was not started during TPCR4.

1.12. The Beauly Denny upgrade of the existing 132kV transmission line to 400kV between Beauly in the north of Scotland and Denny in central Scotland is the largest project covered by the TIRG mechanism. SHE Transmission will be responsible for delivering the majority of the project, while SPTL will construct the final 22km, which lie in its transmission area. The project will be completed during RIIO-T1.

1.13. The Sloy project was constructed jointly between SHE Transmission and SPTL and was intended to increase the transmission capacity in West Scotland. Both companies completed construction in 2009-10, but the project was not commissioned until 2011-12, due to the transformers that were supplied by SHE Transmission's manufacturer being damaged in transit from Europe.

1.14. The England-Scotland interconnector works were designed to increase the capability of the boundary between England and Scotland by upgrading both of the west and east coast circuits. The project required works in both NGET and SPTL's transmission areas with each party responsible for the works in its area. Both companies completed construction in 2010-11.

1.15. The South West Scotland project being delivered by SPTL focuses on constructing power lines and an interconnector as part of developing the infrastructure for wind developments in south west Scotland. Construction work has not yet commenced.

1.16. Project costs and outputs are summarised below. Actual expenditure does not necessarily match allowances due to the timing of particular projects. The TIRG licence condition includes a five year incentive period to reward TOs for delivering projects efficiently. Following the five years, any cost savings are shared with consumers.

Table 1: TIRG projects

Scheme	TO	Outputs expected to be delivered	Funding under the Licence (£m)	Delivery date	Outputs delivered	Actual Capex to 31 March 2013 (£m)
Beauly-Denny	SPTL	– 22km of new overhead lines (OHL) (of the 220km total) – New double busbar substation at Denny North	72.5	Ongoing	TBA	32.8
	SHE Transmission	– Replace existing 132kV double circuit overhead line with a new OHL of 200km (one circuit at 400kV and the other at 275kV)	321.5	Ongoing	TBA	352.9
England – Scotland interconnection	SPTL	– Increase capability of the England – Scotland interconnection from 2200MW to 2800MW. – West Coast: upgrading the existing 275kV circuit between the Strathaven and Harker substations to 400kV – East Coast: Upgrading the 400kV OHL system between Eccles and Stella West substations	106.6	2010-11	Yes	85.2
	NGET		139.5	2010-11	Yes	140.0
Sloy	SHE Transmission	– New substation at Inverarnan	9.5	2011-12	Yes	14.5
	SPTL	– Diverting one 275kV OHL into a new substation – Creating two new circuits (Inverarnan-Dalmally and Inverarnan-Windyhill)	18.3	2009-10	Yes	18.4
B5 Boundary	SPTL	– Clydes Mill, Easterhouse and Windyhill substation upgrades	13.8	2011-12	Yes	13.2
South West Scotland	SPTL	– Construct 80km OHL from Kilmarnock South to Kendoon	52.1	Ongoing	TBA	6.5

Transmission Investment Incentive (TII)

1.17. We introduced TII in April 2010 to provide project-specific interim funding for investment projects that did not have funding under TPCR4. The TOs received funding for efficient pre-construction costs for all identified projects and construction costs for projects where work was planned to commence before 2010-11. We also established a process in the TOs' licences to annually review TII funding requests for works planned to begin the following year. The TII framework was intended to operate until TPCR4 ended on 31 March 2012.

1.18. On 4 October 2010, we announced the new RIIO (Revenue = Incentives + Innovation + Outputs) model for network regulation. To implement this model at the next price control, we decided to delay the start of the new price control by one year. A one-year TPCR4 rollover was implemented to cover the gap between the expiry of TPCR4 on 31 March 2012 and the start of the new price control (RIIO-T1) on 1 April 2013. The TII framework was extended for one year to remain aligned with the TPCR4 price control period.

1.19. Project costs and outputs are summarised by company below. Actual expenditure does not necessarily match allowances due to the timing of particular projects. On project completion, where there is an under or overspend against allowances there is a sharing factor to protect consumers.

NGET

Table 2: Construction Works

Project	Outputs expected to be delivered	Delivery Date	Total allowance (£m)	Actual Capex (£m)
Anglo Scottish Incremental	– Increase in network capacity across the B6 boundary of 400MW – Pre-fault winter rating of 2800MVA on the Harker-Hutton-Quernmore Tee circuit	2013-14	82.1	57.0
East Anglia	– Pre-fault winter ratings of 2580MVA and a post-fault winter ratings of 3070MVA on the Walpole-Norwich and Norwich-Bramford 400kV circuits – New Bramford 400kV substation	2016-17	197.2	152.4
North Wales	– Pre-fault winter rating of 2800MVA on Trawfynydd to Treuddyn Tee circuit	2014-15	27.2	10.2
Western HVDC link	– New substation at Connah's Quay to fully replace the existing substation at Deeside	2017-18	217.7	211.7

Table 3: Pre-construction Works[21]

Project	Funding (£m)	Actual Expenditure (£m)
Ironbridge 400kV circuit and the Central Wales substation	5.7	9.6
Eastern HVDC link	3.7	3.7
Substation works and optioneering report to determine whether a Humber-Walpole HVDC link or 400kV overhead line is preferred	14.3	0.9
Hackney-Waltham Cross project	5.6	26.3
New line and substation in the south west	8.7	36.3
Wylfa-Pembroke HVDC link	1.1	0.1

SHE Transmission

Table 4: Construction Works

Project	Outputs expected to be delivered	Delivery Date	Total allowance (£m)	Actual Capex (£m)
Knocknagael	– 275/132kV substation built to 400kV specification	2011-12	45.8	43.1
Beauly-Blackhillock-Kintore	– Beauly-Blackhillock and Blackhillock-Kintore lines reconductored with 2x208mm^2 GTACSR GAP sub-conductors	2014-15	36.7	35.5
Beauly-Dounreay	– Second 725kV conductor installed and two quad boosters installed on the 132kV circuits – Reinforcement at Dounreay substation	2012-13	80.3	67.0
Beauly-Mossford	– New 132kV switching station	End of 2013	12.5	7.8

Table 5: Pre-construction Works[22]

Project	Funding (£m)	Actual Expenditure (£m)
Eastern HVDC link	4.3	2.4

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[21] Outputs for these projects will be agreed under RIIO-T1
[22] Outputs for these projects will be agreed under RIIO-T1

SPTL

Table 6: Construction Works

Project	Outputs expected to be delivered	Delivery Date	Total allowance (£m)	Actual Capex (£m)
SPTL-NGET interconnection	– Two new terminal towers of L12 specification at Eccles – reduce impedance of Strathhaven-Harker and Eccles-Stella West lines by approximately 35%	2015	34.7	1.4
Western HVDC link	– Hunterston East 400kV substation	2015	66.2	83.9
East-West upgrade	– Uprate the Strathaven-Wishaw-Kaimes-Smeaton 275kV circuits to 400kV operation – Install second cable per phase on Torness-Eccles No.1 and 2 400kV circuits	2015	18.1	9.7

Table 7: Pre-construction Works[23]

Project	Funding (£m)	Actual Expenditure (£m)
Hunterston-Kintyre link	0.6	0.5

[23] Outputs for these projects will be agreed under RIIO-T1

Appendix 4 – Transmission Owner spend by year

Table 1: Annual TO capital (load and non load related) and operating expenditure (£m) during TPCR4 and rollover.

		2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	TPCR4+rollover
NGET	Load related	309.7	339.6	473.2	332.2	140.6	210.4	**1805.7**
	Non load related	383.8	326.5	387.8	392.8	474.6	460.3	**2425.8**
	Opex	234.9	258.3	231.9	223.1	225.8	249.5	**1423.6**
	Total	**928.4**	**924.4**	**1092.9**	**948.1**	**840.9**	**920.3**	**5655.1**
SHE Transmission	Load related	22.7	31.9	20.0	22.0	22.2	36.0	**154.9**
	Non load related	16.1	18.5	14.7	11.7	13.4	23.1	**97.6**
	Opex	6.6	6.8	7.0	7.3	8.3	15.2	**51.2**
	Total	**45.5**	**57.2**	**41.7**	**41.0**	**43.9**	**74.3**	**303.6**
SPTL	Load related	25.5	41.7	32.2	29.7	65.5	39.4	**233.9**
	Non load related	62.1	68.0	35.9	51.0	49.6	66.2	**332.8**
	Opex	23.6	22.4	21.3	23.6	32.9	37.4	**161.3**
	Total	**111.2**	**132.1**	**89.4**	**104.3**	**148.0**	**143.0**	**728.0**
NGGT	Load related	619.8	205.4	46.7	34.5	22.0	23.3	**951.7**
	Non load related	43.2	59.9	93.0	85.5	86.6	98.1	**466.4**
	Opex	73.7	75.6	73.2	61.0	75.9	80.1	**439.4**
	Total	**736.7**	**340.9**	**212.9**	**181.0**	**184.6**	**201.5**	**1857.5**

Appendix 5 – System Operator performance

1. Electricity SO incentive performance

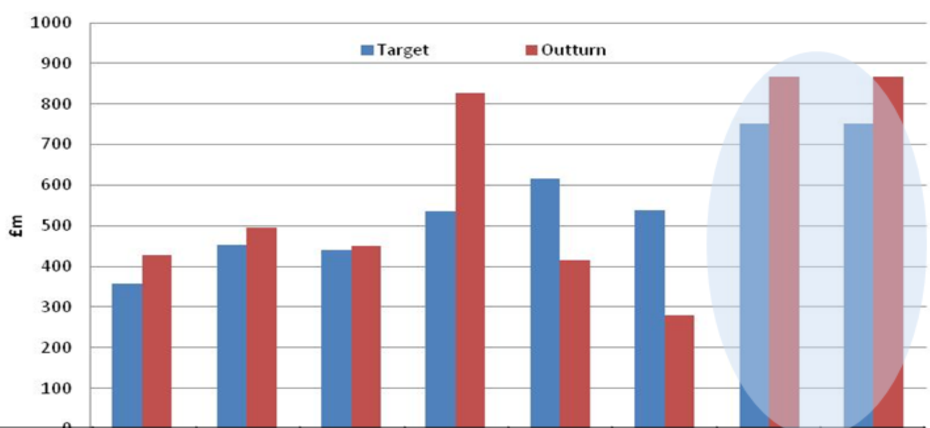
1.20. National Grid Electricity Transmission plc (NGET) is the GB system operator (SO) responsible for balancing the electricity system on a continuous basis.

1.21. Ofgem sets NGET's SO incentives outside of the TPCR4 (or RIIO-T1) price control mechanism, owing largely to the differences in timing and uncertainty of costs which make it more efficient to regulate on shorter timescales.

1.22. Ofgem has been setting SO incentives using a target formulated under the New Electricity Trading Arrangements (NETA) since 2001. These schemes have lasted one or two years and incentivise NGET to operate efficiently through setting a target for its balancing actions. NGET then retains a percentage of any under or overspend against this target with the remainder being passed on to consumers.

1.23. Until 2010-11 the incentive scheme was set annually, with the target set before the scheme commenced. Since 2011 the incentive schemes have been based on the combination of forecast and actual data inputs on a two year period where the target is estimated by the pre-agreed models.

Figure 1: Out-turn costs against target costs since 2005-6[24]



	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Payment to/from NGET	£-4	No Scheme	-£1.2	-£15	-£15	-£15	-£48.3	
	In Range	No Scheme	In Range	Floor Hit	Cap Hit	Cap Hit	In Range	

1.24. Figure 1 above shows actual expenditure against target costs up to the current scheme period. The SO receives an incentive payment when their costs are less than the

[24] The cost data presented here is in real prices as at the time that the payment to/from NGET was calculated.

target (subject to a cap) and the SO is not fully funded for the costs it incurs greater than the target (subject to a floor on the costs not funded).

1.25. Market developments in recent years have increased the complexity of identifying a scheme target. A rapidly changing generation mix with a growing role for renewable generation has increased the volatility and uncertainty regarding balancing actions, and has particularly impacted on constraint costs. As a result, significant divergence between scheme target and actual costs has been observed since 2008 with NGET hitting the scheme cap or floor in each scheme year.

2. Gas SO incentive performance

1.26. National Grid Gas Plc is the gas System Operator (SO) for GB. It is responsible for the economic and efficient management of the gas transmission system. Whereas with the electricity incentives there is one cost-based incentive designed to motivate NGET to keep down the costs of managing the overall system, the gas incentive package is comprised of a small number of separate behavioural incentives.

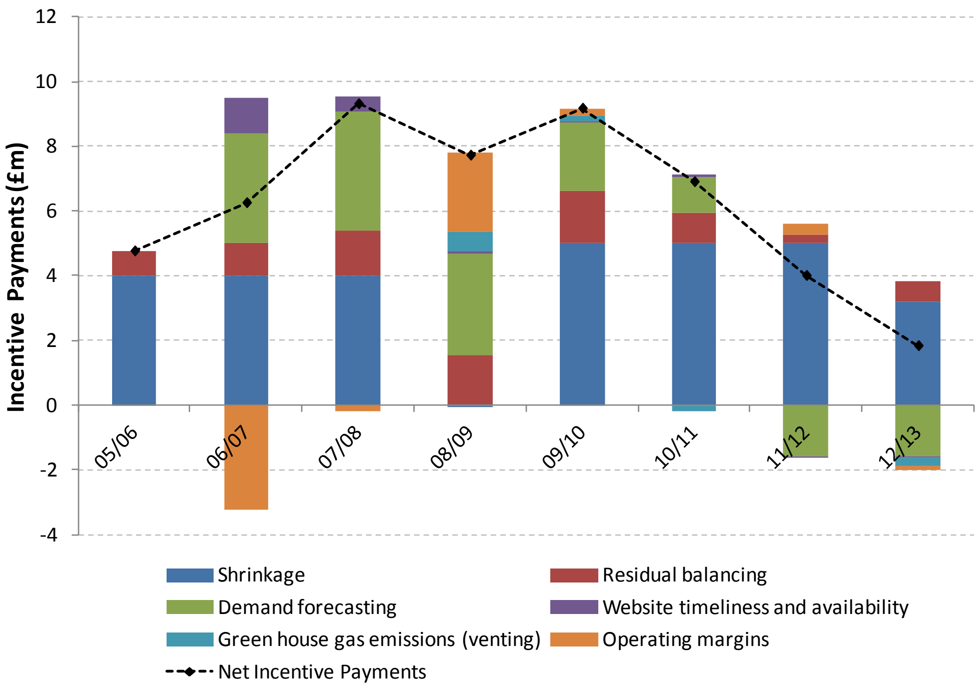
1.27. A new incentive package was introduced from 1 April 2013. This is an eight-year scheme, designed to align with RIIO, and sets longer term defined-output behavioural incentives which are aligned with the incentive packages of the Transmission Owners under the RIIO-T1 framework. The new package maintains relevant aspects of previous incentives as well as introducing some new components. The current incentives are as follows:

- Demand Forecasting
- Residual Balancing
- Shrinkage
- Greenhouse Gas Emissions
- Maintenance
- Unaccounted for Gas (UAG)
- Operating Margins

1.28. The first five of these are financial, with NGGT SO rewarded or penalised for over or underperformance against a target.

1.29. UAG and Operating Margins are reputation-based incentives without financial implications, due to being license requirements.

Figure 2: Summary of the performance of NGGT SO from 2005-6 to 2012-13[25]



1.30. In the last eight years, NGGT SO has outperformed the incentives each year, receiving incentive payments ranging from less than £2m in 2012-13 to over £9m in 2008-09.

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[25] Website timeliness is no longer an incentive. Maintenance is a new incentive.