Annual Regulatory Report

for the year from 1 July 2012 to 30 June 2013

Incorporating Transpower's 2012/13 *Annual Compliance Monitoring Statement* and information required under a s53ZD notice issued to Transpower by the Commerce Commission on 18 April 2013

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of contents

Table of figures

Table of tables

Executive summary

This is our second Annual Regulatory Report under the Commerce Commission's economic regulation framework.

In this report we provide information regarding the performance of our transmission network, our expenditure, and our delivery of projects. We also update the revenue amounts that we will use to set prices for the 2014/15 year (starting 1 April 2014). Our aim with this report is to satisfy our formal regulatory disclosure obligations in a way that is accessible and useful for our customers. We would welcome any feedback you have on how we can improve this report.

Contents and Structure

The report is structured to provide a logical build-up towards the updated 2014/15 revenue figure that will be used for pricing, as follows:

- brief overview of our regulatory framework
- review of capital expenditure and major projects
- 'wash-up' of our 2012/13 maximum allowable revenue ("MAR"). The MAR accounts for most of our transmission revenue, including asset-related revenues and revenues relating to 'controllable' operating expenditure. We established initial forecast MAR figures in 2011 for each of the years from 2011/12 to 2014/15[1]. After each year, we reconcile the initial forecast MAR with an *ex post* MAR based on the actual timing and value of assets commissioned. The difference between forecast and *ex post* MAR is washed-up in the next available pricing year
- review of controllable operating expenditure and associated MAR adjustments
- review of the balance of our operating expenditure – termed 'pass-through' and 'recoverable' costs
- review of network performance. From 2015/16 onwards, revenues will be adjusted based on annual network performance relative to target performance
- updated 2014/15 revenue forecast. This will be reviewed by the Commission, and the approved forecast will be used to set prices from 1 April 2014.

We have also added the following sections this year:

- analysis of return on investment (ROI) for our transmission business
- review of System Operator expenditure and revenue.

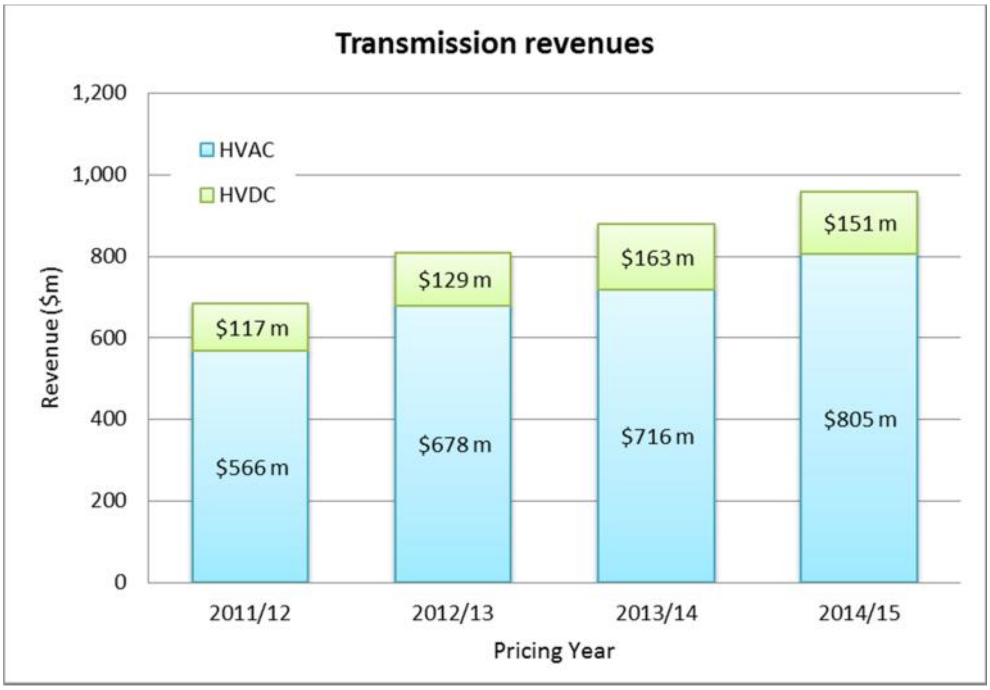
System Operator revenues are set under a contract with the Electricity Authority (the System Operator Service Provider Agreement, or "SOSPA") and recovered via a levy. The SOSPA revenue model follows a similar 'building blocks' approach to our transmission revenue model.

[1] See the Commerce Commission website: http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-price-path-compliance/maximum-allowable-revenues-2012-13-2014-15/

RCP1 Revenue Path

This report provides the final revenue update for our first regulatory control period (RCP1). Forecasts for the five years from 2015/16 to 2019/20 will be included with the RCP2 expenditure proposal that we will submit to the Commerce Commission on 2 December this year. The chart below sets out the full RCP1 revenue path.

Figure 1: Final RCP1 revenue path



Figures shown are the forecast total revenue used to set HVAC and HVDC charges[2] each year (i.e., MAR plus pass-through and recoverable costs, including all prior year wash-ups and adjustments).

Movement in forecast of 2014/15 revenue

Table 1 below shows the movement from the forecast of 2014/15 revenues calculated at the beginning of the control period, through to the updated figures that will be used to set prices. 2014/15 revenues were last updated in last year's Annual Regulatory Report, and the focus of this report is the movement from that update to the final forecast.

[2] HVDC charges are recovered directly from grid-connected South Island generators. Remaining charges are mostly recovered from distributors and connected consumers.

Table 1: Movement in forecast of 2014/15 revenue

		Total $m	HVAC $m	HVDC $m
Initial IPP forecast (Nov 2011)		979.1	821.4	157.7
Previous update (Oct 2012)		974.9	816.9	158.0
Final Forecast (used for pricing)	See Table 32	953.9	809.0	145.0
Movement (from previous update)		*(21.0)*	*(7.9)*	*(13.0)*

Most of the movement in forecast 2014/15 revenues is due to wash-ups and adjustments driven by performance in 2012/13.

Forecast revenue calculations assume mid-financial year (i.e., December) commissioning of all assets. For assets actually commissioned earlier in the year, the forecast revenue figure will have been too low. The wash-up allows us to correct this shortfall in 2014/15. Conversely, for assets commissioned later in the year, the wash-up returns the over-recovery to customers. The wash-up similarly allows future prices to be adjusted if we commission assets at a higher or lower value than forecast.

The key drivers of the wash-ups and adjustments relating to 2012/13 performance are:

- HVAC assets were, on average, commissioned earlier than forecast. This was more than offset by the lower commissioned value. The net effect is that our return on HVAC assets was $3.3 million too high.
- HVDC assets were, on average, commissioned later than forecast. This was partially offset by higher commissioned value and by un-forecast tax charges on liquidated damages. The net effect is that our return on HVDC assets was $3.4 million too high.
- our operating expenditure allowance incorporates forecast CPI movement of 2.4% each year. Actual CPI movement has been less than forecast, so we have over-recovered $8.5 million compared to the CPI-adjusted allowance.

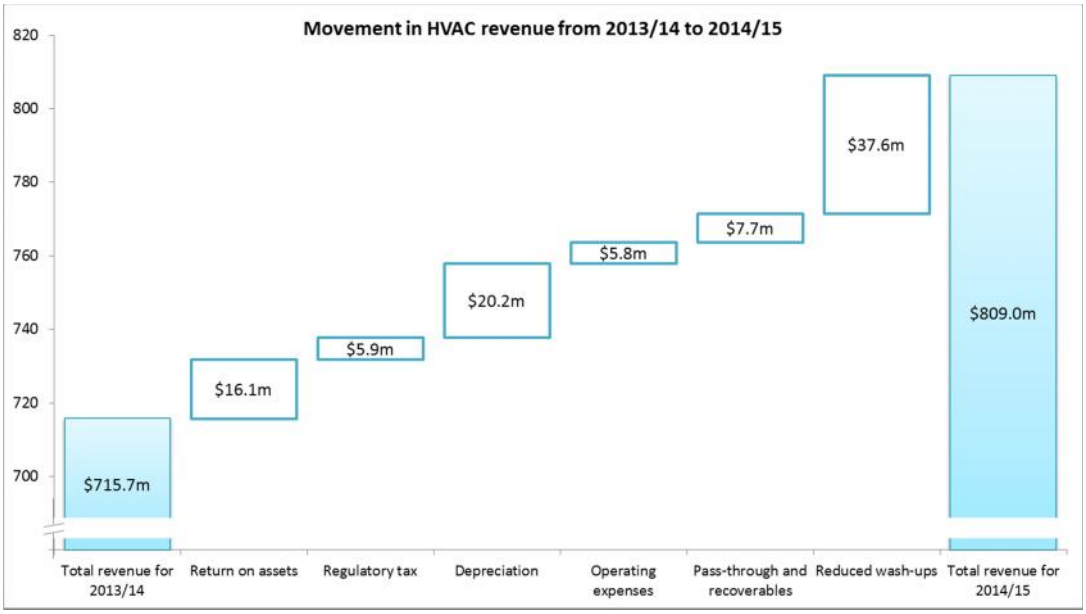
Additional factors also causing movement in our forecast 2014/15 revenues include:

- the Commerce Commission increased the major capex allowance ("MCA") for the Otahuhu substation diversity project. This allows us to reverse a $5.3 million adjustment we made to 2013/14 revenues.
- we are forecasting that our 2014/15 Auckland Council rates will increase by $3 million.
- we are forecasting spend of $5.1 million on demand-side response in 2014/15.

Movement from 2013/14 to 2014/15

Current transmission charges (from 1 April 2013) are based on our 2013/14 forecast revenue figures. We will set new charges from 1 April 2014 based on our 2014/15 forecast revenue. The revenue update is a key driver for changes in prices for individual customers and end consumers. Other drivers include changes in connection asset configurations, customer demand during peak periods, and customer contracts for new assets (priced outside the revenue setting process). The following charts show the changes in the main components of our revenue from 2013/14 to 2014/15.

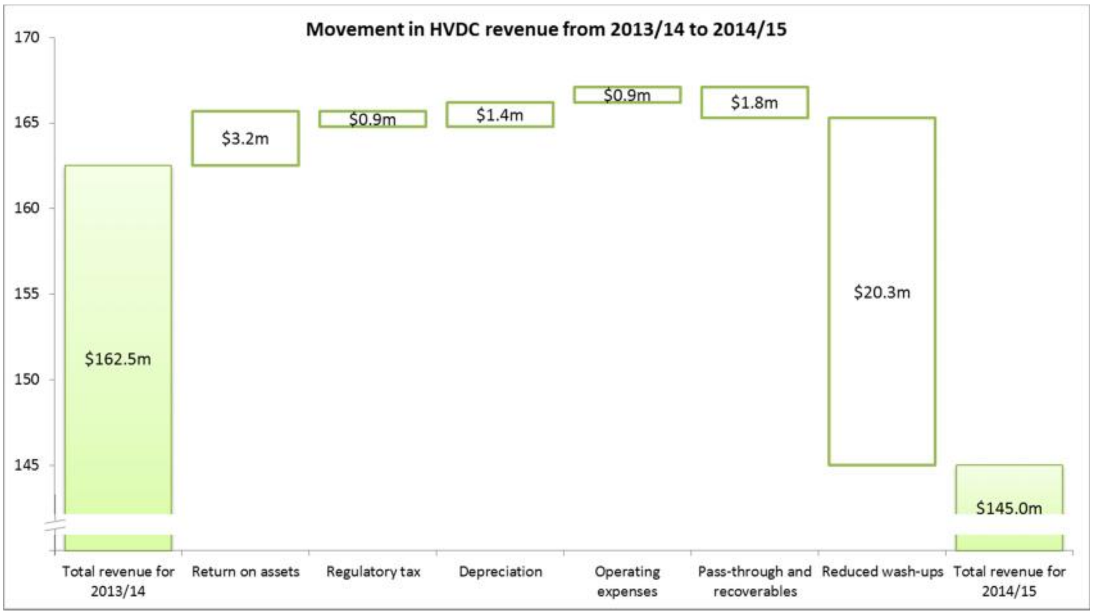
Figure 2: Movement in HVAC revenue (forecast 2013/14 to forecast 2014/15 revenue)



Key drivers for the 13% increase year-on-year in our HVAC revenue are:

- our HVAC regulatory asset base is forecast to increase as we complete our programme of major upgrades. This increases our return on assets and depreciation by $16.1 million (5.3%) and $20.2 million (11.4%) respectively.
- 2013/14 revenue was reduced due to a relatively large wash-up of $53.5m relating to 2011/12 performance. The wash-up applied to 2014/15 revenue is $15.9m, $37.6m less than the prior year.
- pass-through and recoverable costs are forecast to increase, largely due to Auckland Council rates ($3m increase) and forecast spending on demand response ($5.1m).

Figure 3: Movement in HVDC revenue (forecast 2013/14 to forecast 2014/15 revenue)



Key drivers for the 11% reduction year-on-year in our HVDC revenue are:

- upgrade work on Pole 2 is forecast to be completed half-way through 2013/14. 2014/15 will be the first full year with all HVDC upgrade assets in place. This increases our return on assets and depreciation by $3.2 million (5.5%) and $1.4 million (3.5%) respectively.
- 2013/14 revenue was increased due to a $9.1 million wash-up relating to 2011/12 performance. The wash-up applied to 2014/15 revenue is a $11.2 million reduction, which produces a $20.3 million reduction year-on-year.

We expect that wash-up volatility will decrease as we near the end of our programme of major upgrades. Our future revenue profile will also flatten considerably.

Movement in EV balances

Transpower operates HVAC and HVDC 'economic value' (EV) accounts that are used to clear wash-ups and adjustments.

As well as clearing on-going annual adjustments, we are required to zero historical accumulated EV balances in equal instalments over the period from 2012/13 to 2019/20. The HVAC EV account had an opening balance of $82.4 million (owing to customers) at 1 July 2011 that will be zeroed by returning $12.2 million to HVAC customers each year. The HVDC EV account had an opening balance of $106.7 million (owed by customers) at 1 July 2011 that will be zeroed by recovering $24.4 million from HVDC customers each year[3]. The following table updates the movement in the EV balances from 30 June 2012 to 30 June 2013.

Table 2: Amounts due to (from) our customers

		Total $m	HVAC $m	HVDC $m
Balance on historic accounts at 30 June 2013	Table 35 & Table 36	(46.9)	47.1	(94.0)
Wash-ups and adjustments in 2011/12[4]		31.0	36.5	(5.5)
Interest to 30 June 2013 on 2011/12 wash-ups	at 7.2%	2.2	2.6	(0.4)
Asset-based wash-up[5]	Table 15	21.2	14.9	6.3
Pass-through and recoverable cost wash-up[5]	Table 21	3.0	1.7	1.2
Reversal of the 2011/12 Otahuhu adjustment[5]		(5.3)	(5.3)	-
Balance at 30 June 2013		**5.2**	**97.6**	**(92.4)**

Note: figures may not add exactly due to rounding.

[3] To achieve a $17.6 million reduction in the HVDC EV account, we charge HVDC customers $24.4 million. The difference ($6.8 million) is paid as tax.

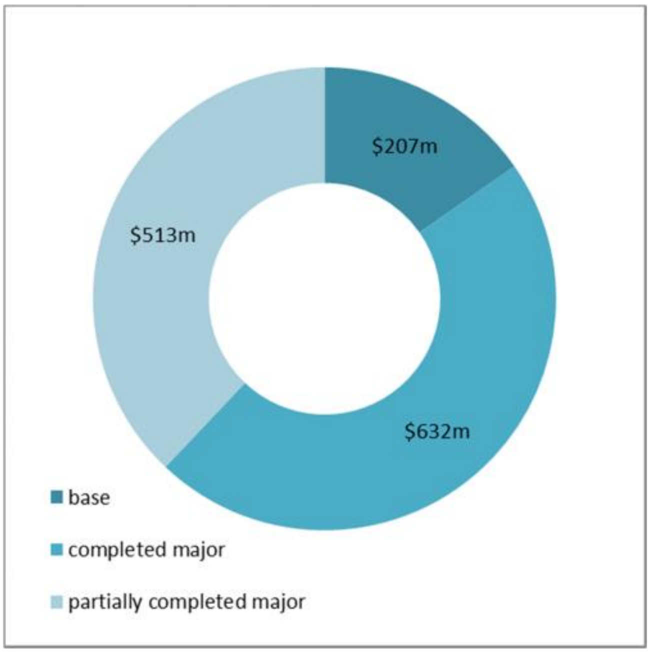
[4] Being cleared through adjustments to the 2013/14 pricing year

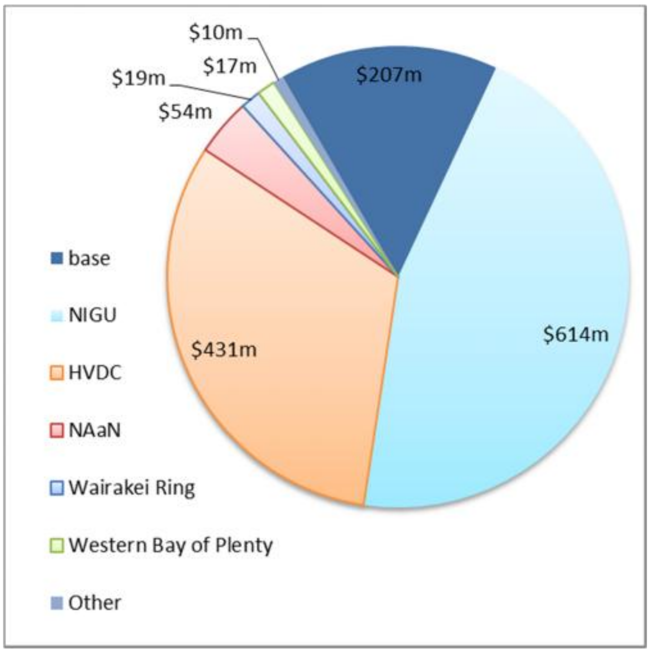
[5] To be cleared through adjustments to the 2014/15 pricing year

2012/13 capital expenditure

We completed three 'major projects'[6] during the 2012/13 year, and partially commissioned a further eight major projects.

Figure 4: Assets commissioned in 2012/13





Completed major projects added $632 million to our asset base, being almost one-half of our total commissioned assets for the year of $1,352 million. We commissioned a further $207 million of base capital projects, with the balance ($513 million) being due to partially-commissioned major capital projects.

The North Island Grid Upgrade (NIGU), HVDC upgrade and North Auckland and Northland (NAaN) projects accounted for $1,099 million. Across the portfolio of major projects still under construction on 30 June 2013, the forecast end cost is 17% below the total approved allowance ($1,212.3 million against a portfolio allowance of $1,468.5 million)[7].

The expected final cost of the NIGU project is $894 million, which is 8% higher than the approved allowance. We have applied to the Commerce Commission for an increase in the allowance to $894 million. However, we have made a commitment that we will only recover revenues on not more than $876 million of NIGU assets, regardless of the Commission determination. We will adjust prices in 2014/15 accordingly, and will make further revenue adjustments in RCP2.

---

[6] 'Major projects' are capital projects subject to individual regulatory approval. By contrast, 'base' capex is funded from an allowance that spans all remaining RCP1 capex. From RCP2 enhancement projects larger than $20 million are subject to individual approval, but lower thresholds have applied at various times.

[7] If NIGU is included, the portfolio cost is 6% under the portfolio allowance.

The inflation adjusted base capex allowance for 2012/13 is $295.3 million, compared to actual commissioning of $207.0 million[8]. Around 30% of this reduction is due to re-phasing of a programme to build a new fibre telecommunications network. We forecast that we will commission a maximum of $952 million of base capex assets across RCP1 compared to a forecast (inflation adjusted) allowance of $1,003 million.

Operating expenditure

Operating expenditure for 2012/13 was $254.1 million[9], against an allowance of $271.3 million. The allowance has been adjusted to reflect lower-than-forecast CPI movement in 2011/12 and 2012/13. The unadjusted allowance was $279.8 million.

The under-spend against the allowance is primarily a result of less expenditure on grid maintenance during the year, which was due to improved cost control, job vetting and planning, together with detailed review and prioritisation of work.

Network performance

Network performance for 2012/13 outperformed targets set by the Commission for all measures. The following table summarises network performance.

Table 3: Summary of network performance

Performance measure	Target	Actual	Target achieved?
Number of loss of supply events greater than 0.05 system minutes	21	12	Y
Number of loss of supply events greater than 1 system minute	3	2	Y
Unplanned HVAC circuit unavailability (%)	0.054	0.032	Y
Unplanned HVDC bi-pole unavailability[10] (%)	(no target set)	0.684	n/a
Total impact of interruptions (measured in system minutes)	16.69	7.62	Y

The two events involving a loss of supply of more than one system minute were:

- the in-service 220/110kV interconnecting transformer at the Redclyffe substation tripped on 18 December causing interruption to supply in Hawkes Bay and the East Coast (2.42 system minutes)
- an 11kV supply bus at Cambridge tripped due to a phase-to-phase bus fault on 18 April, resulting an interruption to supply at Cambridge (2.23 system minutes)

[8] The allowance applies to the value of assets commissioned each year, rather than to the amount spent each year.

[9] This includes costs of $7.1 million that will be offset by insurance, but which are shown gross in this report.

[10] Half of Pole 1 was decommissioned in 2007, and the other half was only available for limited operation until it was decommissioned in August 2012, and the new Pole 3 was commissioned in May 2013. Therefore, only Pole 2 has been included in this calculation for 2012/13.

We have developed new network performance measures for RCP2 that move away from system average measures, and recognise that service expectations differ across points of service. We have also developed forward-looking targets for performance, rather than relying on past performance to guide future targets. We will report against these new measures in next year's report[11].

Return on investment

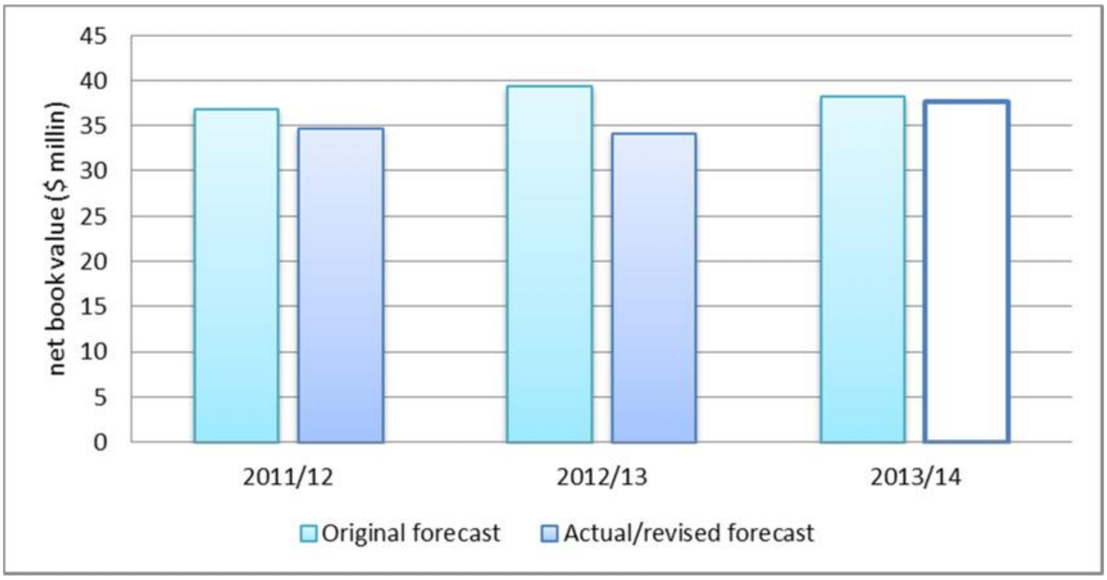
We have assessed return on investment for our transmission business following the same method used for information disclosure by electricity distribution businesses. We have adjusted this figure to remove wash-up amounts and to account for modelling effects.

Based on this analysis, our return on investment is 8.61%. This includes an uplift of 0.56% (relative to our regulatory vanilla WACC of 8.05%) due to achieving a saving of $24.2 million against our CPI-adjusted opex allowance.

System Operator

2012/13 was the middle-year of the System Operator's three-year revenue period. To date, the value of assets commissioned in the period is lower than the forecast used to set revenues. We expect this to reverse during 2013/14 such that the closing asset base for the period will be similar to the original forecast, as shown below.

Figure 5: Forecast and actual movement in System Operator asset base



Key drivers for the change in profile are:

- we delayed and re-scoped a number of lifecycle and efficiency projects to align with upgrades to operating system software that is due to come out of support in 2015

[11] For more information, refer to https://www.transpower.co.nz/about-us/industry-information/customer-facing-grid-performance-measures-consultation.

- market development projects are identified, scoped, and committed via consultative regulatory processes led by the Electricity Authority, and are inherently challenging to forecast.

The following table sets out our current forecast of the wash-up amount and revenues for the next period.

Table 4: System Operator forecast revenue and estimated wash-up

	2011/12 $m	2012/13 $m	2013/14 $m	2014/15 $m	2015/16 $m	2016/17 $m
revenue forecast	34.3	36.7	38.7	41.3	43.9	47.3
ex post revenue	34.2	35.8	-			
updated forecast	-	-	37.9			
variance	(0.1)	(0.9)	(0.8)			
pre-emptive wash-up	-	-	1.5			
estimated wash-up balance			(0.3)			

Because we have commissioned assets later than originally forecast, we have over-recovered $1 million to date and forecast this to grow to $1.8 million by the end of the current period.

Rather than wait until after 2013/14, we are making a pre-emptive wash-up payment of $1.5 million this year to reduce the size of the final wash-up.

RCP2 revenue

We will submit a proposal to the Commission in December for our operating expenditure and base capex requirements for the next regulatory control period, RCP2. The proposal will include an initial assessment of our revenue path from 2015/16 to 2019/20. The final price path for RCP2 will depend on:

- the impact of remaining RCP1 expenditure on the 2015/16 opening regulatory asset base (RAB)
- approval of any major projects
- carry-forward of RCP1 incentive adjustments and wash-ups into RCP2
- the regulatory WACC set by the Commission
- any amendments to regulatory rules
- the Commission’s final decision on opex and base capex allowances

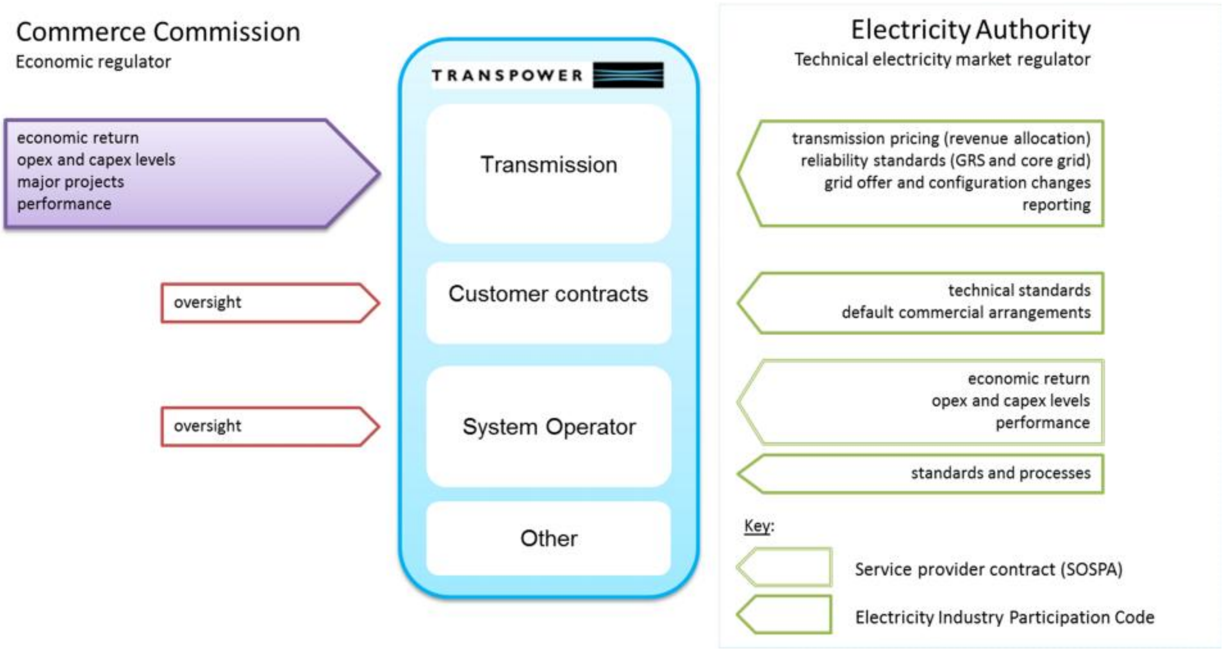
Next year’s Annual Regulatory Report will include forecast revenues for RCP2.

1 Introduction

This report covers Transpower's regulated transmission activities for the period from 1 July 2012 to 30 June 2013 (the 'disclosure year'). It reviews capital and operating expenditure, and the performance of the transmission network.

The report also updates earlier forecasts of our transmission revenue for 2014/15. This updated forecast will be used to set transmission prices for the 'pricing year' starting 1 April 2014.

Figure 6: Regulation of Transpower's activities



This is the second report from our first regulatory control period ('RCP1'), which runs from 2011/12 to 2014/15. This year we have added information on:

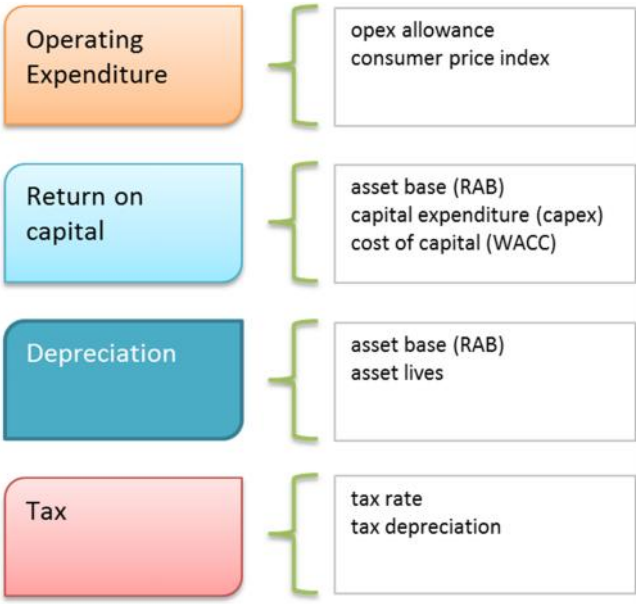
- return on investment for the transmission business (Chapter 9)
- the System Operator (Chapter 10)
- expected delivery of assets over the RCP1 period (Appendix A.9).

We welcome any feedback you have on this report.

1.1 Maximum Allowable Revenue (MAR)

The Commerce Commission ("Commission") has established rules that are used to set the allowable revenue for transmission services. The MAR is calculated by adding together revenue 'building blocks'.

Figure 7: MAR building blocks and inputs



Some of the inputs to the building blocks are set by the Commission at the beginning of each control period. These are:

- operating expenditure allowances for each year
- 'base' capital expenditure for each year
- cost of capital (WACC).

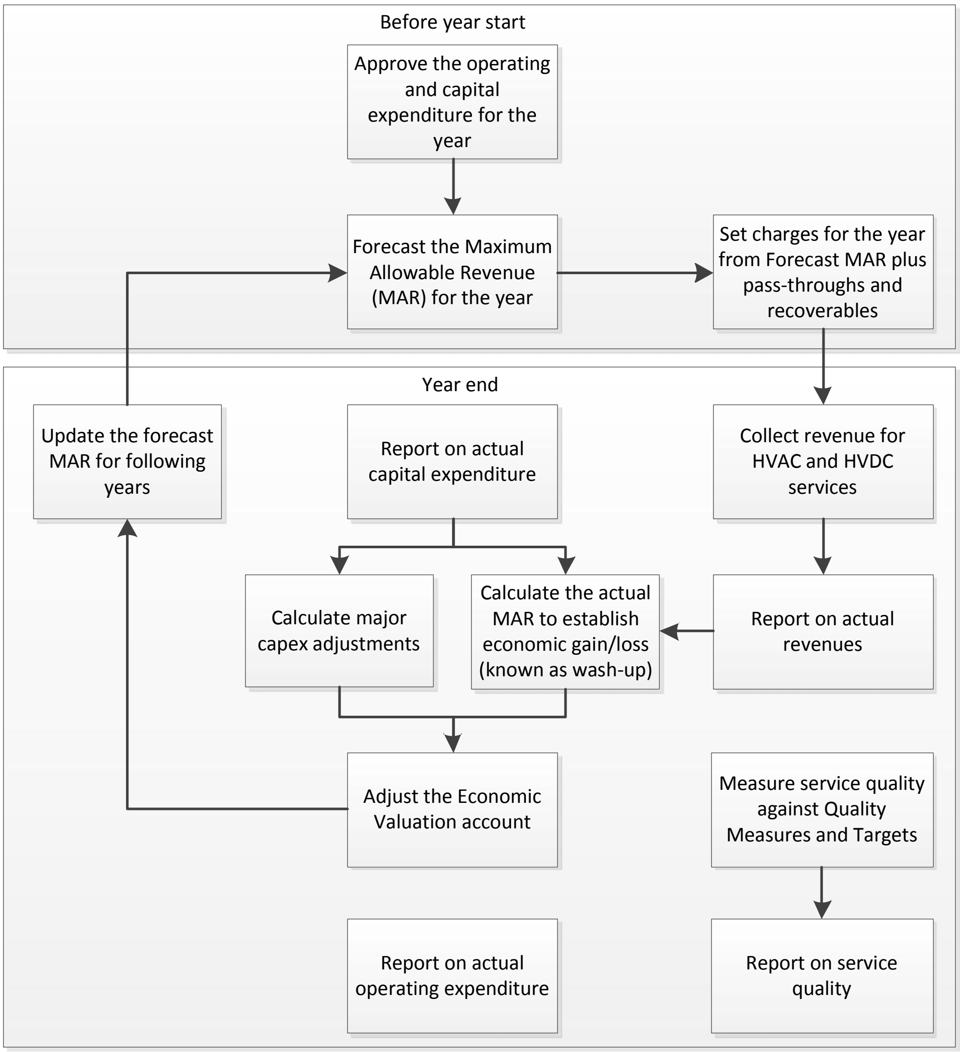
We use these inputs to calculate an initial forecast of transmission revenue, that is then updated each year to take account of actual expenditure and performance. The updating process is explained in more detail below.

1.2 Revenue setting process

In this report, we calculate a 'wash-up' amount that ensures our revenue for 2012/13 is correct in light of our actual capital expenditure for the year. We also make a series of other adjustments that are explained in detail in this report. The wash-up and adjustments will be carried forward and used to update forecast revenue for 2014/15. This process ensures that, over time, the amount that people are paying for transmission services is consistent with the MAR.

The following diagram sets out this 'individual price path' (or 'IPP') process in more detail.

Figure 8: Process diagram for operation of the IPP framework



The figure below explains each step of the IPP process, as it applies this year.

Figure 9: Overview of the IPP framework and the structure of this report

Step	Description	Reference
Approve the operating and capital expenditure for the year Forecast the Maximum Allowable Revenue (MAR) for the year	Before the start of RCP1, the Commerce Commission approved annual allowances for operating expenses and capital expenses for each year of the RCP. The Commerce Commission used the allowances, and a range of other information, to determine initial forecasts of the maximum allowable revenue (MAR) figures for each year of RCP1.	Not part of this report.

Step	Description	Reference
Set charges for the year from Forecast MAR plus pass-throughs and recoverables	In November 2011, we set our charges for the 2012/13 pricing year. This took into account the applicable forecast MAR, plus estimated pass-through and recoverable costs.	Not part of this report.
Report on actual capital expenditure	During the year, we incurred actual capital expenditures that do not exactly match the forecast used to set revenue.	Capital expenditures are covered in Section 2.
Collect revenue for HVAC and HVDC services Calculate the actual MAR to establish economic gain/loss (known as wash-up) Calculate major capex adjustments	We collected revenues for our HVAC and HVDC transmission services during 2012/13. In this report, we have re-calculated the 2012/13 MAR using the actual timing and values of assets commissioned during the year. Comparing this '*ex post* MAR' with actual revenues provides a 'wash-up' amount representing over- or under-recovery for the year. In some cases, we must also make adjustments relating to the delivery of major projects.	MAR wash-up calculations are covered in Section 4. Major projects are covered in Section 3.
Report on actual operating expenditure	During the year, inflation has differed from the forecast used to set the allowance. An adjustment is made to correct for this disparity.	Operating expenditure is covered in Section 5.
Measure service quality against Quality Measures and Targets ↓ Report on service quality	During the year, we measure service quality against a set of reliability metrics and targets. In RCP2, quality performance will be used to adjust our revenues. In RCP1, we report on what the revenue impact would be if this adjustment were in place now.	Quality performance is covered in Section 7.

Step	Description	Reference
Update the forecast MAR for following years	We have updated our forecast MAR and forecast revenue for the coming year (2014/15) using wash-up amounts, major project adjustments, and updated estimates of pass-through and recoverable costs.	Pass-through and recoverable costs are covered in Section 6. Updated revenue forecast figures are covered in Section 8.

We will use the updated forecast revenue for 2014/15 to set HVAC and HVDC prices[12] for the pricing year starting April 2014[13]. The process of translating the forecast revenues into transmission prices is governed by a methodology that is approved by the Electricity Authority.

The pricing methodology allocates charges to distributors, generators and major users. We will publish our prices for the 2014 year in early December 2013 to allow our electricity distribution customers to update the prices that they set for their electricity retailer customers.

This report includes a number of historical and forecast figures, which are presented in nominal terms.

[12] 'HVDC' refers to our High-Voltage Direct Current link between Benmore in the South Island and Haywards (near Wellington) in the North Island. Our South Island generation customers fund this link. 'HVAC' refers to our High-Voltage Alternating Current networks in the North and South islands that make up the balance of our assets. All of our customers fund these networks.

[13] This report discusses 'pricing years' and 'disclosure years'. Pricing years start on 1 April, and disclosure years start on 1 July. More detail is provided in Appendix A.1.9.

2 Capital expenditure

This section covers 'base' capital expenditure (base capex). For 2012/13, base capex includes:

- all grid asset replacement and refurbishment
- grid asset enhancement projects or programmes less than $5 million[14]
- non-grid capital expenditure.

The Commission has approved an overall base capex allowance for RCP1, based on its assessment of forecasts we made in 2011 for each year of RCP1. The allowances relate to the value of the assets we commission, rather than to the amount we spend. This is a change from the way allowances operated prior to RCP1.

Assets are classed as 'commissioned' when they are brought into use to provide electricity transmission services – i.e. only once construction and testing is complete and they are actually being used. Commissioned assets are added to our regulatory asset base (RAB) and we then earn a return *on* capital (the assets in our RAB), plus a return *of* capital (via depreciation of the assets in our RAB).

If our commissioned base capex at the end of RCP1 exceeds our allowance then we may apply to the Commission for an increase in our allowance, subject to suitable justification.

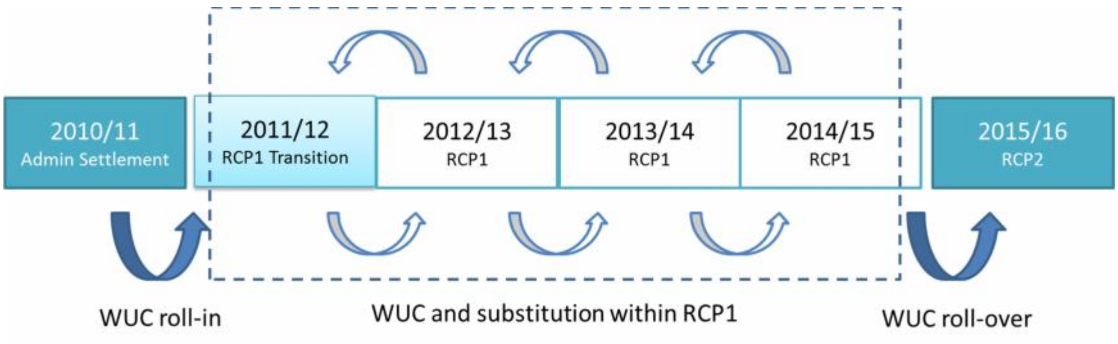
The remainder of this section:

- discusses commissioning-based accounting
- compares actual commissioned values for 2012/13 with forecast values
- explains material variances between forecast and actual figures
- reports on base capex adjustments.

2.1 Commissioning-based accounting

Like any business, we plan, monitor and control expenditure on a spend basis. However, the IPP framework operates on a commissioning basis for capex.

Figure 10: Movement of commissioning dates within and between control periods



14 Lower thresholds have applied in the past, and the threshold increases to $20m for projects or programmes expected to be completed after RCP1.

Asset commissioning lags expenditure, and this is reflected in a 'works under construction' (WUC) balance that is carried over between years. In addition to WUC carryover, we have flexibility within our base capex allowance to substitute between years of RCP1, including by bringing work forward. These movements between years and between control periods are illustrated in Figure 10.

The WUC balance for base capex at the start of RCP1 was $134 million. At present, we forecast a closing base capex WUC balance for RCP1 of $97 million.

2.2 Comparison of actual with forecast base capex

This section compares forecast and actual base capex at a 'category' level, and to explain any material variances.

Actual and forecast values are set out below. In the context of our forecast MAR for 2012/13 of $783.8 million, we have interpreted 'material variance' to be a variance that is both greater than $16 million[15] and more than 10% of the category forecast.

Table 5: Forecast and actual base capital expenditure (commissioned basis)

Category	Allowance[16] $m	Actual $m	Variance $m	Variance %	Material Y or N
Asset Enhancement	5.2	3.0	(2.2)	(42%)	N
Asset Refurbishment[17]	32.3	22.9	(9.4)	(29%)	N
Asset Replacement[17]	173.4	123.0	(50.4)	(29%)	Y
TOTAL GRID CAPEX	210.9	148.8	(62.1)	(29%)	
Information Services and Technology (IST)	80.5	50.2	(30.3)	(38%)	Y
Business Support	3.9	7.9	4.0	103%	N
TOTAL	**295.3**	**207.0**	**(88.3)**	**(30%)**	

Note: Figures may not add exactly due to rounding.

The following table sets out the more material identifiable cost variances across the range of base capex.

[15] A capital expenditure variance of $16 million in 2012/13 would typically (depending on the depreciation rate for the asset) have a revenue impact of about 0.2% of the MAR in the year and therefore about 1% of MAR over a 5 year RCP.

[16] The allowance set an overall allowance, rather than an allowance broken down by category. From this year (2012/13) an adjustment applies to this allowance, to correct for any disparity between actual and forecast CPI movement.

[17] The regulations require us to show amounts relating to asset refurbishment and asset replacement separately. In practice we do not make this distinction and so the 'allowance' and 'actual' numbers here have been split on the basis of historic results. The variance explanation in Table 6 combines the variances for these two categories.

Table 6: Material cost variances for individual base capex projects

	Variance $m	Explanation
Asset Refurbishment and Replacement	(59.8)	• Power Transformers: $13.5 million less than forecast due to commissioning 3 transformers (including 1 spare), compared to 4 in the original plan, and unit cost was lower due to one unit being a spare. • Outdoor to indoor conversion programme: converted 4 sites as planned. Prioritisation (using asset health and criticality tools) changed the choice of sites converted, reducing commissioning by $3.9 million. • Dynamic reactive power: scope of work was restricted due to Pole 3 commissioning, leading to commissioning of $8.1 million less than forecast. • Metering: 83 meters commissioned, compared to planned 147 due to a decision to slow the programme to match available resource. This led to $6.0 million reduction. • Buildings and grounds: $6.3 million less than forecast due to a general reprioritising of spending in 2012/13. For example, replaced fewer fences than originally planned. • Buildings & seismic: resource constraints following Christchurch earthquake resulted in commissioning $4.2 million less seismic strengthening. • Transmission line conductors: reviewed and revised policy on urban copper, leading to decision not to spend the forecast $6.2 million.
Information Services and Technology (IST)	(30.3)	Telecommunications and Networking Programme (TNP)[18] TNP was re-phased: • 2012/13 commissioning $36m less than forecast. • programme expected to have been completed by the end of 2012/13, now spread over RPC1 period due to external resource limitations. • forecast end cost is in line with original forecast. Maximo Initial release of asset management system brought forward. • 2012/13 commissioning $16m more than forecast • originally expected to be commissioned in 2014/15, but initial release brought forward to enable benefits to be delivered earlier and to enable a more effective business change process. • forecast end cost in line with original forecast.

[18] TNP is a programme to build a new fibre telecommunications network.

Appendix A.9 sets out forecast variances and explanations for base capex over the full RCP1 period. This information is provided to support assessment of our base capex proposals for the next control period, and complements the information contained in the full RCP2 proposal documents we will submit to the Commerce Commission on 2 December 2013[19].

2.3 Base capex adjustments

The following table summarises the adjustments relating to base capex that can apply through RCP1 or at the end of the period.

Table 7: Adjustments that can apply to base capex

	Description	When it applies
Unapproved amount	Revenue is adjusted to remove the benefit of any base capex that has not been through our internal approval processes.	Each year
Conversion	Expenditure that was included in the base capex allowance may instead be covered by a new major project. The base capex allowance is reduced accordingly. Similarly, the cost of a project or programme included in the base capex allowance may increase such that it exceeds the expenditure thresholds and must be removed from the base capex allowance.	Each year
CPI	The base capex allowance is adjusted to account for any disparity between forecast and actual consumer price index (CPI) rates.	Each year, from 2012/13
Excess amount	Revenue is adjusted to remove the revenue benefit of any base capex that exceeds the overall allowance for RCP1.	End of RCP1
Allowance increase	We may apply for an increase to approved base capex allowances.	End of RCP1

All base capex for 2012/13 has been through internal processes, so no 'unapproved amount' adjustment to revenue is required this year.

The Kawerau Generation Export Enhancement project was previously included in the base capex allowance and has now been designated as a major capex project. We have reduced our 2013/14 base capex allowance by $4.6 million accordingly.

The following table shows the base capex allowance for each year as set at the start of RCP1, and compares CPI forecasts made at the time with actual CPI to date, and updated forecasts[20] for the remainder of RCP1. This data is used to produce an adjusted base capex allowance for 2012/13 and updated forecast allowances for future years.

[19] This information fulfils some of the requirements set out in an information request the Commission made under s53ZD of the Commerce Act on 2 July 2013 as part of the RCP2 preparation process. A reconciliation from that request to the information in this report is provided in Appendix A.14

[20] Forecasts are based on the September 2013 release of the Reserve Bank's Monetary Policy Statement.

Table 8: Adjustment to base capex allowance for CPI movement

	2011/12	2012/13	2013/14	2014/15
Allowance set at the start of RCP1	$208.6m	$301.9m	$240.3m[21]	$278.4m
Forecast CPI for the year at that time	*2.4%*	*2.4%*	*2.4%*	*2.4%*
CPI-adjusted base capex allowance	n/a	$295.3m	$232.3m	$267.1m
Actual († or revised forecast) of CPI	*0.95%*	*0.68%*	*1.40%†*	*1.87%†*

Note: figures are in nominal dollar terms

2.4 Historical base capex

For comparison with the figures in Table 5, the following table sets out historical base capex from 2008/09 to 2011/12. Figures prior to 2011/12 are on a spend basis, consistent with reporting requirements in those years.

Table 9: Historical base capex

Category	2008/09 $m	2009/10 $m	2010/11 $m	2011/12 $m
Basis	*Spend*	*Spend*	*Spend*	*Commissioned*
Enhancement and Development	12.7	22.1	7.1	4.9
Refurbishment and Replacement	57.4	114.4[22]	152.1	168.9
IST[23]	38.9	66.5	62.5	46.2
Business support[24]	-	-	-	1.7
Total	**109.1**	**203.0**	**221.7**	**221.7**

Note: figures are in nominal dollar terms and may not add exactly due to rounding.

2.5 Forecast capital expenditure

The table below provides updated aggregate forecasts of base capex and major project expenditure for the remainder of RCP1. Figures are on a commissioning basis.

[21] This figure includes an adjustment for the Kawerau Generation Export Enhancement project, as described above.

[22] This includes expenditure of $16.5 million approved by the Commerce Commission subsequent to publication of the 2009/10 threshold compliance statement

[23] Prior to 2011/12, this category included 'operating leases', which are now treated as operating expenditure.

[24] We did not report against the 'business support' category prior to 2011/12, and accordingly we have not reported these figures here.

Table 10: Forecast base and major capex

	2013/14 $m	2014/15 $m
Base capex	295.6	228.1
Major projects	507.5	90.4
Total	**803.1**	**318.5**

Note: figures are in nominal dollar terms and may not add exactly due to rounding.

Forecast maximum total base capex for RCP1 is $952.4 million, compared to an inflation-adjusted allowance of $1,003.3 million.

3 Major projects

Grid enhancement projects and programmes expected to cost more than $5 million were approved by the Commission individually, based on an assessment of the market benefit of the project compared to other viable alternatives. Each 'major project' has an approved allowance, timeframe and 'outputs'.

This section covers:

- progress reports on major projects partially commissioned during 2012/13 and close-out reports on completed major projects
- major projects newly approved by the Commission
- other variations and adjustments.

3.1 Progress reports – costs

Several major projects still under construction on 30 June 2013 had assets commissioned during 2012/13. Table 11 compares the current expected cost of each of these projects to the expected cost at the time the projects were approved. Material variances are explained below.

Table 11: Updated cost forecasts for partially completed major projects

Title	Major Capex Allowance $m	Expected cost[25]		Expected cost variance $m	Expected cost variance (%)
		Current Forecast $m	Original Forecast[26] $m		
Wairakei Ring	141.0	128.6	124.9	3.7	3.0
Upper North Island Dynamic Reactive Support	110.2	76.9	90.1	(13.2)	(14.7)
NAaN[27]	418.9	338.3	333.6	4.7	1.4
Lower South Island Reliability	62.4	31.6	55.6	(24.0)	(43.2)
Kawerau Generation Export Enhancement	9.5	7.0	7.2	(0.2)	(2.8)
Auto Synchronisation Points	9.5	7.8	9.1	(1.3)	(14.3)
Wanganui-Stratford Transmission	44.1	25.8	42.3	(16.5)	(39.0)
HVDC	672.9	596.3	603.0	(6.7)	(1.1)
TOTAL	1,468.5	1,212.3	1,265.8	(53.5)	(4.2)

Note: Figures may not add exactly due to rounding.

[25] When making the case for investment in a major project, we assess the expected cost as well as a likely upper bound that is used to set the maximum allowed cost.

[26] This is the Expected Cost (also called the P50 cost) approved by the Electricity Commission or, for more recent projects, the Commerce Commission.

[27] Amounts stated here exclude Hobson Street and Wairau Road substation costs funded via contracts with Vector.

As with base capex, we have interpreted 'material variance' as being both more than $16 million and greater than 10% of the forecast value. Two partially-completed major projects have material variances between the current and original forecast end cost. Explanations are provided below.

Lower South Island Reliability Transmission Investment

The expected cost in the approval includes $16.7 million for a 220kV series capacitor at Three Mile Hill that is now not expected to be required until 2020 or later. This cost is excluded from the forecast end cost, and we are reviewing whether we should prepare a variation to the regulatory approval for the project so it can be closed out.

Other savings include the cost of two transformers being $3 million less than forecast, and having successfully avoided draw down of $4 million of the contingencies allowance.

Wanganui-Stratford Transmission Investment

Construction costs were forecast to be $20 million, including contingencies. Successful management of most construction risks meant that there was limited draw-down of contingencies and actual construction costs were $13 million. This also reflects a successful procurement strategy of awarding all line sections to a single contractor.

Other savings against forecast included $2.3 million on procurement and $4.8 million on property.

3.2 Progress reports – timing

The following table compares the current forecast commissioning date for partially completed major projects with the forecast made at the time the projects were approved. Material variances are explained below.

Table 12: Updated timing forecasts for partially completed major projects

Title	Forecast commissioning date (at approval)	Forecast commissioning date (updated)	Material Variance ?
Wairakei Ring	Mid 2013	March 2014	Y
Upper North Island Dynamic Reactive Support	2011 to 2015	2011 to 2016	N
NAaN	2014	December 2013	N
Lower South Island Reliability	2012 to 2015	April 2015	N
Kawerau Generation Export Enhancement	2012 to 2014	December 2013	N
Auto Synchronisation Points	3 years starting 2011	2013 to 2014	N
Wanganui-Stratford Transmission	2011	2010 to 2016	Y
HVDC	Stage 1 – 2012 Stage 2 – 2014	Stage 1 – May 2013 Stage 2 – Dec 2013	Y

We have interpreted 'material variance' as being a difference of more than six months (unless a judgment-based view of materiality suggests a higher threshold).

Wairakei Ring

It took longer than planned to gain property agreements, with the last agreements secured in August 2013. Property access delays have a consequential impact on access tracks and construction (foundations, towers, and stringing).

A three-month delay by the end of 2012 pushed the programme for completion of tower erection and stringing into winter. We decided to defer stringing operations until after winter, which also provided a buffer between the completion of tower erection and the start of stringing operations.

Wanganui-Stratford Transmission Investment

Commissioning of individual lines sections was phased more slowly than originally forecast to better manage outages and to fit with contractor resourcing. The first, second and third sections were completed in 2010, early 2012 and 2013.

Substation work at Stratford and Waverly has been completed, but work at Hawera is scheduled to be competed over the next three years so that we can minimise disruption and avoid major outages.

HVDC Stage 1

Final design and control systems testing for Pole 3 of the HVDC link was delayed due to the challenges inherent in ensuring that this complex equipment would operate successfully in the New Zealand power system.

3.3 Close-out reports

Three major projects were commissioned in 2012/13. All of these were approved under rules developed by the Electricity Commission, which have since been superseded.

When a project is commissioned, several revenue or allowance adjustments may occur. The following table summarises these potential adjustments.

Table 13: Summary of possible adjustments to major projects

Adjustment	Description
CPI and FX	The approved allowance may be updated to account for differences between CPI and foreign exchange rates anticipated when the project was approved, and the rates that actually occurred during the project.
Excess amount	If the actual cost of a project exceeds the relevant approved allowance, then a revenue adjustment is made to remove the value of the 'excess amount'.
Output	If a project does not deliver the relevant approved outputs, then a revenue adjustment may be made to remove one-third of the value of the project.

In addition to these adjustments, we may apply to the Commission for approval of an amended allowance, and/or agreement to vary agreed project outputs. At the end of RCP1, we may also apply to the Commission to retain a portion of the value of any cost efficiencies achieved for major projects completed during the period.

The following tables provide close out reports for each major project completed in 2012/13:

- North Island Grid Upgrade
- Bay of Plenty Interconnection Capacity Upgrade
- Upgrade of bus security on the Bombay 110kV bus

North Island Grid Upgrade (NIGU)

Project Description				
The North Island Grid Upgrade project provides two large circuits from the central North Island (Whakamaru, WKM) to Auckland (Pakuranga, PAK and then onto Otahuhu, OTA) at 220kV, with the overhead line constructed to operate at 400 kV.				
Commissioned values				
	FEC (FTC)	**Expected (P50)**	**Variance**	**Material?**
Total project	$893.8m	$763.9m	+$129.9m	Y
Commissioning dates				
Component	**Actual**	**Approved date**	**Variance**	**Material?**
Install 350MVAr static reactive plant at Otahuhu.	30 May 2008 30 May 2008	**2009**	Y	N
Establish Drury switching station	10 May 2010		N	N
Implement thermal upgrade for Otahuhu-Whakamaru C line	14 Apr 2011	**2010**	Y	N
Install 2x100MVAr static reactive plant at Otahuhu	June 10 and Nov 10		Y	N
Establish 220kV substation adjacent to existing Whakamaru sub (WKM North)	Livened 10 Sep 2012 Commissioned 30 Oct 2012		Y	Y
BHL Transition Station, South Auckland	Live Jul 12 Commissioned 30 Oct 12		Y	Y
400kV double circuit line from Whakamaru to cable transition station in South Auckland. Circuits operated at 220kV.	30 Oct 12		Y	Y
2 x 220kV cables from transition station to Pakuranga substation (BHL)	Live 29 Jun 12 Commissioned 30 Oct 12	**2011**	Y	N

220kV gas insulated substation at Pakuranga: Install 3 x 120MVA supply transformers	T1: 22 Nov 12 T2: 22 Nov 12 T3: 15 Mar 13		Y	Y
Increase operating voltage of existing 110kV OTA-PAK line to 220kV	Circuit 1: 22 Nov 12 Circuit 2: 10 Feb 2012		Y	Y
Easements and resource consents	Draft 27 May 09 Final 18 Sep 09		Y	Y

Project Outputs

Achieved Outputs	**Variance to Approved Outputs?**
Install 350MVAr static reactive plant at Otahuhu	refer variance explanation below
220kV substation at Pakuranga	
Easements and resource consents	
Establish Drury switching station	N
Implement thermal upgrade for Otahuhu-Whakamaru C line	
Install 100Mvar static reactive plant at Otahuhu	
Establish 220kV substation adjacent to existing Whakamaru substation (Whakamaru North)	
Cable Transition Station, South Auckland	
400kV double circuit line from Whakamaru to cable transition station in South Auckland. Circuits operated at 220kV.	
2 x 220kV cables from transition station to Pakuranga substation (BHL)	
Install 3 x 120MVA supply transformers at Pakuranga substation	
Increase operating voltage of existing 110kV OTA-PAK line to 220kV	
Output adjustment	n/a

Lessons Learned

NIGU included the first significant transmission line to be built in New Zealand since the introduction of the Resource Management Act 1991 (RMA), and was also one of the first major projects to be considered by the Electricity Commission. These overlapping regulatory processes contributed to difficulties in securing timely and cost-effective land access, which in turn led to difficulties managing risks relating to geotechnical assessment, foundation design, route selection, and procurement.

Experience gained through NIGU has influenced how Transpower (and other utilities) approach land access for major infrastructure projects. A particular insight is the value of obtaining regulatory sanction prior to engaging with land owners regarding route access. This helps mitigate risks of land owners not accepting the need for the investment.

There have also been several amendments to the RMA since NIGU, which are intended to better facilitate construction of major infrastructure projects, including changes to the call-in process.

The approval process for NIGU influenced how Transpower engaged with the Electricity Commission and the sector on subsequent major project approvals, and on how Transpower analysed investments and built the case for regulatory approval. This included improved project cost estimation and, in particular, a more appropriate approach for determining reasonable contingency estimates. Lessons were also applied in the design of the Commerce Commission's framework for major project approvals.

There have also been lessons for Transpower on contracting for and managing very large projects.

Cost Efficiencies		
	Estimated Value	**Assumptions**
Novel design at the Drury 220kV switching station.	$0.7 million initial capex, ongoing maintenance savings.	This design required fewer disconnectors, bus posts and foundation sets than the existing standard design.

Major Capex Overspend Adjustment	
Allowance (P90)	$824m
Actual cost	$898m
CPI and FX disparities adjustment applies?	N
Excess amount	n/a[28]
Overspend adjustment	n/a

Variance Explanations	
Reference	
Commissioning Dates	Delays in obtaining land access for the new circuit led to an overall delay in the circuit project. Construction of connecting substations was delayed accordingly.
Commissioned Values	Transpower submitted an application to the Commission on 30 September to amend the allowance for the NIGU project. The application provides detailed analysis of project costs (see http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/).
Project Outputs	Detailed design work showed that it was preferable to distribute static reactive plant across Otahuhu (200 MVAr), Hepburn Road (50 MVAr) and Penrose (100 MVAr) substations instead of installing all 350 MVAr at Otahuhu. The original project proposal included the construction of a new gas-insulated 220kV substation at Pakuranga. As the project progressed we were successful in obtaining the necessary resource consents for the construction of a lower-cost air-insulated solution. In relation to a 2km stretch of cable from Brownhill to Otahuhu, it is not considered cost effective to acquire all of the planned easements at this time. These output variances are of a technical nature only. When this project was approved, the output adjustment framework was not in place and outputs were not described so as to accommodate design refinements. Nonetheless, we have applied to the Commission for amendment of the project outputs.

[28] The excess amount, if any, will be determined once the Commission has completed consideration of the amendment application. We expect this to happen in time for next year's Annual Regulatory Report.

Bay of Plenty Interconnection Capacity Upgrade

Project Description

Thermally upgrade the Tarukenga to Kaitimako circuits and increase their operating voltage from 110kV to 220kV.

Commissioned values

	Actual	Expected (P50)	Variance	Material?
Total project	$18.84m	$20.5m	$1.7m	N

Commissioning dates

<table>
<tr><th>Component</th><th>Actual</th><th>Approved date</th><th>Variance</th><th>Material?</th></tr>
<tr><td>Install two 220/110 kV 150 MVA interconnecting transformers at Kaitimako;</td><td rowspan="2">November 2012, (KMO-TRK circuit 2 & T4 transformer)
December 2012 (KMO-TRK circuit 1, & T2 transformer)</td><td rowspan="3">2011</td><td rowspan="2">Y</td><td>Y</td></tr>
<tr><td>Increase operating voltage of Kaitimako to Tarukenga circuits (Hairini – Tarukenga A) from 110 kV to original construction voltage of 220 kV;</td><td>Y</td></tr>
<tr><td>Thermally uprate Kaitimako to Tarukenga circuits (Hairini – Tarukenga A) for operation at 80°C.</td><td>October 2011 (KMO_TRK_1)
July 2011 (KMO_TRK_2)</td><td>N</td><td>N</td></tr>
</table>

Project Outputs

Achieved Outputs	Variance to Approved Outputs?
2x 220/110 kV 150 MVA interconnecting transformers at Kaitimako	N
Line upgrade for 220kV operation	
Line uprated for 80°C operation	
Output adjustment	n/a

Lessons Learned

n/a

Cost Efficiencies

n/a

Major Capex Overspend Adjustment

Allowance (P90)	$21.5m
Actual cost	$18.84m
CPI and FX disparities adjustment applies?	N
Excess amount	n/a
Overspend adjustment	n/a

Variance Explanations

Commissioned Date	Commissioning of the line upgrade was on time. Commissioning of the transformers, and hence use of line at its full capability, was delayed by 11 months. The delivery work was complex, including resolving fundamental protection scheme issues. The investigation work necessary to define the scope exactly, in order to tender and award the detailed design works, took longer than anticipated.

Upgrade of bus security on the Bombay 110kV bus

<table>
<tr><th colspan="5">Project Description</th></tr>
<tr><td colspan="5">Installation of a bus coupler circuit breaker, full local backup protection and bus zone protection measures on 110kV bus at the Bombay substation.</td></tr>
<tr><th colspan="5">Commissioned values</th></tr>
<tr><th></th><th>Actual</th><th>Expected (P50)</th><th>Variance</th><th>Material?</th></tr>
<tr><td>Total project</td><td>$4.4m</td><td>$4.5m</td><td>0.1m</td><td>N</td></tr>
<tr><th colspan="5">Commissioning dates</th></tr>
<tr><th>Component</th><th>Actual</th><th>Approved</th><th>Variance</th><th>Material?</th></tr>
<tr><td>Install bus coupler circuit breaker on Bombay 110kV bus</td><td rowspan="5">March 2012</td><td rowspan="5">March 2011</td><td rowspan="5">Y</td><td rowspan="5">Y</td></tr>
<tr><td>Add back up line protection to five circuits and replace main line protection on another four circuits</td></tr>
<tr><td>Replace four adjacent bulk oil circuit breakers</td></tr>
<tr><td>Relocate compressor house and voltage transformer No. 2</td></tr>
<tr><td>Install low impedance bus zone scheme</td></tr>
<tr><th colspan="5">Project Outputs</th></tr>
<tr><th colspan="3">Achieved Outputs</th><th colspan="2">Variance to Approved Outputs?</th></tr>
<tr><td colspan="3">Bus Coupler circuit breakers</td><td colspan="2" rowspan="5">N</td></tr>
<tr><td colspan="3">Replace 4 Bulk Oil CB’s for clearance</td></tr>
<tr><td colspan="3">Full local backup protection</td></tr>
<tr><td colspan="3">Back up line protection for transmission circuits</td></tr>
<tr><td colspan="3">Replace main line protection on four 110 kV transmission circuits</td></tr>
<tr><td colspan="3">Relocate compressor house</td><td colspan="2" rowspan="2">refer variance explanations below</td></tr>
<tr><td colspan="3">Low impedance bus zone protection scheme</td></tr>
<tr><td colspan="3">Output adjustment</td><td colspan="2">n/a</td></tr>
<tr><th colspan="5">Lessons Learned</th></tr>
<tr><td colspan="5">This project was one of the first to use monthly project health check meetings with designer and contractor during each major contract phase. This worked well for the project where greater controls were sought around the key project management measures and created an increased visibility of project performance for regional project management.</td></tr>
</table>

Cost Efficiencies		
	Estimated Value	**Assumptions**
This project trialled use of a dead tank disconnecting circuit breaker (DCB) with integral current transformer (CT) installed offset into a bay as a bus section breaker. This approach overcomes space limitations that arise due to sites not being designed with space provision for future installation of conventional bus section circuit breakers. This approach provides good ongoing access to the bus section CB and avoids the need to relocate existing bays and extend the existing yard. Approach was subsequently also used at Redclyffe and Maungatapere.	$1-2m	Estimated value includes cost of new equipment, circuit relocations, consenting and easements that would have been required if DCB had not been used at Bombay.

Major Capex Overspend Adjustment	
Allowance (P90)	$4.7m
Actual cost	$4.4m
CPI and FX disparities adjustment applies?	N
Excess amount	n/a
Overspend adjustment	n/a

Variance Explanations	
Reference	
Commissioned Value	Use of a high impedence bus zone scheme instead of a low impedence scheme enabled a cost saving. Removal of remaining bulk oil circuit breakers (under a different project) meant that the air supply was able to be removed rather than relocated.
Commissioning date	1. Requirement for increased clearances at substations drove need for additional earthworks. 2. Feeder and bus outages were not available over winter. 3. Late delivery of enabling works delayed start of electrical installation contractor until August 2011. 4. A hold was placed on work during Rugby World Cup in late 2011.
Project Outputs	Because the proposed design had to be changed to meet safety clearances, a lower-cost high impedance bus zone scheme was able to be used, and the compressor house was able to be removed rather than relocated. These output variances are of a technical nature only. When this project was approved, the output adjustment framework was not in place and outputs were not described so as to accommodate design refinements. Nonetheless, we have applied to the Commission for amendment of the project outputs.

Close-out adjustments

Our report last year included an interim overspend adjustment of $5 million (plus interest and tax) for the Otahuhu substation diversity project. The Commission has now approved a revised allowance equivalent to the actual cost of the project, so we will reverse the interim adjustment in 2014/15.

No other revenue adjustments relating to major projects are required in 2014/15.

3.4 New major projects

In February 2013, the Commission approved work on the first stage of a series of enhancements to transmission capacity into the Upper South Island. The approval covered investigation work and installation of substation plant and equipment up to $4.99 million, of which $3 million is capital expenditure. Commissioning is forecast for mid-2014, with an incremental revenue impact of $0.3 million from 1 April 2014.

Further details on this project are available at http://www.comcom.govt.nz/upper-south-island-grid-upgrade-stage-1/.

3.5 Non-transmission solutions

Major projects can include 'non-transmission solutions', which are funded via recoverable costs. Refer to Section 6.3 for explanations of variances and forecasts relating to non-transmission solutions.

We did not complete any non-transmission solutions during the disclosure year.

3.6 Other variations and adjustments

We can seek approval to recover 'sunk costs' for major projects that have been approved but subsequently abandoned. We have made no such applications in 2012/13.

4 MAR wash-up

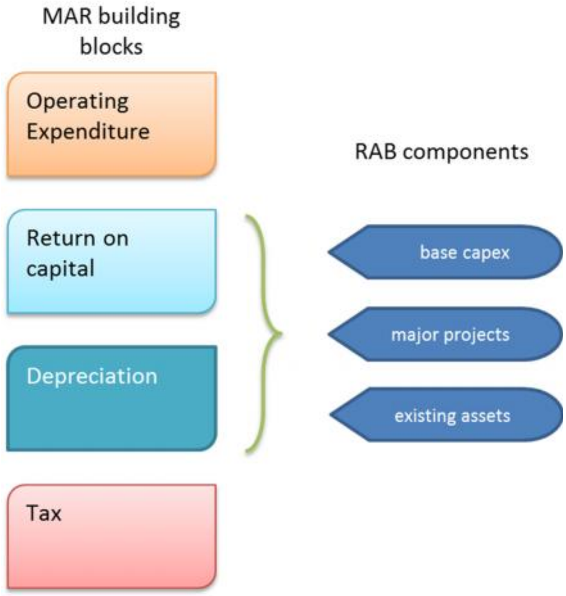
This section covers the revenue 'wash-up' calculation used to update prices for the pricing year starting April 2014.

The wash-up compares the revenues we earned in 2012/13 with an *ex post* assessment of the revenue permitted under the IPP framework. Any over- or under-recovery from 2012/13 is returned or recovered from customers via an update to our 2014/15 revenues (and prices).

4.1 Forecast and actual MAR for 2012/13

We calculated prices for our 2012/13 pricing year (starting 1 April 2012) based on forecasts of the MAR 'building blocks' for the year[29]. The main building blocks are illustrated again below.

Figure 11: Simplified representation of main MAR building blocks



Our forecast MAR for 2012/13 was determined by the Commission in October 2011 to be $783.8 million. Included in that forecast was $12.2 million relating to zeroing historic under-recoveries.

We have now recalculated our MAR for 2012/13 to reflect the actual opening regulatory asset base (RAB) value at 1 July 2012, the timing and value of assets commissioned during 2012/13, and actual CPI movement during 2012/13.

[29] Prices are set based on a forecast total revenue number that includes the forecast MAR, plus estimates of pass-through and recoverable costs. Pass-through and recoverable costs are covered in Section 4 of this report. Updated forecast total revenues for 2013/14 and 2014/15 are included in Section 8 of this report.

Table 14: Actual 2012/13 MAR

Description	TOTAL $m	HVAC $m	HVDC $m
Approved forecast MAR	783.8	664.7	119.1
Actual (*ex post*) MAR	753.7	658.6	95.2

Note: Figures may not add exactly due to rounding.

4.2 MAR wash-up

The table below calculates our 2012/13 MAR wash-up by comparing HVAC and HVDC revenues received in the pricing year with our actual MAR.

Table 15: Summary calculation of the MAR wash-up for 2012/13

	TOTAL $m	HVAC $m	HVDC $m	Description
Opening RAB	2,807.5	2,571.5	236.0	Closing RAB as at 30 June 2012
Commissioned assets	617.8	542.8	75.0	The value of assets that are weighted to take into account the date they are commissioned (e.g., an asset commissioned in month eight is included at one-third of its value).
RAB	3,425.3	3,114.3	311.0	Not strictly the 'RAB' but rather the opening RAB plus the weighted commissioned assets in the disclosure year.
WACC	8.05%	8.05%	8.05%	75th percentile estimate of Vanilla WACC applicable during RCP1 as determined by the Commission on 3 March 2011.[30]
Capital charge	275.7	250.7	25.0	RAB x WACC
Operating expenditure	271.3	249.8	21.5	Commission's approved operating expenditure allowance of $278.8m million specified in clause 5.2(7)(b)(i) of the IPP Determination and adjusted for actual CPI
Term credit spread differential	1.8	1.6	0.2	Estimated in accordance with clause 3.5.10 in Subpart 5 of Part 3 of the IM Determination.
Depreciation	162.4	138.7	23.8	Calculated in accordance with clause 3.3.1 in Subpart 3 of Part 3 of the IM Determination.

[30] Commerce Commission, *Determination of the Cost of Capital for Services Regulated under Part 4 of the Commerce Act 1986*, Pursuant to Decisions 709, 710, 711, 712 and 713. Decision Number 718, 3 March 2011.

	TOTAL $m	HVAC $m	HVDC $m	Description
Tax	42.5	17.8	24.7	The regulatory tax allowance calculated in accordance with clause 3.4.1 in Subpart 4 of Part 3 of the IM Determination.
Actual MAR	753.7	658.6	95.2	Sum of capital charge, operating expenditure, term credit spread differential, depreciation and tax.
Operating revenue	783.7	664.7	119.1	Sum of the HVAC revenue and HVDC revenue, excluding pass-through and recoverable costs.
Ex-post economic gain or loss (gross wash-up)	30.0	6.1	23.9	The difference between the Actual MAR and operating revenue for the disclosure year.
Intended wash-up from earlier years	(8.8)	8.8	(17.6)	Intended return to (from) customers relating to wash-ups from earlier years. Net of tax. See Table 35 and Table 36.
Net wash-up	**21.2**	**14.9**	**6.3**	

Note: Figures may not add exactly due to rounding.

In summary, excluding consideration of wash-ups from earlier years, we recovered $30.0 million more than permitted in 2012/13. However, we had intended to over-recover $8.8 million (due to historical accumulated wash-ups). As such, the net wash-up for 2012/13 is a $21.2 million over-recovery, comprising a $14.9 million over-recovery from HVAC customers and a $6.3 million over-recovery from HVDC customers.

More detail on these calculations is in Appendix A.3.

This analysis does not include the effect of over- or under-recovery of pass-through and recoverable costs. These are covered in Section 4. Further adjustments are also made to produce our updated total revenue figure for 2014/15. These are covered in Sections 3 (major project adjustments) and 8 (forecast revenue updates).

4.3 Explanation of MAR wash-up

The following table provides an alternative presentation of the MAR wash-up calculation. This presentation highlights the variance in each revenue building block.

Table 16 - MAR wash-up (building block variance presentation)

Building blocks (all in $m)	Forecast 2012/13 MAR	Revised 2012/13 MAR	Due (to) or from Customers	HVAC	HVDC
Return on assets	290.0	275.7	(14.3)	(3.3)	(11.0)
Tax	34.4	39.1	4.7	(1.2)	5.9
Depreciation	167.2	162.4	(4.8)	(4.1)	(0.7)
Opex allowance (CPI-adjusted)	279.8	271.3	(8.5)	(7.8)	(0.7)
TCSD	0.2	1.8	1.6	1.4	0.2
Building block revenue	771.6	750.3	(21.3)	(15.0)	(6.3)
Historic EV account spread	12.2	12.2	-		
Maximum Allowable Revenue	783.8	762.5	(21.3)	(15.0)	(6.3)
Charging variations in the year	(0.1)		0.1	0.1	-
Revenue actually charged	783.7	783.7			
Due (to) or from customers		(21.2)	(21.2)	(14.9)	(6.3)

Forecast revenue calculations assume mid-financial year (i.e. December) commissioning of all assets. If we actually commission assets earlier in the 2012/13 year, then the forecast revenue figure will be too low. The wash-up allows us to make up for this shortfall in 2014/15. Conversely, if we commission assets later in the 2012/13 year, then the wash-up allows us to return our over-recovery to customers in 2014/15. The wash-up similarly allows future prices to be adjusted if we commission assets at a higher or lower cost than forecast.

The key drivers from 2012/13 are:

- HVAC assets were, on average, commissioned earlier than forecast. This was more than offset by lower commissioned value. The net effect is that our return on HVAC assets was $3.3 million too high.
- HVDC assets were, on average, commissioned later than forecast. This was partially offset by higher commissioned value and by un-forecast tax charges on liquidated damages. The net effect is that our return on HVDC assets was $3.4 million too high.
- our operating expenditure allowance incorporates forecast CPI movement of 2.4% each year. Actual CPI movement has been less than forecast, so we have over-recovered $8.5 million compared to the CPI-adjusted allowance.

4.4 Historical and forecast MAR

For comparison, the following table sets out HVAC and HVDC MAR from 2008/09 to 2012/13, and updated forecast MAR figures for 2013/14 and 2014/15. All figures exclude pass-through and recoverable costs.

Table 17: Historical and forecast HVAC and HVDC MAR

	2008/09 $m	2009/10 $m	2010/11 $m	2011/12 $m	2012/13 $m	2013/14 $m	2014/15 $m
HVAC	495.1	537.3	534.3	555.9	664.7	713.7	789.5
HVDC	82.9	81.6	84.8	66.5	119.1	160.5	145.1
Total	**578.0**	**618.9**	**619.1**	**622.5**	**783.7**	**874.2**	**934.6**

Note: figures are in nominal dollar terms and may not add exactly due to rounding.

4.5 Other disclosures

We are also required to disclose any material changes to our MAR calculation model, and any material changes in our policy of hedging capital expenditure. There have been no such changes for 2012/13.

We are required to make adjustments under certain circumstances for costs associated with hedging arrangements. There are no such adjustments for 2012/13.

We can make adjustments to recognise the cost of an asset that has become ‘stranded’ in 2012/13. There are no such adjustments for 2012/13.

5 Controllable operating expenditure

This section compares forecast and actual operating expenditure (opex) for 2012/13, and explains material variances. The Commission originally set an allowance of $279.8 million for 2012/13, but we have reduced this to $271.3 million due to lower than forecast CPI movement.

We have interpreted ‘material variance’ to be a variance that is both greater than $8 million[31] and more than 10% of the (unadjusted) category forecast.

Table 18: Actual operating expenditure for 2012/13

Category	Original Allowance $m	Adjusted for CPI $m	Actual $m	Variance $m	Variance %	Material ?
Grid maintenance	119.7	116.7	91.8	(24.9)	(21)	Y
IST maintenance	28.5	27.5	30.5	3.0	11	N
IST leases	14.6	14.2	13.3	(0.9)	(6)	N
Investigations	10.8	10.4	11.1	0.7	7	N
Ancillary services	5.7	5.5	1.5	(4.0)	(73)	N
Departmental	84.6	81.8	92.6	10.8	13	Y
Insurance	16.0	15.6	13.2	(2.4)	(15)	N
Total Opex	**279.8**	**271.3**	**254.1**	**(17.2)**	**(6)**	

Note: figures may not add exactly due to rounding.

Key reasons for the material variance between the grid maintenance allowance and actual spend are:

- a detailed review and prioritisation of work resulted in a reduction in the scope of work required
- a focus on budget management, job vetting and planning resulted in more targeted expenditure and greater efficiency in works delivery.

There was also a material variance in departmental spending. Efficiencies were achieved by in-sourcing the grid operating centres and system modelling, but overall costs were higher than the allowance because more than anticipated was spent building asset management capability, and on asset lease costs, consultants and contractors.

5.1 Historical and forecast operating expenditure

For comparison, the table below shows actual operating expenditure for 2008/09 to 2012/13, and updated forecasts for the remainder of RCP1. Expenditure is broken down by categories for each year.

[31] $8 million is approximately 1% of 2012/13 total revenue.

Forecast operating expenditure for RCP1 is $1,023.8[32] million, compared to a CPI-adjusted allowance of $1,064.9 million. We continuously review our operating expenditure. Accordingly, the forecast is subject to on-going change over the remainder of RCP1.

Table 19: Historical and forecast operating expenditure

	2008/09 $m	2009/10 $m	2010/11 $m	2011/12 $m	2012/13 $m	2013/14 $m	2014/15 $m
Grid maintenance	94.7	93.7	104.1	96.6	91.8	99.7	105.8
IST maintenance	19.4	20.3	21.0	26.6	30.5	31.9	31.8
IST leases	8.3	8.7	10.6	12.4	13.3	12.9	12.4
Investigations	13.8	8.3	10.9	12.2	11.1	9.8	11.3
Ancillary services	1.1	1.8	1.9	1.8	1.5	2.8	2.4
Departmental	79.9	78.4	86.3	80.4	92.6	89.5	87.3
Insurance	9.2	9.3	9.2	11.2	13.2	15.2	15.5
Total operating expenditure[33]	**226.4**	**220.6**	**244.0**	**241.3**	**254.1**	**261.8**	**266.6**
Opex allowance (see Table 20)				*248.5*	*271.3*	*269.9*	*275.2*
Reconciliation to historical compliance statements							
Add HVDC reserve costs (2008/09 -2010/11)	*27.5*	*7.2*	*4.7*	*0.0*			
Less operating leases (2008/09 - 2010/11)	*(8.8)*	*(13.3)*	*(15.3)*	*(16.5)*			
Total	***245.1***	***214.5***	***233.4***	***224.7***			

Note: figures are in nominal dollar terms and may not add exactly due to rounding

The following table shows the opex allowance for each year as set at the start of RCP1 and the CPI assumption at that time, together with revised opex allowances, based on actual CPI movement to date and revised forecast CPI rates.

Table 20: Opex allowance and the CPI adjustment

	2011/12	2012/13	2013/14	2014/15
Allowance set at the start of RCP1	$248.5m	$279.8m	$281.2m	$287.9m
Forecast CPI for the year at that time	*2.4%*	*2.4%*	*2.4%*	*2.4%*
Revised opex allowance	n/a	$271.3m	$269.9m	$275.2m
*Actual (*or revised forecast) of CPI*	*0.95%*	*0.68%*	*1.40%**	*1.87%**

Note: figures are in nominal dollar terms

32 This includes costs of $7.1 million that will be off-set by insurance, but which are shown gross in this report.

33 Excluding pass-through costs, recoverable costs, and reserves costs.

5.2 Overall RCP1 opex variance

Appendix A.8 sets out variances and explanations for operating expenditure over the full RCP1 period. This information is provided to support assessment of our operating expenditure proposals for the next control period, and complements the information contained in the full RCP2 proposal documents we will submit to the Commerce Commission on 2 December 2013[34].

[34] This information fulfils some of the requirements set out in an information request the Commission made under s53ZD of the Commerce Act on 2 July 2013 as part of the RCP2 preparation process. A reconciliation from that request to the information in this report is provided at Appendix A.14

6 Pass-through and recoverable costs

Our operating expenditure allowance is intended to be limited to controllable expenditure. This helps to ensure that regulatory incentives to pursue efficiencies and reduce ongoing expenditure can operate as intended.

Costs that are not controllable are treated separately and classed as either ‘pass through’ or ‘recoverable’. In both cases, we forecast costs annually and wash-up any over- or under-recovery.

Pass-through costs comprise:

- local government rates
- Commerce Commission levies
- Electricity Authority levies.

Recoverable costs include:

- instantaneous reserves (IR) charges[35]
- non-transmission solutions (NTS)[36].

This section calculates a wash-up for the 2012/13 year, updates forecast costs for 2014/15, presents a comparison of forecast and actual costs for the last four years, and explains changes to forecast non-transmission solutions.

6.1 2012/13 wash-up

The table below shows the wash up of 2012/13 pass-through and recoverable costs, calculated by comparing the forecast costs used for pricing with the actual costs we incurred.

Table 21: Allocation of pass-through and recoverable wash-up amounts

Description	TOTAL $m	HVAC $m	HVDC $m
Forecast pass through and recoverable costs	23.1	13.4	9.7
Actual pass through and recoverable costs	20.1	11.6	8.5
Wash-up amount due to (from) customers	3.0	1.7	1.2

Note: Figures may not add exactly due to rounding.

The $3 million over-recovery in 2012/13 is primarily due to lower than forecast Electricity Authority and Commerce Commission levies (HVAC) and lower than forecast IR charges (HVDC).

[35] We purchase back up supply (or demand interruption) from the IR market to cover the risk of a failure of the HVDC link causing an under-frequency event in the island receiving supply from the link.

[36] Most major grid upgrade projects are designed to improve the reliability of the grid. In some cases, it is possible to achieve similar reliability improvements by non-transmission means (i.e., by use of a ‘non-transmission solution). For example, paying some customers to reduce their consumption at times of peak demand may defer the need for a grid upgrade.

6.2 Updated forecast costs

Forecast pass-through and recoverable costs for 2014/15 are set out below.

Table 22: Updated forecast pass-through and recoverable costs

	2014/15		
Forecast[37]	**TOTAL $m**	**HVAC $m**	**HVDC $m**
Electricity Authority levy	5.6	5.6	-
Commerce Commission levy	2.5	2.5	-
Local government rates	8.0	7.9	0.1
Total pass-through costs	16.2	16.1	0.1
Instantaneous Reserves (IR)	1.0	-	1.0
Non-transmission solutions	5.1	5.1	-
Total recoverable costs	6.1	5.1	1.0
Total pass-through and recoverable costs	**22.3**	**21.2**	**1.1**
Amounts previously forecast (October 2012)	*15.2*	*12.5*	*2.8*

Note: figures are in nominal dollar terms and may not add exactly due to rounding.

The increase in pass-through costs is driven by a forecast $3 million increase in rates payable to Auckland Council. Auckland Council sets rates based on capital values and, unlike many regions, does not have a separate 'infrastructure' rating category. As such, we expect our Auckland Council rates to continue to increase steeply as we complete commissioning of major projects in the Auckland region, and as the Council completes its process of unifying and rebalancing rates across the region.

The increase in recoverable costs is due to forecast expenditure of $5.1 million on demand-side response. This is to cover activities related to further developing demand response capabilities in the New Zealand electricity industry. The focus will be on growing capability in the light commercial and residential customer segments by developing commercial frameworks, systems, operational procedures and promotional material that will enable and encourage participation in demand response.

We have reduced forecast IR costs, as the availability of two HVDC poles will improve resilience and reduce the need to provide reserves to cover the sudden loss of one pole.

6.3 Non-transmission solutions

The following table compares forecast and actual expenditure on non-transmission solutions for 2012/13.

[37] Forecast numbers taken from the most recent business plan

Table 23: Forecast and actual non-transmission solution expenditure

GUP Code	Title	Forecast $m	Actual $m	Variance $m	Material ?
GUP2009 Part VII	Upper North Island Dynamic Reactive Support	-	0.6	0.6	N
IGE - 3	Upper South Island DSP trial for grid support contracts	-	0.2	0.2	N

Note: figures are in nominal dollar terms

6.4 Historical pass-through and recoverable costs

For comparison, this section presents forecast and actual pass-through and recoverable costs for the five years to 2011/12.

Table 24: Historical pass-through and recoverable costs

	2008/09 $m	2009/10 $m	2010/11 $m	2011/12 $m	2012/13 $m
Pass-through costs[38]					
Forecast	12.5	14.3	13.2	13.4	13.4
Actual	8.8	12.6	10.5	10.1	11.0
HVAC wash-up	3.7	1.7	2.7	3.3	2.4
HVDC wash-up	0.0	0.0	0.0	0.0	0.0
Recoverable costs					
Forecast	3.7	0.0	0.1	25.8	9.7
Actual	4.4	0.4	0.4	18.5[39]	9.1
HVAC wash-up	(0.7)	(0.4)	(0.3)	6.7	(0.7)
HVDC wash-up	0.0	0.0	0.0	0.7	1.3

Note: figures are in nominal dollar terms and may not add exactly due to rounding.

[38] Prior to 2010/11, there was not a separate category of 'recoverable' costs. In this table, historical non-transmission solutions are shown under recoverable costs

[39] HVDC Reserves were not treated as pass-through or recoverable costs prior to 2011/12.

7 Network Performance

This section reports on the network performance measures monitored by the Commission for RCP1.

We have been developing a new suite of performance measures for RCP2 that help inform and challenge our expenditure proposals, and that will be linked to revenue. The new measures move away from system average measures, and recognise that service expectations differ across points of service. We have developed forward-looking targets for performance, rather than relying on past performance to guide future targets. We will report against these new measures in next year's report[40].

There is no link between network performance and revenue for RCP1, but we are required to calculate what the revenue adjustment would have been were such an arrangement in place based on current measures and targets.

7.1 Network performance measures and targets

The Commission has specified a set of measures and target performance levels. The following table compares actual performance against the targets.

Table 25: Actual performance against targets for four performance measures

Performance measures	Target	Actual	Target achieved?
Number of loss of supply events greater than 0.05 system minutes[41]	21	12	Y
Number of loss of supply events greater than 1 system minute	3	2	Y
Unplanned HVAC circuit unavailability (%)	0.054	0.032	Y
Unplanned HVDC bi-pole unavailability[42] (%)	(no target set)	0.684	n/a
Total impact of interruptions (measured in system minutes)	16.69	7.62	Y

We outperformed all of the RCP1 network performance targets for 2012/13.

[40] For more information, refer to https://www.transpower.co.nz/about-us/industry-information/customer-facing-grid-performance-measures-consultation.

[41] A 'system minute' is a loss of supply equivalent to losing peak demand for one minute. For example, losing supply to a city the size of Hamilton for around 40 minutes during a peak winter night would be roughly equivalent to one system minute.

[42] Half of Pole 1 was decommissioned in 2007, and the other half was only available for limited operation until it was decommissioned in August 2012, and the new Pole 3 was commissioned in May 2013. Therefore, only Pole 2 has been included in this calculation for 2012/13.

7.2 Interruptions greater than 1 system minute

There were two loss-of-supply events greater than one system minute in 2012/13:

- interruption of several supply points in Hawkes Bay and the East Coast due to tripping of a transformer at the Redclyffe substation on 18 December (2.42 system minutes)
- interruption of supply at Cambridge due to failure of an insulated support leading to flashover between two busbars on 18 April 2013 (2.23 system minutes).

Together, these events caused a total loss of supply of 4.64 system minutes. The following tables provide more information.

Redclyffe Substation 18 December 2012

Impact	This event caused 2.42 system minutes of non-supply and impacted end consumers across seven points of service in Hawkes Bay and the East Coast.
Reason	One of the two 220/110 kV interconnecting transformers at the Redclyffe substation tripped, causing unplanned supply interruptions. There are two interconnecting transformers at Redclyffe to supply the East Coast 110 kV grid. Earlier on the day of the event, we removed one of the transformers from service for a maintenance outage. This left the 110 kV system on N-security (i.e. without fully redundant supply). At 09:45, the in-service transformer (T4) was tripped by a high-temperature protection device. This interrupted supply at Transpower's substations at Redclyffe, Fernhill, Gisborne, Wairoa, Waipawa (11 kV and 33 kV), and Tuai. Subsequent investigation determined the root causes of the event were:- - an incorrectly commissioned winding temperature indicator gave incorrect information - we were using incorrect contingency ratings for operational purposes for the Redclyffe transformers - inadequate operational information and operator training resulted in a failure to appreciate the need for urgent load management in response to the winding temperature alarm that arose shortly before the transformer tripped.

Our response	As the underlying reason for the high-temperature trip was not immediately known, our immediate response to the incident was to cancel the outage on the out-of-service transformer (T3) and return it to service to restore supply. Some load was also restored by switching within a customer's system to transfer load to the Whakatu point of service (which is supplied from the 220 kV grid). Subsequent inspection showed that the T4 transformer was not damaged during the incident, and it was returned to service later on the day of the event. Contingency ratings for the transformers were also revised later on the same day. Following further investigation, the following measures were taken to avoid recurrence of similar events:- - we have provided technicians and operators with improved information about winding temperature indicators (via an internal reliability bulletin) - we have reviewed and updated commissioning process for winding temperature indicators - we are working with the System Operator to improve the operating procedures and parameters for power transformers - we have modified our outage management system so that outages that will cause a reduction to N-security are flagged and brought to the attention of the Regional Services Manager. If necessary, a specific risk mitigation plan can then be prepared.

Cambridge Substation 18 April 2013

Impact	This event caused 2.23 system minutes of non-supply and impacted end consumers supplied from the Cambridge substation
Reason	At 23:52, the 11 kV supply bus at Cambridge tripped due to a phase-to-phase fault. This caused an unplanned supply interruption to customers connected to the Cambridge point of service. The Cambridge substation has two 11 kV busbars, but is designed to operate with only one in service at a time. The fault occurred in a section of the enclosed indoor 'B' busbar when an insulating support flashed over. Protection systems operated correctly, but the flashover caused significant damage to the in-service 'B' bus, and some smoke damage to the out-of-service 'A' bus. The underlying cause of the fault was unexpected age-related deterioration of the insulating support.

Our response	Our immediate response was to clean and test the 'A' bus and restore supply. We restored supply after approximately 13 ½ hours. The existing equipment at Cambridge is 30 years old, but we had considered that it was in good order and not at risk. At the time of the incident, we had a project underway to replace the busbar and switchgear to meet customer demand growth and requirements for more feeders. This work continues to be progressed and is scheduled for completion by the end of 2013. The project will completely replace the components that caused this incident. The model of switchgear involved in the incident is in use in a number of other substations. However, only one other substation has the same configuration with respect to the insulating support. We have checked this site.

In addition to the specific responses described above, we made the following changes to improve our overall ability to actively identify and respond to events:

- we now have daily cross-divisional operations meetings aimed at strengthening operational awareness
- we have established a dedicated emergency event co-ordination room at Transpower House in Wellington to improve management of significant events.

7.3 Historical and forecast network performance

For comparison, the following table sets out performance against each of the RCP1 targets, plus total outages in system minutes, from 2008/09 to 2012/13. We also provide updated forecasts for the remainder of RCP1 and RCP2.

Table 26: Historical and forecast network performance

Measure	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	RCP2 (15/16 to 19/20)
Events >0.05 system minutes	18	19	18	19	12	17	17	17
Events >1 system minute	4	4	3	2	2	3	3	3
Unplanned HVAC circuit unavailability (%)	0.064	0.052	0.079	0.064	0.032	0.058	0.058	0.058
Unplanned HVDC bi-pole unavailability (%)	1.035	0.319	0.086	0.109	0.684	0.314	0.314	0.314
Total impact of interruptions (in system minutes)	18.10	23.45	15.17	14.45	7.62	15.76	15.76	15.76

Because network performance is primarily event-driven in the short-term, the forecasts are based on an average of performance over the previous five years[43].

7.4 Hypothetical revenue adjustments

This section calculates the revenue adjustments that we would apply in 2014/15 if there were a linkage between network performance and revenue.

The adjustments are based on the following assumptions:

- four of the measures each have an equal weighting (HVDC bi-pole unavailability is excluded)
- no revenue adjustment applies if actual performance is the same as target performance
- out-performance (up to a ‘cap’) results in a positive revenue adjustment, and under-performance (down to a ‘collar’) results in a negative revenue adjustment
- the combined adjustment may increase or decrease revenue by up to 1% of our 2012/13 forecast MAR.

The results of these hypothetical adjustments for 2012/13 are set out below for information purposes. Target, cap and collar figures are all as specified by the Commission.

Table 27: Hypothetical revenue adjustments based on 2012/13 outcomes

Performance measure	Collar	Target	Cap	Actual	Adjustment $m
Events >0.05 system minutes	31	21	10	12	1.7
Events >1 system minute	5	3	1	2	1.0
Unplanned HVAC circuit unavailability (%)	0.083	0.054	0.029	0.032	1.6
Total system minutes (planned and unplanned)	29.07	16.69	4.31	7.62	1.5
Hypothetical revenue adjustment					**5.8**

Details of supporting calculations, plus graphical representation of each hypothetical revenue adjustment, are included in Appendix A.6.

7.5 Variance analysis

We have developed new performance measures and forward-looking targets that we propose to use for RCP2 (2015/16 to 2019/20). These will be explained in more detail in our RCP2 proposal documents.

[43] We note that decommissioning of HVDC Pole 1, commissioning of Pole 3 and re-commissioning of Pole 2 makes comparison against previous performance less valid. However, there is not another suitable basis available for forecasting HVDC bi-pole unavailability. As the HVDC unavailability (unplanned) in 2012/13 was relatively high because of incidents related to Pole 3 project work, the forecast is based on the years 2007/08 to 2011/12.

To complement the above information, the Commission has requested[44] information on:

- how performance in RCP1 compares to targets for the existing network performance measures
- the revenue adjustments that would apply if performance in the remaining years of RCP1 was to meet updated targets for the existing measures.

We set targets for the existing measures based on average performance for the seven year period from 2002/03 to 2008/09 (i.e. on a backward-looking basis). We have updated targets for the remaining years of RCP1 based on performance in the previous five years. As such, the information requested is effectively a comparison of recent performance against earlier performance.

2012/13 variances from historic performance

The following table compares 2012/13 performance against existing network performance measures with 'target' performance.

Table 28: Performance variances against targets

Performance measure	2012/13 target	2012/13 actual	Variance to target
Total impact of interruptions (in system minutes)	16.69	7.62	(9.07)
Number of loss of supply events >0.05 system minutes	21	12	(9)
Number of loss of supply events >1 system minute	3	2	(1)
Unplanned HVAC circuit unavailability (%)	0.054	0.032	(0.022)

Results from a single year do not provide enough information to draw firm conclusions about underlying network performance. However, the following analysis provides some further insight to 2012/13 performance against the total impact, >0.05 system minutes, and HVAC circuit unavailability measures.

Total interruptions

The total system impact of planned and unplanned interruptions in 2012/13 was 54% lower than the average for the target-setting period. Key observations are:

- there were only two large (>1 system minute) events in 2012/13, and neither of these were more than 2.5 system minutes
- interruptions caused by equipment failure were significantly lower in 2012/13 than in previous years
- interruptions due to planned equipment outages were lower in 2012/13 than in previous years.

[44] This information fulfils some of the requirements set out in an information request the Commission made under s53ZD of the Commerce Act on 2 July 2013 as part of the RCP2 preparation process. A reconciliation from that request to the information in this report is provided at Appendix A.14.

The comparison period on which the targets are based included five very large (>3 system minutes) unplanned interruptions. Together, these events contributed 8.1 system minutes, or 48%, to the target of 16.69 system minutes. These events are listed below.

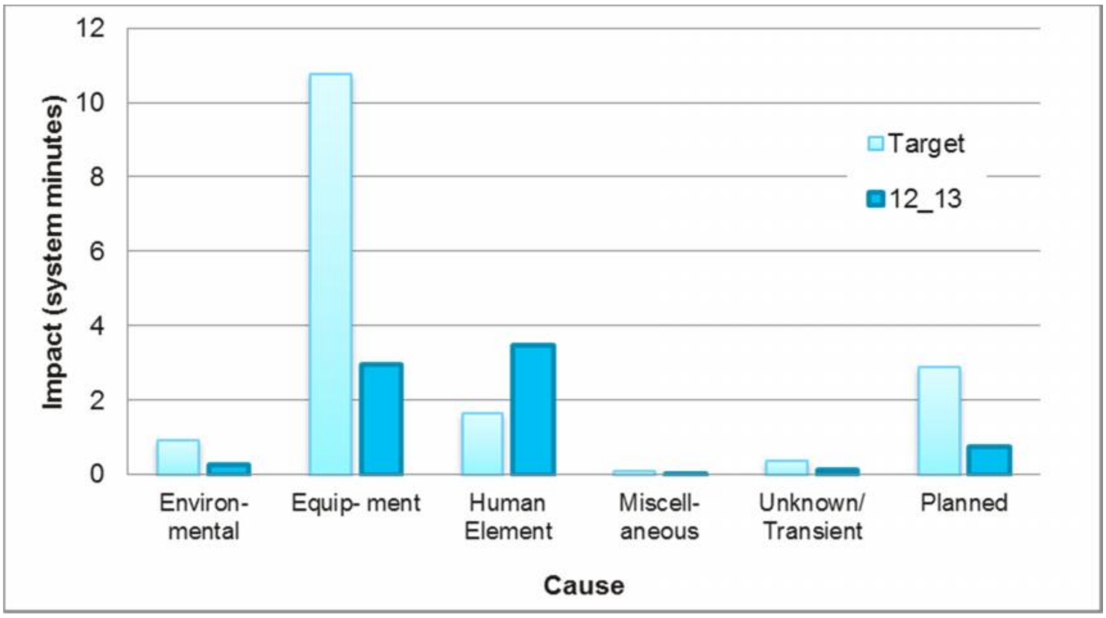
Table 29: Very large (> 3 system minutes) unplanned interruptions in target setting period

Date	System Minutes	Description
12 June 2006	29.8	Otahuhu 110 kV bus fault following earth wire failure
12 October 2007	14.1	Kawerau 11 kV bus shut down to investigate bus noise
1 September 2008	4.9	Whirinaki 11 kV cable fault
3 February 2009	4.1	Penrose 33 kV transformers tripped after transformer fault
7 October 2007	3.9	Westport 11 kV bus exploded following close-in lightning strike

These major incidents are relatively low probability events, with respect to cause and impact. The Otahuhu substation diversity project has addressed the cause of the largest event from the comparison period, such that a recurrence is extremely unlikely. The underlying causes of the other events are, to some extent, likely to be mitigated by ongoing improvements to asset management and to the condition of the asset fleets.

The following chart compares the causes of interruptions in 2012/13 with previous years.

Figure 12: Impact of Interruptions by cause category



The most significant variations from the comparator period are with respect to equipment failures and planned interruptions.

Interruptions due to planned outages only occur at sites where there is not duplicate supply equipment (termed 'N-security' sites). Planned interruptions contributed 2.88 system minutes per annum, or 17%, to the target of 16.69 system minutes. Five sites accounted for the majority (59%) of the planned outages. Only one of those sites had an outage in 2012/13, as set out below.

Table 30: Planned Interruptions (system minutes) at selected N-security sites

Grid Exit Point	Total for 2002/03 to 2007/08	Average per year	Actual 2012/13	Comment
Kaitaia	3.56	0.51	-	Site sold to Top Energy
Te Awamutu	3.48	0.50	0	No planned interruptions for line maintenance in 12/13
Waiotahi	1.85	0.26	0	Contribution to target was due to several interruptions in 2004 for upgrade of EDG-WAI2 circuit.
Mataroa	1.52	0.22	0.23	-
Hinuera	1.46	0.21	0	Installation of a second supply transformer has reduced the need for station shutdowns.
Total	**11.85**	**1.69**	**0.23**	

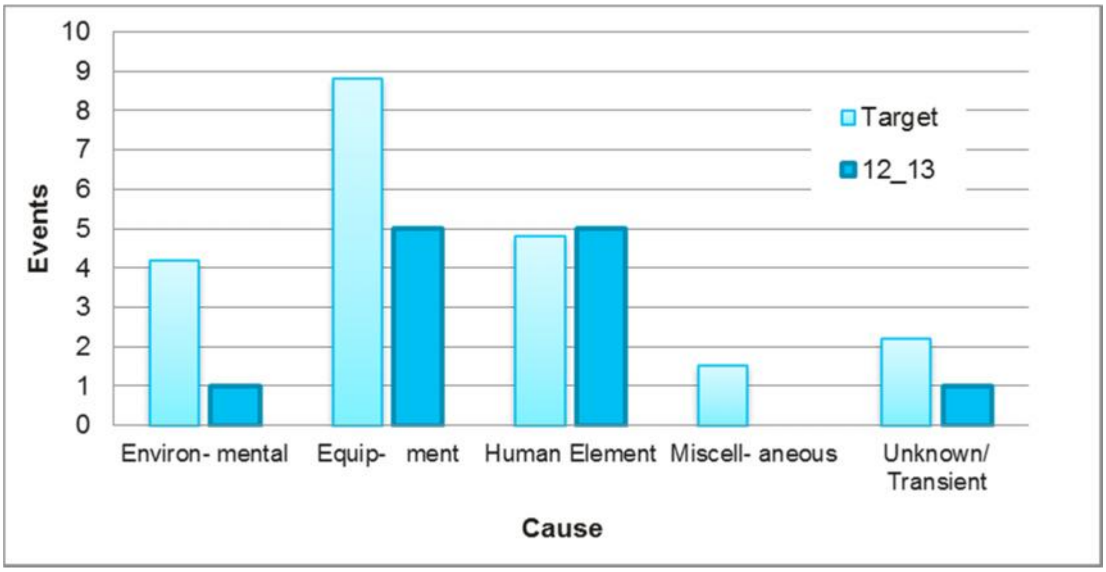
The reduction in planned outages is partly explained by our programme of divesting lower-voltage fringe assets to distribution businesses where they are more natural owners. Further reduction will occur over time as some sites are upgraded with second supply transformers (for example, Woodville and Hinuera).

The low number of equipment failures in 2012/13 is reflected in the measure for events >0.05 system minutes (as well as the total impact measure).

Number of Unplanned Events > 0.05 System Minutes

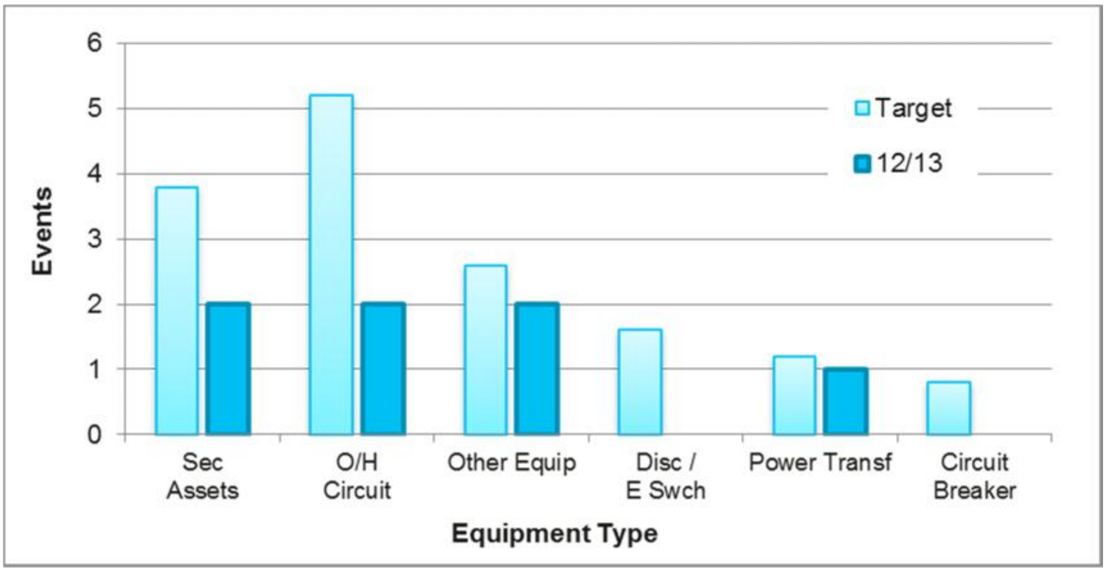
Figure 13 analyses performance for 2012/13 in comparison with the target-setting period (2004/05 to 2008/09), with events categorised by cause.

Figure 13: Number of unplanned events > 0.05 system minutes in 2012/13 (by cause)



This shows that reductions in equipment-driven and environmental-driven events explain most of the variance. Figure 14 analyses differences in types of equipment failure between 2012/13 and the target setting period.

Figure 14: Unplanned events >0.05 system minutes in 2012/13 (by equipment type)

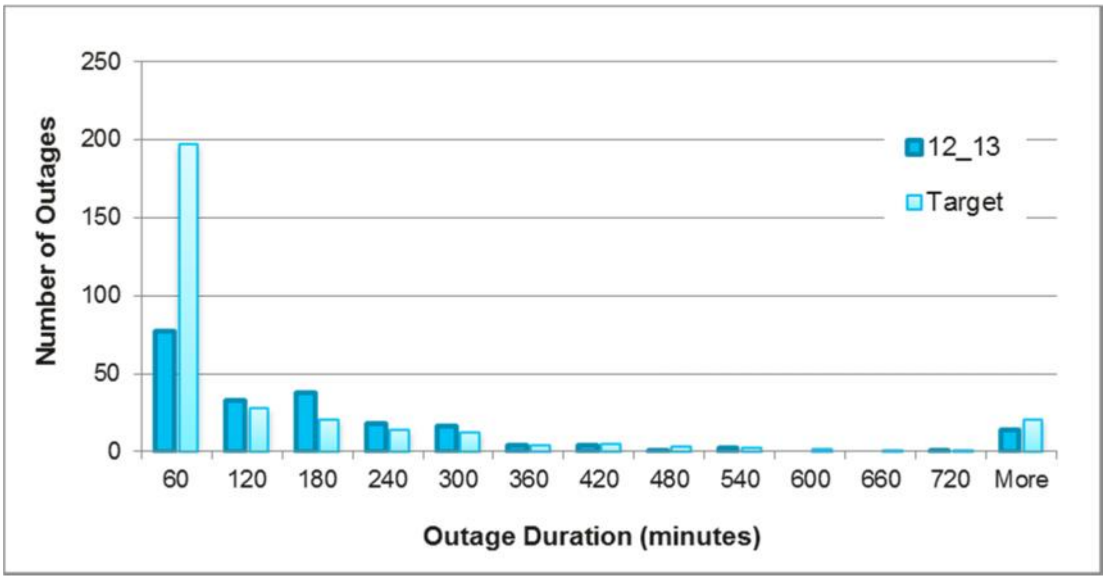


This shows that most of the variance from target is due to improvement in the performance of 'secondary assets' (predominantly protection systems) and overhead circuits when compared to performance in the target setting period.

Unplanned HVAC Circuit Unavailability

Figure 15 compares the frequency distribution of different outage durations for the 2012/13 and the target setting period.

Figure 15: HVAC unplanned circuit outages (frequency by duration)



The main variance from the target setting period is the relatively low number of long outages in 2012/13.

In the target setting period, there were 20 unplanned outages with durations in excess of 6,000 minutes and:

- half of these exceeded 10,080 minutes (1 week)[45]
- ten were caused by extreme environmental conditions (flooding, high winds or snow)
- seven were caused by failures of station equipment.

In 2012/13 the longest unplanned circuit outage was 4,447 minutes and resulted from a circuit breaker failure.

7.6 Hypothetical revenue adjustment based on our forecast performance

Below are the results of the hypothetical revenue adjustments that would apply if our performance were equal to the figures forecast in Table 26. Target, cap and collar figures are all as specified by the Commission.

[45] Outages are capped at one week, i.e. any outage longer than one week is recorded as being 10080 minutes.

Table 31: Hypothetical revenue adjustments based on current performance forecasts

Performance measure	Collar	Target	Cap	Forecast	Adjustment $m
Number of loss of supply events greater than 0.05 system minutes	31	21	10	17	0.8
Number of loss of supply events greater than 1 system minute	5	3	1	3	-
Unplanned HVAC circuit unavailability (%)	0.083	0.054	0.029	0.058	(0.3)
Total system minutes (planned and unplanned)	29.07	16.69	4.31	15.76	0.1
Hypothetical revenue adjustment					**0.6**

Details of supporting calculations are included in Appendix A.7.

8 Updated revenue forecasts

This section brings together the MAR update and the major project and pass-through and recoverable cost information from Sections 2 to 6 to provide updated revenue forecasts for the remainder of RCP1 (being just 2014/15).

Table 32: Updated forecast revenue for the remainder of RCP1

	2014/15		
	Total $m	**HVAC $m**	**HVDC $m**
Previous MAR forecasts	959.7	804.5	155.2
Adjustment to the 2014/15 MAR (see Appendix A.4)	(25.1)	(15.0)	(10.1)
Updated MAR forecasts	934.6	789.5	145.1
2012/13 pass-through and recoverable costs wash-up	(3.0)	(1.7)	(1.2)
Previous forecast pass-through and recoverable costs	15.2	12.5	2.8
Change in forecast pass-through and recoverable costs	7.1	8.8	(1.7)
Updated revenue forecasts	**953.9**	**809.0**	**145.0**
Previous revenue forecasts	*974.9*	*816.9*	*158.0*

Note: figures are in nominal dollar terms and may not add exactly due to rounding

Subject to confirmation of these figures by the Commission, we will use the updated forecast 2014/15 revenues as an input to prices for the pricing year starting on 1 April 2014. We expect to advise our customers of their individual charges in December this year.

The following two figures show the breakdown of the movement from the previous forecast of 2014/15 revenue to the current forecast.

Figure 16: Movement in the 2014/15 HVAC Revenue

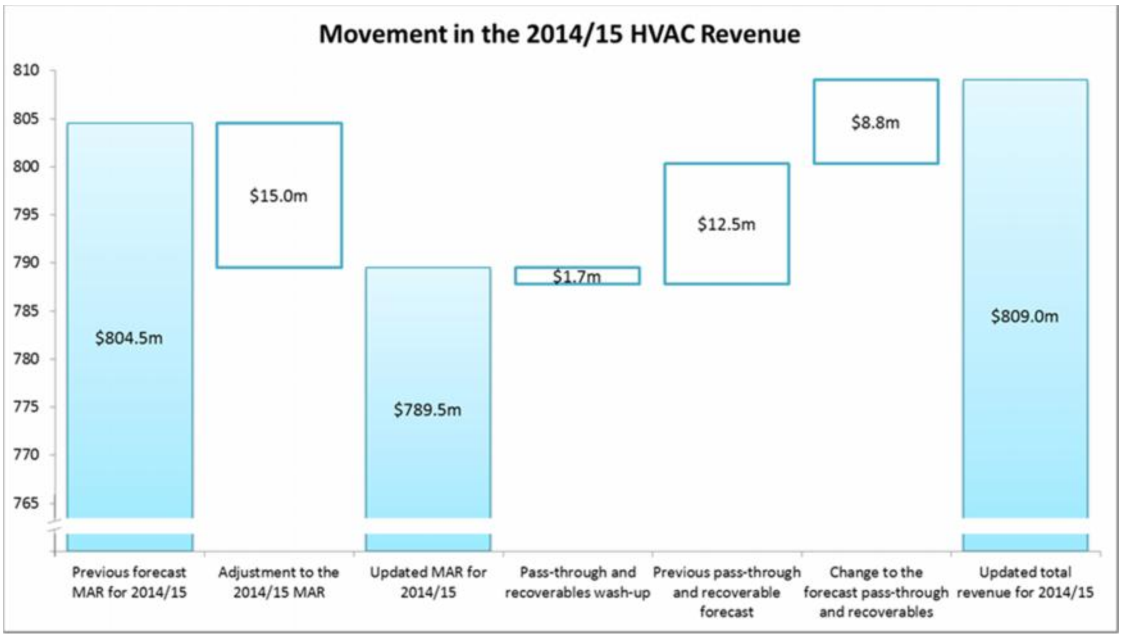
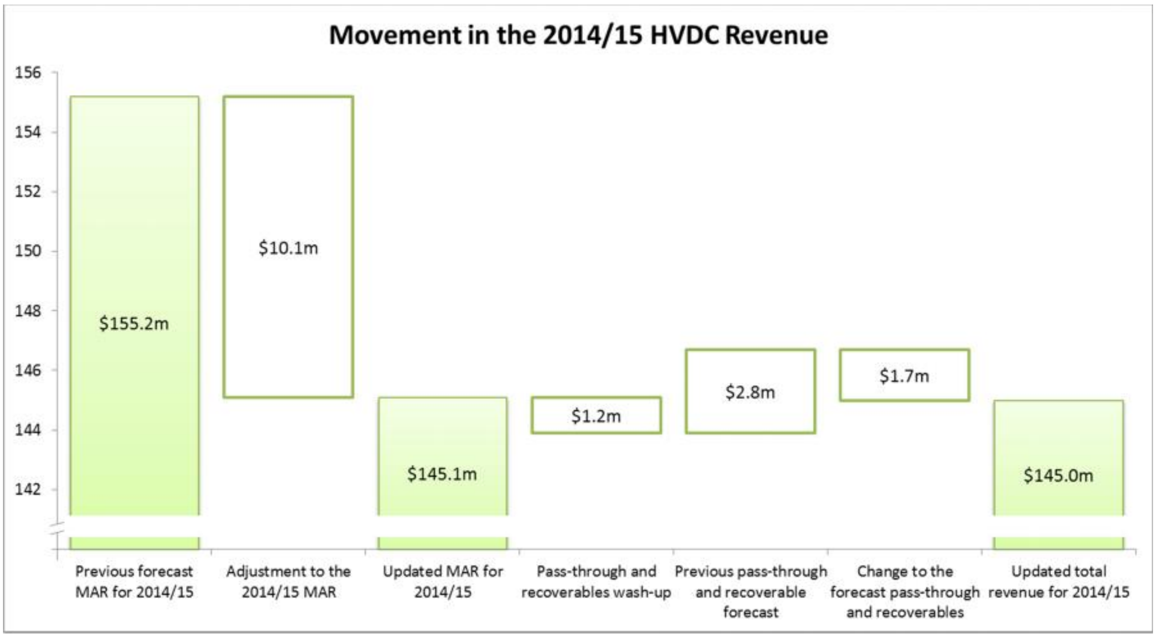


Figure 17: Movement in the 2014/15 HVDC Revenue



9 Return on investment

The regulatory framework is designed to ensure that revenues earned by our transmission business are sufficient to:

- cover efficient debt costs, and
- fund an appropriate return on equity capital.

In addition, our revenue may be adjusted to reflect incentives for us to achieve efficiency gains, manage costs effectively, and deliver improved network performance.

Rather than regulating return on equity directly, the revenue building blocks provide an allowance for the combined cost of debt and equity (i.e. an estimated weighted average cost of capital or WACC). This provides an incentive for us to seek the most efficient combination of debt and equity funding.

This section compares the Commission's WACC with an assessment of our actual return on investment (ROI) for 2012/13.

To assess return on investment, we have followed the method used for information disclosure by electricity distribution businesses[46]. This involves modelling opening and closing RAB values as cash flows at the start and end of the year, and modelling income and expenditure as cash flows at mid-year.

To isolate the return on investment due to regulatory incentive mechanisms, we make two adjustments to the ROI derived by this method. These are:

- a 'modelling adjustment' that accounts for the ROI method producing a systematically higher result than the method used to determine our capital charge revenue building block
- an 'EV adjustment' that adjusts for amounts washed-up to (or from) customers via the EV account.

Table 33 presents our ROI for 2012/13 and 2011/12.

Table 33: Calculation of the ROI

	IRR treatment of the cash flow	2012/13 $m	2011/12 $m
Opening RAB	Start of the year	(2,807)	(2,607)
Regulatory income	Mid-year	784	622
Operating expenses	Mid-year	(247)[47]	(241)
Net cash flow from asset disposals	Mid-year	12	10
Assets commissioned	Mid-year	(1352)	(345)

[46] Under NZCC22: *"Electricity Distribution Information Disclosure Determination 2012"*

[47] The figure used here is net of expected insurance proceeds, which differs from the approach taken in reporting 2012/13 operating expenditure in Table 18.

	IRR treatment of the cash flow	2012/13 $m	2011/12 $m
Regulatory tax	Mid-year	(49)	(23)
Closing RAB	End of the year	3,987	2,807
Half year IRR		**4.9%**	**4.2%**
Full year ROI		**10.11%**	**8.60%**
Modelling adjustment		(0.59%)	(0.58%)
Wash-up adjustment		(0.91%)	0.24%
Adjusted ROI		**8.61%**	**8.26%**
Regulatory vanilla WACC[48]		8.05%	8.05%
Incentive return		0.56%	0.21%

In 2012/13, incentive mechanisms provided a 0.56% uplift to return on investment. This was due to achieving a saving of $24.2 million against the CPI-adjusted opex allowance.

Asset valuation

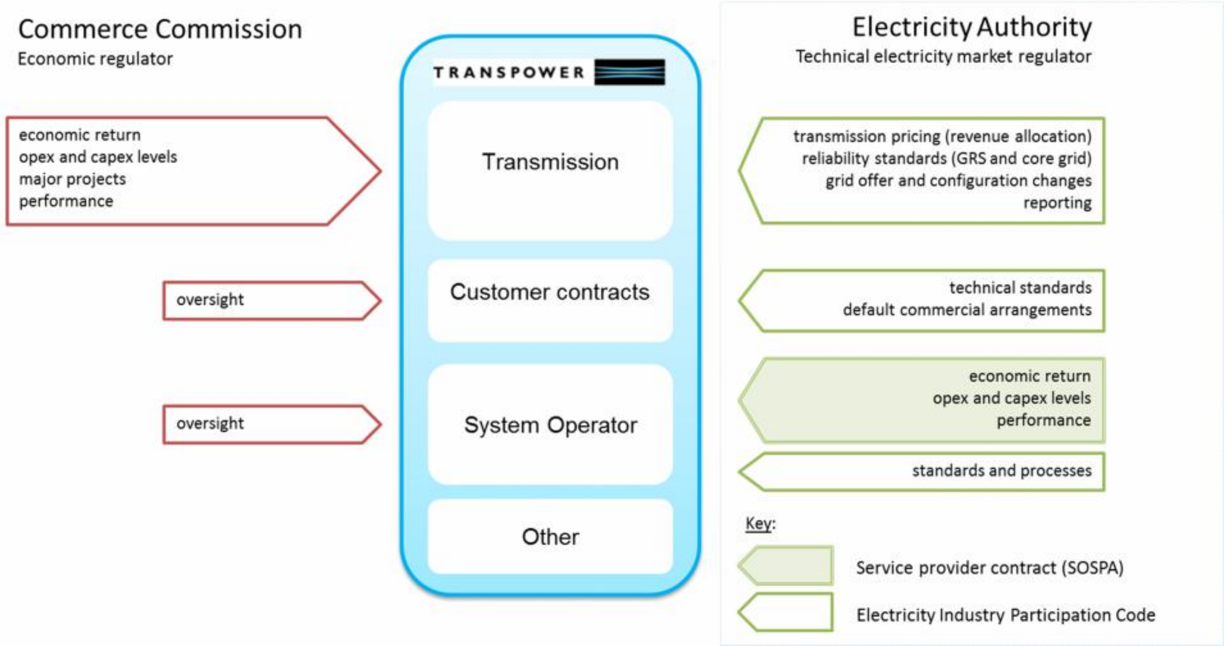
A key assumption in making the ROI calculation above is that the opening value of the investment is correct. We have used our opening regulatory asset base (RAB) as the opening value, as this is consistent with the way the revenue building blocks are derived.

In practice, the RAB includes assets that were re-valued under earlier regulatory arrangements. The opening RAB at 1 July 2011 was $2.6 billion. At that time the replacement value was assessed at approximately $7 billion. Assets commissioned since 1 July 2011 have been added to the RAB at cost and depreciated on a straight-line basis.

[48] Regulatory 'vanilla' WACC excludes the effects of the 'tax shield' that arises from tax depreciation treatment. Tax shield impacts are passed through to customers, so do not impact on returns.

10 System Operator

Transpower, as System Operator, manages the real-time operation of New Zealand's power system. The Commission's regulatory oversight includes the System Operator but, in practice, economic regulation of the System Operator occurs via a contract between Transpower and the Electricity Authority. This is illustrated below.



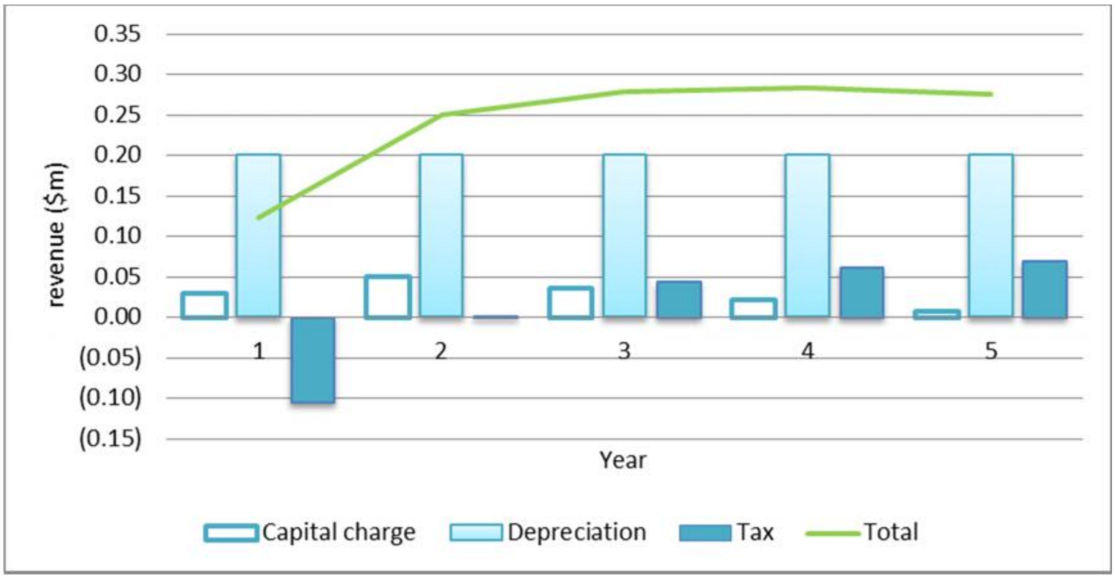
The System Operator Service Provider Agreement (SOSPA) is based on a revenue building blocks model very similar to that used for transmission regulation.

Under the current SOSPA:

- operating expenditure is fixed in real terms at $22.8 million (with an annual CPI adjustment)
- capital expenditure allowances are based on a three-year capex plan
- a three-year wash-up cycle is used to adjust revenue to reflect actual capex.

Compared to transmission, asset lives are typically shorter for the System Operator and, as a result, accounting and tax depreciation rates are both significantly higher. This results in system operator assets typically producing a short, upward sloping revenue path as illustrated in Figure 18.

Figure 18: Revenue profile for a $1 million software asset



The capital charge under the SOSPA applies the cost of capital determined by the Commerce Commission for Transpower's transmission business.

The System Operator is funded by the Electricity Authority, which, in turn, recovers its costs via a levy on electricity industry participants.

Capital expenditure

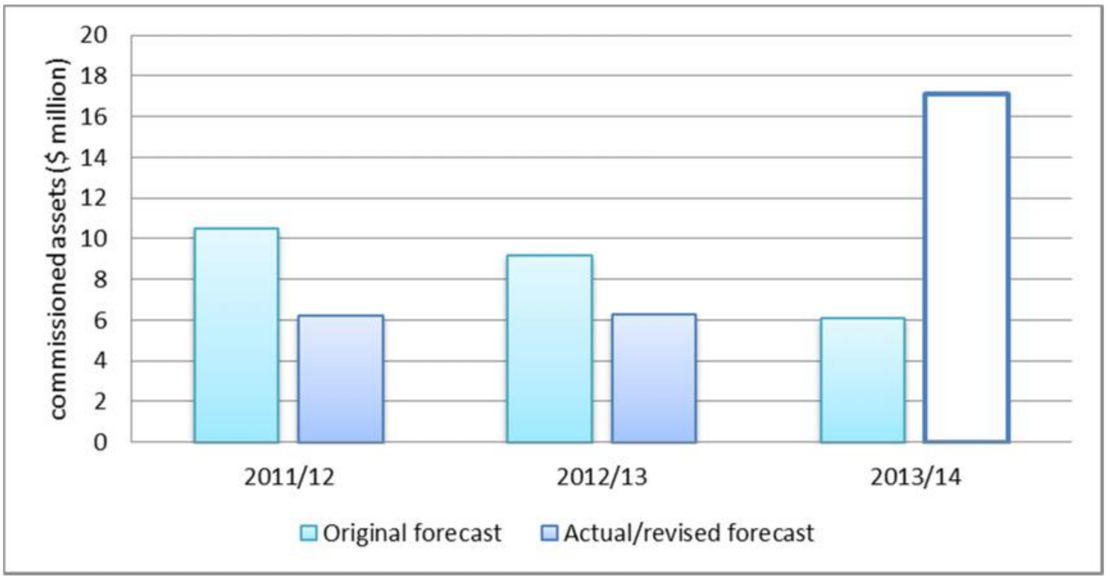
The System Operator manages capital expenditure using the categories described below. For each category we have shown the expected capital spend for the current three-year revenue period:

- buildings and maintenance: accommodation for the national co-ordination centre in Hamilton and the corporate office and control centre in Wellington ($3.2 million)
- lifecycle and efficiency: maintaining core functionality and supportability of the market system ($10.3 million)
- market development: enhancing the market system, typically flowing from Electricity Authority initiatives ($8.2 million)
- reasonable and prudent operation (RPO): supporting our ability to act as a reasonable and prudent system operator ($8.6 million)
- corporate projects: System Operator share of corporate-wide capital projects ($1.8 million)

Although revenue is set on a fixed three-year capex allowance, the capex plan is updated annually to maintain a three-year rolling plan. This is informed by long-term strategic planning, joint planning with the Electricity Authority, and operational planning (e.g. coordination, deliverability and risk).

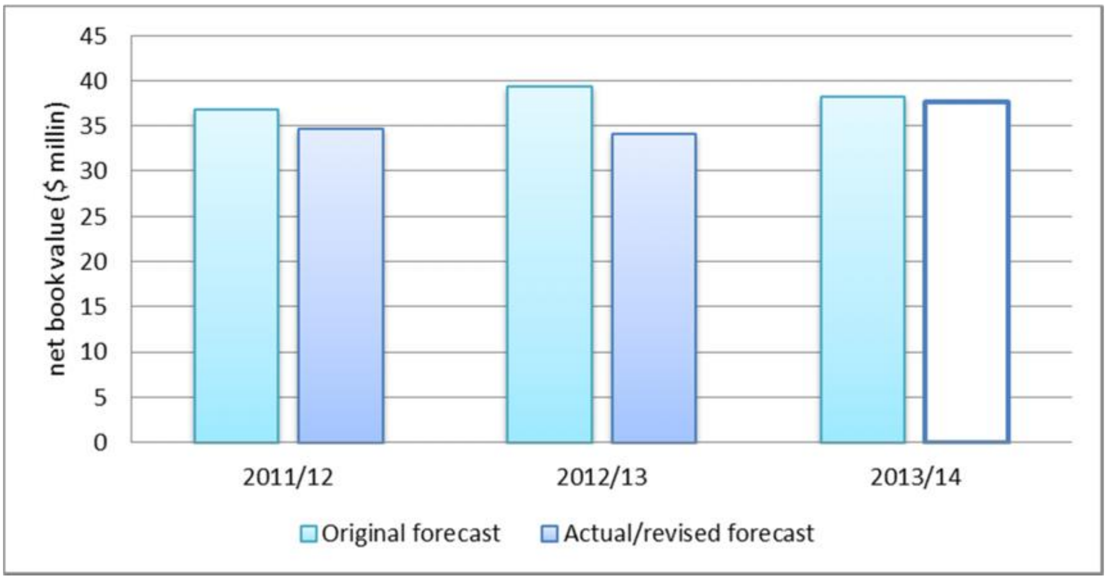
2012/13 was the middle year in the current three-year revenue period (i.e. the period runs from 2011/12 to 2013/14). Figure 19 compares the commissioning forecast used to set revenue, with actual commissioning to date and an updated forecast for the final year of the period.

Figure 19: Forecast and actual commissioned assets for current SOSPA revenue period



To date, the value of assets commissioned has been lower than originally forecast. We expect this to reverse during 2013/14. Figure 20 compares the original forecast asset base with actual movements to date, plus an updated forecast for 2013/14.

Figure 20: Forecast and actual asset base for the current SOSPA revenue period



The value of the asset base has to date grown more slowly, but is expected to be close to the original forecast by 30 June 2014.

Key drivers for the change in profile are:

- we delayed and re-scoped a number of lifecycle and efficiency projects to align with upgrades to operating system software that was due to come out of support in 2015
- market development projects are identified, scoped, and committed via consultative regulatory processes led by the Electricity Authority, and are inherently challenging to forecast.

Revenues

At the end of 2013/14, a comparison of forecast and *ex post* revenue will be made to calculate a wash-up for the current period to be returned to (or recovered from) the Electricity Authority. We will also set revenues for the next revenue period (2014/15 to 2016/17). Table 34 sets out current forecast of the wash-up amount and revenues for the next period.

Table 34: System Operator forecast revenue and estimated wash-up

	2011/12 $m	2012/13 $m	2013/14 $m	2014/15 $m	2015/16 $m	2016/17 $m
revenue forecast	34.3	36.7	38.7	41.3	43.9	47.3
ex post revenue	34.2	35.8	-			
updated forecast	-	-	37.9			
variance	(0.1)	(0.9)	(0.8)			
pre-emptive wash-up	-	-	1.5			
estimated wash-up balance			(0.3)			

Because we have commissioned assets later than originally forecast, we have over-recovered $1 million to date and forecast this to grow to $1.8 million by the end of the current period.

Rather than wait until after 2013/14, we are making a pre-emptive wash-up payment of $1.5 million this year to reduce the size of the final wash-up.

The higher forecast revenue through the next period is partly a consequence of commissioning approximately $30 million of assets in the current period. In addition:

- we expect lifecycle and efficiency expenditure to increase next period as work is carried out to extend the life of the market system through to 2021
- based on joint planning with Electricity Authority, we expect there to be ongoing market development work through the next period.

A.1 The legislative context for this report

This appendix sets out the legislative context for this report, and incorporates compliance statements we are required to make.

A.1.1 Annual compliance monitoring statement

This annual regulatory report incorporates:

- the annual compliance monitoring statement required by Part 5 of the Commerce Act (Transpower Individual Price-Quality Path) Determination 2010 (including all consolidated amendments to 31 October 2012)[49] ("the IPP Determination")
- information required by the Notice to Supply Information under Section 53ZD of the Commerce Act 1986[50] ("the s53ZD Notice") issued by the Commerce Commission in April 2013.
- some of the information required by the Notice to Supply Information under Section 53ZD of the Commerce Act 1986[51] ("the s53ZD Notice") issued by the Commerce Commission in July 2013. Appendix A.14 details the parts of that Notice that have been addressed in this document.

A.1.2 Input parameters to regulated price and quality path

Unless otherwise specified, or separately agreed with the Commission, input parameters to Transpower's regulated price and quality path disclosed in this Statement are calculated or determined, where applicable, in accordance with:

- the Transpower Input Methodologies Determination [2012] NZCC17[52] ("the IM Determination")
- the Transpower Capital Expenditure Input Methodologies Determination [2012] NZCC2 ("the Capex IM Determination").

We have relied on certain interpretations that we have agreed with the Commission, and which are listed in an email from the Commission dated 1 October 2012.

A.1.3 Terms and references

Unless the context otherwise requires, terms used in this report have the same meanings as in the Commerce Act 1986 or the IPP Determination and references to Parts or clauses are references to Parts or clauses in the IPP Determination unless otherwise specified.

[49] Issued on 31 October 2012.

[50] Notice to Supply Information to the Commerce Commission, Section 53ZD of the Commerce Act 1986 dated 18 April 2013 from the Commerce Commission to Transpower NZ Ltd.

[51] Notice to Supply Information to the Commerce Commission, Section 53ZD of the Commerce Act 1986 dated 2 July 2013 from the Commerce Commission to Transpower NZ Ltd.

[52] Issued on 29 June 2012

A.1.4 Compliance with the information requirements

As required by clause 5.1(1), Transpower confirms that it has complied with the information requirements, including relevant calculations, specified in Part 5 in relation to the price path in Part 3, the quality standards in Part 4 and the quality incentive mechanism referred to in clause 5.6.

A.1.5 Information supporting and explaining Transpower's compliance with the IPP Determination

In accordance with clause 5.1(2), Transpower has included in this report the associated information specified in Part 5 for the disclosure year and for comparative years, and any further information necessary to fully support and explain Transpower's compliance with the IPP Determination.

As required by clause 5.8, this report comprises a written statement, a directors' certificate executed by two directors of Transpower in Appendix A.9 and an independent assurance report in Appendix A.11.

A.1.6 Checklist of all information required

In Appendix A.12 of this report, Transpower has provided a checklist of all information required by Part 5 of the IPP Determination and the s 53ZD Notices and references to where in this report that information can be found

A.1.7 Approval of updates to Forecast MAR

Section 8 of this report seeks from the Commission the approval of updates to the 2014/15 Forecast MAR in accordance with clauses 3.3(1) and 3.3(2).

A.1.8 Monetary figures

Monetary figures in this Statement are in New Zealand dollars and at nominal prices unless otherwise stated.

A.1.9 Pricing years and disclosure years

This report discusses 'pricing years' and 'disclosure years'. Pricing years run from 1 April to 31 March, whereas disclosure years run from 1 July to 30 June.

Where we report on quality performance, forecast and actual capital expenditure and operating expenditure, and quality performance, we use disclosure years. Where we report on revenue, we use pricing years. For example, the operating revenue that we report in Section 4 for the disclosure year 1 July 2012 to 30 June 2013 was the revenue we recovered from 1 April 2012 to 31 March 2013. In effect, we treat pricing year revenue as if it were earned during the applicable disclosure year.

A.2 Adjustment to zero historical accumulated wash-ups

The IPP framework requires the zeroing of historical accumulated wash-up balances over the eight-year period from 2012/13 to 2019/20. The historical balances were accumulated in HVAC and HVDC 'economic valuation' (EV) accounts. This appendix shows the calculation of the figure to be used to zero the historical EV balances. The zeroing adjustment is already factored into the approved forecast MAR figures for 2012/13 to 2014/15.

The calculations take into account the EV balances as at 1 July 2011, the EV adjustments made in 2011/12, and forecast interest. The calculated EV adjustments are grossed up to a forecast pre-tax input to be used in forecast MAR calculations.

Table 35: HVAC Economic Value (EV) account zeroing adjustment

HVAC	RCP1				RCP2				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
WACC (IPP 5.3 (2) (b))	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%
Tax	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%
Opening balance (IPP5.3 (2) (a)) $m	82.4	52.1	47.1	41.7	35.9	29.7	23.0	15.9	8.2
2011/12 EV adjustment	**(36.2)**								
Opening balance $m	46.2	52.1	47.1	41.7	35.9	29.7	23.0	15.9	8.2
Forecast interest $m	5.9	3.7	3.3	3.0	2.6	2.1	1.7	1.1	.6
Return EV balance $m		(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)
Forecast closing $m	52.1	47.1	41.7	35.9	29.7	23.0	15.9	8.2	-
Net EV return $m	(36.2)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)	(8.8)
Gross EV return $m	**(50.3)**	**(12.2)**	**(12.2)**	**(12.2)**	**(12.2)**	**(12.2)**	**(12.2)**	**(12.2)**	**(12.2)**

Table 36: HVDC Economic Value (EV) account zeroing adjustment

HVDC	RCP1				RCP2				
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
WACC IPP 5.3 (2)(b)	**7.19%**	**7.19%**	**7.19%**	**7.19%**	**7.19%**	**7.19%**	**7.19%**	**7.19%**	**7.19%**
Tax	**28.0%**	**28.0%**	**28.0%**	**28.0%**	**28.0%**	**28.0%**	**28.0%**	**28.0%**	**28.0%**
Opening AC balance IPP5.3 (2) (a) $m	(106.7)	(104.1)	(94.0)	(83.2)	(71.6)	(59.2)	(45.9)	(31.7)	(16.4)
2011/12 EV adjustment	**10.3**								
Opening balance $m	(96.4)	(104.1)	(94.0)	(83.2)	(71.6)	(59.2)	(45.9)	(31.7)	(16.4)
Forecast interest $m	(7.7)	(7.5)	(6.8)	(6.0)	(5.1)	(4.3)	(3.3)	(2.3)	(1.2)
Recovery EV balance $m		17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Forecast closing $m	(104.1)	(94.0)	(83.2)	(71.6)	(59.2)	(45.9)	(31.7)	(16.4)	-
Net EV recovery $m	10.3	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Gross EV recovery $m	**14.3**	**24.4**	**24.4**	**24.4**	**24.4**	**24.4**	**24.4**	**24.4**	**24.4**

A.3 Calculation of the MAR wash-up

This appendix provides more detail on the calculation of the 2012/13 MAR wash-up.

The first table below sets out MAR wash-up calculations for the HVAC and HVDC accounts. The following tables show the working calculations for each of the notes identified in the first table.

Table 37: MAR wash-up for HVAC and HVDC accounts

MAR wash-up building block	Formula	Notes:	Total $m	HVAC $m	HVDC $m
RAB	A	1	3,425.3	3,114.3	311.0
Vanilla WACC	B		8.05%	8.05%	8.05%
Capital charge	**C = A x B**		**275.7**	**250.7**	**25.0**
Revenue	D	2	783.7	664.7	119.1
Operating expenditure	E	8	271.3	249.8	21.5
Term credit spread differential *(Note: allocated on RAB HVAC/HVDC basis)*	F		1.8	1.6	0.2
Depreciation	G	3 & 4	162.4	138.7	23.8
Net operating profit before tax	**H = D-E-F-G**		**348.3**	**274.7**	**73.6**
Tax	I		42.5	17.8	24.7
Net operating profit after tax	**J = H – I**		**305.8**	**256.9**	**48.9**
MAR Wash-up (EV account entry)	**K = C – J**		**(30.0)**	**(6.1)**	**(23.9)**

Note: figures may not add exactly due to rounding.

Table 38: Note 1 – Regulated Asset Base (RAB) calculation

RAB			HVAC $m	HVDC $m	Total $m	HVAC $m	HVDC $m
Opening balance					2,807.5	2,571.5	236.0
		Mid-month	**Commissioned assets**				
Weighted average commissioned assets (assuming mid-month commissioning)	July	11.5	24.2	0.2	23.4	23.2	0.2
	August	10.5	18.9	15.1	29.8	16.6	13.2
	September	9.5	21.8	5.9	21.9	17.3	4.7
	October	8.5	593.9	3.9	423.5	420.7	2.8
	November	7.5	24.1	5.4	18.5	15.1	3.4
	December	6.5	30.5	1.2	17.1	16.5	0.6
	January	5.5	9.7	0.4	4.6	4.4	0.2
	February	4.5	8.2	9.0	6.4	3.1	3.4
	March	3.5	35.3	0.3	10.4	10.3	0.1
	April	2.5	27.7	4.4	6.7	5.8	0.9
	May	1.5	61.1	349.0	51.3	7.6	43.6
	June	0.5	54.2	47.8	4.2	2.3	2.0
	Total		**909.7**	**442.5**			
					3,425.3	**3,114.3**	**311.0**

Note: figures may not add exactly due to rounding.

Table 39: Note 2 – Revenue

Revenue	**Total $m**	**HVAC $m**	**HVDC $m**
Transmission revenue for the 3 months 1 April - 30 June 2012	209.5	177.2	32.2
Transmission revenue for the 9 months 1 July - 31 March 2013	628.6	532.1	96.6
Transmission revenue for the pricing year ended 30 June 2012	838.1	709.3	128.8
less customer projects and new investment contracts	(31.2)	(31.2)	0.0
less pass through and recoverable cost related revenue	(23.1)	(13.4)	(9.7)
Regulated transmission Revenue pricing year ended 31 March 2013	**783.7**	**664.7**	**119.1**

Note: figures may not add exactly due to rounding.

Table 40: Note 3 – Depreciation

Depreciation		**Total $m**	**HVAC $m**	**HVDC $m**
Total depreciation for 2013 financial year per GAAP		167.9	147.7	20.3
plus pseudo asset depreciation		6.4	6.4	0.0
less depreciation in commissioning year		(25.3)	(21.6)	(3.7)
less depreciation on assets which will be fully depreciated in RCP1		(17.9)	(17.7)	(0.1)
plus allocated depreciation from assets fully depreciated in RCP1		17.7	17.4	0.3
plus dismantling costs		8.8	1.5	7.3
plus net asset write-offs		9.0	7.7	1.3
Capitalised interest adjustment for the difference between GAAP and WACC	Note 4	(4.3)	(2.8)	(1.5)
		162.4	**138.7**	**23.8**

Note: figures may not add exactly due to rounding.

Table 41: Note 4 – Capitalised interest depreciation adjustment

Capitalised interest depreciation adjustment			Total $m	HVAC $m	HVDC $m
Capitalised interest on commissioned assets[53]	A		95.4	57.7	37.6
Capitalised interest rate used on commissioned assets	B	7.4% and 7.62%			
Gross-up of capitalised interest	C= A/B		1,267.5	764.8	502.7
WACC post-tax interest rate used in MAR 2012/13 year	D	7.19%			
Capitalised interest at WACC	E=CxD		91.1	55.0	36.1
Depreciation Adjustment	**A-E**		**(4.3)**	**(2.8)**	**(1.5)**

Table 42: Note 5 – Operating allowance

Operating allowance	Total $m	HVAC $m	HVDC $m
2013 opex allowance, adjusted for cpi	**271.3**		
Actual Opex[54]	254.1	234.8	19.4
2012/13 opex allowance, adjusted for actual cpi rates	**271.3**	**249.8**	**21.5**
Shareholder total; Variance actual to opex allowance	**(17.2)**	**(15.0)**	**(2.2)**

Note: figures may not add exactly due to rounding.

[53] Some of the interest on assets that were commissioned during the year was capitalised during 2011/12, but is still subject to the interest rate cap. The amount shown is the total of amounts capitalised in 2011/12 and 2012/13 and each amount has been grossed up by the respective interest rate (7.4% in 2011/12 or 7.62% in 2012/13) to arrive at the total grossed-up figure.

[54] Including $7.1 million of costs in 2012/13 that are covered by insurance, but which are shown gross in this report.

Table 43: Historic *ex-post* customer economic gain/loss (including intended gains/losses)

Disclosure Year	Ex-post economic gain / (loss) $m		
	Total	HVAC	HVDC
2007/08	(33.7)	(37.1)	3.4
2008/09	(1.1)	3.0	(4.1)
2009/10	12.2	10.6	1.6
2010/11	(44.4)	(55.5)	11.0
2011/12	(10.6)	(14.7)	4.1
2012/13	(30.0)	(6.1)	(23.9)

Note: figures may not add exactly due to rounding.

A.4 Detailed breakdown of the wash-up and revenue adjustments

Building blocks (all in $m) (See Section 1.1)	Forecast 2012/13 MAR	Revised 2012/13 MAR	Due (to) or from Customers	HVAC	HVDC
Return on assets	290.0	275.7	(14.3)	(3.3)	(11.0)
Tax	34.4	39.1	4.7	(1.2)	5.9
Depreciation	167.2	162.4	(4.8)	(4.1)	(0.7)
Opex allowance (CPI-adjusted)	279.8	271.3	(8.5)	(7.8)	(0.7)
TCSD	0.2	1.8	1.6	1.4	0.2
Building block revenue	771.6	750.3	(21.3)	(15.0)	(6.3)
Historic EV account spread	12.2	12.2	-		
Maximum Allowable Revenue	783.8	762.5	(21.3)	(15.0)	(6.3)
Charging variations in the year	(0.1)		0.1	0.1	-
Revenue actually charged	783.7	783.7			
Due (to) or from customers (The Net Wash-up also see Table 15)		(21.2)	(21.2)	(14.9)	(6.3)
Otahuhu reversal			5.3	5.3	-
			(15.9)	(9.6)	(6.3)
Interest for 2 years (2012/13 to 2014/15)		at 7.2% per annum	(2.4)	(1.4)	(0.9)
			(18.3)	(11.0)	(7.2)
Grossing up for tax at 28% (to transfer post-tax economic value to/from customers)			(7.1)	(4.3)	(2.8)
New major projects		Section 3	0.3	0.3	-
Adjustment to the MAR for 2014/15 (including new major projects)			(25.1)	(15.0)	(10.1)
Previous forecast MAR for 2014/15			959.7	804.5	155.2
Updated MAR for 2014/15			934.6	789.5	145.1
Pass-through and recoverable cost wash-up		Section 6.1	(3.0)	(1.7)	(1.2)
Forecast pass-through and recoverable costs		Table 22	22.3	21.2	1.1
Updated revenue for 2014/15			953.9	809.0	145.0

A.5 Calculation of updated forecast MAR and revenue for 2014/15

The calculations that support the updates are

- Appendix A2: Adjustment to zero historical accumulated wash-ups over eight years
- Appendix A3: MAR wash-up
- Appendix A4: Major capex overspend adjustment

Table 44: Calculation of updates to forecast MAR and revenue for 2014/15

	2014/15		
	Total $m	**HVAC $m**	**HVDC $m**
Maximum Allowable Revenue (MAR) set on 31 October 2011	958.9	803.7	155.2
Updates to MAR for 2014/15			
Kawerau generation export enhancement: (approved April 2012, forecast December 2013 commissioning)	0.8	0.8	-
Upper South Island Grid Upgrade, stage 1: (approved February 2013, forecast mid 2014 commissioning)	0.3	0.3	-
2012/13 Wash-up adjustment (see Appendix A.4, excluding new major projects)	(25.4)	(15.3)	(10.1)
Updated forecast MAR for 2014/15	934.6	789.5	145.1

	2014/15		
	Total $m	HVAC $m	HVDC $m
Updates to forecast revenue			
Pass-through and recoverable costs wash-up	(3.0)	(1.7)	(1.2)
Rates forecast for 2014/15	8.0	7.9	0.1
EA levies as per latest forecast for 2014/15	5.6	5.6	-
CC levies as per latest forecast for 2014/15	2.5	2.5	-
Pass-through costs forecast for 2014/15	16.2	16.1	0.1
Reserves as per latest forecast for 2014/15	1.0	-	1.0
Non-transmission solutions as per latest forecast for 2014/15	5.1	5.1	-
Recoverable costs forecast for 2014/15	6.1	5.1	1.0
Updated forecast revenue	**953.9**	**809.0**	**145.0**

Note: figures may not add exactly due to rounding.

A.6 Calculation of hypothetical revenue adjustments

This appendix provides supporting calculations and graphs for the hypothetical revenue adjustments that would apply if the Commission's current network performance measures were linked to a performance incentive regime. We have assumed that the total value at risk is 1% of the 2012/13 forecast MAR, and that the four measures are evenly weighted. As such, the value at risk per measure is ($784 million * 1% * 25% =) $2.0 million. The table below sets out calculations for each revenue adjustment.

Table 45: Calculation of hypothetical revenue adjustments

Performance measure	Collar	Cap	Unit range	Revenue range $m	Gradient $m per unit	Target	Actual	Difference	Adjustment $m
	x_{min}	x_{max}	$aX = (x_{max} - x_{min})$	aY	aY/aX	x_0	x	$dx = (x - x_0)$	$dy = dx*(aY/aX)$
Number of loss of supply events greater than 0.05 system minutes[55]	31	10	(21)	4.0	(0.19)	21	12	(9)	1.7
Number of loss of supply events greater than 1 system minute	5	1	(4)	4.0	(1.0)	3	2	(1)	1.0
Unplanned HVAC circuit unavailability (%)[56]	0.083	0.029	(0.054)	4.0	(74.1)	0.054	0.032	(0.022)	1.6
Total system minutes (planned and unplanned)	29.07	4.31	(24.76)	4.0	(0.16)	16.69	7.62	(9.07)	1.5
Hypothetical revenue adjustment									**5.8**

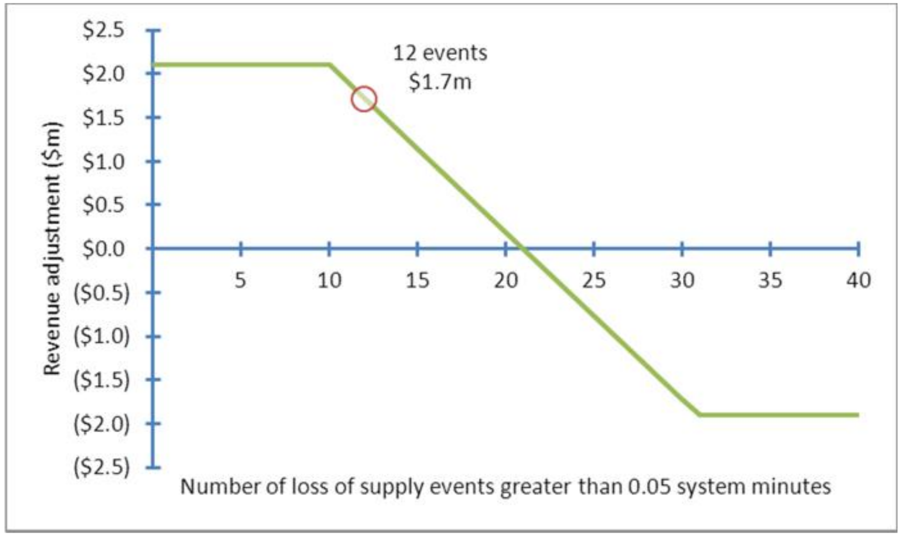
[55] For this quality measure, the target figure is not mid-way between the cap and the collar. Rather than using asymmetric gradients above and below the target, we have adopted a consistent gradient. This means that the revenue adjustment would be a $2.1 million increase if we achieved the cap and $1.9 million reduction if we reached the collar.

[56] ditto

In summary, if the current network performance measures were linked to revenue as described above then our 2014/15 revenue would increase by $5.8 million to reward very good network performance in 2012/13.

The following charts illustrate the hypothetical revenue adjustment for each of the network performance measures.

Figure 21: Performance incentive (loss of supply events)



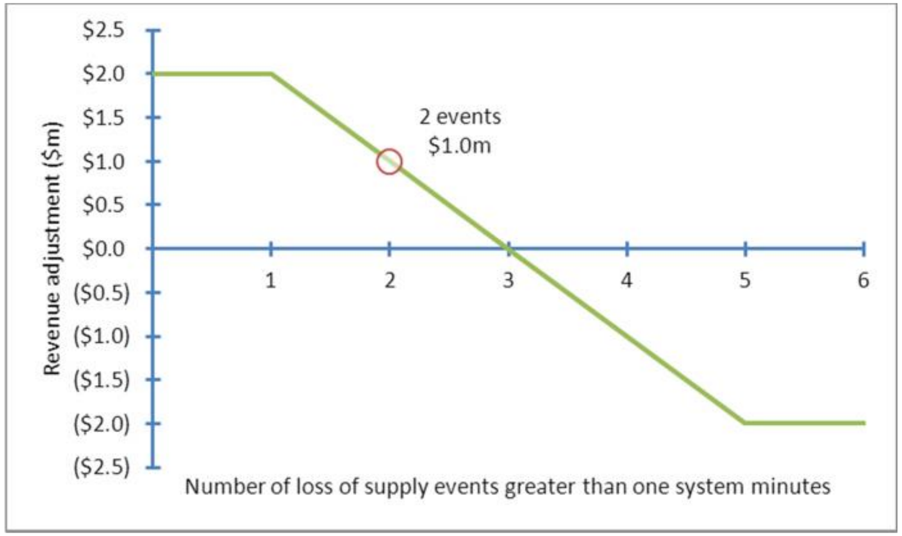
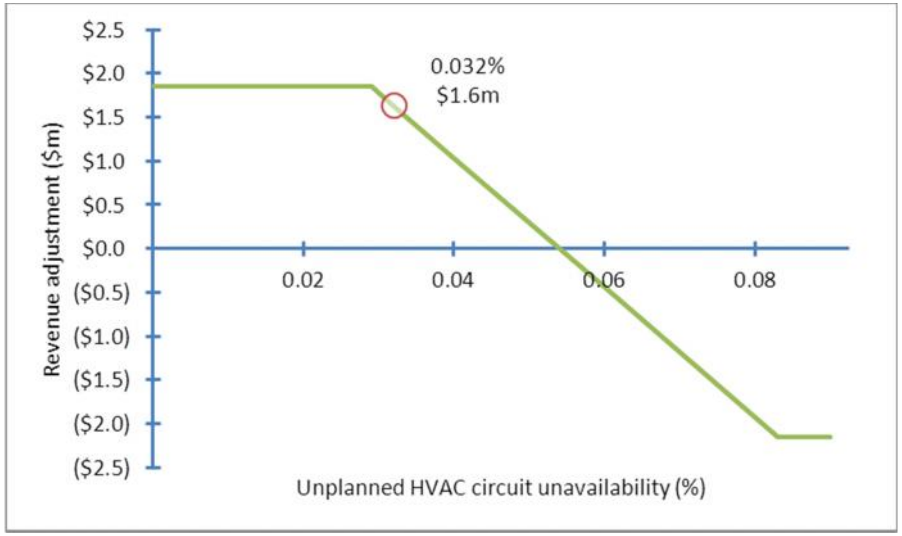
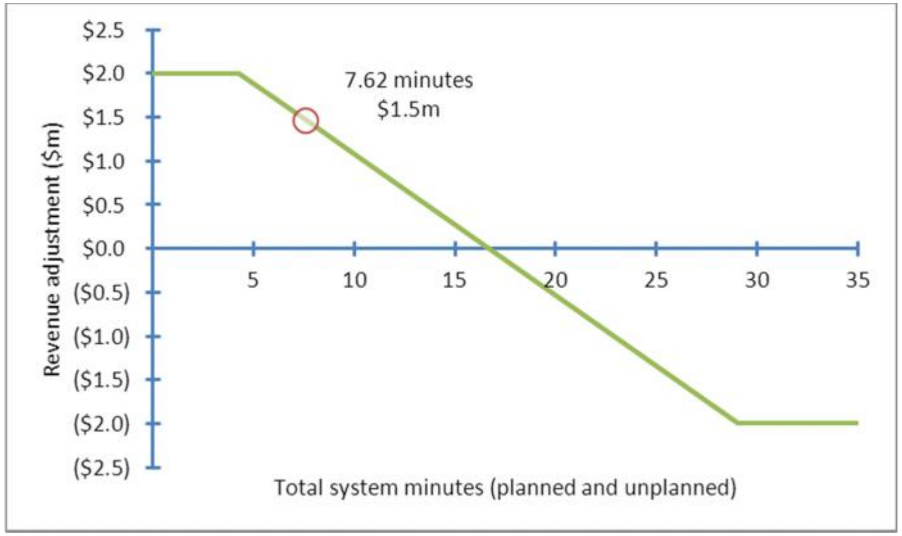


Figure 22: Performance incentive (circuit unavailability and total system minutes)





A.7 Calculation of hypothetical revenue adjustments – based on forecast figures

This appendix provides supporting calculations for the same hypothetical revenue adjustments calculated in Appendix A.6, but based on the current forecast numbers in Table 26.

Table 46: Hypothetical revenue adjustments based on forecast performance numbers

Performance measure	Gradient $m per unit[57]	Target	Forecast	Difference	Adjustment $m
	aY/aX	x_0	x	$dx = (x - x_0)$	dx*(aY/aX)
Number of loss of supply events greater than 0.05 system minutes[58]	(0.19)	21	17	(4)	0.8
Number of loss of supply events greater than 1 system minute	(1.0)	3	3	-	-
Unplanned HVAC circuit unavailability (%)[59]	(74.1)	0.054	0.058	0.004	(0.3)
Total system minutes (planned and unplanned)	(0.16)	16.69	15.76	(0.93)	0.1
Hypothetical revenue adjustment					**0.6**

[57] As in Table 45

[58] For this quality measure, the target figure is not mid-way between the cap and the collar. Rather than using asymmetric gradients above and below the target, we have adopted a consistent gradient. This means that the revenue adjustment would be a $2.1 million increase if we achieved the cap and $1.9 million reduction if we reached the collar.

[59] ditto

A.8 Overall RCP1 opex variance

RCP1 - OPERATING EXPENDITURE (nominal $)		Transpower Forecast				Commerce Commission Allowance				Variance					Variance explanation
		Actual	Forecast	Forecast	Total	Remainder Period			Total	Remainder Period			Total	% var	
		2013	2014	2015		2013	2014	2015		2013	2014	2015			
Maintenance Projects	Aerial Line Survey	-	-	-	-	-	1.6	0.5	2.1	-	(1.6)	(0.5)	(2.1)	(100%)	ALS expenditure incurred under Routine Maintenance in 12/13.
	Buildings & Grounds	1.8	1.7	2.6	6.2	2.3	1.4	1.6	5.4	(0.5)	0.3	1.1	0.8	16%	Work rephrased and scoped following prioritisation review in 2012/13.
	Tower	5.9	7.2	9.4	22.5	10.0	10.4	10.2	30.6	(4.1)	(3.2)	(0.8)	(8.0)	(26%)	Detailed review and prioritisation of work resulted in reduction in scope of work required in RCP1.
	Conductor	5.2	4.6	6.5	16.3	9.0	8.2	8.5	25.6	(3.8)	(3.6)	(2.0)	(9.3)	(36%)	
	Foundation	1.6	2.1	4.1	7.8	3.5	2.7	3.2	9.5	(1.9)	(0.7)	0.9	(1.6)	(17%)	
	Insulators	0.2	-	-	0.2	1.1	0.7	1.0	2.8	(0.9)	(0.7)	(1.0)	(2.6)	(93%)	
	Pole	0.2	0.5	1.6	2.3	0.8	0.8	1.0	2.6	(0.6)	(0.3)	0.6	(0.3)	(11%)	
	Access	0.1	-	0.2	0.3	0.3	0.4	0.4	1.1	(0.2)	(0.4)	(0.2)	(0.8)	(75%)	
	Power Transformer	3.1	1.7	0.6	5.4	2.9	2.2	2.0	7.0	0.2	(0.5)	(1.4)	(1.7)	(24%)	
	Outdoor Circuit Breakers	0.1	0.3	-	0.4	0.8	0.5	0.5	1.9	(0.7)	(0.2)	(0.5)	(1.4)	(77%)	
	Indoor Switchgear	0.3	0.0	0.1	0.4	0.5	0.5	0.5	1.6	(0.2)	(0.5)	(0.4)	(1.1)	(72%)	
	HVDC	0.4	0.6	1.5	2.5	1.3	0.9	0.3	2.6	(0.9)	(0.3)	1.2	(0.1)	(3%)	Minor Variance
	Other	0.3	0.1	0.0	0.4	-	-	-	-	0.3	0.1	0.0	0.4	-	
Routine Maintenance	Stations	31.7	36.6	33.4	101.6	40.3	39.8	39.6	119.7	(8.6)	(3.2)	(6.2)	(18.0)	(15%)	Focus on budget management, job vetting, prioritisation and planning resulted in better targeted expenditure and greater efficiency in works delivery. Reduced frequency of lines inspection resulted in saving of $2.2m
	Transmission Lines	28.0	29.1	28.7	85.8	31.3	31.0	31.8	94.1	(3.3)	(1.9)	(3.1)	(8.3)	(9%)	
	HVDC	8.0	9.4	10.6	28.0	8.5	9.3	9.8	27.6	(0.5)	0.1	0.8	0.5	2%	Minor variance.
	Operating	1.2	1.4	1.6	4.1	2.0	2.0	2.0	6.0	(0.8)	(0.6)	(0.4)	(1.9)	(32%)	Insourcing, timeliness of fault response and increased auto-reclose activity resulted in reductions in fault response costs.
	Training	2.9	4.5	4.8	12.2	1.4	1.4	1.5	4.3	1.5	3.1	3.3	7.8	181%	Significant extension of training programme in 13/14 and 14/15. Costs include transfer of programme to Palmerston North and re-branding as "Grid Skills".
	SCADA Model Maintenance	0.7	-	-	0.7	0.6	-	-	0.6	0.1	-	-	0.1	22%	
	TOTAL GRID MAINTENANCE	91.8	99.7	105.8	297.4	116.7	113.9	114.4	345.0	(24.9)	(14.2)	(8.6)	(47.7)	(14%)	

	RCP1 - OPERATING EXPENDITURE (nominal $)	Transpower Forecast Actual 2013	Forecast 2014	Forecast 2015	Total	Commerce Commission Allowance Remainder Period 2013	2014	2015	Total	Variance Remainder Period 2013	2014	2015	Total	% var	Variance explanation
IST Grid	Asset Management	0.8	1.4	1.4	3.6	0.9	0.9	2.2	4.0	(0.1)	0.5	(0.8)	(0.4)	(10%)	
IST Grid	Transmission Systems Plan	3.3	3.5	3.5	7.8	5.6	5.8	6.4	17.8	(2.3)	(2.3)	(2.9)	(7.5)	(42%)	Substation Management System (SMS) & Remote Engineering Access (REA) rollout licencing and support now moved out to RCP2; refinement of function and consolidation of servers.
IST Grid	Telecommunication Services	28.2	26.5	25.3	80.0	22.0	22.4	22.9	67.3	6.2	4.1	2.4	12.7	19%	Increased usage of leased dark fibre as a more cost effective option than build. Repair of fibre cable in Cook Strait (Cable 9) in 2012/13 $4.5m.
IST Grid	Network Services	2.3	2.4	2.5	7.2	2.1	2.4	2.4	6.9	0.2	0.0	0.1	0.3	5%	
IST Other	Corporate Services	3.8	4.2	4.1	12.1	3.0	3.2	3.4	9.6	0.7	1.0	0.8	2.5	26%	Increase in licencing fees
IST Other	ICT Shared Services	4.1	5.3	5.2	14.6	6.2	6.4	6.6	19.2	(2.1)	(1.1)	(1.4)	(4.6)	(24%)	Efficiencies through renegotiation of outsourced contracts.
IST Other	Security Services	1.4	1.5	2.1	5.0	1.8	2.0	2.1	5.9	(0.5)	(0.4)	(0.0)	(0.9)	(16%)	
	TOTAL IST MAINTENANCE	43.8	44.8	44.2	132.8	41.7	43.1	46.0	130.7	2.2	1.7	(1.8)	2.1	2%	
Corporate	Departmental	92.6	89.5	87.3	269.4	81.4	82.6	83.7	247.6	11.3	6.9	3.7	21.9	9%	Proposal and allowance was over optimistic in terms of scope for efficiencies to offset costs of new initiatives and additional capabilities/requirements. Increases in asset management capability, asset lease costs, consultant and contractor support for PAS55 and other RCP initiatives, partly offset by savings from insourcing Grid Operating Centres and SCADA system modelling.
Corporate	Investigations	11.1	9.8	11.3	32.2	10.4	8.6	8.6	27.6	0.7	1.2	2.8	4.6	17%	Increase investigation into innovation and use of new technologies.
Corporate	Insurance	13.2	15.2	15.5	43.9	15.6	16.3	16.8	48.6	(2.4)	(1.0)	(1.3)	(4.7)	(10%)	Self- insured Transmission and Distribution cover.
Corporate	Ancillary Services	1.5	2.8	2.4	6.6	5.5	5.6	5.8	16.8	(4.0)	(2.8)	(3.4)	(10.2)	(60%)	To date there have been no HVDC event charges.
	TOTAL CORPORATE	118.4	117.3	116.6	352.2	112.8	113.0	114.8	340.6	5.5	4.3	1.8	11.6	3%	
	TOTAL OPEX	**254.1**	**261.8**	**266.6**	**782.4**	**271.3**	**269.9**	**275.2**	**816.4**	**(17.2)**	**(8.1)**	**(8.6)**	**(34.0)**	**(4%)**	

12/13: note that the total opex of $254.1m excludes insurance income of $7m. The net cost in the year when insurance income is taken into account is $247.1m.

A.9 Detailed base capex variance explanation

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	2014	2015	Total	2013	2014	2015	Total	2013	2014	2015	Total	
Power Transformers	$	10.1	39.6	24.3	74.0	23.6	44.9	26.8	95.3	(13.5)	(5.3)	(2.5)	(21.3)	**2012/13** •commissioned 2 transformers and 1 spare transformers compared to planned 4 •variance due to postponement of Central Park transformer to RCP2 and unit cost lower due to lower costs of spares **RCP1** •forecast to commission 12 transformers and 6 spare transformers over the period, compared to a planned 25 •variance on volume due to reprioritisation of portfolio based on Asset Health and Criticality factors •variance on cost is due to reduced number of transformers delivered and lower cost of spare versus fully installed transformers
	Number	3	10	5	18	5	9	11	25	(2)	1	(6)	(7)	
Outdoor to Indoor Conversion	$	21.8	27.6	14.5	63.9	25.7	25.7	19.9	71.3	(3.9)	1.9	(5.5)	(7.4)	**2012/13** •commissioned 4 sites, 33kV outdoor to indoor conversion at Glenbrook, Hamilton, Masterton and Redclyfe • no variance in number, actual sites converted have changed based on Asset Health and Criticality factors **RCP1** •forecast to convert 12 sites compared to a planned 14 sites •variance on volume due to divestment of sites (1) and prioritising conversions based on Asset Health and Criticality factors •variance on cost is due to higher cost per conversion, primarily due to civil works and cabling costs not adequately provided for in original estimates
	Number	4	6	2	12	4	6	4	14	-	-	(2)	(2)	
Dynamic Reactive Power	$	13.9	0.8	34.5	49.2	22.1	0.0	0.0	22.1	(8.1)	0.8	34.5	27.1	**2012/13** •commissioned refurbished synchronous condenser, protection and controls upgrade, and other condenser works •variance due to restrictions on work due to Pole 3 commissioning **RCP1** •forecast to complete the refurbishment of 5 synchronous condensers at Haywards as planned •variance in costs is primarily due to the condensers being in a more worn state than envisaged and restrictions on work due to Pole 3 Commissioning delaying the programme.
HVDC	$	2.8	5.0	2.6	10.4	1.2	4.4	2.0	7.6	1.6	0.6	0.6	2.8	**2012/13** •commissioning water tanks, pumps and monitoring equipment at Haywards originally planned for 2011/12 **RCP1** •forecast to install thermo vision camera at Haywards & Benmore to monitor valves equipment and enhanced fire suppression and alarm systems at Haywards and Benmore substations •variance due to underspend in 2011/12 rolling in to 2012/13
Outdoor Circuit Breakers	$	1.9	8.8	2.6	13.2	2.4	8.6	5.3	16.2	(0.5)	0.2	(2.7)	(3.0)	**2012/13** •commissioned 12 circuit breakers (CB) replacements compared to a planned 16 CB •variance due to phasing differences **RCP1** •forecast to commission 71 CB replacements compared to a planned 85 CB •variance due to completing replacement of 10 CB at Otahuhu earlier (2011/12) than planned
	Number	12	36	23	71	16	48	21	85	(4)	(12)	2	(14)	

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	2014	2015	Total	2013	2014	2015	Total	2013	2014	2015	Total	
ACS Indoor Switchgear	$	0.2	4.7	5.6	10.5	2.3	1.8	4.8	8.9	(2.1)	2.9	0.8	1.6	**2012/13** • no commissioned assets - project cancelled as a result of planned divestment **RCP1** •forecast to commission 2 switchgear replacements and 1 portable switchboard compared to a planned 3 switchboard replacements. Mix has changed due to planned divestments and prioritisation changes as result of Christchurch earthquake
Metering	$	4.4	4.4	0.0	8.9	10.4	1.4	0.0	11.8	(6.0)	3.1	0.0	(2.9)	**2012/13** •commissioned 83 meters compared to a planned 147 •variance due to phasing the programme more evenly over the RCP1 period **RCP1** •forecast to commission 105 sites compared to planned 174 sites •variance due to completing more sites in 2011/12. Including 2011/12 year, forecast is to commission 269 sites, compared to a planned 292
Substation Mgmt Systems	$	3.0	6.7	3.5	13.2	4.5	4.4	4.7	13.6	(1.5)	2.3	(1.2)	(0.4)	**2012/13** •commissioned replacement of remote terminal units (RTU) at 7 sites compared to a planned 25 •variance due to system and resource constraints **RCP1** •forecast to commission 46 RTU replacements compared to a planned 76 RTU •variance due to constraints related to outage availability and resources. The average cost per site has increased by 19% due to design and installation costs increases and adding increased functionality
Buildings & Grounds	$	0.7	7.8	8.9	17.4	7.1	6.2	6.6	19.9	(6.3)	1.6	2.3	(2.5)	**2012/13** • commissioned significantly fewer projects than planned •variance due to review and reprioritisation of the portfolio during 2012/13 **RCP1** •forecast to commission approximately the same amount of work as planned
Buildings & Seismic	$	0.5	6.5	3.7	10.7	4.7	4.8	4.9	14.3	(4.2)	1.8	(1.2)	(3.6)	**2012/13** • commissioned seismic strengthening in 7 buildings in Lower North Island and completed seismic review on 144 structures through the country • variance in the programme has been caused by constraints on structural engineering resource following seismic events across the country **RCP1** • completed seismic review on 144 structures identifying that 50 structures require strengthening which will be completed over the RCP1 period

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	2014	2015	Total	2013	2014	2015	Total	2013	2014	2015	Total	
Protection	$	5.4	11.5	7.1	24.0	6.7	5.4	15.2	27.3	(1.3)	6.1	(8.1)	(3.3)	**2012/13** •commissioned transformer protection at Glenbrook and Maungaturoto. Bus zone and feeder protection replacements were carried out at numerous sites. Battery replacements were carried out at numerous sites •variance due to less line protection completed than planned **RCP1** •forecast to commission $24m compared to a planned $27m •variance $3m due to deferring duplicate bus zone protection to allow for the development of a revised strategy
Other	$	5.8	11.3	4.1	21.1	13.3	9.2	14.2	36.7	(7.5)	2.1	(10.1)	(15.5)	
Total Substations		**70.5**	**134.8**	**111.1**	**316.5**	**123.9**	**116.8**	**104.4**	**345.0**	**(53.4)**	**18.0**	**6.8**	**(28.6)**	
Tower Painting (New)	$	17.3	24.7	23.5	65.6	21.9	26.1	32.2	80.2	(4.6)	(1.4)	(8.7)	(14.7)	**2012/13** •painted 233 towers at an average cost of $74,000 per tower compared to a planned 393 at an average costs of $56,000 •variance in costs is due to a greater deterioration of the tower fleet than assumed in the allowance, therefore requiring more preparatory work and a switch to higher grade paint for a greater portion of the towers •variance in volume is due to limited availability of skilled resource and longer timeframe for new contracting resources to become available **RCP1** •forecast to commission 842 towers at an average cost of $78,000 per tower compared to a planned 1,361 at an average costs of $59,000 •variance is for the same reason as 2012/13
Tower Painting (New)	Number	233	317	292	842	393	444	524	1,361	(160)	(127)	(232)	(519)	
Tower Painting (Recoat)	$	9.8	13.1	7.6	30.5	8.3	10.3	7.3	25.8	1.5	2.9	0.4	4.7	**2012/13** •painted 161 towers at an average costs of $61,000 per tower compared to a planned 269 at an average costs of $31,000 •variance in costs is due to: a greater deterioration of the tower fleet than assumed in the allowance, therefore requiring more preparatory work; limited availability of skilled resource; and longer timeframe for new contracting resources to become available **RCP1** •forecast to commission 486 towers at an average cost of $63,000 per tower compared to a planned 778 at an average costs of $33,000 •variance is for the same reason as 2012/13
Tower Painting (Recoat)	Number	161	209	116	486	269	303	206	778	(108)	(94)	(90)	(292)	

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	2014	2015	Total	2013	2014	2015	Total	2013	2014	2015	Total	
TL Conductor	$	12.7	4.2	4.2	21.2	16.7	7.3	5.4	29.4	(4.0)	(3.1)	(1.1)	(8.2)	**2012/13** • commissioned 86.5 circuit kms of Conductor, 3.2 circuit kms of Earthwire, 2.6 circuit kms Aerial Communication Cable and 4 circuit kms of HVDC cable • variance due to $6.2m urban copper reassessed under a revised policy and deemed not required and condition assessment reviews giving effect to cancellation of some work and re-scheduling of others **RCP1** • forecast to commission 112 circuit kms •variance due to $16.6m being reviewed and either moved out of RCP1 ($6m) or cancelled ($10.6m) and $8.6m of substituted expenditure
Grillage	$	17.3	9.8	8.0	35.1	14.0	11.8	16.7	42.6	3.3	(2.1)	(8.7)	(7.5)	**2012/13** •completed 625 tower grillages at an average costs of $28,000 per tower compared to a planned 533 at an average costs of $26,000 •variance due rollover of commissioning from the 2011/12 year **RCP1** •forecast to complete 1,262 tower grillages at an average cost of $28,000 per tower compared to a planned 1,500 at an average costs of $27,000 •variance in number of grillage completed is due to additional steel work requirement due to greater severity in corrosion and weather/access issues
	Number	625	450	187	1,262	533	434	592	1,559	92	16	(405)	(297)	
Foundation	$	2.3	2.1	3.3	7.8	2.2	2.9	2.9	8.0	0.1	(0.8)	0.5	(0.2)	
TL Pole		7.4	8.7	5.3	21.4	7.5	6.7	6.6	20.8	(0.1)	2.0	(1.3)	0.6	
TL Insulators		8.1	9.0	6.0	23.1	6.9	5.9	6.5	19.2	1.2	3.2	(0.5)	3.9	
Other Lines		0.4	4.5	1.9	6.8	4.4	3.2	4.6	12.2	(4.0)	1.3	(2.7)	(5.4)	
Total Lines		75.4	76.2	59.9	211.5	81.9	74.1	82.3	238.3	(6.5)	2.1	(22.3)	(26.7)	
Total Grid R&R		**145.9**	**211.0**	**171.1**	**528.0**	**205.7**	**191.0**	**186.6**	**583.3**	**(59.9)**	**20.1**	**(15.5)**	**(55.3)**	
Total Grid E&D		**3.0**	**0.8**	**7.0**	**10.7**	**5.2**	**3.1**	**7.8**	**16.1**	**(2.2)**	**(2.3)**	**(0.8)**	**(5.4)**	

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	2014	2015	Total	2013	2014	2015	Total	2013	2014	2015	Total	
IT Asset Management	$	16.0	4.1	10.6	30.7	0.9	2.7	32.7	36.3	15.1	1.4	(22.1)	(5.6)	**2012/13** •commissioned phase 1 of new Maximo Asset Management System and the new Outage Management System •variance due to phased approach to the implementation of new Asset Management System **RCP1** •forecast to commission 2nd phase of new Asset Management Systems •variance due to implementing Asset Management System at lower costs than planned
IT SCADA/RTS	$	1.3	2.7	7.3	11.3	4.5	11.5	4.0	19.9	(3.2)	(8.7)	3.3	(8.6)	**2012/13** •commissioned SCADA hardware refresh •variance due to SCADA upgrade delay **RCP1** •forecast to commission first phase of SCADA upgrade $8m •variance due to the delay to the SCADA upgrade which is now split between RCP1 & 2, plan included full SCADA upgrade in RCP1
IT Spatial & Drawings	$	-	1.3	1.0	2.4	0.3	0.4	0.3	1.1	(0.3)	0.9	0.7	1.3	
Telecoms and Networking programme	$	18.0	29.1	5.9	53.0	53.9	-	-	53.9	(36.0)	29.1	5.9	(1.0)	**2012/13** •commissioned new telecommunications equipment at 61 sites •variance due to programme being delivered over longer timeframe than planned **RCP1** •forecast to commission 168 sites to the "TransGo" network
IT Security Infrastructure	$	0.3	5.7	3.6	9.7	2.6	3.0	7.2	12.9	(2.3)	2.7	(3.6)	(3.2)	**2012/13** •no major commissioned items •variance due to Identity Management System being delayed to later in RCP1 **RCP1** •forecast to commission Security Enforcement Point System and Identity Management System •variance due to efficiency gains through implementing Security Enforcement Points at 16 Regional Aggregation sites rather than all 180 sites planned in the RCP1 allowance. This change in approach delivers the objective to provide protection by internal or external threats and results in $5.2m in savings
IT Enabling Infrastructure	$	2.0	5.8	2.4	10.3	3.8	4.2	3.9	12.0	(1.8)	1.6	(1.5)	(1.6)	**2012/13** •commissioned desktop refresh $1.2m and Hardware and Software Life Cycle costs $0.8m. • variance due to delay in commissioning Integrated Technology refresh $1.2m **RCP1** •forecast to deliver refreshes of Integrated Technology, Storage Capacity Lifecycle and Email hardware and software. New initiative of SCADA Connection Gateway $1m allowing Genco customers to exchange data.

		Actual / Revised Forecast				RCP1 Commissioning Allowance				Variance				Commentary
		2013	**2014**	**2015**	**Total**	**2013**	**2014**	**2015**	**Total**	**2013**	**2014**	**2015**	**Total**	
IT Service Management	$	3.4	2.6	1.2	7.2	1.2	1.2	1.2	3.6	2.2	1.4	0.0	3.6	**2012/13** •$2.3m license fee increases •variances due to incurring licence fees not allowed for in the plan **RCP1** •forecast to commission new change management system, tools for modelling of critical IST infrastructure •variance due to unplanned licences fees
IT Workforce Mobility	$	1.1	2.2	0.1	3.4	0.7	0.1	0.5	1.3	0.3	2.2	(0.4)	2.1	**2012/13** •commissioned "Applications in a Bubble" **RCP1** •forecast to commission capabilities for mobile & collaborative working •variance due to increased provision for mobile working
Other IST		8.1	15.2	10.9	34.1	12.4	8.8	11.7	32.9	(4.3)	6.4	(0.8)	1.3	
Total IT&T		50.2	68.9	43.1	162.2	80.5	31.9	61.5	173.9	(30.3)	36.9	(18.4)	(11.7)	
Business Support	$	7.9	14.9	7.0	29.9	7.8	13.2	26.0	47.0	0.1	1.8	(19.0)	(17.1)	**2012/13** •commissioned new regional office at Islington; refurbishment of floors in Wellington Head Office **RCP1** •commissioning new regional offices (Christchurch & Auckland) and refurbishment of Wellington Head Office •variance due to postponement of proposed move of Wellington Head office moved out of RCP1 period and no strategic properties purchased, partially offset by the new Auckland office (planned for 2014).
Adj't	$	-	-	-	-	(3.9)	(6.9)	(14.8)	(25.6)	3.9	6.9	14.8	25.6	•Adjustment for actual / forecast CPI
TOTAL		**207.0**	**295.6**	**228.1**	**730.7**	**295.3**	**232.3**	**267.1**	**794.6**	**(88.3)**	**63.3**	**(38.9)**	**(63.9)**	

A.10 Directors' certificate

Directors' Certificate

We, Mark Verbiest and Alastair Scott, being directors of Transpower New Zealand Limited (Transpower), certify that, having made all reasonable enquiries, to the best of our knowledge and belief, the attached *Annual Regulatory Report* (and associated information) for the period 1 July 2012 to 30 June 2013 and dated 17 October 2013 complies with the requirements of the Commerce Act (Transpower Individual Price-Quality Path) Determination 2010, and with the Commission's information requirements, which were issued by notice in writing to Transpower under section 53ZD of the Commerce Act 1986 on 18 April 2013 and 2 July 2013.

Mark Verbiest
Chairman, Transpower New Zealand Limited

Alastair Scott
Director, Transpower New Zealand Limited

A.11 Independent assurance report

The following pages contain an independent assurance report from PricewaterhouseCoopers.

pwc

INDEPENDENT ASSURANCE REPORT – ANNUAL COMPLIANCE MONITORING STATEMENT

To the readers of the Annual Compliance Monitoring Statement (and associated information) of Transpower New Zealand Limited (Transpower) for the disclosure year ended 30 June 2013:

We have been engaged to provide an independent assurance report on the Annual Compliance Monitoring Statement (ACMS) (and associated information) in respect of the individual price-quality path prepared by Transpower for the year ended 30 June 2013 and dated 17 October 2013 for the purposes of Part 5 of the Commerce Act (Transpower Individual Price-Quality Path) Determination 2010 (the Determination).

Directors' and Auditor's Responsibilities

Transpower's directors are responsible for the preparation of the ACMS (and associated information) in accordance with the Determination and for such internal controls as the directors determine are necessary to enable the preparation of the ACMS (and associated information) that is free from material misstatement.

We are qualified as an auditor as defined in the Determination. Our responsibility is to express an independent opinion on whether Transpower's ACMS (and associated information) with respect to the individual price-quality path has been prepared in accordance with the Determination.

Basis of opinion

We have conducted an assurance engagement in accordance with the framework for Assurance Engagements and the Standard on Assurance Engagements 3100 (SAE 3100) issued by the External Reporting Board.

The objectives of an assurance engagement carried out under SAE 3100 are to:

(1) Obtain assurance about whether, in all material respects, an entity has complied with requirements contained in legislation, regulation, agreements, contracts or similar, or internally imposed standards, codes or practices; and

(2) Express a conclusion on that compliance in the form of an opinion.

The professional standards require that we comply with ethical requirements and plan and perform the assurance engagement to obtain reasonable assurance about whether the ACMS (and associated information) is free from material misstatement in respect of compliance with the Determination.

Considering materiality requires that we understand the factors that might influence the decisions of the intended users of the information contained in the ACMS (and associated information) when determining the nature and extent of our evidence-gathering procedures.

PricewaterhouseCoopers, 113-119 The Terrace, PO Box 243, Wellington 6140, New Zealand
T: +64 (4) 462 7000, F: +64 (4) 462 7001, www.pwc.com/nz

Page 1

An assurance engagement involves performing procedures to obtain appropriate evidence about the amounts and disclosures in the ACMS (and associated information). The procedures selected depend on judgment, including the assessment of the risks of material misstatement, whether due to fraud, error or other reasons. In evaluating those risks we consider the internal controls that are relevant to Transpower's preparation of the ACMS (and associated information) in order to design assurance procedures that are appropriate in the circumstances. We do not express an opinion on the effectiveness of Transpower's internal controls.

An assurance engagement also includes evaluating the appropriateness of the calculations and the reasonableness of estimates made by Transpower in preparing the information that it is required to disclose in the ACMS (and associated information).

In relation to the information requirements in Part 5 that relate to the price path in Part 3, quality standards in Part 4 and quality incentive mechanism in Part 5 of the Determination, our assurance engagement included examination, on a test basis, of evidence relevant to the amounts and disclosures contained in the sections of the ACMS (and associated information) set out in Appendix A to this report.

The procedures we have undertaken in relation to the amounts and disclosures contained in the sections of the ACMS (and associated information) set out in Appendix A to this report included:

(1) Examining, on a test basis, internally and externally generated documents and records;

(2) Interviewing Transpower personnel;

(3) Reviewing calculation methodologies and judgments used to derive the amounts and disclosures;

(4) Testing the mathematical accuracy of the calculations;

(5) Identifying key inputs to the calculations and reconciling or agreeing them to source documents and systems; and

(6) Such other procedures as we considered necessary.

In performing our procedures we have placed reliance on Transpower's underlying systems and business records.

Our assurance engagement also included an assessment of significant estimates and judgments, if any, made by Transpower in the preparation of the ACMS (and associated information) and an assessment of whether the basis of preparation of the individual price-quality path has been adequately disclosed.

Opinion

We have obtained all the information and explanations we required to express our opinion.

In our opinion:

(1) The forecast HVAC revenue and forecast HVDC revenue that Transpower used for the purpose of setting charges under the Transmission Pricing Methodology for the 2012/13

Page 2

pwc

pricing year did not, in aggregate, exceed the forecast Maximum Allowable Revenue (MAR) of $783.8 million.

(2) The information included in Section 7 of the ACMS regarding the quality standards for the disclosure year ended 30 June 2013 has been prepared or calculated in accordance with the requirements of clause 4.3 (2) of Part 4 of the Determination.

(3) The information included in Section 7 of the ACMS regarding the quality incentive mechanism for the disclosure year ended 30 June 2013 has been prepared or calculated in accordance with the requirements of clause 5.6 (2) of Part 5 of the Determination.

(4) The disclosures included in the ACMS (and associated information) listed in Appendix A to this report prepared by Transpower for the disclosure year ended 30 June 2013 and dated 17 October 2013, have been prepared and presented, in all material respects, in accordance with the Determination.

Other matters

Our assurance procedures and the opinions included in this report relate to the specific disclosures set out in the ACMS that are required under Part 5 of the Determination (as set out in Appendix A to this report). There is other information in the ACMS that Transpower is not required to disclose under Part 5 of the Determination (including disclosures required by the Notice to Supply Information to the Commerce Commission under Section 53ZD of the Commerce Act 1986 dated 18 April and 2 July 2013). Our assurance procedures have been undertaken only in relation to information that Transpower is required to disclose under the Determination. Accordingly we express no opinion on disclosures made in the ACMS that are not required by the Determination.

Independence

We have no relationship with, or interests in Transpower other than in our capacity as auditors of the ACMS and in the provision of other assurance, taxation and professional advisory services.

We are not aware of any relationships between our firm and Transpower that, in our professional judgment, impairs our independence.

Completion

Our independent assurance engagement was completed on 17 October 2013 and our opinion is expressed as at that date.

PricewaterhouseCoopers

PricewaterhouseCoopers
Chartered Accountants
Wellington

A.12 IPP Compliance checklist

This appendix shows how the information in this report demonstrates Transpower's compliance with each part of IPP Determinations and Section 53ZD Notice. It lists the clauses in Part 5 of the Determinations and Notice in order, with an explanation of which parts of the report demonstrate compliance with the clause.

The regulations shown in this appendix are as follows.

- Part 5 of the IPP Determination dated 22 December 2010
- Part 5 of the IPP Determination dated 1 November 2011
- Part 5 of the IPP Determination dated 31 January 2012
- Section 53ZD Notice

A.12.1 Part 5 of the IPP Determination dated 31 January 2012

Table 47: Compliance cross-reference – IPP Part 5

Clause	Information or action required	Demonstration of compliance
5.1	Requirement to provide annual compliance monitoring statement and associated information	-
5.1(1)	Transpower must provide to the Commission and publish on Transpower's website, no later than the close of business on the Friday of the third complete week of the month of October following the end of each disclosure year, an annual compliance monitoring statement that includes a statement in writing confirming whether or not Transpower has complied in respect of that disclosure year with the information requirements, including relevant calculations, specified in this Part 5 in relation to the price path in Part 3, the quality standards in Part 4 and the quality incentive mechanism referred to in clause 5.6	Appendix A.10
5.1(2)	The annual compliance monitoring statement provided under clause 5.1(1) must be accompanied by the associated information specified in this Part 5 for the disclosure year and for comparative years, and any further information necessary to fully support and explain Transpower's compliance with this determination.	-

Clause	Information or action required	Demonstration of compliance
5.2	Information requirements relating to price path	-
5.2(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.2 for Transpower's price path.	-
5.2(2)	Forecast MAR calculation model	-
5.2(2)(a)	any material variations made during the disclosure year to the forecast MAR calculation model	Section 4.5
5.2(3)	Revenues	-
5.2(3)(a)	For each disclosure year	-
5.2(3)(a)(i)	the forecast MAR for the relevant pricing year determined by the Commission in accordance with Part 3; and	Table 14
5.2(3)(a)(ii)	the MAR for the disclosure year calculated in accordance with clause 5.2(7) and Schedule E; and	Table 14
5.2(3)(a)(iii)	the update of any forecast MAR that is calculated at the end of the disclosure year in accordance with clause 5.4 and Schedule D; supported by sufficient detail to demonstrate that each forecast MAR, each MAR or each update of a forecast MAR has been calculated in accordance with the relevant requirements and definitions specified in this determination	Appendix A.4
5.2(3)(b)	For the relevant pricing year	-
5.2(3)(b)(i)	HVAC revenue	Table 17
5.2(3)(b)(ii)	HVDC revenue	Table 17
5.2(4)	Capital Expenditure	-
5.2(4)(a)	for each disclosure year, a list of base capital expenditure (broken down by each expenditure category in the definition of that term in Part 2) including	Table 5
5.2(4)(a)(i),	base capital expenditure that was commissioned during the disclosure year; and	Section 2.2

Clause	Information or action required	Demonstration of compliance
5.2(4)(a)(ii)	an explanation of any material variation between base capital expenditure that was forecast to be commissioned during the disclosure year and base capital expenditure that was commissioned during the disclosure year	Section 2.2
5.2(4)(b)	for each disclosure year, a list of base capital expenditure asset enhancement projects that ceased during the disclosure year to continue to meet the definition of base capital expenditure due to the total level of capital expenditure incurred on the project.	Section 2.3
5.2(4)(c)	for each disclosure year, a list of the base capital expenditure asset enhancement projects included in the approved base capital expenditure for which Transpower has submitted a major capex proposal to the Commission, and the result of reducing the approved base capital expenditure for the regulatory period for the amount of major capex.	Section 2.3
5.2(4)(d)	a forecast for each of the remaining disclosure years in the period from 1 July 2011 to 30 June 2015, calculated by providing base capital expenditure and major capital expenditure separately, including major capital expenditure approved by the Commission during the current disclosure year that will be commissioned during a subsequent disclosure year.	Table 10
5.2(4)(e)	in the last annual compliance monitoring statement for the period from 1 July 2011 to 30 June 2015, all relevant material necessary to assess any application within the annual compliance monitoring statement for ex-post approval of base capital expenditure in excess of the aggregate level of approved base capital expenditure, including a description in each instance, of why each relevant project or programme: (i) was unable to be reasonably foreseen by Transpower; (ii) is required to maintain the security of supply of the grid; and (iii) could not be reasonably deferred.	Not applicable for 2012/13 disclosure year
5.2(4)(f)	for each disclosure year, a list of assets determined by the Commission to be stranded assets.	Section 4.5
5.2(5)	Operating expenditure for each disclosure year (broken down by each expenditure category in the definition of operating expenditure), including:	-
5.2(5)(a)	actual operating expenditure during the disclosure year; and	Table 18

Clause	Information or action required	Demonstration of compliance
5.2(5)(b)	an explanation of any material variation between operating expenditure that was forecast by Transpower for the disclosure year and actual operating expenditure during the disclosure year.	Section 5
5.2(6)	Ex-post economic gain or loss, HVAC ex-post economic gain or loss, and HVDC ex-post economic gain or loss for each disclosure year, including:	-
5.2(6)(a)	details of how each ex-post economic gain or loss has been calculated in accordance with the building blocks calculation in Schedule E; and	Appendix A.3
5.2(6)(b)	the allocation of the resulting EV account entry to each of the EV accounts for HVAC customers and HVDC customers; and	Table 2
5.2(6)(c)	a reconciliation of the opening and closing balances of the EV accounts, including details of the calculation of interest and any other adjustments to the balances of the EV accounts; and	Table 2
5.2(6)(d)	details of any changes to Transpower's policy of hedging capital expenditure during the disclosure year; and	Section 4.5
5.2(6)(e)	details of all gains and losses in the disclosure year that are recorded in the EV accounts in respect of any instrument that ceases to be an effective hedge or in respect of any commodity instrument that is not an effective hedge.	Section 4.5
5.2(7)	MAR for the purposes of the calculation of the ex-post economic gain or loss:	Table 15
5.2(7)(a)	using applicable input methodologies;	-
5.2(7)(b)	using as the operating expenditure allowance: (i) for the disclosure year from 1 July 2011 to 30 June 2012, $248.5 million; (ii) for the disclosure year from 1 July 2012 to 30 June 2013, $279.8 million, adjusted for any disparity between the forecast CPI and the actual CPI; (iii) for the disclosure year from 1 July 2013 to 30 June 2014, $281.2 million, adjusted for any disparity between the forecast CPI and the actual CPI; (iv) for the disclosure year from 1 July 2014 to 30 June 2015, $287.9 million, adjusted for any disparity between the forecast CPI and the actual CPI;	-

Clause	Information or action required	Demonstration of compliance
5.2(7)(c)	excluding pass-through costs and recoverable costs;	-
5.2(7)(d)	using actual base capital expenditure that was commissioned in the disclosure year;	Table 38
5.2(7)(e)	using actual major capital expenditure that was commissioned in the disclosure year; and	Table 38
5.2(7)(f)	using, for all other building blocks, actual costs for the disclosure year.	Table 15
5.2(8)	Pass-through costs and recoverable costs for each disclosure year, including:	-
5.2(8)(a)	the pass-through costs and recoverable costs incurred by Transpower during the disclosure year;	Table 21
5.2(8)(b)	the pass-through costs and recoverable costs recovered by Transpower from customers as part of its revenue for the relevant pricing year; and	Table 21
5.2(8)(c)	the allocation of adjustment amounts arising from the differences between the amounts in sub-clauses (a) and (b) above, applied in the forecast of pass-through costs and recoverable costs in the setting of transmission charges under the TPM in the next relevant pricing year.	Table 21
5.2(9)	Major capex adjustments for each disclosure year, calculated where applicable using the major capex incentive rate of 33%.	None this year
5.3	Information requirements and calculations relating to EV adjustments	-
5.3(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.3 for calculating EV adjustments.	-
5.3(2)	For the purposes of calculating the forecast MAR for each pricing year of the remainder period, the EV account balances are: (a) the opening EV account balances; less (b) EV adjustments applied to the forecast MAR for the transition year; plus (c) forecast interest on the opening EV account balances, for each disclosure year in the period 1 July 2012 to 30 June 2015 plus five additional years, applying the WACC and applying the EV adjustment calculation requirement in subclause (4)(a) below.	Appendix A.2 Appendix A.3

Clause	Information or action required	Demonstration of compliance
5.3(3)	For the purposes of calculating an update of a forecast MAR for a disclosure year of the remainder period, the EV account balances are: (a) the EV account balances, excluding the balances calculated under subclause (2); plus (b) forecast interest for each disclosure year of the remainder period on the EV account balances in subclause (3)(a), in accordance with the interest rate specified in the definition of EV account.	Appendix A.4
5.3(4)	Transpower must:	-
5.3(4)(a)	calculate EV adjustments that attribute one-eighth of the balances calculated in subclause (2) to the forecast MAR for each disclosure year in the remainder period;	Appendix A.2
5.3(4)(b)	at the end of each disclosure year, calculate EV adjustments that attribute the balances calculated in subclause (3) to the update of the forecast MAR for the next pricing year commencing after the time of calculation;	Appendix A.3
5.3(4)(c)	gross up the EV adjustments applied to the forecast MAR for each disclosure year in terms of subclauses (4)(a) or (4)(b) to a forecast pre-tax input to the forecast MAR calculation using the corporate tax rate; and	Appendix A.2 Appendix A.3
5.3(4)(d)	for base capital expenditure in excess of aggregate approved base capital expenditure for the regulatory period or any base capital expenditure that has not been fully subject to Transpower's internal approval processes, make each EV account entry sufficient to fully offset the revenue impact of such capital expenditure over the life of the applicable assets, in the disclosure year that ends on 30 June 2015; and	Section 2.5 (no excess)
5.3(4)(e)	make an EV account entry for the major capex adjustments, as applicable to the disclosure year, on an annual basis.	Appendix A.4
5.3(5)	Where Transpower applies for, and the Commission provides, ex-post approval of base capital expenditure after the regulatory period, Transpower must make an EV account entry at the time of that approval to adjust the EV account entry in clause 5.3(4)(d) to fully offset the revenue impact of that adjustment, with such adjustment to exclude the revenue impact over the regulatory period.	n/a

Clause	Information or action required	Demonstration of compliance
5.3(6)	The approved base capital expenditure for the purposes of clause 5.3(4)(d) is the aggregate of: (a) for the disclosure year from 1 July 2011 to 30 June 2012, $208.6 million; and (b) for the disclosure year from 1 July 2012 to 30 June 2013, $301.9 million, adjusted for any disparity between the forecast CPI and the actual CPI; and (c) for the disclosure year from 1 July 2013 to 30 June 2014, $244.9 million, adjusted for any disparity between the forecast CPI and the actual CPI; and (d) for the disclosure year from 1 July 2014 to 30 June 2015, $278.4 million, adjusted for any disparity between the forecast CPI and the actual CPI.	n/a
5.4	Information requirements relating to forecast MAR updates	-
5.4(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.4 for Transpower's forecast MAR updates.	-
5.4(2)	Transition year: No forecast MAR updates apply.	-
5.4(3)	Remainder period:	-
5.4(3)(a)	an update to each of the future forecast MARs in the remainder period in Schedule F, calculated in accordance with the building blocks in Schedule D and the forecast MAR calculation model in order to reflect the revenue impact of major capital expenditure approved by the Commission; and	Appendix A.4
5.4(3)(b)	for each update under subclause (a):	-
5.4(3)(b)(i)	identification of each major capital expenditure project approved by the Commission in the disclosure year if the project is forecast to be commissioned during the period from 1 July 2012 to 30 June 2015; and	Section 3.4
5.4(3)(b)(ii)	for each such project, separately detailing the forecast date that the project will be commissioned and the incremental revenue impact of the project on each applicable future forecast MAR.	Section 3.4

Clause	Information or action required	Demonstration of compliance
5.4(3)(c)	for each update under subclause (a), use as the operating expenditure allowance: (i) for the pricing year from 1 April 2013 to 31 March 2014, $281.2 million; and (ii) for the pricing year from 1 April 2014 to 31 March 2015, $287.9 million; and	n/a
5.4(3)(d)	for each update under subclause (a), use for each relevant pricing year the approved base capital expenditure: (i) for the disclosure year from 1 July 2011 to 30 June 2012, $208.6 million; and (ii) for the disclosure year from 1 July 2012 to 30 June 2013, $301.9 million; and (iii) for the disclosure year from 1 July 2013 to 30 June 2014, $244.9 million; and (iv) for the disclosure year from 1 July 2014 to 30 June 2015, $278.4 million.	n/a
5.5	Information requirements relating to quality measures and targets	-
5.5(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.5 for Transpower's quality measures and targets.	-
5.5(2)	Disclosure year from 1 July 2011 to 30 June 2012: (a) actual performance for each of the quality measures in clauses 4.1(1)(a)-(d); (b) reasons for any failure to meet the quality targets specified in clauses 4.2(1)(a)-(c); (c) for all interruptions over 1 system minute, a report that sets out: (i) the reason or reasons for the interruption; (ii) Transpower's response to the interruption; (iii) any change to Transpower's policies as a result of the interruption; and (iv) the impact of the interruption in system minutes.	n/a

Clause	Information or action required	Demonstration of compliance
5.5(3)	Disclosure years in the period 1 July 2012 to 30 June 2015: (a) actual performance for each of the quality measures in clauses 4.1(1)(a)-(d); (b) reasons for any failure to meet the quality targets to be specified in clause 4.2(2); (c) for all interruptions over 1 system minute, provide a report that sets out: (i) the reason or reasons for the interruption; and (ii) Transpower's response to the interruption; and (iii) any change to Transpower's policies as a result of the interruption; and (iv) the impact of the interruption in system minutes.	The Commission has specified a set of measures and target performance levels. The following table compares actual performance against the targets. Table 25 and Section 7.2
5.6	Information requirements relating to quality incentive mechanism	-
5.6(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.6 for Transpower's quality incentive mechanism.	-
5.6(2)	Disclosure year from 1 July 2011 to 30 June 2012: (a) the impact that Transpower's actual performance would have had on Transpower's forecast MAR under the quality incentive mechanism outlined in clause 5.6(2)(b), had that quality incentive mechanism applied to Transpower's forecast MAR in the relevant pricing year; (b) Transpower must use the targets, caps, collars and weightings for each quality measure as set out in the following table: [...]	n/a

Clause	Information or action required	Demonstration of compliance
5.6(3)	Disclosure years in the period 1 July 2012 to 30 June 2015: (a) the impact that Transpower's actual performance would have had on Transpower's forecast MAR under the quality incentive mechanism outlined in clause 5.6(2)(b), had that quality incentive mechanism applied to Transpower's forecast MAR in the relevant pricing year; (b) Transpower must use the targets, caps, collars and weightings for each quality measure as set out in the following table: […]	Appendix A.6 Table 45 Appendix A.6 Figure 21 Appendix A.6 Figure 22
5.7	Information requirements relating to comparative years	-
5.7(1)	The information requirements referred to in clause 5.1 are as specified in this clause 5.7 for comparative years.	-
5.7(2)	Historical information, as specified under this clause 5.7(4), for the disclosure year and the prior four years	-
5.7(3)	Forecast information, as specified under this clause 5.7(4), for the remaining disclosure years in the regulatory period.	-
5.7(4)	Including information of the types set out in:	-
5.7(4)(a)	clause 5.2(3)(b)(i) and (ii), being both the historical and forecast information;	Table 17
5.7(4)(b)	clause 5.2(4)(a)(i), being the historical information only;	Table 9
5.7(4)(c)	clause 5.2(4)(d), being the forecast information only;	Table 10
5.7(4)(d)	clause 5.2(5)(a), being both the historical and forecast information;	Table 19
5.7(4)(e)	clause 5.2(6), being the historical information only;	Table 43
5.7(4)(f)	clause 5.2(8)(a) to (c), being the historical information only; and	Table 24
5.7(4)(g)	clause 5.5(2)(a), clause 5.5(3)(a) and clause 4.1(1)(a) to (d), being both the historical and forecast information.	Section 7.3

Clause	Information or action required	Demonstration of compliance
5.8	Independent assurance reports and certification requirements Transpower must provide to the Commission, at the same time it provides its annual compliance monitoring statement and associated information under this Part 5:	Appendices A.9, A.11
5.8(a)	a directors' certificate in respect of the annual compliance monitoring statement (and associated information) in the form specified in Schedule B; and	Appendix A.10
5.8(b)	an independent assurance report in respect of the annual compliance monitoring statement (and associated information) in the form specified in Schedule C, which may be qualified only if: (i) the auditor considers that the annual compliance monitoring statement or associated information fails to have been prepared, in any material respect, in accordance with this determination; and (ii) the independent assurance report explains with full reasons the respects in which the annual compliance monitoring statement or associated information so fails.	Appendix A.11

A.13 Annual notice compliance checklist

This appendix shows how the information in this report demonstrates Transpower's compliance with each part of the information request issued to Transpower by the Commission on 18 April 2013 under section 53ZD of the Commerce Act.

Table 48: Compliance cross-reference – s53ZD dated 18 April 2013

Clause	Information/Action Required	Demonstration of Compliance
7.1	a list of the base capital expenditure asset enhancement projects for which Transpower has submitted a major capex proposal to the Commission in the 2012/13 disclosure year, and the reduction in the approved base capital expenditure for RCP1 made in respect of the amount of major capex.	Section 2.3
7.2	for each approved major capex project where the last asset to be delivered by the project is not yet commissioned or, in the case of non-transmission solutions, the project has not yet reached its completion date as at 30 June 2013:	-
	7.2.1 for transmission investments, an update to the expected cost of each major capex project (P50) compared against the major capex allowance;	Section 3.1
	7.2.2 for non-transmission solutions, an update to the expected cost of each major capex project (P50) compared against the maximum recoverable amount;	Section 6.3
	7.2.3 an explanation for any material variance between the updated expected project cost and the expected project cost specified in the major capex project approval; and	Section 3.1
	7.2.4 the forecast completion date and an explanation for any material variance from the commissioning date assumption specified in the major capex approval.	Section 3.2
7.3	for each major capex project that was commissioned in the 2012/13 disclosure year:	Section 3.3
	7.3.1 commissioning date for assets commissioned under the project;	Section 3.3
	7.3.2 for transmission investments, actual major capex;	Section 3.3
	7.3.3 for non-transmission solutions, actual costs intended to be recoverable costs; and	Section 6.3

Clause	Information/Action Required	Demonstration of Compliance
	7.3.4 major capex project outputs achieved by the project.	Section 3.3
7.4	for each major capex project that was commissioned in the 2012/13 disclosure year, where there was a material variation in any of the components of the major capex project of the types listed in clause 3.3.3(5) of the Capex IM Determination:	Section 3.3
	7.4.1 explanations for any material variances between the actual commissioning dates of assets associated with the project and the forecast commissioning dates specified in the major capex project approval;	Section 3.3
	7.4.2 for transmission investments, an explanation for any material variance from the major capex that was forecast to be commissioned;	Section 3.3
	7.4.3 for non-transmission solutions, an explanation for any material variance from the forecast recoverable costs;	Section 6.3
	7.4.4 an explanation of any variance from the approved major capex project outputs;	Section 3.3
	7.4.5 a summary of lessons learned during and after completion of the project; and	Section 3.3
	7.4.6 an assessment of the amount of any cost efficiencies that Transpower considers it has achieved in the course of the project and explanations of the assumptions made in that assessment	Section 3.3
7.5	for each major capex project for which the major capex overspend adjustment in clause 3.3.7(1)(a) of the Capex IM Determination applies in the 2012/13 disclosure year:	Section 3.3
	7.5.1 Transpower's calculation of the major capex overspend adjustment for the project, calculated in accordance with clause B4(1) of Schedule B of the Capex IM Determination;	n/a
	7.5.2 the 'excess amount' for the project, as defined in clause B4(3)(a) of Schedule B of the Capex IM Determination;	n/a
	7.5.3 the adjusted major capex allowance for the project, as calculated in accordance with clause B4(4) of Schedule B of the Capex IM Determination; and	n/a
	7.5.4 the amounts for each project, as defined in terms *o*, *p, q,* and *r* in clause B4(4) of Schedule B of the Capex IM Determination;	n/a

Clause	Information/Action Required	Demonstration of Compliance
	7.5.5 a narrative explanation for the overspend; and	n/a
	7.5.6 a narrative explanation for any amount that Transpower considers should not be included in the major capex overspend adjustment, being item *r* in clause B4(4) of Schedule B of the Capex IM Determination, with the extent of narrative being appropriate to the amount of the overspend.	n/a
7.6	for each major capex project for which the major capex overspend adjustment in clause 3.3.7(1)(b) of the Capex IM Determination applies in the 2012/13 disclosure year:	n/a
	7.6.1 Transpower's calculation of the major capex overspend adjustment for the project, calculated in accordance with clause B4(1) of Schedule B of the Capex IM Determination;	n/a
	7.6.2 the 'excess amount' for the project, as defined in clause B4(3)(b) of Schedule B of the Capex IM Determination; and	n/a
	7.6.3 a narrative explanation for the overspend, with the extent of narrative being appropriate to the amount of the overspend.	n/a
7.7	for each major capex project for which the major capex project output adjustment in clause 3.3.7(2) of the Capex IM Determination applies in the 2012/13 disclosure year:	Section 3.3
	7.7.1 Transpower's calculation of the major capex project output adjustment for the project, calculated in accordance with the calculation in clause B5(1) of Schedule B of the Capex 1M Determination;	n/a
	7.7.2 Transpower's calculation of the capital expenditure amount for each project where the approved major capex project outputs were not met, in accordance with the definition in term t in clause B5(1) of Schedule B of the Capex IM Determination; and	n/a
	7.7.3 a narrative explanation of the reasons why the approved major capex project outputs were not met.	n/a

A.13.1.1 Update of forecast MAR for 2013/14 and 2014/15 pricing years

Table 49: Compliance cross-reference – "update of forecast MAR" part of s53ZD

Clause	Information/Action Required	Demonstration of Compliance
8	Transpower must calculate an update of the forecast MAR for the 2013/14 and 2014/15 pricing years in accordance with clause 5.4(3)(a) of the IPP Determination.	Appendix A.4
9	An update of a forecast MAR is not intended to be a full recalculation of the forecast MAR.	Appendix A.4
	Transpower must demonstrate the incremental revenue impact of the additional approved major capex and the EV adjustment, calculated for the affected building blocks on a consistent basis with the calculation of the forecast MAR as determined on 1 November 2011.	Appendix A.4
	The calculation is to be carried out on a basis that is consistent with the Commission's notice of 15 July 2011 and subsequent necessary amendments and clarifications.	-
10	The forecast opening RAB value at 1 July 2013 that is to be used in the applicable 2014/15 building block calculations is the opening RAB value used in determining the initial forecast MAR in Schedule F of the IPP Determination. This is not required to be updated to the actual closing RAB value that will separately be used in the calculation of the 2012/13 MAR wash-up.	n/a
11	No other amendments to the forecast MAR may be made apart from approved major capex and the EV adjustment relating to the 2012/13 MAR wash up.	Appendix A.4
12	The calculation must update the 2014/15 forecast MAR for the following major capex amounts up to 30 June 2013:	-
	12.1 new approved major capex proposals that were not included in the calculation of the forecast MAR set on 31 October 2012;	Appendix A.4
	12.2 amendments approved to the major capex allowance of an existing approved project included in the calculation of the forecast MAR set on 31 October 2012; and	n/a
	12.3 amendments approved to the commissioning date assumption of an existing approved project included in the forecast MAR set on 31 October 2012.	Appendix A.4

Clause	Information/Action Required	Demonstration of Compliance
13	The incremental revenue adjustments in the update of the forecast MAR for major capex must include the forecasts of the capital charge, depreciation and the regulatory tax allowance.	Appendix A.4
14	No adjustments are to be made in the update of the forecast MAR for changes in the timing assumptions for base capital expenditure.	-
15	No adjustments are to be made to the forecast MAR for any other forecast MAR building block.	-

A.13.1.2 Certification and supporting information

Clause	Information/Action Required	Demonstration of Compliance
16	Transpower must provide the Commission with a directors' certificate for the information provided in response to this notice in the format set out in Attachment 1, to be completed and signed by a minimum of two directors of Transpower. If the information required by this notice is provided in Transpower's annual compliance monitoring statement, this information requirement may be satisfied by inclusion of the relevant certification within an appropriately amended form of directors' certificate provided under clause 5.8(a) of the IPP Determination.	Appendix A.10
17	Transpower must provide copies of supporting work papers in respect of each of the calculations in the information, showing how the numbers have been calculated, identifying any significant adjustments to the numbers, referencing the sources of the data used, and identifying any material judgments or estimates made in applying the data with particular reference to any variations from Transpower’s internal approval processes.	-

A.13.1.3 References

Clause	Information/Action Required	Demonstration of Compliance
18	If Transpower uses any reference material other than that specified in this notice in its calculations, it must provide the Commission with a list of such reference material.	No other reference material used

A.13.1.4 Format

	Information / Action Required	Demonstration of Compliance
19	The numerical information requested in this notice is to be provided in electronic form in MS Excel file format with every formula intact, apart from cross-references to the TM1 database. The narrative information is to be provided in Adobe PDF format.	-
20	Transpower may elect to provide the information requested in this notice as part of its 2012/13 annual compliance monitoring statement. If the information is provided on this combined basis, the directors' certificate may be combined in suitable amended form with the applicable certification provided under the IPP Determination.	-
21	All information provided in response to this notice will be made publicly available on the Commission's website.	

A.13.1.5 Date and place of response

	Information / Action Required	Demonstration of Compliance
22	Transpower must supply the information requested in this notice by email to the following address: regulation.branch@comcom.govt.nz (Attn: Matthew Lewer) by no later than 5pm on 25 October 2013.	-

A.14 RCP2 compliance checklist

This appendix shows how the information in this report demonstrates Transpower's compliance with relevant parts of the information request issued to Transpower by the Commission on 2 July 2013 under section 53ZD of the Commerce Act.

Table 50: Compliance cross-reference – RCP2 part of s53ZD

Clause	Information/Action Required	Demonstration of Compliance
15	Please provide the following quantitative information:	-
15.1	a mapping of the cost categories used for opex as part of Transpower's RCP1 proposal onto opex portfolios and a list of all opex portfolios deemed to be identified programmes;	Not covered in this report
15.2	actual opex for each of the opex portfolios for each disclosure year from 2009/10 until the end of RCP1 for which actual opex is available;	Appendix A.8
15.3	forecast opex for each of the opex portfolios for all disclosure years from 2009/10 until the end of RCP1 for which actual opex is not available;	Appendix A.8
15.4	actual and forecast opex for each of the opex portfolios submitted as part of the RCP1 proposal for each disclosure year from 2009/10 until 2014/15; and	Appendix A.8
15.5	an explanation of any variances between the opex values provided for the same opex portfolios and disclosure year under paragraph 15.4 and under paragraph 15.2 or 15.3, where these variances are greater than or equal to: 15.5.1 10% of annual forecast opex for the relevant opex portfolios and disclosure year; or 15.5.2 a forecast annual opex spend of $750,000 in 2012/13 prices for the relevant opex portfolios and disclosure year.	Appendix A.8
18	Please provide the following information in relation to quality measures:	-
18.1	the actual performance for each quality measure and disclosure year from 2009/10 until the end of RCP1, where actual performance information is available;	Table 26

Clause	Information/Action Required	Demonstration of Compliance
18.2	the forecast performance for each quality measure and disclosure year for all disclosure years from 2009/10 until the end of RCP2, where actual performance information is not available;	Table 26
18.3	the variance between each actual performance figure for each quality measure provided under paragraph 18.1 and forecast performance figures for each quality measure submitted as part of Transpower's RCP1 proposal;	Section 7.5 Here "forecast performance" for RCP1 should be read as "target" for RCP1.
18.4	the variance between each forecast performance figure for each quality measure provided under paragraph 18.2 and forecast performance figures for each quality measure submitted as part of Transpower's RCP1 proposal;	Our forecast performance figures are always an average of the previous 5 years of actual performance. The difference requested here is therefore simply a statement of the change in actual performance over time.

Clause	Information/Action Required	Demonstration of Compliance
18.5	in relation to variances in quality measures provided under paragraphs 18.3 and 18.4: 18.5.1 an explanation of the reason for each variance; 18.5.2 an explanation of any forecast failure to meet quality targets in any disclosure year; 18.5.3 a calculation of the impact that Transpower's forecast performance would have on Transpower's forecast MAR under the quality incentive scheme outlined in clause 5.6(2)(b) of the IPP determination; 18.5.4 an explanation of any actions taken, being taken or proposed to be taken to meet or better forecast performance for each quality measure for RCP2; and 18.5.5 any further explanation required to explain remedial action taken to mitigate the failure to meet the quality targets for RCP1.	18.5.1: Section 7.5 18.5.2: Performance targets are an average of the previous 5 years of actual performance. As such we do not explicitly forecast to meet or to fail any target. 18.5.3: Section 7.6 18.5.4 & 18.5.5: n/a.