Response to IPP Draft Decision

Transpower New Zealand Limited

27 June 2014

Keeping the energy flowing




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Transpower New Zealand Limited The National Grid

EXECUTIVE SUMMARY

This submission responds to the Commerce Commission's draft decision[1] on our expenditure proposal for the 2015-2020 regulatory period (RCP2).

The Draft Decision was generally supportive of our proposal and the forecasting processes, governance approach, and customer consultation we used to develop it. Our original forecasts were developed to achieve our RCP2 objectives.[2] Achieving them will require material service improvements while meeting our challenging productivity targets. Our objectives were developed holistically, based on our proposed levels of investment.

The Commission has proposed material reductions to elements of our Base Capex and Opex, and adjustments to our service performance measures. We have considered issues raised by the Commission and its advisors and where possible have made revisions to our proposal.

In this submission, we:

- propose a revised Base Capex programme and an associated incentive mechanism (based on asset health and work volumes) to address concerns raised in the Draft Decision;
- express serious concerns about the Commission's proposed Opex reductions. In particular, we explain how the proposed reductions in Corporate Opex:
  - appear to be based on incorrect assumptions in the Strata report;
  - in practice, will have a direct and negative impact on our ability to deliver our RCP2 objectives contrary to the long-term interest of consumers; and
- explain why the proposed changes to our service performance measures are too severe and should not be adopted.

Our submission also addresses issues relating to the regulatory framework.

Constructive Engagement

We want to acknowledge the open and constructive engagement we have had with the Commission and its advisors. These interactions have fostered common understanding and transparency, and have resulted in some refinements to our proposal – as outlined below.

Revised Capex Forecasts

The Draft Decision raised concerns with some of our Capex forecasts. We have reviewed the relevant portfolios and considered the comments and concerns raised. We have revised our proposal as follows.

- **Replacement and Refurbishment (R&R) Capex:** we propose a set of asset health and volumetric based incentives to address concerns raised about deliverability risks, removing the need for the proposed 5% reduction from R&R Capex.
- **Substation Management Systems:** we propose a more gradual rollout of SMS technology, reducing our forecast RCP2 expenditure by $7.9m.

1 "*Setting Transpower's Individual Price-Quality Path for 2015-2020, Reasons for Draft Decision*", Commerce Commission, 16 May 2014, (Draft Decision).

2 These are explained in Chapter 2 of our Main Proposal (MP01).

- **Enhancement and Development (E&D) Capex:** we have undertaken a full review of the individual projects used to underpin our proposed E&D Capex. This has resulted in a revised programme with $24.4m less Capex than originally forecast.
- **IST Capex to support changes to the Transmission Pricing Methodology (TPM):** we accept that there is significant uncertainty over future TPM changes. Therefore, we accept the Draft Decision to remove associated ICT Capex of $15.1m. This should now be considered a "listed" (i.e. contingent) project for which funding would be approved if the Electricity Authority determines that a material change to the TPM is required during RCP2.

We feel confident that the revisions we propose will not undermine our ability to achieve our objectives and recommend that these revisions be adopted by the Commission.

Corporate Opex

The Draft Decision proposes an 'across-the-board' 10% reduction to Corporate Opex.[3] We have carefully considered the Draft Decision and the Strata report[4].

Our concern is that the proposed reductions are based on high level and/or incorrect assumptions in the Strata report. As demonstrated in this submission the proposed reductions would, in practice, significantly impact on our ability to achieve our RCP2 objectives to the detriment of consumers.

Impact of Reductions

In our assessment, a 10% reduction in Corporate Opex could only be achieved through significant reductions in a limited range of activities. This is because some of our costs (see below) are effectively 'fixed' while reductions to others would have unacceptable consequences.[5]

- A significant portion of Departmental Opex is directly related to the real-time operation and management of our Grid assets (e.g. the Grid Operating Centres). Reductions in these areas could lead to unacceptable increases in safety and reliability risks.
- Forecast insurance premiums are based on specialist, independent advice. Reducing these would simply transfer risk to consumers.
- We are effectively a 'price taker' for Ancillary Services costs, as we have little scope to influence them.
- Others are unavoidable costs of "doing business" (e.g. accommodation costs, audit, and regulatory assurance fees) that cannot realistically be reduced significantly.

As a result, a 10% 'across-the-board' reduction in Corporate Opex could only be achieved by reducing expenditure on asset management; network planning; and corporate support by 20-25%.

As proposed by the Commission, these cuts would need to occur from 'day-one' or, otherwise, the percentage reduction required would increase as these cuts were phased-in. This in effect requires immediate cuts to the affected areas.

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[3] Corporate Opex comprises: investigations, ancillary services, insurance and departmental (primarily personnel related costs). The personnel costs include all (non-capitalised) staff costs including the management and engineering staff that support field operations.

[4] *Technical Advisor Report on the Transpower New Zealand Ltd IPP Proposal for RCP2, Report to Commerce Commission*, Strata Energy Consulting Limited and Energy Market Consulting Associates, 12 May 2014.

[5] While the discussion here focuses on Corporate Opex, similar categories of spend can be identified in ICT Opex.

As detailed in our submission, such cuts would have significant implications for the efficiency of capital investment, heighten safety and reliability risks in the medium-term, and have a direct and negative impact on our ability to deliver our RCP2 work programme. They would also compromise our ability to meet our RCP2 performance targets. Our envisaged improvement efforts in RCP2 (e.g. RCP2 Initiatives) would need to be curtailed or discontinued. Reductions in customer and stakeholder service and reporting, including regulatory reporting would be felt immediately. The cuts would also seriously undermine the intended operation of the IRIS.

We know from past experience that reduced investment in our internal capability, particularly in key engineering and operating areas, leads to higher costs and inefficient delivery in the medium to long term. These costs can be many times greater than the initial cost 'saving' which compromised that capability.

Overall, we agree that finding efficiencies is vital, but in order to avoid adverse impacts for consumers, they must be genuine efficiencies. It is also critical to take account of the consequences of driving down costs.

Basis for Reductions

The Commission's Draft Decision to reduce Corporate Opex by 10% appears to be largely based on conclusions reached by Strata. However, as we explain in this submission the Strata report:

- is inconsistent with the Commission's position on the use of productivity adjustments (and the purpose of the IRIS) when it suggests reductions in anticipation of efficiency gains in RCP2;
- is based on a number of high level assumptions which, as we demonstrate in this submission, are not well founded or are in error; and
- includes no consideration of the impact of proposed reductions, including whether they would be in the long-term benefit of consumers.

The proposed reduction to Corporate Opex has been raised for the first time in the Draft Decision. As a result, we have not had an opportunity to provide the Commission with further information. We trust that the information we provide in this submission will enable the Commission to more fully understand the unintended impacts of the reduction, and to recognise issues with the associated analysis by Strata.

In our view, our proposed Corporate Opex would best ensure optimal outcomes for consumers and, accordingly, should be approved by the Commission.

ICT Opex

The Draft Decision proposed an 'across-the-board' 2% reduction to ICT Opex.

While superficially such a reduction may be seen as modest, we think that the proposed adjustment is not well supported by the analysis and justification provided.

Self-insurance allowance

The Draft Decision proposed removing our self-insurance provision. As set out in our proposal in December, this allowance plays a key role in the efficient mitigation of the risks we face as a network utility.

We intend to put in place an explicit mechanism to 'ring-fence' this funding. Risk Reinsurance Limited (RRL) is the logical vehicle for this and we will extend its remit to include identified self-insured risks. The Commission should approve the self-insurance provision set out in this submission.

Service Performance

The Commission commended our consultation approach on service performance and accepted all our proposed measures. Our original measures and targets were supported by our customers and the wider industry. The Draft Decision proposes material changes to some targets, and additional measures.

The proposed changes to our GP1 targets are too severe. Our proposed targets are already challenging and linked to a strong financial incentive mechanism. In our view the analysis does not support the change to the target. We propose more reasonable targets in Chapter 6. We are comfortable with removing the impact of AUFLS incidents.

The additional measures proposed should not be mandated. They would be of little, if any, benefit to customers, given the similar information already provided. We require flexibility during RCP2 to refine 'Other Measures'. These should be treated as customer-service improvements rather than codified compliance requirements.

Form of the Individual Price-Quality Path (IPP)

The Draft Decision sets out the proposed form of the RCP2 IPP and potential amendments to the associated Input Methodologies. We are generally supportive of the proposals but propose improvements in four key areas.

- **Catastrophic events:** we provide drafting to improve and clarify the test for establishing whether an event is 'catastrophic'.
- **High-uncertainty capital projects:** we support the 'listing' mechanism for large re-conductoring projects and propose refinements to avoid unintended incentive outcomes.
- **Consumer Guarantees Act (CGA):** we propose that indemnity costs should be treated as 'recoverable' to reduce overall costs for consumers, while supporting the objectives of the CGA.
- **Base Capex allowance:** we reiterate the benefits of an expenditure-based (rather than a commissioned-based) allowance.

Conclusion

As noted above, our original forecasts were developed to achieve our RCP2 objectives. We are confident that the revisions made to Base Capex will not undermine our ability to achieve these objectives. However, Opex reductions of the scale proposed in the Draft Decision would have significant implications for risk management in the medium-term and our long-term efficiency. They would have a direct and negative impact on our ability to deliver our RCP2 programme.

To deliver our objectives, and promote the long-term benefit of consumers, we need to invest in our people – particularly in key engineering and operational areas. These are essential investments that will, over time, deliver increased value to consumers.

REVISED EXPENDITURE PROPOSAL

The following tables set out our revised expenditure in those expenditure areas that were subject to proposed reductions in the Draft Decision. There may be minor variances in figures due to rounding.

Table 1: Revised Base Capex during RCP2 ($m real 2012/13)

Capital Expenditure	Original Proposal	Draft Decision	Revised Proposal
Enhancement and Development < $20m	123.8	56.6	**99.4**
TL and ACS Replacement and Refurbishment	683.5	649.3	**683.5**
Substation Management Systems	47.2	35.0	**39.3**
ICT Capex (Transmission Pricing Model)	15.1	0	**0**
ICT Capex (Other)	188.6	183.9	**188.6**
Total Base Capex	**1,188.6**	**1,055.3**	**1,141.1**

Table 2: Revised Opex during RCP2 ($m real 2012/13)

Operating Expenditure	Original Proposal	Draft Decision	Revised Proposal
ICT	241.2	236.4	**241.2**
Departmental	417.6	375.9	**417.6**
Investigations	54.3	48.9	**54.3**
Ancillary Services	16.5	14.8	**16.5**
Insurance	75.8	68.2	**75.8**
Self-Insurance	12.1	0.0	**12.1**[6]
Demand Response Platform	10.3	1.5	**8.0**
Total Opex	**1,319.6**[7]	**1,237.5**	**1,317.3**

6 In the event that the Commission does not allow CGA indemnity costs to be recoverable, we would need to add a premium for CGA, of $0.2m per annum, to our Self-Insurance allowance.

7 This total represents our original Opex Proposal of $1,309.3m plus $10.3m for demand response (see Issues Paper).

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Table of Contents

1. INTRODUCTION

This document sets out our response to the IPP draft decision[8] (Draft Decision) published by the Commerce Commission (Commission) on 16 May 2014.

1.1. Process to Date

We submitted our original proposal[9] (Main Proposal) together with supporting information on 2 December 2013. This set out our proposed capital expenditure (Capex), operating expenditure (Opex) and service performance targets for the five year regulatory control period, 1 July 2015 to 30 June 2020 (RCP2).

Following the Commission's initial review of the proposal we provided further explanation and justification for our forecasts through a series of workshops, and by responding to a set of formal information requests. Some of the issues addressed included:

- detailed explanation and 'walk-throughs' of our cost estimation and forecasting systems;
- information outlining our internal challenge rounds; and
- further detail on the cost savings we have incorporated into our forecasts.

The engagement process included an issues paper[10] (Issues Paper). In our response[11] to this we:

- emphasised the importance of taking a holistic view of our proposal;
- set out the rationale behind our approach to Opex productivity;
- explained why our Service Performance consultation process was appropriate; and
- reiterated the need to consider the impact of adjustments on other elements of the proposal.

Following these reviews the Commission published its Draft Decision and supporting material from its advisors.

[8] *Setting Transpower's Individual Price-Quality Path for 2015-2020, Reasons for Draft Decision*, Commerce Commission, 16 May 2014.

[9] Our original submission is available here.

[10] *Invitation to have your say on Transpower's individual price-quality path and proposal for the next regulatory control period: Issues Paper*, Commerce Commission, 10 February 2014.

[11] *Transpower Response to IPP Issues Paper*, 3 March 2104, is available here.

1.2. Document Structure

The remainder of this document is structured as follows.

Chapter 2	**Overview of our Response** This chapter sets out our general response to the Draft Decision and highlights key issues.
Chapter 3	**Grid Expenditure** This chapter addresses the proposed reductions to our Grid Capex.
Chapter 4	**ICT Expenditure** This chapter addresses the proposed reductions to our ICT Capex and ICT Opex.
Chapter 5	**Corporate Opex** This chapter addresses the proposed reductions to our Corporate Opex.
Chapter 6	**Grid Output Measures** This chapter sets out our proposed Asset Health incentive mechanism and responds to proposed changes to our Service Performance Measures.
Chapter 7	**Regulatory Framework** This chapter discusses our key concerns with proposed amendments to our regulatory framework.

We have provided the following supporting documents.

- *Cost escalation forecasts: frameworks, forecasts and forecast methods*, NZIER, June 2014 (NZIER)
- *E&D Base Capex: Response to Draft Decision*, Transpower, May 2014
- A set of revised E&D PODs
- *Development of Demand Response as a Transmission Alternative*, June 2014 (DR Response)
- *Substation Management Systems – Business Case*, May 2014.
- Asset Health and Volume-based Incentive Regime
  - MD14 – Model – Outdoor Circuit Breakers – RCP2 Programme
  - MD15 – Model – Power Transformers – RCP2 Programme
  - MD16 – Model – Tower Painting – RCP2 Programme
  - MD17 – Model – Asset Health and Volume Delivery Incentive Regime
- Revised financial schedules
- An example demonstrating cash-flow adjusted revenue calculations

Unless stated otherwise all figures in this document are presented as **real (2012/13) expenditure**.

2. OVERVIEW OF OUR RESPONSE

This chapter sets out our general response to the Draft Decision and discusses the following issues.

- **Summary of Revised Proposal** sets out our revised expenditure forecasts.
- **RCP2 Expenditure** explains how the proposed expenditure reductions would impact our activities during RCP2.
- **Basis for Expenditure Assessment** highlights key concerns with the approach used to justify proposed expenditure reductions.
- **Service Performance** summarises our response to proposed service performance changes.
- **Asset Management** provides an update on our asset management improvements.
- **RCP2 Initiatives** sets out our views on proposed RCP2 Initiatives.
- **Forecasting Methodology** responds to concerns raised in the Draft Decision.
- **Expenditure Governance** reiterates that our forecasts have undergone thorough internal review and include challenging productivity targets.
- **Deliverability** responds to concerns raised on the deliverability of our RCP2 plan.
- **Changes to Regulatory Framework** sets out our views on proposed changes to the IPP framework.

2.1. SUMMARY OF REVISED PROPOSAL

This section provides an overview of our revised expenditure forecasts and their impact on our overall allowances. There may be minor variances in figures due to rounding.

2.1.1. REVISED EXPENDITURE

The following tables summarise our revised expenditure for RCP2. They set out expenditure areas subject to proposed reductions.

Table 3: Revised Base Capex during RCP2 ($m)

Capital Expenditure	Original Proposal	Draft Decision	Revised Proposal
Enhancement and Development < $20m	123.8	56.6	**99.4**
TL and ACS Replacement and Refurbishment	683.5	649.3	**683.5**
Substation Management Systems	47.2	35.0	**39.3**
ICT Capex (Transmission Pricing Model)	15.1	0	**0**
ICT Capex (Other)	188.6	183.9	**188.6**
Total Base Capex	**1,188.6**	**1,055.3**	**1,141.1**

Table 4: Revised Opex during RCP2 ($m)

Operating Expenditure	Original Proposal	Draft Decision	Revised Proposal
ICT	241.2	236.4	**241.2**
Departmental	417.6	375.9	**417.6**
Investigations	54.3	48.9	**54.3**
Ancillary Services	16.5	14.8	**16.5**
Insurance	75.8	68.2	**75.8**
Self-Insurance	12.1	0.0	**12.1**[12]
Demand Response Platform	10.3	1.5	**8.0**
Total Opex	**1,319.6**[13]	**1,237.5**	**1,317.3**

2.1.2. RCP2 Opex Allowance

The table below sets out our Opex forecast in real terms and the proposed RCP2 Opex allowance in nominal terms (i.e., inflated by CPI and RPE)[14].

Table 5: Revised RCP2 Opex Allowance ($m)

Opex ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Opex (Real)	264.6	265.5	266.6	262.2	258.5	1,317.3
Proposed Opex Allowance (Nominal)	**283.8**	**290.6**	**297.7**	**298.9**	**300.8**	**1,471.9**

2.1.3. RCP2 Base Capex Allowance

The table below sets out:

1. our revised Base Capex in real terms;
2. nominal Base Capex following inflation adjustment (for example, inflated by CPI and RPE);
3. nominal Base Capex on a commissioned basis;
4. top-down productivity adjustment of 7.5%; and
5. proposed RCP2 Base Capex allowance.

12 In the event that the Commission does not allow CGA indemnity costs to be recoverable, we would need to add a premium for CGA, of $0.2m per annum, to our Self-Insurance allowance.

13 This total represents our original Opex Proposal of $1,309.3m plus $10.3m for demand response (see Issues Paper).

14 Consumer Price Index (CPI) and Real Price Effects (RPE).

Table 6: Revised RCP2 Base Capex Allowance ($m)

Base Capex ($m)	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Base Capex (Real)	237.8	250.3	237.1	216.9	199.1	1141.1
Base Capex (Nominal)	260.4	280.7	272.7	254.2	237.9	1306.0
Base Capex (Nominal, Commissioned)	260.6	276.0	268.0	252.7	234.5	1291.7
Productivity Adjustment (Nominal, Commissioned)	-20.2	-20.2	-15.9	-16.9	-16.3	-89.5
Proposed Base Capex Allowance (Nominal, Commissioned)	**240.4**	**255.8**	**252.1**	**235.7**	**218.2**	**1,202.2**

2.2. RCP2 EXPENDITURE

The Draft Decision proposed significant reductions to our RCP2 expenditure. The majority of these reductions apply to broad expenditure categories (e.g. Corporate Opex). Below we explain how these reductions (to Corporate Opex in particular) would impact our activities during RCP2.

2.2.1. IMPACT OF PROPOSED REDUCTIONS

The proposed reductions will have a direct impact on our day-to-day activities during RCP2. This includes restricting our ability to deliver our work programmes and achieve our RCP2 objectives.

The impact of the reductions would be exacerbated given the productivity targets that we have applied to Grid Capex, Grid Opex and ICT Capex in our proposal. The expenditure and performance objectives proposed in these areas represent ‘stretch’ targets that are predicated on further development of our planning and asset management capabilities.

Our capability improvements are unlikely to be achieved in conjunction with the proposed reductions in Corporate Opex (and Departmental Opex and Investigations in particular).[15] Specifically, as explained in Chapter 5, the proposed reductions will have to be achieved by making much more significant reductions in certain capability areas, resulting in the following impacts:

- personnel reductions equivalent to 61 staff in our planning, asset management and key support functions;[16]
- reduced ability to achieve our RCP2 service performance objectives[17];
- a need to reduce the scope of our Capex programmes, with the potential for increased asset-related risk;
- reduced flexibility when addressing system issues and network constraints;
- fewer investigations supporting optimal Capex/Opex trade-offs;
- reduced scope for investigating new innovations and improvement initiatives; and
- potential for reduced levels of support for critical ICT systems.

15 It should be noted that we considered applying similar adjustments to the remaining Opex categories however these weren’t pursued due to expected upward pressure in associated costs.

16 This would be in addition to the reduction of 24 full time equivalents included in the RCP2 proposal.

17 In particular, our ability to improve performance at “High Priority” and “Important” points of service.

Constraints caused by the proposed reductions will ultimately impact on our customers, leading to:

- reductions in customer service and stakeholder reporting, including regulatory reporting, which would be felt immediately; and
- over the longer-term, lower relative reliability and reduced Capex efficiency.

As set out below, the proposed reductions will also undermine the intended operation of the IRIS mechanism, ultimately negatively impacting on the extent of efficiency gains shared with consumers.

We know from past experience that reduced investment in our internal capability, particularly in key engineering and operating areas, leads to higher costs and inefficient delivery in the longer term. This is a problem for infrastructure utilities that are capital intensive, with extended development times and long-lived assets. Inefficient, low utilisation of assets due to reduced capability can lead to costs over the long-term that are many times greater than the initial cost 'saving' which compromised that capability.

We are only now beginning to achieve the performance in asset management and planning necessary to optimise value for consumers. It is important that core capability is not compromised as we enter an era where emerging technologies must be used aggressively to maximise asset utilisation and network performance.

We discuss these impacts in further detail throughout this submission.

2.2.2. EXPENDITURE LINKAGES

The components of our RCP2 proposal are interrelated and seek to minimise the whole-of-life costs of our assets: for example our preventive maintenance volumes reflect our proposed levels of R&R Capex. Adjusting expenditure, and thereby scope, of certain components (e.g. Investigations portfolio) will impact other activities (e.g. expansion of AHI). The proposed reductions will impact on the activities we plan to undertake to improve and develop our asset management capability.

The proposed reductions do not appear to have taken these linkages into account. There is no commentary on either the direct consequences of the proposed reductions or their impact on related expenditure areas. We emphasised these interrelationships in our original proposal and also highlighted it in our submission on the Issues Paper.

2.3. BASIS FOR EXPENDITURE ASSESSMENT

The Commission and its advisors undertook a review of our proposed expenditure and supporting information. The review included an assessment of our governance processes, samples of individual projects, and a review of our financial models, asset management data, cost estimation systems and supporting data.

The Draft Decision included a set of 'across-the-board' reductions that have been applied to full portfolios or groups of portfolios. These subjective reductions form the majority of the proposed reductions and, as noted above, are largely based on the Strata report.

As explained below and in Chapter 5, the Strata report:

- is inconsistent with the Commission's position (and the purpose of the IRIS[18]) where it suggests reductions should capture potential efficiency gains in RCP2; and

[18] Refers to the Incremental Rolling Incentive Scheme.

- concludes incorrectly and without basis that the benefits from the RCP1 Initiatives will reduce Corporate Opex materially compared to the forecasts included in our RCP2 forecasts.

The 10% reduction proposed by Strata is based only on high level and/or incorrect assumptions which we address in Chapter 5. In addition the Strata report does not consider the impact of the proposed reduction on consumers (summarised above in Section 2.2).

The Draft Decision appears to simply rely on the conclusions in the Strata report. There is a lack of any further detailed justification for the scale of reductions and an absence of commentary on either the direct consequences of the proposed reductions or their impact on related expenditure areas. Where provided, analysis and justification for adjustments is insufficiently detailed given the scale and impact of the adjustments.

We trust the information set out in this submission will assist the Commission and other stakeholders to better understand our limited ability to further reduce Corporate Opex and the practical consequences of such reductions.

Issues with the Strata report are discussed in greater detail in Chapter 5. Specific issues relevant to the Commission's reliance on the Strata report are highlighted below.

Use of a Productivity Adjustment

The Strata report concludes that a reduction of 10% to Opex reflects reductions that should be available from four listed areas, one being:[19]

> *"... extracting benefits from proposed business improvement initiated and investment in staff capability, retention and recruitment proposed to be undertaken in RCP2,"*

This position is directly inconsistent with the Commission's view that a productivity adjustment on Opex is not appropriate, and accordingly it does not provide a sound basis for the proposed Corporate Opex reduction.[20]

As efficiencies are achieved, prices in competitive markets will reduce over time, thereby sharing efficiency gains between the service provider and its customers. If a regulatory regime is to mimic this aspect of a workably competitive market, it is important for the regime to provide confidence to the regulated company that it will benefit from efficiency improvements. This ultimately benefits consumers as the efficiency improvements are shared.

The Commission has previously stated[21] that the IRIS incentive mechanism should drive Opex efficiency improvements over time. The IRIS is designed to mimic the operation of a workably competitive market by allowing us to retain the benefit of efficiency improvements for a limited period. These savings are subsequently passed through to customers through lower prices. However, if our Opex allowance already includes future efficiency improvements, the IRIS will not deliver outcomes that are consistent with a workably competitive market. In particular:

- if we achieve the assumed efficiency improvements, our share of the cost saving will be zero as prices already anticipate the achievement of these savings; and
- if we don't achieve the assumed efficiency improvements, the IRIS would require us to further reduce prices in RCP3. This is because the IRIS treats Opex above our allowance as an inefficiency that should be penalised.

Such outcomes are contrary to the intended operation and purpose of the IRIS.

19 Strata, paragraph 592.

20 Draft Decision, page 63.

21 *Input Methodologies (Transpower) Reasons Paper*, 22 December 2010, Commerce Commission paragraph 7.1.5.

As is clear from its report[22] Strata's proposed 10% productivity factor is precisely the type of forward-looking productivity assumption that the Commission considers should not apply. In particular, it is a speculative assessment of efficiency gains that have not yet been achieved. As explained above, it changes and undermines the incentive properties of the IRIS. The incentive effects are further diminished by the application of 'productivity' adjustments at the start of the period rather than as gradual reductions.

We note that the Commission does not refer to Strata's view that benefits can be extracted from RCP2 as a reason for the reduction in Opex. Nor does the Commission cite Strata's discussion of a "productivity factor" to be applied to our Opex forecasts. We assume this reflects the Commission's position that a productivity adjustment and/or anticipating efficiencies during RCP2 is not appropriate. It is of concern, therefore, that the Commission has nevertheless simply adopted the 10% reduction proposed by Strata without adjusting for this fundamental inconsistency.

Opex Categorisation

Seeking to understand the rationale for the reductions to our Corporate and ICT Opex categories has led us to the conclusion that they are, at least partially, driven by the perception that they are not directly related to Grid activities.

References to "Non-Grid" expenditure have featured in both the Issues Paper and the Draft Decision. We raised concerns about this approach in our response to the Issues Paper.[23] Below we provide further explanation of our Opex categories.

"Grid" vs. "Non-Grid"

The Draft Decision seeks to differentiate our Opex based on whether the expenditure supports our Grid activities. Ultimately all of our activities support the Grid and the delivery of transmission services.

Below we set out examples of activities deemed to be part of "Non-Grid" by the Draft Decision. All of these are intrinsically related to our Grid assets.

- Corporate Opex:
  - Non-capitalised engineering staff e.g. Grid planning, operations, asset managers and field staff
  - Regional operating centres
  - Ancillary Service payments
  - SCADA modelling
  - Maintenance management
- ICT Opex:
  - Asset management systems[24]
  - Telecom and security operations
  - Geographic information systems (GIS)
  - Outage management systems
  - SCADA maintenance

The potential for confusion around Opex categories is increased due to the inconsistent terminology used to refer to it in the Draft Decision and Strata report. We do not use a number of the terms referenced by the Commission and Strata (e.g., non-Grid Opex, routine Opex and non-network Opex).

[22] Strata, paragraph 592.

[23] Page 8 of our response to the Issues Paper.

[24] There are 65 ICT systems that support our asset management activities.

For clarity we have again set out the components of expenditure included under Grid Opex.

- **Grid Opex**: includes Opex that is outsourced to external service providers, including:
  - routine maintenance
  - maintenance projects
  - external technical training for field staff
  - outsourced field switching

We have explained the make-up of these expenditure categories in detail throughout our proposal. The attempts to distinguish between 'Grid' and 'Non-Grid' are unhelpful, and potentially misleading.

Potential for misunderstanding arises from a lack of consistency and using different terms to describe our expenditure. We remain concerned that such misunderstanding may have led to the Commission's reliance on the assumptions in the Strata report (without closer scrutiny of the basis for the assumptions) and, ultimately, its proposed Opex reductions.

At the very least, such inconsistency is unlikely to foster common understanding amongst stakeholders.

Level of Analysis

Reductions in forecast expenditure should be based on reasoned, factual analysis, rather than speculative or arbitrary efficiency factors. Using speculative assumptions from a single portfolio (Departmental) to adjust unrelated expenditure types (e.g., Ancillary Services) further undermines the approach used. This will create pressure to make cost savings in activities where such reductions are not warranted.

The use of 'across-the-board' reductions without factual basis is contrary to the disciplined approach the IMs are intended to foster, and undermines regulatory certainty. More importantly, it risks cost reduction decisions that may result in adverse outcomes for consumers.

Other issues with the Strata report, and the Commission's reliance on its conclusions, relate to incorrect assumptions around asset investigations and the application of the vacancy adjustment. These are discussed further in Chapter 5 together with our concerns regarding proposed reductions to Ancillary Services and Insurance.

2.4. SERVICE PERFORMANCE

The Draft Decision commended our consultation approach and subsequent development of Service Performance Measures and targets. These included a set of measures and targets for Grid Performance, Asset Performance and Other Measures[25]. The Draft Decision:

- accepted all of the proposed measures;
- proposed removing the impact of AUFLS incidents on our frequency of interruption measure (GP1) and amendments to a subset of the associated targets; and
- proposed three additional 'Other Measures'.

In principle, we are comfortable with removing the impact of AUFLS incidents. However, the proposed changes to GP1 targets are too severe and not readily achievable, undermining the effectiveness of the service performance incentives. We have proposed more reasonable alternative targets in Chapter 6.

[25] See Chapter 10 of our Main Proposal for details on the measures.

As set out in our response to the Issues Paper, we compiled a set of representative measures having considered the views of stakeholders. We believe the three further 'Other Measures' proposed will provide little additional benefit for customers given the information[26] we already provide. Moreover, they would be difficult to implement if the proposed reduction in Corporate Opex is adopted.

2.5. Asset Management

The Draft Decision recognised the improvements that we have made to our asset management approach. These have culminated in our application for PAS 55 certification – the audit for which we are currently undergoing.[27]

Notwithstanding our progress to date we agree there is scope for further improvement.

We had intended to continue developing our asset management capability to support our service performance and efficiency objectives during RCP2. These improvements and those suggested as potential RCP2 Initiatives will require significant internal resources and potential external advice and support. Our ability to undertake these improvements is likely to be significantly undermined by the proposed reductions to Corporate Opex.

2.6. RCP2 Initiatives

As discussed above we agree that there is scope for further improvement in our asset management approaches and other capability areas. Our asset management documentation sets out a series of such improvement initiatives. These correlate well with those suggested in the Draft Decision and together provide a basis for discussions on a new set of initiatives.

It should be noted that the extent and timing of any RCP2 initiatives will depend on both staff capability and their availability. As a result, our ability to undertake future initiatives would be undermined by the proposed reductions to Corporate Opex.

The suggested date of July 2015 for finalising an agreed set of RCP2 initiatives is appropriate, allowing us to take into account the implications of the final decision on our capacity to deliver further business improvements.

2.7. Forecasting Methodology

The Commission and its advisors reviewed our forecasting methodology in detail as part of their assessment process. In the sections below we respond to the main findings.

2.7.1. Need Case

In general, analysis supporting the Draft Decision agreed with the identified needs and options analysis undertaken as part of our forecasting process. A number of issues were raised in relation to our E&D forecasts and we have addressed these through updated justification material (see Section 3.2). We have also provided additional material supporting our decision to develop a Substation Management System platform.

26 We provide information equivalent to OM7 and OM9.

27 At the time of submission we are being formally audited by PAS 55 assessors.

As a more general comment, we believe that the deterministic approach (based on assessments of discrete projects) used to assess E&D expenditure is not wholly appropriate. Consideration of an 'expenditure envelope' in tandem with project-by-project reviews would better reflect the variable nature of E&D expenditure (over the medium-term).

2.7.2. COST ESTIMATION

Both the Draft Decision and Strata report include references to an "estimation bias" in our processes. As explained below, these discussions appear inconsistent and we are unsure to what extent, if any, they have influenced the proposed expenditure reductions.

The Draft Decision states "*we have concerns with estimation bias and the probability of projects rolling into RCP3. Consequently, we are proposing to reduce the expenditure by $34.2m to $649.3m*". The consideration of estimation bias is inconsistent with Strata's report which made its recommendation based solely on potential "roll-outs" from RCP2 to RCP3.[28]

The only evidence of aggregate bias presented by Strata is towards under-estimation of costs, "*Transpower has assumed a lower unit cost for its RCP2 budget than its most recent actual/forecast unit costs for that type of project*".[29] The Draft Decision's proposed reduction to R&R Capex is inconsistent with a bias towards under-estimation.

More generally, Strata acknowledge the progress made in improving our cost estimation approach stating that our "*cost estimation tools and processes appear to be on a path towards good practice*". In relation to our specification of unit costs and process for updating these, they concluded that there are "*no specific weaknesses*". They also state that if our cost estimation framework has been implemented as documented it is likely that our forecasts "*meet the expenditure criteria*".

In summary, we would be concerned if a perceived bias towards overestimation was a factor in the Commission's proposed reductions.

2.7.3. COST ESCALATION INPUTS AND ASSUMPTIONS

The Draft Decision accepted the majority of our cost escalation proposals. It proposed the following amendments.

- The Commission has sought views from interested parties on the approach used to forecast metals costs. We provide further information below.
- Removal of the foreign exchange exposure assumption for IST hardware and software cost escalation. We discuss this below.
- Replacing our proposed NZ dollar/ US dollar exchange rate forecast with forward exchange rates from Bloomberg. We are comfortable with this approach, subject to there being an appropriate mechanism that corrects for the differences between the forward exchange rates used to forecast RCP2 expenditure and the actual rates achieved.
- Amending the Capex IM definition of forecast CPI. The Commission is consulting separately on the associated amendment and we will engage with this process in due course.

[28] Page 58 of Strata states that the "data both for volumetric and non-volumetric projects does not provide unequivocal evidence for a cost estimation bias that would lead us to recommend a specific cost estimation-based adjustment".

[29] Strata, page 56.

Metals Cost Escalation Factors

While the Commission has provisionally agreed with the metal cost escalation factors we proposed, it is concerned that sharp changes forecast for some commodities have limited explanation.[30] They have sought submitter's views on this issue.

The indices used for our forecasts were derived by an external specialist consultancy, the New Zealand Institute of Economic Research (NZIER). NZIER set out the forecasting methods and indices in a paper[31] submitted as part of our original proposal. This paper stated that:

> *"The forecast method for metals prices used:*
>
> - *futures markets prices for copper and aluminium prices 1 to 2 years ahead (futures prices are not available for steel)*
> - *average consensus forecasts for*
>   - *steel prices*
>   - *copper and aluminium prices beyond futures market horizons*
> - *World Bank forecasts to forecast the World Bank metals and minerals price index."*

In response to the Commission's concerns NZIER has updated its paper to include further reasoning for their chosen methodology, including the following overview on the use of consensus forecasts.[32]

> *"The mid-point of consensus forecasts are used to forecast prices on the grounds that these reflect a variety of different perspectives and forecast methods and consequently embody more information and better formed expectations than the forecasts of a single forecaster"*

The updated NZIER paper is attached to this submission. We continue to believe that the cost escalation factors determined by NZIER reflect the most suitable method for forecasting metals costs over RCP2.

ICT Hardware

The Commission has proposed removing foreign exchange exposure from the 'IST Other (hardware and software)' ("IST Other") real price effects rate which applies to a proportion of our ICT portfolios. The Commission used the following rationale to justify the change:[33]

> *"Transpower has not provided sufficiently detailed reasoning to allow for foreign currency exposure in this cost category.*
>
> *In the absence of suitable justification we propose to remove the foreign currency exposure. Under our approach the real IST other (hardware and software) costs will be escalated by forecast CPI inflation, consistent with NZIER's report to Transpower."*

We disagree with the proposal to disallow the IST Other rate.

In our original proposal, the IST Other rate used to escalate a proportion of ICT costs was determined and provided by NZIER. The proportion of ICT costs escalated was determined from the products in each portfolio that are affected by, or tied to, exchange rates.[34]

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30 Draft Decision, Paragraph X21.

31 *Cost escalation forecasts: Frameworks, forecasts and forecast methods*, NZIER, October 2013.

32 NZIER, page 13.

33 Draft Decision, paragraph F21.

34 The proportion of ICT costs escalated by the IST Other rate are set out in 'RT04 - Inflation and Price Input Model', provided with our original proposal.

It includes Capex costs relating to:

- software licences (e.g. Oracle, Alstom, IBM Netcool); and
- large systems (e.g. telecoms equipment, SAN storage, virtualisation environments, Cisco networking products).

It includes Opex costs relating to:

- annual support of software (e.g. Oracle, InfoVista); and
- third level support and maintenance agreements with original equipment manufacturers (e.g., Cisco) where services are provided from off-shore.

In response to the Draft Decision NZIER has updated its paper to include the IST Other rate and to clarify the type of ICT expenditure that this rate should apply to. The updated paper states:[35]

> *"Products sourced directly or indirectly from overseas, where costs are tied to an exchange rate, also require adjustment to account for exchange rate movements, in addition to CPI indexation, as these products are exposed to potentially large exchange rate movements.*
>
> *Products which are exposed to potentially large exchange rate movements include specialised capital equipment, technical software and services supplied in conjunction with these products. International markets for these products are characterised by few suppliers and prices which are tied to prices denominated in currencies other than the New Zealand dollar."*

The IST Other rate and its application in our original proposal is consistent with advice originally provided by NZIER and now set out in its revised report.

We will have a significant volume of ICT transactions that are exposed to foreign exchange movements in RCP2. In order to recover these costs the IST Other rate provided by NZIER and used in our original proposal should be allowed.

2.8. EXPENDITURE GOVERNANCE

As set out in our Main Proposal, our RCP2 expenditure is based on detailed bottom-up forecasts that have been subject to a robust approvals process and a series of top-down challenges. During these reviews, our proposal was thoroughly challenged, both in terms of estimated cost and deliverability. This is evidenced by the series of reductions to both programme scope and associated expenditure.[36]

It should be noted that our internal approvals and challenge process:

- applied to all expenditure categories;
- made considered adjustments that aligned scope and expenditure within portfolios;
- resulted in material productivity improvement targets; and
- was commensurate with the scale and complexity of the expenditure.

Despite acknowledging the thorough nature of our internal challenges the Draft Decision seeks to apply further reductions to the resultant expenditure.

As discussed above, we consider the proposed reductions to be inappropriate as a number of the assumptions used to justify them are incorrect or inappropriate. This is particularly the case given our internal challenge processes and the productivity targets already included in our allowances.

[35] NZIER, page 13.

[36] This was set out in our response to a Commission's information request (Q004).

2.9. DELIVERABILITY

During the assessment process we discussed the deliverability of our RCP2 programme with the Commission and its advisors. This included discussions on specific portfolios (e.g. tower painting) and our approach to mitigating deliverability risk.

These risks have been used to justify a proposed 'across-the-board' adjustment to our AC Stations and Transmission Lines Capex. The Draft Decision and supporting material only include high-level discussions on deliverability, and provide no basis for the scale of the reduction, or its coverage.

We note the Commission may be receptive[37] to an incentive mechanism that links our proposed expenditure to our Grid Capex outputs including Asset Health[38].

2.9.1. BASIS FOR ADJUSTMENT

The Draft Decision states that *"A material difference between the grid capex programme that was delivered compared to what was submitted before RCP1 raises concern about delivery."* We believe this view is overly simplistic and does not take sufficient account of factors[39] that drive some variation. The presence of full substitutability under an IPP also limits the significance of historic variance.[40]

The Draft Decision states that *"the issue is not that the variations have occurred, rather the effect of these variations."* We agree with this statement but would expand it to also include the reasons for variations. However, in the absence of any discussion of the "effect" (or reasons) it is surprising that the Draft Decision proposes a significant, 'across-the-board' reduction on the basis that variations may occur.

We agree that *"reduced spending can be seen as positive so long as it is efficient and not detrimental in achieving network performance targets."* The basis for the proposed reduction appears at odds with this view given the use of an incentive regime that underpins our network performance.

There is limited forward-looking analysis to support the view that deliverability will be a significant issue during RCP2. In our view, there will be a number of factors during RCP2 that will support the successful delivery of our programme, most notably:

- a reduced level of Major Projects will increase the availability of service providers;
- our proposed incentives linking asset health and delivery performance to revenue will support our R & R programme;
- our proactive development of tower painting resources; and
- the increasing maturity of our R&R programmes incorporating improved practices and planning.

Reflecting the above factors we are confident that we will deliver our RCP2 programme and believe that the deliverability based reduction should be removed. As noted above, our ability to deliver our RCP2 programme is likely to be significantly compromised if the reductions to Corporate Opex are adopted.

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37 Draft Decision, paragraph 5.38.

38 We define Asset Health and associated measures in our original proposal.

39 The Draft Decision (page 57) lists such factors.

40 Notwithstanding this point, we have provided the Commission and Strata with detailed explanations and justification for the variances that occurred during RCP1.

2.10. CHANGES TO REGULATORY FRAMEWORK

The Draft Decision sets out the proposed form of the RCP2 IPP and potential amendments to the associated Input Methodologies. We are generally supportive of the proposals but have concerns in four key areas.

To address our key concerns, we propose the following improvements:

- revised wording to remedy the test for determining whether an event is 'catastrophic';
- refining the 'listing' mechanism for large or highly uncertain capital projects;
- defining Consumer Guarantees Act indemnity costs as 'recoverable' to reduce overall costs for consumers, while preserving the intended properties of the indemnity; and
- changing to an expenditure-based allowance for Base Capex to improve efficiency.

3. GRID EXPENDITURE

The Draft Decision imposes a reduction of $113.6m on our proposed Grid Capex. This includes a reduction of $46.4m to Replacement and Refurbishment (R&R) portfolios and $67.2m for Enhancement and Development (E&D).

We have already set challenging cost reduction targets. The lower level of expenditure can only be achieved by significant scope reductions.

As discussed in Section 2.1, reductions of this significance would impact:

- our capacity to maintain Asset Health and achieve our RCP2 service performance objectives;
- our flexibility to address changing circumstances on the Grid; and
- our ability to provide an appropriate service to our customers and meet their requirements.

Following our robust challenge process and the application of our productivity adjustment we believe that these further reductions are unwarranted.

The remainder of this chapter addresses the proposed reductions to Grid Capex, both R&R and E&D.

3.1. REPLACEMENT AND REFURBISHMENT

The Draft Decision proposes a significant reduction to our R&R programme during RCP2. This is based on an 'across-the-board' reduction to 21 portfolios across our Transmission Line and AC Station assets.

In addition there is a separate reduction to our proposed substation management systems (SMS) programme. Our response to the proposed reductions is set out below.

3.1.1. GENERAL REDUCTION

The Draft Decision proposes a 5% reduction across our Transmission Line and AC Station Capex. This equates to a reduction of $34.2m. We note the Commission may be receptive[41] to an incentive mechanism that links the scale of this reduction to Grid Capex outputs, including Asset Health, during RCP2.

As discussed in Section 2.3, we consider 'across-the-board' adjustments to be inappropriate. In addition, we have the following reservations on the proposed reduction as it relates to R&R Capex.

- It has been applied to 21 portfolios, each of which has different forecasting approaches and potential delivery risks.
- By applying our own 'productivity adjustment' we have already made a commitment to deliver efficiencies in Grid Capex.
- Our challenge round process already reduced the scope of our programmes to a prudent level.
- Constraining R&R programmes may lead to increased asset-related risk and the potential for deteriorating reliability for our customers.

For the above reasons, the proposed reduction to R&R Capex is inappropriate.

41 Draft Decision, paragraph 5.38.

Notwithstanding this view, and to address concerns raised in the Draft Decision, we propose to directly link the outputs of our R&R programme to revenue. We would do so using an incentive mechanism based on our performance delivering our Asset Health targets and planned replacement volumes.

For practical purposes, our proposal is focussed on our larger portfolios encompassing the majority[42] of our planned R&R Capex. Our proposal is set out in detail in Section 6.1.

On this basis, we propose that the reduction be removed.

3.1.2. Substation Management Systems

The Draft Decision proposes a reduction of $12.2m to our Substation Management System (SMS) portfolio. This reduction is based on a slower rollout through RCP2.

Strata accepted our assessment that our RTU fleet needs to be replaced by modern equivalent equipment. They questioned the pace of the deployment and elements of the needs case as set out in our original business case.

We have reassessed and updated the SMS business case based on feedback, including up-to-date delivery performance, from the ongoing RCP1 programme. This included a reassessment of the programme's overall benefits. Based on this analysis we believe a revised, less aggressive SMS rollout in RCP2 is acceptable.

The revised SMS programme lowers required Capex by $7.9m compared to our original proposal.

Substation Management System

Our existing telemetry fleet is based on Remote Terminal Units (RTU) that require replacement due to:

- 60% of the fleet approaching end of life;
- 30% of deployed RTUs no longer have the capacity to transfer the increasing volume of data required;
- 25% are obsolete and no longer supported by the manufacturer; and
- poor functionality of existing RTUs presents a significant safety issue due to inconsistent and poor situational awareness during field operations.

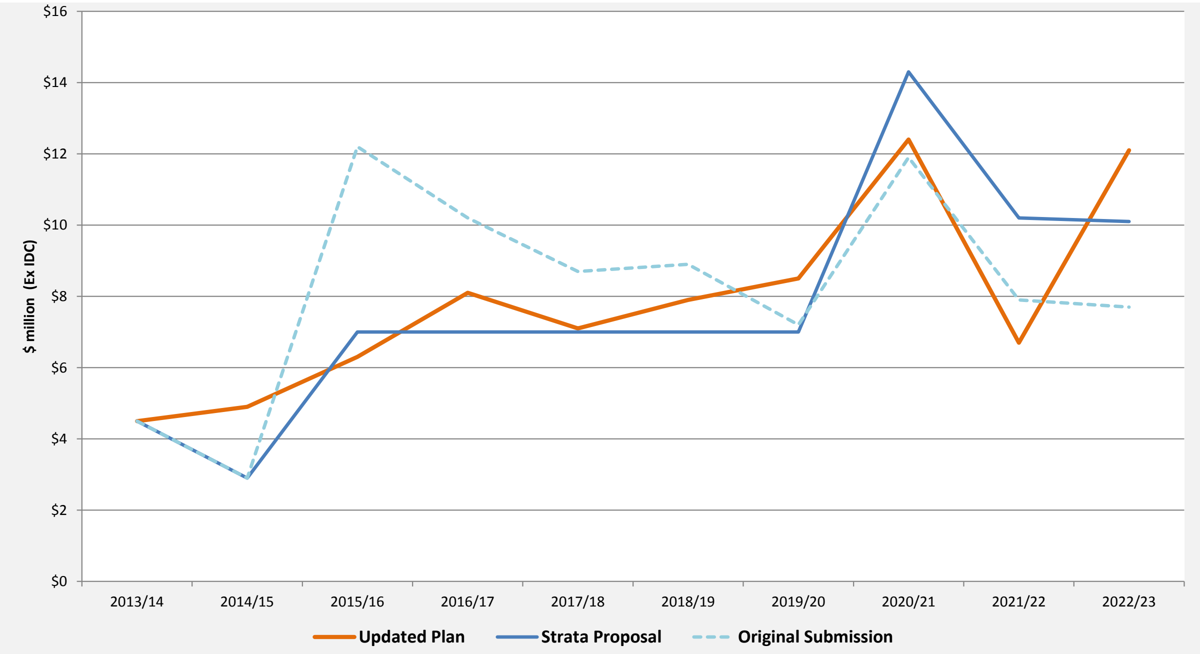
Our strategy is to replace RTU-based telemetry systems with SMS based systems. SMS allows for implementation of advanced remote engineering access, situational awareness at adjacent sites, improved resilience, and tolerance to faults on control systems. This approach has the highest net benefit relative to other replacement options.

Strata agreed with the need to replace these assets and proposed an alternative roll-out plan. We have reassessed our original roll-out plan based on robust, up-to-date information and our experience during RCP1. Based on this we have revised our approach and now propose a more conservative roll-out. This is based on 14 SCADA facing RTUs per year as opposed to 18 in our original plan.

The chart below compares the alternative expenditure profiles. Our original SMS deployment plan (dotted), Strata's proposal (blue) and our revised SMS deployment (orange).

Our revised approach is generally consistent with the expenditure proposed by Strata but reflects the practicalities of the roll-out (e.g., site size, relative priority, and number of RTUs per site).

[42] The six portfolios cover 68% of total expenditure subject to the proposed 5% reduction (on a nominal commissioned basis).



Our updated plan has been prioritised based on the following criteria:

- sites that have obsolete or end of life RTUs and those that have reached their processing capacity limit;
- those with limited functionality; and
- aligning work at sites with other protection projects.

Our updated forecast represents a practical roll-out at a similar scale to that proposed by Strata. It is based on robust and up-to-date information and uses experience gained from the roll-out to-date. As a result we are confident that it will be successfully delivered.

Our approach is described in further detail in the accompanying business case.

Supporting Material	Business Case

3.2. Enhancement and Development Projects

The Draft Decision proposed a reduction in our E&D[43] Capex from $123.8m to $56.6m. The combined reductions amount to $67.2m or 54% of our original forecast requirement.

A reduction of this size will restrict our ability to efficiently manage our E&D portfolio and to respond to changing circumstances on the Grid. This will increase the risk that we will not meet the Grid Reliability Standards at some points on the core Grid during RCP2. Lower levels of reliability would impact our Service Performance Measures as we would run a higher risk of interruptions particularly during maintenance.

Our assets, and the network in general, would have a higher risk of failure. This could have a direct impact on our customers if, for example, the System Operator had to manage customer load or constrain generation.

[43] Unless otherwise stated all references to 'E&D' relate to projects with expenditure less than $20m, and that form part of our Base Capex.

The remainder of this section:

- explains our concerns with the approach used to review E&D Capex;
- addresses concerns raised about our general forecasting and planning approach;
- discusses specific projects planned for RCP2; and
- sets out our revised E&D Capex for RCP2.

We have also prepared a supporting paper[44] in response to the Draft Decision and the Strata Report.

3.2.1. Approach to Reviewing our E&D Capex

The approach used to review our E&D Capex was based on an assessment of individual Project Overview Documents (PODs) leading to individual projects being either: accepted, amended, or declined. We believe that sole reliance on a deterministic approach, based on the assessment of discrete projects, is not appropriate as it does not adequately recognise the uncertainties involved in the associated expenditure drivers for E&D.

Estimating E&D Capex over a five year period is inherently uncertain. While we plan 10+ years into the future and identify issues and projects through our Annual Planning Report we do not make definitive decisions to invest until the investment need is relatively certain.

Reviewing projects purely on a case-by-case basis makes no provision for the following sources of uncertainty.

- Many E&D projects are dependent on third party decisions and can arise very quickly once third parties decide to connect new generation or load. We consider it likely that projects, not identified in our proposal, will be required during RCP2.
- System conditions and constraints will arise unexpectedly leading to a need to reprioritise our E&D expenditure.
- There is limited scope for effective substitution, as E&D projects address specific issues and can vary greatly in scope and value.[45]
- To maintain a degree of flexibility, it is often appropriate to delay finalising a preferred option until late in the E&D planning process, with potentially significant impacts on project cost.

We seek to manage this uncertainty by adopting a portfolio-based approach. This approach concentrates on the most likely projects but recognises that others will emerge, and that these may be higher priority. Changing circumstances may also lead to identified projects being deferred or brought forward

The projects that we used to build-up our E&D portfolio represented our best view, at the time of submission, of investment needs driven by forecast growth and security requirements during RCP2.

Project priorities and optimal solutions will inevitably change as new information becomes available and we complete more detailed investigations. It is neither practical nor cost-effective to complete exhaustive, detailed option investigations for projects many years in advance of an RCP submission.

For this reason, total E&D Capex is as important as the individual component projects. The proposed reduction in the Draft Decision restricts our ability to efficiently address actual system issues and constraints, and may leave us unable to adequately respond.

[44] *E&D Response to Draft Decision*, Transpower, May 2014.

[45] Whereas in an R&R portfolio substitutions will tend to involve reprioritising similar projects that address the same fundamental driver (e.g. Asset Health or fleet obsolescence).

3.2.2. GENERAL CONCERNS

The Draft Decision raised general concerns about our demand forecasting, and our needs identification and option analysis. We respond to these concerns below.

Demand Forecasting

Our demand forecasts were based on our 2013 APR. During the Commission's assessment process we provided information[46] on the impact of the updated 2014 APR demand forecast.

Our supporting paper[47] provides an explanation of our revised demand forecasting approach, and summarises the impact on our growth driven projects.

This includes opportunities to defer the following two asset interventions.

- Upper North Island Reactive Support (PD32): a lower regional demand forecast indicates that one of the new capacitors can be deferred to RCP3.
- Opunake and Te Awamutu (PD44): supply transformer works can be deferred to RCP3.

Need Identification and Option Analysis

Strata reviewed the needs identification and option analysis for each E&D project. We have responded to their project-specific concerns in our supporting paper. In addition, two general concerns were raised: a perceived lack of customer consultation on needs; and a lack of consideration of Special Protection Schemes (SPS) and Demand Response (DR) as alternatives to larger transmission investments.

We consult with our customers on an annual basis as we compile our APR. This includes customer's demand forecasts at their points of supply and their views on regional E&D investment needs. Our investment approval and planning process includes further consultation, and we continue to discuss our projects with customers as they progress through delivery.

We have included SPS and DR in our options analysis for a number of projects. SPS are a reasonably well established option for deferring investment but can be complex and expensive in some situations. We have also considered DR in some projects. However, we did not explicitly include the costs in our estimates because, under the Capex IM, DR expenditure cannot be included.

3.2.3. CONCERNS WITH SPECIFIC PROJECTS

We address the Draft Decision's concerns on individual projects, including revised costs, in our supporting paper. For some projects we have also submitted revised PODs.

Strata argued[48] that there is scope to substitute projects as it will be possible to delay some. We have reviewed the PODs to test the need dates for the projects. In some cases they could be deferred, but similarly there is justification to bring others forward. Whilst there may be some scope to substitute smaller projects, the proposed E&D allowance of $56.6m will seriously restrict our ability to introduce new projects, and effectively manage and prioritise existing projects.

Below we describe the main projects that the Draft Decision rejected (completely or partially) that, following a further and more detailed review, are most likely to be required during RCP2.

46 This was set out in our response to a Commission's information request (Q051).

47 *E&D Response to Draft Decision.*

48 Strata Report, paragraph 321.

Otahuhu-Wiri Transmission Capacity **$18.0m**

We will not meet the Grid Reliability Standards at Bombay and Wiri from 2014. An outage of one 110kV Bombay-Otahuhu circuit will cause the remaining circuit to overload at peak demand from 2014. Our current preferred option is to install an interconnecting transformer at Bombay with a tee connection onto one of the Huntly-Otahuhu circuits. In addition to meeting the Grid Reliability Standards, we expect this option to have significant loss-reduction benefits of around $0.9m a year, which further justifies the project's inclusion in RCP2.

Since our December submission we have completed a detailed option analysis[49] which includes expanded need analysis and comparison of options.

Supporting POD	PD30 Otahuhu-Wiri Transmission Capacity
Main Driver	Grid Reliability Standards

Bus Section Fault Reliability **$10.9m**

This portfolio improves reliability on three important 220 kV and 110 kV buses on the core Grid, these are: Haywards, Bunnythorpe and Mt Roskill. Following the investments, a fault on one of these bus sections will no longer result in a loss of supply. The Draft Decision proposes to decline the Mt Roskill investment.

Without investment at Mt Roskill we will not meet the Grid Reliability Standards. Further work will be required in RCP3. For this reason we need to undertake this project in RCP2.

Supporting POD	PD33 Bus Section Fault Reliability
Main Driver	Grid Reliability Standards

North Taranaki Transmission Capacity **$13.7m**

This project enables us to exit the New Plymouth site by 2018 with resulting cost savings and reduced system losses. It involves installation of a new interconnecting transformer at Stratford and conversion of the 220 kV New Plymouth-Stratford circuits to 110 kV. The new Stratford transformer would meet future peak demand in the area.

We have made significant changes to this project since our submission, taking into account discussions with the site owners, Port Taranaki, and economic analysis of our options for New Plymouth. The analysis indicates a net benefit of at least $2m, primarily from avoiding a planned $8m replacement of New Plymouth interconnecting transformer in RCP3, control room relocation, and condition-driven cable replacement, and loss benefits.

Supporting POD	PD37 North Taranaki Transmission Capacity
Main Driver	Economic benefit

49 Otahuhu-Wiri Transmission Capacity – Options Analysis.

Hororata and Kimberley **$3.4m**

This project will install a 27 MVAr capacitor bank on the Hororata 66 kV bus. The capacitor bank avoids the need to manage load at Hororata or to constrain on Coleridge generation. The Islington-Kimberly-Hororata circuits are not part of the core grid as defined in the Electricity Industry Participation Code. Any investment to mitigate the effects of an outage of one of these circuits needs to show a net market benefit.

We have prepared a revised POD which includes an indicative but conservative benefit of $6m NPV avoided lost load.

Supporting POD	PD31 Transmission Option to Relieve Generation Constraints
Main Driver	Economic benefit

3.2.4. Revised E&D during RCP2

Based on our reassessment of our programme using the most up to date information, we propose to reduce E&D Capex during RCP2 to $99.4m. We believe this will provide sufficient flexibility to respond to system needs as they arise.

Table 7 below summarises our revised Capex for each project.

Table 7: Revised E&D Projects for RCP2 ($m)

	Project	Original Proposal	Draft Decision	Revised Proposal	Revised POD
30	Otahuhu-Wiri Transmission Capacity	$18.5	$0.3	**$18.0**	✓
31	Relieve Generation Constraints	$16.7	$6.0	**$6.1**	
32	Upper North Island Reactive Support	$8.0	$8.0	**$8.0**	
33	Bus Section Fault Reliability	$13.9	$6.4	**$10.9**	✓
34	Wellington Supply Security	$11.4	-	**-**	
35	Otahuhu and Penrose Interconnection Capacity	$16.6	$11.0	**$10.9**	
36	Bunnythorpe Interconnection Capacity	$8.8	$8.8	**$8.8**	
37	North Taranaki Transmission Capacity	$3.0	-	**$13.7**	✓
38	Timaru Interconnecting Transformers Capacity	$2.5	$2.5	**$2.5**	
39	Southland Reactive Power Support	$6.0	$4.2	**$6.0**	
40	High Impact Low Probability Event Mitigation	$9.2	$9.2	**$9.2**	
41	Hororata and Kimberley Voltage Quality	$3.4	-	**$3.4**	✓
42	Islington Spare Transformer Switchgear	$2.4	-	**$0.5**	✓
43	Haywards Local Service Third Incomer	$1.8	-	**$0.6**	✓
44	E&D Other	$1.7	$0.3	**$0.85**	✓
	Totals	**$123.8**	**$56.6**	**$99.4**	

4. ICT EXPENDITURE

The Draft Decision proposes reductions to our ICT Capex portfolios of $19.7m and $4.8m across ICT Opex during RCP2.

This chapter sets out our views on the proposed reductions and the basis by which the reductions have been determined. It also discusses the potential effect on our ICT capability.

4.1. ICT CAPITAL EXPENDITURE

The Draft Decision proposes two reductions to our ICT Capex: an 'across-the-board' reduction of 2.5% to all portfolios ($4.7m), and the removal of the TPM replacement project ($15.1m).

4.1.1. GENERAL REDUCTION

The Draft Decision imposes a 2.5% "efficiency/prudency"[50] adjustment on our ICT Capex. This would apply in addition to our own 7.5% productivity adjustment. Again, for the reasons set out in Chapter 2 we consider this form of adjustment to be inappropriate.

Our proposal, incorporating a 7.5% productivity adjustment, is at a level that requires all proposed projects to be implemented at optimal efficiency. This is already a significant challenge.

The further reduction proposed would put undue pressure on the Capex programme, leading to cuts that may lead to our systems deteriorating, becoming more expensive to maintain and reduced levels of business capability.

As set out previously[51] our ICT Capex is based on a number of distinct drivers. These include:

- refresh/capacity expansion Capex allows us to maintain benefits from established systems;
- compliance and risk mitigation projects manage residual risk within the business; and
- cost saving/avoidance projects that seek to reduce our ICT Opex.

We would be reluctant to further reduce expenditure in our refresh/capacity expansion or compliance/risk mitigation projects. The bulk of any cost reduction would therefore likely fall on projects seeking to ensure effective Capex/Opex trade-offs. As discussed in Section 2.2, this form of short-term saving is likely to have negative implications in the longer term.

There does not appear to be a clear justification for a further 2.5% adjustment. Indeed, the proposed reduction has been applied despite the overall positive assessment of our Capex programme and forecasting process. For example, Strata concluded that:

- the link between strategic objectives and expenditure is sound;
- our strategy to switch to recognised 'off-the-shelf' ICT platforms and software is well established;
- our policy of staying within vendor support agreements is appropriate;

50 Strata, page 126.

51 This information was provided as part of our response to Commission information request Q053.

- the balance of spend towards maintaining capability rather than adding new capability is appropriate;
- our cost estimation approach is sound; and
- the programme is deliverable.

We believe this reduction is unwarranted as our programme is appropriate (a view supported by Strata's review), was subjected to robust internal and external challenge, and has already had a challenging productivity adjustment applied.

The main basis for the reduction is a perceived lack of benefits analysis. As Strata acknowledged[52] it is more difficult to estimate the costs and benefits of transformational ICT programmes than transmission system upgrades or replacements. The current rapid changes in technology make predictions over 3-5 year timeframes more difficult.

To mitigate against this, we manage risks and benefits at a whole of portfolio level as well as at a project level.[53] This ensures that over time aggregate benefits can be tracked and reported.

We are implementing improved benefits measurement and analysis, allowing for more detailed performance analysis. However, forecasting tangible benefits will continue to contain a level of uncertainty due to the variance in the technology landscape.

4.1.2. Transmission Pricing Methodology

The Draft Decision proposed a reduction of $15.1m to our IT Finance portfolio based on the removal of a proposed system upgrade to implement a major revision of the Transmission Pricing Methodology (TPM).

A major revision of the TPM has been the subject of a series of consultations by the Electricity Authority (EA). To implement the major changes in the signalled timeframe would require large ICT system investments during RCP2.

Strata commented that the timing and scope of the required changes are not certain at this time while acknowledging that the upgrade may eventually be necessary. We acknowledge that the need for an upgrade of this scale is contingent on major revision of the TPM and that these consultations are ongoing and protracted leading to a degree of uncertainty.

Therefore, we understand and accept the proposed removal. However, were this situation to change in RCP2 due to the decisions of the EA, and a confirmed timeline and scope to emerge, we would legitimately seek agreement from the Commission to recover the required expenditure before committing any expenditure. We think this is a reasonable compromise and would leave the Commission and the Authority to resolve the requirements and regulatory implications.

In the absence of the upgrade it will be necessary to invest in a lifecycle extension project. This may be commissioned in RCP2 and is estimated to cost in the order of $1.5m. There is no provision for this within our forecasts. The potential need to fund this work within the current forecast is made more onerous by the proposed 2.5% reduction.

[52] Strata, paragraphs 495-496.

[53] This information was provided as part of our response to Commission information request Q053.

4.2. ICT OPERATING EXPENDITURE

The Draft Decision proposes an 'across-the-board' 2% reduction across our ICT Opex portfolios. This equates to a reduction of $4.8m during RCP2. As discussed in Section 2.3, we consider this type of productivity adjustment to be inappropriate.

Similar to other areas of the Draft Decision the level of analysis presented does not, in our view, explain or justify the application or level of the proposed adjustment. In particular, we have the following reservations on the assessment approach used for ICT Opex.

- The adjustment is indiscriminately applied to portfolios with different drivers, some of which include material expenditure reductions compared with RCP1.
- Our decision to outsource data hosting to a service provider has increased Shared Services expenditure significantly (approx. $17m during RCP2). Strata viewed this approach as "a sound business decision".[54] To minimise the overall impact of this increase we have sought and achieved operational efficiencies in this and other portfolios.
- As set out in our response to the Issues Paper we negotiated significant savings to telecoms (TransGo) support and maintenance costs through renegotiation with our service provider. We also reduced our support costs for security services substantially limiting the forecast increases in the number of security devices now required to ensure safe operations.
- To illustrate that we are pursuing operational efficiencies we have set out additional information (below) demonstrating how our original Shared Service and Telecoms and Networking forecasts have already incorporated material cost saving targets. During RCP2 these represent an aggregate saving of $14.5m (approximately 6% of total ICT Opex).[55]

Table 8: ICT Opex – Example of Cost Saving Targets

Portfolio	Budget Item	2015/16	2016/17	2017/18	2018/19	2019/20
Telecomm & Networking	Telecom leased services	1.5	1.5	1.5	1.5	1.5
Shared Services	Support - Server Management	0.8	1.1	1.1	1.1	1.1
Shared Services	Software Licences - Other	0.2	0.4	0.4	0.4	0.4
Total Savings ($m)		**2.5**	**3.0**	**3.0**	**3.0**	**3.0**

- Strata speculate that there are opportunities for Opex savings by simply noting that contracts are being renegotiated. While we have successfully reduced support contracts during RCP1, the opportunity to realise further savings will depend on a number of factors, including:
  - prevailing market conditions;
  - the number of competing vendors; and
  - the role or criticality of the services.
- Strata raise no issues with the external benchmarking analysis that deems our Opex to be appropriate. This analysed our performance against peer institutions in New Zealand. Strata suggest that benchmarking with Australian transmission utilities would be of benefit. We note that the neither Strata nor the Commission pursued this approach.

54 Strata, paragraph 613.

55 The figures represent reductions compared to our 2013/14 budgets. Details of our ICT Opex savings were provided to the Commission as part of our response to Q032.

Our expenditure plans were subjected to robust internal challenge and external benchmarking. We assessed whether a productivity adjustment could be made to ICT Opex but concluded that upward cost pressure during RCP2 would make this approach inappropriate.

Our ICT Opex ensures that critical business functions are properly maintained and supported. The proposed reduction would undermine our ability to provide required service levels to the wider business.

5. CORPORATE OPEX

The Commission has proposed an 'across-the-board' 10% reduction to Corporate Opex (i.e. to each of Departmental Opex, Investigations, Ancillary Services and Insurance portfolios). The Commission uses the following rationale to justify the 10% reduction.[56]

- *" …extracting the full benefits of business improvement initiatives and investment in staff capability, retention and recruitment that were made in RCP1;*
- *a more rigorous focus on activity that enhances and improves the performance of the existing asset base compared with non-grid activities;*
- *eliminating the average vacancy rate from the Departmental cost assumption on the basis that there will always be a 3–5% active vacancy level;*
- *disallowing the proposed $6m opex for the proposed Wellington Head Office relocation and consolidation, as it is not supported by a business case; and*
- *reducing corporate services investigations allocation by 20% to $43.5m…"*

This largely replicates the findings in the Strata report although the Strata report included the following addition rationale:[57]

- *"...extracting benefits from proposed business improvement initiated and investment in staff capability, retention and recruitment proposed to be undertaken in RCP2,"*

We disagree with the proposed 10% reduction and the analysis and justification upon which it is based.

The remainder of this chapter:

- sets out the impact of the proposed reduction on our capabilities, future efficiency, and the impact on asset risk and reliability;
- describes how a reduction of this size would not promote the long-term benefit of consumers;
- demonstrates that Strata's (and the Commission's) assumptions and associated rationale (as set out above) are incorrect; and
- notes where the Strata report is inconsistent with the position of the Commission and the IRIS mechanism.

In addition to the 10% reductions the Commission has proposed removing the self-insurance allowance entirely. This is discussed in Section 5.7 of this chapter.

5.1. IMPACT OF PROPOSED REDUCTION TO CORPORATE OPEX

Our RCP2 proposal sets out the necessary expenditure required to achieve an appropriate transmission service for our customers in RCP2. Our Corporate Opex has been developed alongside Grid and ICT expenditure with the objective of reaching an optimal balance between Capex and Opex and delivering on our RCP2 objectives.

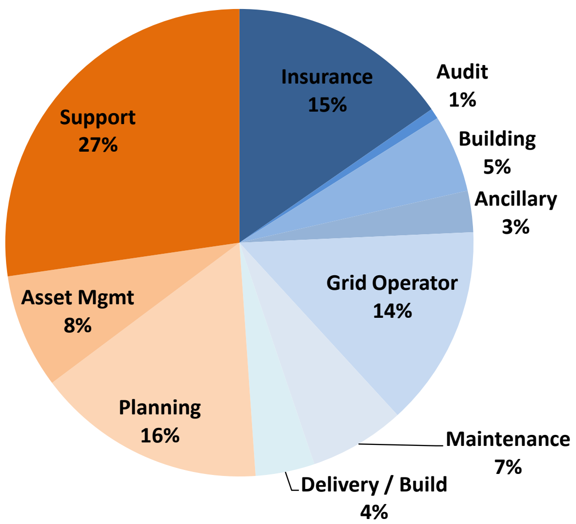
[56] Draft Decision, paragraph 5.67. Note that it is unclear from the Draft Decision whether the rationale set out in paragraph 5.67 applies to insurance premiums.

[57] Strata, paragraph 592.

Corporate Opex includes: the costs of the people that design, build, and operate the Grid; 'fixed' costs of doing business such as audit, insurance and building leases; and necessary support services including finance, treasury, legal and human resources.

The primary activities covered by Corporate Opex are depicted below.

Figure 1: Corporate Opex by Activity



A significant proportion of Corporate Opex is effectively 'fixed' or directly related to the day-to-day delivery and operation of the Grid. These are set out below. Expenditure in these areas cannot realistically be reduced significantly as doing so would lead to unacceptable risks to safety, reliability, and the deliverability of our Capex programme.

- **Grid Operator:** Activities directly related to the real time operation and management of our Grid assets.[58] Any reduction to these costs would lead to unacceptable increases in risks to safety and reliability.
- **Insurance:** Premiums based on specialist, independent advice from Marsh Actuarial. Reducing these costs would simply transfer risk to consumers.
- **Ancillary Services:** Payment for ancillary services, where we are effectively a price taker with little scope to influence the costs.
- **Grid maintenance:** Activities related to the management of our service providers including service delivery standards and policies.
- **Grid delivery:** The activities related to programme delivery that cannot be capitalised.
- **'Unavoidable' Costs:** The 'fixed' costs of doing business such as accommodation costs, audit and regulatory assurance fees that cannot be reduced significantly.

As a result, the effect of a 10% 'across-the-board' reduction in Corporate Opex could only be achieved by reducing our asset management, network planning, and corporate support services activities by 20-25%. In terms of headcount the proposed reduction would require a reduction of approximately 61[59] full time equivalents. As proposed, these cuts would need to occur from "day-one" or, otherwise, the percentage reduction required would increase as these cuts were phased-in.

58 For example our Grid Operating Centres were insourced in 2012 and now form part of Corporate Opex.

59 This would be in addition to our forecast reduction of 24 full time equivalents (FTE) (after capitalisation) by 2019/20 included in the RCP2 proposal. Regulated transmission headcount is forecast to reduce by 19 FTE during the last two

5.1.1. Affected Activities

We have undertaken an assessment of the activities that would have to be reduced or discontinued in RCP2 to achieve a reduction of this size. This included the associated impact on our ability to deliver a cost effective service. The activities and impact on the business include (*impacts are italicised for ease of reference*):

- **Grid Planning**: all long and medium term power system planning and outage coordination would need to be reduced. This would directly affect our ability to forecast and plan for changes to the grid resulting in a reactive approach to planning. Reduction in outage coordination would lead to inefficient allocation of the scarce outage resource, increased cancellations and associate re-work. *Over time capital costs would increase and there would be a potential decline in system reliability and overall reliability.*
- **ICT Planning**: The planning activities undertaken by in-house solution architects would need to be discontinued. This would directly affect the planning and continuity of the programme to separate the critical and non-critical systems; ICT design and approval process; and the selection of appropriate technologies through the RCP2 lifecycle investment programme. *Over time Capex would increase and wider operational support costs would be given less scrutiny putting at risk efficient expenditure in licensing, maintenance contracts and outsourcing.*
- **Performance and Condition Assessment**: Asset incident and failure investigations, asset condition and risk assessments and asset performance improvement work would need to be reduced. *Over time information used to manage asset incidents and make asset management decisions would degrade resulting in increasing in costs, potential decline in the health of our assets, and reduced service performance.*
- **Asset Information, Policy and Process Improvements**: Maintaining and improving the accuracy of existing as-built information, developing and improving quality control processes, ensuring operation and maintenance documentation is fit for purpose, and updating existing policies and standards based on environmental requirements would need to be reduced. This would lead to incomplete or incorrect information and processes being used to make operating and asset management decisions, resulting in an increase in non-standard, higher cost and less reliable work practices, increased risk of non-compliance, and an increased level of rework. *Over time this would impact our asset management capability resulting in a potential decline in the health of our assets and reduced service performance.*
- **Landowner Relations**: The landowner relations service would need to be reduced, limiting this to supporting individual capital projects. This would have a material impact on how we deal with landowners and land occupiers including lower levels of engagement, less flexibility to accommodate requirements, greater number of issues, and longer issue resolution time. *From experience we know that this would detrimentally impact on the access we require to maintain, operate, upgrade and build our transmission lines, substations and communications network, ultimately resulting in programme delays and increasing costs.*

5.1.2. Impact on Consumers

Reducing or stopping the above activities would reduce Corporate Opex and the net cost of transmission services in the short-term, but would have the following negative impacts on consumers:

years of RCP1 to 500 FTE (after capitalisation) at the start of RCP2 (note this reduction is not related to major projects). A further reduction of 5 FTE to 495(after capitalisation) is forecast to occur by 2019/20.

- increased Grid and ICT Capex in the medium term leading to an increase in prices;
- increased risk of asset failure and lower reliability in the long term, reducing our ability to improve service performance in line with customer expectations;
- reduced ability to plan and deliver our Capex and maintenance in a cost effective manner leading to a potential increase in prices; and
- constraining our ability to deliver improved customer service and further improvement initiatives .

We know from past experience that reducing investment in our internal capability, particularly in key engineering and operating areas leads to higher costs and inefficient delivery in the long term. These outcomes are not consistent with promoting the long term benefit of consumers.

Before reaching its final decision the Commission should consider the impact of any proposed reduction to Corporate Opex.

5.2. Issues with Commission's Conclusions

We agree with the Commission's conclusion that a general productivity adjustment should not be applied to Opex. This recognises that the proposed price quality path, including the IRIS incentive mechanism, provides continuous incentives to innovate and achieve productivity gains.[60]

In keeping with this view, any proposed reductions to Opex should be based on evidence that our 2014/15 expenditure levels and associated RCP2 forecasts are too high.[61]

Strata's review of Corporate Opex uses both anecdotal evidence and forecast productivity gains to justify a 10% reduction in corporate operating expenditure. Specifically, Strata label this 10% reduction a 'productivity adjustment'. Strata specifically refer to extracting benefits from proposed business improvement initiatives and investment in staff capability, retention and recruitment proposed to be undertaken in RCP2.[62]

It is evident from the above description that Strata's 10% productivity factor is the type of forward-looking productivity assumption that the Commission considers should not apply.

The Commission has removed any reference to Strata's 'productivity adjustment' and to the benefits from RCP2 business improvement initiatives in its Draft Decision. However, it is of concern that no corresponding adjustment is made to the 10% reduction recommended by Strata.

The Commission provides no explanation of the selective use of the Strata analysis or the change in focus from a productivity adjustment in the draft decision.

Notwithstanding the inconsistent use of Strata's analysis, a number of the remaining points used by Strata to justify a 10% reduction, and adopted by the Commission, are incorrect. These are discussed below.

5.3. Issues with Commission's Assumptions

As stated above, the Commission has largely replicated Strata's findings without further analysis or justification. In our view, these findings do not provide a good basis for the 10% reduction and risk adverse impacts for consumers.

[60] Draft Decision, paragraphs 5.68-5.71.

[61] Our forecasting approach used 2014/15 as a 'base year' for projecting RCP2 forecasts.

[62] Strata, paragraph 592.

As referred to above, the Strata report is inconsistent with the Commission's position on productivity adjustments and the IRIS mechanism.[63]

In addition, the Strata report incorrectly assumes that the benefits from initiatives in RCP1 will materially reduce Corporate Opex compared to our forecasts. Otherwise the report relies on high-level and incorrect assumptions or conclusions relating to "Non-Grid activities", application of the vacancy rate, asset investigations, and Wellington Head Office relocation.

The issues relating to total Corporate Opex are discussed below with those specifically related to investigations and the Wellington head office relocation discussed in sections 5.4 and 5.9 respectively.

5.3.1. BENEFITS OF BUSINESS IMPROVEMENT INITIATIVES

The Commission has referenced extracting the benefits from the RCP1 business improvement initiatives when justifying the 10% reduction to Corporate Opex, relying on the Strata report. It is incorrect to conclude that the benefits from the RCP1 initiatives will reduce Corporate Opex below the forecasts included in our RCP2 submission.

During RCP1, we have delivered a programme of business improvement initiatives focused on core areas of our business including: safety management, asset risk management, performance monitoring and cost estimation. The objectives, benefits and milestones for each of the RCP1 Initiatives were set out in the RCP1 Business Improvements Initiatives report provided to the Commission in March 2012.[64] We are planning to complete other initiatives in RCP2 that are a natural extension to the work undertaken in RCP1.

A summary of the RCP1 initiatives and associated benefits is set out below.

Table 9: RCP1 Initiatives

Initiative	Benefits Overview
Safety	Enhanced awareness of safety, reductions in serious injuries and asset damage, transparent data management
Asset Management	Improved risk and integrated asset management across the organisation
Asset Management Information System	Replace the maintenance management system resulting in a better understanding of the condition and performance of assets, improved works delivery through better scheduling and cost management tools, consistent work methods, works/stock management integration, reduced health and safety reporting costs
Asset Risk Management	Introduce a framework for identifying and assessing asset risk and implement control measures to identify areas for improvement in the management of grid assets, demonstrate effective management of asset risks
Asset Health Indices	Establish asset health indices for three fleets to provide a robust, consistent and readily accessible means of identifying, assessing and managing the health of assets
Asset Criticality Framework	Introduce an asset criticality framework to provide a consistent approach for the prioritisation of investments

[63] See also Section 2.3 above.

[64] *Business Improvement Initiatives,* Transpower, March 2012.

Network Performance Measures	Set long-term performance measures to provide a simple, clear and readily accessible means of monitoring and reporting the risks to, and the performance of, the supply of electricity transmission services
Maintenance Management	Align contracted service deliverables with our objectives and move towards condition-based risk maintenance to improve efficiency, including reduced site visits, reduced outages, better understanding of planned and unplanned work
Integrated Works Planning	Improve policies and processes for managing, monitoring and prioritising expenditure
Cost Estimation	Enhance cost estimating practices across the business
Procurement	Improvement plan and implement a new contract management system
Grid Operating Centres	Bring operations function in-house to improve capability and its integration with maintenance and make an overall reduction in operating costs

The majority of the initiatives reflect the ongoing enhancement of our approach to asset management and provide:

- a greater focus on the achievement of outcomes, linking those outcomes to expenditure and a more consistent and robust approach to the identification, assessment and management of asset health and risk;
- performance measures and targets for the level of grid reliability improvement in the medium and long term with the medium term measures directly linked to revenue;
- the application of a formal risk management system for grid assets, including the use of asset health, to determine and justify the link between required investment and the overall asset condition of the grid; and
- improved line of sight from the organisation's strategic plan through to asset management policy, asset strategies and objectives and asset management plans.

Collectively, the result is improved risk management (and service performance) and more efficient capital investment both in terms of dynamic efficiency (i.e. better investment decisions) and productive efficiency (i.e. delivering investments at lower cost). These outcomes are reflected in our proposed capital investment requirements and network performance expectations during RCP2.

The majority of the initiatives do not provide savings in Corporate Opex through RCP2. The one exception is the replacement of the asset management information system.[65] This project will deliver productivity improvements from health and safety reporting; more accessible works tracking and defect flagging; tighter coupling between financial systems and works management; and improved visibility of the linkage between work and outages. The benefits were quantified as $0.34m per annum and included in the forecasts contained in the RCP2 submission.

5.3.2. Reference to "Non-Grid" Activities

As part of its justification for the 10% reduction to corporate operating expenditure the Commission refers to Strata's finding that we should have *"a more rigorous focus on activity that enhances and improves the performance of the existing asset base compared with non-grid [sic] activities."*[66]

[65] Note that the insourcing of the grid operating centres results in a reduction in Grid Opex and an increase in corporate Opex with a net saving overall. These changes were included in the RCP2 forecasts.

[66] Draft Decision, paragraph 5.67.

Transpower's RCP2 proposal set out the necessary expenditure required to achieve reasonable service performance expectations for the national transmission grid. The proposal contains no "non-grid" activities. While the reference to "non-grid activities" may be open to misunderstanding, it is important to stress that there are no parts of our proposal unrelated to the grid and the delivery of the "transmission service".

The statement seems to be drawn from an assumption by Strata that our capitalisation rate is too low and that too many staff are involved in non-grid project work:[67]

> *"Given that Transpower staff book investigation expenditure to a separate regulatory opex category, at an average of about 26%, the capitalisation rate appears to be low.*
>
> *Our conclusion is that Transpower has too many staff involved in non-grid project (or investigations work) or it is not correctly booking time to capital projects."*

We disagree with the Commission's conclusion and with Strata's analysis of our capitalisation rates.

Analysis of the capitalisation and investigation (transfer) rates varies by division level based on the functions each division performs.

Table 10: Capitalised Salary Costs

Division	Transferred to Invex (%)	Capitalised (%)	Non Capital/Invex (%)	Total
Grid Projects	1%	83%	16%	100%
Grid Development	46%	23%	31%	100%
Grid Performance	2%	14%	84%	100%
ICT	9%	30%	61%	100%
Support	1%	5%	94%	100%
Total	**9%**	**26%**	**64%**	**100%**

The capitalisation rates reflect the functions undertaken by each division:

- **Grid Projects:** Capitalisation rate of 83% reflects its primary responsibility for delivering capital projects. It also provides the project management office and supply chain management services which are capitalised to the extent that they relate directly to capital project delivery.
- **Grid Development**: Investigation rate of 46% and a capitalisation rate of 23% as it is responsible for providing the initial investigations (across a number of options) that are expensed and the detailed investigations based on a chosen option that are capitalised. It also undertakes activities such as long-term network planning and provision of the cost estimation platform that cannot be capitalised.
- **Grid Performance**: Has lower levels of investigation and capitalisation rates as its primarily responsible for operating and maintaining the grid. It includes the grid operating centres, outage planning, grid skills training, geospatial and drawings management and general landowner relations most of which cannot be related to capital projects.
- **ICT**: Undertakes a mix of operational and capital related work. Staff (and specialist contractor) time is capitalised where this relates to capital projects.
- **Support groups**: Low levels of capitalisation as it is made up of divisions that provide functions that support the grid functions including finance, regulatory affairs, legal support, human resources, corporate affairs etc.

[67] Strata, paragraph 570-571.

In summary: all corporate operating expenditure relates to grid work directly or in support of the service delivery groups. Investigation and capitalisation rates vary by division based on the nature of the work undertaken. All capitalisation is undertaken in accordance with applicable accounting standards.

As set out in chapter 2, the term "*non-grid activities*" (and similar variants used in the draft decision material) is confusing and should not be used when discussing and analysing corporate operating expenditure. There is no expenditure related to "*non-grid activities*" and accordingly no need or ability to change our focus to grid activities in order to reduce our corporate operating expenditure.

5.3.3. Application of Vacancy Adjustment

The Commission states that an average vacancy rate should be eliminated from our departmental forecasts, given that there will always be a 3-5% active vacancy level.

Our RCP2 submission was based on the approach proposed by the Commission, with departmental expenditure forecasts including an ongoing vacancy adjustment of 3.4% ($1.9m) per annum. The 3.4% vacancy adjustment was based on historic average vacancy levels through RCP1.

Given that our RCP2 submission includes an ongoing vacancy adjustment within the range proposed by the Commission and calibrated with historical data, it is incorrect to cite the inclusion of a vacancy rate in justification for the proposed 10% reduction to corporate operating expenditure.

This reference to the inclusion of the vacancy rate appears to stem from an error in the Strata report.

5.4. Investigations

The Draft Decision proposes a reduction of 10% to our Investigations portfolio. This represents a reduction of $5.4m over RCP2. As with departmental expenditure, we disagree with the form of adjustment and the lack of rationale in the Draft Decision.

Strata questioned whether there would be similar levels of project investigation and business improvement work during RCP2 as there have been in RCP1. Before discussing this in detail, it is helpful to re-summarise the activities funded under the investigations portfolio.

Investigations includes four distinct types of activities (including approximate annual expenditure):

- Asset Investigation ($3.4m p.a.): investigating technical options for complex asset interventions. For example alternative options to replacing overhead line conductors or selecting the best option to increase transmission capacity into a region (options could range from a STATCOM, a new substation, or a new line).68
- Innovation ($2.1m p.a.): trialling and testing new technologies or systems and undertaking research on specific Grid issues.
- Business Improvement ($4.1m p.a.): is associated with improvement initiatives focused on our business processes. Examples originally planned for RCP2 include the asset management improvement objectives set out in our lifecycle strategies (similar to the proposed RCP2 Initiatives) and the continued development and maintenance of our technical standards, (e.g. design, construction, testing, commissioning) in accordance with good electricity industry practice.

[68] These investigations are distinct from 'capital investigations' which occur after a preferred option is chosen and are effectively the detailed design for the chosen technical solution.

- ICT ($1.3m p.a.): developing options and recommended solutions for IT infrastructure and systems that support operation of the transmission network and the business as a whole.

Strata's comments are relevant to two of these categories: asset investigations and business improvement.

5.4.1. Asset Investigations

Strata's view that asset investigation work will decline is based on an assumed reduction in Major Capex Project (MCP) investigations compared with RCP1.

We disagree with this conclusion. The majority of the large, recently completed MCPs were investigated and approved prior to the start of RCP1.[69] This results in MCP investigations representing a reducing portion of asset expenditure in both RCP1 and RCP2.

Given project lead times the primary driver of asset investigation costs through both RCP1 and RCP2 are the Grid Capex plans (both R&R and E&D) through RCP2 and RCP3. Grid Capex is forecast to be relatively constant through that period, with the later years of RCP2 and RCP3 characterised by large re-conductoring projects[70].

In summary, to undertake the level of asset investigations required by our forecast Grid Capex plans we will require the level of investigations expenditure set out in our original Proposal.

5.4.2. Business Improvement

Our RCP2 objectives have been developed to build on our RCP1 initiatives. This includes seeking further improvements in asset management, increasing our operation efficiency, and embedding our Service Performance Measures and targets.

Our asset management documentation submitted as part of our expenditure proposal identified a number of business improvements to meet this goal. There is considerable overlap between these initiatives and those initiatives recommended by Strata and proposed by the Commission. Notwithstanding our comments in Section 2.6, we would expect the extent of RCP2 initiatives to be similar to those undertaken in RCP1. On this basis a similar level of effort and resource will be required to achieve these.

5.5. Ancillary Services

The Draft Decision proposes a 10% reduction to ancillary services as part of its 'across-the-board' Corporate Opex reduction. This equates to a reduction of $1.65m during RCP2. This adjustment is inappropriate and contrary to the advice of the Commission's advisors.

The cited reasons for the 'across-the-board' 10% reduction (including RCP1 initiatives, reference to non-grid activities and vacancy rates) have no impact on Ancillary Services expenditure.

The procurement of ancillary services is governed by the ancillary service Procurement Plan, developed by the System Operator and approved by the Electricity Authority[71]. In its analysis of the ancillary services forecast Strata concludes that "assuming that the System Operator is adopting a prudent approach to procuring Ancillary Services, we consider Transpower's forecasting methodology is reasonable".

[69] This included the HVDC, North Island Upgrade and North Auckland and Northland projects.

[70] Total Grid Capex costs are set out in RT06 – Integrated Transmission Plans, submitted with our original proposal.

[71] In accordance with the Electricity Industry Participation Code 2010, Clauses 8.40 – 8.54.

Our ability to control these costs extends only to ensuring an effective approach to recovering these costs on behalf of the electricity market. In 2013 we asked the Commission to treat Ancillary Service costs relating to black start and over-frequency arming as recoverable costs.

The Commission indicated to us[72] that it would consult on this issue as part of its IPP Draft Decision paper. We have not been able to identify where this issue is dealt with. We recommend that the Commission make this change in its final decision.

5.6. Insurance

The Commission has applied a 10% reduction to insurance. There is no specific reasoning given for the reduction and, in other comments, the appropriateness of the proposed (non-self) insurance expenditure is endorsed. Accordingly, the Commission should confirm in its final decision that the proposed insurance spend is approved as part of the final Opex allowance.

We undertake a competitive process to place insurable risk with underwriters at the lowest possible cost. The approach involves effective marketing of our insurable risks to local, European and other international underwriters, layering of policies, meaningful retained deductibles and participation by our captive insurer (RRL) to provide additional tension.

Were a material reduction imposed, the only realistic option available would be to purchase less insurance.

Using estimates from our most recent insurance renewal (2013), options to reduce premium costs by 10% include:

- reducing the limit of cover on Material Damage/Business Interruption from $750m to $350m;
- reducing cover across our three main policies:
  - on Material Damage/Business Interruption from $750m to $500m.
  - on submarine cables from $90m to $40m.
  - on the General Liability programme from $150m to less than $75m.

The reduced level of cover means that, consistent with the Commission's objective that we should recover prudent net additional costs incurred due to a catastrophic event, consumers would bear greater risk[73]. In other words, a 10% reduction in the costs of insurance, that is already efficiently procured, effectively transfers catastrophic risk from underwriters prepared to accept and manage this risk, to consumers.

5.7. Self-insurance

The Commission should:

- approve our proposed self-insurance allowance of $12.1m; or
- in the event that the Commission does not allow CGA to be a recoverable cost, increase the allowance to $13.1m to include cover for potential claims under the Consumer Guarantees Act (CGA).

72 Commission letter to Transpower, 14 March 2014.

73 Attachment D of the Draft Decision discusses mechanisms the Commission can use to enable us to recover costs in excess of its insured limits.

The Commission has proposed removing any self-insurance allowance. The decision is based on the lack of a specific mechanism to 'ring-fence' the allowance for funding the costs of future self-insured events.

As set out in our proposal in December, the self-insurance allowance is an important element of the mitigations we have in place for the risks we face as a network utility. As part of our original proposal, we commissioned and provided a report from Marsh Actuarial.[74] Our approach and methodology is similar to that used in our RCP1 proposal and that used in other jurisdictions.

To provide a more transparent and explicit ring-fencing mechanism, we plan to utilise, where practical, our captive, Risk Reinsurance Limited (RRL) in future to reserve self-insurance allowances. We have begun the process to seek the necessary RRL and Transpower Board, and regulatory approvals[75] to extend RRL's remit to include identified self-insured risks.

5.7.1. Consumer Guarantees Act exposure

In our RCP2 proposal, we requested that CGA claims be considered as a recoverable cost. Treatment of the costs as recoverable (i.e. conditionally able to be passed through) is a more efficient means of managing this new and highly uncertain risk.

In the event that the Commission were not to allow CGA to be a recoverable cost we would need to add a premium for CGA to the self-insurance allowance. Based on advice from Marsh Actuarial this would increase the self-insurance allowance by $0.2m per annum ($1m over RCP2).

We discuss the appropriate treatment of the CGA exposure further in section 7.1.3.

5.8. Demand Response

Our submission to the Issues Paper included a request to increase our Opex allowance by $10m over RCP2 to develop demand response (DR) capability for use as a future transmission alternative. This initial amount comprised internal staff costs, DR programme costs, and costs of operating and developing a Demand Response Management System (DRMS).

The EA raised a number of concerns[76] about the potential uses of DR. These concerns appear to have arisen from a misconception on the scope of DR and our role in that development. Our development of DR is limited to its role as a transmission alternative.

There may also be a lack of clarity around the differences between the DRMS and the DR programmes that we are proposing to undertake to build a DR capability. The former is the software platform which enables the co-ordination and management of DR.

The Draft Decision concluded that only the DRMS operating and development costs should be included in the Opex allowance for RCP2. We agree that staff costs were already included in other portfolios, and therefore, should be excluded. However, we believe there is a strong case for including the non-staff DR programme costs ($6.5m). Our rationale for this view is set out in our DR Response paper. Reflecting this view, our forecast Opex for DR should be amended to $8m[77].

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74 "*RCP2 Self Insurance Quantification*", Marsh Actuarial, 1 November 2013.

75 RRL is regulated by the Cayman Islands Monetary Authority (CIMA).

76 Letter to the Commission of 14 April 2014.

77 Made up of $1.5m DRMS operating and development costs and $6.5m DR programme costs.

5.9. WELLINGTON HEAD OFFICE RELOCATION

Our RCP2 proposal included the forecast costs (capital and operating expenditure) for the relocation from Transpower House (TPH) to alternative Wellington premises. A move from TPH was contemplated in RCP1 but, ultimately, not undertaken in the absence of identifying a suitable, cost-effective alternative.

There are strong drivers for reconsidering a move away from TPH in RCP2.

To meet our needs in this period, TPH would require significant refurbishment to maintain the integrity of its facade, replace the current lifts and modernise other building services. These measures would be highly disruptive to staff and operations if the works were to be conducted while we remained in TPH and in any event some works may need to be undertaken in an entirely vacant building. In addition, based on recent engineering reports, the seismic capability of the building is unlikely to be suitable for commitment to another extended lease period, even if the proposed upgrades currently under discussion are successfully undertaken.

These practical factors are in addition to other potential benefits from relocation, of which one would be co-location of staff currently spread over various Terrace locations and multiple floors. Other potential benefits from moving to more modern premises may include: more efficient space utilisation, applying floor layouts that support more supportive collaborative working arrangements, more flexible working arrangements such as greater use of mobile technology, desk sharing etc. The extent to which benefits of this type can be realised will dependent on the specific nature of the alternative premises.

In its draft decision, the Commission, drawing on advice from Strata, questioned the justification of the forecast Opex increase associated with relocation and cited it as one of the reasons for seeking an 'across-the-board' reduction in Corporate Opex.

Our RCP2 proposal identified a forecast increase in Opex of $6m ($2m per annum for the last three years of RCP2) to reflect anticipated higher rental costs[78]. This estimate in turn reflects an expected increase in unit rental costs moving from TPH to an alternative, more modern office development that meets 100% of the new building standard. There is limited stock of such accommodation in Wellington. It is based on reasonable estimates for the cost of A-grade or upper B-grade space.[79]

Given the Opex incentive regime, and recognising our monopoly role, there are strong pressures on us to minimise the cost of (alternative) office space and negotiate a cost effective arrangement, including seeking introductory incentives from a new landlord.

Opportunities to defray cost increases will arise primarily by finding ways to reduce the total net lettable area from that currently occupied. Measures such as desk-sharing and increased occupant density may be applicable. Although, as suggested above, the ability to accommodate such measures is a function of the particular building and how readily it can be configured and re-fitted to allow more flexible working arrangements.

In summary: we must plan for a move from TPH during RCP2. The reasonable costs of a move (Capex and Opex) were identified in our original proposal and remain appropriate.

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[78] The projected increases are estimated by reference to the existing rent levels. If and when Transpower House is refurbished, the rental sought for this building is likely to rise reducing the effective rental increase associated with relocation.

[79] Based on market soundings and our previous experience in RCP1, the forecast cost increase would not be sufficient for a new build development in central Wellington.

6. GRID OUTPUT MEASURES

For RCP2 we are now proposing Grid Output Measures based on Asset Health[80], Grid and Asset Performance, and a set of Other Measures. This chapter describes the Asset Health based measures. Detailed discussion of the remaining measures can be found in our Main Proposal and an accompanying report.[81]

In summary, our response to the Draft Decision is as follows.

- As discussed in Section 3.1, the Draft Decision proposes an 'across-the-board' 5% reduction across Transmission Line and AC Station R&R Capex. Below we set out a proposed incentive mechanism that addresses the rationale for this adjustment.
- The Draft Decision commended our consultation approach and accepted all our proposed measures. However, it proposes changes to some targets, which we believe are too severe. Below we propose more reasonable targets.
- The Draft Decision also proposes additional measures. These will provide little additional benefit for consumers given the information we already provide.

We would also like to reiterate that our original measures and targets were supported by our customers and the wider industry. We are reluctant to revisit them unnecessarily.

6.1. ASSET HEALTH INCENTIVES

Unless stated otherwise all figures in this section are presented as **nominal commissioned**.

6.1.1. OVERVIEW

To support the integration of Asset Health Indices (AHI) in our day-to-day activities, and to address the Commission's concerns around deliverability of our R&R programme, we have developed a set of financial incentives to link outputs of the R&R programme directly to revenue. This would form an expansion of our proposed revenue-linked grid output measures.

We have proposed a target index, a cap and collar and an incentive rate for each asset fleet proposed for inclusion in the incentive regime. The regime is designed to underpin efficient delivery of our planned RCP2 programme.

[80] While we refer to these as "Asset Health" based, they also reflect our performance in delivering on replacement volumes in key asset fleets.

[81] Service Performance Measures Report (BR04) was included as part of our original submission.

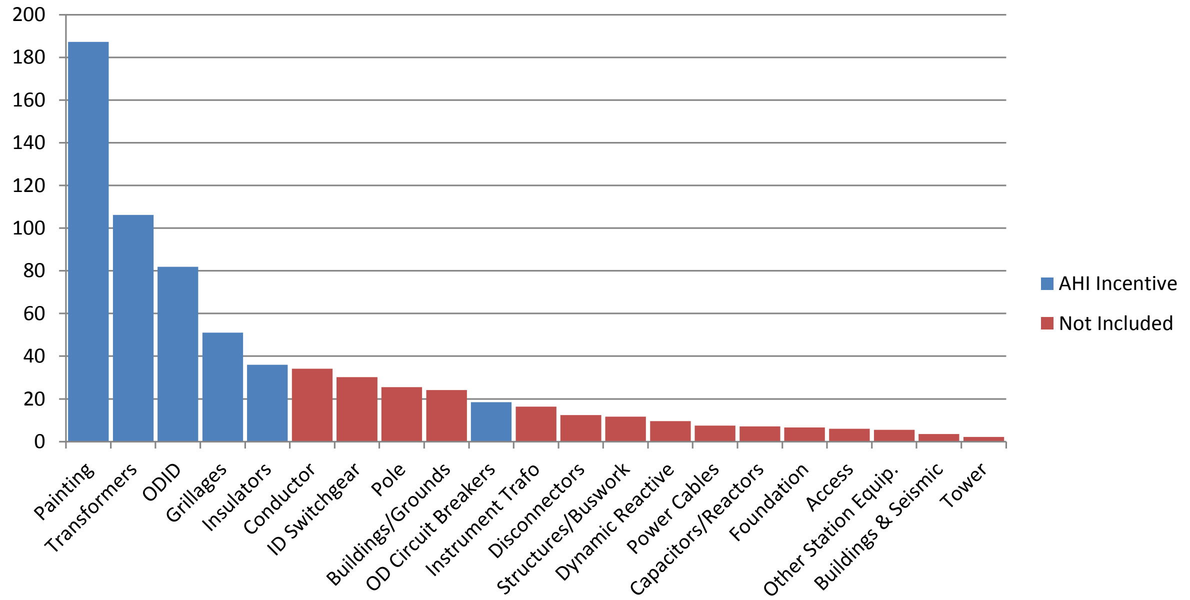
Included Asset Fleets

We have chosen to apply these incentives to six key portfolios in total, with the first three linked to asset health and the last three linked to volumes delivered.

- **Tower Painting:** is our largest Grid Capex portfolio;
- **Power Transformers:** is our largest AC Stations portfolio;[82]
- **Outdoor Circuit Breakers:** which includes assets affecting our service performance;
- **Outdoor to indoor conversions (ODID)** includes large complex projects that have led to historical variance;
- **Grillages:** is one of our largest transmission lines portfolios; and
- **Insulators** programme includes a large number of volumetric projects.

The above portfolios cover 68% (by value) of our Transmission Lines and AC Station R&R portfolios.[83] As depicted below these represent our five largest portfolios. In addition, we have included Outdoor Circuit Breakers, which has an available AHI model.

Figure 1: AHI Incentive Coverage by Portfolio ($m real 2012/13)



The portfolios were chosen with the objective of striking an optimal balance between the value covered and the number of portfolios included.

Role of Substitution

We provide for substitution of work between the fleets within the incentive framework, but propose a cap such that we cannot benefit from net over-delivery across the portfolios. This allows flexibility to change the mix of work to respond appropriately to operational demands, changes to asset condition assessments or other situations. Substitution means that, from a financial incentive

82 To ensure the impact of the R&R works are accurately reflected we will only take into account asset replacements within the specific portfolio, i.e., for the purpose of calculating the incentive we will ignore the impact of customer-funded works, E&D projects and maintenance projects.

83 We assessed the incentive's coverage against these portfolios to reflect the scope of the proposed reductions.

perspective, over-delivery in one or more fleets can offset under-delivery in others. The cap means we cannot achieve an aggregate benefit from the asset health incentive arrangements.

6.1.2. Level of Revenue at Risk

During RCP2, we propose to link $14.3m of revenue to our performance under the AHI incentive mechanism. This figure has been set with reference to the Base Capex incentive mechanism (under which we ordinarily retain 33% of any under-spend and bear 33% of any over-spend) and the level of proposed expenditure reduction in the Draft Decision.[84] The financial weighting between the fleets is based on the relative forecast spend on each fleet, giving the following "revenue at risk" for each portfolio.

Table 11: Revenue at Risk by Portfolio

Portfolio	Revenue at risk ($m)
Tower painting	5.64
Power transformers	2.74
Outdoor to indoor conversions	2.71
Grillages	1.53
Insulators	1.08
Outdoor circuit breakers	0.57
Total	**14.26**

6.1.3. Measures and Targets

To ensure transparency and to simplify implementation, we have specified a single representative measure for each fleet. In some portfolios, targets are set for each year of the period. In others, due to the lumpy profile of work, we have proposed a 'whole of RCP' target.

The rationale for the choice of targets by portfolio is described below. The intention is to avoid small changes in project timings giving rise to perverse incentives or unintended outcomes.

Asset Health Based Measures

Some fleets (e.g. steel towers) have relatively well developed asset health models making them suitable for assessment based on an asset health measure. These models calculate, for each asset, the remaining life (RL) in any given year based on the condition assessments and a number of other factors. For example, towers are identified as being in one of a number of different corrosion zones, each zone having a different rate of expected degradation of the tower's protective coating (paint or galvanising).

For towers and other fleets with sufficiently developed asset health data (transformers and circuit breakers), the health measures are a function of the remaining life of the fleet, for example:

- total aggregate RL of the fleet;

[84] We have set the asset health incentive rate to be approximately 10% more than the Base Capex incentive rate (i.e. at approximately 36%). That relationship will provide further incentive for delivery of the planned work (relative to under-delivery). This revenue at risk figure of $14.3m corresponds to the nominal value of the proposed reduction (being about $40m) at the asset health regime incentive rate of about 36%.

- average RL;
- change in average RL; and
- number of assets in certain RL bands (e.g., RL<0 years).

For these fleets the measure we have selected is change in average RL.

Volume Based Measures

For the other fleets (outdoor to indoor conversions, grillages and insulators), a simple volume-based measure is more appropriate than asset health. This is because the related asset health models are still under development or relatively immature. Grillages and insulators also involve high volumes of reasonably uniform 'units' that are discrete and readily identifiable and therefore lend themselves to a volume-based approach.

6.1.4. Portfolio Targets

During our assessment of potential targets for the selected portfolios, we used the following criteria to inform our choice so that measures would be likely to give reliable financial outcomes.

- Targets need to be statistically meaningful and stable as far as possible, to get the best correlation between delivery and the selected measure.
- Annual targets are not suitable for portfolios with low replacement numbers, lumpy profile of work and/or high value units (such that the time of commissioning for an individual unit can materially shift incentive outcomes).
- Where annual targets are suitable, they should reflect incremental progress during a year, rather than an absolute measure. This avoids the risk of 'falling behind', whereby delays or failure to meet the target early in the RCP makes it impossible to meet the target in subsequent years – reducing the effectiveness of the incentive regime.

The following table sets out the chosen basis for the targets for each of the six portfolios.

Table 12: Summary of Target Type

Portfolio	Basis of Targets	Units	Timeframe
Tower painting	Asset Health	Change in average RL	Annual
Power transformers	Asset Health	Change in average RL	RCP
Outdoor circuit breakers	Asset Health	Change in average RL	RCP
Outdoor to indoor conversions	Volume Delivered	Number of conversions	RCP
Grillages	Volume Delivered	Number of grillages	Annual
Insulators	Volume Delivered	Number of insulators	Annual

Below we set out the caps, collars and targets for each portfolio including a brief explanation of how these have been determined.

Tower Painting

There are sufficient towers (more than 24,000) and a sufficient number being painted each year (> 500 on average) for an annual target to be used. The remaining life profile of the towers, combined with the annual variability in planned work, leads to annual variations in the remaining life of the fleet, which is reflected in variable targets for the period (see Table 13).

The RCP2 plan for tower painting produces an improvement in remaining life over the period of 1.47 years, compared to a 'do nothing' scenario[85]. We use this relative improvement of 1.47 years over the period, at 36.3% of the nominal commissioned portfolio cost of $211.0m, to calculate the incentive rate of $52.4m/year of remaining life.[86]

The revenue at risk ($1.13m per year and $5.64m over the RCP) and the incentive rate ($52.4m/year) have been used to determine the 'spread' between the cap and collar of about 0.043 years. The following table sets out the annual targets, collars and caps for the tower painting portfolio.

Table 13: Tower painting targets, collars and caps

Year	Revenue at risk	Target (years)	Collar (years)	Cap (years)	Spread (years)
2015/16	$1.128m	(0.696)	(0.718)	(0.674)	0.043
2016/17	$1.128m	(0.565)	(0.587)	(0.543)	0.043
2017/18	$1.128m	(0.678)	(0.700)	(0.656)	0.043
2018/19	$1.128m	(0.712)	(0.734)	(0.690)	0.043
2019/20	$1.128m	(0.697)	(0.719)	(0.675)	0.043
Total over RCP2[87]	**$5.64m**	**(3.348)**	**(3.456)**	**(3.240)**	**0.216**

Transformers

The asset health model for transformers uses the year of manufacture and a number of other characteristics to arrive at an expected remaining life. The remaining lives in the model are notional, in the sense that they are used to rank transformers in order of priority, rather than representing an *actual* expected remaining life. The model produces a 'long tail' of negative remaining lives that could distort the results and incentive effects in the regime unless they are all given the same weight.

To address this simply, the transformer asset lives are grouped into remaining life 'buckets', to which each has is assigned a single value. For example, all transformers with five or fewer years of remaining life are assigned a remaining life of zero years (i.e. 'due') and all transformers with 15 or fewer years but more than 5 years are assigned a remaining life of 10 years.[88] The principal effect of this approach is to remove the long tail of negative remaining lives, which normalises incentives across the tail end of the fleet.

Having allocated transformers to these 'buckets', the RCP2 plan results in an improvement in the average remaining life of 2.26 years compared to doing nothing. We use this improvement of 2.26 years over the period, at 36.3% of the nominal cost of $102.4m, to derive the incentive rate of $16.5m/year of remaining life.

[85] It should be noted that the average remaining life of the fleet deteriorates over RCP2 despite the proposed painting programme. The expenditure proposed is, effectively, constrained by painting contractor resource availability.

[86] The incentive rate has to be expressed in terms of $/year and the 'plan vs do nothing' comparison produces the most reliable average for that rate. It also includes, by default, an average over the number of units in the plan and therefore an implicit full average cost per unit.

[87] Targets, collars and caps are applied on an annual basis. The totals over the RCP are not used in practice

[88] The other categories are '15 to 25 years' (=20 years) and 'more than 25 years' (=30 years).

The RCP2 transformer plan is quite lumpy[89] and the units are relatively high-valued[90]. If an annual target, collar and cap were used, there is a risk that small timing changes[91] could have a significant impact on the financial outcome, potentially leading to perverse incentives.

The revenue at risk of $2.74m and the incentive rate of $16.5m/year are used to determine a 'spread' between the cap and collar of about 0.33 years. We propose the following whole-of-RCP target.

Table 14: Transformer AHI Target, Collar and Cap

	Revenue at risk	Target (years)	Collar (years)	Cap (years)	Spread (years)
Total over RCP2	**$2.74m**	**(0.194)**	**(0.359)**	**(0.028)**	**0.332**

Outdoor Circuit Breakers

The asset health model for outdoor circuit breakers uses a similar approach to that for transformers. This model also produces a large tail of negative remaining lives and similar remaining life buckets to those used for transformers have also been used for circuit breakers.

The outdoor circuit breaker plan is also relatively lumpy[92], compared to the spread between the collar and the cap, and so we have proposed a whole-of-RCP target for this fleet as well.

Using the circuit breaker model, and allocating circuit breakers to remaining life 'buckets', the planned work results in an improvement in the average remaining life over the period of 3.63 years compared to doing nothing. We use this improvement of 3.63 years over the period, at 36.3% of the nominal cost of $21.2m, to derive the incentive rate of $2.1m/year of remaining life.

The revenue at risk of $0.57m and the incentive rate of $2.1m/year are used to determine the 'spread' between the cap and collar of about 0.54 years. We propose the following for the circuit breaker portfolio.

Table 15: Outdoor Circuit Breaker AHI Target, Collar and Cap

	Revenue at risk	Target (years)	Collar (years)	Cap (years)	Spread (years)
Total over RCP2	**$0.57m**	**(0.258)**	**(0.526)**	**0.010**	**0.536**

Outdoor to Indoor Conversions

The outdoor to indoor (ODID) conversion plan over RCP2 is lumpy (ranging from 2 to 5 conversions per year). The commissioned value of each conversion is also relatively high, $6.4m on average. Based on a similar rationale to the transformer fleet, we propose a whole-of-RCP target for the ODID portfolio.

89 The plan is to replace 26 transformers as follows: 2015/16 (2), 2016/17 (8), 2017/18 (7), 2018/19 (5), 2019/20 (4).

90 The planned 26 replacements are forecast to have a nominal cost of $102.4m (i.e. average $4m per transformer).

91 A general principle of the IPP is that expenditure is fungible during an RCP such that we may substitute projects or change their timing if these changes are justified.

92 The plan is to replace 155 circuit breakers: 2015/16 (24), 2016/17 (33), 2017/18 (40), 2018/19 (15), 2019/20 (43).

Using the 36.3% incentive rate, the revenue at risk of $2.71m and the average unit cost of $6.4m, we calculate a theoretical cap to collar 'spread' of 2.3 units. However we require a 'per unit' measure restricting the spread to being a whole, even number – in this case 2. We propose the following target, cap, and collar for the ODID portfolio.

Table 16: ODID AHI Target, Collar and Cap

	Revenue at risk	Target (no.)	Collar (no.)	Cap (no.)	Spread (no.)
Total over RCP2	**$2.71m**	**16**	**15**	**17**	**2**

Grillages

The number of grillages planned for RCP2 is sufficiently large and consistent over time to permit a constant annual target.[93] Using the 36.3% incentive rate for this measure, the annual revenue at risk of $306k and the average unit cost of $28k we calculate a theoretical annual cap to collar spread of 60.1 units. As for ODID, we require an even, whole number and have used a 'spread' of 60 units.

We propose the following annual targets, caps, and collars for the grillages portfolio.

Table 17: Grillages AHI Target, Collar and Cap

Year	Revenue at risk	Target (no.)	Collar (no.)	Cap (no.)	Spread (no.)
2015/16	$306k	408	378	438	60
2016/17	$306k	408	378	438	60
2017/18	$306k	408	378	438	60
2018/19	$306k	409	379	439	60
2019/20	$306k	409	379	439	60
Total over RCP2[94]	**$1,530k**	**2,042**	**1,892**	**2,192**	**300**

Insulators

The level of planned work on insulators in each year of RCP2 is sufficiently consistent to allow an annual target, but not sufficiently consistent over time for a constant target. We propose, therefore, to set the target for each year equal to the RCP2 plan.

Using the 36.3% incentive rate for this measure, the annual revenue at risk of $216k and the average unit cost of $5,700 we can calculate a theoretical annual collar to cap spread of 208.8 units. To ensure that we have a whole even number we have proposed a 'spread' of 208 units.

We propose the following annual targets, caps, and collars for the insulators portfolio.

[93] The precise target would be 408.4. We have used whole numbers requiring a change in the latter two years. A similar approach has been used for the cap and collar.

[94] Targets, collars and caps are applied on an annual basis. The totals over the RCP are not used in practice

Table 18: Insulators AHI Target, Collar and Cap

Year	Revenue at risk	Target (no.)	Collar (no.)	Cap (no.)	Spread (no.)
2015/16	$216k	1,526	1,422	1,630	208
2016/17	$216k	1,466	1,362	1,570	208
2017/18	$216k	1,402	1,298	1,506	208
2018/19	$216k	1,315	1,211	1,419	208
2019/20	$216k	1,380	1,276	1,484	208
Total over RCP2[95]	**$1,080k**	**7,089**	**6,569**	**7,609**	**1,040**

6.1.5. Reporting

Subject to the Commission's acceptance of the proposed incentive regime, we will propose a process to manage the reporting needed to support revenue adjustments and to provide transparency for stakeholders. This process would be aligned with our annual disclosure and revenue setting process and would include:

- annual disclosure of performance against the targets, and resulting revenue implications; and
- independent assurance and Director certification.

To make the regime manageable, performance would be assessed using asset health models 'frozen' at the time of the final decision. Each year we will update asset condition to reflect asset interventions. We will not update condition information (e.g., based on inspections) for the remaining assets but will reduce their remaining life. If material divergence emerges between the frozen models and our "live" operational models then we will approach the Commission to reopen the incentive settings to ensure the regime properly recognises the optimal work plan.

6.2. Grid Performance Measures

The proposed framework reflects our RCP2 objective (see Chapter 2) to improve service performance with a focus on high priority and important points of service. The Draft Decision commends our consultation approach and subsequent development of Service Performance Measures and targets.

Prior to the draft decision the Commission asked us to adjust our data and targets to exclude AUFLS events. This generally resulted in tighter targets for GP1 (number of interruptions) and relaxed targets for GP2 (average duration) and GP3 (P90 duration). We are comfortable with excluding AUFLS events.

The Commission accepted our adjusted targets for all measures except for GP1-High Priority, GP1-N-security and GP1-Standard. In these cases, the Commission proposes more challenging targets.

[95] Targets, collars and caps are applied on an annual basis. The totals over the RCP are not used in practice

Our proposed targets should be reinstated. The rationale for change is not strong and the resulting targets are too severe. In addition, the spread between the cap and collar for GP1-Standard should be increased to expand the operative range of the incentive.

6.2.1. Number of Unplanned Interruptions – Revised Targets

Our targets are based on transitioning from historic performance towards long-term targets over two control periods. The RCP2 targets are based on 'closing the gap' between historic and long-term performance by 40%. Accordingly, the targets are forward-looking but rely on measuring historic performance as a key step in setting the RCP2 transition targets.

GP1 Target – High Priority

The following table sets out our revised target, cap and collar for the number of unplanned interruption (GP1) targets for RCP2 at High Priority points of service.

Table 19: RCP2 GP1 Target – High Priority

	Original Proposal[96]	Draft Decision	Revised Proposal
Target	4	2	**4**
Cap	1	0	**1**
Collar	7	4	**7**

The amended target (set at 4 interruptions) for High Priority sites is too low to provide an effective incentive – in our historic sample we have never achieved better than the amended target and there have been several occasions where a single event would have caused the number of interruptions to exceed the collar.

In our view, the effectiveness of the incentive regime is severely diminished if it is not based on achievable targets. The Commission's rationale for tighter targets is based on a view that the median is more representative of historic performance than the mean. This analysis is not strong enough to support a significant tightening of the target – we discuss this below.

The original target, caps and collars should be reinstated.

GP1 Target – Standard

The following table sets out our revised target, cap and collar for the number of unplanned interruption (GP1) targets for RCP2 at Standard points of service.

Table 20: RCP2 GP1 Target – Standard

	Original Proposal[97]	Draft Decision	Revised Proposal
Target	28	26	**28**
Cap	11	21	**19**
Collar	45	31	**37**

96 Adjusted to reflect exclusion of AUFLS events.

97 Adjusted to reflect exclusion of AUFLS events.

The Commission's rationale for significantly tightening the cap and collar 'spread' for standard sites rests on establishing an incentive rate to VoLL relationship that is close to 85% for important, standard and generator sites. This is not a compelling rationale (given the VoLL analysis lacks a robust empirical basis) and produces an excessively tight operative range for the incentive – historic performance was outside the proposed collar or cap in three out of seven years. In our view this diminishes the effectiveness of the regime.

The original target should be reinstated and the cap and collar should be set a 19 and 37, respectively, to broaden the operative range such that it spans historic performance.

GP1 Target – N-Security Sites

The following table sets out our revised target, cap and collar for the number of unplanned interruption (GP1) targets for RCP2.

Table 21: RCP2 GP1 Target – N-Security

	Original Proposal[98]	Draft Decision	Revised Proposal
Target	66	50	**63**
Cap	53	26	**39**
Collar	76	74	**87**

The Commission's proposed target for N-security sites demands performance in excess of our proposed *long-term* performance target. This is inconsistent with our approach of setting forward-looking targets founded on customer expectations (rather than simply perpetuating historic performance). We are comfortable with the size of the cap to collar spread proposed by the Commission.

We have used our long-term performance target with the Commission's proposed spread in our revised proposal.

6.2.2. Assessment of Performance Measures

This section provides more detailed assessment of the revised performance measures for GP1-High Priority, GP1-Standard and GP1-N-security.

GP1-High Priority

The amended GP1-High Priority target and collar are set so low that they undermine the effectiveness of the incentive. For example, there have been several occasions in the past seven years when a single uncontrollable event would breach the collar. This is unacceptable and the Commission should revert to our proposed target of four interruptions, with a cap and collar of one and seven.

For our proposal, we took the average (mean) performance during the seven years to June 2013 to represent historic performance. There are only 23 High Priority sites and our long-term target is that interruptions should have a 10-year return period. With a small population and a sampling period shorter than our target return period, we cannot obtain an accurate measure of underlying performance by considering the mean or median alone. Nonetheless, the Draft Decision argues that the median of our sample provides an accurate indicator of underlying performance. This is based

98 Adjusted to reflect exclusion of AUFLS events.

on assuming that the number of interruptions at high priority sites has a significantly asymmetric distribution.

The data in our sample includes a clear outlier – in 2009/10 there were 20 interruptions[99], compared to a mean of 5.2 and median of three. The next highest number of interruptions in a single financial year was four in 2011/12.

Because performance is strongly influenced by the timing of large, random events, it is valid to consider how the sample data would alter if these events had *not* all occurred in 2009/10. To do this, we modified the data by shifting the forklift event to 2006/07, leaving the fire event in 2009/10 and shifting the other three interruptions from that year to 2007/08. These modifications leave the mean unchanged, but lift the median from three to four. The skew is also reduced from 2.6 to 0.9.

This experiment shows that:

- we cannot be confident that the underlying distribution is materially asymmetric;
- the observed median is sensitive to the timing of random events (e.g. fires and forklift clashes) while the mean is not sensitive to the timing of the observed random events; and
- it may be more appropriate to express historic performance as being within a range, rather than using a point estimate.

The most important consideration is the incentive effects of the target, rather than which point estimate of historic performance is most accurate. The key problem with adopting a low target is that the collar must be set no higher than four if the incentive regime is to be symmetric[100]. This is too low as it means there is a strong likelihood of reaching or exceeding the collar in multiple years, and there is a plausible risk of exceeding the collar due to a single event[101]. This undermines the effectiveness of the incentive[102].

Important Sites

The amended cap and collar are too close together, such that the range within which the incentive operates is too small. These should be changed so that the spread between the cap and collar encompasses the range of historic data points. The target should also revert to 28, as the reduction to 26 is founded on the questionable assumption that the median accurately characterises underlying performance.

Unlike High Priority sites, where we intend to lift performance, our RCP2 objective for Standard sites is to hold the historic level of performance. Our initial analysis of the long-term target is that a reduced level of performance would be appropriate, but we intend to test this further before RCP3. Accordingly our initial long-term target is for a two-year return period, whereas our proposed RCP2 target is a return period of 2.8 years. Given that the overarching objective is to hold performance, particular care should be taken not to set targets for Standard sites that may require a level of investment inconsistent with our best view of the needs of our customers.

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99 The year 2009/10 is an outlier because there were two significant events in that year – a forklift contacted lines in Auckland in October 2009 causing interruptions at six High Priority sites, and a vegetation fire in January 2010 led interruptions across eleven High Priority sites.

100 We agree with the suggestion by Carter Holt Harvey that an asymmetric design may be appropriate in future (e.g. from RCP3) if the target is reduced to 2 or 3 interruptions. For example, settings of 0, 2 and 8 could be appropriate for the cap, collar and target in future control periods.

101 We note that exceeding the collar in one year does not imply that we are not meeting the performance target. The innate variability in the occurrence of interruptions means that we should expect to exceed the collar in some years, even if underlying performance is at the target level.

102 We also note the Commission's ability to seek pecuniary penalties or criminal sanctions if we exceed the collar.

N-Security Sites

Our proposed target of not more than 66 interruptions for N-security sites is based on closing the gap between historic average (mean) performance of 68 and our long-term target of 63. The long-term target reflects an interruption return period of 10 months. The Commission proposes an amended target of 50.

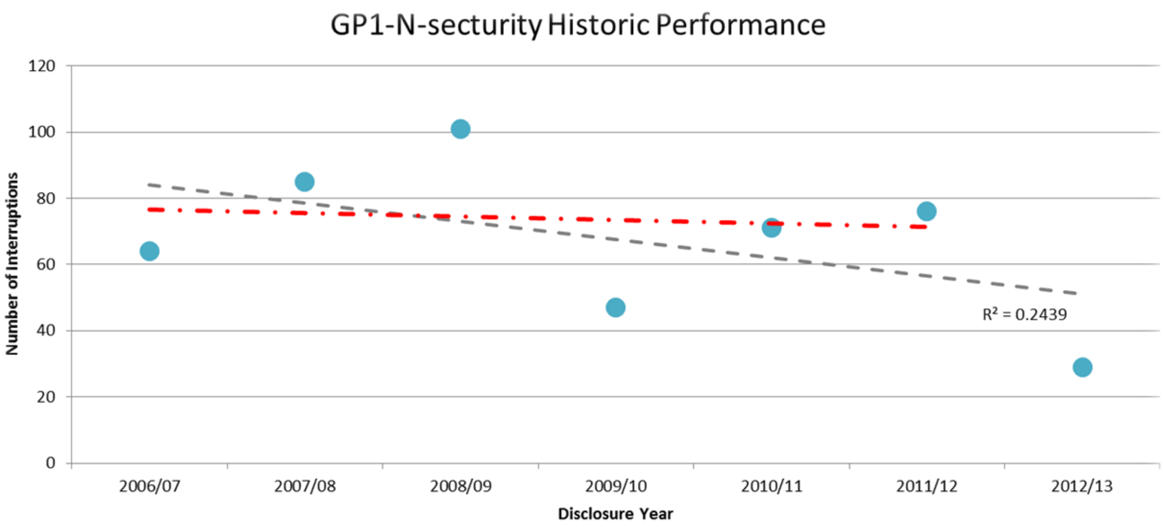
The Commission's revised target is based on arguments that the data shows a trend of improving performance, and that we have made investments that should be lifting performance. There is no discussion of whether it is appropriate to target performance in RCP2 that is significantly better than our long-term target. Our view is that a target of 50 is not appropriate and the Commission should not adopt a target any tighter than 63.

It is particularly important that we do not to set targets for N-security sites that are more challenging than economically justified. This is because customers at N-security sites are often in a position to make a direct price-quality trade-off.

The key driver of performance for N-security sites is the absence of redundant connection circuits and supply transformers. Customers can, if they wish, elect to fund investment in additional assets that will provide redundant supply. In doing so, they can lift the target interruption return period from 10 months to two years (which is the target for standard sites). In addition, N-security customers can elect to purchase their assets from us and make their own price-quality trade-off for all drivers of performance (e.g. maintenance level, spares, contractor call out times, etc.).

We do not agree that there is an observable trend of improving performance in the historical data. The seven year sample is too small to conclude that this is the case given that weather and other environmental events drive more than half of the interruptions at N-security sites[103]. The following chart illustrates that the (linear) trend line for the sample has a low R^2 value, and is strongly influenced by 2012/13 performance. This reinforces that the underlying performance is variable and care should be exercised in concluding there is a trend.

Figure 2: Historic Performance at N-Security Sites



[103] This is based on cause analysis for a five year period.

The Draft Decision also refers to investment in auto-reclose capability as a driver of improved performance. During RCP1 we have installed auto-reclose functionality on six circuits[104], two of which were subsequently transferred to an EDB customer[105]. There are three N-security points of service that could experience reduced (non-momentary) interruptions due to the auto-reclose capability of three of the remaining upgraded circuits. This capability was put in place this year.

The following table analyses the uplift in N-security performance that could be anticipated from investment in auto-reclose capability.

Table 22: Auto-reclose capability – uplift in performance at N-security sites

Circuit	Historic Interruption Rate (per year)	Avoidable non-momentary interruptions	
		Success rate (60%)	Success rate (80%)
OAM-WTK-BPT1	1.8	1.1	1.4
OAM-STU-WTK-BPD2	2.1	1.3	1.7
BAL-BWK-HWB1	4.9	2.9	3.9
Total	8.8	5.3	7

At best, auto-reclose may reduce the mean number of interruptions across N-security sites from 66 to 59. In summary:

- we cannot be confident that there is a trend of improving performance given the underlying variability and the high contribution of environmental factors to annual performance;
- investment in auto-reclose may, at best, drive a 10% improvement in performance, whereas the Draft Decision is based on a 24% improvement; and
- our RCP2 target reflects that our long-term target (which is not based on historic performance) is for a moderate improvement only.

6.3. Other Measures

The Commission has accepted our proposed non-revenue linked 'Other Measures' and codified these into the draft IPP determination. The Commission has also proposed three further measures – estimated energy not supplied (OM7), outage start time compliance (OM8) and post-outage reporting compliance (OM9).

We accept the rationale for OM8 as a complement to OM4 (outage end time compliance). We do not accept OM7 and OM9 because these duplicate contractual reporting obligations governed by the Electricity Industry Participation Code.

In our view, it is also inappropriate for any of the Other Measures to be codified into the IPP determination.

[104] These are OAM-WTK-BPT1, OAM-STU-WTK-BPD2, BLN-ARG-KIK1, HWB-PAL1, HWB-PAL2 and BAL-BWK-HWB1.

[105] We transferred the HWB-PAL circuits to OtagoNet in April 2014.

6.3.1. Codification

Development of the Other Measures is part of our work to understand the aspects of our performance that are important to our customers. The Other Measures are not part of the Grid Output Measures framework under the Capex IM[106] and should not be codified in IPP.

The Other Measures we have proposed variously:

- do not fit the Capex IM definition of Grid Output Measures at all (e.g. our performance against the measure 'time to provide information following an unplanned interruption ' is not a product of the grid assets or our investment in those assets);
- could be Grid Output Measures in the future, but development is required to establish the best measurement approach and to capture baseline information (e.g. 'number of unplanned momentary interruptions' and 'extent to which customers are on N-security'); or
- not only require further development but may also have perverse incentive properties if linked to revenue (e.g. the outage window compliance measures).

By measuring and reporting the Other Measures during RCP2 we expect to strengthen our focus on the aspects of our service customers have identified as important to them, to develop a clearer view of how well we are meeting customer expectations and to refine our methods and systems for future measurement and reporting. In short, the measures are about business improvement and not at all about Capex IM compliance.

This does not preclude their codification as part of the broader IPP framework, but our concern is that codifying the requirements will impair our ability to learn and develop. This concern is reinforced by the Commission's draft codification of the measures, which goes beyond the details we had proposed. This clearly undermines our ability to develop the best ways of reporting these new measures.

Accordingly, the Other Measures should not be codified in the IPP and should be treated as akin to the business improvement initiatives we agreed in RCP1[107].

6.3.2. Additional Measures

The Draft Decision proposes three additional Other Measures that the Commission proposes to codify into the IPP. As discussed above, codification is not appropriate for these developmental measures in RCP2[108]. Our view is that the Other Measures should be finalised as part of a process to agree business improvement initiatives.

Without prejudice to our view on codification, we provide comments below on each of the additional measures.

[106] In our proposal we identified that our proposed Grid Performance Measures and Asset Performance Measures comprise the Grid Output Measures required under the Capex IM, and that the Other Measures are *not* Grid Output Measures.

[107] As discussed in Section 2.6, we will agree business improvement initiatives with the Commission by 1 July 2015 in light of the draft decision. If the Commission takes the view that it should codify the Other Measures in the IPP then it must adopt a non-prescriptive approach that provides flexibility for these measures to evolve. Our submission on the IPP draft addresses how this could be achieved.

[108] We also note that two of the additional measures (OM8 and OM9) would not meet the Capex IM definition of Grid Output Measures.

Table 23: Commentary on Additional 'Other Measures'

Measure	Detail	Comments
OM7: Estimated energy not supplied	Estimated MWh not supplied for each point of service	The benchmark agreement[109] requires us to provide customers with post-event reports within 42 days. These are required to include an estimate of unserved energy. The proposed 'additional measure' would create an overlapping requirement with a different timeframe. We are not convinced that it would be helpful to customers generally to publicly report interruption information in multiple forms: • our primary disclosure will be number and duration of interruptions – an approach arrived at through thorough and widely commended consultation • under the Commission's information disclosure framework we must continue reporting RCP1 interruption metrics (number of events above certain system minute thresholds) • our customers[110] receive estimated GWh information, and EDBs also report information on transmission interruptions.
OM8: Outage start time compliance	For the key HVAC circuits and (separately) for the HVDC: • percentage planned outages started within 30 minutes of notified start time • percentage planned outages started more than 60 minutes after notified start time	Outage start time compliance is a logical complement to OM4 (outage end time compliance). We are working through how we best operationalise these measures in a manner that is cost effective, captures valuable information and is compatible with outage management processes – including those governed under the Electricity Industry Participation Code. Given this is a work in progress, it is particularly inappropriate to codify detailed requirements at this time.
OM9: Timeliness of post-event reports	Number of post-event reports supplied more than 15 working days after the event	As with OM7, this requirement overlaps with our Code and contract-governed obligation to provide post-event reports within 42 days.

[109] The benchmark agreement provides default or 'fall back' contract terms and conditions for grid access. The benchmark agreement is set out in the Electricity Industry Participation Code, which is governed by the Electricity Authority. We publish information on customer contracts and any negotiated variations to the benchmark agreements on our website.

[110] We acknowledge that the suggestion we publish estimated GWh information was made by Carter Holt Harvey who, following recent network reconfiguration at Kinleith, is no longer a direct transmission customer.

7. REGULATORY FRAMEWORK

This Chapter is structured as follows:

- **Key Concerns** proposes ways of addressing our key regulatory framework concerns
- **IPP Design** responds to other regulatory framework matters raised in the Draft Decision
- **IPP Evolution** responds to the Commission's views on evolution of the IPP.

7.1. Key Concerns

To address our key concerns with the regulatory framework, we propose:

- revised wording to remedy the test for determining whether an event is 'catastrophic';
- refining the 'listing' mechanism for large or highly uncertain capital projects;
- defining Consumer Guarantees Act indemnity costs as 'recoverable' to reduce overall costs for consumers, while preserving the intended properties of the indemnity; and
- changing to an expenditure-based allowance for Base Capex to improve efficiency.

7.1.1. Treatment of Catastrophic Events

In Attachment D of the Draft Decision the Commission confirms that it will "…allow Transpower to recover prudent net additional costs that arise in the period between the occurrence of a catastrophic event and a reconsidered individual price-quality path taking effect"[111]. The Commission argues that this treatment will strengthen our incentives to focus on restoring network services in the aftermath of a catastrophic event, and recognises that normal planning and oversight of expenditure may not apply under such circumstances. To achieve this outcome (which we support), requires a clear definition of what constitutes a catastrophic event.

The existing test is defective and requires amendment if it is to support the Commission's objective. In this section, we provide a draft amendment to clarify the catastrophic event definition and to improve its operation. This includes decoupling the cost threshold from consideration of insurance proceeds.

Defective Cost Threshold

The cost threshold is set out in clause 3.7.1(c)(iv) of the Transpower IM:

> "the cost of remediation net of any insurance or compensatory entitlements would have an impact on the price path over the **disclosure years** of the **IPP** remaining on and after the first date at which a remediation cost is proposed to be or has been incurred, by an amount at least equivalent to 1% of the aggregated **forecast MARs** for the **disclosure years** of the **IPP** in which the cost was or will be incurred."

The wording of the clause is convoluted and open to different interpretation. It appears to specify that the threshold:

[111] Draft Decision, paragraph D5.

- is a function of the aggregate forecast MARs for the years in which the costs are incurred. This means, for example, that the threshold doubles if expenditure spans two financial years rather than occurring entirely within a financial year; and
- depends on the impact of the expenditure on the price path: for Opex there is no impact on the price path from additional expenditure until the following control period, while for Capex the impact is delayed by several years.

The following table illustrates how the threshold would vary across the years of RCP2 under the existing threshold, based on the (unrealistically simplified) scenario that all of the catastrophic event expenditure is incurred and capitalised within one financial year[112].

Table 24: Capital expenditure thresholds in RCP2 under the current clause

Insurance Cover	Capex Cost Threshold for a Catastrophic Event ($m)				
	2015/16	2016/17	2017/18	2018/19	2019/20
0	984	85	31	∞	∞
$100m	1084	185	131	∞	∞
$500m	1484	585	531	∞	∞

The threshold is erratic for the first three years of the control period and there is no amount of capital expenditure that could trigger the catastrophic event mechanisms in the final two years. The reason for this is that the price path impact occurs through offsetting EV account entries from the Capex wash-up process and the Base Capex incentive mechanism. There is no wash-up process for Opex, so there is no amount of expenditure that would alter the price path and qualify as 'catastrophic'. This is clearly not the Commission's intention.

A further problem with the existing cost threshold is its interaction with insurance cover:

- the threshold is net of insurance entitlements, meaning it cannot be assessed with confidence until after insurance claims are resolved; and
- an event must give rise to costs significantly in excess of our insurance cover before the catastrophic event mechanism is available.

The first point exacerbates the lack of clarity as to what constitutes a catastrophic event. The second undermines the Commission's objective of allowing us to recover prudent additional net costs after an event.

To correct these defects the cost threshold should be based on costs incurred (rather price impact) and should be independent of the level of insurance cover. Insurance proceeds should be taken into account *ex post* (in the process of determining prudent additional net costs) rather than as part of the entry test.

Improved Cost Threshold

The following re-drafting of the Transpower IM addresses these defects and supports the Commission's objectives as described in Attachment D of the Draft Decision.

112 We can provide the worksheet used to calculate these figures on request.

3.7.1 Catastrophic event

Catastrophic event means an event-

(a) beyond the reasonable control of **Transpower**;

(b) that could not have been reasonably foreseen by **Transpower** at the time the most recent **IPP determination** was made; and

(c) in respect of which-

(i) action required to rectify its adverse consequences cannot be delayed until a future **regulatory period** without the **grid outputs** associated with the **revenue-linked grid output** measures being outside the range specified by the relevant cap and **collar** in the remaining **disclosure years** of the **regulatory period**;

(ii) remediation requires either or both of **capital expenditure** or **operating expenditure** during the **regulatory period**;

(iii) the full costs of remediation are not provided for in that **IPP determination**; and

(iv) the cost of remediation ~~net of any insurance or compensatory entitlements would have an impact on the price path~~ over the **disclosure years** of the **IPP** remaining on and after the first date at which a remediation cost is proposed to be or has been incurred~~, by an amount~~ is at least equivalent to $10 million~~1% of the aggregated **forecast MARs** for the **disclosure years** of the **IPP** in which the cost was or will be incurred~~.

This drafting provides us, the Commission, consumers and other interested parties with clarity as to the cost threshold before which the Commission will contemplate altering Base Capex incentive adjustments or permitting recovery of increased Opex. The threshold is independent of the timing of expenditure within a period and is independent of whether expenditure is treated as Opex or Capex.

A cost threshold of $10m is appropriate because it:

- exceeds the deductible amounts for our material damage (property) insurance policy – meaning that the incentive effects of the insurance deductibles are preserved;
- is commensurate with the total revenue at risk through revenue-linked grid output measures – this provides a degree of consistency between the grid outputs trigger and the cost trigger; and
- is roughly equivalent to 1% of average transmission revenue and 2% of average annual total expenditure – providing consistency with the way the existing drafting was arguably intended to operate.

Once an event has met the test for a 'catastrophic event', the Commission can take into account insurance and disposal proceeds (and any return on damaged assets) and the prudency of net additional remediation costs (including whether substitution opportunities have been exhausted).

If the Commission decides to permit recovery of additional costs then, as described in Attachment D of the Decision Paper, the IPP provides relatively simple and low-cost mechanisms for this to occur. The ability for the Commission to fully consider the situation *ex post*, and the existence of low-cost mechanisms for recovering costs both support a case for not setting the threshold too high[113].

[113] We also note that there is no cost threshold for firms with default price-quality path control seeking a customised price-quality path to deal with remediation following a catastrophic event.

7.1.2. Listed Projects

The Commission proposes to introduce a mechanism whereby 'listed' projects are excluded from the initial Base Capex allowance used to set the RCP2 price path, but can be added at a later date on approval by the Commission. This mechanism has been adopted in response to a concern we raised i.e. that large projects with high cost or timing uncertainty (such as large re-conductoring projects) are a poor fit with the Base Capex framework. We welcome the Commission's acceptance of the issue we raised, but the proposed inclusion of these projects within the Base Capex incentive is likely to generate material rewards or penalties due to estimation uncertainty rather than underlying efficiency gains or losses.

Our original proposal was to enable these projects to be approved on an individual basis during the control period for treatment in the same way as Major Capex projects. This provides timing flexibility and, due to the incentive arrangements for major projects, avoids rewarding or penalising estimation uncertainty.

In the Commission's analysis of this issue, it has taken the view that the material uncertainty for these projects is a transitional issue that will be resolved by RCP3. We disagree with this view. Accurate cost estimation for lines projects is inherently difficult, even at a relatively advanced planning stage. As a guide, cost uncertainty of 30% or more is expected at the regulatory approval stage, reducing to 20% following detailed design work. The alternative to reduce cost uncertainty below 30% is to significantly increase resources for investigation work for the 'listed' re-conductoring projects prior to seeking approval.

The Commission is proposing to list projects with an aggregate cost of ca. $275m. As a result, the Base Capex incentive regime would expose us to an economic reward or penalty of +/-$27m[114]. In our view, this exposure undermines the proper operation of the Base Capex incentive framework on the remainder of the portfolio with the risk that genuine efficiency gains could be swamped by the impact of estimation uncertainty.

A further difficulty with the Commission's proposal would arise as a result of 'listed' projects spanning RCP2 and RCP3. It is unclear how this would be accommodated under the Base Capex framework. This situation would require the Commission to approve RCP3 Base Capex allowance components in advance of considering the RCP3 Base Capex programme as a whole. This does not fit well with the regulatory control period framework.

In light of these issues, we remain of the view that the listed project mechanism should be:

- available for capital projects with high cost or timing uncertainty that renders them unsuitable for inclusion in the Base Capex allowance;
- a permanent feature of the IPP, not just a transitional mechanism for RCP2; and
- built on the Major Capex framework rather than Base Capex.

We are comfortable with other aspects of the Commission's proposed treatment of listed projects. We note that the analysis, consultation and approval process for re-conductoring projects should be more straightforward than for typical E&D projects – the need case is condition-based, options are relatively constrained and the benefits should be relatively uncontroversial.

In Section 4.1.2 we discuss the Commission's decision not to approve $15.1m of capital expenditure on a pricing system capable of delivering the Electricity Authority's proposed SPD pricing methodology. We accept this decision but emphasise that new pricing capability is likely to be required during RCP2 based on the Electricity Authority's latest programme. The timing and cost of this is outside our control. Although this work is very unlikely to exceed $20m, it is not part of a

[114] That is, one-third (the Base Capex incentive rate) of the uncertainty.

portfolio of projects and it has very uncertain costs and timing. In our view, this makes expenditure on implementing the Electricity Authority's changes to transmission pricing an additional candidate for treatment as a listed project.

7.1.3. Consumer Guarantees Act (CGA) Indemnity Costs

The Draft Decision argues that CGA indemnity payments should not be treated as a recoverable or pass-through cost on the basis that these costs should be under our control. The Commission proposes to observe how the operation of the new provisions develops in practice, and may consider an allowance for material claims that are outside of our control for future regulatory periods.

A new and unknown cost that is not in our control

The CGA requires us to indemnify retailers for payments made to customers for breaches of the acceptable quality guarantee where the failure "…was wholly or partly the result of an event, circumstance, or condition associated with" our services.

Our earlier submissions to the Commission explained that the statutory indemnity creates a new and difficult-to-quantify commercial risk for us. The costs of responding to an event are determined by the retailer, or by the Electricity and Gas Complaints Commission (EGCC), and are not in our control. As such, we are unable to control or accurately forecast its exposure (as there is no suitable evidence base). In these circumstances, we proposed that the indemnity payments under the CGA should be treated as a "recoverable cost" for RCP2 or included as an additional self-insurance allowance.

All submitters agree that we will incur additional costs as a result of the CGA indemnity obligations and none suggest that we should not be permitted to recover its efficient costs.

Interaction with other incentives and potential for quadruple jeopardy

We are concerned that the Draft Decision does not provide us with a reasonable opportunity to recover its efficient operating costs. In addition, we are concerned that effective operation of the Incremental Rolling Incentive Scheme (IRIS) would be compromised.

As proposed, an event will attract financial penalties under the service performance incentive arrangements and we will be exposed to two further penalties:

- there would be no mechanism to recover the efficient costs arising from our exposure;
- the IRIS will carry additional penalties into the next regulatory period if GCA costs exceed the regulatory allowance (which is proposed to be zero).

The Commission also proposes that, for the same event, we may also be subject to pecuniary penalties or criminal sanctions under the Commerce Act. For example, the impact of a single interruption to a High Priority site could be:

- **a Grid Output Measure charge:** of $606k;
- **CGA indemnity costs:** as determined by a retailer (or the EGCC);
- **IRIS multiplier:** as CGA indemnity costs flow through IRIS into the next period; and
- **Commerce Act charges:** pecuniary penalties or criminal sanctions.

Our proposal has been misunderstood by MEUG and the Commission

We agree with MEUG that we should not be "immunised" from exposure to the CGA – we support the application of revenue linked performance measures and we support IRIS. We also respect the Commission's discretion to take action under the Commerce Act (without prejudice to our comments on how this discretion is exercised).

We have not suggested that we are "immunised" from the CGA. This is why we proposed treating CGA costs as "recoverable" (not as "pass-through" costs) on the basis of the distinction between these terms in the Input Methodologies Reasons Paper in December 2010[115]:

> *"Pass-through costs are those costs that are outside the control of Transpower. Recoverable costs may also be passed through to prices, but are subject to an approval process."*

As a recoverable cost, therefore, the Commission would need to approve the annual CGA costs claimed by us. While the detail of the approval process would need to be developed we would, as a general principle, expect the Commission to consider whether we had acted reasonably to minimise the compensation paid to the relevant customers.

The guiding principle for designing an appropriate regulatory approach to the CGA costs is that the outcome should be consistent with a workably competitive market. In a workably competitive market, transmission revenue would reflect the efficient costs of providing transmission services. To achieve this outcome, the regulatory approach should allocate risks appropriately between ourselves and our customers, and provide incentives to deliver efficient outcomes.

In applying these regulatory principles, we maintain the view that treating the CGA costs as recoverable is an appropriate approach for RCP2. In particular, this approach:

- does not diminish our incentive to minimise the compensation paid to customers;
- manages the uncertainty associated with the CGA provisions by allowing cost recovery, subject to regulatory approval on an *ex post* basis;
- provides us with a mechanism to recover its efficient costs; and
- preserves the incentive properties of the IRIS, as recoverable costs are excluded from the operation of scheme.

There are two alternative regulatory approaches to addressing the CGA costs that would be consistent with good regulatory practice and the effective operation of the IRIS:

1. provide an operating expenditure allowance that reflects the expected cost of the CGA; or
2. provide an insurance premium that places a limit on our exposure.

In relation to the first approach, our RCP2 submission explained that the data to support such an assessment is not currently available. As a consequence, any estimate of the expected costs arising from the CGA may be subject to material error.

In relation to the second approach, a firm with an uncapped exposure operating in a workably competitive market would seek insurance and set prices at a level that recovered its premiums and deductible. It is a design feature of any insurance policy that the insured party continues to face incentives to minimise its liabilities in order to avoid the problems of "moral hazard". This regulatory approach, therefore, would be in keeping with MEUG's observation that "in a workably competitive market environment no business could immunise itself from some risk of exposure to CGA indemnity obligations."

We have obtained advice from Marsh regarding the structure and premiums that would be expected in the insurance market for the type of performance risk arising from the CGA. Marsh's advice is that an allowance for an insurance premium of $200k per annum would be an appropriate cover in order to cap the exposure at $1m. We would obtain cover from our captive insurer, Risk Reinsurance Limited.

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[115] Commerce Commission, Input Methodologies (Transpower), Reasons Paper, December 2010, paragraph X33.

By including an insurance premium in our Opex allowance, the Commission would preserve the incentive on us to minimise payments under the CGA, while making an appropriate allowance for the expected costs of the new risks that we face. It therefore provides a more appropriate outcome compared to the draft decision, which precludes Transpower's recovery of the efficient costs arising from the CGA.

For the reasons set out above, our preferred approach is to treat the CGA costs as a recoverable cost[116].

7.1.4. Form of the Base Capex Allowance

The Draft Decision dismisses our proposal that the Capex IM should be amended such that the Commission would approve an amount of Base Capex directly, rather than approving a commissioned value allowance. The Draft Decision discusses the difficulties applying CPI and FX disparity adjustments to a commissioning allowance, but does not discuss any of the efficiency benefits of a spend-based allowance. In our view:

- the proposed 'practical protocol' does not resolve the difficulties with applying CPI and FX disparity adjustments to a commissioned value allowance
- CPI and FX difficulties are a secondary concern in any event – the main driver for change is the potential for efficiency gains
- the Commission should pursue the efficiency gains associated with moving to a spend-based allowance now, rather than waiting until RCP3.

Efficiency Gains

Like any business, we *have* to manage projects on a spend basis. The costs associated with managing our finances on a spend basis are unavoidable. The commissioned-value allowance means that we must also manage our Base Capex programme on a commissioned value basis. This adds an unnecessary layer of complexity and uncertainty.

Unlike expenditure, it is not possible to accrue a portion of an incomplete asset. This means that the commissioned value of an asset at year end is very sensitive to the timing of physical commissioning. For example, a shift of one day in the commissioning date for a single transformer could alter performance against the Base Capex allowance by $5m or more. Commissioning timing is (and should be) dictated by engineering and network considerations rather than regulatory deadlines.

The challenges associated with managing to a commissioned-value allowance will become more acute in RCP2 due to the value at risk through the Base Capex incentive regime. Shifting to an expenditure based allowance would allow a tighter link between corporate governance actions and regulatory outcomes – producing more predictable and less volatile outcomes, and simplifying management of our capital programme at all levels of the business.

We note that shifting to a spend-based allowance would not alter how our revenue is determined – our forecast MAR and MAR wash-up would still be based on forecast and actual commissioned values (respectively). However, the Base Capex incentive mechanisms would operate based on the difference between actual and approved expenditure.

[116] In the event that the Commission were not to allow CGA indemnity costs to be recoverable, we would need to add a premium for CGA, of $0.2m per annum, to our Self-Insurance allowance.

CPI and FX disparity Protocol

We appreciate the Commission's proposal to work with us on a practical protocol for applying the Base Capex adjustment. Having considered the single large project concept, contemplated at C45, we have reservations about its efficacy. It does not address the fundamental concern that there is a variable (and potentially large) delay between the time when we transfer CPI and FX risk to our suppliers and the time we commission the resulting assets. Most of this delay relates to the time between expenditure outlays and commissioning and could be eliminated by moving to an expenditure-based allowance. This would make the CPI and FX adjustment more closely aligned to underlying variations in input costs.

7.2. IPP DESIGN

The Draft Decision discusses various design decisions regarding the RCP2 IPP. We provide our responses in the following table.

Table 25: IPP Design Features

Proposal	Response
Standard 5-year control period	Agree. Our proposal is on this basis and there is no compelling reason to adopt a shorter period.
Compliance point is *ex ante* forecast MAR based on unsmoothed building blocks updated annually to wash-up under- and over-recoveries and apply incentive adjustments	Agree. This approach has worked well in RCP1. Our expectation is that wash-ups will stabilise in RCP2 because the capital programme has fewer large commissioning events.
Substitution of opex for approved major Capex to be allowed	Agree. This situation arises when work carried out under an MCP is required under GAAP to be classified as opex – for example, if a staged approval approach is taken (as per the USI MCP) then an output of the MCP may be investigation-stage design work that cannot be capitalised. Recovery of such expenditure through the 'recoverable cost' mechanism, with a matching reduction in the MCP allowance, is a sensible way to deal with this situation without interfering with the IRIS. We will comment further on this proposed new feature in our submission on proposed IM amendments.
Legacy 2011 EV account balances to be cleared by the end of RCP2	Agree. This remains an appropriate transition approach.
Outstanding RCP1 EV entries to be carried forward to RCP2	Agree. This aligns with our understanding of how the framework should operate.
We may voluntarily under-recover the forecast MAR	Agree. This is consistent with the concept that the IPP controls maximum allowable revenue.
Mid-year cash flow timing assumptions to be applied to forecast MAR and MAR wash-up building blocks	The IPP drafting carries forward an error from the Transpower ID ROI formula. The error treats the mismatch between our pricing and disclosure years as generating a revenue double-up, whereas the actual effect is to advance the timing of any change in revenue – i.e. the adjustment is zero if forecast MAR is constant from one year to the next, positive if the forecast MAR is declining year-on-year and negative if the forecast MAR is increasing. We provide further detail in our supporting documents.

Major Capex and Base Capex incentive rates will be 33%	Agree.
The approved Opex allowance for the MAR wash-up will adjust for the disparity between actual and forecast CPI	Agree. We expect that this mechanism should produce adjustments to the Opex allowance that are reasonably valid. We remain concerned about the CPI disparity adjustments for Base Capex and for MCPs. For Base Capex, our concern is that CPI movements influence expenditure whereas the adjustment applies to a commissioned-value allowance. The lag between expenditure and commissioning degrades the accuracy of the disparity adjustment. For MCPs our concern is that the adjustment cannot account for the fact that it is not valid to adjust for CPI disparity that occurs at any time after we have transferred escalation risk to our suppliers.
We may request a reduction in the Opex allowance for material changes to the scope of a project.	Agree.
'Other regulated income' will be defined	Agree.
Accounting treatment of pass-through and recoverable costs will be codified.	Agree.
We may request approval to spread large EV adjustments over one of more pricing year.	Agree. This is a prudent inclusion. We note that in addition to supporting more stable and predictable prices, spreading can assist to avoid financial shocks that could increase our costs and deter investment.

7.3. IPP Evolution

This Section responds to Chapter 2 of the Draft Decision '*The individual price-quality path evolves over time*'. We welcome the Commission's effort to share its thinking. We agree with the Commission that predictability is important and that changes to the IPP should be "incremental, gradual and well-signalled".

7.3.1. Supporting Predictability

The regulatory framework under Part 4 of the Commerce Act was explicitly designed to support predictability, but the way that the Commission operates the framework (and how we engage) has an important bearing on whether this is achieved in practice. In particular, predictability is supported by:

- professional, constructive working relationships;
- careful, thorough and transparent decision-making processes; and
- principled, evidence-based decisions.

Our overall view is that development and operation of the framework to date is progressing well in these areas despite the challenges posed by the volume of work involved in establishing the initial IPP and IMs. The key threats and areas for improvement include:

- managing the availability of key resources. Carrying out IPP framework development and IM changes concurrently with assessing expenditure allowances can stretch resources for us and the Commission. This can result in efficiency-enhancing developments (such as the Capex allowance basis) and 'moveable' regulatory processes (such as the NIGU amendment application) being displaced by resource-intensive work streams such as the WACC percentile review and the telecommunications TSLRIC determination;
- adopting different, fit-for-purpose processes for different types of IM development. In our view, predictability could be enhanced by establishing a clear policy that complex, value-shifting IM settings (such as the WACC percentile) will be subject to deliberate, well-signalled process with a high hurdle for change. In contrast, efficiency is enhanced by adopting a comparatively nimble, responsive process for non-controversial IM changes (such as the twelve we proposed prior to the RCP2 process); and
- providing the conditions needed for incentive mechanisms to operate effectively. The Commission has carefully designed and implemented incentive mechanisms, which we support as the best way to continually drive towards sustainable, efficient expenditure levels. We want to continue our 'high-trust' approach, where we transparently put forward our best view of costs with confidence that, while our analysis will be tested carefully, the Commission will not make broad-brush cuts.

7.3.2. Developments for RCP3

Below we respond to several of the Commission's specific comments on how the IPP may develop in RCP3.

Table 26: IPP Developments for RCP3

Comment	Response
The Commission's interventions during a period may reduce over time.	We agree that, for the sake of efficiency, we should strive to minimise administrative burdens created by the IPP. We support moving to an arrangement where the Commission is not required to make annual price-path update determinations. This would not reduce assurance costs, but would reduce the Commission's costs and would help us to avoid some of the workload peaks created by the timing requirements in the current process. This would enable us to focus more of our effort on ensuring the information we generate is adding value for our customers and other stakeholders. Given the efficiency gains that could be created, we encourage the Commission to challenge itself again as to whether we could move from a determination-based to a disclosure-based update process in RCP2.
The Commission's examination of expenditure proposals may move further towards a high-level (top-down) approach, with greater emphasis on governance and monitoring reasonableness.	It is not clear whether this comment refers to examining progress against plan within a period, or to assessing expenditure proposals. If the latter, then we agree that the Commission should rely on the incentive mechanisms it has put in place as the primary means of establishing and maintaining efficient expenditure levels. This is the most effective way of driving efficient whole-of-life costs.

RCP2 Grid Output Measures (GOMs) are based on historical performance.	We disagree with this observation. We have developed long-term targets based on our efforts to understand customer preferences. These targets are not on based on historic performance. Because some of these long-term targets (particularly for High Performance and Important sites) present a significant challenge that will take some time to achieve, we have used a transition model to inform RCP2 targets. The transition model is based on 'closing the gap' between historical and long-term performance – i.e. it is a forward-looking model.
RCP3 GOMS should include asset health and criticality measures	We are open to the idea that there should be one or more revenue-linked GOMs relating to asset health in RCP3, but the asset health and volume-linked measures we propose for RCP2 should not be a permanent feature of the IPP. The RCP2 measures have been proposed specifically to allay deliverability concerns. They rely on a 'frozen' asset health model and data set and they are constructed to neutralise the Base Capex incentives for the in-scope asset fleets. It would be counter-productive to repeat this approach again in RCP3. We may, depending on resources available for business improvement, be in a position to put forward network or circuit-level asset health metrics in RCP3 or 4 that properly complement the suite of service output measures while reinforcing our internal asset management practices and avoiding interference with Base Capex incentives.
RCP3 may include more granular or VoLL-based service measures	We are not convinced that either of these developments would be constructive. There are benefits to have a relatively simple (five category) framework given that: • there are diverse consumers 'behind' most N-1 security GXPs with varying willingness to pay for reliability (and hence varying VoLL); and • GXP-level performance is influenced by network and firm-level investments in assets and capability (meaning performance cannot be 'tuned' too finely). In addition, while there have been advances in methodologies for estimating VoLL (notably by the Electricity Authority in recent years) we doubt it will ever be possible to derive a matrix of VoLL figures that accurately capture the economic cost of interruptions.

In addition to the above comments, Chapter 2 of the Draft Decision appears to imply that measures will be added to each control period. In our view, the set of measures should be adaptive rather than additive. The next set of measures will build on experience with RCP2 measures, development of our asset management capability and engagement with our customers.