ENHANCEMENT AND DEVELOPMENT BASE CAPEX

Response to Draft Decision

25 June 2014

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of Contents

EXECUTIVE SUMMARY

The Commerce Commission's (Commission's) Draft Decision[1] proposed a reduction in our Enhancement and Development (E&D) Base Capex of $67.1m, from $123.8m to $56.6m. This is the result of the Commission declining and amending some of the projects we included in the portfolio.

A reduction of this size would restrict our ability to efficiently manage our E&D portfolio and to respond to changing circumstances on the Grid. It may increase costs to our customers over the longer-term and reduce service performance. In some cases the System Operator will need to manage customer load or constrain generation leading to increased costs to customers.

The reduction would place our assets at a higher risk of failure and reduce our ability to meet our Service Performance targets in RCP2. An inability to undertake required projects would increase the risk that we do not meet the Grid Reliability Standards (GRS) at some parts of the core Grid during RCP2.

Our response to the proposed reductions addresses the following:

- the Commission's approach to reviewing our E&D base capex;
- concerns raised about our general forecasting and planning approach; and
- concerns raised about specific projects.

Commission approach to reviewing our E&D Capex

The Commission's approach to reviewing E&D Base Capex was to assess individual project overview documents (PODs) and accept, amend or decline projects based on their needs and cost benefit analysis.

This discrete approach does not adequately recognise the uncertainties involved in E&D Capex.

Estimating E&D Capex over a five to seven year period is not straightforward. While we plan years ahead and identify issues and projects through our Annual Planning Report we generally do not make definitive decisions to invest until much closer to the need date when the needs are relatively certain. We know from experience that circumstances can change rapidly making the investments that seemed to meet customer needs early on no longer appropriate.

Reviewing E&D projects purely on a case-by-case basis prior to an RCP makes no provision for the following sources of uncertainty:

- projects dependent on third party decisions, particularly the late release of decisions by those operating in competitive sectors including the generation sector. We consider it very likely that such projects, as-yet unidentified , will be required during RCP2;
- system conditions and constraints that arise unexpectedly leading to a need to reprioritise our E&D expenditure; and

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

- the reduced ability to effectively substitute E&D projects to address specific issues due to scope and value.[2]

We seek to manage these uncertainties by planning a portfolio of projects. This concentrates on the most likely projects but recognises other projects may become higher priorities while remaining flexible to change in circumstances.

The projects that we used to build up our E&D portfolio represented our best view, at the time of submission, of which growth or security issues were most likely to justify investment during RCP2. Most of these projects are still at the early stages of development and must go through our full planning processes.

It is neither practical nor cost-effective to complete several detailed options investigations for projects many years in advance of the need date. We would duplicate the detailed work: once for the RCP submission and again closer to the need date to confirm we have the right solution.

We fully expect that some project priorities and optimal solutions will change with new information and further investigation. Some will be deferred and some brought forward, including some not identified in our proposal.

For this reason, total E&D Base Capex is as important a consideration as the individual projects. The proposed reduction in the draft decision would restrict our ability to efficiently address eventual system issues and constraints, leaving us unable to respond to needs as they arise. This will have impacts on both longer-term costs and service performance experienced by our customers.

General forecasting and planning concerns

The Draft Decision raised general concerns about our demand forecasting, needs identification and option analysis.

Demand forecasting

Our demand forecasts were based on our 2013 Annual Planning Report (APR) which raised issues for the Commission, including that the2013 APR was developed in the period following a particularly harsh weather event in 2012 which masked flattening demand.:

We have now reviewed and updated our demand forecasting since our 2013 APR.

During the review process we provided information[3] on the impacts of the 2014 APR demand forecast on our demand-growth driven projects. In our response we noted two possible revised timings (to projects in PD 32 and PD 44).

Need identification and option analysis

Strata reviewed the needs identification and option analysis for each of the PODs. Three general concerns were raised in relation to several PODs: the lack of customer consultation on needs; our options analysis; and our consideration of Special Protection Schemes (SPSs) and Demand Response (DR) as alternatives to transmission investment.

The main source of identified E&D investments is our APR. We consult with our customers each year when preparing the APR on the demand forecasts at their points of supply and on

2 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 Response to Commerce Commission question Q051.

the regional chapters (where the E&D investment needs and indicative transmission solutions are described).

We regard SPSs and DR as enabling us to defer more expensive transmission investments and as mitigation measures against delays in commissioning or demand increasing faster than forecast. We have considered these where appropriate.

Specific projects

In Chapter 4, we address Draft Decision concerns on individual projects and also provide updates where we have progressed analysis on projects since the expenditure proposal. For some projects we submit revised PODs.

Revised E&D Capex

We propose to reduce our expenditure proposal for E&D Capex to $99.4m. This reflects revisions to our PODs, and will provide us with the flexibility to respond to other needs as they arise.

The table below summarises our revised Capex for each project.

	Project	Proposal	Draft Determination	Revised Proposal	Revised POD
30	Otahuhu-Wiri Transmission Capacity	$18.5	$0.3	$18.0	✓
31	Relieve Generation Constraints	$16.7	$6.1	$6.1	
32	Upper North Island Reactive Support	$8.0	$8.0	$8.01	
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	$10.9	$10.9	
36	Bunnythorpe Interconnection Capacity	$8.8	$8.8	$8.8	
37	North Taranaki Transmission Capacity	$3.0	-	13.68	✓
38	Timaru Interconnecting Transformers Capacity	$2.52	$2.52	$2.52	
39	Southland Reactive Power Support	$5.95	$4.2	$5.95	
40	High Impact Low Probability Event Mitigation	$9.23	$9.23	$9.23	
41	Hororata and Kimberley Voltage Quality	$3.36	-	$3.36	✓
42	Islington Spare Transformer Switchgear	$2.4	-	0.54	✓
43	Haywards Local Service Third Incomer	$1.8	-	$0.6	✓
44	E&D Other	$1.7	$0.3	$0.85	✓

1 INTRODUCTION

1.1 Purpose

This paper responds to the Commission's Draft Decision on our RCP2 E&D Capex and the Strata Report[4].

In this submission "E&D Capex" refers to capital expenditure on all E&D projects that are below the $20m threshold.

1.2 Overview

The Draft Decision proposes to reduce our E&D Capex from $123.8m to $56.6m, the result of the Commission declining and amending some of the projects in the portfolio.

A reduction of this size would restrict our ability to efficiently manage our E&D portfolio and to respond to changing circumstances on the Grid. This may increase costs to our customers over the longer-term and reduce service performance. In some cases the System Operator will need to manage customer load or constrain generation leading to increased costs to customers.

The reduction would place our assets at a higher risk of failure and reduce our ability to meet our Service Performance targets in RCP2. The reduction would also increase the risk that we do not meet the Grid Reliability Standards (GRS) at some parts of the core Grid.

This paper presents a revised E&D Capex proposal for RCP2 and addresses the following:

- the Commission's approach to reviewing and reducing our E&D Capex;
- concerns about our general forecasting and planning approach; and
- concerns raised about specific projects.

1.3 Document structure

The document structure is as follows.

Chapter 2 provides our views on the Commission's approach to reviewing our E&D Capex. It also describes in more detail the way we forecasted E&D Capex for RCP2 as this is important context for our proposal.

Chapter 3 responds to concerns about our general forecasting and planning approach. This chapter provides an explanation of our revised demand forecasting approach, and summarises the impact on our projects. It also provides relevant background on our needs identification and options analysis.

Chapter 4 responds to concerns about specific projects. It also provides updates on a number of the projects.

Chapter 5 provides a summary of our revised proposal.

[4] Strata Energy, Technical Advisor report on the Transpower New Zealand Ltd IPP Proposal for RCP2, 16 May 2014

2 COMMISSION'S ASSESSMENT APPROACH

2.1 Introduction

Our December 2013 proposal for RCP2 E&D Capex was $123.8 million built up from 25 projects grouped into 15 portfolios.

These projects represented our view of demand growth or security issues identified in our APR that were most likely to justify investment during RCP2, and provide the most significant benefits to customers. Most of these projects are still at the early stages of development and must go through our planning and investment approval processes.

It is likely costs and designs will change, that some of the projects might not eventuate in RCP2, but others not included will become more urgent.

The Commission's approach to reviewing and reducing the E&D Capex was to review the individual project overview documents (PODs) and accept or decline projects based on the needs and cost benefit analysis.

This approach does not recognise the uncertainties involved in E&D investment.

The result of the Commission's approach is a significantly lower E&D Capex allowance of $56.6m based on a lower number of projects. This reduction would restrict our ability to efficiently manage our E&D portfolio and to respond to changing circumstances on the Grid.

The rest of this section:

- describes our approach to planning our E&D portfolio for RCP2; and
- explains why the approach used to reviewing our E&D Capex is not appropriate and outlines the potential impacts on costs and service performance.

2.2 Forecasting the E&D portfolio for RCP2

Estimating the E&D Capex we require over a given five year period is not straightforward. We plan years ahead and identify issues and projects through our Annual Planning Report (APR) but we do not make detailed plans to invest until the needs are relatively certain. We manage this uncertainty by planning a portfolio of projects. This concentrates on the most likely projects but is flexible to changes in circumstances.

We fully expect that some projects will change with new information and further investigation. Some will be deferred and some brought forward, including some not identified in our proposal.

For our RCP2 expenditure proposal we selected indicative E&D projects to demonstrate the required level of expenditure in the E&D RCP2 portfolio. These projects represented our view of the projects most likely to be required in the RCP2 period.

We used the following approach to select projects and build up our E&D Capex forecast:

- developing a 'long-list' of potential E&D Capex projects for RCP2. This was based on projects identified in Grid Reliability Report and the Grid Economic Investment Report in the 2013 Annual Planning Report, additional projects that we identified through our risk management processes. The long list of around 50 projects is included in Appendix B;

- reducing the long list to a short list of 25 projects that we believe are most likely to be required during RCP2;
- developing 15 PODs for the 25 short listed projects. The PODs summarise the need for the investment, identify a long list of options, summarise the rationale for shortlisting options, cost the options, and indicate the potential preferred option. The 15 PODs provide an evidence base for the level of E&D expenditure in RCP2; and
- building up our E&D Capex forecast from the estimates in the 15 PODs.

We expect that some of the E&D projects will change as new information and further investigation indicates more optimal developments. Some E&D projects will be deferred or brought forward based on new information. From experience we know there will be E&D projects that we have not identified in our proposal that will become a higher priority during RCP2.

During RCP2, we will substitute projects where necessary. We will not progress projects that we find do not pass the investment test. We will substitute new projects that do pass the investment test within the E&D Capex envelope as appropriate.

All E&D Capex projects will go through our Planning Processes[5] before we make the investment. This requires, amongst other things, that we consult with stakeholders and that the investments provide favourable net benefit against other options. The process is similar to the process we follow for our Major Capex Projects (MCPs) but commensurate with the value of the investment.

2.2.1 Project overview documents

Most of the 25 short listed projects are in the early stages of planning. All but two are at the BC1 stage[6], in which we undertake initial need analysis.

We have considerable analysis and planning, customer consultation and internal approval processes to undertake for most of the projects before they eventuate. Over the next year and in the early years of RCP2 we will progress these projects but will remain open to alternative approaches or alternative projects. Maintaining the integrity of our approval processes and ensuring flexibility allows us to refine projects and to take account in changes in forecast demand or generation.

The 15 PODs provide overviews of our current analysis and options for the E&D shortlist. The PODs provide high level scope and cost estimates alongside projected benefits, provided to support our E&D Capex submission.

2.3 Commission approach to reviewing our E&D Capex

The approach used to review our E&D Capex was based on an assessment of individual PODs leading to these individual projects being either accepted, amended or declined. This discrete approach is not appropriate for the following reasons:

- it does not adequately recognise the following uncertainties:
  - projects dependent on third party decisions, particularly the late release of decisions by those operating in competitive sectors including the generation

5 Appendix A provides an overview of these.

6 See Appendix A for an explanation of our Business Case process.

sector. We consider it very likely that such 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. This was the case during RCP1. Two examples of such projects during RCP1 were the Wilton bus rationalisation and Roxburgh bus spitting scheme; and
    - limited scope to effectively substitute E&D projects to address specific issues due to scope and value;

- the need to maintain a degree of flexibility, it is often appropriate to finalise a preferred option as late as possible in the planning process to see if better options become available; and
- it is neither practical nor cost effective to complete several detailed options investigations for projects many years in advance of the need. We would end up duplicating work: once for the RCP submission and again closer to the need date to confirm we have the right solution.

2.3.1 Impacts of Reduced E&D expenditure

Restricted ability to substitute projects

We have reviewed several of the PODs to test the need dates for the projects. In some cases the need dates could be deferred, but similarly our reviews have shown that there could be justification to accelerate others, including larger projects not already considered in our proposal. Whilst there may be scope to substitute smaller projects, a E&D Capex of $56.6m would restrict our ability to introduce any larger projects that fall below the $20m threshold. It may provide an incentive to prioritise approved projects.

Given the Commission view that R&R expenditure has been justified and they are seeking an incentive to ensure we deliver the outputs, it is unlikely we will be able to cover additional, material E&D projects with forecast R&R expenditure.

In the Strata Report[7], Strata argues that the reduced allowance is a prudent amount to allow for needs, particularly considering that:

- major project risk is mitigated for contingent unforeseen needs in excess of $20 million;
- some of the adjusted projects could be re-scoped to fit within a major project; and
- there is scope for project substitution as Strata considers that it will be possible to delay some projects.

Under the Capex IM we must pursue projects over $20m as major capital projects (MCP). This could lead to an incentive to package projects as MCP unnecessarily, weakening incentives to keep projects below $20m.

If larger projects, such as Otahuhu-Wiri Transmission Capacity or North Taranaki Transmission Capacity are declined it would be very difficult to include them as a substitute for other projects, or to accommodate any other larger projects.

[7] Paragraph 321

Cost and performance impacts

The E&D investments we undertake in RCP2 will be required to meet the investment test. The investment test requires that the option with the greatest net benefit is selected. This requirement helps ensure that the best investment is made with efficient costs.

There are several consequences if we are unable to fund E&D projects in RCP2, for example:

- the system operator may be required to manage customer load or constrain generation. Load management will have economic costs for consumers. The costs of constrained generation will increase costs to market participants;
- reduced ability to meet our service performance targets for RCP2. We run our assets closer to power system limits with increased risk of interruptions or widespread collapse; and
- replacing or refurbishing assets without taking the opportunity to optimise investments over a longer-term period.

3 GENERAL CONCERNS

The Strata Report raised general concerns[8] about:

- demand forecasting; and
- needs identification and options analysis.

This section addresses these concerns.

3.1 Demand Forecasting

Our demand forecasts were based on our 2013 APR which raised issues for Strata and the Commission, including that the 2013 APR was developed in the period following a particularly harsh weather event in 2012 which masked flattening demand.

During the review process the Commission asked us[9] what the impacts of the 2014 APR demand forecast would be on our demand-growth driven projects.

This section explains the changes we have made to demand forecasting and the impact this has had on our 2014 APR. It also outlines the impacts the 2014 APR demand forecast would have on our demand-growth related projects.

3.1.1 Changes to our demand forecasting

In 2013 we reviewed our forecasting methodology in light of recent low levels of growth. This included gathering opinions on recent and future levels of growth, and the perceptions of key industry stakeholders on drivers for growth. These stakeholders included generator/retailers, lines companies, industrial consumers, interest groups, and Government departments.

As a result of the review, and in response to comments we received, we made a number of changes, including:

- adding a model to our ensemble forecasting approach that is based on fitting a short-term trend. This model assumes more recent trends in demand growth are more indicative of future trends and recognises that the recent low level of growth could continue;
- removing an 'ad-hoc' model which was based on experts making predictions. While this model has merit it is simplistic and subjective;
- taking explicit account of industrial loads and embedded generation in our models. Significant changes in industrial loads, if included in regression type models, can obscure trends in underlying demand. The commissioning of new embedded generation has been significant in the last 10-15 years and has obscured underlying trends in grid offtake demand. Where possible we have tried to account for these changes;

8 These are outlined in section 6.3.5 of the Strata Report. Appendix B provides a review of each individual POD.

9 Commerce Commission question Q051.

- altering the econometric (or exogenous) model to focus on producing peak demand forecasts. Previously it produced an energy forecast from which it derived a peak demand forecast;
- adding a temperature variable to reflect the influence temperature has on peak demand in winter; and
- changing our approach to directly forecast regional and seasonal demand, rather than forecasting national demand and allocating it to regions. This approach better identifies divergent trends between regions and seasons.

3.1.2 Impact of revised demand forecasting (2014 APR)

As a result of our new approach, our view of the expected level of future demand growth has reduced significantly, shown in Figure 1 as the bold red line.

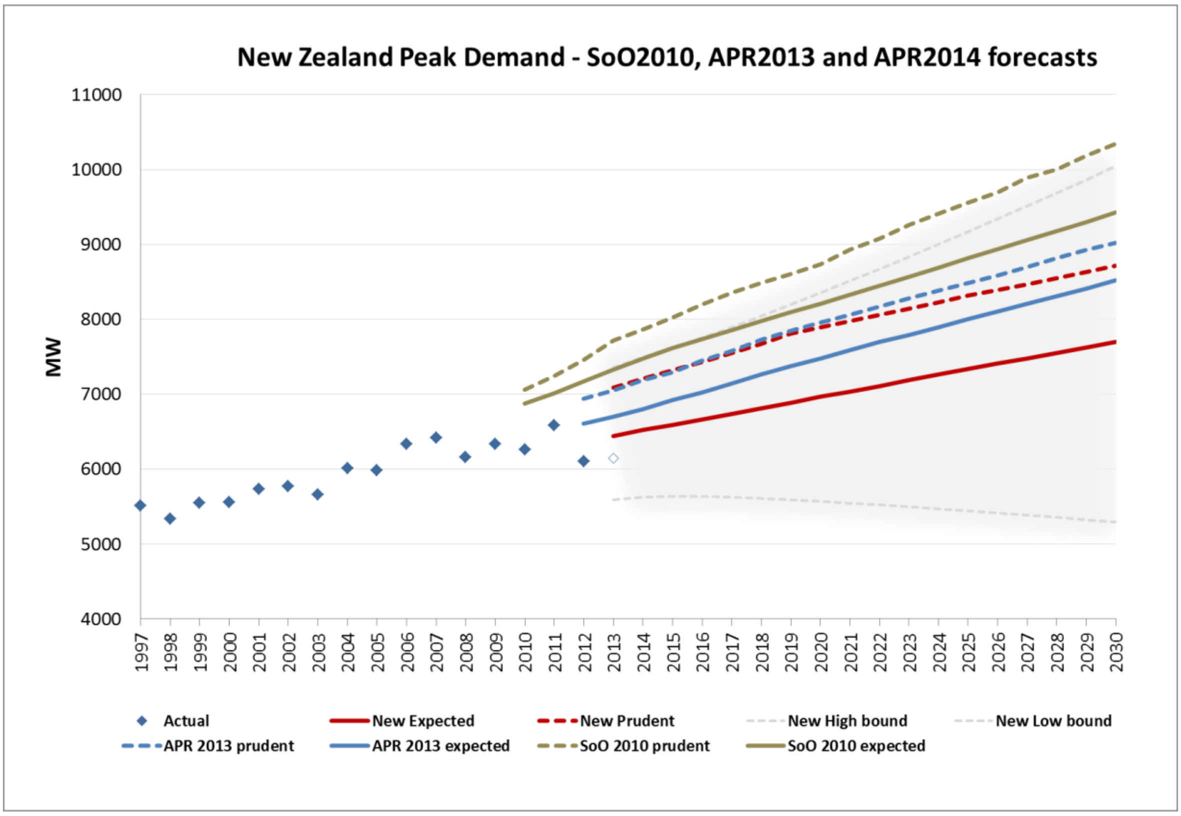

Figure 1 Comparison of peak demand forecasts

As noted by Strata, there is no corresponding, significant reduction in the prudent forecast. This is because the prudent forecast captures the future uncertainty in peak demand. Whilst the underlying trend in actual demand growth continues to slow, the uncertainties remain high.

Within our models there are uncertainties associated with the estimation of the ensemble models and the forecasted parameters, such as GDP and population. We statistically quantify the uncertainty associated with each of these factors and define a plausible range of future demand growth - shown by the grey shaded area in Figure 1. As can be seen above, our models suggest that future levels of demand are very uncertain. Recent growth, while relatively flat has also been more variable across regions and seasons. This acts to increase the uncertainty in our forecasts.

In our planning we use the 'prudent' forecast. It represents a 10% Probability of Exceedence (PoE) forecast until 2019, and then grows at the expected level of growth. This means that up until 2019 there is a 1 in 10 chance that the forecast will be exceeded. This 10% PoE definition is well established, being similar to that produced by the Electricity Commission in the 2010 Statement of Opportunities.

We use a prudent forecast as transmission upgrades can take 5-7 years to complete and we need to identify issues with enough time to complete upgrades without exposing New Zealand consumers to excessive risks of unserved energy, or excessive costs. The consequence and risks associated with planning and investing too late could be very significant and we believe they need to be managed conservatively.

Strata comments that our forecasts give the impression of on-going conservatism which they attributed to our ensemble approach to modelling. Our prudent forecasts are conservative by construction as they are influenced more by extremes that the expected forecasts. The apparent step up in the prudent forecast has also been exacerbated by ongoing weakness in demand in 2012 and 2013.

As we seek to increase demand response capability in the future, there is an opportunity to use this as a risk mitigation tool and potentially adopt a less conservative view of future levels of growth in our planning approach and investment timing.

3.1.3 Changes to E&D for 2014 Demand Forecast

The 2013 APR prudent demand forecast was used to identify E&D Capex projects during RCP2, being the most recent available forecast. We finalised the national demand forecast for the APR 2014 in Oct 2013 and the first draft regional report in Nov 2013, the same time we were finalising the RCP2 expenditure proposal.

This section describes how the demand forecast in the 2014 APR affects the timing of projects in the E&D portfolio.

The larger E&D projects, where timing is driven solely by expected demand growth, are:

- PD 35, Otahuhu-Wiri Transmission Capacity (primarily demand at Wiri and Bombay Grid Exit Points); and
- PD32, Upper North Island Reactive Support 2015-2020.

The timing of PD 44, E&D Other Supply Transformer Capacity projects, is also driven by expected demand growth. These projects enhance the capability of ancillary assets (e.g. metering and protection current transformers) that limit the use of installed supply transformer capacity.

The projects, where timing is influenced by condition, but the benefit of enhancement is driven by expected demand growth, are:

- PD 35, Otahuhu and Penrose Interconnection Capacity; and
- PD 36, Bunnythorpe Interconnection Capacity.

In these projects assets being replaced have reached end of life, based on condition assessment in or around RCP2. There is a benefit in enhancing the replacement assets capability to meet the long term anticipated demand.

The remainder of the E&D Capex projects are not primarily driven by demand. There is either a Code requirement (with associated benefits for customers) or there is an economic benefit to enhance Grid capability.

Since we submitted our proposal we have checked the need date for E&D projects based on the 2014 APR demand forecast. We identified three changes:

- Upper North Island (UNI) Reactive Support 2015-2020 (up to $4m). A lower regional demand forecast indicates that one of the new capacitors (100 MVAr) could be moved into RCP3. We will carry out a more detailed investigation to confirm this as there are likely to be other benefits (e.g. managing other regional voltage issues) in installing that capacitor in RCP2.
- Opunake supply transformer constraint relief ($0.52m). Need date shifted to RCP3 due to lower 2014 forecast.
- Te Awamutu supply transformer constraint relief ($0.52m). Need date shifted to RCP1 due to higher 2014 forecast.

While two supply transformer capacity projects have shifted out of RCP2 according to the most recent demand forecast it is quite likely that other supply transformer capacity issues will arise in RCP2 due to actual Grid exit point demands increasing faster than forecast.

The following table summarises our assessment of how the 2014 APR demand forecast changed the timing of projects from the timing in our expenditure proposal. All other projects are unchanged.

Table 1 APR 2014: Changes to the timing of projects

E&D Drivers	POD	Changes
Load	PD32. Upper North Island Reactive Support 2015-2020	The additional reactive power required during RCP2 has reduced to 100 MVar. We will carry out a more detailed investigation to confirm this.
Load	PD44. E& D Other. Opunake supply transformer capacity	This project is to resolve the metering constraint of the supply transformer. Lower GXP forecast in APR 2014 defers need for investment until RCP3.
Load	PD44. E& D Other. Te Awamutu supply transformer capacity	The need date for this project has advanced to RCP1 due to the higher GXP load forecast

3.2 Needs identification and options analysis

Strata reviewed the needs identification and option analysis for each of the PODs, and we have responded to their project specific concerns in Chapter 4. There are some general concerns that Strata mentions in relation to our consultation with customers, options analysis and use of SPSs and DR as alternatives to larger transmission investment.

This section responds to each of these issues.

3.2.1 Customer consultation

Each year, when preparing the APR, we consult with our customers on the demand forecasts at their points of supply and on regional issues (including E&D investment needs and indicative transmission solutions).

In some cases, we agree that issues can be managed in the interim by operational measures such as customers carrying out load management or load shifting. For connection assets (e.g. supply transformers) we will agree with customers what the preferred solution will be. For interconnection assets, we determine an indicative solution that meets the GRS.

As part of our normal development process we engage with customers to discuss the projects as they progress and where there are multiple customers for a major project we will set up a customer working group (for example, on Otahuhu-Wiri Transmission Capacity).

3.2.2 Options Analysis

We assembled a long list of options for each POD. We refined that list using a set of criteria such as cost, practicality, and good industry practice. We then selected a likely option that would meet the investment need and developed a high level cost for that option. In this process we necessarily discarded some options for various reasons. We do not consider the discarding of options at this stage to be of great concern as:

1. The option may well be considered again as part of our approval process. We carried out the long list to short list to likely option to get an indicative cost for the project.
2. Our past experience with E&D projects is that we do not identify the preferred option with certainty until late in the investigation. We are required to select the option that provides the greatest net benefit. This requires the detailed investigation of the scope of costs for a number of options. We often find that promising options at early stages look poor in comparison after costs are refined.

3.2.3 Use of Special Protection Schemes and Demand Response

Strata has concerns as to whether we consider SPSs and DR as pragmatic options to be used to defer investment in the Grid (for example in the Otahuhu-Wiri Transmission Capacity POD, PD30) as we have not included costs for them in the likely option.

As indicated the PODs we will consider DR as an option to defer investment or manage risks of construction. However, DR costs are treated as Opex. Opex associated with an E&D project needs to be included in our Opex expenditure proposal. While the DR cost is not included in the base Capex estimates in the PODs, it is factored into the cost-benefit analysis.

The use of SPS to defer investment is reasonably well established on the transmission grid. An SPS can reconfigure the grid (for example for the Tokaanu bus splitting scheme), trip load or ramp generation up or down. Simple SPSs can be implemented at low cost. A more complex SPS can be quite expensive especially if new communications links are required.

SPSs do not work in all situations. In some cases (for example an SPS designed to react to low voltage situations) an SPS is not be able to distinguish between normal system conditions and abnormal conditions where the SPS needs to act. In other cases we are not be able to design an SPS that can operate with discrimination with other SPS or protection or control systems.

We can use SPS to defer investment and/or as a mitigation measure prior to another investment and we have indicated this in some PODs, for example the Otahuhu-Wiri Transmission Capacity POD.

4 INDIVIDUAL PROJECT CONCERNS AND UPDATES

This section provides our responses to Commission concerns about individual projects. It also provides an update on any further analysis we have undertaken on the projects since our December 2013 expenditure proposal.

4.1.1 PD30 Otahuhu-Wiri Transmission Capacity

Load growth at both Bombay and Wiri means that, if there are outages on the 110 kV Bombay-Otahuhu circuits, we expect circuits between Otahuhu and Wiri 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 GRS, we expect this option to deliver significant loss benefits of around $0.9m a year[10]. This further justifies the projects inclusion in RCP2. Since our December proposal, and in response to Commission concerns, we have completed a supporting report[11] which documents the needs analysis, and investigates and assesses options. We have revised the PD30 substantially to reflect this work.

The Strata Report[12] noted four concerns about the December 2013 POD:

- the need identification was unclear and not substantiated;
- conflicting information was provided in respect of the expected project timing;
- the options analysis was weak (at least it was weakly documented); and
- there was no information provided relating to customer consultation.

Our revised POD and supporting report should address the first three concerns. We have already consulted with customers as part of the APR process (see section 3.2.1), and we have discussed the project with both Vector and Counties Power. As part of our normal process for large projects involving multiple customers, we will establish a customer working group with Vector and Counties Power to confirm the inputs and secure detailed feedback on the options.

Summary

We continue to propose this project and submit a revised POD with supporting report. There are small changes to the costs (from $18.5m in the December expenditure proposal to $18.0m). These changes reflect design changes to the preferred option, which we would expect to see as we progress projects through the approval process.

The costs for this project are approaching the threshold for base capex. Given the cost uncertainty the project may become an MCP. If the expenditure is declined, but costs fall below $20m, given the size of the E&D portfolio we will be unable substitute expenditure to complete the project in RCP2.

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10 We may advance the timing of the interconnection at Bombay, removing the need for the SPS, if sufficient loss savings indicate this is the most economic alternative.

11 Options Analysis - Otahuhu Wiri Transmission Capacity

12 Section A.1

4.1.2 PD31 Relieve Generation Constraints

This portfolio covers investments to relieve generation constraints using a range of approaches including capacity upgrades, the installation of SPSs, and a generation runback scheme. The investments we make will depend heavily on the investment choices of electricity industry participants.

Since our December expenditure proposal, and in response to Commerce Commission concerns, we have undertaken more detailed investigations of the largest project in this portfolio, the proposed upgrade of Kawerau T13.

Strata had two primary concerns with this project[13]:

- the rationale behind our current project to upgrade T12; and
- whether upgrading T13 within RCP2 is the best option.

The rationale behind our current project to upgrade T12

We have upgraded Kawerau T12 under a Commission-approved Grid Upgrade Plan (GUP)[14]. Strata queried the rationale behind upgrading T12 rather than T13 in the current project.

> *Paragraph 648: 'Given the upgrade of only one of the two interconnecting transformers was able to pass the Grid Investment Test, it is in retrospect unfortunate that the healthier of the two transformers was chosen for replacement.'*

The reason only one transformer needed upgrading is the uneven power sharing between the transformers due to their different impedances. There were sound reasons for choosing the healthier of the two transformers for replacement given in the GUP. As stated in the GUP, the advantage of replacing the younger transformer was that the remaining life of T12 could then be used at Edgecumbe.

Our asset condition information indicated that both transformers were in reasonable condition. The poor condition of Kawerau T13 was discovered during the commissioning of the new T12.

Whether upgrading T13 within RCP2 is the best option

We have reassessed the condition of Kawerau T13, our contingency plans for its failure, and load and generation in the region.

Recent oil analysis on T13 shows the paper insulation has degraded. The transformer has a high risk of a winding short circuit failure following a close in system fault on either the 220 kV or 110 kV network.

Should the transformer need to be replaced or removed from service during RCP2 we will replace it with one of the following (in order of preference):

- the old Kawerau T12 unit (if available);
- the 150 MVA spare transformer (if available); or
- the 250 MVA spare transformer.

[13] Section A.2

[14] GUPs have been replaced by MCPs.

If and when generators commit to new generation in the region we will determine any requirement for additional interconnection capacity. Such enhancement is likely to be an MCP that includes 220 kV development options.

Summary

We are no longer proposing to include expenditure of $10.6m for upgrade of Kawerau T13, but continue to propose the remaining projects in this portfolio as accepted by the Commission in its Draft Decision.

4.1.3 PD32 Upper North Island Reactive Support

This portfolio provides additional reactive support in the Upper North Island to support increasing regional loads.

Although supporting the portfolio, Strata held the following minor concerns[15]:

- inconsistency between the rationale for additional reactive power support in this portfolio and the 2013 APR, which forecasted a need for local voltage support investment at points in Northland, north of Marsden;
- the relative lack of specificity in considering options such as SPS and DR, and whether SPS and/or DR defer the timing; and
- a high likelihood that flat demand growth will further delay this project.

Inconsistency between the rationale for additional reactive power support in this portfolio and the 2013 APR

This POD does not relate directly to the north of Marsden transmission issue (noting that any reactive support installed north of Marsden would affect the timing of PD32). The north of Marsden low voltage issue relates to the loss of a bus section at Maungatapere and relates to low voltages at Kaikohe and Kensington. The 2014 APR has concluded there is no longer a need for Transpower to provide voltage support north of Marsden within the RCP2 period[16].

It was intended at the time of the publication of the 2013 APR that this project would be an MCP (combining both static and dynamic reactive support). Since then we have reviewed the need for reactive support in the Upper North Island. A reduced demand forecast combined with a revised voltage recovery requirement has enabled investment in dynamic reactive support to be deferred until after RCP3. There is still a need for static reactive support before then hence the inclusion of this POD.

The relative lack of specificity in considering options such as SPS and DR

DR costs are treated as opex. Opex associated with an E&D project needs to be included in our opex expenditure proposal. While the DR cost is not included in the base capex estimates in the PODs, it is factored into the cost-benefit analysis. We note the Commission intends to reduce DR opex in RCP2 to cover only development costs.

The static capacitors are required to supply the pre-contingent regional reactive needs. This enables the dynamic reactive plant (e.g. statcoms) to operate in the middle of their reactive range, maximising the dynamic reactive support provided during system disturbances. A

15 Paragraph 654.

16 We have divested some assets in Northland. There is no longer a low voltage issue on the remaining grid assets.

post event load shedding SPS can be used in conjunction with the dynamic reactive devices although this will reduce the ability of the dynamic reactive devices to support the system. The benefits of post event under voltage load shedding will need to be assessed through detailed transient studies.

Flat demand growth means this project may be further delayed

As for all projects, we will continue to assess the need against any new information. For any particular project this may indicate the project can be deferred, or accelerated.

Summary

We continue to propose this project and to seek Commission agreement.

4.1.4 PD33 Bus Section Fault Reliability

This portfolio improves reliability on three important 220 kV and 110 kV buses on the core grid; Haywards, Bunnythorpe and Mt Roskill. Following the investments, a fault on one of these buses will no longer result in a loss of supply and the risks of customer interruptions will be reduced. The bus arrangements will satisfy the requirements of the GRS as set out in the Electricity Industry Participation Code 2010 (Code).

The Draft Decision proposes to decline the expenditure proposed for Mt Roskill. We are resubmitting a revised PD33.

The Strata Report raised the following concerns for the Mt Roskill project[17]:

- inconsistencies in whether this was a GRS or customer-driven project and lack of information on customer needs; and
- it was unclear why a three bus section arrangement is preferable to other arrangements.

Inconsistencies in whether this was a GRS or customer-driven project and lack of information on customer needs

The Strata report[18] observed that 2013 APR[19] noted that Vector had not (at least at the date of publication) requested additional security beyond that provided by the current arrangement and that further investment would be customer driven.

In the 2014 APR[20] we updated the requirement for investment at Mt Roskill and noted that Vector has confirmed their support for the installation of a 110 kV bus section circuit breaker at Mount Roskill. Such investment is also a Code requirement (GRS).

To meet the GRS there should be no loss of load for a single contingent event (for example outage of bus section or circuit) on the core grid. The outage of the Mt Roskill bus will remove the core grid circuits attached to it[21].

17 Section A.4

18 Paragraph 660

19 2013 APR, page 126

20 Section 8.9.1

21 This is the position taken by the Electricity Commission in its *Reasons for Decision set out in its Notice of Intention to Approve Transpower's Bombay 110kV Bus Security Investment Proposal*, 10 July 2009.

We have also discussed this investment with Vector who has confirmed support[22] for the work to resolve the GRS issue.

It is unclear why a three bus section arrangement is preferable

The Strata report said it was not clear why a three bus section arrangement was the optimal solution.

There are several arrangements that improve customer security at Mt Roskill and enable us to meet the GRS. Bus sections can be created to ensure no load is lost for a bus fault and/or the bus reconfigured to ensure a more even distribution of load. One possible option is to add one bus circuit breaker during RCP2 and a second during RCP3. We have revised the POD costs to reflect this option.

Summary

This project is required to meet the GRS. We continue to propose all projects in this portfolio but have rephased the Mt Roskill work. We will split the bus section work between RCP2 and RPC3. This revised staging offers option benefits and a more balanced outcome for customers. We have submitted a new version of PD33.

4.1.5 PD34 Wellington Supply Security

As part of our RCP2 expenditure proposal we included a POD on Wellington Supply Security. This provided an initial overview of investment at the Central Park site which would allow us to safely take the Wilton-Central Park line B circuits out of service for reconductoring whilst maintaining supply to Wellington. We plan to reconductor at least the last five spans of the line B circuits during RCP2.

We have since investigated options for Central Park in more detail.

In particular, we looked at:

- the condition of the two oldest transformers which shows these two transformers have a remaining life of approximately 12 years;
- our demand forecast which indicates that we do not need higher capacity transformers until beyond the RCP2 period;
- ways to manage outages required to support the reconductoring work on the triple circuit section of line B supplying Central Park; and
- what seismic work is needed and whether this can be carried out separately from the transformer replacements.

We have concluded that we can undertake the reconductoring work without major substation development costs and we can defer replacing the transformers.

Summary

We have withdrawn PD34.

22 Email from John Welch (Vector) to Graeme Ancell (Transpower), "*RE: Future 110 kV bus section CB at Roskill*", sent 18/3/2014.

4.1.6 PD35 Otahuhu and Penrose Interconnecting Capacity

This project originally involved upgrading three interconnecting transformers at Otahuhu and Penrose, driven by the need to replace Otahuhu T2 and Penrose T10 in RCP2.

The Strata Report questioned whether we needed to replace Otahuhu T4 in RCP2.

Since our December expenditure proposal we have undertaken more detailed analysis of the optimum interconnecting transformer configurations for the Auckland region and on the condition of the transformers. This shows that the optimum configuration is two 250 MVA, 15% impedance units at Penrose and one at Otahuhu. This means the replacement of Otahuhu T4 for capacity reasons can be deferred until 2030.

Our work reinforces the need to upgrade Otahuhu T2 and Penrose T10 during RCP2, particularly as the condition of T10 exposes us to catastrophic fire risks.

Summary

We continue to support expenditure to upgrade Otahuhu T2 and Penrose T10 in RCP2 as accepted by the Commission in its Draft Decision. We withdraw the expenditure for T4 ($5.7m) from this portfolio.

4.1.7 PD36 Bunnythorpe Interconnecting Transformer

This project involves the replacement of three interconnecting transformers at Bunnythorpe.

Summary

We continue to propose this portfolio, as accepted by the Commission in its Draft Decision.

4.1.8 PD37 North Taranaki Transmission Capacity

At the time of our December expenditure proposal, this project involved the installation of a new 200 MVA transformer at Stratford to increase transmission capacity to meet demand in North Taranaki.

Since December we have undertaken related analysis prompted by discussions with Port Taranaki about our continued operations at New Plymouth. This analysis concludes that it is economic for us to decommission our New Plymouth substation and exit the site completely by 2018. This would mean we avoid costs of around $8m for future replacement of the New Plymouth interconnecting transformer and $2m to relocate the control room. Consequently we have revised PD37. The preferred option is to install a new 250 MVA transformer at Stratford and convert the New Plymouth-Stratford 220 kV circuits to 110 kV within RCP2.

The Strata report cited a number of concerns about the POD[23];

- the preferred option did not appear to address the needs;
- the preferred option required a 200 MVA transformer when PD35 rejected the option of installing a 200 MVA transformer as it is non-standard, and
- there was a very good chance that this project will slip into RCP3.

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23 Section A.8

The preferred option did not appear to address the needs.

The new analysis supporting our exit from New Plymouth by 2018 means that the project is now driven by the economic benefits of decommissioning the New Plymouth substation. The revised POD explains this need.

Preferred option required a 200 MVA transformer when PD35 rejected the option of installing a 200 MVA transformer as it is non-standard.

We agree and have amended our plans to include a 250 MVA transformer.

There is a very good chance that this project will slip into RCP3.

The main driver for the revised POD is the economic benefit of decommissioning the New Plymouth substation by 2018. This is explained in the revised POD.

Summary

We have revised the PD37 in light of new information about our continued operation at the New Plymouth substation. The revised POD includes costs for converting the New Plymouth-Stratford 220 kV circuits as well as a new transformer at Stratford.

4.1.9 PD38 Timaru Interconnecting Transformers Capacity

This project increases the Timaru 220/110 kV interconnection capacity.

Summary

We continue to propose this portfolio, as accepted by the Commission in its Draft Decision.

4.1.10 PD39 Southland Reactive Power Support

This project is to install additional reactive support in the Southland region to avoid voltage instability. The loss of a circuit or generation in Southland will result in voltage instability and widespread loss of supply (including Tiwai Point) during times of low Southland generation.

Our expenditure proposal allowed for a new 70 MVAr bank at North Makarewa and replacement of two 50 MVAr banks with two 70 MVAr banks at the same time.

The Draft Decision proposes to decline one third of the cost on the basis that it is not clear that upgrading the two existing banks at this time can be justified.

Replacement of the two banks is scheduled for 2020/21. There are efficiency savings in combining the replacements with the installation of the new capacitor bank. These efficiencies will include savings from project management, design, procurement and installation efficiencies and reduced risks from undertaking one construction phase. We expect the efficiency savings to outweigh the benefits of deferring replacement.

Summary

We continue to propose the full costs of this portfolio given the likelihood of efficiency savings from replacing the existing banks at the same time as installing the new one.

4.1.11 PD40 High Impact Low Probability Event Mitigation

This portfolio aims to improve system security by implementing economic investments to reduce the extent of high impact, low probability (HILP) events at key substations.

Summary

We continue to propose this portfolio, as accepted by the Commission in its Draft Decision.

4.1.12 PD41 Hororata and Kimberley Voltage Quality

This project is to 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 Code. Any investment to mitigate the effects of an outage of one of these circuits needs to show a net market benefit.

The Strata report had the following concerns about the project[24]:

- the POD did not have a cost benefit assessment;
- the marginal level of demand growth is unlikely to trigger investment; and
- less costly options appear to be feasible but not preferred.

We have prepared a revised POD which includes an indicative but conservative $6m NPV cost of lost load due the operation of the Automatic Under Voltage Load Shedding scheme.

This revised POD also notes that an option to extend the existing SPS (which would be less costly) will not be viable once load exceeds a certain level.

Summary

We continue to propose this portfolio with no changes to the costs. We have submitted the new version of PD41 which addresses Commission concerns.

4.1.13 PD42 Islington Spare Transformer Switchgear

The project described in the December 2013 POD was to install dedicated circuit breakers, protection and a neutral earthing resistor for the system spare transformer at Islington. We have reviewed this project and have prepared a revised PD42 which recommends installing an SPS at an estimated cost of $0.5m.

The Strata report had three main concerns with the December POD[25]:

- the project should have been included in the original business case for the spare transformer;
- it represented an enhanced N-2 level of security with no evidence that the customer requires this; and
- it needed at least an indicative cost benefit analysis.

The project should have been included in the original business case for the spare transformer.

The spare transformer is part of a national programme to purchase new system spares. These spares are provided to enable us to replace transformers in the event of a catastrophic failure. The switchgear originally recommended in PD42 addressed a different need which is unique to this situation.

24 Section A.12

25 Section A.13

It represented an enhanced N-2 level of security with no evidence that the customer requires this.

We have discussed this project with Orion who have indicated their support for this project[26].

Indicative cost benefit analysis.

We have revised this POD to include indicative benefits of avoiding lost load of $1.07m NPV. There are additional benefits from avoiding HILP events and deferral of future interconnector investment at Bromley or Islington which we will analysis as this project progresses.

Summary

We continue to propose this project but with revised costs of $0.54m. We have submitted a new version of PD42.

4.1.14 PD43 Haywards Local Service Third Incomer

A total loss of local service supply to the Haywards Synchronous Condensers will cause an HVDC run-back, leading to a major under-frequency incident and operation of automatic under-frequency load shedding (AUFLS). This project provides for installation of a third 11 kV local service incomer, supplying the synchronous condenser auxiliaries at Haywards.

The Draft Decision proposes to decline this capex and the Strata report raised the following concerns[27]:

- the net present cost for this contingency of $20 to $70k did not justify a capex of $1.8m; and
- there may be less costly solutions.

Since our expenditure proposal we have revised costs and benefits for this project. A revised POD includes quantified benefits of $0.9m (NPV) and revised costs of $0.6m. The estimated benefits now take account of the costs of constraints which we estimate at $0.9m NPV.

Costs and benefits will need to be confirmed by detailed investigation. If the detailed investigation concluded the actual cost to be higher than $900k then we not proceed with the project.

Summary

We have submitted a new version of PD43 with revised costs of $0.6m.

4.1.15 PD44 E&D Other

This POD covers five small E&D projects. The Strata report noted concerns with some of these projects.

Christchurch reactive power controller (RPC)

Strata concern: The basis for undertaking this project is unclear

26 Email from Glenn Coates (Orion) to Graeme Ancell (Transpower), 'Re: Islington spare transmission energisation, 19/3/2014.

27 Section A.14

We have updated the PD 44 to better explain the need for this project and the benefits associated with it.

North of Huapai transmission security

Further information is required to fully explain the proposal and to quantify the benefits.

We have reassessed the benefits of the project. The project is not economic at this stage as the current performance of the relevant 220 kV circuits in terms of forced outages is within reasonable limits. We have withdrawn this project**.**

De-rate Bombay capacitor

This project appears to remedy an earlier mistake.

The project is not intended to remedy a mistake but to better use the asset. The Bombay capacitor was initially put in prior to North Island Grid Upgrade Project in conjunction with the Bombay special protection scheme. The scheme opens the Bombay–Wiri circuits post contingency event to manage 110 kV loading for a tripping of the 220 kV Huntly–Otahuhu circuit. The operation of the scheme causes low voltages at Bombay which are mitigated by switching in the capacitor.

The capacitor bank at Bombay is rated at 50 MVAr. Switching the capacitor into service under normal grid configurations when the Bombay–Wiri circuits are in service often results in high voltages. Following the commissioning of NIGUP, de-rating the capacitor bank to 25 MVAr would enable us to better utilise it as it can be switched into service without causing high voltages.

We plan to de-rate the Bombay capacitor but will look at including this as part of the Otahuhu-Wiri Transmission Capacity project.

Real –time digital simulator (RTDS) upgrade

The Commission accepted this project cost.

Supply transformer minor replacement project

The Commission accepted this project cost.

Summary

We have submitted a new version of PD44 with an amended capex of $0.85m.

5 REVISED BASE CAPEX PROPOSAL

We propose to reduce our E&D Capex to $99.4m. This reflects revisions to our PODs summarised in the Table 2, but also provides us with the flexibility to respond to system needs as they arise.

Reducing the E&D Capex further would constrain our ability to manage the E&D portfolio efficiently and to meet system needs in an appropriate and timely manner.

Table 2 Summary of changes to E&D Capex portfolios ($m)

	Project	Proposal	Draft Determination	Revised Proposal	Revised POD
30	Otahuhu-Wiri Transmission Capacity	$18.5	$0.3	$18.0	✓
31	Relieve Generation Constraints	$16.7	$6.1	$6.1	
32	Upper North Island Reactive Support	$8.0	$8.0	$8.01	
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	$10.9	$10.9	
36	Bunnythorpe Interconnection Capacity	$8.8	$8.8	$8.8	
37	North Taranaki Transmission Capacity	$3.0	-	13.68	✓
38	Timaru Interconnecting Transformers Capacity	$2.52	$2.52	$2.52	
39	Southland Reactive Power Support	$6.0	$4.2	$6.0	
40	High Impact Low Probability Event Mitigation	$9.23	$9.23	$9.23	
41	Hororata and Kimberley Voltage Quality	$3.36	-	$3.36	✓
42	Islington Spare Transformer Switchgear	$2.4	-	0.54	✓
43	Haywards Local Service Third Incomer	$1.8	-	$0.6	✓
44	E&D Other	$1.7	$0.3	$0.85	✓

6 SUPPORTING DOCUMENTATION

2013 Annual Planning Report

2014 Annual Planning Report

Portfolio Overview Documents

Options Analysis - Otahuhu-Wiri Transmission Capacity

Taranaki 110 kV Regional Plan

Taranaki 110 kV RCP2 Options Analysis

APPENDIX A: OVERVIEW OF E&D PLANNING AND APPROVAL PROCESSES

A1 E & D Planning and Approval Processes

Our planning and approval processes enable us to refine projects to take account of changes in forecast needs, and involve a rigorous governance process for project approval. This is important in ensuring we pursue optimal investments.

All base capex E&D projects follow our planning process which involves needs identification, options analysis and project integration. Most of the projects we will undertake during RCP2 are at the early stages of our planning process and we have considerable analysis and planning to undertake for each of them. This means that project design, timing, cost or even the projects themselves may change. As part of the planning process, the projects will be subject to our internal approval processes.

Maintaining the integrity of our planning and approvals processes allows us to refine projects to take account of changes in forecast demand and generation, and to continue to seek the most efficient outcomes as we progress projects.

Our planning process is described in further detail in the planning lifecycle strategy[28]. This section provides an overview of the planning process as applied to E&D.

A2 Needs Identification

The principal need driving E&D Capex investments is demand for service which can lead to capacity, security or other capability issues.

To ensure we have a robust view of future demand, we produce long-term forecasts for electricity demand and generation on an annual basis. These are set out in the Annual Planning Report (APR) together with an assessment of the required capability of the grid and potential investments that may be required to meet constraints.

The timing of E&D projects can be influenced by the need to replace certain assets for condition reasons. E&D projects can be brought forward because assets are nearing the end of their useful life.

A3 Options Analysis

The options analysis approach for E & D projects is commensurate with the size and the complexity of the project.

We identify a long list of potential transmission and non-transmission solutions.

The long list is reduced to a 'credible options list' by applying specific criteria. A credible option is one that:

- addresses the identified need
- is commercially and technically feasible, including meeting legislative requirements
- meets Good Electricity Industry Practice
- addresses environmental issues, and meets Resource Management Act requirements

28 AM03 Planning Lifecycle Strategy

- can be implemented in sufficient time to meet the need.

A4 Investment Test

For major E&D projects, we apply the regulated investment test as prescribed in the Capex Input Methodology Decision (Capex IM). For smaller E & D projects we apply the same principles as the regulated investment test, but modify the level of analysis to be commensurate with the size of the investment. This stage of the process determines the preferred option.

A5 Stakeholder Consultation

Throughout the investment planning process for E & D, we consult with relevant stakeholders, including customers, affected landowners, local authorities and the wider community as appropriate.

A6 Cost Estimation

We want to ensure stakeholders are confident that our forecast expenditure is driven by genuine needs and that it is efficient and prudent. Our cost estimates:

- reflect our best estimate of the efficient and prudent costs;
- have been developed using the best available information and reasonable assumptions;
- exclude any ‘blanket’ contingency; and
- where appropriate, include specific risk adjustments.

Grid capex cost estimation is built around the Transpower Enterprise Estimating Tool (TEES). Using this tool, both staff and service providers can develop robust cost estimates using a centrally managed dataset. TEES provides a number of benefits including consistent and traceable pricing, automated rate updates and centralised management of foreign exchange risk.

A7 Business case process

The Planning Lifecycle Strategy also covers our planning governance processes. Our internal approval processes follow a three-step process which enables us to refine project designs and costs. At any one time our E&D portfolio includes projects at all three stages.

- **BC1:** authorises the entry of works into the approvals system. Portfolio owners approve these documents which include confirmation that the project is aligned to overall asset management objectives and strategy. For large projects we prepare a more detailed BC1+ document with a detailed scope for cost estimation.
- **BC2:** gives approval for a detailed investigation to begin. This is generally only necessary for large, complex projects that require detailed design to finalise the solution.
- **BC3:** finalises the budget and, subject to the relevant management sign-off, gives authority for the work to proceed.

APPENDIX B: LONG LIST OF E&D PROJECTS LESS THAN $20 MILLION IN RCP2

This appendix sets out the long list of E&D projects for RCP2. The long list is set out in five tables based on data drawn from the following sources.

- The Grid Reliability Report (GRR) in the 2013 APR.
- The Grid Economic Investment Report (GEIR) in the 2013 APR.
- Regional issues concerning core bus section outages from the 2013 APR.
- Proposed asset replacements that might bring forward possible upgrades or development work (derived from tables of regional significant maintenance work identified in the 2013 APR.)
- Other projects identified separately, for example through our risk management processes.

Table 3 Possible E&D Base Capex for RCP2 (identified from the GRR)

Issue affecting n-1	Projects	Indicative timing
North of Huapai transmission security (Issue already exists)	Splitting Huapai 220 kV bus once the NAaN project is completed.	2016/17
North of Marsden low voltage (Issue arises from 2013)	Additional voltage support at Kaitaia or Maungatapere.	2017/18-2018/19
Kaikohe–Maungatapere 110 kV transmission capacity (Issue arises from 2013)	In the short term, issue can be managed operationally. In the long term, issue is resolved by thermally upgrade 110 kV Kaikohe–Maungatapere circuits.	To be advised
Otahuhu–Wiri 110 kV transmission capacity (Issue arises already exists)	Transpower is investigating several options such as: • A new cable from Otahuhu connecting to a new 110/33 kV transformer at Wiri. • A new 110/33 kV transformer at Otahuhu and a new 33 kV cable to Wiri • Reconductor Otahuhu–Wiri circuit, or • A new 220/110 kV connection at Bombay and supply Wiri from here and a 110 kV bus at Wiri.	To be advised
Wiri supply transformer capacity (Issue arises from 2019)	Resolving the protection constraints will delay the overload until 2021. In the long term, issue is resolved, by limiting the peak load to the transformer capacity or replace existing transformers with higher rated units.	2018/19 2020/21
Wiri Tee transmission capacity (Issue already exists)	Likely to be resolved by Otahuhu–Wiri 110 kV transmission capacity solution.	NA
Hamilton–Piako–Waihou 110 kV transmission capacity (Issue arises from 2016)	In the short term, issue can be managed operationally. In the long term, issue is resolved by constructing a new Hamilton–Waihou or upgrading existing Hamilton–Piako circuits.	NA 2016/17
Piako–Waihou–Waikino–Kopu spur low voltage (Issue already exists)	Install capacitors, either on the grid or within the distribution network, or replace supply transformers at Waikino and Waihou with on-load tap changers.	2014/15-2017/18 2015/16-2022/23
Te Awamutu supply transformer capacity (Issue arises from 2015)	Resolve the protection limits.	2013/14
Bunnythorpe interconnecting transformer capacity (Issue already exists)	In the short term, issue can be managed operationally. In the long term, issue is resolved by replacing the existing transformers with higher rated units.	NA 2014/15-2016/17
Bunnythorpe–Mataroa 110 kV transmission capacity	In the short term, issue can be resolved operationally. In the long term, issue is resolved by installing either	

Issue affecting n-1	Projects	Indicative timing
(Issue already exists)	series reactors or reconductor Bunnythorpe–Mataroa 110kV circuit.	
Bunnythorpe–Woodville 110 kV transmission capacity (Issue already exists)	Longer-term options include: upgrade the existing SPS to operate for a 220 kV circuit outage reconductor the Bunnythorpe–Woodville circuits with higher rated conductors, or convert the Bunnythorpe–Woodville circuits to 220 kV operation.	To be advised 2015/16-2020/21
Waipawa supply transformer capacity and security (issue arises from 2017)	Resolve the metering and protection limits on the 110/33 kV transformers.	2017/18
North Taranaki transmission capacity and low voltage issues (Issue already exists)	Options include: • A second transformer at (or near) New Plymouth. • Convert 220 kV New Plymouth–Stratford circuits to 110 kV operation. • Constraining on generation. • Upgrade terminating spans capacity on the Carrington Street–Stratford circuits	2017/18-2022/23
Hawera voltage quality (Issue already exists)	Install reactive support at Hawera.	2015/16-2020/21
Opunake supply transformer capacity (Issue arises from 2014)	Resolve the metering and protection limits.	2014/15
Wellington interconnecting transformer capacity (Issue arises from 2015)	Install a second 250 MVA interconnecting transformer.	2018/19
Central Park supply transformer capacity (110/33 kV transformer capacity issue arises from 2013)	110/33 kV: replace the existing 110/33 kV transformers with 120 MVA units.	2014/15
Hororata and Kimberley voltage quality and transmission capacity (Issue arises 2013)	Issue can be managed operationally for the forecast period.	2013
Timaru interconnecting transformer capacity (Issue already exists)	Increase interconnecting transformer capacity.	2018/19-2020/21
Waitaki 220/110 kV interconnecting transformer capacity (Issue already exists)	Replace the Waitaki interconnecting transformers with higher rated units.	2014/15-2018/19

Table 4 Possible E&D Base Capex for RCP2 (Identified from the GEIR)

Issue	Projects	Indicative timing
Central North Island transmission capacity	Tranche 1, range of options includes: • limit power flow on the 110 kV regional network • reconductor Tokaanu–Whakamaru circuits, and • thermal upgrade or reconductor Bunnythorpe–Tangiwai–Rangipo circuits. Tranche 2, range of options includes: • reconductor Bunnythorpe–Tokaanu circuits • provide new transmission capacity between Bunnythorpe and Whakamaru • a new line in the Taranaki area, from Taumarunui to Whakamaru, and Lower North Island wide System Protection Scheme.	To be advised
Transmission capacity between N and S Islands	HVDC link expansion Stage 3	2020/21

Table 5 Possible E&D Base Capex for RCP2 (core bus section outages)

Transmission bus outage	Transmission issue
Redclyffe 220 kV	Redclyffe 220/110 kV transformer overloading
Whirinaki 220 kV	Loss of supply to Whirinaki 11 kV
New Plymouth 110 kV	Loss of supply to Moturoa 33 kV
Stratford 110 kV	Loss of supply to Kapuni
Bombay 110 kV	Bombay 33 kV Meremere
Mount Roskill 110 kV	Loss of supply to Mount Roskill 110 kV and 22 kV
Otahuhu 110 kV	Bombay–Wiri Tee overloading
Ashburton 220 kV	Loss of bus section overloads Ashburton 220/66 kV transformer
Ashburton 220 kV	Ashburton low voltages
Bromley 220 kV	Bromley low voltages
Islington 220 kV	Islington area low voltages
Edgecumbe 220 kV	Loss of supply to Edgecumbe
Tarukenga 110 kV	Loss of supply to Rotorua 11 kV and 33 kV Loss of supply to Tarukenga
Bunnythorpe 220 kV	Bunnythorpe–Woodville overloading Regional low voltage
Bombay 110 kV	Bombay–Hamilton overloading
Hamilton 220 kV	Loss of supply to Hamilton 55 kV
Halfway Bush 220 kV	Loss of supply to Halfway Bush 33 kV
Maungatapere 110 kV	North of Marsden low voltage
Haywards 110 kV	Loss of supply to Haywards 33 kV or 11 kV

Table 6 Issues identified from proposed significant maintenance work (that could bring forward upgrades)

Issue	Projects	Indicative timing
Otahuhu Interconnecting Transformers end of life	Penrose and Otahuhu Interconnecting Transformer Capacity	2019-2021
Penrose T10 end of life.	Penrose and Otahuhu Interconnecting Transformer Capacity	2017-2019

Table 7 Other issues

Issue	Projects	Indicative timing
Christchurch reactive power controller (RPC)	The RPC and training simulator will require upgrading when the Bromley ICTs T5 and T6 are replaced.	2018-2020
De-rate Bombay Capacitor	This project is to de-rate the capacitor bank to 25 MVAr so that it can be switched into service without causing high voltage steps and high voltages.	Existing issue
Real Time Digital Simulator (RTDS) upgrade	This project will enhance our RTDS capability by upgrading the simulator processor capability so the system can be more accurately modelled and, consequently, understood.	Existing issue
HILP projects	HILP event investigations are being carried out at key substations to identify risks arising from HILP events and possible means of mitigation.	To be advised