

# Grid Upgrade Plan 2009 Instalment 2

## Part IV: Bay of Plenty Interconnection Capacity Upgrade Investment Proposal

*Keeping the energy flowing*



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## Document Revision Control

Document Number/Version	Description	Date
001/Rev A	Bay of Plenty Interconnection Capacity Upgrade Investment Proposal	November 2009

## Executive Summary

The purpose of this Bay of Plenty 110 kV Capacity Upgrade Investment Proposal is to obtain Electricity Commission (the **Commission**) approval to recover the full costs (up to \$21 million) associated with thermally upgrading the Tarukenga to Kaitimako circuits and increasing their operating voltage from 110 kV to 220 kV.

### Proposal at a Glance

What:	Thermally upgrade the Tarukenga to Kaitimako circuits and change the operating voltage from 110 kV to the original construction voltage of 220 kV, and install two 150 MVA transformers at Kaitimako.
When:	Commissioning in 2011.
How much:	Transpower is seeking approval for up to \$21.5 million.

### Background

The two 220/110 kV, 200 MVA single phase interconnecting transformer banks at Tarukenga currently supply load in the Western Bay of Plenty region (including Tauranga, Mt Maunganui and Te Matai) and Rotorua, Tarukenga, Lichfield and Kinleith.

Power systems analysis indicates that, without any new generation or load reduction measures, the firm capacity of the Tarukenga interconnecting transformers could be exceeded by 2011, potentially resulting in unserved energy.

The Tarukenga transformers are also nearing the end of their serviceable life. They are more than 40 years in age and are showing advanced signs of deterioration. The optimum replacement capacity will be determined once a preferred solution has been identified in the Waikato 110 kV investigation that is currently underway.

### Process to date

In May 2009, Transpower issued a consultation document outlining the proposed assumptions and approach used in the investigation as well as the long list of options under consideration. The consultation document also acted as a Request for Information (RFI) on any other options.

Submissions were received from Contact Energy and Powerco. Further inputs were obtained at meetings with Trustpower, Tauranga City Council and Priority One (the Tauranga business development agency). In general, the parties supported the investigation and recognised the need for a capacity upgrade in the region. Powerco noted that the proposed demand forecast was lower than its own forecast and as a result of this feedback the demand forecast has been revised - refer to Appendix C of Attachment A, Technical Report. There were no non-transmission alternatives proposed as a result of the consultation, which also acted as an RFI for non-transmission alternatives.

Following the long-list consultation, the long-list was refined to a short-list, as set out in this document and the attachments.

The process was carried out in accordance with the timetable agreed between the Commission and Transpower and in accordance with the GUIRP.

### Options considered

To resolve the need for additional interconnecting capacity in the Western Bay of Plenty region, the short-list of options for stage 1 of the project were as follows:

1. Replacement of the Tarukenga transformers with two 250 MVA transformers
2. Replacement of the Tarukenga transformers with three 150 MVA transformers

3. Installation of a third 150 MVA transformer at Tarukenga
4. Installation of a third 250 MVA transformer at Tarukenga
5. Installation of two 150 MVA transformers at Kaitimako and, for the Tarukenga–Kaitimako circuits, increase the operating voltage from 110 kV to the original construction voltage of 220 kV and upgrade the thermal rating
6. Installation of a third 150 MVA transformer at Tarukenga. This option will convert to 220 kV supply to Kaitimako in the future..

All short-listed options include a post-contingency operational split between Kinleith and Tarukenga to manage peak loads on the existing Tarukenga interconnecting transformers until the preferred option can be implemented.

For the GIT evaluation, Option 1, installation of two 250 MVA transformers at Tarukenga, was chosen as a reference case against which the other short-list options were compared, rather than comparing each option to a base case. This is consistent with the previous approach adopted by Transpower and the Commission in circumstances where a reliability investment is required in order to meet the GRS.

The short-list options by themselves do not meet the GRS for the full 20 year analysis period required to complete the GIT analysis. Therefore, additional staged upgrades over the longer term were included as modelled projects for each option. Transpower seeks Commission approval for a stage 1 upgrade only, with any necessary stage 2 or subsequent upgrades to be included in a future grid upgrade plan.

The development plan for each short-listed option (including staged modelled projects) is described in section 4.2.3.

### Option costs

The costs have been estimated at a level of accuracy commensurate with the capital expenditure for the various investment options. Transformer costs make up a significant proportion of the costs for all options and these are assumed to affect all options equally reducing the impact of cost uncertainty on the ranking of options. Most cost estimates are within +/- 30% although the preferred option is based on a more detailed assessment bringing down the cost uncertainty of this to +/- 15 % for most cost items. Modelled projects appearing later have higher uncertainty.

### Application of the GIT

The short-list includes a number of alternatives, but Transpower considers that there are no material benefit differences between the short-list options, with the exception of cost of losses and terminal values.<sup>1</sup>

By treating these latter differences as costs, the GIT application condenses to become a cost comparison (on a Present Value basis), with the lowest overall cost alternative passing the GIT. The GIT results are shown in Table 0-1.

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<sup>1</sup> Because the development plans differ in the number of years of load growth they cover, some alternatives do have a terminal value at the end of the 20 year analysis period, and this value is included in the analysis.

**Table 0-1: Grid Investment Test Results**

Stage 1 Upgrade Option	Transmission Costs (\$m) (A)	Loss Cost (\$m) (B)	Terminal Cost (\$m) (C)	Expected net market cost (\$m) (A + B + C)
Reference Case				
Two 250 MVA Tarukenga transformers	23.37	16.07	7.01	46.44
Option 2				
Three replacement 150 MVA Tarukenga transformers	25.47	16.07	7.04	48.57
Option 3				
Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer	20.94	16.07	7.01	44.02
Option 4				
Add a 3 <sup>rd</sup> 250 MVA Tarukenga transformer	21.85	16.07	6.98	44.90
Option 5				
Two 150 MVA transformers at KMO, convert <sup>2</sup> Kaitimako–Tarukenga to 220 kV	27.70	4.98	3.68	36.36
Option 6				
One 150 MVA transformer at Tarukenga (convert to 220 kV operation later)	25.92	8.88	3.70	38.50

**Notes:**

**Costs are all pre-tax , discounted at 7%, in \$m, and in \$2009**

Option 5 has the least expected net market cost and therefore becomes the Proposal. Option 5 includes the use of a temporary post-contingency operational split<sup>3</sup> between Tarukenga and Kinleith in 2009/10, followed in 2010/11 by the installation of two 150 MVA transformers at Kaitimako, and changing the operating voltage of the Kaitimako–Tarukenga circuits from 110 kV to the original construction voltage of 220 kV as well as thermally upgrading these circuits..

This analysis does not take into consideration certain un-quantified benefits. Although not quantified, Transpower considers these benefits are real and should be taken into consideration. These benefits include the following:

- Installation benefits. Transportation of smaller 150 MVA transformers is easier, faster and less damaging to roads than larger 250 MVA units.
- Flexibility benefits. Additional transformer capacity can be added as and when required.
- Environmental and Community benefits. These are largely equal across the options, recognising that the impact of physical works on the community and the environment is similar. Some moderate disruption is expected.
- Longevity benefits. Options that require less physical works in the development plans will cause less disruption to landowners.

<sup>2</sup> “Convert” denotes increasing the operating voltage from 110 kV to the original construction voltage of 220 kV and thermally upgrading to 80°C, when “convert” is used in the tables in the GUP.

<sup>3</sup> The post-contingency split will not be required following commissioning of the new Kaitimako transformers.

A qualitative assessment of these benefits against each of the options is described in Table 0-2 below. The assessment has been conducted for the short to medium term. The benefit for each option has been qualitatively ranked between ✓ and ✓✓✓.

**Table 0-2 Qualitative assessment of un-quantified benefits**

Item	GIT Result (\$m)	Installation Benefits	Flexibility Benefits	Environmental & Community Benefits	Longevity Benefits
Reference Case Two 250 MVA Tarukenga transformers	46.44	✓	✓	✓✓	✓✓✓
Option 2 Three 150 MVA Tarukenga transformers	48.57	✓✓	✓✓	✓✓	✓✓
Option 3 Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer	44.02	✓✓✓	✓✓	✓✓	✓
Option 4 Add a 3 <sup>rd</sup> 250 MVA Tarukenga transformer	44.90	✓	✓	✓✓	✓✓
Option 5 Add two 150 MVA transformers at Kaitimako, convert Kaitimako–Tarukenga to 220 kV	36.36	✓✓	✓✓✓	✓✓	✓✓✓
Option 6 Add one 150 MVA transformer at Tarukenga (convert to 220 kV operation later)	38.50	✓✓✓	✓✓	✓✓	✓✓

The qualitative assessment of the un-quantified benefits supports the Proposal.

### Accuracy of GIT

Transpower recognises there is inherent uncertainty in several of the input assumptions used in the GIT analysis, namely the demand forecasts and cost assumptions.

However, Transpower considers the rigour and comprehensiveness of the analysis undertaken is commensurate with the estimated capital expenditure required for the proposed investment.

### Timing

Given the Western Bay of Plenty load may exceed the interconnecting capacity limit at Tarukenga as soon as 2011, coupled with the condition of the Tarukenga transformers, it is desirable to reduce the loading on those transformers as soon as practical.

We propose to complete upgrade works in the following order of priority:

1. begin site works at Kaitimako, and complete necessary enabling work for the thermal upgrading

2. install the transformers and associated equipment at Kaitimako and complete the thermal upgrading of the circuits
3. connect the circuits to the 220 kV bus at Tarukenga and Kaitimako.

The exact timing of activities will be influenced by a range of factors, including resource consent approvals, line and substation construction crew availability, the coordination of upgrade works with scheduled maintenance, and the timing of equipment delivery. However, we will target commissioning by 2011.

### Maximum Approval Costs

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal. The Expected Cost of the Proposal, comparable to that used in the GIT<sup>4</sup>, is estimated to be \$18.6 million and the MAC of the Proposal is estimated to be \$21.5 million.

**Table 0-3 – Maximum Approval Cost**

\$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	16.9	18.6						
Expected End cost	16.9	18.6	0.3	–	–	1.2	0.4	20.5
Maximum Approved Cost	16.9	18.6	0.9	0.3	–	1.2	0.5	21.5

### This document

The remainder of this document is Transpower's formal submission to the Commission for approval of the costs of the Proposal. It is split into two parts:

- Part A sets out the actual proposal for which approval of cost recovery up to \$21.5 million is sought; and
- Part B, together with the attachments, sets out the technical and economic analysis of the proposal, and justifies the Proposal against the requirements of the Rules.

<sup>4</sup> The cost used in the GIT represents the net present value of the costs of the development plans incurred in current dollars, and includes operating and maintenance (O&M) costs. The Expected Cost is measured in current dollars and does not include O&M costs.

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### Attachments

Ref	Title
A	Technical Report
B	Options and Costing Report

## Part A - Proposal

This part describes Transpower's Bay of Plenty Interconnection Capacity Upgrade Investment Proposal (the **Proposal**).

### Components of the Proposal

- Install two 220/110 kV 150 MVA interconnecting transformers at Kaitimako
- Increase the operating voltage of the Kaitimako to Tarukenga circuits (Hairini–Tarukenga A line) from 110 kV to the original construction voltage of 220 kV
- Thermally uprate the Kaitimako to Tarukenga circuits (Hairini–Tarukenga A line) for operation at 80°C

### Timing

Transpower will work towards commissioning of the Proposal by 2011. A post-contingency system split between Kinleith and Tarukenga will be used as a temporary measure to manage peak loadings on the two Tarukenga transformers.

### Costs

Transpower is seeking Commission approval to recover the full costs associated with the Proposal upon commissioning up to a total amount of \$21.5 million. This amount is the estimated Maximum Approval Cost (**MAC**) to implement the Proposal, expressed in New Zealand dollars exclusive of GST.

Appendix B describes how the MAC has been derived.

## Part B - Justification

### 1 Introduction

*This section outlines the purpose and structure of Part B*

#### 1.1 Purpose

This document is Transpower's request for Commission approval to recover the costs of the Proposal.

The purpose of Part B of this document is to provide information for the Commission to assess compliance of this Proposal with the Rules.

In the course of assessing the options presented in this document, Transpower has sought feedback from interested parties so as to be able to incorporate their views into the decision-making.

This document has not been prepared to satisfy the statutory requirements of the Resource Management Act 1991 (RMA) or Electricity Act 1992.

#### 1.2 Document structure

The document consists of this paper and two attachments as follows:

**The Proposal:**

- **Attachment A: Technical Report**
- **Attachment B: Options and Costing Report**

The attachments provide the detail of the analysis presented in this document.

#### 1.3 The Proposal as part of the 2009 Grid Upgrade Plan

This document forms Part IV of the 2009 Grid Upgrade Plan.

Transpower has already submitted the following parts of the 2009 GUP to the Commission:

- Part I: Comprehensive Plan for Asset Management and Operation of the Grid;
- Part II: Investment Contracts; and
- Part III: Wanganui–Stratford Transmission Investment Proposal.

#### 1.4 Compliance with the GUIRP

Transpower notes that the development of the Investment Proposal and alternative options, and the analysis of those options, does not follow in a number of respects the processes and policies set out in the Grid Upgrade and Investment and Review Policy (GUIRP).

However, for smaller projects, Transpower will abbreviate the process consistent with the principles that the analysis undertaken in applying the Grid Investment Test (GIT) is

commensurate with the estimated capital expenditure required for the proposed investment.<sup>5</sup> This approach reflects one of the key principles of the GUIRP.<sup>6</sup>

## 1.5 Glossary/terminology

A glossary of terms and acronyms used in this document is included in Appendix A.

All references to Rules in this document refer to those in section III of Part F of the Electricity Governance Rules 2003 unless otherwise specified.

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<sup>5</sup> Clause 12, Schedule F4 of the Rules.

<sup>6</sup> Grid Upgrade Investment and Review Policy, June 2008, para 2.1.1(h).

## 2 Needs Assessment

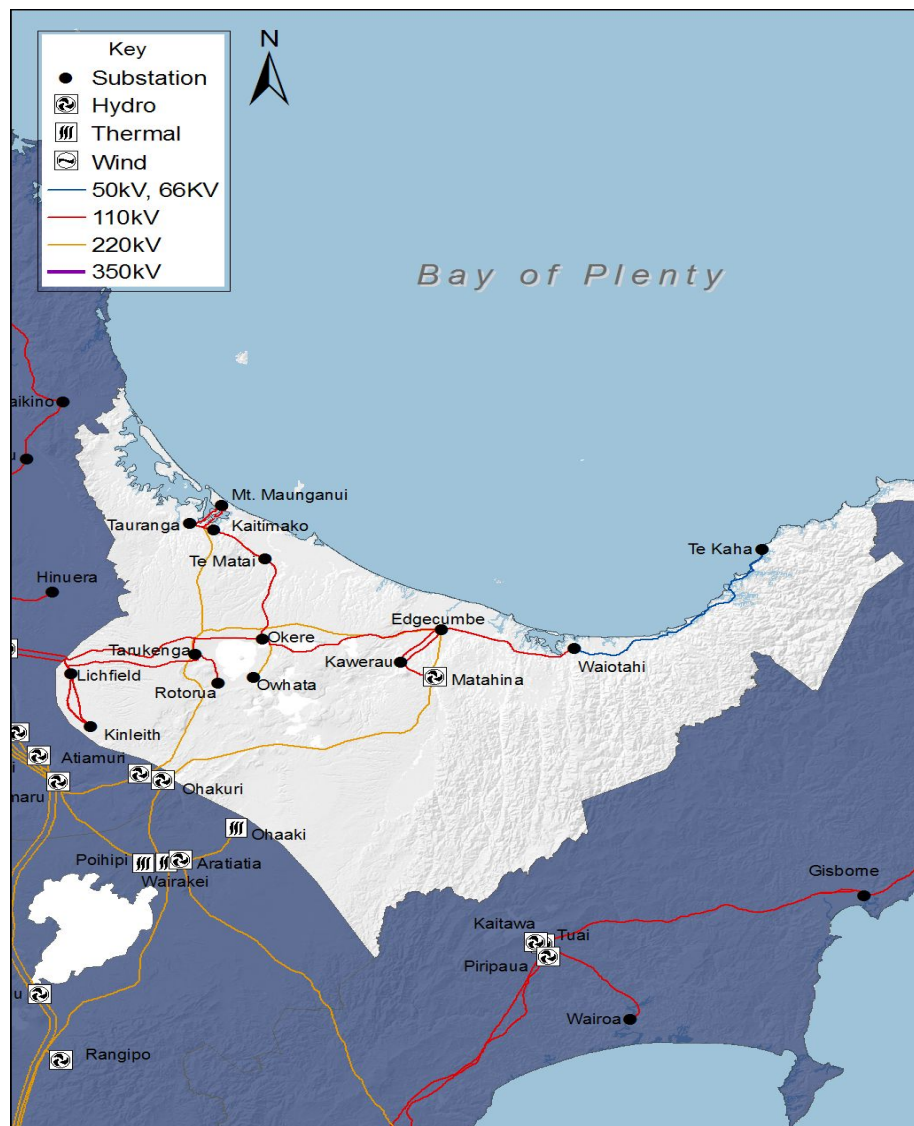
*This section provides background on the Bay of Plenty Interconnection Capacity Upgrade Project*

### 2.1.1 Background to the Proposal

The Bay of Plenty region is shown geographically in Figure 2-1 with Tauranga, Mount Maunganui and Te Matai occupying the western area of the region near the east coast of the central North Island.

There are three 110 kV circuits supplying the western region, a 39 km double circuit line (coloured orange) directly between Kaitimako and Tarukenga, and a 65 km single circuit line route which passes via Okere and Te Matai. The orange colour signifies that the line was constructed to a 220 kV specification even though it is currently operated at 110 kV. All other orange lines on the map denote 220 kV operation.

Figure 2-1: Map of the Bay of Plenty region



These three circuits are connected to the 220 kV transmission network via the two 200 MVA interconnecting transformers at Tarukenga. The double-circuit tower line

from Kaitimako to Tarukenga and the two Tarukenga interconnecting transformers are defined as part of the core grid.

The two Tarukenga transformers have three operational ratings; continuous, 24 hour summer rating and a 24 hour winter rating. The seasonal 24 hour ratings are only used when one transformer is out of service, either for planned maintenance or as a result of transformer failure. The ratings of the Tarukenga interconnecting transformers (continuous, 24 hour summer, 24 hour winter) are as follows:

- Tarukenga T1 200/248/264 MVA
- Tarukenga T2 200/246/262 MVA

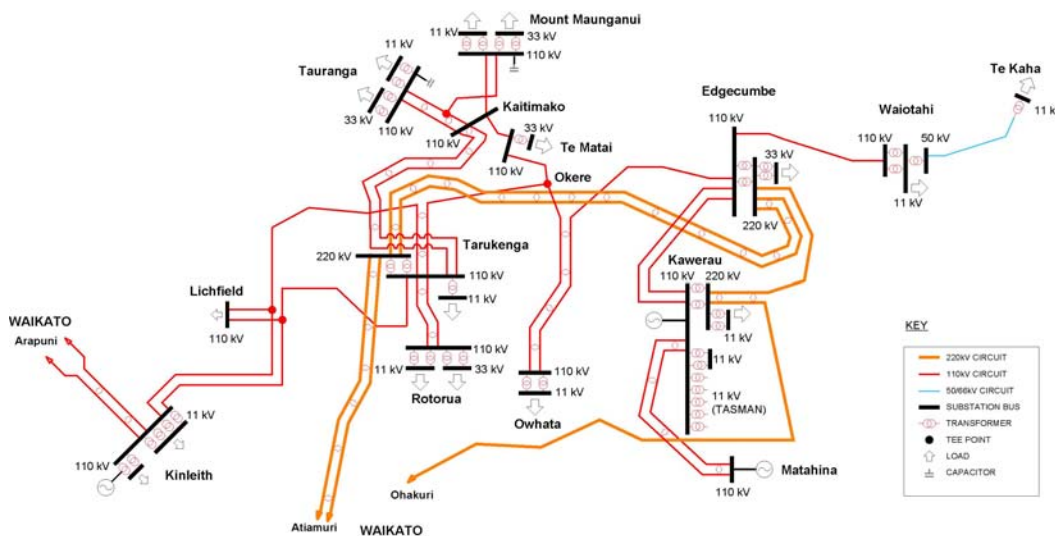
The relatively strong projected increase in demand at Tauranga, Mt Maunganui and Te Matai means that the firm capacity of the Tarukenga interconnection may be exceeded:

- by 2011 for the T2 transformer
- by 2012 for the T1 transformer.

At this time, the Grid Reliability Standards will not be met and there will be the potential for unserved energy. Therefore, Transpower needs to consider ways in which customers at the Tauranga, Mt Maunganui and Te Matai grid exit points can continue to be supplied reliably.

A future Grid Exit Point at Papamoa, connected to the Okere–Te Matai circuit, is assumed to be required to relieve load growth from Mount Maunganui substation and is assumed to be connected 6.4 km from Te Matai and 11.5 km from Kaitimako via a 6.8 km loop-in-loop-out deviation.

**Figure 2-2: Existing transmission circuits in the Kaitimako–Tarukenga region**



As illustrated in Figure 2-2, the Tarukenga 220/110 kV interconnection supplies the western Bay of Plenty loads as well as:

- the Rotorua and Tarukenga substations
- the Lichfield and Kinleith substations
- an inter-area connection to Arapuni power station.

As a result, the actual loading of the Tarukenga interconnecting transformers is not the arithmetic sum of the western loads but a value that can only be calculated from a power system network analysis.

The loading on the Tarukenga interconnecting transformers depends on:

- the western Bay of Plenty loads of Tauranga, Mt Maunganui and Te Matai
- Rotorua, Tarukenga, Kinleith and Lichfield loads
- the Bay of Plenty hydro and geothermal generation
- the inter-area power flow through the 110 kV network from Tarukenga to Arapuni which is dependent on the total North Island generation mix.

The firm capacity of the Tarukenga interconnection is defined by the Tarukenga T2 transformer. The transformer ratings and loss of N-1 security are:

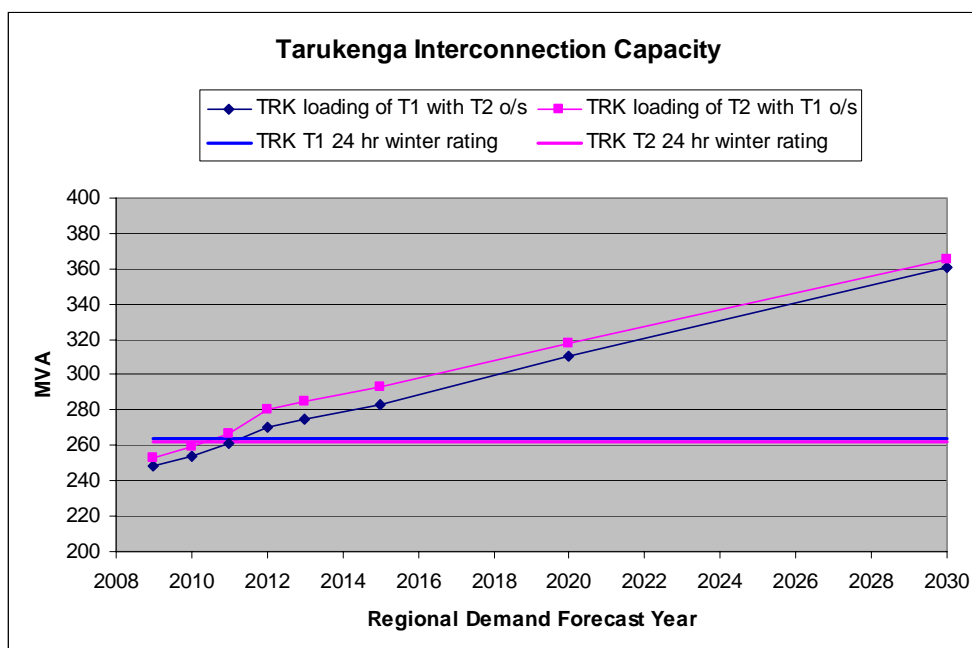
- Tarukenga T2 (200/246/262 MVA) N-1 24 hour winter rating will be exceeded in 2011
- Tarukenga T1 (200/248/264 MVA) N-1 24 hour winter rating will be exceeded in 2012.

The peak N-1 loadings of the Tarukenga interconnecting transformers with increasing Bay of Plenty load are shown in Figure 2-3. As the electrical parameters and ratings of the two transformers are only slightly different, the forecasted years when the 24 hour ratings are exceeded are also only slightly different.

The firm capacity of the Tarukenga 220/110 kV interconnection will be exceeded by the winter of 2011. Capacity will be exceeded based on the following assumptions:

- Kaimai maximum generation is available during peak demand periods
- Arapuni generation is 120 MW
- Wheao generation is 7 MW
- a slack bus is located at Huntly

Figure 2-3: Tarukenga T1 and T2 N-1 loading over time



Options 1 to 4 address the loading on the two Tarukenga transformers by increasing transformer capacity by adding more and/or higher rated transformers.

Options 5 and 6 address the loading on the Tarukenga transformers by moving more than 120 MVA of peak load from the Tarukenga transformers to Kaitimako by extending the 220 kV network. These two options significantly reduce system losses.

### 2.1.2 Summary of Need

The investigation has identified short, mid and long term issues on the core grid area between the 220 kV Tarukenga bus to the 110 kV Kaitimako bus and the non-core grid 110 kV circuits between Tarukenga, Okere, Te Matai and Kaitimako.

In the short term:

- winter failure of the Tarukenga T1 transformer will overload the Tarukenga T2 transformer during winter peaks from 2011 onwards
- winter failure of the Tarukenga T2 transformer will overload the Tarukenga T1 transformer during winter peaks from 2012 onwards
- post-contingency splitting of the 110 kV network between Tarukenga and Kinleith is a temporary means of ensuring security of supply is maintained should the delivery of a permanent solution be delayed for any reason.

In the mid-term:

- any planned or unplanned outage of Tarukenga T1 during the summer daily peaks may require load curtailment to prevent Tarukenga T2 transformer overloading from 2016 onwards. There are no daylight periods under a prudent demand forecast where transformer maintenance will not require load curtailment.
- any planned or unplanned outage of Tarukenga T2 during the summer daily peaks will require load curtailment to prevent Tarukenga T1 transformer overloading from 2017 onwards. There are no daylight periods under a prudent demand forecast where transformer maintenance will not require load curtailment.

In the long term:

- the Okere–Te Matai circuit will overload from the winter of 2020 onwards for the loss of any of the Kaitimako–Tarukenga circuits. Any load shifting from Mount Maunganui to Papamoa will advance the overload date.
- voltage support will be needed at Papamoa as soon as substantial load is shifted from Mount Maunganui. The reactive support would be required at Papamoa to protect the transmission voltage against the loss of the Kaitimako–Papamoa circuit.
- the Kaitimako–Tarukenga 1 and 2 circuits will need to be upgraded by the winter of 2026 as one circuit will overload for the loss of the other.

Six options have been developed to address the need over the long term and the resulting development plans can be found in section 4.2.3.

### 3 Type of investment

The Proposal is a “reliability investment”, in that:

- the Proposal is an investment by Transpower in the grid
- the primary effect of the Proposal is to reduce expected unserved energy on the grid
- the expected unserved energy will result from likely planned or unplanned outages of primary transmission equipment (namely a Kaitimako–Tarukenga circuit).

#### 3.1 Stakeholder engagement process

The stakeholder engagement process for this project has helped identify and refine the long-list and short-list options and inform and refine the selection of a preferred solution.

In May 2009, Transpower commenced its consultation process in accordance with the timetable for consultation and approval agreed between Transpower and the Commission.<sup>7</sup> At this time, feedback was sought from interested parties on the various assumptions, methodologies and the long-list of options proposed.

Submissions were received from Contact Energy and Powerco. Further inputs were obtained at meetings with Trustpower, Tauranga City Council and Priority One (the Tauranga business development agency). In general, the parties supported the investigation and recognised the need for a capacity upgrade in the region. Powerco noted that the proposed demand forecast was lower than its own forecast and as a result of this feedback the demand forecast has been revised - refer to Appendix C of Attachment A, Technical Report. There were no non-transmission alternatives proposed as a result of the consultation, which also acted as an RFI for non-transmission alternatives.

More information about the consultation can be found on the Grid New Zealand website:

<http://www.gridnz.co.nz/Kaitimako-reinforcement-consultation>

Following receipt of feedback from stakeholders, Transpower:

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<sup>7</sup> The Commission must consult with Transpower in relation to a process for consultation with persons that the Commission thinks are representative of the interests of persons likely to be substantially affected by reliability investments and content of grid upgrade plans. Rule 13.2.3 of Section III, Part F.

- considered and incorporated the feedback received
- refined the options (as presented in this paper)
- developed the economic approach
- analysed the results.

## 4 Identification and Consideration of Options

***This section outlines how Transpower has identified alternative projects to be considered in applying the Grid Investment Test***

### 4.1 Requirements under the Rules

The application of the GIT requires an analysis and comparison of the market benefits and costs of a proposed investment and those of a number of alternative projects<sup>8</sup>. Therefore, Transpower must first identify those options that fall within the definition of “alternative projects” under the Rules.

### 4.2 Option identification

The initial need investigation found that investment is needed in a relatively short period of time to prevent the two transformers at Tarukenga from exceeding their firm capacity. The overloading risk is compounded by the condition of the two transformers that are more than 40 years old and are showing signs of deteriorating condition.

In the interests of expediency, only the timing of the individual components of each development plan were revised as a result of the change in demand forecast resulting from the initial consultation feedback – refer Appendix C of Attachment A for details of the changes made to the demand forecast.

#### 4.2.1 Long list of options

The long-list aims to canvas a broad range of viable investment options, while balancing the desirability of a broad range of options with the resources and time invested in the options that are likely to be progressed to the short-list.

In compiling the long-list of options, Transpower considered the technical feasibility of each option and information received in response to Transpower’s consultation on a draft long list and request for information (RFI) in relation to non-transmission alternatives published in May 2009.<sup>9</sup>

Transpower identified four categories of investment options for inclusion in the long list:

- non-transmission alternatives to reduce load on the Bay of Plenty 110 kV network
- reconfiguring existing assets to reduce load on the Bay of Plenty 110 kV network
- increasing the interconnecting capacity at Tarukenga
- extending the 220 kV transmission system.

A full description of the long-list of options is provided in Attachment B - Options and Costs Report.

<sup>8</sup> Schedule F4, clause 4 of the Rules.

<sup>9</sup> <http://www.gridnz.co.nz/Kaitimako-reinforcement-consultation>

## 4.2.2 Short-listing approach

The purpose of the short-listing analysis was to reduce the long-list of options to a short-list, for further development and analysis to select a preferred option. The short-listed options that are not selected as the preferred option comprise the alternative projects against which the preferred option is compared under the GIT.

In summary, Transpower's short-listing approach was to screen its long list to formulate a short-list, based on the following criteria:

- fitness for purpose
- technical feasibility
- practicality of implementation
- Good Electricity Industry Practice (GEIP)
- system security
- indicative cost
- feedback from consultation

In addition, the Rules require that the alternative projects used in applying the GIT must be limited to those appropriate in number and technology given the cost magnitude of the proposed investment, the complexity of the modelling and the urgency of the proposed investment.<sup>10</sup>

The short-listing approach and application is also fully described in Attachment B - Options and Costs Report.

## 4.2.3 Further staged investments for short-list options

Some of the options do not ensure the GRS can be met for the next 20 years. In order to complete the GIT analysis, longer term development plans, which include additional staged upgrades as modelled projects, were developed as necessary for each short-list option.

The following tables show the development plans for each of the short-list options.

**Table 4-1 – Short-list Development Plans**

Option	Stage	Description	Implementation date
1	Stage 1	Two 250 MVA transformers at Tarukenga	2011
	Modelled Projects	Upgrade Okere–Te Matai circuit	2017
		40 Mvar capacitor at Papamoa	2021
		Upgrade Okere–Tarukenga circuit	2023
		Upgrade Kaitimako–Tarukenga circuits 1&2	2024
		250 MVA transformer at Tarukenga	2024
		Upgrade Kaitimako–Papamoa circuit	2027
		30 Mvar capacitor at Kaitimako	2030
		Upgrade Papamoa–Te Matai circuit	2033
2	Stage 1	Three replacement 150 MVA transformers at Tarukenga	2011
	Modelled Projects	Upgrade Okere–Te Matai circuit	2018
		40 Mvar capacitor at Papamoa	2021
		Upgrade Okere–Tarukenga circuit	2024

<sup>10</sup> Schedule F4 clause 11.

		Upgrade Kaitimako–Tarukenga circuits 1&2	2024
		Upgrade Kaitimako–Papamoa circuit	2027
		150 MVA transformer at Tarukenga	2028
		30 Mvar capacitor at Kaitimako	2029
		Upgrade Papamoa–Te Matai circuit	2033
3	Stage 1	Additional 150 MVA transformer at Tarukenga	2011
	Modelled Projects	Upgrade Okere–Te Matai circuit	2018
		Replace Tarukenga transformers with 150 MVA transformers	2020
		40 Mvar capacitor at Papamoa	2021
		Upgrade Okere–Tarukenga circuit	2024
		Upgrade Kaitimako–Tarukenga circuits 1&2	2024
		Upgrade Kaitimako–Papamoa circuit	2027
		150 MVA transformer at Tarukenga	2028
		30 Mvar capacitor at Kaitimako	2029
		Upgrade Papamoa–Te Matai circuit	2033
4	Stage 1	Additional 250 MVA transformer at Tarukenga	2011
	Modelled Projects	Upgrade Okere–Te Matai circuit	2018
		Replace Tarukenga transformer with 250 MVA transformers	2020
		40 Mvar capacitor at Papamoa	2021
		Upgrade Okere–Tarukenga circuit	2023
		Upgrade Kaitimako–Tarukenga circuits 1&2	2024
		Upgrade Kaitimako–Papamoa circuit	2027
		30 Mvar capacitor at Kaitimako	2030
		Upgrade Papamoa–Te Matai circuit	2033
5	Stage 1	Convert <sup>11</sup> Kaitimako–Tarukenga circuits to 220 kV operation	2011
	Modelled Projects	Two 150 MVA transformers at Kaitimako	2011
		Two 150 MVA transformers at Tarukenga	2020
		40 Mvar capacitor at Papamoa	2022
		Add 3 <sup>rd</sup> 150 MVA transformer at Kaitimako	2025
		Upgrade Okere–Te Matai circuit	2028
		Upgrade Kaitimako– Papamoa circuit	2029
		Upgrade Okere– Tarukenga circuit	2032
6	Stage 1	Additional 150 MVA transformer at Tarukenga	2011
	Modelled Projects	Two 150 MVA transformers at Kaitimako	2018
		Convert Kaitimako–Tarukenga line to 220 kV operation	2018
		Dismantle Tarukenga T1 and T2	2020
		1 x 150 MVA transformer at Tarukenga	2020

<sup>11</sup> “Convert” denotes increasing the operating voltage from 110 kV to 220 kV and thermally upgrading to 80°C, when “convert” is used in the tables in the GUP.

40 Mvar capacitor at Papamoa	2022
Add 3 <sup>rd</sup> 150 MVA transformer at Kaitimako	2025
Upgrade Okere–Te Matai circuit	2028
Upgrade Kaitimako–Papamoa circuit	2029
Upgrade Okere– Tarukenga circuit	2032

Transpower's approach is to seek Commission approval for only a stage 1 upgrade.

#### 4.2.4 Final short-list

The final short-list, including the development plan for each short-listed option, is set out in Table 4-2 below.

**Table 4-2: Final short-list**

Option	Stage 1 Upgrade
1	Replace the Tarukenga transformers with two 250 MVA transformers
2	Replace the Tarukenga transformers with three 150 MVA transformers
3	Install a third 150 MVA transformer at Tarukenga. This option will maintain 110 kV supply to Kaitimako in the future.
4	Install a third 250 MVA transformer at Tarukenga
5	Add two 150 MVA transformers at Kaitimako and convert the Tarukenga–Kaitimako circuits to 220 kV
6	Install a third 150 MVA transformer at Tarukenga. This option will convert to 220 kV supply to Kaitimako in the future.

### 4.3 Reflecting Good Electricity Industry Practice in meeting the GRS

Rule 13.4.1.1 permits the Commission to approve a reliability investment where the proposed investment reflects GEIP in meeting the GRS.

#### 4.3.1 The short-list options reflect GEIP

The Rules define GEIP in relation to transmission as:

*"The exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced **asset** owner engaged in the management of a transmission network under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."*

Accordingly, comparable international practice should be considered in assessing what is GEIP in terms of grid investment planning. Transpower, as a prudent planner, owner and operator of a transmission network, can reasonably be expected to adopt solutions consistent with good international practice.

Transpower considers that all the Short-list options reflect GEIP as required by rule 13.4.1.1. Specifically, the approach taken for the Proposal is consistent with international practice as being a prudent investment given the size, nature and importance of the Western Bay of Plenty, Rotorua, Tarukenga, Lichfield and Kinleith load.

### 4.3.2 The short-list options meet the Grid Reliability Standards

The GRS are contained in Schedule F3 of the Rules. These provide that the grid satisfies the grid reliability standards if:

- "4.1 *the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented; and*
- 4.2 *with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following any **single credible contingency event** occurring on the **core grid**."*

As the Proposal is a reliability investment on the core grid, the Proposal must meet both clauses 4.1 and 4.2 of the GRS. Accordingly, Transpower undertook a power system analysis to ensure that the short-list options would provide the level of security required by the n-1 safety net criterion under clause 4.2 from the commissioning date, and will reduce expected unserved energy.

Transpower considers that all short-list options (including the Proposal) meet the GRS as required by rule 13.4.1.1.

## 4.4 Base case

For the purposes of the GIT, the Rules require that the Proposal and the alternative projects be assessed against a base case, which is defined as the market development scenarios developed for the reasonable future state of the electricity industry without the proposed investment or any alternative project.<sup>12</sup>

As noted by both the Commission and Transpower in analysis of the North Island Grid Upgrade Proposal, it is difficult to identify a suitable base case for the analysis when an investment proposal is required to meet the GRS, because the base case must meet the GRS but not be an alternative project.

The Commission has previously resolved this issue by using one of the "alternative projects" as a reference case. Transpower has adopted this approach.

Transpower considers that a reasonable reference case for this investigation would be replacement of the Tarukenga transformers with two 250 MVA transformers. This reference case reflects Option 1 of the short-list, and therefore Transpower has chosen Option 1 as a reference case against which the other short-list options are compared.

## 5 Methodology and assumptions

***This section sets out Transpower's approach to applying the Grid Investment Test***

<sup>12</sup> Clause 20 of Part F Section III Schedule F4

## 5.1 Approach to the GIT analysis

The GIT requires Transpower to determine the market benefits and costs of each of the short-list options under a number of market development scenarios for the future.<sup>13</sup>

The GIT analysis requires certain input assumptions and parameters to be determined and applied and then results tested against various sensitivities.

Under the Rules, the rigour and comprehensiveness of the GIT analysis should be commensurate with the estimated capital expenditure of a proposed investment.<sup>14</sup>

In order to ensure commensurate analysis for this investigation project, Transpower assessed the requirements for application of the GIT and considers that only the following need to be considered in applying the GIT:

- project costs
- reliability differences (under limited circumstances).

Transpower considers that there are no material benefit differences between the short-listed options, with the exception of the reduction in losses and terminal values. The development plans include different timings for modelled projects and some of those modelled projects have un-utilised capacity at the end of the analysis period. The cost of un-utilised capacity has been credited back as a terminal value.

By treating these differences (losses and terminal values) as costs, the GIT application condenses to become a cost comparison, with the lowest overall cost alternative passing the GIT.

## 5.2 Approach to market development scenarios

Reflecting the approach outlined above, there is no new generation in any of the market development scenarios detailed in the Electricity Commission's 2008 SoO, or in any other reasonable future state of the electricity industry, that would materially impact on the GIT analysis. In this case, Transpower considers that an analysis of the net market benefits of the short-list options under multiple market development scenarios would yield the same results for each scenario. Therefore, Transpower has assessed the net market benefits of the short-listed options on the basis of one generation scenario, in which there is no new generation built in the region. This scenario is assigned a 100% probability. In effect, the future market development scenarios have a neutral effect on the analysis of the comparative net market costs of the short-list options.

Transpower notes that this approach is broadly similar to the approach adopted by the Commission in the Reasons to Approve the North Island Grid Upgrade Proposal.<sup>15</sup>

## 5.3 Market costs

Assessment of the costs of each short-list option requires identification and quantification of the following categories of costs over the analysis period:

- transmission costs for each transmission option
- statutory compliance costs

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<sup>13</sup> Clause 5 of Schedule F4.

<sup>14</sup> Clause 12 of Schedule F4.

<sup>15</sup> See Reasons for Decision set out in Notice of Intention to Approve Transpower's North Island Grid Upgrade Proposal, para 6.3.22.

- inflation costs
- interest during construction
- exchange rates.

For the purposes of applying the GIT, Transpower has costed the short-list options to a level of accuracy which:

- confirms the scope of the technical work required
- is to an accuracy of +/-30% or less, subject to exchange rate variations.<sup>16</sup>

Operating and Maintenance costs have been included in each of the development plans to ensure comparative consistency for the purposes of the GIT, however, these costs are not included in the approval amount.

Interest during construction (IDC) costs have not been explicitly included in the GIT analysis as they are not material to differentiating between the costs of the short-list options, as all short-list options are new-build options by Transpower and IDC will not vary disproportionately between options.

### 5.3.1 Loss Costs

Losses are calculated by scaling observed 2008 line flows in the region by the demand forecast growth rates and calculating the losses based on the physical resistance of each line. Losses in MW are costed at the weighted LRMC of generation from the five scenarios in the Electricity Commission's 2008 Statement of Opportunities. For full details of the loss cost calculation, see Appendix A of Attachment B Options and Cost Report.

### 5.3.2 Summary of market costs

The following is a summary of the approach to estimating costs.

**Table 5-1 Summary of market costs**

Market Cost		Approach
Transmission costs	Line and substation capital costs	Included
	Property and easement costs	Included
	Project management	Included
	Consenting costs	Included
	Operating and maintenance costs	Included
	Decommissioning costs	Included
Statutory compliance costs		Included
Inflation costs		Included as appropriate, 3%
Interest during construction		Not explicitly included in GIT, but used to determine approval cost, 7.7%.
Exchange rates		USD reflected at a rate of 0.6884, varied for calculating \$2011
Loss Costs		Losses are costed based on weighted LRMC of new generation from the five 2008 Statement of Opportunities scenarios.

<sup>16</sup> The actual accuracy level of the costs differs by component. For detailed breakdown refer to Attachment D, the cost report.

## 5.4 GIT Sensitivities

***This section sets out sensitivities used by Transpower in applying the Grid Investment Test***

The sensitivities analysed or considered in applying the GIT to the short-list of options is described in the table below:

**Table 5-2 Summary of Sensitivities**

Sensitivity	Value
Forecast demand	Included –2008 SoO expected forecast as a lower demand sensitivity
Variations in the size, timing, location, and operating and maintenance costs	Not included as a sensitivity
Capital cost	Transformer costs +/- 30%
Timing of decommissioned assets	Not significant therefore not included
VoLL	Not significant therefore not included
Discount rate	4% and 10%

Under the Rules, the rigour and comprehensiveness of the GIT analysis should be commensurate with the estimated capital expenditure of a proposed investment.

Transpower considers this level of sensitivity analysis is sufficient to ensure the rigour and comprehensiveness of the analysis is commensurate with the estimated capital expenditure required for the Proposal, and therefore further sensitivity analysis is not reasonably necessary.<sup>17</sup>

## 6 Application of the Grid Investment Test

***This section sets out Transpower's application of the Grid Investment Test***

### 6.1 Compliance with the Grid Investment Test

As the Proposal concerns the core grid and must therefore meet the grid reliability standard set out in clause 4.2 of Schedule F3, the Proposal will satisfy the GIT under clause 4.1 of Schedule F4 if:

- the **proposed investment** maximises the **expected net market benefit** or minimises the **expected net market cost** compared with a number of **alternative projects**; and
- if sensitivity analysis is conducted, the conclusion (on net market benefits or net market costs) that a **proposed investment** satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis.

As identified below, Transpower considers that Option 5 complies with the GIT. Option 5 is the installation of two 150 MVA transformers at Kaitimako, and changing

<sup>17</sup> Clause 17, Schedule F4.

the Kaitimako–Tarukenga circuits from an operating voltage of 110 kV to the original construction voltage of 220 kV and a thermal upgrade in 2011.

## 6.2 GIT results

The GIT results are presented as a comparison of the expected net market costs for the short-list options under a prudent demand growth forecast.

The following table summarises the results of the GIT analysis:

**Table 6-1: Grid Investment Test Results**

Stage 1 Upgrade Options	Transmission Costs (\$ m) (A)	Loss Cost (\$ m) (B)	Terminal Cost (\$m) (C)	Expected net market cost (\$m) (A + B +C)
Reference Case				
Two 250 MVA Tarukenga transformers	23.37	16.07	7.01	46.44
Option 2				
Three 150 MVA Tarukenga transformers	25.47	16.07	7.04	48.57
Option 3				
Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer	20.94	16.07	7.01	44.02
Option 4				
Add a 3 <sup>rd</sup> 250 MVA Tarukenga transformer	21.85	16.07	6.98	44.90
Option 5				
Two 150 MVA transformers at KMO, convert Kaitimako–Tarukenga to 220 kV	27.70	4.98	3.68	36.36
Option 6				
Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer (convert to 220 kV later)	25.92	8.88	3.70	38.50

**Notes:**

Costs are all pre-tax , discounted at 7%, in \$m, and in \$2009

## 6.3 Sensitivity analysis

The sensitivity analysis is presented as a comparison of the expected net market cost for the short-list options when various parameters are varied.

The following table summarises the results of the sensitivity analysis:

**Table 6-2: Grid Investment Test sensitivity analysis**

<b>Expected Net Market Cost \$NZ million</b>	<b>Option 1 (Reference Case)</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>	<b>Option 6</b>
	two 250 MVA Tarukenga transformers. Maintain 110 kV supply	three 150 MVA Tarukenga transformers. Maintain 110 kV supply	Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer. Maintain 110 kV supply	Add a 3 <sup>rd</sup> 250 MVA Tarukenga transformer. Maintain 110 kV supply	two 150 MVA transformers at Kaitimako. Convert Kaitimako–Tarukenga to 220 kV	Add a 3 <sup>rd</sup> 150 MVA Tarukenga transformer. Convert to 220 kV supply later
Base results	<b>46.44</b>	<b>48.57</b>	<b>44.02</b>	<b>44.90</b>	<b>36.36</b>	<b>38.50</b>
<b>Sensitivities</b>						
Low demand	39.16	41.29	36.74	37.61	34.13	35.67
+30% transf. cost	49.35	51.61	46.23	47.41	39.55	41.41
-30% transf. cost	43.53	45.53	41.82	42.38	33.17	35.58
Discount rate 4%	66.80	68.99	65.71	65.81	47.97	52.81
Discount rate 10%	34.53	36.67	31.31	32.52	29.19	29.34
<b>Notes: Costs are all pre-tax , discounted at 7% unless otherwise noted, in \$m, and in \$2009</b>						

The results of the sensitivity analysis indicate that Option 5 minimises the expected net market costs under each of the variations of the variables considered as part of the sensitivity analysis. Therefore Transpower considers the sensitivity analysis shows that the conclusion that Option 5 minimises the expected net market costs compared with the other short-list options is robust.

### 6.3.1 Accuracy of GIT

Transpower recognises there is inherent uncertainty in several of the input assumptions used in the GIT analysis, namely the demand forecasts and cost assumptions.

However, Transpower considers the rigour and comprehensiveness of the analysis undertaken is commensurate with the estimated capital expenditure required for the proposed investment.

### 6.3.2 GIT analysis conclusion

Transpower considers that Option 5 satisfies the GIT because:

- it minimises the expected net market cost when compared with the alternative projects
- it is robust having regard to the results of sensitivity analysis.

## 6.4 Timing of the Proposal

The Proposal is a reliability investment required to meet the n-1 reliability criteria on the Bay of Plenty 110 kV network. The GRS will not be met by 2011; hence we are aiming to commission this Proposal by winter 2011.

## 7 Compliance with the processes set out in the Rules

The Commission may approve a proposed reliability investment where the proposed investment complies with the processes set out in the Rules. Transpower notes that the Commission interprets this rule as requiring that Transpower has complied with the processes required by the Rules in relation to the proposed investment under consideration.

The processes in the Rules require Transpower to:

- submit a grid upgrade plan in accordance with Rule 12.2
- comply with any requests from the Commission prescribed in writing to provide information it considers is reasonably required to enable it and interested persons to evaluate the proposed investment – Rule 12.3.4
- comply with the timetable for consultation and approval of reliability investments proposed in Transpower's grid upgrade plan, agreed between Transpower and the Commission, or as stipulated by the Commission, in accordance with Rule 13.2
- respond to any requests for further investigation or further information in accordance with Rule 13.3.3.

The processes under the Rules that Transpower follows in respect of potential investments are project-specific and accordingly do not assist in differentiating between the short-list options.

### 7.1.1 Submission of a Grid Upgrade Plan

Rule 12.2.1 provides that either:

- Transpower must submit a grid upgrade plan to the Commission within 3 months of receiving a written request from the Commission, or such other date as the Commission agrees; or
- Transpower may submit a grid upgrade plan for the Commission's consideration at any other time.

Transpower has not received a written request for submission of a grid upgrade plan. Transpower is submitting this document, as part of its 2009 Grid Upgrade Plan to the Commission.

### 7.1.2 Provision of information

Rule 12.3.4 requires a grid upgrade plan to, amongst other things, include:

*"such other content as prescribed in writing by the **Board**, to ensure that **grid upgrade plans** includes such information that the **Board** considers is reasonably required to enable the **Board** and interested parties to evaluate **proposed transmission investments**, such as indicative pricing impacts of **investment proposals**."*

The Commission has not requested any information under Rule 12.3.4. No further requests for information under Rule 12.3.4 or otherwise were made.

Accordingly, Transpower has complied with the requirements of Rule 12.3.4.

### 7.1.3 Compliance with the timetable and process

Rule 13.2.1 requires the Commission and Transpower to agree a timetable for consultation and approval of reliability investments. In the absence of agreement, the Commission may stipulate such a timetable.

Additionally, the Commission must consult with Transpower on the process for consultation and persons who the Commission will consult with.

Transpower and the Commission have agreed on a timetable for consultation and approval of the Proposal, including persons who the Commission will consult with.

Transpower considers that, to date, it has complied with the timetable and process agreed with the Commission.

### 7.1.4 Requests for further investigation and further information

Under rule 13.3.3, the Board may:

- direct Transpower to undertake further investigations into its proposed reliability investment
- ask questions of Transpower or require further information or consultation on part or all of Transpower's Proposal
- ask Transpower to evaluate alternative reliability investments
- where Transpower possesses relevant expertise, ask Transpower to evaluate transmission alternatives.

The Commission has not requested any information under rule 13.3.3. Transpower will endeavour to continue to comply with any reasonable requests the Commission may have in accordance with the above requirements.

## 7.2 Transpower's application of the Grid Investment Test

The Commission may approve a proposed reliability investment where the proposed investment complies with the processes set out in the Rules. Transpower notes that the Commission interprets this rule as requiring that Transpower has complied with the processes required by the Rules in relation to the proposed investment under consideration.

The processes in the Rules require Transpower to:

- submit a grid upgrade plan in accordance with Rule 12.2
- comply with any requests from the Commission prescribed in writing to provide information it considers is reasonably required to enable it and interested persons to evaluate the proposed investment – Rule 12.3.4
- comply with the timetable for consultation and approval of reliability investments proposed in Transpower's grid upgrade plan, agreed between Transpower and the Commission, or as stipulated by the Commission, in accordance with Rule 13.2
- respond to any requests for further investigation or further information in accordance with Rule 13.3.3.

The processes under the Rules that Transpower follows in respect of potential investments are project specific and accordingly do not assist in differentiating between the short-list options.

## 8 The Proposal meets the Rule requirements

As the Proposal is a “reliability investment”, the Commission can approve the Proposal under rule 13.4.1 if the Proposal:

- reflects good electricity industry practice in meeting the Grid Reliability Standards
- complies with the processes set out in the Rules
- meets the requirements of the GIT.

Transpower considers the Commission may approve the Proposal on the grounds that it satisfies the criteria under rule 13.4.1.

## 9 Approval Amount for the Proposal

### 9.1 Approval amount sought

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal. The Expected Cost of the Proposal, comparable to that used in the GIT<sup>18</sup>, is estimated to be \$18.6 million and the MAC of the Proposal is estimated to be \$21.5 million.

### 9.2 Approval amount methodology

Transpower has previously used what is known as a P90 methodology to calculate the approval amount. However, Transpower proposes to use a simplified methodology to determine a formulaic Maximum Approval Cost (MAC). This will allow for variations in such items as financing costs, exchange rates and commodity prices, costs typically beyond the control of Transpower. Transpower considers the use of a MAC also aids transparency and makes tracking of project costs against the approved amount much simpler.

The amount for which approval is sought from the Commission is shown below, in comparison to the Expected Cost, as used in the GIT analysis, and the Expected End Cost, which is the cost Transpower expects the Proposal to cost. The Expected End cost is similar to the previously used P50 figure.

**Table 9-1 – Maximum Approval Cost**

\$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected cost	16.9	18.6						
Expected End cost	16.9	18.6	0.3	–	–	1.2	0.4	20.5
Maximum Approved Cost	16.9	18.6	0.9	0.3	–	1.2	0.5	21.5

Full details of the MAC methodology can be found in Appendix B.

<sup>18</sup> The cost used in the GIT represents the net present value of the costs incurred in current dollars, and includes operating and maintenance (O&M) costs. The Expected Cost is measured in current dollars and does not include O&M costs.

## Appendix A Glossary

Term	Description
<b>Alternative Project</b>	Projects that are reasonable to consider as alternatives to the proposed investment in applying the Grid Investment Test, in accordance with rule 19, Schedule F4, Part F Section III, Electricity Governance Rules.
<b>APR</b>	<b>Annual Planning Report</b>
<b>base case</b>	The “counterfactual” for other options to be considered against.
<b>Consultation Paper</b>	Document published by Transpower in October 2008 outlining the project assumptions, methodologies and long list of options.
<b>expected project costs</b>	Expected project costs (or expected costs) represent the estimated (P50) cost plus a contingency for scope accuracy. Scope accuracy allows for unexpected variations in the design scope and a standard allowance, based on experience, for items not considered in the design.
<b>expected unserved energy</b>	A forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment.
<b>GEIP</b>	<b>Good Electricity Industry Practice.</b>
<b>GEM</b>	<b>Generation Expansion Model</b> , a model for generation expansion modelling developed by the Commission.
<b>GIT</b>	<b>Grid Investment Test.</b> A cost-benefit analysis for both reliability and economic investments. The specific rules defining the Grid Investment Test, as developed according to the process in rule 6 of section III, are set out in Schedule F4 of section III of Part F.
<b>GPS</b>	<b>Government Policy Statement on Electricity Governance.</b>
<b>GUP</b>	<b>Grid Upgrade Plan.</b> A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules.
<b>MAC</b>	<b>Maximum Approval Cost</b>
<b>modelled projects</b>	Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are: <ul style="list-style-type: none"> <li>▪ likely to occur in a market scenario;</li> <li>▪ reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects; and</li> <li>▪ the likelihood, nature and timing of which will be affected by whether the proposed investment or any alternative project proceeds.</li> </ul>
<b>Monte Carlo</b>	Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of numbers randomly generated

	within certain ranges as inputs. It creates a distribution of possible outcomes on which descriptive statistics can then be run.
<b>P90 cost</b>	Estimated 90 <sup>th</sup> percentile of project costs.
<b>Reference case</b>	An “alternative” option against which the other options can be compared.
<b>reliability investment</b>	Investments by Transpower in the grid, or alternative arrangements by Transpower, the primary effect of which is, or would be, to reduce expected unserved energy.
<b>Rules</b>	The Electricity Governance Rules 2003. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments.
<b>SCADA</b>	Supervisory Control and Data Acquisition.
<b>SDDP</b>	<b>S</b> tochastic <b>D</b> ual <b>D</b> ynamic <b>P</b> rogramming, a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies.
<b>SoO</b>	Statement of Opportunities, published by the Commission.
<b>Transpower</b>	Transpower New Zealand Limited, owner and operator of New Zealand’s high-voltage electricity network (the National Grid).

## Appendix B Maximum Approval Cost methodology

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal.

The Expected Cost of the Proposal, as used in the GIT, is estimated to be \$18.6 million and the MAC of the Proposal is estimated to be \$21.5 million. This section sets out how Transpower has estimated the MAC and describes the difference between the Expected Cost and the MAC.

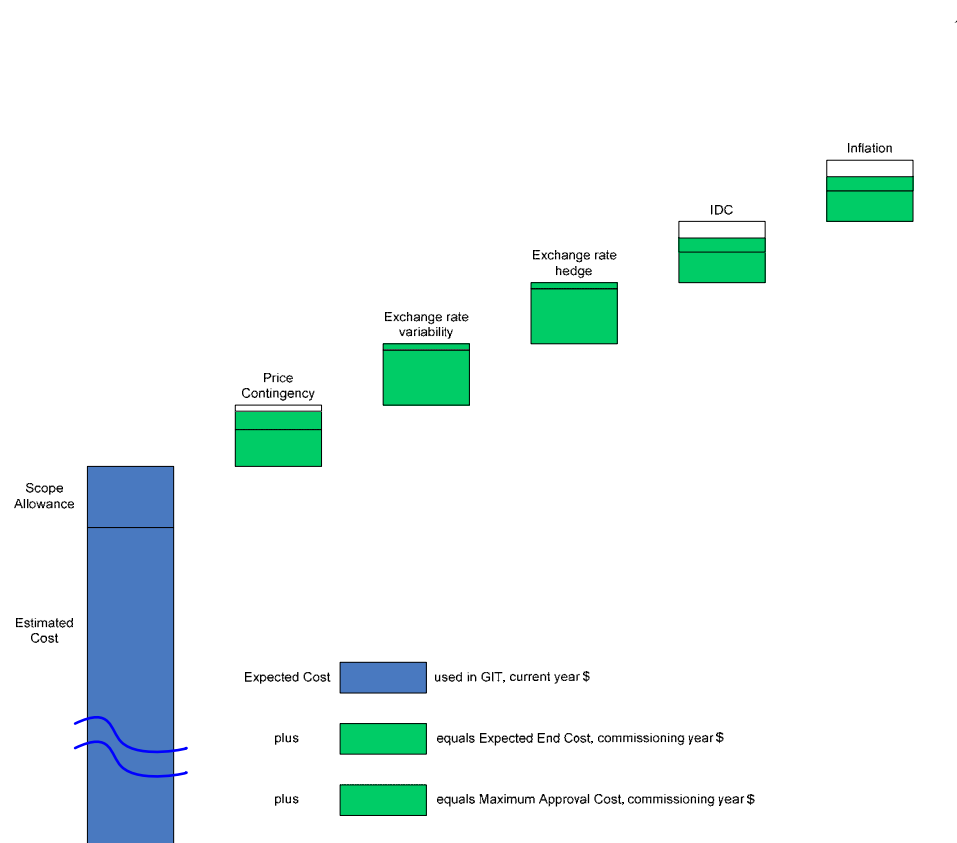
In previous Investment Proposals submitted to the Commission, Transpower has sought approval to recover up to a P90 cost. It is expected there is only a 10% probability that the P90 figure would be exceeded once the Proposal was commissioned. The P90 figure was derived from a probabilistic analysis of the expected cost of the Proposal using a Monte Carlo approach.

However, experience has shown that the development of a P90 figure lacks transparency and in particular it is difficult to relate the P90 back to actual, trackable, project specific costs. Transpower has applied a different method for the Wairakei Ring Proposal and has determined a MAC. The methodology for determining a MAC is described below.

For comparison, Transpower has also calculated and reported a P90 figure, in order to assist the Commission in understanding how the new approach for calculating a maximum approval amount relates to the previous approach.

The relationship between the Expected Cost used in the GIT and the MAC is represented in Appendix B Figure 1.

**Appendix B Figure 1: Relationship between Expected Cost and MAC**



The approval amount is higher than the Expected Cost used in the GIT because of the following factors:

- The Expected Cost comprises an estimated cost plus an allowance for scope variations. It does not include an allowance for all uncertainties present in a construction project of the type proposed.
- The Expected Cost is in current (today's) dollars, whereas the approval amount is an estimate of the end cost of the project in future (commissioning year) dollars.
- The approval amount is required to cover the full cost of the project including financing costs, price variations on materials, exchange rate variations and foreign exchange hedging, etc.

Importantly, at the approval stage the actual costs are known at a high level only as there is a reasonable interval between approval and when the majority of actual costs are incurred.

Appendix B Figure 1 shows that the Expected Cost used in the GIT is the Estimated Cost plus Scope Allowance only, in current dollars.

The Maximum Approved Cost is higher than the Expected Cost because it includes an allowance for price contingencies and all other variables. Estimates are used to produce an overall MAC similar in magnitude to the previously calculated P90.

#### Method of calculating Maximum Approval Cost

The following inputs and variables are considered in deriving the Expect End Cost and MAC:

- **Estimated Cost.** The Estimated Cost is the estimated cost of designing, procuring, constructing and commissioning the components which make up the Proposal. These costs can include decommissioning costs and the costs of obtaining designations, easements, resource consents and property purchases for these works if applicable. The Estimated Cost does not include contingencies. The Estimated Cost is in current dollars, as calculated on the Reference Date.
- **Reference Date.** Transpower prepared estimated capital costs as at 19 October 2009. A reference date is used to ensure consistency between the estimated capital costs of components within each option considered in the GIT and between options. For calculating costs at commissioning time, Transpower has assumed a commissioning date of July 1<sup>st</sup>, 2011. These commissioning dates are assumed to be the dates at which accumulated costs for the project would be included in Transpower's regulated asset base and from which costs would start to be recovered through the Transmission Pricing Methodology.
- **Scope allowance.** Transpower also estimates a scope allowance, which is added to the Estimated Cost, to cover two distinct categories of costs:
  - costs for works which are planned, but which have not been included in the estimated capital costs except through this general allowance; and
  - costs for works not anticipated at the time costs were estimated. The Estimated Cost plus Scope Allowance equals the Expected Cost of the project or various components of it and this is the cost used in GIT analyses. The Scope Allowance is treated as a fixed percentage of Estimated Costs which are added to the Estimated Cost.
- **Price Contingency.** As regulatory approval occurs prior to the issuing of tenders, there is uncertainty over the price of equipment to be installed. In particular, this includes the risks that:
  - market pressures may affect the cost of capital items, e.g. if worldwide demand for transformers is high at the time Transpower seeks tenders, the prices offered may reflect a tighter supply situation and therefore be higher than at other times; and

- commodity prices may move significantly.. Tender prices for some capital items include escalators linked to market price variations in significant elements of that item eg metals such as steel and copper. As with exchange rate variations, Transpower would not, typically, consider hedging anticipated commitments until a contract is awarded or signed. This is because of the somewhat speculative nature of entering commodity futures contracts in advance of commitment and the costs involved, which may or may not be required, depending upon the terms of the eventual contract. Hence, Transpower is exposed to commodity price movements up until contracts are signed and so an estimate is made of the potential cost variation this might cause.

Price movements could be downward as well as upward and for this reason the price contingency is estimated as the minimum and maximum variations expected. A price contingency of -10% to +20%, would be typical.

For the purposes of calculating the Expected End Cost, the mean-point of this range is taken, ie 3%, for the example above.

For the purposes of calculating the MAC, the 90<sup>th</sup> percentile of this range is taken, ie 12%, for the example above.

- **Exchange rate variations.** Transpower's current practice is to enter foreign exchange contracts to hedge foreign exchange movements, once contractual commitments are made. This provides NZ dollar cost certainty from the point that tenders are awarded/contracts signed.

Transpower does not, typically, hedge anticipated commitments. This is because of the somewhat speculative nature of entering foreign exchange contracts in advance of commitment and the added costs of having to pay option premiums for hedging a range of possible currencies and execution dates, most of which would not be exercised. Hence the requirement to estimate the effect on costs of exchange rates moving in the interim period before signing contracts.

The Estimated Costs were based on the average exchange rate 20 business days either side of 22 September 2009.

The exchange rate variations are based on historical volatility and are estimated on either a 50<sup>th</sup> or 90<sup>th</sup> percentile likely over the period between the Reference Date and when tenders might be accepted. The methodology used to calculate the 50<sup>th</sup> and 90<sup>th</sup> percentile volatility variations is as developed by Bancorp and as used for the HVDC Proposal.

- **Exchange rate hedge.** As mentioned above, Transpower's current practice is to enter foreign exchange contracts to hedge foreign exchange movements, once contractual commitments are made. The hedging cost included has been estimated using current forward exchange rate premiums, for the expected period between committing to contracts which include foreign exchange exposure and the expected payment dates under those contracts.
- **Real interest rates.** Real interest rates are used in the calculation of Interest During Construction costs and are assumed to vary between 3.5% to 5.5%, with a mean of 4.5%. The nominal interest rate is the real interest rate plus the inflation rate, equating to a mean nominal interest rate of 7.7% in this instance. This is approximately Transpower's current cost of debt.

For the purposes of calculating the Expected End Cost, the mean of 4.5% is used. This is also used in the MAC.

- **Inflation.** Transpower assumes inflation will vary between 2% to 4% per annum, with a mean of 3%.

For the purposes of calculating the Expected End Cost, the mean of 3% per annum is used. This is also used in the MAC.

### Results of Expected Cost, Expected End Cost and MAC calculations

The Expected Cost of the Proposal, as estimated in 2009, is \$18.6 million.

This cost includes a scope allowance and represents Transpower's estimate of the cost of designing, purchasing, constructing and commissioning the Proposal, in current dollars. Transpower will not start recovering the costs of a stage of this Proposal until it is commissioned. The cost Transpower will look to recover at that time is higher, due to financing costs incurred throughout the construction period and inflation.

The MAC for the Proposal is \$21.5 million and Transpower is seeking approval to recover the lesser of actual costs or the MAC. Appendix Table 1 shows the break down of the MAC.

**Appendix Table 1: Maximum Approval Cost for the Proposal, \$ million**

Expected Cost	Price Contingency	Exchange Rate Variability	Exchange Rate Hedge	Inflation	Interest During Construction	Maximum Approval Cost
18.6	0.9	0.3	–	1.2	0.5	21.5

There is a probability of exceeding the MAC (and in fact as shown below, the MAC is almost identical to a P90 figure). If there are changes which are materially different to those assumptions used in deriving the MAC then this cost may be exceeded. In such a case, Transpower would apply for approval for the revised costs of the project in accordance with Rule 17.2.

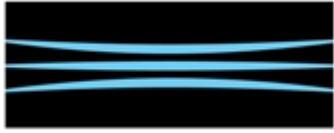
For comparison, Transpower has calculated a P90 figure for the Proposal, using the same approach as used for past Investment Proposals. The MAC and P90 are shown in Appendix Table 2 below:

**Appendix Table 2: Maximum Approval and P90 Costs**

Maximum Approval Cost	P90
21.5	21.5

### Summary of estimated Expected End Cost and Maximum Approval Cost

Transpower estimates the expected cost, with variations accounted for, to be \$20.5 million and the Maximum Approval Cost of the Proposal to be \$21.5 million.



**T R A N S P O W E R**

**Bay of Plenty Interconnection Capacity Upgrade  
Investment Proposal**

**Attachment A  
Technical Report**

November 2009

## Executive Summary

### Scope

This investigation examines the Bay of Plenty transmission issues between Tarukenga and Kaitimako as identified in the 2008 APR and re-evaluates the needs and timings with the latest Demand Forecast and some further specific customer load shifting plans communicated to Transpower.

The investigation explores the requirements for the next 20 years, to the beginning of 2030.

The specific customer load shifting plans are between:

- Tauranga and the committed Kaitimako supply transformer
- Mt Maunganui and the proposed Papamoa substation.

### Findings

The investigation has identified short, mid and long term issues that cover the core grid area between the 220 kV Tarukenga bus to the 110 kV Kaitimako bus and the non-core grid 110 kV lines between Tarukenga, Okere, Te Matai and Kaitimako.

In the short term:

- the rating of the current transformer associated with Tarukenga 220/110 kV interconnecting transformer T1 (CT 192) needs to be increased so that it matches the transformer 110 kV winding rating by the winter of 2009
- failure of the Tarukenga 220/110 kV interconnecting transformer (T1) will overload the parallel interconnecting transformer (T2) during winter peaks from 2011
- failure of the Tarukenga 220/110 kV interconnecting transformer T2 will overload the parallel interconnecting transformer (T1) during winter peaks from 2012.

In the mid term:

- any planned or unplanned outage of Tarukenga 220/110 kV interconnecting transformer T1 during the summer daily peaks will require load curtailment to prevent the parallel interconnecting transformer (T2) overloading from 2016 (ie. There are no daylight periods in the year where transformer maintenance will not require load curtailment)
- any planned or unplanned outage of Tarukenga 220/110 kV interconnecting transformer T2 during the summer daily peaks will require load curtailment to prevent the parallel interconnecting transformer (T1) overloading from 2017 (ie. There are no daylight periods in the year where transformer maintenance will not require load curtailment).

In the long term:

- The Okere–Te Matai line section will overload from the winter of 2020 onwards for the loss of any of the Kaitimako–Tarukenga circuits. Any load shifting from Mount Maunganui to a new GXP at Papamoa will accelerate this date;
- a substantial load shift from Mount Maunganui to a new GXP at Papamoa will result in low transmission voltage during the loss of the Kaitimako–Papamoa circuit; and
- by the winter of 2026, loss of one of the Kaitimako–Tarukenga 1 and 2 circuits will overload for the loss of the remaining circuit.

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# 1 Introduction

Due to load growth in the Bay of Plenty area of Tauranga, Mt Maunganui and Te Matai the 110 kV transmission system from Kaitimako back to the 220 kV/110 kV Tarukenga interconnection is coming under pressure of exceeding equipment ratings, in the short term of two to three years and over the long term out to 2030 of this study.

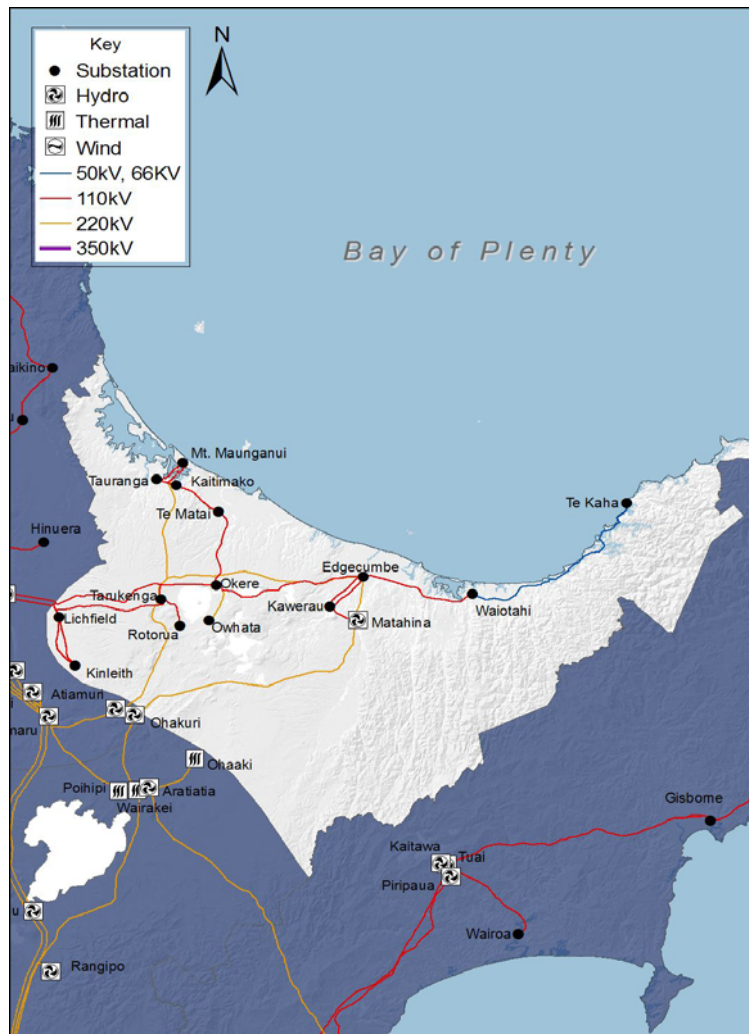
The following sections provide an overview to the location of the above substations, the relevant transmission lines and some issues with the load growth and demand forecasts at these substations.

## 1.1 Geographic Overview

The Bay of Plenty region is shown geographically in Figure 1-1 with the port of Tauranga, the tourist destination of Mount Maunganui and the vineyards of Te Matai occupying the western area of the region near the east coast of the central North Island.

There are three 110 kV circuits supplying the western region, a double circuit, shown in yellow, directly between Tarukenga and Kaitimako and a single line which passes via Okere and Te Matai. The yellow colour signifies that the line was constructed to a 220 kV specification but currently operated at 110 kV.

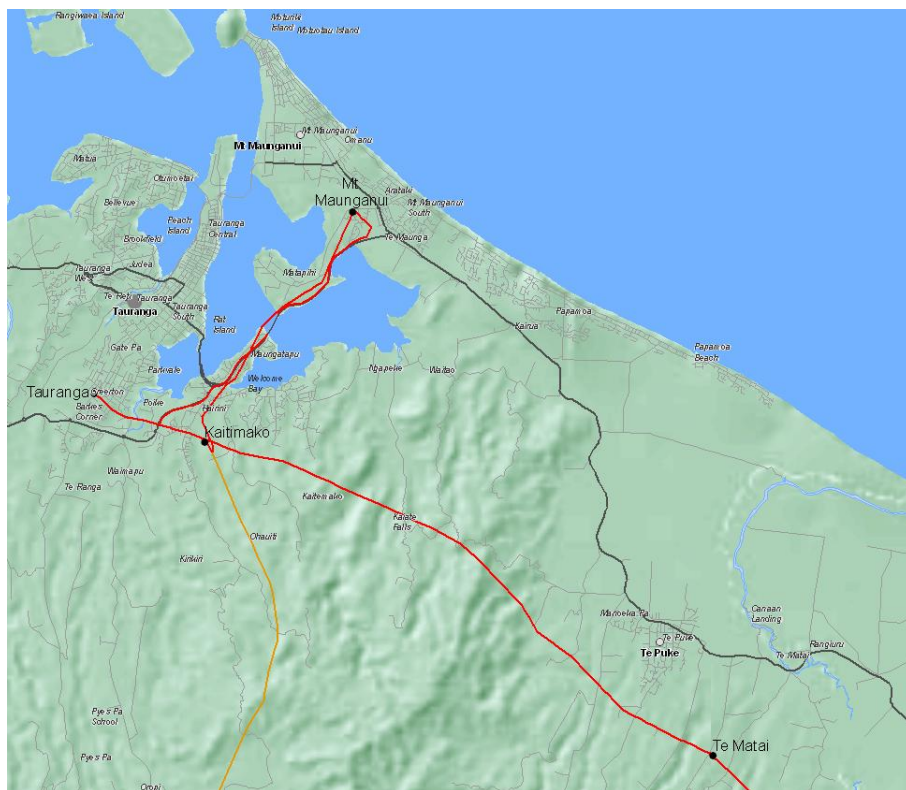
**Figure 1-1: Bay of Plenty Transmission Regional Network Geographically**



In the close up view of Figure 1-2 more details are revealed:

- The strategic importance of the Kaitimako substation to the western Bay of Plenty loads.
- The access difficulties of the Tauranga circuit and Mount Maunganui circuits as they cross heavily occupied residential land. Additionally the Mount Maunganui circuits have a harbour crossing.
- The location of the Papamoa area south-east of Mount Maunganui along the beach front. The proposed Papamoa substation location has been described as 6 km north of Te Puke.
- The Poike tee connection where the B line splits to supply Tauranga and Mount Maunganui.

**Figure 1-2: Locating the proposed Papamoa substation**



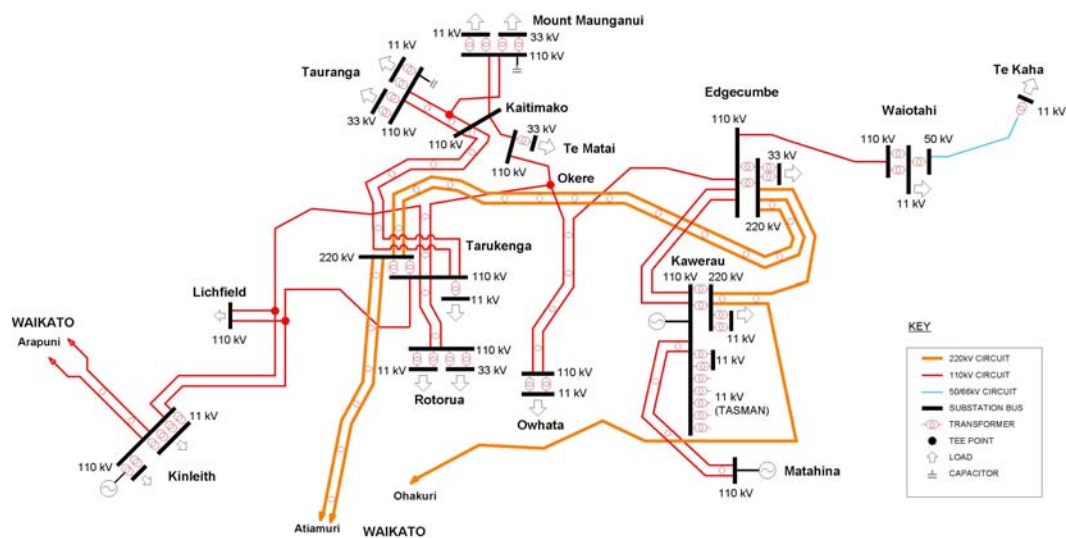
## 1.2 Transmission network diagrammatically

The network diagram of Figure 1-3 reveals that Tarukenga 220/110 kV interconnection supplies the western Bay of Plenty as well as:

- Rotorua substation
- Lichfield and Kinleith mill substations
- an inter-area connection to Arapuni power station.

The actual loading of the Tarukenga interconnecting transformers is determined by the demand at the above supply points as well as the generation in the area.

Figure 1-3: Bay of Plenty regional transmission network (schematically)



## 1.3 Load Growth Issues

The historical high load growth for Tauranga and Mount Maunganui and the difficulties in expanding these urban substations resulted in:

- the newly created Kaitimako switching substation being upgraded to a one 75 MVA supply substation (Ref 1) to relieve the Tauranga supply, and
- a proposed two 75 MVA supply substation at Papamoa (Ref 2), 6 km north of Te Puke, to relieve the Mount Maunganui supply. The new substation is expected to be looped into the Kaitimako–Te Matai circuit. Papamoa is the subject of a High Level Response (HLR) with Powerco (Ref 1), anticipating the new GXP:
  - to be commissioned and initially taking 15 MVA from Mount Maunganui by 2011
  - transferring 50 MVA by 2025
  - reaching its maximum transfer of 80 MW by 2050.

However, while this project is still at the planning stage, there is some serious doubt a new line into Papamoa could be built within this timeframe.

## 2 Assumptions

### 2.1 Load

This study is based on the 2009 APR ADMD demand forecast that:

- includes a load shift from Tauranga to Kaitimako
- excludes the possible new 110/33kV GXP at Papamoa, with corresponding load shift from Mount Maunganui.

The demand forecast predicts the combined Tauranga, Kaitimako, Mount Maunganui and Te Matai load grows approximately 3.75 MW/year.

The load shifting (from Tauranga to Kaitimako) is not going to have a significant effect on the loading of the Tarukenga interconnection but will slightly alter the loading on the 110 kV circuits out of Tarukenga.

Winter regional peak and summer national peak forecasts and diversities are used in this investigation.

Table 2-1 lists the peak demand forecast used in this study for the grid exit points in the Bay of Plenty.

**Table 2-1: Demand forecast of the grid exit points in the Bay of Plenty**

Grid Exit Point	Peak Demand (MW)										
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Edgecumbe	61.6	63.5	65.6	67.2	68.5	69.8	71.2	72.5	73.9	75.4	77.0
Kaitimako <sup>2</sup>	15.0	15.5	16.1	16.1	16.0	15.7	15.6	15.7	15.7	15.8	15.9
Kawerau Horizon	16.4	16.8	17.4	17.9	18.2	18.5	18.9	19.2	19.6	20.0	20.5
Kawerau T6-T9	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Kawerau T11/ T14	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Mt Maunganui 11 kV	20.1	20.7	21.4	21.9	22.4	22.8	23.2	23.7	24.1	24.6	25.1
Mt Maunganui 33 kV	43.0	44.3	45.7	46.9	47.8	48.7	49.6	50.5	51.5	52.6	53.7
Owhata	15.6	16.1	16.6	17.0	17.3	17.7	18.0	18.3	18.7	19.1	19.5
Rotorua 11 kV	32.8	33.8	34.9	35.8	36.5	37.2	37.9	38.6	39.4	40.2	41.0
Rotorua 33 kV	40.9	42.1	43.5	44.6	45.5	46.3	47.2	48.1	49.0	50.0	51.1
Tauranga 11 kV	26.1	26.9	27.7	28.4	29.0	29.5	30.1	30.7	31.2	31.9	32.6
Tauranga 33 kV <sup>2</sup>	39.6	40.8	42.0	43.5	44.8	46.2	47.5	48.6	49.8	51.0	52.4
Tarukenga 11 kV	8.9	9.2	9.4	9.7	9.9	10.1	10.3	10.4	10.6	10.9	11.1
Te Kaha	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8
Te Matai	26.2	27.0	27.9	28.6	29.2	29.7	30.3	30.9	31.5	32.1	32.8
Waiotahi	8.6	8.8	9.1	9.4	9.5	9.7	9.9	10.1	10.3	10.5	10.7

1. The Commission's demand forecasts at the industrial grid exit points in this region have been adjusted to reflect 0% growth year on year.

2. Some of the 33 kV load at Tauranga will be shifted to a new grid exit point at Kaitimako in 2009.

See Appendix A for the complete 40 year forecast (including power factors and diversity factors).

Please note, that while the system studies were completed using this forecast, the short list plans were developed under a revised forecast which was changed as a result of feedback

received from the long-list consultation in May 2009. Details of these changes can be found in Appendix C.

## 2.2 Generation

TrustPower's Kaimai hydro scheme is embedded in the Tauranga 33 kV network and therefore its generation is not specifically included in the model. The demand forecast is based on the historical net demand as seen at the Tauranga 33 kV bus (ie net of the Kaimai generation).

The generation pattern of Kaimai is unlikely to change over the planning horizon.

The Kawerau 110 kV bus was upgraded to include the new injection from the Mighty River 100 MW station. The maximum value of the installed generation is used for the planning studies as the energy source is geothermal.

The other 110 kV connected Bay of Plenty generators are modelled with historical minimum generation as found from the last four years of Avalon metering data. As these are all hydro stations with some small storage ability, the minima are used anticipating low generation during dry years. The historical minima and maxima are:

- Aniwhenua minimum/maximum 5 MW / 20 MW
- Matahina minimum/maximum 20 MW / 78 MW
- Wheo minimum/maximum 7 MW / 25 MW

Similar to the demand forecast, the generation assumptions used to develop the short-list development plans were altered as a result of the consultation feedback, refer Appendix C.

## 2.3 Voltage Support

Voltage support in the sub region is provided by the:

- existing 25 Mvar capacitors on the Mt Maunganui 110 kV bus
- new 25 Mvar capacitors on the Tauranga 110 kV bus.

In the planning studies, 110 kV capacitors are placed in the model to:

- provide solution convergence
- defer line overloading due excessive reactive power flows
- re-establish transmission voltage limits as the load increases.

## 2.4 Interconnecting transformer tap changers

The transformers with on-load tap changers<sup>1</sup> are set to keep the 110 kV bus voltage at 1.05 pu.

## 2.5 Power Analysis and Base Case

The analysis for this report is performed using DigSILENT PowerFactory version 13.2.

The base case used is the latest North Island case available as of 13 May 2008, with the following changes.

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<sup>1</sup> Tarukenga T1 tap changer is modelled as an "off load" tap changer.

- The Edgcumbe 220/110 kV interconnection has been opened on the LV side to prevent the Edgcumbe to Kawerau circuits overloading under N-1 during high Kawerau based generation, (Ref 3).
- The 110 kV distribution network has been upgraded with all the proposed new supply transformers, as listed in the 2008 APR, to remove excessive reactive power flows in the future. These are:
  - The Tauranga 30 MVA T2 transformer is replaced with a 120 MVA transformer (possible customer-specific investment).
  - Kaitimako is fitted with a 110/33 kV 75 MVA supply transformer (committed customer-specific investment).
  - The Mt Maunganui 33 kV 20 and 40 MVA transformers are replaced with two 75 MVA transformers (possible customer-specific investment).
  - The Mt Maunganui 11 kV supply transformers are decommissioned and the load shifted to the 33 kV bus (possible customer-specific investment).
  - A new Papamoa GXP is created 6km north of Te Puke with two 110/33 kV 75 MVA transformers, fed from a loop in and out connection from the Kaitimako–Te Matai circuit (Ref 2).
  - Te Matai gains a second 110/33 kV 40 MVA transformer (commissioned).
  - Owhata gains a second 110/33 kV 20 MVA transformer (possible customer-specific investment).

## 2.6 Operating Practices

The System Operator manages the system so that an interconnecting transformer is not overloaded with all parallel interconnecting transformers in service for the worst case circuit outage. An outage of an interconnecting transformer is not considered an N-1 contingent event in the real-time operating environment.

The ratings of the Tarukenga interconnecting transformers are based on those in the Asset Capability Information (ACI) database. Transformers have a continuous rating which applies when all circuits and transformers are in service, and a short-term 24 hour summer/winter rating which applies when a circuit or transformer is out of service.

Should the power flow through a transformer exceeds its rated capacity, which can not be reduced by any other means available to the System Operator, then they will request a load reduction from the affected lines company.

## 2.7 Electricity Governance Rules (EGRs)

The need to maintain the power system reliability provided by the core grid assets is recognised in the Grid Reliability Standards (GRS). The GRS states that with all assets that are reasonably expected to be in service, the power system should remain in a satisfactory state during and following any single credible contingency event (i.e. N-1 security).

The credible contingencies are defined in the GRS, and include a single interconnecting transformer interruption. This ensures there is sufficient interconnecting transformer capacity so the load can be supplied following a transformer failure. While this is different to the operational practices of the System Operator, the need for investment in the grid is determined by Part F of the EGRs and hence is used here as the criteria for determining the need to invest.

### 3 Methodology

Modify the base case with all the system configurations listed in 2.7.

Build in the ability to shift load from the Mt Maunganui 33 kV bus to the Papamoa 33 kV bus, and shift as much as required each year to prevent the Kaitimako–Poike-2 section from overloading.

## 4 Establishing the system needs

The following section lists the transmission issues between Tarukenga and Kaitimako that result in asset overloading from the present out to 2030.

### 4.1 Pre 2008 Summer Island Peak: Loss of a Kaitimako–Tarukenga circuit and the subsequent loss of the Okere sections (Appendix B1)

The Kaitimako–Tarukenga circuit conductor will overload for the N-2 situation where one of the Kaitimako–Tarukenga circuits and the Okere sections (Kaitimako–Okere–Te Matai) are out of service. This is the situation during planned outages in summer, when a circuit is out of service for maintenance and there is a subsequent loss of another circuit feeding a common bus, in this case the Kaitimako 110 kV bus.

### 4.2 2009 Peak Region Forecast: Overloading Tarukenga T1 CT 192 while Tarukenga T2 is out of service (Appendix B2)

The 110 kV CT 192 on the Tarukenga T1 interconnecting transformer will exceed its 238.2 MVA winter branch rating, if the Tarukenga 2 interconnecting transformer comes out of service during winter.

### 4.3 2011 Peak Region Forecast: Overload of Tarukenga 2 for the loss of Tarukenga T1 (Appendix B3)

The Tarukenga T2 110 kV winding exceeds its 24 hour winter rating of 262 MVA, if Tarukenga T1 comes out of service during winter.

### 4.4 2012 Peak Region Forecast: Overload of Tarukenga T1 for the loss of Tarukenga T2 (Appendix B4)

The Tarukenga T1 110 kV winding exceeds its 24 hour winter rating of 264 MVA, if Tarukenga T2 comes out of service during winter.

### 4.5 2016 Summer Peak Forecast: Overload of Tarukenga 2 for the loss of Tarukenga T1

The Tarukenga T2 110 kV winding exceeds its 24 hour summer rating of 246 MVA, if Tarukenga T1 comes out of service during summer.

### 4.6 2017 Summer Peak Forecast: Overload of Tarukenga 1 for the loss of Tarukenga T2

The Tarukenga T1 110 kV winding exceeds its 24 hour summer rating of 248 MVA, if Tarukenga T2 comes out of service during winter.

### 4.7 2018 Summer Island Peak Forecast: Loss of a Kaitimako–Tarukenga circuit and the subsequent loss of the Kaitimako–Te Matai circuit (Appendix B5)

The Kaitimako–Tarukenga circuit conductor will overload for the N-2 situation where one of the Kaitimako–Tarukenga circuits and the Kaitimako–Te Matai circuit are out of service. This is the situation during planned outages in summer, when a circuit is out of service for maintenance and there is a subsequent loss of another circuit feeding a common bus, in this case the Kaitimako 110 kV bus.

### 4.8 2020 Peak Region Forecast (Appendix B6)

The Okere–Te Matai section reaches 100% loading for the loss of a Kaitimako–Tarukenga 1 or 2 circuit.

The Kaitimako–Poike-2 section reaches 100% loading for the loss of the Kaitimako–Tauranga circuit. This can be deferred by shifting more Mount Maunganui load to Papamoa.

A minimum of 10 MW must be shifted from Mount Maunganui to Papamoa.

#### **4.9 2022 Peak Region Forecast: Tarukenga T2 continuous rating exceed (Appendix B7)**

The Tarukenga T2 110 kV winding exceeds its continuous rating of 200MVA.

The Okere–Tarukenga section reaches 100% loading for the loss of a Kaitimako–Tarukenga 1 or 2 circuit.

A minimum of 15 MW must be shifted from Mount Maunganui to Papamoa.

#### **4.10 2026 Peak Region Forecast: Overload of the Kaitimako–Tarukenga 1 and 2 circuits. (Appendix B8)**

The Kaitimako–Tarukenga 1 or 2 circuits will reach 100% of their rating for a Kaitimako–Tarukenga 2 or 1 loss.

A minimum of 35 MW must be shifted from Mount Maunganui to Papamoa

#### **4.11 2029 Peak Region Forecast**

To complete the 20 year study; a minimum of 48 MW must be shifted from Mount Maunganui to Papamoa to avoid the Kaitimako–Poike-2 section from overloading for the loss of the Kaitimako–Tauranga circuit.

## 5 Analysis of the Tarukenga 220/110 kV interconnection

As discovered in this investigation, the firm capacity of the Tarukenga 220/110 kV interconnection was found to be the most imminent transmission asset that will turn into a system constraint in the western part of the Bay of Plenty.

The loading on the Tarukenga interconnecting transformers depends on:

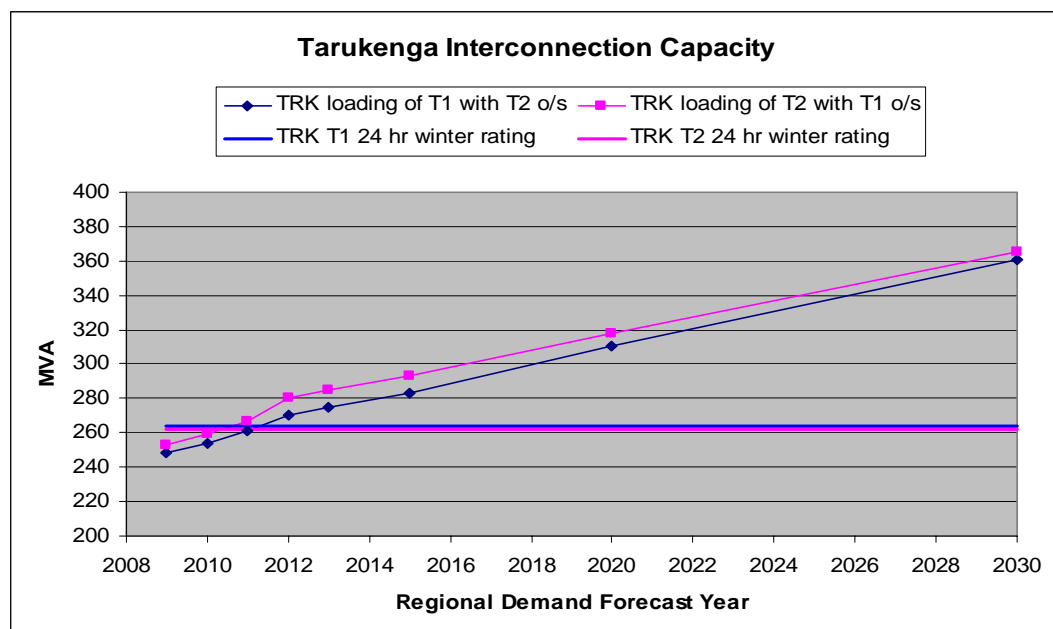
- the western Bay of Plenty loads of Tauranga, Mt Maunganui and Te Matai
- Rotorua, Kinleith and Lichfield loads
- the Bay of Plenty hydro and geothermal generation
- the inter-area power flow through the 110 kV network from Tarukenga to Arapuni which is dependent on the total North Island generation mix.

The Tarukenga interconnecting transformer (continuous, 24 hr summer, 24 hr winter) ratings<sup>2</sup> are:

- Tarukenga T2 (200/246/262 MVA)
- Tarukenga T1 (200/248/264 MVA).

The forecast N-1 loadings of the Tarukenga interconnecting transformers with time are shown in Figure 5-1. The chart shows the loading of Tarukenga T2 with T1 out of service as being just over the Tarukenga T2 24 hr rating whereas the Tarukenga T1 loading is just under the limit in 2011, but well exceeded in 2012.

Figure 5-1: Tarukenga T1 and T2 N-1 loading with time



<sup>2</sup> Transformers have three ratings associated with them. The continuous is only used when a load is supplied with all circuits in service. The 24 hour rating is a seasonally adjusted rating that can be allowed when an asset is out of service for planned (maintenance) or unplanned (faulted) reasons.

## 6 Conclusion

The investigation has identified short, mid and long term issues that cover the core grid area between the 220 kV Tarukenga bus to the 110 kV Kaitimako bus and the non core grid 110 kV lines between Tarukenga, Okere, Te Matai and Kaitimako.

In the short term:

- the rating of the current transformer associated with Tarukenga 220/110 kV interconnecting transformer T1 (CT 192) needs to be increased so that it matches the transformer 110 kV winding rating by the winter of 2009
- failure of the Tarukenga 220/110 kV interconnecting transformer (T1) will overload the parallel interconnecting transformer (T2) during winter peaks from 2011
- failure of the Tarukenga 220/110 kV interconnecting transformer T2 will overload the parallel interconnecting transformer (T1) during winter peaks from 2012.

In the mid term:

- any planned or unplanned outage of Tarukenga 220/110 kV interconnecting transformer T1 during the summer daily peaks will require load curtailment to prevent the parallel interconnecting transformer (T2) overloading from 2016 (ie. There are no daylight periods in the year where transformer maintenance will not require load curtailment)
- any planned or unplanned outage of Tarukenga 220/110 kV interconnecting transformer T2 during the summer daily peaks will require load curtailment to prevent the parallel interconnecting transformer (T1) overloading from 2017 (ie. There are no daylight periods in the year where transformer maintenance will not require load curtailment).

In the long term:

- The Okere–Te Matai line section will overload from the winter of 2020 onwards for the loss of any of the Kaitimako–Tarukenga circuits. Any load shifting from Mount Maunganui to a new GXP at Papamoa will accelerate this date
- a substantial load shift from Mount Maunganui to a new GXP at Papamoa will result in low transmission voltage during the loss of the Kaitimako–Papamoa circuit
- by the winter of 2026, loss of one of the Kaitimako Tarukenga 1 and 2 circuits will overload for the loss of the remaining circuit.

## 7 References

- 1/ Kaitimako New Point of Supply, FMIS CP\_Kaitimako\_02\_00\_00, PAD APR 12 Dec 2007 with a commission date of 20 March 2009.
- 2/ HLR Powerco-New GXP at Papamoa, File 15/Papamoa, 15 January 2009
- 3/ Customer Advice Notice (CAN) Edgecumbe 11/Sep/2008.

## Appendix A Demand Forecast

CODE	BAY OF PLENTY	Peak	Peak	Trough	Light	Summer	Peak	Peak	Trough	Light	Summer													
		Region Power Factor	Island Power Factor	Island Power Factor	Island Power Factor	Island Power Factor	Region Diversity	Island Diversity	Island Diversity	Island Diversity	Island Diversity	Peak Island Diversity	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EDG_33	Edgecumbe	0.959	0.963	1.000	0.902	0.945	94.31%	93.98%	100.00%	47.89%	85.29%	59.7	61.6	63.5	65.6	67.2	68.5	69.8	71.2	72.5	73.9	75.4	77.0	78.7
KMO_33	Kaitemako	0.958	0.956	1.000	0.982	0.923	83.41%	84.33%	100.00%	40.86%	61.63%	0.0	15.0	15.5	16.1	16.1	16.0	15.7	15.6	15.7	15.7	15.8	15.9	16.0
KAW_11 T1/T2 Horizon	Kawerau Horizon	0.973	0.952	1.000	0.604	0.978	85.90%	75.45%	100.00%	2.05%	86.91%	16.0	16.4	16.8	17.4	17.9	18.2	18.5	18.9	19.2	19.6	20.0	20.5	20.9
KAW_11/T6	Kawerau T6	0.982	0.978	1.000	0.887	0.990	84.07%	61.40%	100.00%	0.19%	81.66%	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
KAW_11/T7	Kawerau T7	0.982	0.978	1.000	0.887	0.990	84.07%	61.40%	100.00%	0.19%	81.66%	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
KAW_11/T8	Kawerau T8	0.982	0.978	1.000	0.887	0.990	84.07%	61.40%	100.00%	0.19%	81.66%	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
KAW_11/T9	Kawerau T9	0.982	0.978	1.000	0.887	0.990	84.07%	61.40%	100.00%	0.19%	81.66%	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
KAW_11/T11	Kawerau T11	-0.999	-0.999	1.000	0.996	-0.999	93.27%	80.05%	100.00%	19.07%	91.57%	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
KAW_11/T14	Kawerau T14	-0.999	-0.999	1.000	0.996	-0.999	93.27%	80.05%	100.00%	19.07%	91.57%	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
MTM_11	Mt Maunganui 11kV	0.974	0.974	1.000	0.942	0.968	92.29%	91.46%	100.00%	26.97%	75.37%	19.5	20.1	20.7	21.4	21.9	22.4	22.8	23.2	23.7	24.1	24.6	25.1	25.7
MTM_33	Mt Maunganui 33kV	0.974	0.973	1.000	0.995	0.977	88.92%	92.07%	100.00%	25.91%	72.76%	41.6	43.0	44.3	45.7	46.9	47.8	48.7	49.6	50.5	51.5	52.6	53.7	54.9
OWH	Owhata	0.991	0.991	1.000	0.996	0.990	92.41%	93.98%	100.00%	25.89%	85.33%	15.1	15.6	16.1	16.6	17.0	17.3	17.7	18.0	18.3	18.7	19.1	19.5	19.9
ROT_11	Rotorua 11kV	0.937	0.940	1.000	0.881	0.923	92.49%	98.09%	100.00%	26.98%	79.78%	31.8	32.8	33.8	34.9	35.8	36.5	37.2	37.9	38.6	39.4	40.2	41.0	41.9
ROT_33	Rotorua 33kV	0.911	0.911	1.000	0.926	0.907	86.19%	88.90%	100.00%	40.88%	80.11%	39.6	40.9	42.1	43.5	44.6	45.5	46.3	47.2	48.1	49.0	50.0	51.1	52.2
TGA_11	Tauranga 11kV	0.983	0.983	1.000	0.982	0.979	96.49%	97.24%	100.00%	27.07%	82.36%	25.2	26.1	26.9	27.7	28.4	29.0	29.5	30.1	30.7	31.2	31.9	32.6	33.3
TGA_33	Tauranga 33kV	0.958	0.956	1.000	0.982	0.923	83.41%	84.33%	100.00%	40.86%	61.63%	52.9	39.6	40.8	42.0	43.5	44.8	46.2	47.5	48.6	49.8	51.0	52.4	53.8
TRK	Tarukenga 11kV	0.997	0.997	1.000	0.999	0.997	74.48%	74.17%	100.00%	27.96%	71.32%	6.6	8.9	9.2	9.4	9.7	9.9	10.1	10.3	10.4	10.6	10.9	11.1	11.3
TKH	Te Kaha	0.970	0.972	1.000	0.857	0.959	79.30%	78.96%	100.00%	44.23%	75.75%	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.9
TMI	Te Matai	0.951	0.953	1.000	0.964	0.947	94.63%	94.38%	100.00%	28.05%	82.27%	25.4	26.2	27.0	27.9	28.6	29.2	29.7	30.3	30.9	31.5	32.1	32.8	33.5
WAI	Waioatahi	0.979	0.979	1.000	0.935	0.976	98.05%	97.12%	100.00%	35.98%	93.78%	8.3	8.6	8.8	9.1	9.4	9.5	9.7	9.9	10.1	10.3	10.5	10.7	11.0

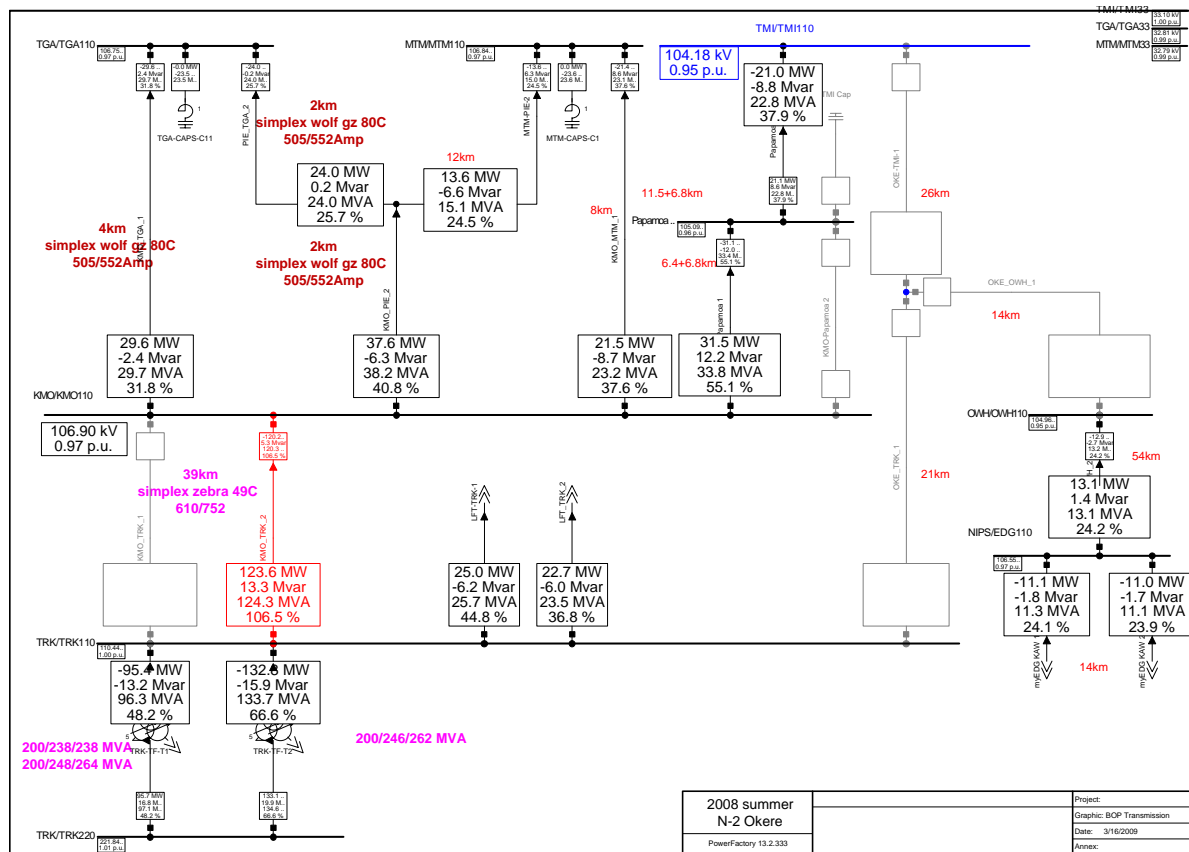
  

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
79.6	80.5	81.5	82.4	83.3	84.2	85.1	86.1	87.0	87.9	88.9	89.9	90.9	91.8	92.8	93.9	95.0	96.1	97.2	98.3	
16.4	16.8	17.2	17.6	18.0	18.4	18.8	19.2	19.6	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.2	23.6	24.1	24.6	
21.3	21.8	22.2	22.6	23.1	23.5	23.9	24.3	24.8	25.2	25.6	26.1	26.5	27.0	27.4	27.9	28.4	28.9	29.4	29.9	
22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	
22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	
22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	
45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	
45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	
26.2	26.7	27.2	27.7	28.2	28.7	29.2	29.7	30.2	30.7	31.2	31.8	32.3	32.9	33.4	34.0	34.6	35.2	35.8	36.4	
55.6	56.4	57.2	58.0	58.8	59.6	60.4	61.3	62.1	62.9	63.8	64.7	65.5	66.4	67.3	68.2	69.2	70.1	71.1	72.1	
20.1	20.3	20.6	20.8	21.0	21.2	21.5	21.7	21.9	22.1	22.4	22.6	22.8	23.1	23.3	23.6	23.8	24.1	24.3	24.6	
42.4	42.9	43.4	43.9	44.5	45.0	45.5	46.0	46.5	47.0	47.6	48.1	48.7	49.2	49.8	50.3	50.9	51.5	52.1	52.8	
52.7	53.3	53.9	54.5	55.1	55.6	56.2	56.8	57.4	58.0	58.6	59.2	59.8	60.4	61.1	61.8	62.4	63.1	63.8	64.5	
33.7	34.2	34.7	35.2	35.7	36.2	36.6	37.1	37.6	38.1	38.7	39.2	39.7	40.3	40.8	41.4	42.0	42.5	43.1	43.7	
55.1	56.5	57.8	59.2	60.6	61.9	63.3	64.7	66.0	67.5	68.9	70.3	71.8	73.3	74.8	76.3	77.9	79.5	81.1	82.7	
11.5	11.6	11.7	11.8	12.0	12.1	12.2	12.4	12.5	12.6	12.7	12.9	13.0	13.1	13.3	13.4	13.6	13.7	13.9	14.0	
1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	
34.0	34.4	34.9	35.4	35.9	36.4	36.9	37.4	37.9	38.4	38.9	39.5	40.0	40.5	41.1	41.7	42.2	42.8	43.4	44.0	
11.1	11.2	11.3	11.4	11.5	11.6	11.7	11.8	11.9	12.0	12.1	12.2	12.4	12.5	12.6	12.7	12.8	13.0	13.1	13.2	

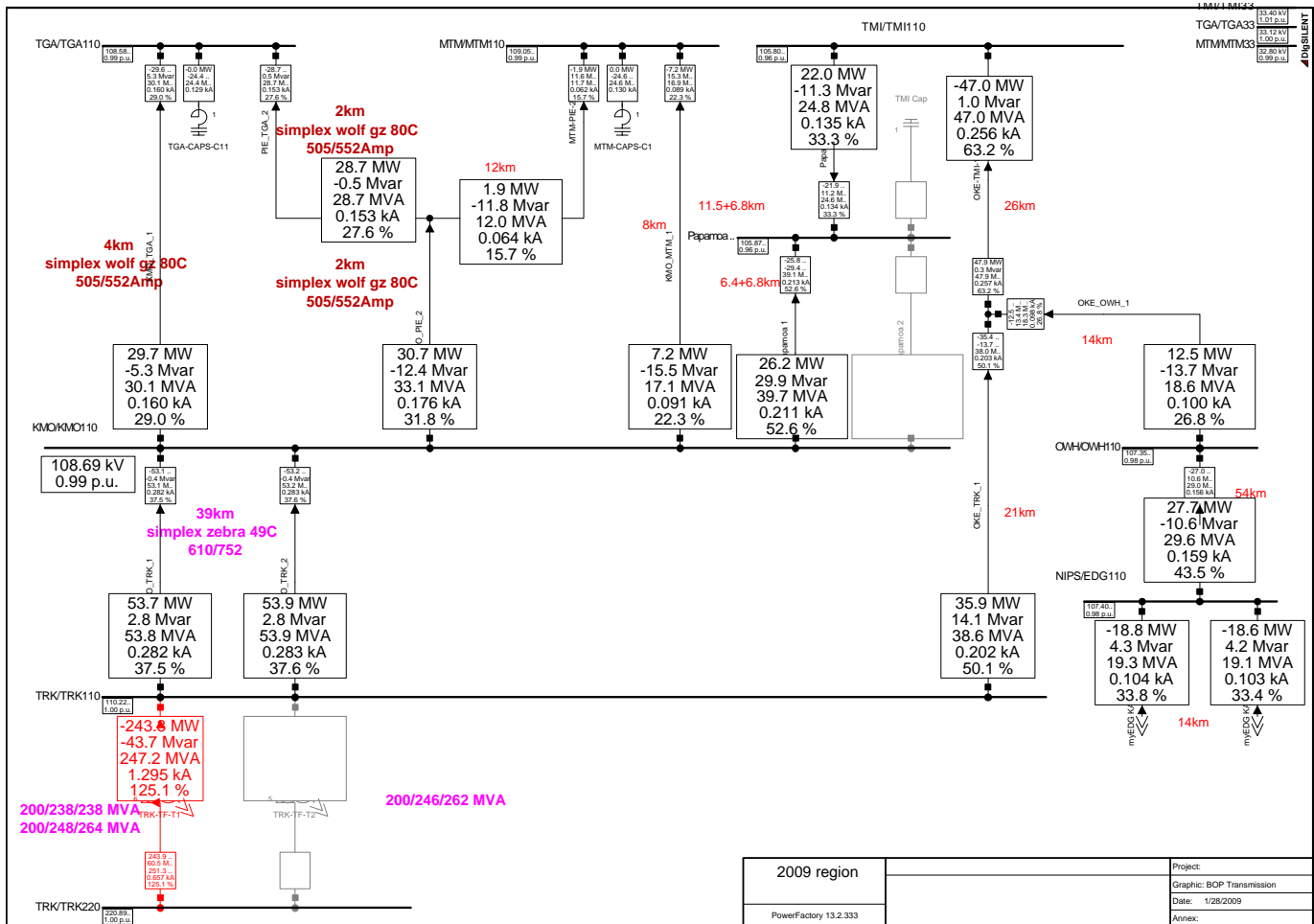
## Appendix B Digsilent Diagrams

### B.1 Pre 2008 Summer Peak Forecast: Loss of a Kaitimako–Tarukenga circuit and subsequent loss of the Okere sections.

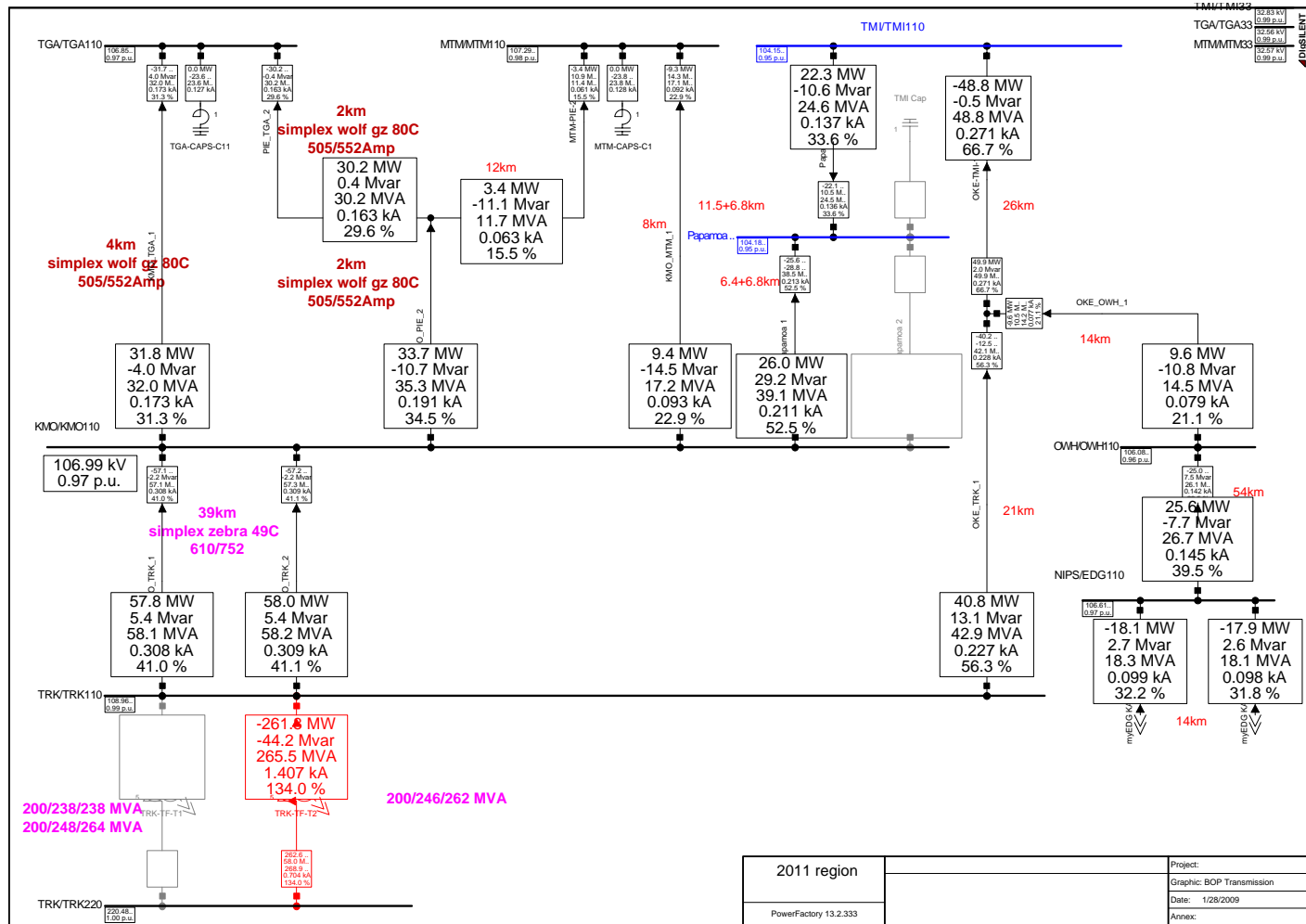
(Note that the model contains a second Kaitimako–Te Matai circuit and a Papamoia capacitor, in anticipation of solution options, but not required for the needs identification).



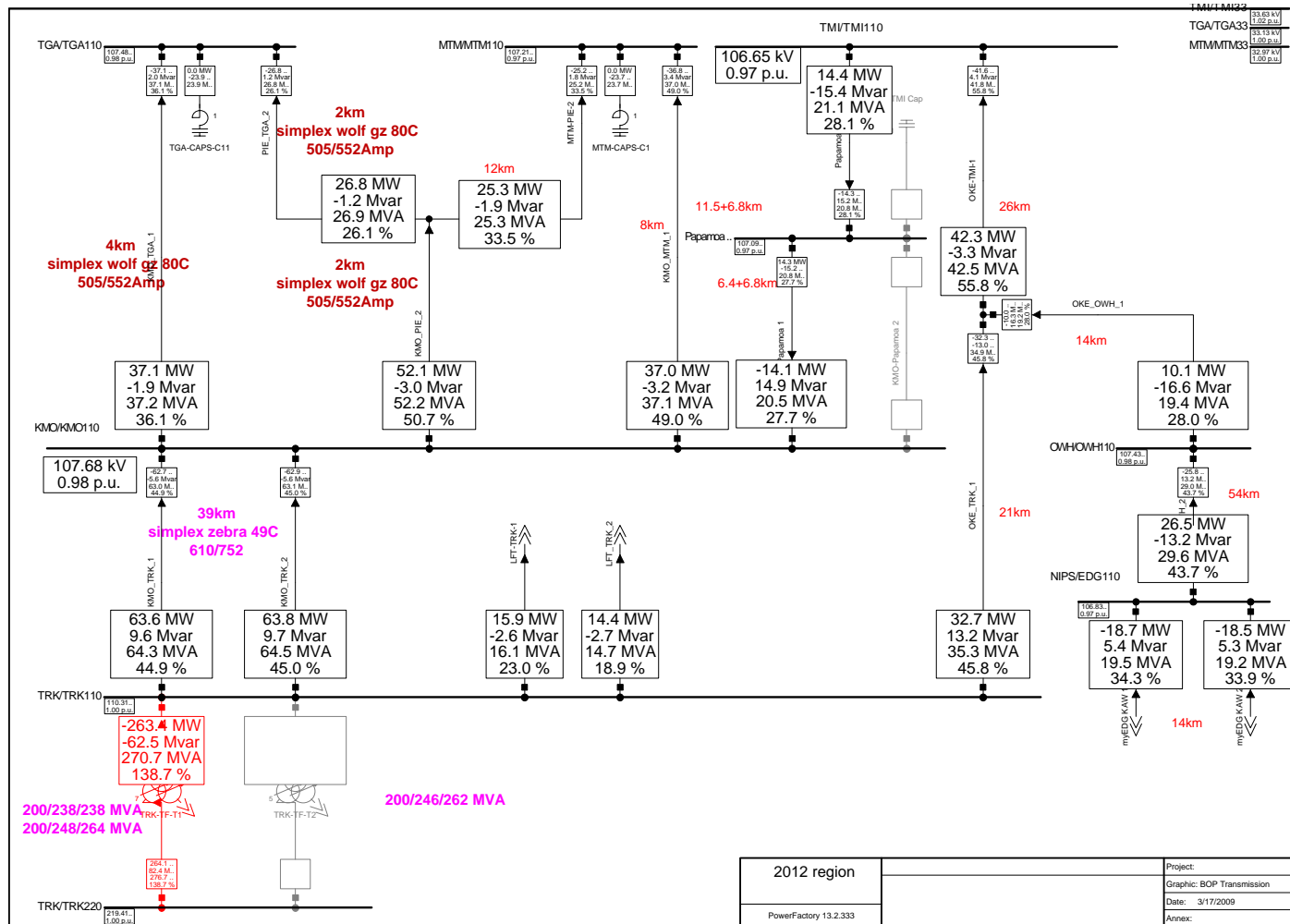
**B.2 2009 Peak Region Forecast: Overloading CT 192 while Tarukenga T2 is out of service.**



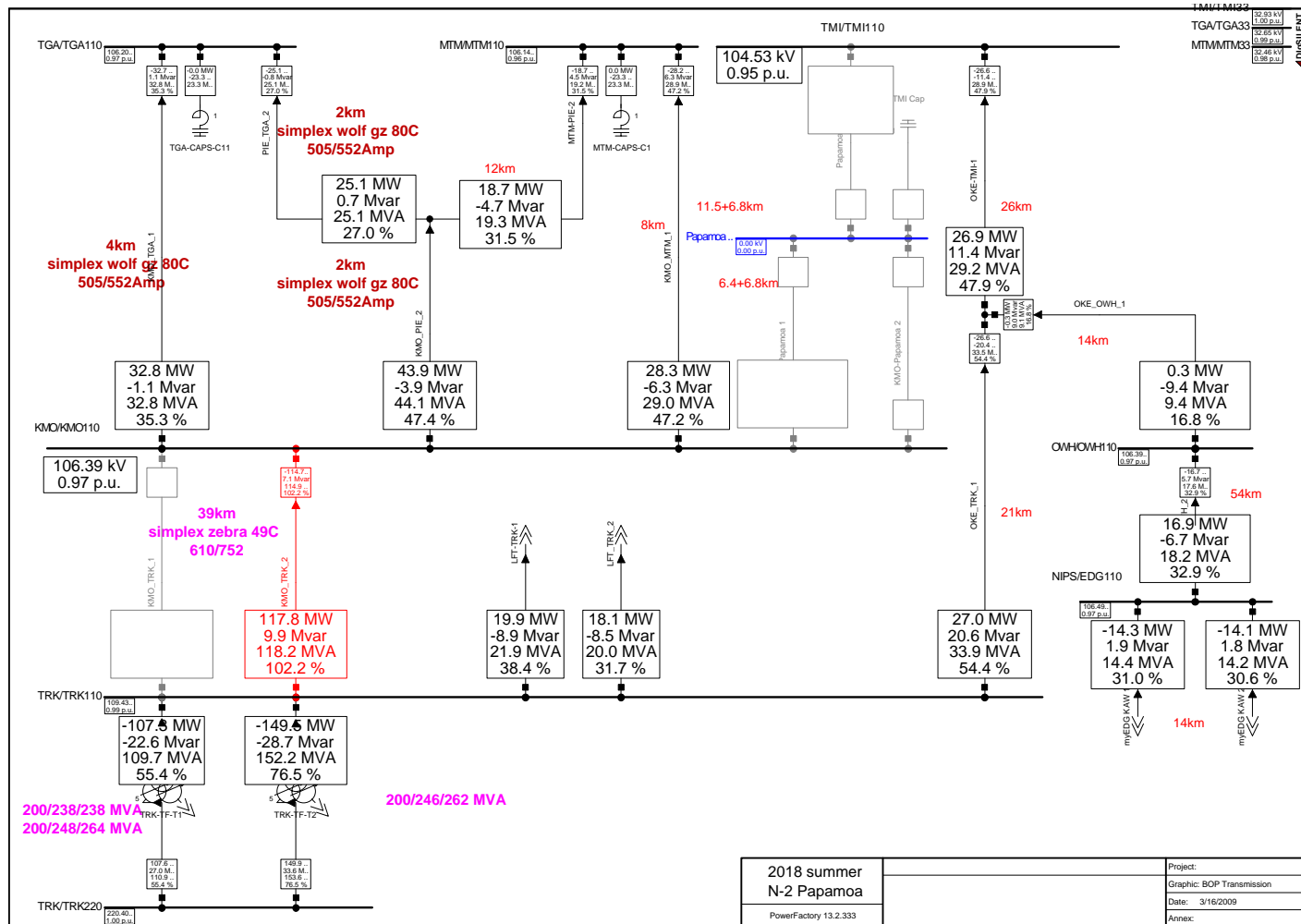
### B.3 2011 Region Forecast: Overload Tarukenga T2 for the loss of Tarukenga T1



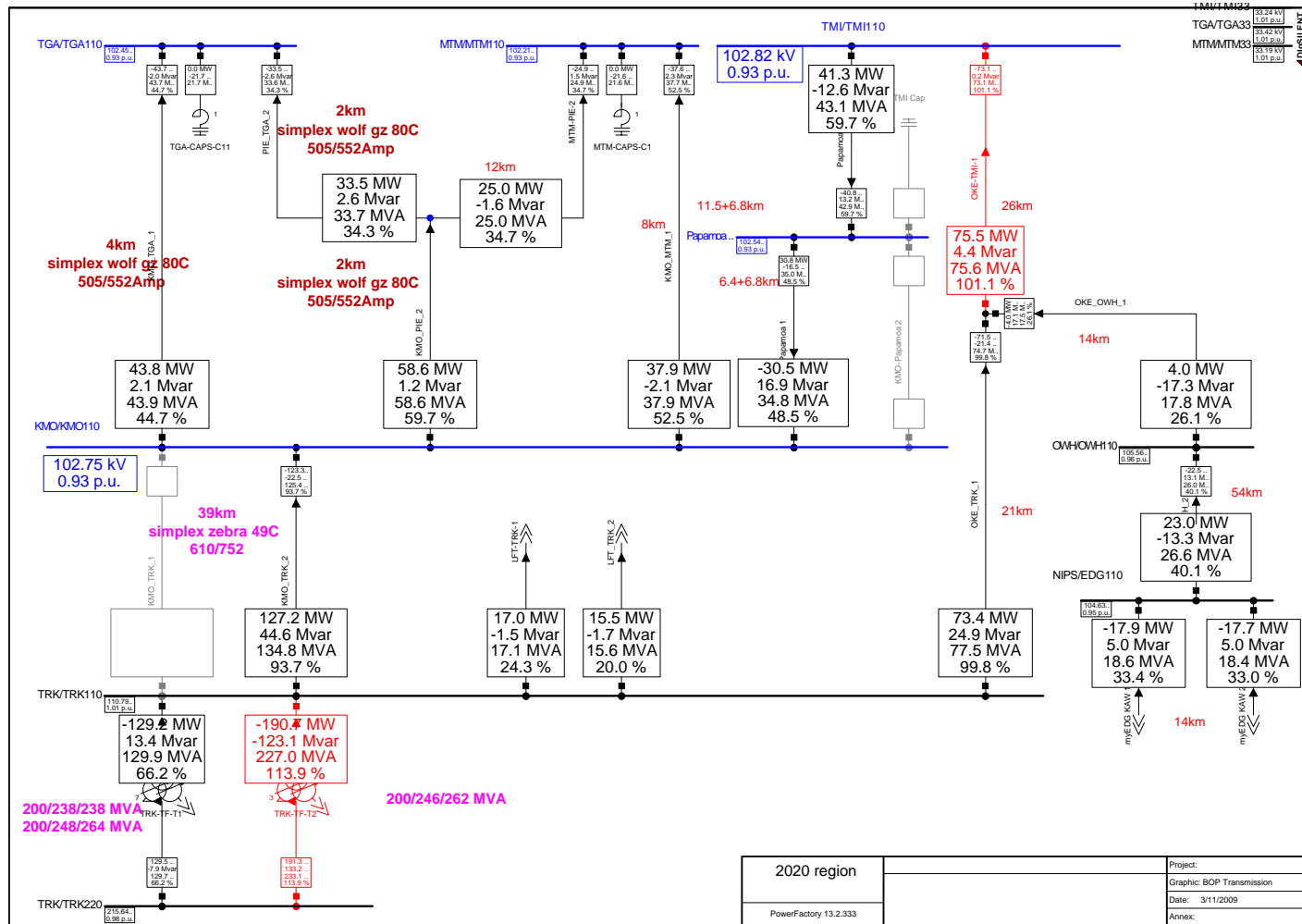
### B.4 2012 Region Forecast: Overload Tarukenga T1



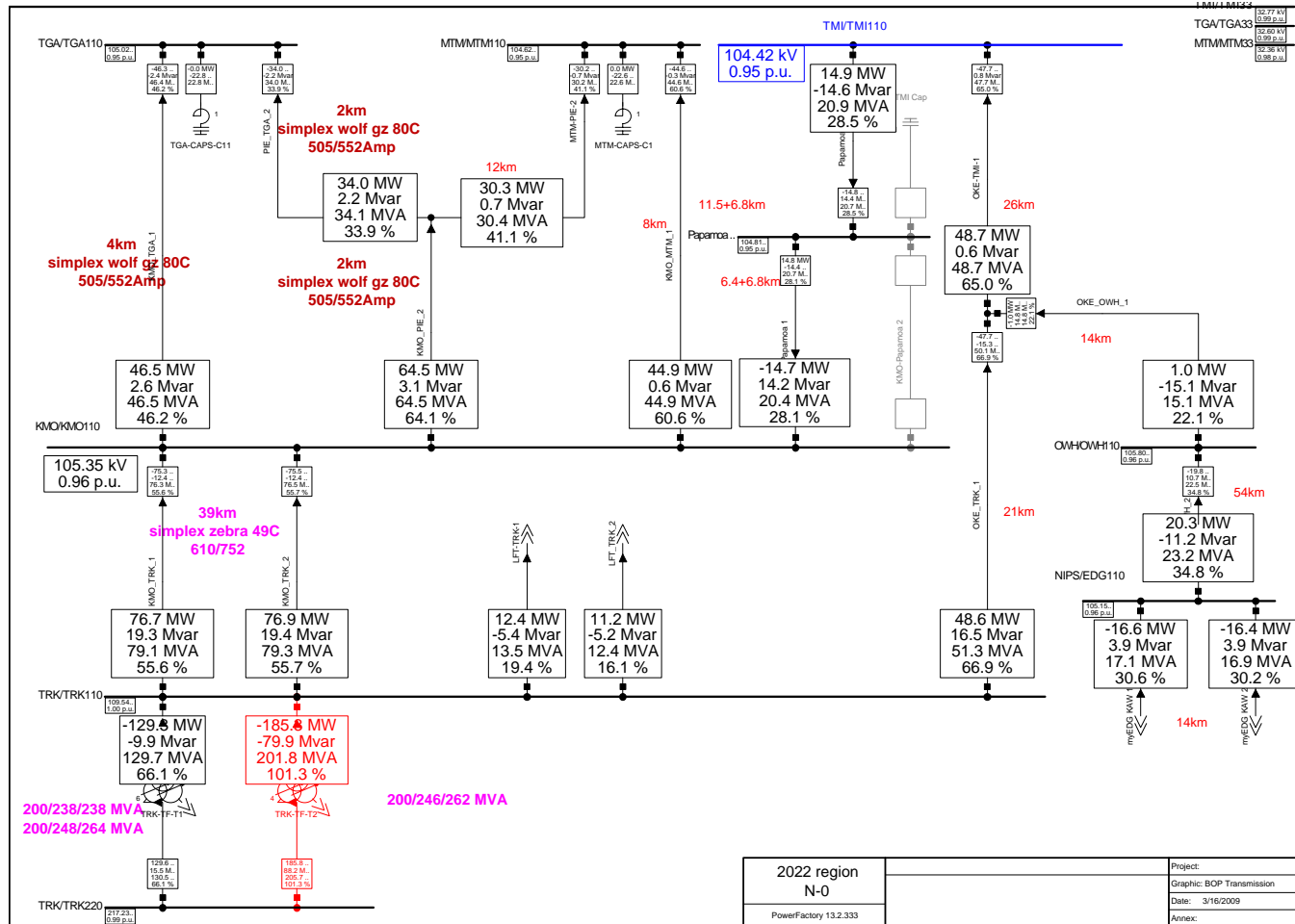
**B.5 2018 Summer Peak Forecast: Loss of a Kaitimako–Tarukenga circuit and subsequent loss of the Kaitimako–Te Matai circuit.**



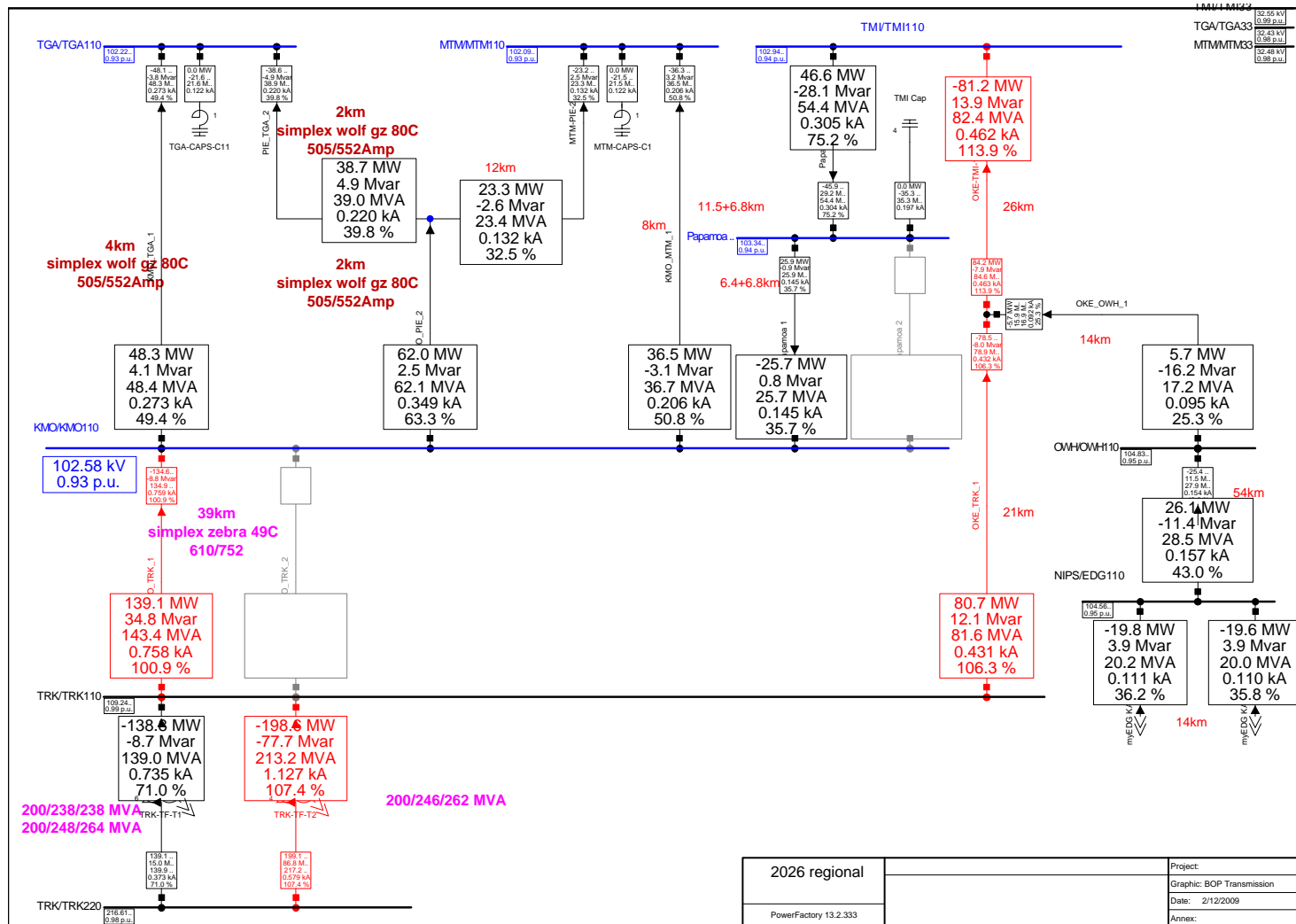
### B.6 2020 region Forecast: Overload OKE Te Matai section



### B.7 2022 Region Peak: Continuous overload of Tarukenga T2



### B.8 2026 Region Forecast: Overload Kaitimako–Tarukenga 1 or 2

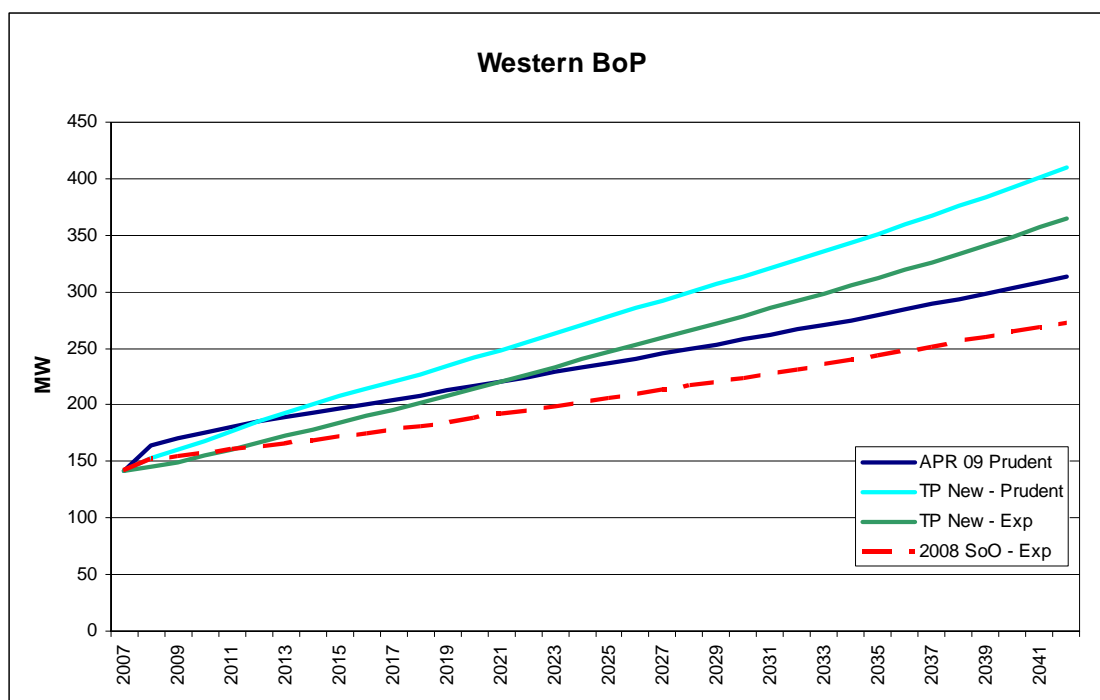


## Appendix C Demand forecast changes

The results contained in this document used the 2009 APR peak demand forecast shown in Section 2.1. This forecast, which is largely based on the 2008 SoO forecast, was amended following customer consultation.

As a result, Transpower developed a new forecast for the region. The figure below shows the comparison between Transpower's forecast and the 2008 SoO forecast for the Western Bay of Plenty region.

Figure 7-1: Revised Western Bay of Plenty demand forecast



The figure shows both the expected forecast and the prudent forecast. The prudent forecast assumes 7 years of high growth and then normal growth rates thereafter.

### C.1 New Demand Forecast

Following consultation with the customer the demand forecast was revised. The following table shows the new forecast.

Table 7-2: Revised Western Bay of Plenty demand forecast

Year	Kaitimako_33	MTM_11	MTM_33	Papamoa	Tauranga_11	Tauranga_33	Te Matai
Power factor	0.958	0.974	0.974	0.974	0.983	0.958	0.951
2010	12.57	18.10	34.57	0.00	24.30	32.07	23.87
2011	13.36	19.05	36.00	0.00	25.31	34.07	24.87
2012	14.18	20.04	37.49	0.00	26.36	36.16	25.89
2013	14.94	20.97	38.89	0.00	27.34	38.10	26.86

Year	Kaitimako_33	MTM_11	MTM_33	Papamoa	Tauranga_11	Tauranga_33	Te Matai
2014	15.61	21.79	40.12	0.00	28.20	39.81	27.70
2015	16.23	22.54	16.07	25.15	28.98	41.41	28.47
2016	16.88	23.30	16.51	25.84	29.78	43.04	29.25
2017	17.51	24.06	16.94	26.52	30.55	44.65	30.02
2018	18.13	24.80	17.37	27.19	31.32	46.24	30.78
2019	18.79	25.58	17.82	27.89	32.14	47.92	31.57
2020	19.48	26.41	18.29	28.63	32.99	49.69	32.41
2021	20.18	27.24	18.77	29.39	33.86	51.46	33.26
2022	20.86	28.06	19.24	30.12	34.70	53.21	34.10
2023	21.57	28.90	19.72	30.87	35.57	55.00	34.95
2024	22.27	29.74	20.21	31.63	36.44	56.80	35.80
2025	23.00	30.62	20.71	32.41	37.35	58.65	36.69
2026	23.70	31.46	21.19	33.17	38.21	60.45	37.54
2027	24.34	32.22	21.63	33.86	39.01	62.08	38.33
2028	25.02	33.04	22.10	34.59	39.86	63.82	39.15
2029	25.71	33.86	22.57	35.33	40.70	65.57	39.99
2030	26.41	34.70	23.05	36.08	41.58	67.36	40.84
2031	27.12	35.54	23.53	36.84	42.45	69.16	41.70
2032	27.82	36.37	24.02	37.59	43.32	70.95	42.56
2033	28.54	37.23	24.51	38.37	44.20	72.77	43.42
2034	29.27	38.10	25.01	39.15	45.11	74.64	44.31
2035	30.01	39.00	25.52	39.95	46.03	76.54	45.22
2036	30.78	39.91	26.05	40.77	46.97	78.48	46.15
2037	31.54	40.81	26.57	41.59	47.92	80.42	47.07
2038	32.32	41.75	27.11	42.43	48.89	82.42	48.03
2039	33.13	42.71	27.66	43.30	49.89	84.47	49.01
2040	33.95	43.70	28.23	44.18	50.91	86.59	50.01

The following table shows the need dates with this new forecast.

**Table 7-3: Revised need dates**

Constraint	Existing Need date	Revised Need date
Tarukenga CT 192 overloads during Tarukenga T2 event	2009	2011
Tarukenga T2 overloads during Tarukenga T1 event	2011	2013
Tarukenga T1 overloads during Tarukenga T2 event	2012	2015
Tarukenga overloads pre-event	2022	2023

The table shows that the new load forecast defers the need for investment by approximately two years. This change is due to the reduction in load and the improved power factors.

This deferral is only applicable in winter. The summer forecast has not changed.

## C.2 Kaimai generation

In Section 2.1 it is stated that the Tauranga 33 kV load is the net load taking Kaimai generation into account. During consultation it was suggested that the Kaimai assumption may be too optimistic. For this reason the Kaimai generation patterns were analysed again. This analysis showed that the Kaimai generation had been overestimated by about 15 MW<sup>3</sup>. This increases the net load off-take from the Tauranga 33 kV bus by 15 MW.

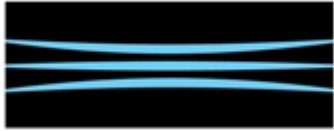
The following table shows the need dates with an additional 15 MW of load at Tauranga. This analysis uses the revised forecast given in Table 2-1

**Table 7-4: Revised need dates with lower Kaimai generation**

Constraint	Existing Need date	Revised Need date
Tarukenga CT 192 overloads during Tarukenga T2 event	2009	2010
Tarukenga T2 overloads during Tarukenga T1 event	2011	2011
Tarukenga T1 overloads during Tarukenga T2 event	2012	2013
Tarukenga overloads pre-event	2022	2021

The table shows that with Kaimai generation at a more realistic level the need date is similar to the analysis in this report.

The need date remains as 2011.



**T R A N S P O W E R**

**Bay of Plenty Interconnection Capacity  
Upgrade Investment Proposal**

**Attachment B  
Options and Costing Report**

November 2009

## Document Revision Control

Document Number/Version	Description	Date
001/ A	Bay of Plenty Interconnection Capacity Upgrade Investment Proposal – Attachment B	November 2009

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# 1 Introduction

The purpose of this report is to:

- explain the long listing process
- identify the short-list options to increase the transfer limits into the Western Bay of Plenty region
- outline development plans for each of these options
- provide summarised costs for all options and detailed costs for the preferred option.

## 1.1 Document structure

This document forms part of the Western Bay of Plenty Upgrade Proposal as illustrated below:

Bay of Plenty Interconnection Upgrade Proposal

- Attachment A – Technical Report
- Attachment B – Options and Costing Report

## 2 Long List - short-list Process

### 2.1 Existing equipment

Table 2-1 shows the parameters of the line assets within the region under consideration.

**Table 2-1: Existing transmission lines**

Line Asset	Length (km)	Current (A)	Conductor	Details
Tarukenga-DEV B	4.8	406	Simplex Wolf ACSR @50°C	Double circuit towers, commissioned 1970
ARI-EDG B	16.1	406	Simplex Wolf ACSR @50°C	Single circuit poles, commissioned 1956
Okere-Te Matai A	26.1	406	Simplex Wolf ACSR @50°C	108 structures, commissioned 1962, single wood poles + 1 tower
HAI-Te Matai A	17.8	406	Simplex Wolf ACSR @50°C	Single circuit poles, commissioned 1958
HAI-Tarukenga A	39	751	Duplex Zebra ACSR @50°C	Double circuit towers, commissioned 1970
HAI-TGA A	1.8	552	Simplex Wolf ACSR @80°C	Double circuit towers, commissioned 1958

### 2.2 Long List Options

Following consultation, the following long list of options has been considered, refer Table 2-2.

**Table 2-2: Long List Options**

	Option	Details
<b>Non transmission alternatives</b>	Load Management	a. Reduce the load on the Bay of Plenty 110 kV network.
	Local Generation	b. Increase capacity through installation of local generation
<b>Transmission Options</b>	System Split	c. Install a system split between Kinleith and Tarukenga
		d. Install a system split between Kinleith and Arapuni
		e. Replace two existing interconnecting transformers with two new 250 MVA transformers
	Increase interconnecting capacity at Tarukenga	f. Replace two existing interconnecting transformers with three new 150 MVA transformers
		g. Add a third interconnecting 150 MVA transformer to supplement capacity
		h. Add a third interconnecting 250 MVA transformer to supplement capacity
		i. Extend 220 kV System to Kaitimako
	Extend 220 kV transmission system	j. Extend 220 kV System to Tauranga and Mount Maunganui

A set of high level screening criteria has been developed to eliminate those options that are not appropriate for Transpower to consider in the short-list. The following criteria were used and these have been compiled with reference to: the definition of

“alternative projects” under the Rules; the Government Policy Statement on Electricity Governance (GPS), and the Grid Upgrade Investigation and Review Policy (GUIRP).

- A. Fit for purpose
  - Will meet the transmission need
- B. Technical feasibility
  - Complexity of solution
  - Reliability, availability and maintainability of the solution
  - Future flexibility - Grid Development Strategy
- C. Practicality of implementation
  - Solution implementable by required date (probability of proceeding)
  - Property and environmental risks
    - a. Implementation risks
- D. Good electricity industry practice (GEIP)
  - Consistent with good international practice
  - Ensure safety and environmental protection
  - Accounts for relative size, duty, age and technological status
- E. System security (additional benefit resulting from an economic investment)
  - Improved system security
  - System operator benefits (controllability)
  - Dynamic benefits (modulation features and improved system stability)
- F. Indicative cost
  - whether an option will clearly be more expensive than another option with similar or greater benefits
- G. Feedback from consultation

Each of the long list options has been assessed against these criteria.

### 2.2.1 Long List Screening

#### Options a and b – non-transmission alternatives

The non-transmission alternatives a and b have both been dismissed as not viable.

**Included in short-list:** ✘

**Reason:** Options a and b have been dismissed on the basis that no feedback was received to the RFI consultation document that indicated either options would have a proponent. Discounted on basis of criteria A, B, G

#### Option c – system split Tarukenga–Kinleith

**Included in short-list:** ✔

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

#### Option d - system split Kinleith–Arapuni

**Included in short-list:** ✘

**Reason:** Splitting the 110 kV network between Tarukenga and Arapuni will only help if this is split on the Kinleith side of the line. Otherwise additional load will be put on the Tarukenga transformers to supply the industrial load at Kinleith<sup>1</sup>. So this sub-option is discarded based on criteria A and G.

#### Option e - replace Tarukenga transformers with two 250 MVA transformers

**Included in short-list:** ✔

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<sup>1</sup> The combined load at Kinleith is ~100 MW at peak some of which will be supplied by a local generator

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

**Option f - replace Tarukenga transformers with three 150 MVA transformers**

**Included in short-list:** ✓

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

**Option g – add a third 150 MVA transformers**

**Included in short-list:** ✓

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

**Option h – add a third 250 MVA transformers**

**Included in short-list:** ✓

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

**Option i – extend 220 kV system to Kaitimako**

**Included in short-list:** ✓

**Reason:** Fits all the criteria including technical practicality and may fall within cost band of other practical alternatives.

**Option h – extend 220kV system to Tauranga and Mount Maunganui**

**Included in short-list:** ✗

**Reason:** Moving 220 kV termination point to Tauranga and Mt Maunganui has not been considered for the short-list as the costs of building new 220 kV lines through urban areas will be orders of magnitude higher than the 220 kV option to Kaitimako. It is therefore ruled out on the basis of criteria F.

## 2.3 Short-list Options

The following options comprise the short-list.

**Table 2-3: Short-list**

Option	Long list reference	Short list reference
Replace Tarukenga T1 and T2 with new 250 MVA 15% impedance transformers	c, e	1
Replace Tarukenga T1 and T2 with three new 150 MVA 10% impedance transformers	c, f	2
Install a 150 MVA 10% impedance transformer at Tarukenga	c, g	3, 6
Install a 250 MVA 15% impedance transformer at Tarukenga	c, h	4
Install two 150 MVA 10% impedance transformers at Kaitimako, upgrade Kaitimako–Tarukenga to 220 kV	c, i	5
Install one 150 MVA 10% impedance transformer at Tarukenga which defers Kaitimako–Tarukenga upgrade to 2018	c, g	6

Each short-list option includes a post-contingency operational split which will be installed between Kinleith and Tarukenga to manage peak loads until the preferred option can be implemented, refer – Special Protection Schemes for more details.

Option 6 is a combination of Option 3 and Option 5. The initial investment is the same, but Option 3 maintains the 110 kV supply to Kaitimako out into the future while Option 6 moves to 220 kV supply as the line constraints start binding in 2018.

## 2.4 Short-list Development Plans

The short-list development plans have been developed under the prudent load forecast given in Appendix C of Attachment A, Technical Report.

### 2.4.1 Reference case (Option 1)

This option involves replacing the existing Tarukenga interconnecting transformers with two 250 MVA 15% impedance transformers. The table shows the developments required to supply the load.

**Table 2-4: Option 1 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Replace Tarukenga T1 and T2 with new 250 MVA 15% impedance transformers	2024 (see below)
2017	Okere–Te Matai circuit overloads for Kaitimako–Tarukenga event	Upgrade Okere–Te Matai circuit	2032-2033
2021	Low voltage at Te Matai during Kaitimako–Tarukenga event	Install a 40 Mvar capacitor bank at Papamoa	2030 (see below)
2023	Okere–Tarukenga overloads during Kaitimako–Tarukenga event	Upgrade Okere–Tarukenga circuit	2033-2038
2024	Tarukenga interconnecting transformers overload for Tarukenga interconnecting transformer event	Install 3 <sup>rd</sup> 250 MVA 15% impedance transformer at Tarukenga	>2040
2024	Kaitimako–Tarukenga circuit overloads during Kaitimako–Tarukenga event	Upgrade Kaitimako–Tarukenga 1 and 2	2035
2027	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2030	Low voltage in the Western Bay of Plenty during Kaitimako–Tarukenga event	Install 30 Mvar capacitor bank at Kaitimako	2034
2033	Papamoa–Te Matai overloads during Kaitimako–Tarukenga event	Upgrade Papamoa–Te Matai circuit	>2040

As the table shows, this option will last until 2033 when further voltage support and an upgrade of Okere–Te Matai are required.

## 2.4.2 Option 2

This option involves replacing the existing Tarukenga interconnecting transformers with three 150 MVA 10% impedance transformers. The table shows the developments required to supply the load.

**Table 2-5: Option 2 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Replace Tarukenga T1 and T2 with three new 150 MVA 10% impedance transformers	2028 (see below)
2018	Okere–Te Matai circuit overloads for Kaitimako–Tarukenga event	Upgrade Okere–Te Matai circuit	2032-2033
2021	Low voltage at Te Matai during Kaitimako–Tarukenga event	Install a 40 Mvar capacitor bank at Papamoa	2029 (see below)
2024	Okere–Tarukenga overloads during Kaitimako–Tarukenga event	Upgrade Okere–Tarukenga circuit	2032-2038
2024	Kaitimako–Tarukenga circuit overloads during Kaitimako–Tarukenga event	Upgrade Kaitimako–Tarukenga 1 and 2	2035
2027	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2028	Tarukenga interconnecting transformers overload for Tarukenga interconnecting transformer event	Install fourth 150 MVA 10% impedance transformer at Tarukenga	>2040
2029	Low voltage in the Western Bay of Plenty during Kaitimako–Tarukenga event	Install 30 Mvar capacitor bank at Kaitimako	2033
2033	Papamoa–Te Matai overloads during Kaitimako–Tarukenga event	Upgrade Papamoa–Te Matai circuit	>2040

As the table shows, this option will last until 2033 when further voltage support and an upgrade of Okere–Te Matai are required.

### 2.4.3 Option 3

This option involves installing a third 150 MVA 10% impedance transformer in parallel with the existing 200 MVA interconnecting transformers at Tarukenga. The table shows the developments required to supply the load.

**Table 2-6: Option 3 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Install a 150 MVA 10% impedance transformer at Tarukenga	2024 (see below)
2018	Okere–Te Matai circuit overloads for Kaitimako–Tarukenga event	Upgrade Okere–Te Matai circuit	2032-2033
2020	Tarukenga T1 and T2 require replacement due to age	Replace Tarukenga T1 and T2 with 150 MVA 10% impedance banks	2028 (see below)
2021	Low voltage at Te Matai during Kaitimako–Tarukenga event	Install a 40 Mvar capacitor bank at Papamoa	2029 (see below)
2024	Okere–Tarukenga overloads during Kaitimako–Tarukenga event	Upgrade Okere–Tarukenga circuit	2032-2038
2024	Kaitimako–Tarukenga circuit overloads during Kaitimako–Tarukenga event	Upgrade Kaitimako–Tarukenga 1 and 2	2035
2027	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2028	Tarukenga interconnecting transformers overload for Tarukenga interconnecting transformer event	Install fourth 150 MVA 10% impedance transformer at Tarukenga	>2040
2029	Low voltage in the Western Bay of Plenty during Kaitimako–Tarukenga event	Install 30 Mvar capacitor bank at Kaitimako	2033
2033	Papamoa–Te Matai overloads during Kaitimako–Tarukenga event	Upgrade Papamoa–Te Matai circuit	>2040

As the table shows, this option will last until 2033 when further voltage support and an upgrade of Okere–Te Matai are required.

#### 2.4.4 Option 4

This option involves installing a third 250 MVA 15% impedance transformer in parallel with the existing 200 MVA interconnecting transformers at Tarukenga. The table shows the developments required to supply the load.

**Table 2-7: Option 4 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Install a 250 MVA 15% impedance transformer at Tarukenga	2026 (see below)
2018	Okere–Te Matai circuit overloads for Kaitimako–Tarukenga event	Upgrade Okere–Te Matai circuit	2032-2033
2020	Tarukenga T1 and T2 require replacement due to age	Replace Tarukenga T1 and T2 with 250 MVA 15% impedance banks	>2040
2021	Low voltage at Te Matai during Kaitimako–Tarukenga event	Install a 40 Mvar capacitor bank at Papamoa	2030 (see below)
2023	Okere–Tarukenga overloads during Kaitimako–Tarukenga event	Upgrade Okere–Tarukenga circuit	2033-2038
2024	Kaitimako–Tarukenga circuit overloads during Kaitimako–Tarukenga event	Upgrade Kaitimako–Tarukenga 1 and 2	2035
2027	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2030	Low voltage in the Western Bay of Plenty during Kaitimako–Tarukenga event	Install 30 Mvar capacitor bank at Kaitimako	2034
2033	Papamoa–Te Matai overloads during Kaitimako–Tarukenga event	Upgrade Papamoa–Te Matai circuit	>2040

As the table shows, this option will last until 2033 when an upgrade of Okere–Te Matai is required.

## 2.4.5 Option 5

This option involves upgrading the Kaitimako–Tarukenga circuits to operate at 220 kV and installing two 150 MVA 10% impedance interconnecting transformers at Kaitimako. The Tarukenga interconnecting transformers are replaced in 2020 for condition assessment reasons. The table shows the developments required to supply the load.

**Table 2-8: Option 5 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Install two 150 MVA 10% impedance transformers at Kaitimako	2025 (see below)
		Upgrade Kaitimako–Tarukenga circuit to 220 kV	2040
2020	Tarukenga T 1 and T2 require replacement due to age	Replace Tarukenga T1 and T2 with two 150 MVA 10% impedance bank	>2040
2022	Low voltage at Papamoa during Kaitimako–Papamoa event	Install a 40 Mvar capacitor bank at Papamoa	>2040
2025	Kaitimako interconnecting transformer overloads during Kaitimako interconnecting transformer event	Install 3 <sup>rd</sup> 150 MVA 10% impedance interconnecting transformer at Kaitimako	>2040
2028	Okere–Te Matai circuit overloads for Kaitimako–Papamoa event	Upgrade Okere–Te Matai circuit	>2040
2029	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2032	Okere–Tarukenga overloads during Kaitimako–Papamoa event	Upgrade Okere–Tarukenga circuit	>2040

As the table shows, this option will last until 2040 when the 220 kV Kaitimako–Tarukenga circuits will overload.

### 2.4.6 Option 6

This option involves installing a 150 MVA 10% impedance transformer in parallel with the existing Tarukenga interconnecting transformers. When a 110 kV circuit overloads the Kaitimako–Tarukenga circuits are upgraded to operate at 220 kV and two 150 MVA 10% impedance interconnecting transformers are installed at Kaitimako. The table shows the developments required to supply the load.

**Table 2-9: Option 6 development plan**

Year	Issue	Upgrade	Year runs out
2011	Tarukenga T2 overloads during Tarukenga T1 event	Install one 150 MVA 10% impedance transformer at Tarukenga	
2018	Okere–Te Matai circuit overloads for Kaitimako–Tarukenga event	Install two 150 MVA 10% impedance transformers at Kaitimako	2025 (see below)
		Upgrade Kaitimako–Tarukenga circuit to 220 kV	2040
2020	Tarukenga T 1 and T2 require replacement due to age	Replace Tarukenga T1 and T2 with one 150 MVA 10% impedance bank	>2040
2022	Low voltage at Papamoa during Kaitimako–Papamoa event	Install a 40 Mvar capacitor bank at Papamoa	>2040
2025	Kaitimako interconnecting transformer overloads during Kaitimako interconnecting transformer event	Install 3 <sup>rd</sup> 150 MVA 10% impedance interconnecting transformer at Kaitimako	>2040
2028	Okere–Te Matai circuit overloads for Kaitimako–Papamoa event	Upgrade Okere–Te Matai circuit	>2040
2029	Kaitimako–Papamoa overloads during Okere loop event	Upgrade Kaitimako–Papamoa circuit	>2040
2032	Okere–Tarukenga overloads during Kaitimako–Papamoa event	Upgrade Okere–Tarukenga circuit	>2040

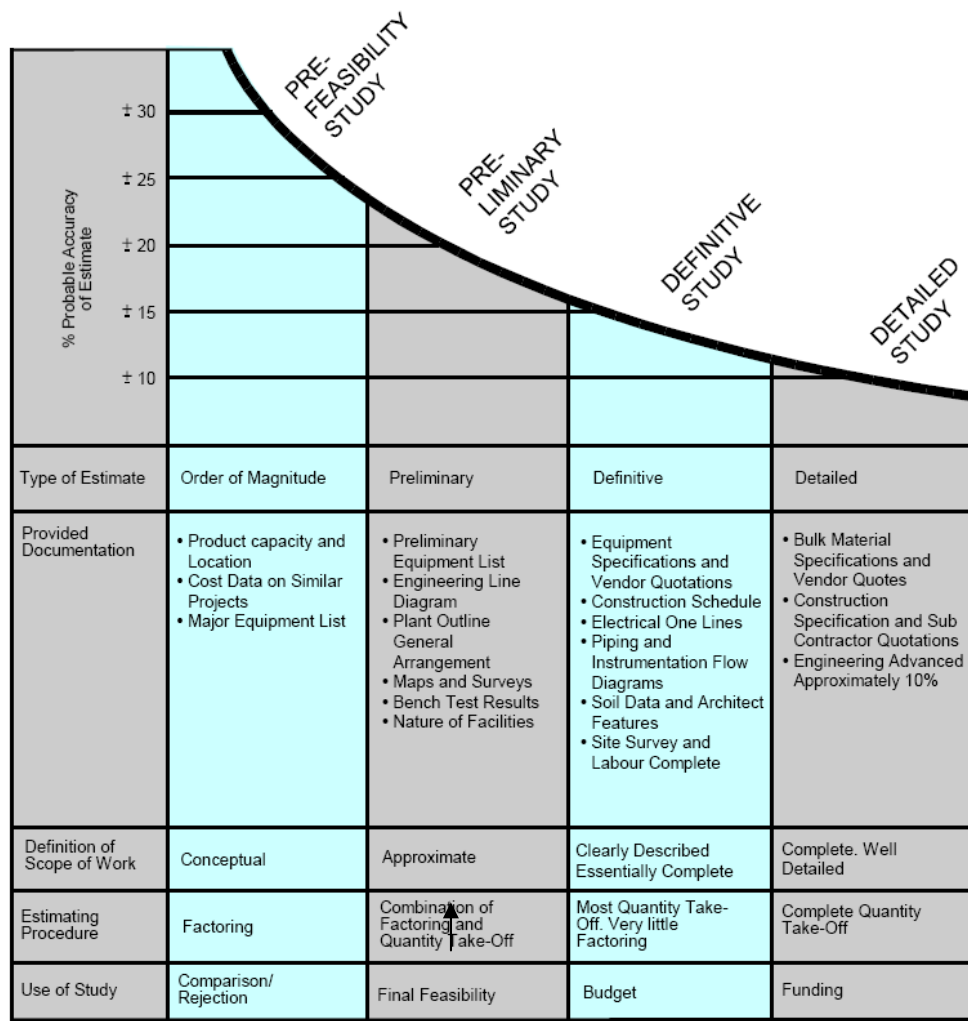
As the table shows this option will last until 2040 when the 220 kV Kaitimako–Tarukenga circuits will overload.

### 3 Option Costs

#### 3.1 Transmission costs

The process of costing a transmission solution is a process of refining the cost estimates over time, recognising there is a trade-off between cost accuracy and timely and efficient investment decisions. This is similar to any cost estimation process where, as more detailed design is undertaken, costs become more refined. This is illustrated in Figure 3-1 below which sets out at each stage what level of detail is undertaken.

Figure 3-1: Transmission costing process



Bottom-up asset estimation costs are generally subject to the orders of accuracy outlined above. This also demonstrates the level of information required to accurately estimate the costs associated with a particular project.

The transmission costs used in this project have been summarised into the following components:

- line capital costs;
- substation capital costs;

- property and easement costs;
- environmental costs;
- project management; and
- operating and maintenance costs.

Transpower comments on each of these factors below.

### **Line capital costs**

Transpower has considered the capital costs of the equipment that would be incurred prior to the commissioning of each option, including line works and any HV cable works required for each option. New transmission line costs are based on indicative costing corridors only. They include dismantling costs as required.

### **Substation capital costs**

Transpower has considered the capital costs of the substation equipment that would be incurred prior to the commissioning of each option, including any HV cable works required for each option.

### **Property and easement costs**

Transpower has taken into account the probable range of property and easement costs as relevant for each short-listed option.

### **Environmental costs**

The costs associated with obtaining RMA approvals and other relevant environmental approvals have been estimated and taken into account for works contemplated in the short-list of options.

### **Project management costs**

Transpower has allowed for project management costs to reflect the cost of managing the design, construction and commissioning of works to be undertaken for each short-list option.

### **Operating and maintenance costs**

Operating, maintenance and dismantling costs over the operating life of each short-listed option are included in the analysis.

### **CommunityCare fund costs**

Funding for community initiated projects is included – refer section 4.3 for more details.

## **3.2 Short-list Option Costs**

The table below shows the items that were included in each of the full development options. It should be noted that the costs for each option were based on present year dollars, but are incurred during the year when they are required. Costs include lines, substations, environment, property and the increase in operations and maintenance.

An additional \$250,000 needs to be added to the following costs to install the post-contingency split between Kinleith and Tarukenga.

Table 3-1: Options

Option	Items	Total Cost (\$M)
Reference Case Replace Tarukenga T1 and T2 with new 250 MVA 15% impedance transformers	2 x 250 MVA transformers @ Tarukenga	Lines: \$12.8
	Upgrade Okere–Te Matai	Substations: \$27.5
	40 Mvar cap at Papamoa	Environment: \$0.54
	Upgrade Okere–Tarukenga	Property: \$3.05
	Upgrade Kaitimako–Tarukenga cct 1&2	O&M: \$1.28
	Upgrade Kaitimako–Papamoa	
	Kaitimako capacitor +30 Mvar	
Option 2 Replace Tarukenga T1 and T2 with three new 150 MVA 10% impedance transformers	3 x 150 MVA transformers @ Tarukenga	Lines: \$12.9
	Upgrade Okere–Te Matai	Substations: \$29.67
	40 Mvar cap at Papamoa	Environment: \$0.54
	Upgrade Okere–Tarukenga	Property: \$3.05
	Upgrade Kaitimako–Tarukenga cct 1&2	O&M: \$1.73
	Upgrade Kaitimako–Papamoa	
	Kaitimako capacitor +30 Mvar	
Option 3 Install a 150 MVA 10% impedance transformer at Tarukenga	Add 150 MVA transformer @ Tarukenga	Lines: \$12.8
	Upgrade Okere–Te Matai	Substations: \$29.82
	40 Mvar cap at Papamoa	Environment: \$0.54
	Upgrade Okere–Tarukenga	Property: \$3.05
	Upgrade Kaitimako–Tarukenga cct 1&2	O&M: \$1.23
	Upgrade Kaitimako–Papamoa	
	KMO capacitor +30Mvar	
Option 4 Install a 250 MVA 15% impedance transformer at Tarukenga	Add 250 MVA transformer @ Tarukenga	Lines: \$12.9
	Upgrade Okere–Te Matai	Substations: \$27.54
	40 Mvar cap at Papamoa	Environment: \$0.54
	Upgrade Okere–Tarukenga	Property: \$3.05
	Upgrade Kaitimako–Tarukenga cct 1&2	O&M: \$0.98
	Upgrade Kaitimako–Papamoa	
	Kaitimako capacitor +30 Mvar	
Option 5 Install two 150 MVA 10% impedance transformers at Kaitimako, upgrade Kaitimako–	2 x 150 MVA transformers @ KMO	Lines: \$11.9
	40 Mvar cap at Papamoa	Substations: \$36.55
	Add 3rd 150 MVA transformer @ KMO	Environment: \$0.64
	Upgrade Okere–Te Matai	Property: \$2.64
	Upgrade Kaitimako–Papamoa	O&M: \$2.18

Option	Items	Total Cost (\$M)
Tarukenga to 220 kV	Upgrade Okere–Tarukenga	
Option 6 Install one 150 MVA 10% impedance transformer at Tarukenga which defers Kaitimako–Tarukenga upgrade to 2018	1 x 150 MVA transformer @ Tarukenga	Lines: \$11.9
	2 x 150 MVA transformers @ KMO	Substations: \$41.08
	1 x 150 MVA transformer @ Tarukenga	Environment: \$0.61
	40 Mvar cap at Papamoa	Property: \$2.64
	Add 3rd 150 MVA transformer @ KMO	O&M: \$2.31
	Upgrade Okere–Te Matai	
	Upgrade Kaitimako–Papamoa	
	Upgrade Okere–Tarukenga	

### 3.3 Loss Costs

The tables below detail the cost of losses arising from each option.

The transmission cost, loss cost and terminal costs are added to identify the preferred option – which is the option with the lowest expected net market cost.

**Table 3-2: Loss costs (\$M)**

Option	Loss	Expected net market cost
<b>Option 1, Reference case</b>	16.07	46.44
<b>Option 2</b>	16.07	48.57
<b>Option 3</b>	16.07	44.02
<b>Option 4</b>	16.04	44.90
<b>Option 5</b>	4.98	36.36
<b>Option 6</b>	8.88	38.50

**Notes:**

Costs are all pre-tax , discounted at 7%, in \$m, and in \$2009

Details of how the losses have been calculated can be found in – Line Loss Calculation.

## 4 Preferred Option Costs

The GIT analysis shows that the preferred option is option 5, moving the Bay of Plenty interconnection from Tarukenga to Kaitimako by installing 150 MVA transformers, refer Bay of Plenty 110kV Capacity Upgrade Transmission Investment Proposal for more details.

The following tables show the itemised costs of the preferred option.

**Table 4-1: Kaitimako substation costs**

<b>Substation Costs</b>	<b>Cost (\$NZ)</b>
Civil Works	259,084
<b>Primary Equipment</b>	
220 kV Circuit Breaker	761,299
220 kV Current Transformer	499,152
220 kV CVT	119,717
220 kV Disconnecter	656,566
220 kV Buswork	251,730
220 kV Transformer	8,229,330
220 kV Overhead line	102,903
220 kV VT	127,467
Protection	825,648
SCADA	20,581
Secondary Equipment	64,257
<b>Communications</b>	
Environmental approvals	42,500
<b>Switching Costs</b>	
Design Costs	962,754
Project Management	593,346
CommunityCare Fund	33,685
<b>Total</b>	<b>13,550,019</b>

**Table 4-2: Hairini–Tarukenga line costs**

<b>Substation Costs</b>	<b>Cost (\$NZ)</b>
Conductor	773,806
Earth Potential Rise	116,446
Insulators	180,500
Other cost (Hurdles etc)	174,669
Structures (incl foundations)	645,755
Switching Costs	34,000
Freight	16,740
Environmental approvals	217,000
Community Care Fund	17,251
Design Costs	123,000
Project Management	234,843
<b>Total</b>	<b>2,534,012</b>

**Table 4-3: Tarukenga substation costs**

<b>Substation Costs</b>	
Post Contingency Split	250,000
Civil Works	73,395
Primary Equipment	
220 kV Circuit Breaker	269,395
220 kV Current Transformer	338,021
220 kV CVT	125,339
220 kV Disconnecter	286,541
220 kV Buswork	231,938
220kV Line work (inside substation)	86,185
110 kV Current Transformer	
110 kV Disconnecter	
110 kV Buswork	
Insulators	
Corrosion protection costs	
Protection	191,007
SCADA	21,546
Secondary Equipment	55,784
Freight	16,792
Communications	
Environmental approvals	42,500
Switching Costs	
Design Costs	162,869
Project Management	208,662

<b>Total</b>	<b>2,359,974</b>
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#### 4.1 Environmental costs scope

The Tarukenga to Kaitimako circuits traverse three district councils and one regional authority. A number of environmental approvals will be required for the voltage increase, the uprating works as well as access track and vegetation clearance works. Both Tarukenga and Kaitimako substations are Transpower designated sites and as such, any work within these substations can be covered through the submission of an Outline Plan of Works to the relevant territorial authority. An 'Authority to Modify' may be required from the NZ Historic Places Trust for works at Kaitimako substation due to the proximity of archaeological sites in the area.

#### 4.2 Property costs scope

Property risk issues are not considered to be high due to the limited extent of activities required to deliver the line work and because stations activities are within existing Transpower property.

The works required with the preferred upgrade option have been assessed in terms of the "injurious affection" test contained in Section 23(3)(b) of the Electricity Act 1992 (the Act) and in terms of the current understanding and interpretation of the Act. The voltage increase is considered to be lawful under the Electricity Act because the line was designed and built for 220kV although it has been operated at 110kV.

The capacity increase of the line increases the rating above the lines original design specification. However as the uprating activities are very minimal, it is reasonably believed that these effects comply with the statutory test and will not require the purchase of easements.

#### 4.3 CommunityCare Fund

Transpower's CommunityCare Fund was developed from the recognition that Transpower needs to offset the impact on communities of major grid investment projects and contribute to communities where we operate, particularly those communities which accommodate Transpower assets which benefit the whole country. The Fund has been developed along similar models used by other power companies in New Zealand and overseas. Through the fund, Transpower supports projects that benefit the community as a whole.

Transpower's community funding approach is aligned with project approval and is based on a funding formula derived from an impact analysis and the number of kilometres of line in an impacted area. The impact scale is determined on a number of factors, including the size of the line required, the impact of the line within the region it traverses and the population of the communities it crosses. The visual impact of the line is dealt with through environmental mitigation.

Once a Grid Upgrade Proposal is approved by the Electricity Commission, community organisations may apply to the CommunityCare Fund for nominated projects that meet specific funding criteria. The CommunityCare Fund is managed in accordance with the guidelines established by the Office of the Auditor General (OAG).

#### 4.4 Potential Additional Costs

The following additional costs have been identified but are not included in the upgrade proposal because the assessed likelihood of these costs being incurred is considered low. If these costs do end up being incurred we will advise the Electricity Commission.

Identified sources of additional costs include:

- Tower 79 is at the upper limit of how much it can be strengthened. If strengthening is not feasible it will be replaced at an additional cost of \$500,000.
- Many towers are located in scenic reserves or water catchment areas. Potential to delay implementation and incur costs through mitigation measures.

## Appendix A – Line Loss Calculation

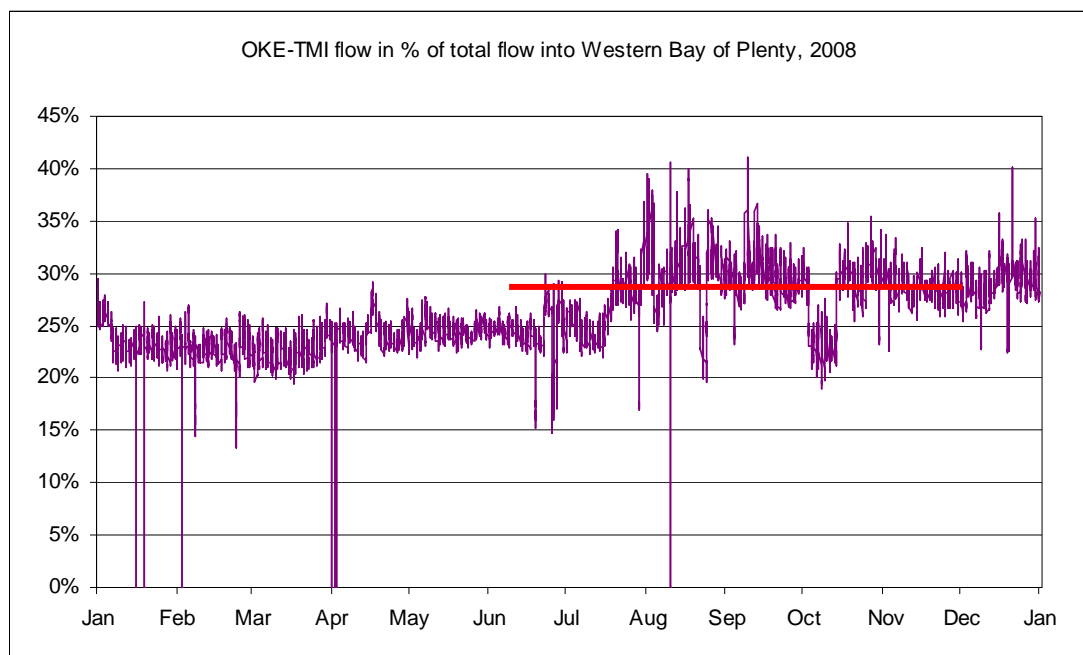
The short-list options can be divided into two major groups, the one keeping 110 kV supply to the Western Bay of Plenty into the future and the one upgrading the connection to 220 kV supply. The major difference between the two groups arises from the line losses.

### Line flows into the Western Bay of Plenty

Options 1 through 4 maintain 110 kV supply to Kaitimako while Option 5 converts the two Tarukenga to Kaitimako circuits to 220 kV operation in 2011 and Option 6 does this by 2018. In these cases, when the voltage is doubled, losses will reduce to just a quarter of what they would have been assuming there are no other parallel lines. In the area of interest, there is a parallel route through the 110 kV line connecting Tarukenga (Tarukenga), Okere (OKE), Te Matai (Te Matai) and Kaitimako (KMO).

Hourly historical flows as observed in 2008 were used to observe split between Tarukenga-KMO transfers and transfers through the Okere loop, i.e. Tarukenga-OKE and Okere–Te Matai. The relationship between these flows is shown below.

Figure 4-1: 2008 flows into region



Following the commissioning of the new power plant at Kawerau was in July there was a step change. Average share of the flow on Okere–Te Matai compared with the total flows was about 28% after this.

DigSilent was used to check this assumption. The flows given in the attachment cases 1 and 3 identify a share for 2011 during peak of 26% while this share for 2031 was forecasted to be 28%. For the purpose of the analysis, the flow of the Okere–Te Matai line was assumed to be 28% in all future.

DigSilent was also used to see what the impact on the share would be if the Kaitimako–Tarukenga circuits were upgraded to 220 kV operation. The attachment cases 2 and 4 show the flows for 2011 and 2031. Again, the share appeared to be relative stable over time at around 14.5%. This is less than the 110 kV case as more current will flow through the higher voltage lines.

The flows through Okere–Tarukenga were treated similarly.

### A physical model for line losses

The line parameters for those circuits transferring power from Tarukenga to the Western Bay of Plenty are shown below:

**Table 4-4: Line parameters**

	Kaitimako– Tarukenga A	Kaitimako– Tarukenga B	Okere– Tarukenga	Okere–Te Matai
Conductor type	Zebra gz simplex (49C)	Zebra gz simplex (49C)	Wolf gz simplex (50C)	Wolf gz simplex (50C)
Resistance ( $\Omega$ per km)	0.06748	0.06748	0.18257	0.18257
Length (km)	39	39	21	26

Based on the information, losses can be calculated using the formula:

$$\text{Loss}_{\text{MW}} = (\text{Flow}_{\text{MW}}/\text{Voltage})^2 \times R$$

where R is the total resistance of the line ( $\Omega$  per km times the length) and Voltage is either 110 kV or 220 kV.

Again, the results of formula given historical peak demand flows were compared with the DigSilent values shown in the Attachment and found to match.

### Calculating losses for each option

The line losses for each option were calculated based on the historical line flows observed each hour in 2008 between Tarukenga and Kaitimako. Power through the Okere loop i.e. Tarukenga-OKE and Okere–Te Matai was assessed as previously discussed.

Hour by hour, losses based on the line flows for the Kaitimako–Tarukenga A&B, Tarukenga-OKE and Okere–Te Matai lines were calculated using the formula given.

This gave the losses for 2008. For future years, the 2008 flows were scaled with the demand forecast growth rates for the Western Bay of Plenty. This could be done as there are no expected generation projects of significant size likely to appear in the region within the next many years.

For a total of 30 years losses have been calculated. The results can be seen in the table below.

**Table 4-5: Forecast losses**

Year	Losses (MWh)		Value of Losses LRMC of gen (NZ\$/MWh)
	110kV	220kV	
2011	9698	3034	91.3
2012	10479	3274	92.5
2013	11264	3516	93.5
2014	12088	3769	94.5
2015	12935	4030	95.3
2016	13828	4304	96.1
2017	14743	4585	96.9
2018	15672	4869	97.4
2019	16682	5179	97.9

Year	Losses (MWh)		Value of Losses LRMC of gen (NZ\$/MWh)
	110kV	220kV	
2020	17782	5516	98.4
2021	18925	5866	98.6
2022	20085	6220	98.9
2023	21309	6595	99.1
2024	22574	6981	99.2
2025	23921	7393	99.2
2026	25261	7802	99.2
2027	26514	8184	99.2
2028	27876	8600	99.2
2029	29291	9032	99.2
2030	30762	9480	99.2
2031	32292	9946	99.2
2032	33836	10416	99.2
2033	35455	10910	99.2
2034	37149	11425	99.2
2035	38919	11964	99.2
2036	40766	12526	99.2
2037	42656	13101	99.2
2038	44650	13707	99.2
2039	46746	14345	99.2
2040	48946	15014	99.2

Losses were valued based on the weighted long-run marginal cost of electricity supply over the five scenarios presented in the Electricity Commission 2008 Statement of Opportunities.

The total costs of the losses are the product of losses and costs. These are given in the table below.

**Table 4-6: Cost of losses**

Year	Cost of Losses		
	110kV	220kV	Difference
2011	\$885,876	\$277,123	\$608,754
2012	\$969,121	\$302,820	\$666,302
2013	\$1,053,290	\$328,775	\$724,515
2014	\$1,142,810	\$356,358	\$786,452
2015	\$1,233,055	\$384,131	\$848,924
2016	\$1,328,960	\$413,624	\$915,337
2017	\$1,428,259	\$444,139	\$984,120
2018	\$1,526,077	\$474,166	\$1,051,912
2019	\$1,632,354	\$506,766	\$1,125,588
2020	\$1,749,088	\$542,553	\$1,206,535
2021	\$1,866,851	\$578,618	\$1,288,233
2022	\$1,986,510	\$615,244	\$1,371,266
2023	\$2,111,213	\$653,386	\$1,457,828
2024	\$2,239,738	\$692,675	\$1,547,063
2025	\$2,373,437	\$733,514	\$1,639,923
2026	\$2,506,305	\$774,081	\$1,732,224
2027	\$2,630,692	\$812,044	\$1,818,649
2028	\$2,765,845	\$853,276	\$1,912,569
2029	\$2,906,240	\$896,092	\$2,010,148
2030	\$3,052,184	\$940,585	\$2,111,599
2031	\$3,203,926	\$986,829	\$2,217,097
2032	\$3,357,124	\$1,033,501	\$2,323,623
2033	\$3,517,785	\$1,082,432	\$2,435,353
2034	\$3,685,857	\$1,133,604	\$2,552,253
2035	\$3,861,453	\$1,187,051	\$2,674,402
2036	\$4,044,748	\$1,242,825	\$2,801,923
2037	\$4,232,196	\$1,299,847	\$2,932,349
2038	\$4,430,035	\$1,360,013	\$3,070,022
2039	\$4,638,080	\$1,423,266	\$3,214,814
2040	\$4,856,367	\$1,489,616	\$3,366,752

Based on a discount rate of 7% the net present value (NPV) of the 30 years of cash flows has been calculated in each case. In 2011 dollars, the planned year of the investment, the 220 kV option will lead to \$15 million in savings if compared with the 110 kV option.

Option 6 includes conversion to 220 kV in 2018, therefore it assumes 110 kV losses up to 2017 and 220 kV losses thereafter.



Table 4-8: Case Two: 2011 – All circuits in service, 220 kV Kaitimako–Tarukenga

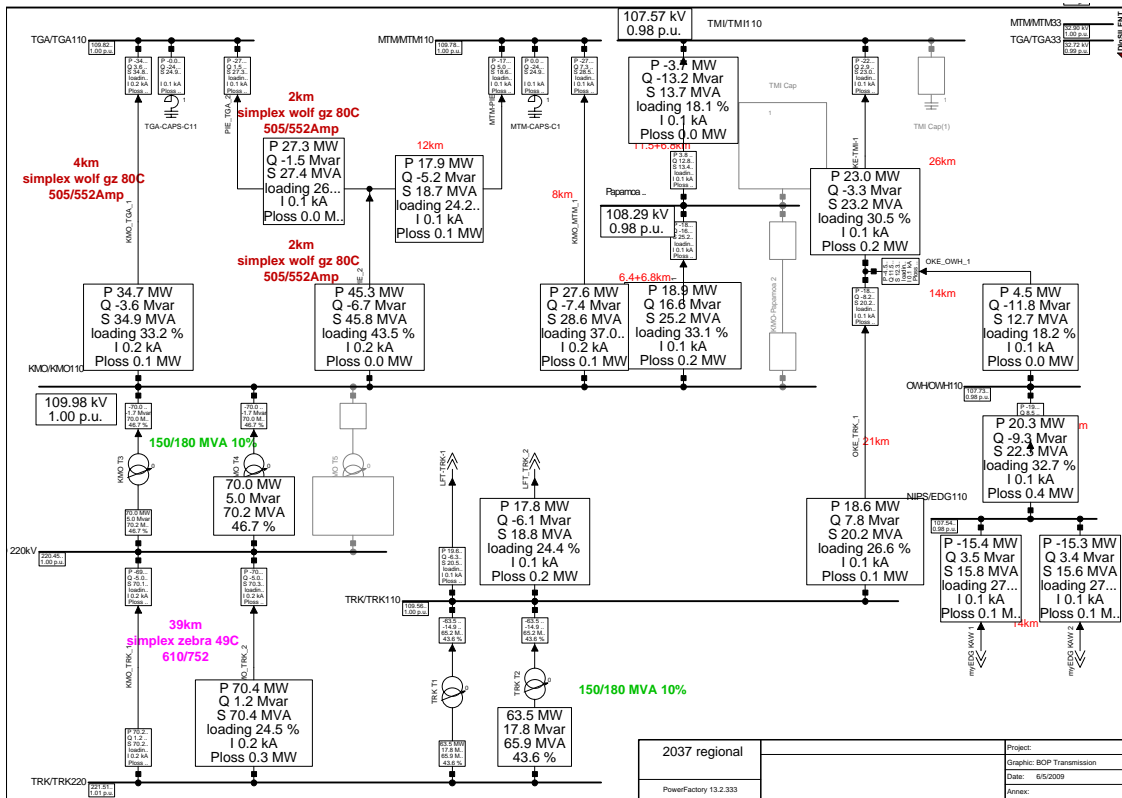


Table 4-9: Case Three: 2031 – All circuits in service, 110 kV Kaitimako–Tarukenga

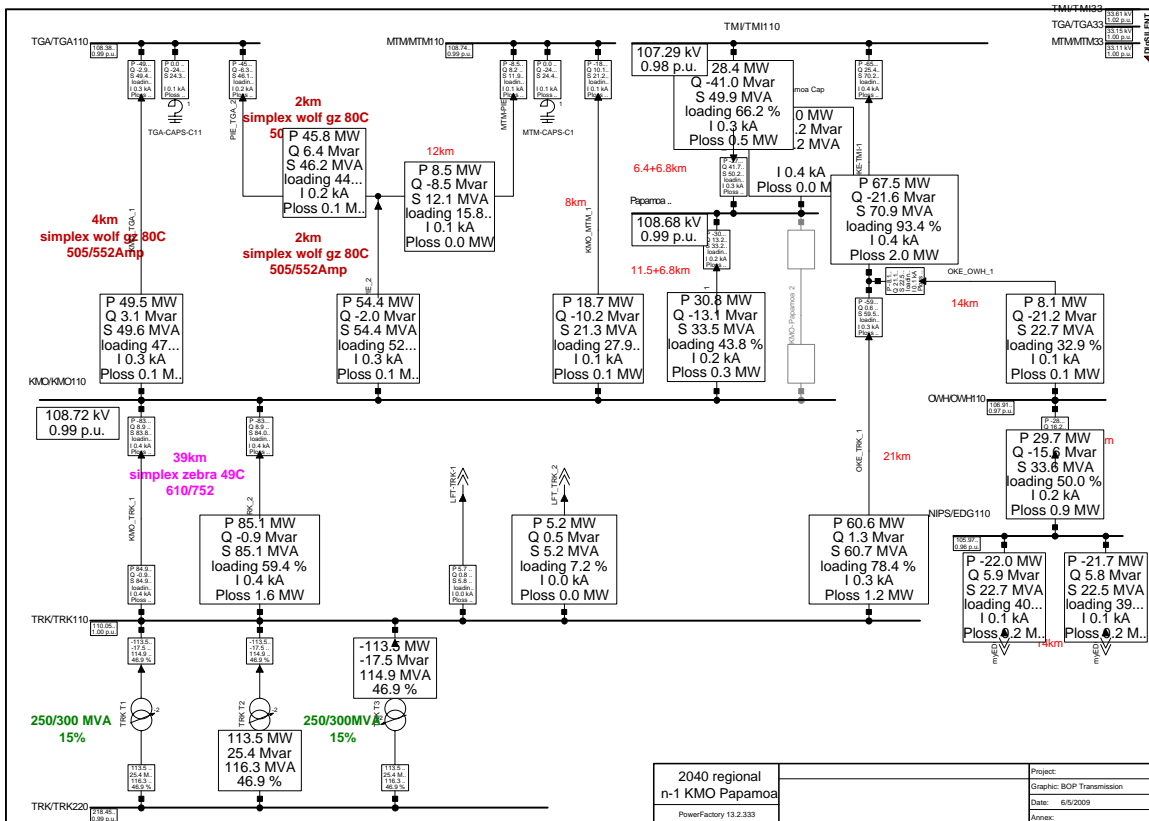
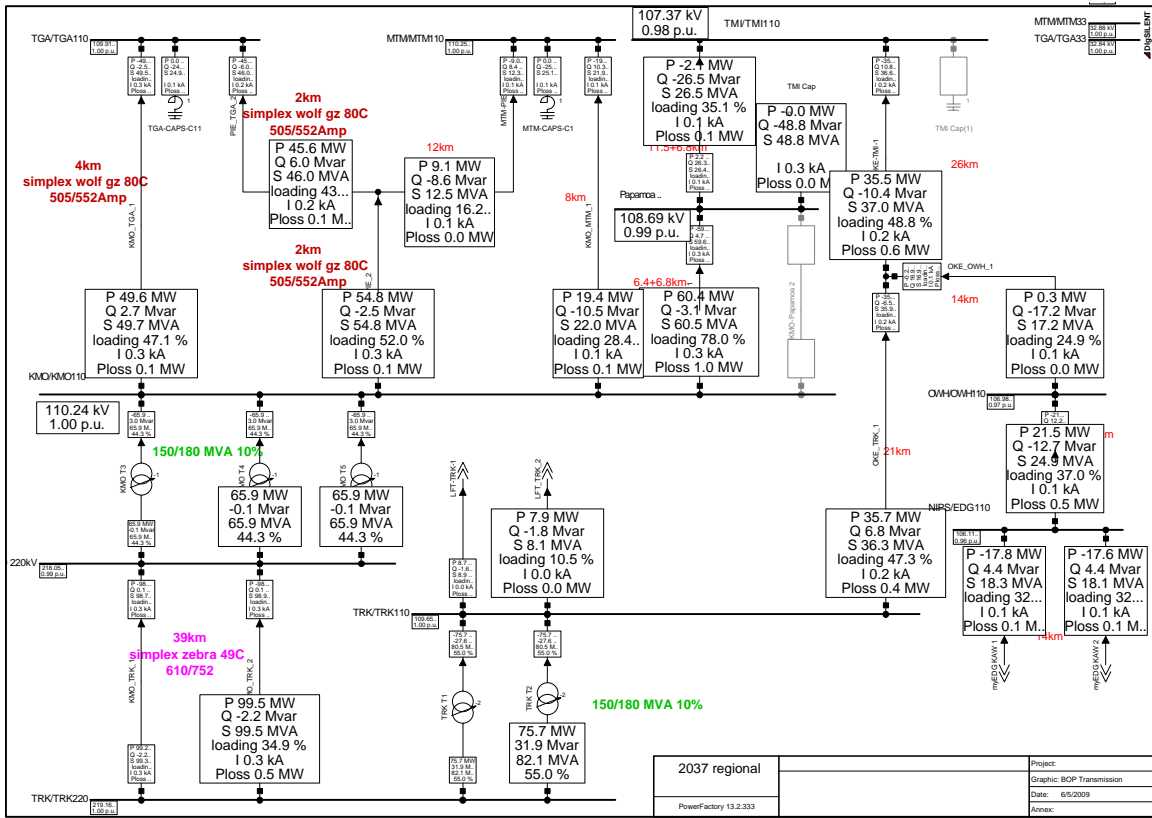


Table 4-10: Case Four: 2031 – All circuits in service, 220 kV Kaitimako–Tarukenga



2037 regional	Project:
PowerFactory 13.2.333	Graphic: BOP Transmission
	Date: 6/5/2009
	Annex:

## Appendix B – Special Protection Schemes

The purpose of this appendix is to illustrate the effectiveness of Special Protection Schemes (SPS) in the Bay of Plenty. These schemes may be used to cover project delays.

There are two system splits that may be used in the Bay of Plenty. They involve automatically opening circuit breakers on healthy circuits following system events.

### B.1 Lichfield-Tarukenga split

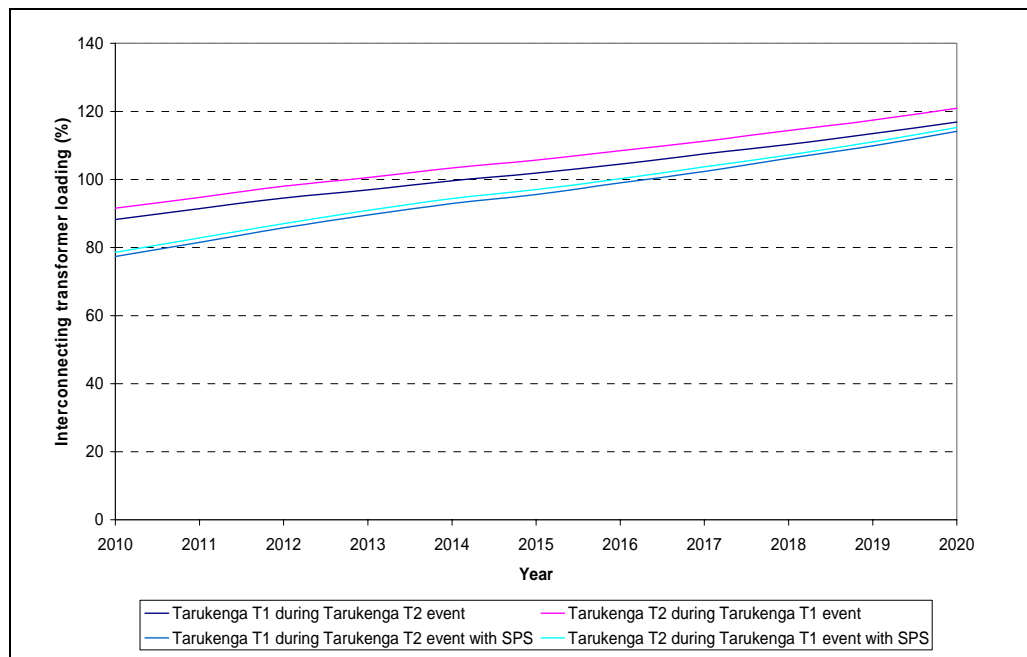
The Lichfield—Tarukenga split involves opening the Lichfield—Tarukenga circuit at Tarukenga when a Tarukenga interconnecting transformer is overloaded during a parallel interconnecting transformer event. The purpose of this SPS is to prevent through transmission between Tarukenga and Otahuhu overloading the Tarukenga interconnecting transformers.

This SPS leaves:

- Kinleith and Lichfield supplied from Arapuni, an event on an Arapuni—Kinleith circuit would result in a loss of supply
- Rotorua and the Western Bay of Plenty on supplied by a single interconnecting transformer

Figure 4-2 shows the impact of this split.

**Figure 4-2: Effect of SPS on Tarukenga interconnecting transformer loading**



The graph shows that without the SPS:

- Tarukenga T2 will overload from 2013 during a Tarukenga T1 event
- Tarukenga T1 will overload from 2015 during a Tarukenga T2 event.

With the SPS:

- Tarukenga T2 will overload from 2016 during a Tarukenga T1 event
- Tarukenga T1 will overload from 2017 during a Tarukenga T2 event.

The Lichfield—Tarukenga split will allow up to three years of deferment or delay.

The downside of this splitting scheme is that it places Lichfield and Kinleith on n security following a Tarukenga interconnecting transformer event. Without this scheme, Lichfield and Kinleith would still have n-1 security for a Tarukenga interconnecting transformer event.

Because of the reduced security at Kinleith and Lichfield, the Lichfield—Tarukenga split is considered to cover project delays. It is not considered as a deferral option.

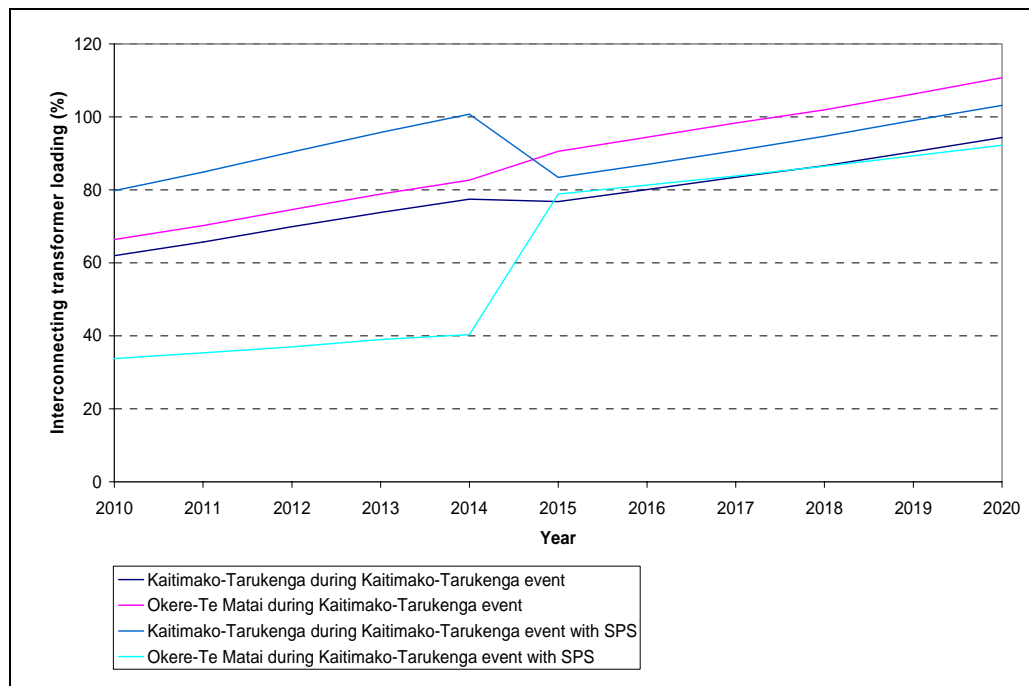
## B.2 Kaitimako—Papamoa split

The Kaitimako—Papamoa split involves opening the Kaitimako—Papamoa circuit at Kaitimako during a Kaitimako—Tarukenga event. This SPS leaves:

- Kaitimako, Tauranga and Mount Maunganui supplied by one Kaitimako—Tarukenga circuit
- Papamoa and Te Matai supplied by one Okere—Te Matai circuit.

Figure 4-3 shows the loading on the Kaitimako—Tarukenga and Okere—Te Matai circuits during a Kaitimako—Tarukenga event. Note that the change that occurs in 2014 is due to the load shifting from Mount Maunganui to Papamoa.

**Figure 4-3: Effect Kaitimako—Papamoa of SPS on 110 kV circuit loadings**



The graph shows that without the SPS:

- Kaitimako—Tarukenga will overload after 2020 during a Kaitimako—Tarukenga event
- Okere—Te Matai will overload in 2018 during a Kaitimako—Tarukenga event

With the SPS:

- Kaitimako—Tarukenga will overload in 2020 during a Kaitimako—Tarukenga event

- Okere—Te Matai will overload after 2020 during a Kaitimako—Tarukenga event

If the Kaitimako—Papamoa split is enabled in 2018 it will allow up to two years of deferral or delay.

This SPS is not required for eight years. It will defer a modeled project, the Okere—Te Matai, upgrade by two years. Therefore, it is not included in the options analysis.