May 2010

Grid Upgrade Plan 2009 Instalment 5

Part VIII: Lower South Island Reliability Transmission Investment Proposal

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Document Revision Control

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001/Rev A	Lower South Island Reliability Investment Proposal	May 2010

Costing information for elements of this proposal is confidential at this time because, if approved, we will be tendering for services and equipment associated with those elements. For that reason, only the gross cost for the bundle of projects is included in this document.

A separate document describing the cost assumptions for the preferred option in detail (Attachment E) is provided as a supplement to this investment proposal and is confidential to the Electricity Commission.

Executive Summary

The purpose of this Lower South Island Reliability Transmission Investment Proposal (the **Proposal**) is to obtain Electricity Commission (the **Commission**) approval to recover the full costs (up to $62.4 million) of increasing the core grid capacity between Roxburgh and Invercargill, and maintaining non-core grid security of supply to Gore and the surrounding region.

The Proposal is submitted as a "reliability investment" as per the Electricity Governance Rules (the **Rules**), Part F, Section III, Clause 13.

Proposal at a Glance	
What:	A staged programme of works to: • tee off both circuits of the 220 kV North Makarewa–Three Mile Hill line, build a 2 km double circuit line to Gore substation, and connect this line to two new 220/110 kV interconnecting transformers • replace the existing 220/110 kV interconnecting transformers at Roxburgh and Invercargill • install a 50% compensation series capacitor on one circuit of the North Makarewa–Three Mile Hill line at Three Mile Hill • install appropriate shunt capacitors to support voltage • install Special Protection Schemes on the 220 kV network to manage security of supply during low inflows into Manapouri. • install Special Protection Schemes as an interim measure on the 110 kV network until the new build is completed..
When:	Further solution design along with continued landowner consultation during 2010-11 followed by staged construction commencing 2012 with completion targeted in 2015.
How much:	Transpower is seeking approval for up to $62.4 million

The Proposal

The Proposal is a package of investments as summarised above on both the core (220 kV) and non-core (110 kV) networks designed to meet:

- security for the region on the 220 kV network when Manapouri is unable to generate due to low inflows
- demand growth.

The Proposal will also enhance competition in the energy and retail market by increasing transmission capacity in the region.

Transpower is seeking approval from the Electricity Commission to recover the costs of the Proposal under rule 13.4 as a reliability investment, because:

- it will reduce expected unserved energy on the 220 kV and 110 kV networks
- it reflects good electricity industry practice in meeting the grid reliability standards (GRS)
- it is justified under the Grid Investment Test
- Transpower has met the processes set out in the rules in respect of this Proposal.

Why the Proposal should be approved

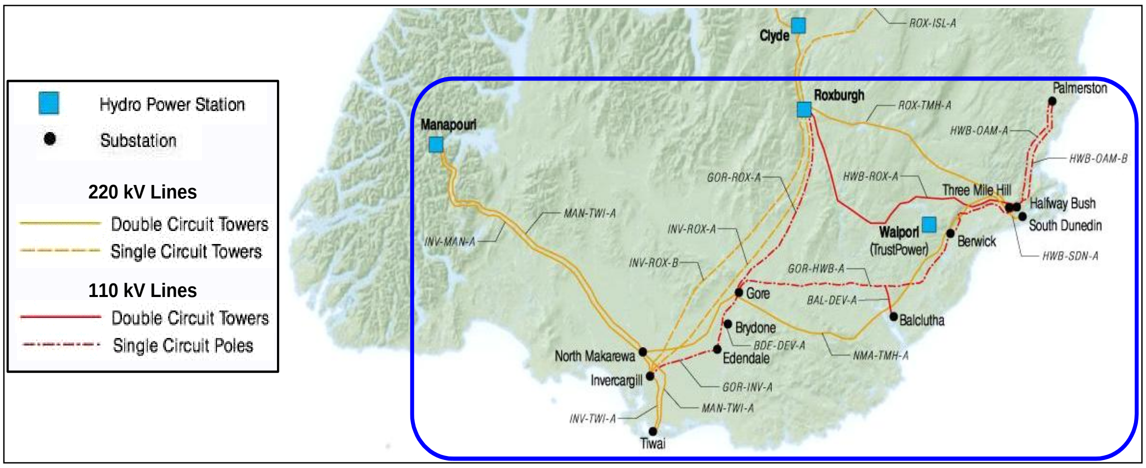
Approval of the Proposal at the earliest opportunity is important because:

- our studies demonstrate that the GRS will be breached on the core grid as soon as 2012 and work is required as soon as possible to reduce the risk to security of supply in a dry period
- it addresses major difficulties in securing outages for maintenance on a regional 110 kV network that is at very near to its capacity limit
- it creates a regional 110 kV grid with different configuration options to enable secure grid maintenance to be carried out, thus minimising the supply risk, especially to the highly sensitive dairy factory load at Edendale
- it reduces the dependence on the 110 kV grid for through transmission so it can better meet local load through implementation of a logical development of the regional grid that has been contemplated for many years
- it does not require significant work post-2015 to provide for forecast load growth over the next 20 years
- it delivers a good outcome for New Zealand in that it maximises the capacity of existing lines without extending the footprint of the National Grid
- it meets the requirements from local stakeholders for a robust and secure supply in the Southland and coastal Otago regions to secure existing critical loads and enable future regional development.

Background

The Lower South Island (LSI) region is shown in Summary Figure 1 below.

Summary Figure 1: The Lower South Island region



The region is a mix of core grid (220 kV) and non-core grid (110 kV) transmission. The core grid supplies major loads at Dunedin, Invercargill and Tiwai, from generation at Roxburgh and Manapouri. The non-core grid supplies smaller load centres throughout the region including some larger industrial loads (Brydone fibreboard plant and Edendale dairy factory). Note that the 220 kV and 110 kV circuits are not currently linked at Gore.

Power transfer into and out of the region is primarily through the two Invercargill–Roxburgh circuits.

There are two issues in this region:

1) *220 kV core grid capacity:* The available transmission capacity from Roxburgh south to Invercargill and North Makarewa is limited and additional capacity is required to:

- meet the Grid Reliability Standards (GRS) by maintaining n-1 security of supply to Invercargill and North Makarewa during low hydrological inflow or low wind periods1
- enhance competition in the energy and retail market
- enable regional development and provide investor confidence.

2) *110 kV non-core grid supply*: The LSI 110 kV network is nearing capacity due to increasing demand in the region, and:

- is vulnerable to loss of supply or low voltage when any 110 kV circuit or 220/110 kV inter-connecting transformer is out for maintenance
- can constrain the import of power into the region when Manapouri generation is low.

Process to date

To meet the identified need, the Lower South Island Reliability investigation started in 2008 with a stakeholder forum held in Invercargill.

In April 2009, we published a consultation document seeking feedback from interested parties on our approach and our initial long list of options[2]. The consultation document also served as a Request for Information (RFI) for transmission alternatives but no expressions of interest was received in response to the RFI.

Submissions were received from seven parties[3], all of which supported the need for Grid reinforcement in the region.

Since that consultation, we have held two further stakeholder forums in Invercargill and maintained regular updates through the Grid NZ website.

In May 2010, we started our consultation with those landowners impacted by potential works around Gore.

Options considered

The investigation spans two mutually dependent sub-projects:

- one on the 220 kV core grid
- one on the local 110 kV non-core grid network.

Each sub-project has potentially multiple-component solutions resulting in a large and complex number of long-list options that can address the need. These can be found in detail in Attachment D.

The long list was reduced to a short list of options using a pre-defined set of high level screening criteria.

Thirteen potential 20-year development plans were then further refined to a short list of four, which have been assessed under the Grid Investment Test.

Short List Development Plans

The short list of development plans is shown in Summary Table 1 below.

All four short-list development plans include:

- The installation of an interim SPS to open the 110 kV Gore–Brydone line post-contingency in the event of the loss of an Invercargill–Roxburgh circuit and, if overloads still persist, to invoke partial load shedding[4].
- The replacement of the interconnecting transformers at Roxburgh and Invercargill in 2013[5].

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[1] Manapouri is effectively "run of the river" and times of low hydro inflows typically coincide with low output from wind generators.

[2] Refer http://www.gridnz.co.nz/f2026,12347089/lsi-reliability-consultation.pdf

[3] For all submissions, please refer http://www.gridnz.co.nz/lsi-grid-reliability-publications

[4] A short-term fix to cover suply risk to 2014 which is the earliest we can commission new build at Gore to address the security issue.

Summary Table 1: Short list development plans

Option	Description	NPV Capex ($m 2010)
0 - Reference Case	Minimum build option to meet GRS on core and non-core grid elements Sectionalise the Gore bus, install interconnecting transformers at Gore, install voltage support equipment throughout the region and commission a series capacitor in 2018	36
4 - New Line	New 220 kV single circuit line from Roxburgh to Gore with switching station near Gore	89
8 – Staged n-1	one interconnecting transformer at Gore in 2014 and one in 2028 and series capacitor in 2018	50
9 – Full Build n-1	Two interconnecting transformers at Gore in 2014 and series capacitor in 2015	43

Application of the Grid Investment Test (GIT)

The final Grid Investment Test assessment shows that Option 9 delivers the lowest net market cost of all the options considered relative to the Reference Case, as shown in Summary Table 2 below.

Summary Table 2: Grid Investment Test Results

Option	Reference case	Option 4 New Line	Option 8 Staged Build	Option 9 Full Build
Capital Cost (A)	36	89	50	43
O & M costs (B)	4	4	4	4
Unserved energy cost normal operation (C)	4	0	0	0
Unserved energy cost maintenance (D)	6	1[1]	2	2
Loss Cost (E)	0	(18)	(3)	(14)
Dispatch Cost (F)	0	(5)	(5)	(3)
Expected Net Market Cost (A+B+C+D+E+F)	49	70	48	32

Notes:
Costs are all pre tax, discounted at 7%, in $m, and in $2010
Unserved energy under normal operation relates to unplanned outages when all assets are in service
Unserved energy under maintenance relates to unplanned outages when another asset is out of service due to maintenance
[1] This value is a conservative estimate of the unserved energy as it was deemed unnecessary to include Option 4 in the unserved energy analysis given the high level of capital cost for this option.

Un-quantified benefits

The quantitative Grid Investment Test analysis results summarised above do not take into consideration other real but un-quantified benefits. We have identified the direction and likely magnitude of the following material market benefits[6]:

- *Option benefits.* Options which include optionality in the development plan may allow investment to be deferred or cancelled should the future not turn out as expected (eg demand does not increase as rapidly as forecast or new generation emerges).
- *Consumer benefits*. Larger capacity options (less constrained) are more likely to result in lower prices particularly within the LSI region.

[5] These are due to be replaced under Transpower's strategy for asset management of the power transformer fleet within the next five years and we have taken the opportunity to optimise the capacity of these transformers consistent with our preferred option.

[6] As required by clause 9, Part F, Section III, Schedule F4 of the Rules.

- *Wider economic benefits.* Some options will enable economic development as there is increased certainty over security of supply to the region.
- *Disruption benefits.* Options which utilise the capacity of the existing network without increasing the footprint of the National Grid will have higher disruption benefits.
- *Diversity benefits.* Options that can provide access to a more diverse electricity supply will have higher diversity benefits.
- *Operational benefits.* Where investment plans add resilience to the network, particularly in relation to high impact low probability (HILP) events.

A qualitative assessment of these benefits against each of the options is described in Summary Table 3 below. The assessment has been conducted for the short to medium term. The benefit for each option has been qualitatively ranked between ✓ and ✓✓✓.

Summary Table 3: Qualitative assessment of non-quantified benefits and overall preferred option

Option	Expected Net Market Cost	Option benefits	Consumer benefits	Wider economic benefits	Minimises disruption	Diversity benefits	Operational benefits	Ranking of non quantified benefits
Reference Case	$49	✓✓✓	✓	✓	✓	✓	✓	4
Option 4 New Line	$70	✓✓	✓✓✓	✓✓✓	✓	✓✓✓	✓✓✓	2
Option 8 Staged Build	$48	✓✓✓	✓✓	✓✓	✓✓	✓✓	✓✓	3
Option 9 **Full** Build	$32	✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓	1

Although there is subjectivity involved in ranking the options, Option 9 ranks higher in terms of non-quantified benefits than all other alternatives and as such it reinforces the outcome of the GIT analysis and the choice of the full build option as the Proposal.

Timing

The technical analysis has demonstrated that the existing grid configuration does not meet the Grid Reliability Standards now, so it is proposed to:

- install an interim SPS on the Brydone–Gore line and install shunt capacitors at Balclutha by 2012
- replace the interconnecting transformers at Roxburgh and Invercargill by 2013
- install two Interconnecting transformers at Gore and complete associated works by 2014
- install a 50% compensation series capacitor on one circuit of the North Makarewa–Three Mile Hill line at Three Mile Hill by 2015 which is considered the earliest possible commissioning date[7].

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 End Cost of the Proposal is estimated to be $55.6 million and the MAC of the Proposal is estimated to be $62.4 million.

[7] We will make best endeavours to install the series capacitor by 2014 if possible.

Summary Table 4: Maximum Approval Cost

$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	40.7	46.9	-	-	-	-	-	46.9
Expected End Cost	40.7	46.9	0.2	-	-	6.1	2.4	55.6
Maximum Approved Cost	40.7	46.9	2.7	3.1	-	7.0	2.7	62.4

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 $62.4 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.

Contents

Attachment	Title
A	*GIT Results*
B	*Analysis Assumptions and Methodology*
C	*Power Systems Analysis*
D	*Options and Costing*
E	*Preferred Option Cost (Confidential)*
F	*Summary of Stakeholder Engagement*

Part A – Proposal

This part describes Transpower's Lower South Island Reliability Transmission Investment Proposal (the **Proposal**).

Components of the Proposal

- Procuring, constructing and commissioning of works to:
  - ~ tee off both circuits of the North Makarewa–Three Mile Hill line build a 2 km double circuit line to Gore substation, and connect this line to two new 220/110 kV interconnecting transformers
  - ~ replace the existing 220/110 kV interconnecting transformers at Roxburgh and Invercargill
  - ~ install a 50% compensation series capacitor on one circuit of the North Makarewa–Three Mile Hill line at Three Mile Hill
  - ~ install appropriate shunt capacitors to support voltage
  - ~ install Special Protection Schemes on the 220 kV to manage security of supply during low storage at Manapouri
  - ~ install Special Protection Schemes as an interim measure on the 110 kV network until the new build is completed.
- Procuring, constructing and commissioning substation facilities to facilitate the above connections and equipment.
- Decommissioning and dismantling components of existing connections, circuits and substations made redundant by these works.
- Obtaining designations, easements, resource consents and property purchases for these works.

Timing

We will commission the components of the Proposal between 2012 and 2015.

Costs

Transpower is seeking Commission approval to recover the full costs associated with the Proposal upon commissioning up to a total amount of $62.4 million. This amount is the estimated Maximum Approval Cost (**MAC**) to implement the Proposal, expressed in New Zealand dollars exclusive of GST. Appendix B sets out how Transpower has estimated the MAC.

Part B – Justification

1 Introduction

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

1.1 Purpose

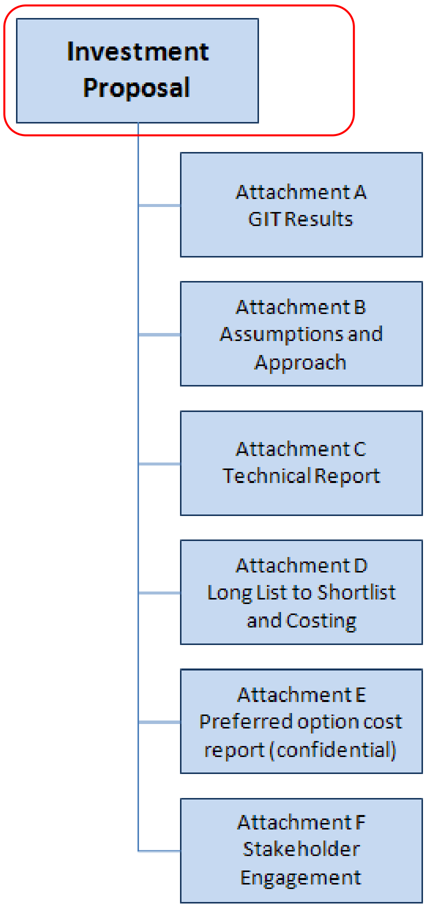
This document is Transpower's request for Commission approval to recover the costs of the Proposal.

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.

1.2 Document structure

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



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 VIII 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; and
- Part II: Investment Contracts
- Part III: Wanganui-Stratford Transmission Investment Proposal
- Part IV: Bay of Plenty Interconnection Capacity Upgrade Investment Proposal
- Part V: Lower South Island Renewables Investment Proposal
- Part VI: Auto Synchronisation Points Investment Proposal
- Part VII: Upper North Island Dynamic Reactive Support Investment Proposal

1.4 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.

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.

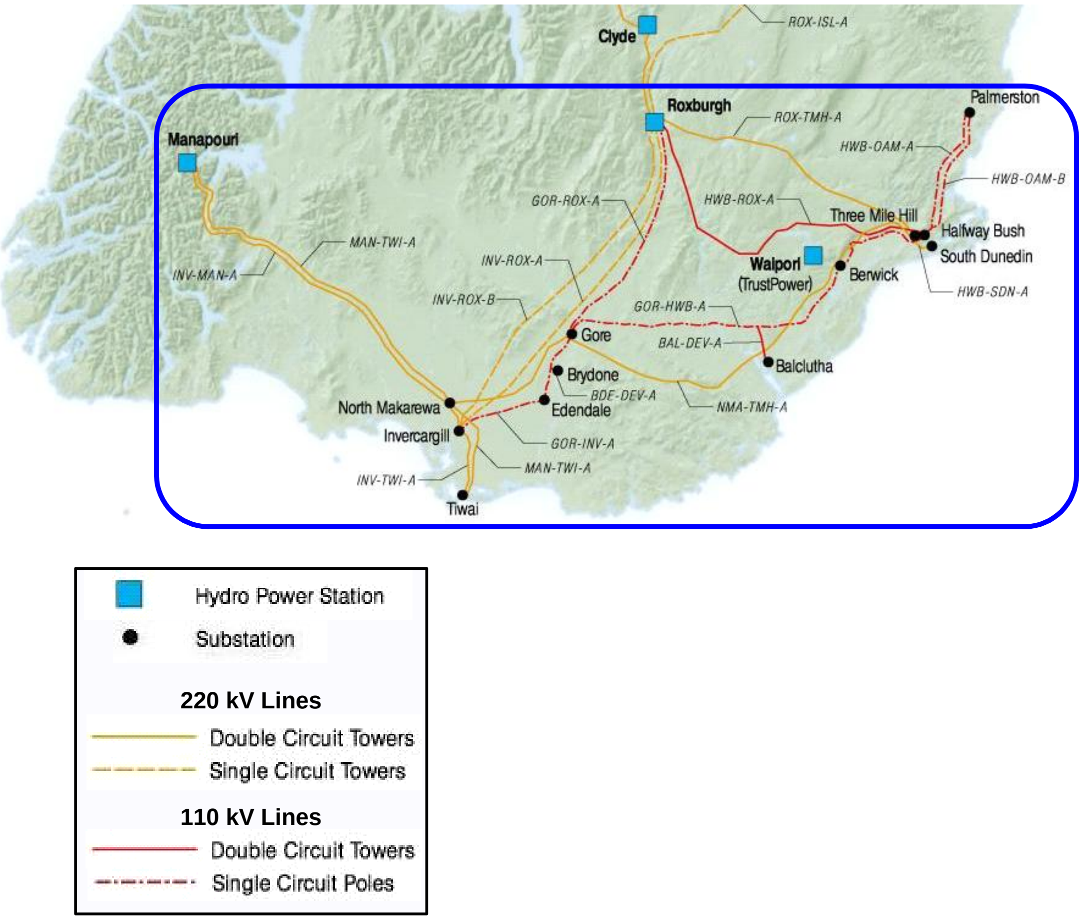
2 Needs Assessment and Type of Investment

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

2.1 Description of assets comprising the Lower South Island region

The existing Southland regional network consists of a set of 220 kV and 110 kV circuits with interconnecting transformers located at Halfway Bush, Roxburgh and Invercargill.

Figure 2-1: Map of the Lower South Island region



Key features of the network are:

- The 220 kV circuits connect generation at Roxburgh and Manapouri to major loads at Dunedin and the Invercargill region along with the Tiwai aluminium smelter.
- The 110 kV network connects generation at Waipori and Roxburgh to loads at Dunedin, smaller towns, Brydone fibreboard plant and Edendale dairy factory.
- The 220 kV and 110 kV networks interconnect at Roxburgh, Halfway Bush and Invercargill (but not currently at Gore).
- The connection to the rest of New Zealand is through the 220 kV circuits to the north from Roxburgh.

There are two issues that drive the need for upgrading the transmission grid south of Roxburgh:

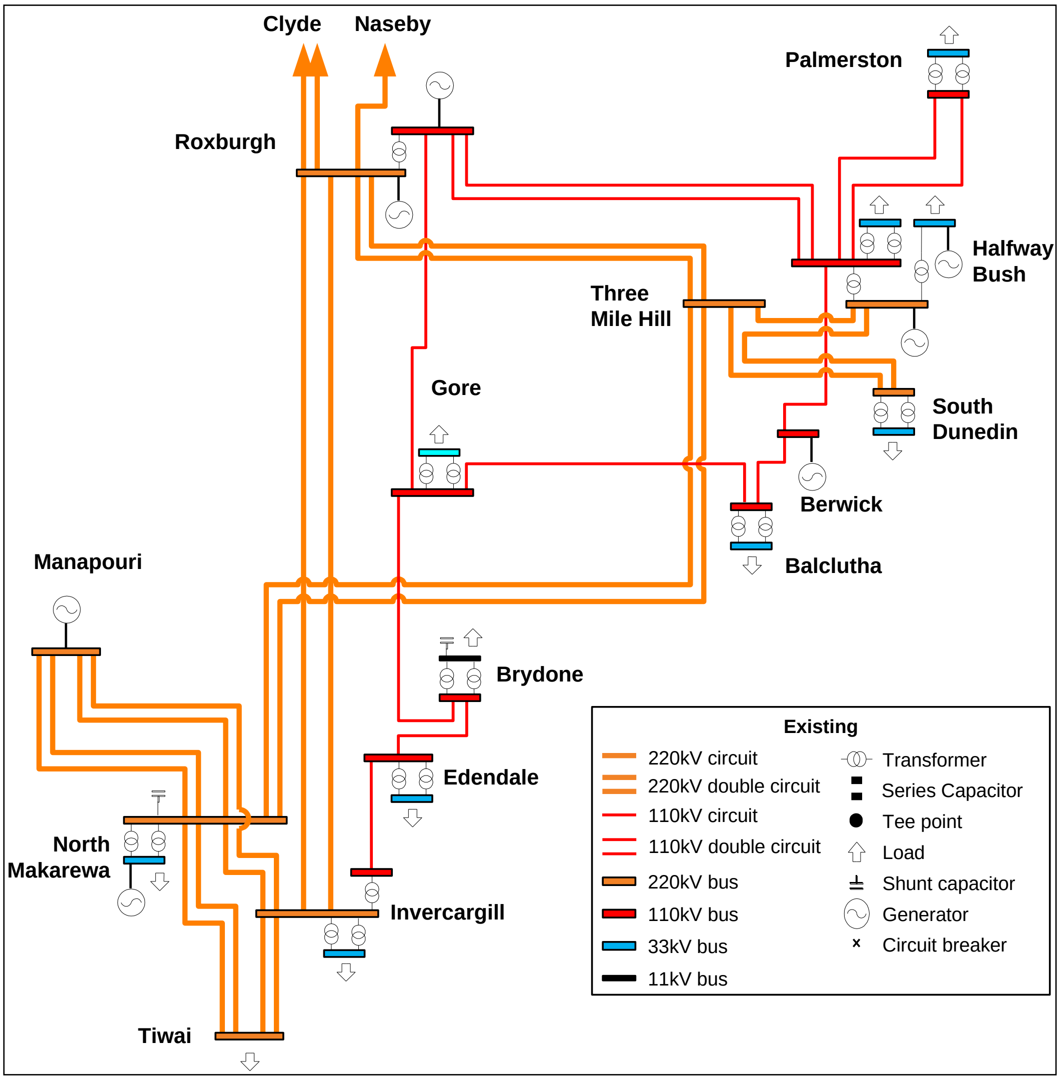
Power transfer limitation on the 220 kV and 110 kV networks

During times of low Otago-Southland generation, part of the regional load is supplied from the north. Power transfer from Roxburgh to south is constrained by the need to avoid overloading the Gore–Roxburgh 110 kV circuit for the loss of a Invercargill–Roxburgh 220 kV circuit. The next constraint is the need to avoid overloading a Invercargill–Roxburgh 220 kV circuit for the loss of the parallel Invercargill–Roxburgh 220 kV circuit.

Power supply limitation on the 110 kV network

The 110 kV transmission network within Otago-Southland region comprises low capacity circuits. Load limits are required on the grid exit points supplied from the 110 kV network in Southland to avoid overloading of assets. The 110 kV network also encounters capacity and voltage issues during various 110 kV circuit outages. A planned outage of 110 kV circuits often requires load management, regional generation being made available during the outage and grid reconfiguration (splitting the 110 kV network to avoid through transmission which places some loads on N security for the duration of the outage). It is increasingly difficult to schedule outages of the 110 kV as the windows where load is low enough to take the outage are decreasing as load continues to grow in the 110 kV network.

Figure 2-2: Existing transmission circuits in the Lower South Island region



2.2 Process to date

This section summarises the stakeholder engagement undertaken throughout the investigation of this project, full details can be found in Attachment F.

This section is divided into two separate parts:

- Industry consultation
- Community and landowner engagement.

2.2.1 Industry consultation

The Lower South Island reliability investigation started at the end of 2008 with a stakeholder forum held in Invercargill.

In April 2009, we published a consultation document seeking feedback from interested parties on our approach and the initial long list of options.[8]

The consultation document also served as a Request for Information (RFI) with respect to transmission alternatives but no expressions of interest were received in response to the RFI.

We received submissions from the following interested parties[9]:

- Aurora Ltd (submitted by Delta Utility Services)
- Contact Energy Ltd
- Dongwha Patinna NZ Ltd
- Fonterra Ltd
- Meridian Energy Ltd
- Powernet Ltd
- Rio Tinto Alcan Ltd

All submitters were very supportive of Transpower's plans to address the system need in the LSI region and in summary, the key issues raised in the submissions and stakeholder forums were as follows:

- The maintenance of N-1 on the non-core grid elements is required given the critical loads.
- Demand forecasts must take into account the potential for strong dairy growth continuing in the region.
- Any significant step load changes assumed at Tiwai post 2019 would be highly speculative.
- The generation assumptions should take into account new wind and coal developments.
- A new 220 kV line connecting Gore to the Waitaki Valley should be considered.
- SPS' should only be considered as short term, interim solutions.
- The value of lost load will vary according to industry: both Edendale and Tiwai load would have significantly higher VoLL than $20,000/ MWh.

Following receipt of feedback from stakeholders in April 2009, Transpower:

- considered and incorporated the feedback received
- further developed the options (as presented in this paper)
- developed the economic approach, as set out in Attachment B
- analysed the results.

[8] refer http://www.gridnz.co.nz/f2026,12347089/lsi-reliability-consultation.pdf.
[9] These submissions can be found at http://www.gridnz.co.nz/lsi-grid-reliability-publications.

2.2.2 Community and landowner engagement

A common theme from all the short-listed options is the need for a connection between Gore substation and the North Makarewa–Three Mile Hill line about 2.5 km to the south. To introduce potentially affected communities to this component, a letter was sent out introducing the project, its need and this component.

The exact design of this configuration is not yet certain at the time of submitting this Investment Proposal, and Transpower has committed to consulting with the local community to help determine its design.

Immediately on submission of this proposal, all stakeholders will be notified.

The delivery phase of the project will involve continued engagement with key stakeholders; as part of the environmental processes around "Greenfield" site/route selection for new assets and also property rights acquisition and access.

3 Identification and Consideration of Options

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

3.1 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[10]. Therefore, Transpower must first identify those options that fall within the definition of "alternative projects" under the Rules.

3.2 Option identification

3.2.1 Long list of options

The long list aimed to canvas a broad range of viable investment options, while balancing Transpower's preference to invest resources, the condition of the existing conductor and time in the options that are likely to be progressed to the short list.

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

- fitness for purpose
- technical feasibility
- practicality of implementation
- Good Electricity Industry Practice (GEIP)
- system security (additional benefits resulting from an economic investment)
- whether an option will clearly be more expensive than another option with similar or greater benefits
- 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.[11]

The investigation spans two mutually dependent sub-projects:

- one on the 220 kV core grid
- one on the local 110 kV non-core grid network.

Each sub-project has potentially multiple-component solutions resulting in a large and complex number of long list of solutions that can address the need. These can be found in detail in Attachment D.

For all options, the ability to meet the prudent load forecast is constrained by the time for commissioning the new build required. As a result in all options as an interim measure until 2014 a Special Protection Scheme will be required on the 110 kV network. This will automatically reconfigure the grid in the event of overloading and, if overloading persists, shed load.

[10] Schedule F4, clause 4 of the Rules.
[11] Schedule F4 clause 11.

220 kV capacity options

The first, and least expensive, option considered is a special protection scheme (**SPS**) to trip a reduction line at Tiwai Point[12]. The operation of the scheme would need to be followed by the re-dispatch of regional generation as the line will need to be returned to service within a short time. This or another SPS could automatically run up generation at Manapouri at the same time. An exception to Transpower's usual policy of not installing SPS' on the core grid can be made here because the SPS would only need to be armed approximately 5% of the time.

There is spare capacity on the Roxburgh-Three Mile Hill and Three Mile Hill-North Makarewa circuits at present, and better balancing of the load on these circuits with the Roxburgh-Invercargill circuits would increase the southward flow capacity. Options include the installation of phase shifting transformers or series capacitors.

Options of increasing the thermal capacity of the Invercargill-Roxburgh 220 kV circuits or building a new 220 kV transmission line are available.

The most overloaded circuit for southward flow is the 110 kV Gore–Roxburgh circuit. The 110 kV circuits could be reconductored to increase their capacity, or reconfigured to remove the constraining parallel route of 110 kV with the 220 kV circuits.

110 kV network options

The majority of options to address the 110 kV need are located at Gore and there are a number of reasons for this:

- The recent and forecast load growth on the 110 kV network is near Gore.
- The North Makarewa–Three Mile Hill line has spare capacity and passes close to the existing Gore substation.
- Gore is the centre of the existing 110 kV network and so provides the most opportunities for reconfiguration.

One possibility is to split the Gore bus into two or three separate sections, removing the north/south 110 kV route parallel with the 220 kV network. The split could either be permanent, manually switched pre-contingency, or automatically switched post-contingency via an SPS. Such a split would leave some or all of the 110 kV network loads, including Edendale, at N security.

Another option is to install one or two interconnecting transformers at Gore, connected to the North Makarewa–Three Mile Hill line. Importantly, this allows the two 110 kV lines from the north (Gore–Roxburgh and Balclutha–Gore) to be split from the Gore 110 kV bus, making one long Roxburgh to Balclutha circuit, while still retaining N-1 supply to Gore and Edendale through the two interconnecting transformers.

The effect of either option on the 220 kV capacity would vary depending on circumstances. The capacity may be reduced by the removal of the 110 kV route or may be increased by the removal of the 110 kV overloading constraint.

In summary the long list of options included:

- Thermal up-rate, voltage increase, addition of circuits or conductor replacement on existing lines to allow increased power flow;
- Installation of series reactors, series compensation and phase shifting transformers to respectively limit, increase and regulate power flow through specific circuits;
- Installation of extensive and complex Special Protection Schemes
- Reconfiguration of the 110 kV network to allow higher transfer capability on 220 kV assets;
- New AC and HVDC lines, buses and transformers

[12] There is an existing SPS - currently disabled – intended for us to cover extreme low storage scenarios at Manapouri .

- Installation of extensive voltage support equipment such as shunt capacitors and SVCs.

The long list was reduced to a short list of options using a pre-defined a set of high level screening criteria. From there we developed thirteen potential twenty year development plans which were then further refined to a short list of four which have been tested under the Grid Investment Test.

3.2.2 Short list of options

The short-listing process resulted in the following short list of options to which the GIT has been applied:

Table 3-1: Short list of options[13]

Option	Description of investment to 2032	NPV Capex ($2010 M)
Option 0 Reference Case	Halfway Bush backfeed protection (SPS) 5 x 4 Mvar capacitor banks at Gore Replacement of 220/110 kV transformers at Invercargill and Roxburgh 20 Mvar capacitor bank at Gore; sectionalise and split Gore bus SPS on Manapouri and/or Tiwai 70% series capacitor on North Makarewa- Three Mile Hill 10 Mvar capacitor bank at Gore 2 tees off North Makarewa–Three Mile Hill line; double circuit line to Gore and two interconnecting transformers at Gore	36
Option 4 New Line	Halfway Bush backfeed protection (SPS) 2 x 4 Mvar capacitor banks at Balclutha; sectionalise and split Gore bus 220 kV switching station adjacent to the North Makarewa–Three Mile Hill line; new 2km 220 kV double circuit line from the switching station to Gore; 2 interconnecting transformers at Gore Replacement of 220/110 kV transformers at Invercargill and Roxburgh 5 x 4 Mvar cap banks at Gore SPS to split Gore load (short term) SPS on Manapouri and/or Tiwai (short term) New 220 kV single circuit line from Roxburgh to the switching station	89
Option 8 Staged Build	Halfway Bush backfeed protection (SPS) 5 x 4 Mvar capacitor banks at Gore SPS on Manapouri and/or Tiwai Replacement of 220/110 kV transformers at Invercargill and Roxburgh Sectionalise and split Gore bus 1 interconnecting transformer at Gore ; new 2 km 220 kV double circuit line from North Makarewa–Three Mile Hill line to Gore 10 Mvar capacitor bank at Gore 20 Mvar capacitor bank at Gore 70% series capacitor on North Makarewa–Three Mile Hill 1 interconnecting transformer at Gore; connect Gore–Roxburgh 110 kV circuit to Balclutha–Gore 110kV circuit Upgrade existing North Makarewa capacitors from 50 MVA to 70 MVA	50

[13] Refer to Attachment D for a detailed explanation of the short-list options.

Option 9 Full Build	Halfway Bush backfeed protection (SPS) 2 x 4 Mvar capacitor banks at Balclutha; SPS Intertrip on Brydone-Gore circuit Replacement of 220/110 kV transformers at Invercargill and Roxburgh 2 x interconnecting transformers at Gore; new 2 km 220 kV double circuit line from North Makarewa–Three Mile Hill line to Gore SPS on Manapouri and/or Tiwai (short term) 50% series capacitor on North Makarewa–Three Mile Hill Connect 110 kV Gore–Roxburgh circuit to the 110 kV Balclutha–Gore circuit Upgrade series capacitor to 70% compensation Uprate 50 Mvar to 70 Mvar 220kV at North Makarewa 220 kV bus	43

The rationale for the choice of reference case is explained in section 3.3.3 below.

3.3 Reflecting Good Electricity Industry Practice in meeting the Grid Reliability Standards

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

3.3.1 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 and are consistent with our Transmission Code.

3.3.2 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 Lower South Island region comprises both core grid (220 kV) and non-core grid elements (110 kV), both clause 4.11 and 4.2 apply.

3.3.3 Base case

For the purposes of the GIT, the Rules also require that the Proposal and alternative projects be assessed against a base case, which is defined[14] as follows:

> ***"Base case"*** *means the* ***market development scenarios*** *developed for the reasonable future state of the electricity industry without the* ***proposed investment*** *or any* ***alternative project****.*

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, and more particularly rule 4.2 of 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 to sectionalise the Gore bus, install the interconnecting transformers at Gore as well as the required voltage support equipment throughout the region as required and commission the series capacitor at Three Mile Hill in 2018. This is probably the minimum build option to ensure that the existing load continues to be served. It does lower the level of reliability in the region, but this is accounted for in the GIT using reliability analysis.

The reference case (Option 0) effectively maximises the use of the existing 110 kV circuits through a three-way split of the 110 kV bus at Gore when necessary to manage the loading on the 110 kV circuits and 220/110 kV interconnecting transformers. The split is implemented so that:

- approximately three quarters of the Gore load is supplied from Roxburgh by the Gore–Roxburgh 110 kV circuit
- approximately a quarter of the Gore load is supplied from Halfway Bush by the Halfway Bush–Berwick–Balclutha–Gore 110 kV circuit
- the Edendale and Brydone loads are supplied from Invercargill by the Invercargill – Edendale–Brydone–Gore 110 kV circuit.

The Gore bus split addresses the southflow capacity issue by:

- removing the parallel connection of the constraining 110 kV Gore – Roxburgh circuit and Roxburgh 220/110 kV transformer from the two Invercargill – Roxburgh 220 kV circuits, allowing the full capacity of the Invercargill – Roxburgh 220 kV circuits to be used.
- continuing to use the Gore – Roxburgh and Halfway Bush – Gore 110 kV circuits to supply part of the LSI load (Gore).

Whilst this maximises the use of the 110 kV network for southflow capacity, a Special Protection Scheme (**SPS**) to trip a reduction line at Tiwai Point followed by re-dispatch of generation or directly ramp up Manapouri generation is required until a series capacitor is installed in 2018.

When the Gore 110 kV bus and load is split, a large amount of relatively small sized shunt capacitor support is needed to support the voltage at the end of the long Gore–Roxburgh and Halfway Bush–Gore circuits. This adds significant cost to this development plan, hence the unusually high build cost for this reference case.

[14] Clause 20 of Part F Section III Schedule F4

4 GIT Methodology and assumptions

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

The GIT requires Transpower to determine the market benefits and costs of the base (reference) case and each of the short-list options for each of a number of market development scenarios for the future[15].

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

4.1 Modelling approach and market development scenarios

The GIT requires Transpower to develop market development scenarios and analyse the base case and each short-list option against each scenario.[16] The market development scenarios utilise a set of generation drivers as inputs. These drivers include details of generation cost, timing, location, carbon charges, demand etc.

To date, the Commission has established the scenarios by using the drivers in its generation expansion model (GEM) as a part of the process of establishing its Statement of Opportunities (SoO) as required under Rule 9. There are five scenarios within the SoO. Transpower has used the five scenarios as a starting point for the analysis and has amended them as described below.

For this proposal, Transpower has reviewed and updated the generation details in the current operative SoO to align with those scenarios used in its Lower South Island Renewables Investment Proposal (Part V of the 2009 Grid Upgrade Plan). The Commission was satisfied that the changes made to the market development scenarios in that proposal were an appropriate update, as they incorporated more current information than used to compile the SoO.

The demand and generation scenarios used reflect a realistic view of likely trends in the near future. They include revisions to demand forecasts to reflect changes in the short term outlook within the region since we started working with stakeholders on the Proposal in 2008.

4.1.1 Demand assumptions

The Tiwai Point Aluminium Smelter operated by Rio Tinto accounts for around 60% of the regional load. Demand in the region has been growing progressively throughout the last decade - on average 3% growth per annum in peak demand has been recorded excluding the predominant regional load at Tiwai Point. This strong demand growth[17] has been driven by the ongoing expansion of the dairy sector in the region. Given that there is still plenty of land available for dairy conversion, it is anticipated that growth will remain strong over the coming years. An example of this growth has been seen at Fonterra's Edendale dairy factory which recently commissioned a fourth dryer and is now the largest dairy processing facility in New Zealand.

The prudent peak demand forecast, upon which the planning studies are based, shows potential increases in peak demand of around 40% over the next 20 years excluding Tiwai's load.

Any significant step change in demand at Tiwai or from other industries in the order of 50 MW increase (or decrease) will have a material impact on the timing of grid investment. Initially when we started work on the investigation, we allowed the possibility of a step change in Tiwai to 700 MW in our prudent forecast. Rio Tinto has since confirmed that such a step change is unlikely in the foreseeable future given the outlook for aluminium production. We have included in the prudent peak demand forecast the possibility of an incremental rise of

[15] Clause 5 of Schedule F4, Part F of the Rules.

[16] Refer to definition of "market development scenarios" at clause 28 of Schedule F4, Part F of the Rules.

[17] Note peak demand for New Zealand has averaged 1% per annum over the same timeframe and South Island peak demand has grown on average by 2% per annum.

5 MW per annum between 2015 and 2024 at Tiwai reflecting the steady incremental increases in the late 1990's and 2000's. There is little certainty over future plans for step increases from other similar mineral extraction[18] and processing industries.

Given that the transmission system cannot meet peak loads in the region without regional generation, supply to region is at risk of being jeopardised during times of low hydro generation availability as occurred in winter 2008. The low inflow risk to security of supply in the LSI region under southward flow conditions requires the additional capacity to be provided to the region as soon as practical.

The electricity demand used in the analysis has been based on the 2008 SoO forecasts. Adjustments to specific grid exit points have been made based on independent forecasts developed by Covec Limited – refer to Appendix E of Attachment B..

Subsequent discussions with stakeholders have resulted in three changes to the Covec demand forecast:

1) The growth in the Gore prudent values has been delayed by 2 years from 2010 on, i.e. 2012 has been set to the previous 2010 value, 2013 to the previous 2011 value, etc.
2) The assumption is made that if the growth at Edendale and Brydone exceeds the capacity of the Edendale-Invercargill line (the N-1 capacity with the Gore-Brydone line out) then the excess will be managed at a distribution level by shifting load to Gore. This results in the Edendale and Brydone combined loads being capped at the level of capacity of the Edendale-Invercargill line.
3) The prudent forecast at Tiwai has been increased by 5 MW per annum from 2015 to 2024 to a total of 690 MW.

While the prudent forecast is used in the planning studies to determine when investment is required, we have used a blend of expected and prudent demand forecasts to establish the relative benefits each development plan. The benefits are expressed as reductions (compared to the reference case) in costs of unserved energy under normal conditions and during maintenance, fuel and dispatch costs and loss costs.

The demand forecast used in this assessment is a combination made up of 70% of the expected and 15 % of the prudent forecast unserved energy calculations. The values of 70% expected and 15% prudent are estimated from the probability of each forecast occurring. The remaining 15% to make 100% represents a demand forecast level with a probability of exceedance on 90%.

A full description of how the demand forecast has been applied can be found in Attachment A.

4.1.2 VoLL assumptions

The value of lost load (VoLL) used at all GXPs except Edendale is $23,185/MWh. This is the December 2004 value of $20,000/MWh prescribed in the EGRs inflated 5 years using an inflation rate of 3%.

Edendale VoLL

Edendale is the site of New Zealand's largest dairy processing plant. For any contingency that results in an outage at the Edendale GXP, the cost of the unserved energy at the Fonterra processing plant has two components:

1) a cost per MWh of unserved energy
2) the second is a per outage event cost.

Advice from Fonterra included an outage cost of $50,000/MWh. This represents a combination of the cost of lost production and environmental costs incurred due to milk being dumped or not collected.

[18] There is also the possibility of significant load coming on due to the potential developments of the lignite resource by Solid Energy or L&M mining, as well as the development of nickel and silica smelting. These are over and above what has been included in the prudent peak demand forecast.

The majority of costs incurred occur during the first few seconds of an outage. This is represented as an outage event cost. Medium level estimates from Fonterra put this at approximately $1.4 million per event in 2011 with the cost increasing over time. We have used an event cost of $1.4 million for all years in the analysis which will tend to under represent the value of any lost load at Edendale.

Included in the GIT analysis is a sensitivity which assumes the site specific VoLL at Edendale is half that assumed in the base analysis, refer section 5.1.2.

4.1.3 Generation assumptions

Generation in the LSI region is dominated by the largest hydro power station in the country, Manapouri, which currently generates up to 720 MW and has a physical capability in excess of 840 MW. It has limited storage capacity with operating restrictions that requires inflows to be used as they occur. Supply into the region cannot be guaranteed if there is any extended “dry” period in Fiordland.

Assessment of Manapouri’s ability to support the region at times of low inflows against the worst case scenario of a three day failure of the Invercargill–Roxburgh line has led to a post-transmission-contingent Manapouri minimum generation assumption of 247 MW average over a 24 hour period. This assumption is supported by Meridian Energy Limited.

To convert the average daily value of 247 MW to a peak figure, an additional 40 MW has been added to this value based on the difference between the peak and trough loads in the Southland region being approximately 80 MW.

However, during a contingent event, running the system at its limit is not desirable and to this end we have assumed a pragmatic 15-25 MW ‘operating margin’ in the level of generation available from Manapouri. This margin will ensure the transmission system does not have to be operated right at the limit during a contingent event.

It is anticipated that a reduction in the post contingency operating margin of 15-25 MW or an increase in the pre-contingency operating margin of 0 MW will not impact on any of the proposals in this GUP.

Table 4-1 summarises the assumptions made.

Table 4-1 Manapouri Generation Assumptions

	Pre Contingency	Post Contingency
Daily Average (MW)	180	247
Adjustment to be at peak load (MW)	+40	+40
Operating margin (MW)	0	-25
Peak(MW)	220	262

A full description of the assumptions around Manapouri generation can be found in Attachment A.

Other smaller local generation includes Waipori hydro generation which is connected at Berwick and White Hill wind farm which is embedded into the local distribution network at North Makarewa.

While Contact Energy is reviewing options for hydro development on the lower Clutha, there are no firm plans for this development in the near future.

Two significant wind farms have been consented – 240 MW Kaiwera Downs wind farm and the 200 MW Lake Mahinerangi wind farm, the first stage of which will comprise 36 MW capacity embedded at Waipori due for commissioning by April next year. However, wind generation as such will have relatively little impact on providing additional reliability to the system at times of peak load, especially as times of low wind typically coincide with low hydro inflows – as evident during winter 2008.

4.1.4 Summary of the approach to the GIT and assumptions

The following is a summary of the high level approach taken to the GIT analysis along with a summary of the assumptions utilised in the analysis.

Table 4-2: Summary of Grid Investment Test Approach and Assumptions

Item	Approach
Type of Investment case	Reliability investment case.
Market development scenarios (MDS)	5 Scenarios based on LSI Renewables Investment Proposal Scenarios
Scenario weightings	Equally weighted
Analysis Period	20 years
Discount rate	7%.
Net present value or real options analysis	PV with scenarios
Demand Forecast	2008 SoO, adjusted for Covec work in LSI, and Waitaki Valley.
Analysis in current or future dollars	$2010

4.2 Calculating the expected market benefits

Market benefits under the Rules cover benefits to those persons who produce, distribute, retail and consume electricity in New Zealand.[19] Transpower's approach to estimating the market benefits of each short-list option is set out in detail in Attachment A. The following is a summary of the approach to estimating benefits:

Table 4-3: Summary of market benefits

Market benefit	Approach
Capital benefits – capital cost of generation	Not included
Fuel costs and transmission losses	Included
Greenhouse gas emission, spill and load shedding	Included
Reliability benefits	Included
Operational benefits	Not included[20]
Market services (ancillary services and reserves)	Not included
Competition benefits	Not included
Consumer benefits	Not included
Future options	Not included
Terminal benefits	Not Included

4.3 Market costs

For the purposes of applying the GIT, we have estimated costs for the short-listed options to a level of accuracy that will determine the difference between the options and between the costs and benefits such that a sufficiently robust decision can be made on the most economic option.

The transmission costs used for options have been designed and costed to a level commensurate with the estimated capital expenditure required for the proposed investment[21].

[19] Clause 27 of the GIT.

[20] Clause 9 of the GIT provides that where a material benefit cannot be quantified, the direction and likely magnitude of the benefit must be identified. Transpower did not consider estimating the "likely magnitude" to be possible or commensurate with the project spend. However, such benefits are important and have been accounted for as discussed in section 6.1.3.

[21] The actual accuracy level of the costs differs by component. For detailed breakdown refer to Attachment D, Cost Report.

Table 4-4: Summary of market costs

Market Cost	Approach	
Transmission costs	Capital equipment costs	Included
	Line and Substation capital costs	Included
	Installation costs	Included
	Property costs	Included
	Project management	Included
	Consenting costs	Included
	Community fund costs	Included
	Operating and maintenance costs	Included
	Investigation costs	Included

4.4 Grid Investment Test sensitivities

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

The sensitivities analysed or considered in applying the Grid Investment Test to the short list of options and the reasoning behind choices made, is fully described in Attachment A. A summary of the sensitivities used by Transpower in the application of the Grid Investment Test to the short-list options is set out in the table below.

Table 4-5: Summary of Sensitivities

Sensitivity	Value
Discount rate	4% and 10%
Capital cost	Included, Low 80%, high 120%
Value of expected unserved energy	Included, $10,000/MWh, $40,000/MWh inflated for 5 years at 3% and VoLL at Edendale @$25,000/MWh and $700,000 per incident
Forecast demand	Included –Prudent forecast (adjusted for Covec)
Property Costs	Included, 200%
Carbon charges	Included, low 80%, high 120% in addition to the variation between scenarios
Variations in the size, timing, location, and operating and maintenance costs	Not included as a sensitivity
Timing of decommissioned assets	No assets are being decommissioned and therefore not included.
Variation in hydrological inflow sequences	Included in base analysis and therefore not included as a sensitivity, modelled within SDDP analysis
Generator and demand side bidding strategies	Not included as a sensitivity, included in scenarios
Competition benefits	Not included

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.

5 Application of the Grid Investment Test

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

5.1 Compliance with the Grid Investment Test

The investment proposal under consideration contemplates an investment in the Lower South Island region which is not part of the core grid. As such, the Proposal, will satisfy the GIT under clause 4.2 of Schedule F4 if the Proposal:

- maximises expected net market benefit compared with a number of alternatives
- results in an expected net market benefit greater than zero, in a robust manner with respect to any sensitivity analysis.

5.1.1 Grid Investment Test results

The GIT results are presented as a comparison of the expected net market benefit for the short-listed options and the sensitivity of the expected net market benefit to various parameters. Table 5-1 below summarises the results of the GIT analysis.

Table 5-1: Overall results of application of the Grid Investment Test

Option	Reference case	Option 4 New Line	Option 8 Staged Build	Option 9 Full Build
Capital Cost (A)	36	89	50	43
O & M costs (B)	4	4	4	4
Unserved energy cost normal operation (C)	4	0	0	0
Unserved energy cost maintenance (D)	6	1[1]	2	2
Loss Cost (E)	0	(18)	(3)	(14)
Dispatch Cost (F)	0	(5)	(5)	(3)
Expected Net Market Cost (A+B+C+D+E+F)	49	70	48	32

Notes:
Costs are all pre tax, discounted at 7%, in $m, and in $2010

Unserved energy under normal operation relates to unplanned outages when all assets are in service

Unserved energy under maintenance relates to unplanned outages when another asset is out of service due to maintenance

[1] This value is a conservative estimate of the unserved energy as it was deemed unnecessary to include Option 4 in the unserved energy analysis given the high level of capital cost for this option.

These results show that Option 9 – the full build option has:

- the highest expected net market benefit of the short-list options
- an expected net market benefit greater than zero.

Transpower concludes that the full build option (Option 9) satisfies the requirements of clauses 4.2.1 and 4.2.2 of the GIT.

5.1.2 Sensitivity analysis

Transpower has considered the sensitivity of this result to changes in key variables and parameters to assess the robustness of this result (in accordance with clause 4.2.3 of the GIT). Table 5-2 below shows the results of these sensitivities.

Table 5-2: Sensitivity of the expected net market benefit of the short-list options

Expected Net Market Cost ($m)	Reference case Minimum Build	Option 4 New Line	Option 8 Staged Build	Option 9 Full Build
Base results ($m)	49	70	48	32
Sensitivity:				
Discount rate, 4%	62	85	59	39
Discount rate, 10%	41	58	40	26
Capital 80%	42	52	38	23
Capital 120%	57	88	58	41
Unserved Energy @$11,592/MWh	46	70	47	31
Unserved Energy @$46,370/MWh	57	70	49	33
Unserved Energy for Edendale@$25,000/MWh and $700,000 per incident	48	70	48	32
High demand (prudent Forecast)	65	20	34	(11)
Property Costs (200%)	50	73	49	33
Low Carbon Cost (80%)	49	81	51	39
High Carbon Cost (120%)	49	79	50	39

The cost for option 9 under a high demand forecast becomes negative due to the large savings in losses relative to the reference case.

The full build option (option 9), the proposal, is the lowest cost option under all sensitivities analysed thus demonstrating it is robust against a number of alternative assumptions including a lower site specific VoLL at Edendale.

5.1.3 Other non-quantified differences

Given that there are three short-listed options which are close economically, we have also considered other non-quantified differences, as a means of helping to differentiate between the options.

Option benefits – does the option include flexibility to be amended in the future if there are significant changes? Options which can be amended include an inherent value, because demand growth could be higher or lower than forecast, new generation may appear, a new grid exit point may be required or technology changes may mean a different solution is preferable, etc.

The preferred option (9), scores fairly low for this benefit given it builds the majority of what is required over the 20 year period by 2015. In contrast, the reference case and the staged build option (8) allow a greater degree of flexibility in responding to slower demand growth. However, that said, the full build option will accommodate a significant step increase in load at short notice beyond 2015 , which the other options cannot.

Consumer benefits through enhanced competition – to what extent will the option enhance competition in the New Zealand electricity market? The more competitive a market is, the more efficient it will be at delivering the advantages that markets can provide to consumers. Transmission investment may enable a more competitive generation investment market through lower nodal prices for consumers and can increase market liquidity (which should result in increased availability of electricity price risk management products).

Both the new line option (4) and the full build option (9) will deliver a benefit in this region over and above the other options since they deliver higher capacity and increased operational flexibility at Manapouri sooner, reducing constraints that may restrict retail competition.

Wider economic benefits – to what extent will the option deliver wider economic benefits? The GIT assesses the benefits of transmission investment in terms of lower electricity costs and avoided unserved energy for only consumers of electricity. There is no consideration of the wider benefit to New Zealand that electricity provides. For example, a low cost and secure supply of electricity will encourage foreign investment in New Zealand, compared to a higher cost, less reliable supply. This factor differentiates between options on the basis of their potential to provide wider economic benefits for all New Zealanders. Options which provide certainty to investors in new generation and/or confidence to investors in the New Zealand economy and/or more tourism, for instance, are preferred.

The reference case (0) would not deliver wider economic benefits given the unserved energy that will occur on the grid. The resulting perception that the region cannot deliver a secure supply of electricity under this option will inhibit regional development and investor confidence. Some future developments[22] are specific to the resources in the region and cannot be assumed to occur elsewhere in another region which can deliver a higher degree of security. Both the new line option (4) and the full build option (9) have the potential to deliver this benefit.

Minimises disruption – to what extent will the local community be disrupted by the implementation of an alternative? While staged options can provide economic benefit by deferring capital expenditure and providing flexibility to deal with future changes, they may also be more disruptive to the community and in particular landowners. Staged options could mean, for instance, that we would be revisiting the same landowners every few years to incrementally increase transmission line capacity. This factor considers the extent to which an option would disrupt the community over the analysis period.

The full build option (9) scores high in this regard since it will result in a relatively short construction timeframe and will be mainly focussed on a concentrated area around Gore and Three Mile Hill. The development plan for this option only requires one additional modelled project beyond 2015, whereas the staged option (8) and the reference case (0) development plans require work to be completed on a regular basis throughout the development period.

Diversity benefits – to what extent will the option provide diversity of supply? GIT analysis typically quantifies reliability benefits for each option, where the differences are considered significant and can be readily quantified. However, some differences are important but too difficult to quantify. For example, providing electricity supply to an area through two separate transmission lines, rather than one, provides protection against losing a portion of a line. The statistics of this and other such low probability events are not available and so rather than guesstimate them, we consider it is more appropriate to rank the options in terms of their ability to provide resilience against such events. Another diversity benefit transmission can provide is access to a more diverse electricity supply. In some circumstances, new transmission will mean consumers in an area have access to more fuel sources than previously available.

The proposed option (9) will provide diversity benefits in the 110 kV network from the different configurations possible at Gore. This will aid restoration after an unplanned outage or failure compared to both the stage build option (8) and the reference case (0).

Operational benefits – to what extent does the option provide operational benefits not reflected in the economic analysis? Some options will provide operational benefits, for example by making outage planning easier. Other options may provide more flexibility to deal with the modified grid configurations required in dry hydrological years. Such benefits are not always reflected in GIT analysis. Some options may result in a more resilient grid, particularly to High Impact Low Probability (HILP) events. Such a benefit is particularly valuable, but notoriously difficult to quantify.

[22] Such developments include silicon, oil and gas and lignite extraction and processing. There is a high potential for such industries to develop in the region above and beyond what has been captured in the prudent demand forecast.

The proposed option (9) will provide high operational benefits compared to both the staged build option (8) and the reference case (0). In particular, maintenance of the 110 kV Gore–Brydone–Edendale–Invercargill circuits can be carried out in winter during the shutdown of the Fonterra dairy factory, and the maintenance on the rest of the network can be carried out during summer.

Alignment with long term grid development – to what extent is the option consistent with our longer term vision for the Grid. Our longer term vision for how the Grid should develop considers a longer time period than considered in the GIT. This factor considers whether an option is consistent with the long term vision, or whether considering a shorter term analysis period may have led to a different decision.

Aligns NZ government environmental goals – to what extent does an option conform to governmental environmental goals, not specifically reflected in the GIT e.g. moving toward a high proportion of renewable energy?

For this particular investment, there is little or no difference between the options in terms of the last two qualitative benefits so they have been omitted from the analysis.

For the others, a qualitative assessment of these benefits against each of the options is given in Table 5-3 below. The benefit for each option has been qualitatively ranked between ✓ (least benefit) and ✓✓✓ (most benefit).

The table also includes the GIT result and our conclusion for the overall preferred option.

Table 5-3: Qualitative assessment of non-quantified benefits and overall preferred option

Option	Expected Net Market Cost	Option benefits	Consumer benefits	Wider economic benefits	Minimises disruption	Diversity benefits	Operational benefits	Ranking of non quantified benefits
Reference Case	$49	✓✓✓	✓	✓	✓	✓	✓	4
Option 4 New Line	$70	✓✓	✓✓✓	✓✓✓	✓	✓✓✓	✓✓✓	2
Option 8 Staged Build	$48	✓✓✓	✓✓	✓✓	✓✓	✓✓	✓✓	3
Option 9 Full Build	$32	✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓	1

Although there is subjectivity involved in ranking the options, Option 9 ranks highly in terms of non-quantified benefits and higher than all other alternatives and as such it supports the outcome of the GIT analysis and the choice of this option as the Proposal.

5.1.4 Accuracy of GIT

There is an inherent level of uncertainty in the input assumptions and the formulation of the GIT analysis.

Taking this uncertainty into account, readers should be careful not to infer a level of precision that does not exist.

However, within the context of the Rules, Transpower considers that the rigour and comprehensiveness of the analysis undertaken is commensurate with the estimated capital expenditure required for the investment proposal. Based on the overall assessment of quantified and un-quantified benefits, Transpower considers the option selected by applying the GIT, the full build option (option 9) is the best option and satisfies the requirements for approval under the Rules.

5.1.5 GIT Analysis conclusion

Transpower considers that the full build option (option 9) satisfies the GIT because:

- it maximises the expected net market benefit (including accounting for the impact of non-quantified market benefits) when compared with the alternative projects
- it has a positive expected net market benefit
- it is robust to the results of sensitivity analysis.

5.2 Timing of the Proposal

The technical analysis has demonstrated that the existing grid configuration does not meet the Grid Reliability Standards now, so it is proposed to:

- install an interim SPS on the Brydone–Gore line and install shunt capacitors at Balclutha by 2012
- replace the interconnecting transformers at Roxburgh and Invercargill by 2013
- install two interconnecting transformers at Gore and complete associated works by 2014
- install a 50% compensation series capacitor on one circuit of the North Makarewa–Three Mile Hill line at Three Mile Hill by 2015.

6 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.

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.

6.1 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.

6.2 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 that Transpower provide any additional information under Rule 12.3.4.

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

6.3 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 with persons that the Commission thinks should be consulted with.

Transpower considers that, to date, it has complied with the Grid Planning Process as agreed with the Commission.

6.4 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 comply with any requests the Commission may have in accordance with the above requirements.

7 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.

8 Approval Amount for the Proposal

8.1 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 End Cost of the Proposal, is estimated to be $55.6 million and the MAC of the Proposal is estimated to be $62.4 million.

8.2 Approval amount methodology

Transpower proposes to use a formulaic Maximum Approval Cost (MAC). The MAC methodology allows 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 aids transparency and makes tracking of project costs against the approved amount simple.

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.

Table 8-1: Maximum Approval Cost

$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	40.7	46.9	-	-	-	-	-	46.9
Expected End Cost	40.7	46.9	0.2	-	-	6.1	2.4	55.6
Maximum Approved Cost	40.7	46.9	2.7	3.1	-	7.0	2.7	62.4

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

Appendix A Glossary

Term	Description
Alternative Project	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.
APR	Annual Planning Report
base case	The “counterfactual” for other options to be considered against.
Consultation Paper	Document published by Transpower in October 2008 outlining the project assumptions, methodologies and long lost of options.
expected project costs	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.
expected unserved energy	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.
GEIP	Good Electricity Industry Practice.
GEM	Generation Expansion Model, a model for generation expansion modelling developed by the Commission.
GIT	Grid Investment Test. 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.
GPS	Government Policy Statement on Electricity Governance.
GUP	Grid Upgrade Plan. A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules.
MAC	Maximum Approval Cost
modelled projects	Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur in a market scenario, are 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 the likelihood, nature and timing of which will be affected by whether the proposed investment or any alternative project proceeds.
Monte Carlo	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.
P90 cost	Estimated 90^{th} percentile of project costs.
Reference case	An “alternative” option against which the other options can be compared.
reliability investment	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.
Rules	The Electricity Governance Rules 2003. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments.
SCADA	Supervisory Control and Data Acquisition.
SDDP	Stochastic Dual Dynamic Programming, a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies.
SoO	Statement of Opportunities, published by the Commission.
Transpower	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.

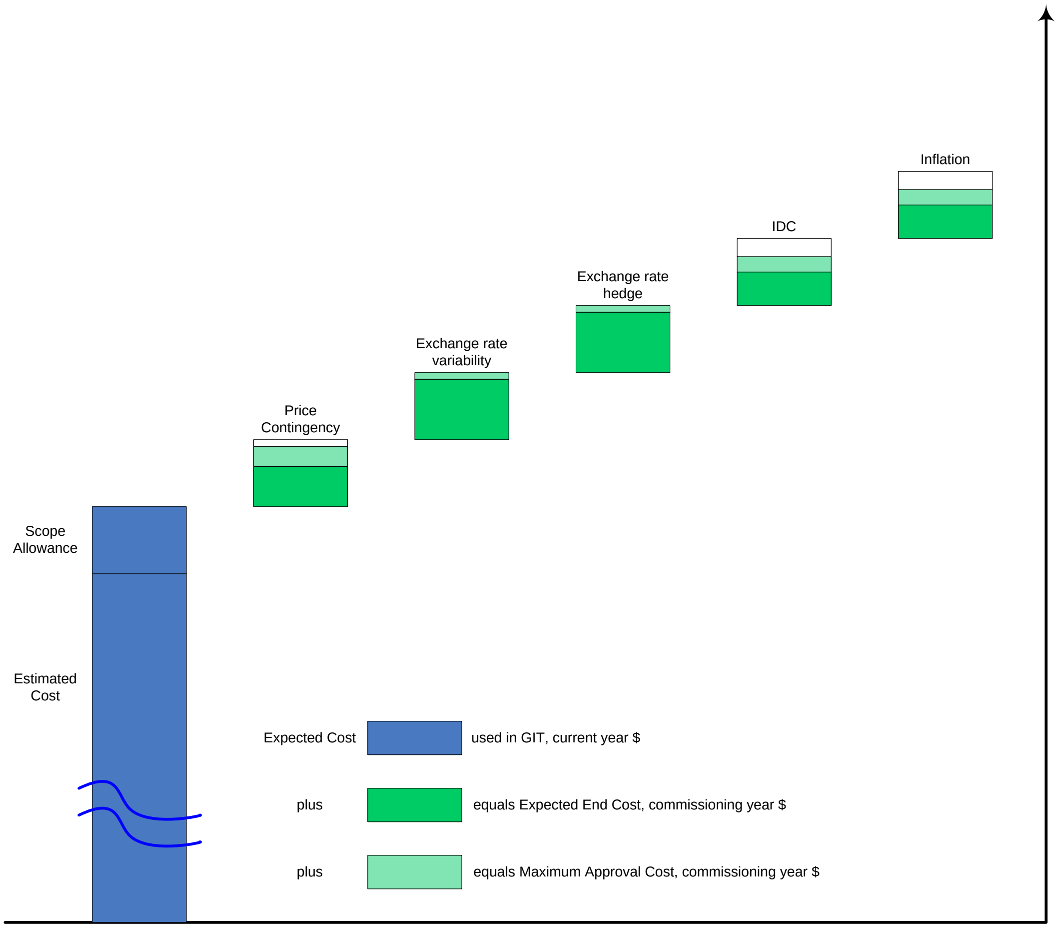
The Expected Cost of the Proposal, as used in the GIT, is estimated to be $46.9 million and the MAC of the Proposal is estimated to be $62.4 million. This section sets out how Transpower has estimated the MAC and describes the difference between the Expected Cost and the MAC.

Transpower is seeking approval for a MAC equivalent 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 is derived from a probabilistic analysis of the expected cost of the Proposal using a Monte Carlo approach.

Further description of the methodology for determining a MAC is given below.

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

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



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

- 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 such things as line routes are yet to be determined and there is also a reasonable time gap between approvals and when the majority of actual costs are incurred.

Appendix Figure B-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.

Method of calculating Maximum Approval Cost

The following inputs and variables are considered in deriving the Expect 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 at the Reference Date.
- **Reference Date.** Transpower prepared estimated capital costs as of May 2010. 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 determined what components of the project will be commissioned in each year from 2011 to 2015. The 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: (a) costs for works which are planned, but which have not been included in the estimated capital costs except through this general allowance, and (b) 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 price movements. Tender prices for some capital items include escalators linked to market price variations in significant elements of that item e.g. metals such as steel and copper. As with exchange rate variations, Transpower would not, typically, consider hedging anticipated commitments until a contract is awarded/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 a triangular distribution. A price contingency range of -10% to +10% is typical for this project.

For the purposes of calculating the Expected End Cost, the mean-point of this range is taken, i.e. 0%, for the example above.

For the purposes of calculating this MAC, the 85th percentile of this range is taken, i.e. 5%, 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 exchange rates as at 30 April 2010. These rates also apply in the Expected End Cost.

  For the MAC, the exchange rate variations are based on historical volatility and are estimated on the 50th percentile of the movement likely over the period between the 30 April 2010 and when tenders might be accepted. The methodology used to calculate the percentile volatility variation is as developed by Bancorp. The rates used are shown in the table below.

Appendix Table B-1: Foreign exchange rate assumptions

	Base rates 30 April 2010	6 months	18 months	30 months	42 months
USD	0.7245	0.6736	0.6141	0.5923	0.5883
EURO	0.5463	0.5184	0.5087	0.5000	0.5009
YEN	68.10	63.45	58.54	53.87	51.44
AUSD	0.7787	0.7572	0.7387	0.7259	0.7078

- **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. For this project, however, we have assumed that hedge costs would reflect the foreign exchange variability for the expected period between committing to contracts and the expected payment dates under those contracts. Hence the hedging costs are subsumed in the overall foreign exchange variation.
- **Real interest rates**. Real interest rates are used in the calculation of Interest During Construction costs and are assumed to vary between 3.4% to 5.4%, with a mean of 4.4%. The nominal interest rate is the real interest rate plus the inflation rate, equating to a mean nominal interest rate of 7.6% in this instance. This is approximately Transpower's current cost of debt.

  For the purposes of calculating the Expected End Cost, the mean of 4.4% 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 2010, is $46.9 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 $62.4 million and Transpower is seeking approval to recover the lesser of actual costs or the MAC. Appendix Table B-2 shows the break-down of the MAC.

Appendix Table B-2: Maximum Approval Cost for the Proposal, $ million

Expected Cost	Price Contingency	Exchange Rate Variability	Exchange Rate Hedge	Interest During Construction	Inflation	Maximum Approval Cost
46.9	2.7	3.1	0.0	2.7	7.0	62.4

The probability of exceeding the MAC is 10% (in fact the MAC has been set equal 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.

Summary of estimated Expected End Cost and Maximum Approval Cost

Transpower estimates the expected end cost, with variations accounted for, to be $55.6 million and the Maximum Approval Cost of the Proposal to be $62.4 million.