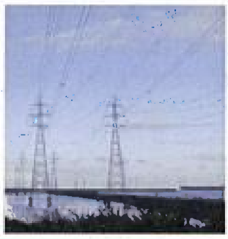
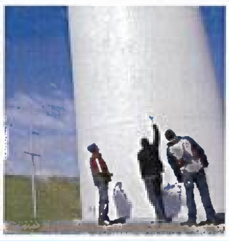
UPPER SOUTH ISLAND RELIABILITY STAGE 1

Major Capex Proposal

June 2012

Keeping the energy flowing



TRANSPOWER

Transpower New Zealand Limited The National Grid

1| Executive Summary

This proposal seeks to maintain a reliable supply of electricity into the upper South Island region by unlocking the full capacity of the existing grid in stages.

The upper South Island region comprises the entire South Island north of Twizel and Timaru including the West Coast.

Our Stage 1 Proposal seeks approval for installation of a bus coupler at Islington, a low cost measure which will allow end-of-life equipment to be decommissioned and at the same time provide at least two years deferral of major investment. We are also seeking approval to undertake remedial works to improve the resilience of our Islington substation to potential high impact but low probability large-scale events, installing equipment to allow for improved analysis of system performance and preliminary funding for a new transmission facility at Orari, near Geraldine.

Because of the low expected cost ($1.9m) of the proposed bus coupler relative to the additional system capacity it provides, we have concluded that non-transmission solutions are unlikely to be economic to meet the 2014 need (Stage 1). However, further investment may be required as early as 2016, for which we intend to submit a Stage 2 proposal early in 2013. We expect the Stage 2 investment will be more significant and non-transmission solutions may be viable to defer this investment.

Deferring the Stage 2 proposal until 2013 will mean some of the uncertainties, such as post-earthquake demand, should become clearer. The extra time will also enable us to refine the costs of transmission solutions and fully explore the viability of non-transmission solutions as a means of further deferring investment.

Stage 1 Proposal at a Glance	
What:	Install a new 220 kV bus coupler at Islington substation. Improve the resilience of our Islington substation to HILP events. Install load monitoring equipment in the upper South Island. Preliminary works for stage 2
When:	By 2015.
How much:	Transpower is seeking approval for up to $13.65 million ($2014-15).

Approximately 90% of peak electricity demand within the upper South Island region is currently supplied from the Waitaki Valley, via four transmission circuits. Such long distance transmission increases the need for voltage support.

Our existing upper South Island voltage support plant includes two end-of-life synchronous condensers and a static var compensator (SVC3) that requires mid-life refurbishment. All are located at Islington. There are also two relatively new devices – a second SVC at Islington and a STATCOM at Kikiwa at the top of the South Island.

Our studies show that unless new generation emerges in the region by 2014, investment in new or existing transmission plant, or non-transmission solutions, is required.

In June 2011, we consulted with our stakeholders on our approach, assumptions and long list of transmission and non-transmission options. As a result of that consultation, we assumed that significant new generation would be commissioned within the upper South Island over the next seven years. This now seems unlikely and we developed new generation scenarios, where new generation which previously appeared before 2020, is deferred for this Stage 1 Proposal. The new generation scenarios were consulted on as part of our short list consultation.

Our application of the Investment Test concludes that building a new transmission facility at Orari, is the leading option for Stage 2. Because of the time needed to construct the Orari facility, we need to start the process now to ensure it remains a potential option for Stage 2. As a result, our Stage 1 Proposal includes $2.14 million for preliminary work, which will allow us to determine the cost more accurately and start the processes for the necessary consents and easements.

Ensuring a resilient grid is a key theme in *Transmission Tomorrow*[1] - our strategic framework for how we see the grid developing over the next 20 years and beyond. A resilient grid not only meets grid planning guidelines, but ensures a robust supply of electricity to consumers following major unexpected events such as the Canterbury earthquakes. We often refer to these as high-impact low-probability (HILP) events.

Islington substation is, and will remain, critical for supply into the entire upper South Island region as it connects our transmission lines supplying power from the Waitaki Valley to Christchurch and further north to Nelson, Marlborough and the West Coast. Implementation of the proposed upgrades will increase our dependence on Islington. Thus, our Stage 1 Proposal includes a number of low-cost mitigations to markedly improve the resilience of the Islington substation to HILP events.

This document includes our proposal, outlines the need for investment, our modified generation assumptions, our short list of options, and our application of the Investment Test to those options. It also describes the rationale for the proposed resilience investments.

[1] http://www.transpower.co.nz/transmission-tomorrow

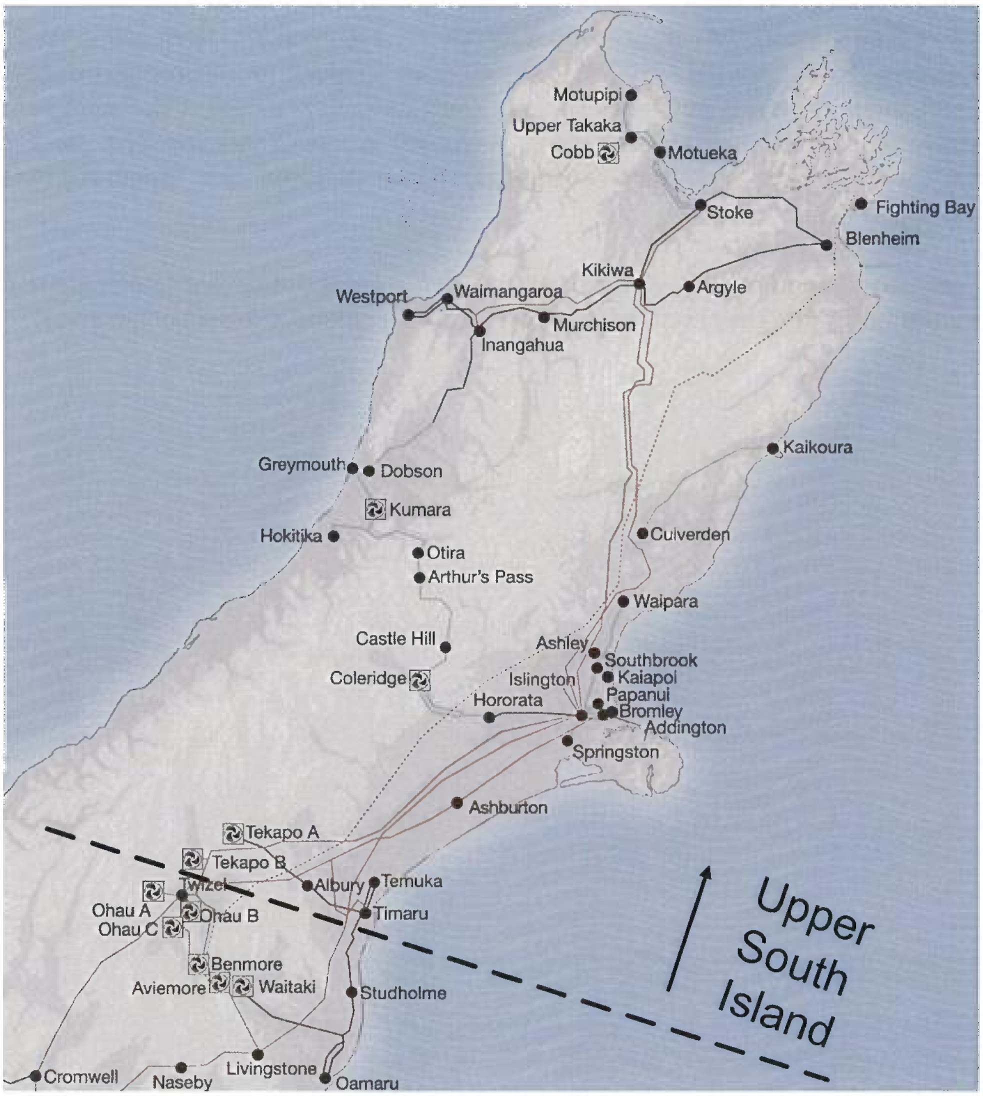
Contents

2| Introduction

Our Stage 1 Proposal comprises a range of investments, mostly within our Islington substation.

The upper South Island comprises that part of the South Island as shown in Figure 2-1 below.

Figure 2-1 Upper South Island region



The upper South Island does not have enough generation to meet electricity demand and the shortfall is supplied via our transmission lines into Islington and then further north.

Our planning studies have identified there is sufficient transmission capacity within the existing transmission lines to meet forecast peak demand until the late 2020s or 2030s, at which time we may need to build a new transmission line to Islington from the south.

However, our studies also show that, to access the available transmission capacity and thus defer the major investment of a new line, investment to address the need for additional voltage support is required for the upper South Island by 2014.

Transmission owners and distribution lines companies invest in voltage support devices or make changes to the configuration of their systems to reduce the need for voltage support. This ensures the system recovers safely from faults and the loss of assets, voltage stays within an acceptable range and any load lost is minimised to the extent practicable. Generation and demand response are alternatives to transmission investment in these circumstances, as they can reduce peak demand on the transmission system.

Examples of voltage support devices are capacitor banks, synchronous condensers, Static Var Compensators (SVCs) and STATCOMs. Configuration changes to transmission include reducing the quantum of assets automatically disconnected to clear a fault. One example is installing additional bus couplers at substations. A second is interconnecting long, parallel transmission lines at new switching substations, which reduces the length of line disconnected after a fault.

We have evaluated a range of options which will ensure our voltage recovery criteria are met using the Investment Test[2]. The results of our analysis are summarised in sections 6 and 7.

[2] The Investment Test is a prescribed cost benefit analysis, detailed in "Transpower Capital Expenditure Input Methodology Determination", dated 31 January 2012, which can be found at www.comcom.govt.nz

3| The Stage 1 Proposal

This section describes our Stage 1 Proposal.

3.1 Major Capex project outputs

Our Stage 1 Proposal comprises the following Major Capex project outputs:

- Installing a new 220 kV bus coupler at our Islington substation.
- Improving the resilience of our Islington substation to HILP events by:
    - upgrading the LVAC system at Islington
    - reducing exposure to damage from fire
    - strengthening Islington control building and crane hall to Building Act 2004 earthquake compliance.
- Installing 10 load monitoring units each at a different substation in the upper South Island.
- Refining the design for a new facility at Orari by way of a more detailed Solution Study Report (SSR).
- Undertaking preliminary processes to obtain consents and easements necessary for Orari.

3.2 Commissioning date assumptions

We will be starting this work in 2012 and completing it as shown below. The following are our commissioning date assumptions for our Stage 1 Proposal:

• New 220 kV bus coupler	Q2 2014
• Islington substation resilience measures	Q2 2015
• Install load monitoring equipment	Q1 2014
• Orari design	Q1 2013
• Preliminary processes	Q1 2013

3.3 Major Capex allowance

We expect the project to cost $12.1 million once commissioned. However, we are seeking Commerce Commission approval to recover the full costs associated with the Stage 1 Proposal, up to a total amount of $13.65 million. This amount includes allowance for uncertainties in the project costs and is the Maximum Capex Allowance required to implement the Stage 1 Proposal.

3.4 Approval expiry date

We consider that an appropriate approval expiry date for this Stage 1 Proposal is 2018.

An approval expiry date should not be close enough to the commissioning date assumption that it is triggered by reasonable commissioning delays. In this case, 2018 is quite close to the commissioning dates of 2014/15, but given the relative simplicity (from a build perspective) of the proposal, it is unlikely to be triggered by commissioning delays.

On the other hand, an approval expiry date should be a point at which it is clear that if a project has not been commissioned, something has changed and it will not be commissioned.

New generation might emerge as early as 2018 in the upper South Island. If this Stage 1 Proposal is not commissioned by then it would be reasonable to at least reassess whether it is still appropriate or not.

4| The Need

The upper South Island region does not have enough local generation to meet local demand, with the shortfall being met from distant generation. As a result, it is difficult to maintain voltage within an acceptable range after a fault and voltage support is required.

Capacitor banks provide low cost voltage support. While they provide steady state or *static* reactive support, they do not ensure voltage is maintained during power disturbances, when a rapid response (milliseconds) is required to maintain voltage quality and avoid the risk of a widespread loss of supply.

For such events, *dynamic* reactive support is required. Generators, synchronous condensers, Static Var Compensators (SVCs) and Static Synchronous Compensators (STATCOMs) all react rapidly and are used to provide dynamic reactive support.

Changing the configuration of transmission assets can reduce the need for dynamic reactive support. Options include installing additional bus couplers to reduce the number of assets lost during a fault, or segmenting long transmission lines (bussing) to reduce the length of transmission line lost when a fault occurs. A fifth bus coupler was added at Islington in 2008 in part to reduce the need for dynamic reactive support.

Static and dynamic reactive support is currently provided in the upper South Island by a combination of capacitor banks, synchronous condensers, and SVCs in Christchurch, and a STATCOM at Kikiwa near the top of the South Island.

As load grows in the region, so does the need for additional dynamic voltage support. Technical analysis is required to determine the timing requirement for new investment. To undertake the analysis, we make assumptions about the following key factors:

- Forecast electricity demand
- Forecast new generation
- Transmission line parameters
- Existing voltage support equipment at Islington
- Voltage recovery criteria

These factors are summarised below. Full details are available in Attachment B, Technical Analysis.

4.1 Forecast electricity demand

Underlying electricity demand in the upper South Island region continues to grow despite a drop following the recent Christchurch earthquakes. Our analysis assumes that upper South Island demand grows at an average 1.2% over the next 20 years and that the drop in demand resulting from the earthquakes is temporary[3].

Significant demand growth is forecast in Canterbury due to increases in irrigation for dairying.

[3] Note that in their May 2012 submission, Orion have indicated that even under the most optimistic scenario, population is not expected to return to pre earthquake levels until 2021 at the earliest. It is too soon to determine how this will impact peak demand but these changes to population forecasts will be accommodated in our update of the demand forecast later this year.

Forecast demand profiles for each grid exit point are used in the technical analysis. Our demand forecasts for the upper South Island were consulted on in June 2011 and are described in detail in Attachment C, Investment Test analysis.

4.2 Forecast new generation

Electricity generation in the upper South Island is another important input into the technical analysis. If sufficient new generation is built in the region, the peak electricity flows on the transmission circuits from the Waitaki Valley will not increase and further voltage support will not be required.

The new generation forecasts we initially used were based on the five market development scenarios (MDS) included in the Electricity Commissions 2010 Statement of Opportunities. We consulted on these forecasts in our June 2011 consultation and updated them accordingly. Those MDS are shown in Table 4-1. The data in red are the changes made to the Electricity Commissions original forecasts.

Table 4-1: Upper South Island region – June 2011 new generation assumptions

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Aorere River (Hydro, run of river)	52 MW 2040				
Arahura (Hydro, run of river)	18 MW 2040				
Arawata River (Hydro, run of river)	62 MW 2039				
Arnold, (Hydro, run of river)	46 MW 2017	46 MW 2017	46 MW 2017		46 MW 2023
Belfast (Diesel)		11.5 MW 2018			
Biomass in Canterbury	21 MW 2036				
Biomass in Nelson/ Marlborough	21 MW 2040				
Bromley (Diesel)		11.5 MW 2020			
Butler River (Hydro, run of river)	23 MW 2037				
Clarence to Waiau Diversion, (Hydro, run of river)	70 MW 2021				
Generic Solar in Nelson/ Marlborough	50 MW 2026 50 MW 2036				
Generic Wave West Coast	38 MW 2027				

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Hurunui (Wind)		76 MW 2020			
Interruptible load in Canterbury					30 MW 2033 +20 MW 2038
Lake Coleridge Development			70 MW 2020		
Matiri (Hydro)	5 MW 2020				
Mokihinui, (Hydro, run of river)	85 MW 2022		85 MW 2018		
Mt Cass (Wind)	34 MW 2039 +16 MW 2040	41 MW 2018	41 MW 2018		
Rakaia (Hydro, run of river)	16 MW 2018		16 MW 2018		
Stockton Mine (Hydro, run of river)				35 MW 2020	
Stockton Plateau (Hydro, run of river)	25 MW 2018				
Taipo (Hydro, run of river)	33 MW 2034				
Toaroha, (Hydro, run of river)	25 MW 2022	25 MW 2038			
Upper Grey (Hydro, run of river)	35 MW 2039				
Wairau, (Hydro, run of river)	73 MW 2020	73 MW 2020	-	26 MW 2035 +47 MW 2036	73 MW 2025

These five MDS provide a range of possibilities for new generation in the upper South Island, ranging from around 100 MW being built in the next 30 years, up to nearly 800 MW. None of the scenarios include enough new generation, early enough, to meet the short-term need.

However, these scenarios do reflect significant amounts of new generation being committed within the upper South Island over the next seven years. There is currently none committed, although there are several projects which are consented, or nearly consented. We recognise that generation investors are exposed to considerable uncertainty at the moment, particularly due to the current, "surplus" of generation and the Transmission Pricing Methodology review. Therefore, in our view, these scenarios now appear optimistic.

We have consulted on a modified set of scenarios, where new generation is deferred and believe these are more realistic. Based on the feedback we received from our long-list and short-list consultations, we have modified the June 2011 MDS as shown in Table 4-2, with the revised dates shown in green.

Table 4-2: Upper South Island region – modified new generation assumptions

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Aorere River (Hydro, run of river)	52 MW 2040				
Arahura (Hydro, run of river)	18 MW 2040				
Arawata River (Hydro, run of river)	62 MW 2039				
Arnold, (Hydro, run of river)	46 MW 2018	removed	removed	46 MW 2030	46 MW 2023
Belfast (Diesel)		11.5 MW 2022			
Biomass in Canterbury	21 MW 2036				
Biomass in Nelson/ Marlborough	21 MW 2040				
Bromley (Diesel)		11.5 MW 2022			
	23 MW 2037				
Marlborough Wind 1	300 MW 2018	300 MW 2022	150 MW 2020	150 MW 2026	
Marlborough Wind 2			150 MW 2024		
Clarence to Waiau Diversion, (Hydro, run of river)	70 MW 2030				
Generic Solar in Nelson/ Marlborough	50 MW 2026 50 MW 2036				
Generic Wave West Coast	38 MW 2027				
Hurunui (Wind)	76 MW 2018	76 MW 2020	76 MW 2022		
Interruptible load in Canterbury					30 MW 2033 +20 MW 2038
Lake Coleridge Development 1	20 MW 2020	20 MW 2021	20 MW 2020		

Name (type)	MDS1 Sustainable Path	MDS2 SI Wind	MDS3 Medium Renewable	MDS4 Coal	MDS5 High Gas
Lake Coleridge Development 2	50 MW 2025		50 MW 2025		
Matiri (Hydro)	5 MW 2020				
Mokihinui, (Hydro, run of river)	removed		removed		
Mt Cass (Wind)	34 MW 2039 +16 MW 2040	removed	41 MW 2022		
Mt Cass (Wind)	+16 MW 2040				
Rakaia (Hydro, run of river)	16 MW 2022		16 MW 2022		
Stockton Mine (Hydro, run of river)				35 MW 2020	
Stockton Plateau 1 (Hydro, run of river)	8 MW 2016	8 MW 2016	8 MW 2016	8 MW 2016	8 MW 2016
Stockton Plateau 2 (Hydro, run of river)	25 MW 2020	25 MW 2022	25 MW 2024		

(Colour key: original MDS, long-list consultation, short-list consultation, final)

The MDS do not specifically reflect new embedded generation. New embedded generation that we were made aware of during our 2011 consultation has been allowed for, as demand reductions. These assumptions have not been changed in the modified MDS.

4.3 Transmission lines

The capacity and electrical characteristics of transmission lines in the upper South Island are important parameters in the technical analysis.

New transmission lines alleviate the need for voltage support, but are expensive compared to other options to manage the need for voltage support until the transfer limit reaches the thermal capacity of the lines into the region.[4]

In this study it was found that a new line from the south may be required into Islington during the late 2020s or 2030s, depending on growth in demand and generation.

[4] This is also consistent with our general planning approach as outlined In Transmission Tomorrow. We recognise the high economic and social impact of transmission lines and minimise the number of transmission lines (our footprint) comprising the national grid. We always explore ways of utilising existing lines, or their footprint, before we will consider new lines. Exceptions can occur – in this study we are considering a new facility at Orari which includes a short section of new line and significantly reduces the need for voltage support.

4.4 Existing equipment condition

There are currently two synchronous condensers at Islington and two Static Var Compensators (SVCs) which provide voltage support to the region.

4.4.1 Synchronous condensers

The two synchronous condensers, C4 and C5, were installed in 1955 and provide a total of 60 Mvar of voltage support. In our 2007 studies it was assumed they would be refurbished and retained. Subsequent investigation has shown significant investment (circa $20 million), would be required to refurbish or replace the condensers to ensure their reliable and safe operation in the long term future. The C4 synchronous condenser has not been available since late 2009.

Figure 4-1: C4 synchronous condenser at Islington

The synchronous condensers have an inherent vibration characteristic. This is a source of nuisance to neighbours and as a consequence, the synchronous condensers are only run when absolutely necessary.

Their poor condition, coupled with the intractable vibration problem, has led us to conclude there is an unacceptable level of risk associated with continued operation in their current state beyond 2014.

Our asset management plan reflects the continued use of C5 on an "as necessary" basis until 2014, with C4 being kept for spares. Both synchronous condensers are due to be decommissioned in 2014.

Replacement with new synchronous condensers in 2014 or later, was one of the short-list options considered in our investigation.

4.4.2 Static Var Compensators (SVCs)

The two Static Var Compensators, SVC3 and SVC9 are modern voltage support devices. SVC3 was installed 15 years ago and SVC9 3 years ago.

The newer SVC9 is in good condition. TransGrid Solutions recently performed a condition assessment of the older SVC3 and they have recommended mid-life refurbishment. This includes replacement or refurbishment of the control system, the water cooling system, the 110V DC supply and the maintenance interface software within the next five years.

Figure 4-2: SVC3 at Islington

The estimated cost of the refurbishment is $11 million.

Decommissioning SVC3, refurbishment in line with these recommendations, and replacement with a new SVC, are all options that have been considered in our investigation.

4.5 Voltage recovery criteria

Our voltage recovery criteria ensure the power system recovers to a stable state and generating units remain connected. Otherwise, loss of generation within the region during a fault or temporary removal of transmission assets could lead to widespread loss of supply.

Between the pre- and post-event steady state conditions, the voltage recovery criteria define voltage maximum and minimum envelopes within which the system voltage recovery trajectory must lie. They are described in detail in Attachment B, Technical Analysis.

Transient analysis is used to identify the maximum demand that can be supplied to a region after a disturbance, while maintaining satisfactory voltage performance.

This analysis considers:

- the behaviour of motor loads as they stall and then speed up again
- transient voltages caused by load disconnecting during faults
- the performance of dynamic reactive devices such as SVCs, STATCOMs
- the performance of generator automatic voltage regulators (AVRs).

Voltage following a disturbance is plotted during the transient recovery phase of around five seconds. During the outage and recovery phase, the system voltage must adhere to the voltage recovery criteria.

4.5.1 Motor Load Assumptions

During the voltage recovery phase some motors loads may disconnect. When they do, unserved energy is incurred. Under some circumstances, it may be economic to avoid motor load disconnecting by advancing or increasing the capacity of dynamic reactive investment.

In these instances, we can assess the energy not served and use an appropriate Value of Lost Load to determine whether further investment is economic or not.

In undertaking our investigation, we realised that the information we have on motor loads in the upper South Island should be further enhanced to aid economic assessment for future investment beyond Stage 2. Our Stage 1 Proposal therefore includes an allowance to install load monitoring equipment to gather long-term performance data on major faults to better inform us of the nature and potential impact of motor load disconnections in the region.

4.6 Need date

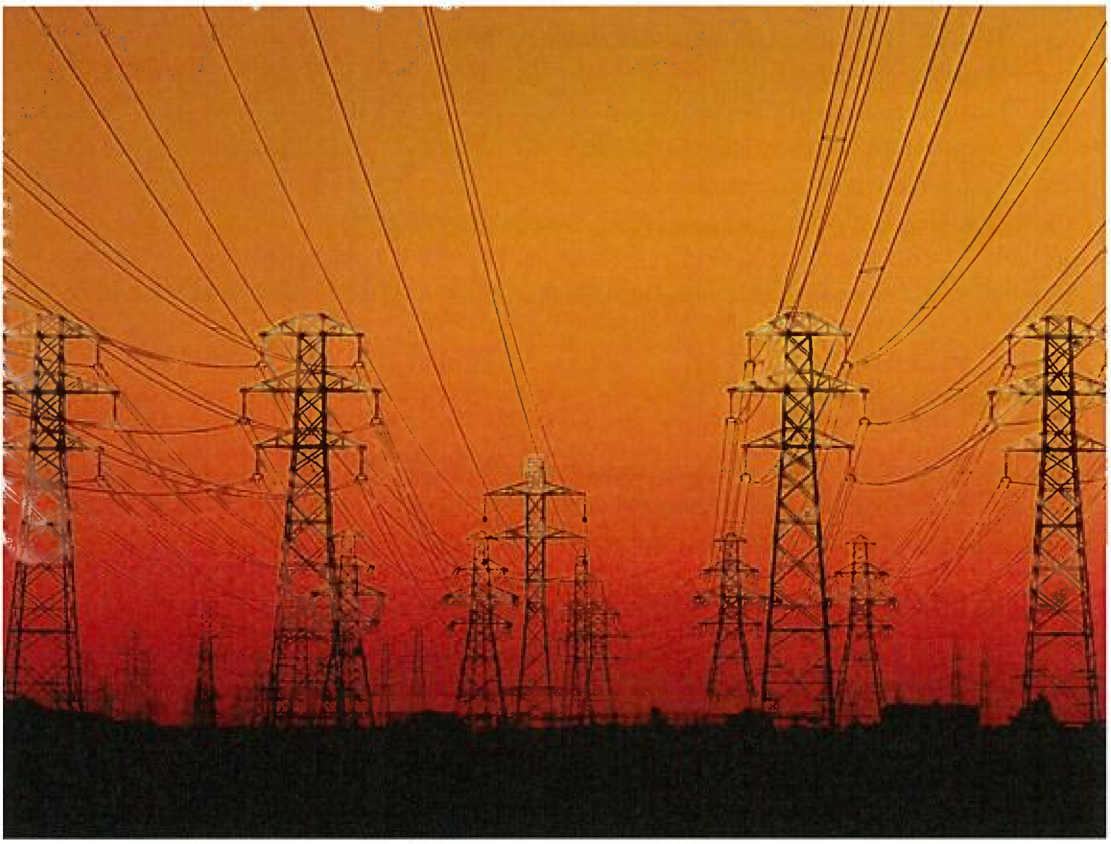
Using these assumptions and assuming the Islington synchronous condensers are decommissioned in 2014, our technical analysis has identified that further investment in voltage support is required by 2014. The details are described in Attachment B, Technical Analysis.

5| Resilience to HILP events

Ensuring a resilient grid is a key theme in *Transmission Tomorrow*[5] - our strategic framework for how we see the grid developing over the next 20 years and beyond. A resilient grid not only meets grid planning guidelines, but ensures a robust supply of electricity to consumers following major unexpected events. We often refer to these as high-impact low-probability (HILP) events.

Islington substation is critical for supply into the entire upper South Island region as it connects our transmission lines supplying power from the Waitaki Valley to Christchurch and further north – to Nelson, Marlborough and the West Coast. Our investment options continue, or increase, this dependency. As a result, Islington must be highly resilient to HILP events.

Figure 5-1: Existing lines as they converge at Islington substation



Our analysis has shown that remedial measures, discussed below, are needed to improve the resilience of Islington substation to fire and earthquake risks and that an upgrade of the substation low-voltage AC supply is required.

A technical report outlining the analysis undertaken and the recommendations can be found in Attachment E, HILP analysis.

[5] http://www.transpower.co.nz/transmission-tomorrow

Earthquake Strengthening (Seismic)

While the recent, localised seismic events in Christchurch have left the Islington site relatively unscathed[6], analysis suggests the site is exposed to a catastrophic earthquake event at other locations such as on the Alpine Fault.

Significant strengthening work is required to bring the control building and crane hall up to seismic standard, at an expected cost of $2.3 million.

The proposed strengthening is consistent with the requirements for earthquake prone buildings in the Building Act 2004 and the lifeline facilities prescribed in the Civil Defence and Emergency Management Act 2002 and with the recommendations of the New Zealand Society for Earthquake Engineering.

Fire protection

A review of the fire hazards at Islington recommended the following:

- Provide sprinkler protection in the cable basement
- Upgrade fire doors
- Install smoke seals
- Apply intumescent coating to cables
- Install early detection equipment
- Design and install a hypoxic system for the relay room

These measures are consistent with our draft fire policy. The total cost is expected to be $3.2 million.

Low Voltage Supplies

The Low Voltage Alternating Current (LVAC) system at Islington was also identified as a risk. It supports the operation of all equipment and control systems at Islington. The existing LVAC system has no spare capacity and has several risk areas. For example:

- the main LVAC switchboard is a single point of failure for the entire LVAC system
- manual switching is required to supply load from the backup generator in the event of loss of normal supply
- the service transformers are adjacent to the control building, the main entrance to the substation, and to the backup generator's diesel tank and are a fire hazard.

The investigation recommended a list of modifications aimed at eliminating identified risks and hazards associated with the existing LVAC system and improving flexibility, operation and maintenance of the system. The total cost of these measures is expected to be $2.0 million.

Our Stage 1 Proposal increases our reliance on Islington, so we consider it prudent for the proposal to also include the necessary investment to improve its resilience.

These costs have not been included in the Investment Test analysis since they are common to all options and would not affect the result.

[6] As an example, ground motions at Islington were not at high as at Bromley, where we incurred material damage.

6| Options

The technical analysis identified that further voltage support is required in the upper South Island by 2014.

Our modified generation MDS assume that new generation will not be commissioned until 2018 at the earliest.

6.1 The Options

A long list of possible options was developed and consulted on in June 2011[7]. The draft long list of options included:

- Add sixth bus coupler at Islington
- Double breakering at Islington
- Double teeing circuits at Bromley
- New switching station
- Bus circuits at Orari, near Geraldine
- Refurbishment or replacement of synchronous condensers
- Static compensator (STATCOM) connected to a 220 kV bus in the upper South Island region
- Static var compensators (SVC) connected to the 220 kV bus in the upper South Island region
- STATCOM at Islington on T6 and T7 tertiary
- Multiple small STATCOMs
- Shunt capacitor banks
- Series compensation
- Non-transmission solutions such as new generation and demand-side options

Submissions to the consultation included:

- Orion offering the development of Belfast and Bromley sites as a diesel generation alternative to transmission
- Energy Response Pty Limited offering their services as an aggregator for demand-side participants
- Metering Technology Ltd detailing their load management system and advocating this to be rolled out nationally.

This feedback was incorporated into the long list prior to producing a short list of options. We have included our assessment of the long list to short list process in Attachment A, Long-list to short-list options report. We have summarised the key points below.

The short-list options were generated by ruling out long-list options that are not feasible for this project or clearly not cost-effective – see Table 6-1.

[7] http://www.gridnewzealand.co.nz/publications-and-resources

Table 6-1: Short-listing summary

Option		Short-Listed?	Reason
	Non-Transmission Solutions		
a)	New generation	✗	None significant committed
b)	Existing generation grid support contract	✗	Already accounted for in power system analysis
c)	Diesel generation	✓	Belfast and Bromley consented
d)	Upper SI load controller	✗	Already accounted for
e)	Special Protection Scheme (SPS)	✗	Too slow, no proponents for load shedding
f)	Fuel switching	✗	Not viable on scale required
g)	Energy efficiency	✗	Not viable on scale required
h)	Local network augmentation	✗	Not feasible on scale required
i)	System Operation improvements	✗	Already achieved via RPC
j)	Ancillary services	✗	Generation: none significant committed
k)	Pre-contingency load shedding	✓	May not be economic
	Transmission – Existing Assets		
a)	Tee 220 kV circuit near Bromley	✗	Only minor improvement
b)	Reconductor existing transmission circuits	✗	Too expensive for marginal improvement in voltage stability
	Transmission – New Assets		
a)	Sixth bus coupler at Islington	✓	Avoids pairing of north and south circuit during bus fault, <$2M
b)	Double breakering at Islington	✗	Similar effect and cost to bus coupler, but with less option value
c)	Islington 220 kV bus tie circuit	✗	Only helps during bus maintenance, $10M
d)	Pound Rd switching station	✗	Only minor improvement in voltage stability, many $10Ms
e)	+/- 80 Mvar STATCOM at Islington (or Bromley)	✓	Increases voltage stability limit, high-level economics ok
f)	+/- 40 Mvar STATCOM on Islington T6 and T7	✓	Smaller STATCOM on 11 kV tertiary may be cost effective
g)	SVC at Ashburton	✗	Reconfiguration of 220 kV bus required or 66 kV solution less useful
h)	SVC at Islington (or Bromley)	✓	Increases voltage stability limit, high-level economics ok
i)	Refurbish SVC3	✓	Increases the voltage stability limit
j)	New synchronous condensers	✓	Provide inertia and modern ones have fast controllers
k)	STATCOMs on the West Coast	✗	Worst contingency is at Islington
l)	SVCs/STATCOMs north of Christchurch	✗	Not as effective as Islington or Bromley
m)	Shunt capacitors	✓	Additional static reactive support required
n)	Shunt reactors	✓	Manage high voltage issues during light load
o)	Orari bussing	✓	Reduces the impact of a single line outage
p)	Series Capacitors	✗	Too expensive at $80M

Option	Short-Listed?	Reason
q) New AC Transmission line from the Waitaki Valley to Christchurch	✘	Too expensive at $350M until reactive limit increased and thermal limit is binding
r) North Canterbury HVDC Tap-off	✘	Too expensive at $100Ms

The short listing process identified a range of options which could be used for this purpose. Each option on its own addresses the voltage support need for a different number of years and more than one investment will be required over time. Therefore, we built up a number of development plans, using different combinations of the short-listed voltage support options.

Each development plan continues to the point where the new line is required. The technical analysis identified a year at which a new line would be required into Islington from the south. The year varies by MDS. Clearly, that prospective line is many years away, and generation or demand scenarios (or technology options) may develop which remove any need for it. However, until that line is built, or the other scenarios develop, we will face the need for increasing voltage support.

We evaluated many plans and found that it was always cheapest to start with the installation of a new 220 kV bus coupler at Islington in 2014. With an expected cost at commissioning of $1.9 million and increase in system limit of 95 MW, this low cost transmission solution is always the logical first step ahead of the investment in other short-listed options with a higher capital cost. It will defer the need for further investment in the upper South Island until at least 2016.

Our assessment is that diesel generation to defer the need for investment to 2016 would cost a minimum $2.9 million and that demand-side response would cost a minimum $3.3 million.

The six cheapest of these development plans, along with three which include diesel generation as an alternative to installing the bus coupler, form our short-listed development plans.

The nine short-listed development plan options are shown in Table 6-2:

Table 6-2: Short-listed development plan options

	Investments required in each development plan option			
Option	2014	2016	2018 (if required)	post 2018
1	Bus Coupler 6	Refurbish SVC3	Orari bussing	New line
2	Bus Coupler 6	Orari bussing		New line
3	Bus Coupler 6	Refurbish SVC3	New SVC	New SVC, new line
4	Bus Coupler 6	New SVC		New SVC, new line
5	Bus Coupler 6	Refurbish SVC3	New sync conds	New SVC, new line
6	Bus Coupler 6	Refurbish SVC3	New STATCOM	New STATCOM, new line
7	Diesel generation	Orari bussing		New SVC, new line
8	Diesel generation	Refurbish SVC3, new SVC		New SVC, new line
9	Diesel generation	Refurbish SVC3, new		New STATCOM, new

STATCOM	line

Table 6-2 shows a succession of need dates. After the new 220 kV bus coupler or diesel generation in 2014, further investment is needed in 2016 and then again, in some development plans, by 2018. The right hand column of Table 6-2 shows the investments required after 2018. The timing for the new line varies between 2028 and 2050.

Our economic analysis determines the total cost of each development plan out to 2050, using the capital costs for each element in the plan, the resultant operating and maintenance costs and other cost differences as detailed in section 7.2.

The costs are then discounted to a present value and the option with the lowest present value cost[8] satisfies the Investment Test.

6.2 Stage 1 Investment

Note that while we apply the Investment Test to the entire development plan to arrive at a preferred development path, this Stage 1 Proposal is concerned only with the investment required in 2014 and preparatory investment for 2016. Our Stage 2 proposal will optimise the economic timing of the 2016 need.

We have taken this approach because of the potential for non-transmission solutions (NTS) to economically defer the investment requirement in 2016 as well as the uncertainty around demand growth in the region.

6.2.1 Non-transmission solutions (NTS)

Given the low cost of the Stage 1 investment to manage the need for voltage support ($1.9m), we are of the view that there are no economic NTS that could meet the 2014 need date.

We have tested this in Options 7, 8 and 9, which assume diesel generation is used as a replacement for the bus coupler. Using a combination of the actual costs for the demand-side trial run in the upper South Island in 2007 and feedback from the upper North Island demand-side initiatives Request for Proposal in 2011, we have also evaluated demand-side response as an alternative, but similarly do not consider it would be economic to meet the 2014 need.

The same does not apply for the Stage 2 investment, which may cost more than $50 million. As a result there is a strong benefit to encouraging viable NTS options to defer the need for transmission investment in 2016 in particular, the control of peak loads. NTS could also be used as a means of mitigating the delivery risk of the Stage 2 option.

6.2.2 Demand growth uncertainty

As discussed earlier, our technical analysis assumes that demand recovers to pre-earthquake levels[9]. Should this not be the case, the need date for Stage 2 investment could be deferred beyond 2016.

[8] Under the Capex IM, to satisfy the Investment Test a proposed investment must maximise expected net electricity market benefit. Our lowest cost approach is the same and is used for ease of presentation.

[9] Note that in their May 2012 submission, Orion have indicated that even under the most optimistic scenario, population is not expected to return to pre-earthquake levels until 2021 at the earliest. .

7| Selecting the investment proposal

This section covers the:

- application of the Investment Test
- robustness of the investment proposal against changes in assumptions.

Under the Capex Investment Methodology (IM), to satisfy the Investment Test a proposed investment must have a positive expected net electricity market benefit unless it is required to meet the deterministic limb of the grid reliability standards. Investment in voltage support for the upper South Island falls into this category. For presentation purposes, all costs and benefits are shown here as costs. This simplifies the presentation and does not affect the result. The least-cost option passes the Investment Test. This produces exactly the same outcome as calculating expected net market benefit, as explained in Attachment C. Attachment F, which demonstrates how our proposal meets the detailed requirements of the Capex IM, uses expected net market benefit.

7.1 Application of the Investment Test

We applied the Investment Test using the modified MDS for each of the nine short list development plans.

7.2 The Costs

The cost of the nine short listed development plans are the costs incurred for the entire development plan, including:

- **Capital costs**

  The expected capital costs to install and commission each element of the development plan. The expected capital costs are listed in Attachment A – Long-list to short-list options report.

- **Contracting costs**

  The expected contracting costs for NTS.

- **Operating and maintenance costs**

  The ongoing operating and maintenance costs of capital equipment.

- **Reactive loss costs**

  Reactive devices such as SVCs and STATCOMs are electrical devices and consume energy while they are operating. Bus couplers are static devices and do not consume energy. We have calculated the amount of energy consumed by the reactive devices in each development plan over the analysis period to identify the reactive loss cost.

- **Transmission loss costs**

Transmission loss costs arise because the different development plans result in different flows over the transmission lines between the Waitaki Valley and grid exit points as far away as the West Coast. We have used the Digsilent modelling tool to calculate the transmission losses at peak. These are then scaled to average losses and valued at a long run marginal cost of generation. We have used a value of $120 per MWh, but have also included a sensitivity of $60 per MWh.

- **Unserved energy**

  Even with a reliable and resilient network there is still some chance of loss of supply. We cost this at the value of unserved energy, $24,200/MWh[10]. The main reliability difference between options is that dynamic reactive devices are about 99% reliable and circuits 99.9%+ reliable.

The total costs have been calculated for each development plan under each MDS. The MDS have been weighted equally to arrive at the figures shown in Table 7-1.

The third column shows the expected cost of each development plan option out to 2050, expressed as a Present Value (PV) to account for phasing of the required works.

The final column shows the difference in costs between the options, relative to the cost for Option 6. Option 6 is the cheapest development plan overall and is the reference case we compare others too.

Table 7-1: Development plan net market costs, modified MDS (Present Value 2012 $m)

Option	Description	Present Value Expected costs (2012 $m)	Present Value Relative Expected costs (2012 $m)
1	BC6, refurb SVC3, Orari bussing	178.7	5.1
2	BC6, decomm SVC3, Orari bussing	174.9	1.3
3	BC6, refurb SVC3, new SVCs	179.1	5.4
4	BC6, decomm SVC3, new SVCs	175.9	2.2
5	BC6, refurb SVC3, new sync cons, new SVCs	199.9	26.2
6	BC6, refurb SVC3, new STATCOMs	173.6	0.0
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	192.6	19.0
8	Diesel gen, refurb SVC3, new SVCs	196.4	22.7
9	Diesel gen, refurbish SVC3, new STATCOMs	207.0	33.4

The expected costs are high because they include the new line as a modelled project, indicatively estimated at $500 million. The new line costs are included because its timing varies between the options within MDS, and this affects the overall cost. It should be noted that the timing of the new line is determined by the thermal limit which will vary depending on when new generation emerges. However, the near term options within each development plan are required to meet voltage stability limits so will not, in themselves, affect the timing of the new line.

A positive value in the final column indicates a higher cost than Option 6.

10 $20,000/MWh in 2004 inflated to 2011 as per our June 2011 consultation.

7.3 Options 2, 4 and 6 are similar

Under the Investment Test, options can be considered "similar" if the difference between the expected net market benefit is less than 10% of the cost of the option to which the proposal is being compared. In such cases, unquantified benefits may be used to differentiate a preferred investment.

In this case, when considering whether to include the 2016 investment in our proposal, we found that two options were similar to our reference case, Option 6.

Table 7-2 shows the difference between the expected net market benefit as a percentage of the expected cost of the 2016 investment for each option. As seen, the difference for options 2 and 4 is less than 10% of the expected cost of the investment required in 2016, hence we conclude that these options are similar.

This means that we consider Orari bussing, installation of a new SVC and refurbishing SVC3 similar and we should use unquantified benefits to determine the preferred investment as detailed in section 7.5.

Table 7-2: Similarity of options

Option	Description	Present Value Expected Cost 2016 investment option (2012 $m)	Present Value Relative Expected Net Market Benefit (2012 $m)	% Expected Net Market Benefit of Expected Cost
1	BC6, refurb SVC3, Orari bussing	7.8	5.1	65%
2	BC6, decomm SVC3, Orari bussing	41.4	1.3	3%
3	BC6, refurb SVC3, new SVCs	7.8	5.4	69%
4	BC6, decomm SVC3, new SVCs	21.4	2.2	10%
5	BC6, refurb SVC3, new sync cons, new SVCs	7.8	26.2	336%
6	BC6, refurb SVC3, new STATCOMs	7.8	0.0	0%
7	Diesel gen, decomm SVC3, Orari bussing, new SVCs	41.4	19.0	46%
8	Diesel gen, refurb SVC3, new SVCs	7.8	22.7	291%
9	Diesel gen, refurbish SVC3, new STATCOMs	7.8	33.4	428%

7.4 Expected Net Electricity Market Benefits by MDS

The results by MDS are shown in Table 7-3.

Table 7-3: Expected net market cost (present value 2012 $m) relative to Option 6 by MDS

Option	Description	Expected Net Market Benefit relative to Option 6 (Present Value 2012 $m)						
		No gen	MDS1	MDS2	MDS3	MDS4	MDS5	Avg
1	BC6, refurb SVC3, Orari bussing	1.0	-1.2	7.8	9.5	3.0	6.3	5.1
2	BC6, decomm SVC3, Orari bussing	-7.1	12.6	-0.5	1.0	-5.0	-1.9	1.3
3	BC6, refurb SVC3, new SVCs	8.6	-5.4	9.9	4.0	8.2	10.5	5.4
4	BC6, decomm SVC3, new SVCs	1.0	2.8	1.4	0.5	0.3	6.1	2.2
5	BC6, refurb SVC3, new sync cons, new SVCs	31.3	17.4	27.4	28.0	31.2	27.2	26.2
6	BC6, refurb SVC3, new STATCOMs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Diesel, decomm SVC3, Orari , new SVCs	17.7	16.6	19.1	18.3	17.6	23.3	19.0
8	Diesel gen, refurb SVC3, new SVCs	27.8	20.2	19.3	17.9	26.2	30.1	22.7
9	Diesel gen, refurbish SVC3, new STATCOMs	35.6	31.3	34.5	27.3	34.4	39.4	33.4

In this table, the 1st, 2nd and 3rd ranked options for each MDS are highlighted in gold, silver and bronze respectively.

This table illustrates how sensitive the outcome is to the generation assumptions. In particular, it shows that Option 6 or 4 is preferred in those MDS where there is a reasonable amount of new generation built in the upper South Island during the 2020s, whereas Option 2 is preferred in those MDS where there is little or none built in that period.

Option 6 reflects minimal investment in transmission due to the impact of increased generation build.

If little, or no, new generation appears during the 2020s the results indicate we should invest in Orari bussing.

The expected cost of development plan for Options 2, 4 and 6 are within $2.2 million of each other on a present value basis. We have determined that the difference in quantum between the quantified expected net electricity market benefit of our reference case,[11] Option 6 (being the option with the highest expected electricity market benefit where only quantified electricity market benefit or cost elements are taken into account), and the expected net electricity market benefit of Options 2 and 4 is 10% or less of the aggregate project costs of Option 6. The analysis supporting this conclusion is set out in Attachment C.

Accordingly, we have undertaken a qualitative assessment taking into account the contribution to the expected net market electricity benefits of associated unquantified electricity market benefit or cost elements.

7.5 Unquantified benefits

Our qualitative assessment shows the relativity between the options as in Table 7-4 below.

[11] There is no requirement to define a reference case under the Capex IM. We have only done so for ease of presentation of the Investment Test results. The reference case is the lowest cost overall development plan, but this does not imply it is the most economic, or preferred option in any way.

The benefit for each option has been qualitatively assessed between ✓ and ✓✓✓, where ✓✓✓ means more benefit than ✓.

Considering both the Investment Test result and the qualitative assessment, our overall ranking of the options is then shown at the bottom of Table 7-4.

Table 7-4: Qualitative assessment non-quantified benefits (NQB) and overall preferred option

Item	Option 2	Option 4	Option 6
Expected Net Market Benefit	-1.3	-2.2	0
Other benefits:			
• Option benefits	✓✓✓	✓✓✓	✓✓✓
• Robust to no new generation	✓✓✓	✓✓	✓✓
• Consumer benefits through enhanced competition	✓	✓	✓
• Minimises disruption	✓	✓✓✓	✓✓✓
• Diversity benefits	✓	✓✓	✓✓
• Operational benefits	✓✓✓	✓	✓
• Aligns long term grid development	✓✓✓	✓✓	✓✓
Overall ranking ENMB + NQB	1	3	2

The following benefits have been considered:

Option benefits – does the option include flexibility to be amended in the future if there are significant changes?

We do not consider there are any significant variation between Options 2, 4 and 6 for option benefits because new investment in voltage support can be added in all options, if required, with the same lead time.

Robust to no new generation – is the option still economic if new generation does not appear in line with the MDS?

Option 2 is the most economic if new generation does not appear in line with the MDS, so does have an advantage in being robust to no new generation which at this stage appears the most likely outcome.

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.

The options are equivalent in terms of enhancing competition in the upper South Island.

Minimises disruption – to what extent will the local community be disrupted by the implementation of an alternative?

Option 2 involves more disruption to the community and landowners because it involves building a new transmission facility with a short section of transmission line, whereas Options 4 and 6 involve development within our existing substation at Islington.

Diversity benefits – to what extent will the option provide diversity of supply?

Option 2 potentially reduces diversity by creating a common point of connection. All practical steps would be taken to reduce this risk, including having two separate switchyards with physical separation, civil works designed to cope with one in 450-year floods, and appropriate breaker/bus configurations.

Operational benefits – to what extent does the option provide operational benefits not reflected in the economic analysis?

Option 2 has operational benefits compared to Options 4 and 6. These arise because Option 2 will make outage planning of the circuits into Islington easier and because Option 2 may allow Alpine Energy and other lines companies to avoid distribution costs:

- Orari is within the Alpine Energy network. We are currently investigating[1] supply to the Alpine network as the Timaru interconnecting transformers are nearing their capacity. Options involving a new point of supply from the 220 kV circuits north-west of Temuka may be lower-cost if the Orari bus is built. The extent of the benefit depends on the alternative connection configuration and location, and whether this becomes the preferred option following the Timaru investigation.

- Option 2 has the advantage of increasing security during maintenance, voltage quality and connection option flexibility and could have value if more supply points are needed by Network Waitaki, Alpine Energy, Electricity Ashburton or Orion.

- Option 2 lessens our dependence on increasing numbers of reactive support devices and associated control equipment. These are not as easy or quick to repair compared to transmission lines and core primary plant and add complexity to grid operation.

None of these benefits are easy to quantify at present.

Aligns 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 investment test analysis. 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.

Option 2 is better aligned with our long term development of the grid as it maximises the capability of existing transmission assets without the need for voltage support. Introducing

[1] http://www.gridnewzealand.co.nz/n5475.html

more reactive devices increases the complexity of the grid. Option 2 also provides another future site for the installation of reactive support, if they were to be required in the future.

In conclusion, having considered both the quantified electricity market benefit or cost elements and unquantified benefits we believe that Option 2 subject to robustness, discussed below, satisfies the Investment Test.

7.6 Robustness of the economic results

The Investment Test results have been tested against a range of sensitivities. The future is uncertain and it is important that we "stress test" the results. By adjusting key variables we can assess how robust the economic results are to changes in assumptions.

We have considered the results of our analysis against the following sensitivities:

- High and low demand
- Changes in capital costs
- Changes in maintenance costs
- Changes in diesel generation costs
- Changes in discount rates
- Changes in exchange rates
- Cost of losses
- Value of Lost Load

We have also considered the results for individual generation scenarios analysis as shown in Table 7-3. The results of the sensitivity analysis are shown in Table 7-5. All numbers are expected cost, present value in $2012, relative to Option 6.

Table 7-5: Investment Test sensitivities – expected cost relative to Option 6

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9
Analysis Results	5.1	1.3	5.4	2.2	26.2	0.0	19.0	22.7	33.4
Sensitivities									
Demand									
High	4.7	-3.5	7.8	2.5	31.0	0.0	19.7	25.6	38.2
Low	4.5	-0.7	4.8	0.1	22.9	0.0	15.5	20.3	30.2
Capital Cost									
120%	7.7	4.5	6.5	3.4	29.9	0.0	24.5	26.3	38.1
80%	2.5	-2.0	4.4	1.0	22.6	0.0	13.4	19.2	28.7
Maintenance									
120%	5.2	1.3	5.4	2.2	26.2	0.0	19.0	22.8	33.5
80%	5.0	1.2	5.4	2.3	26.3	0.0	18.9	22.7	33.3
Diesel Gen Cost									
120%	5.1	1.3	5.4	2.2	26.2	0.0	19.5	23.2	33.9

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9
80%	5.1	1.3	5.4	2.2	26.2	0.0	18.5	22.2	32.9
Discount Rate									
4%	-0.8	-13.5	9.1	0.9	37.2	0.0	13.8	30.2	46.6
10%	7.0	8.1	3.5	2.8	19.6	0.0	20.4	18.3	25.7
Exchange Rate									
120%	8.3	5.9	4.3	1.0	23.9	0.0	21.9	19.7	29.9
80%	0.2	-5.8	7.1	4.1	29.7	0.0	14.5	27.2	38.7
Cost of losses									
$60/ MWh	7.6	5.4	6.0	3.8	22.6	0.0	22.5	22.9	31.5
Value of Lost Load									
150%	5.2	1.0	5.6	2.4	26.5	0.0	20.4	23.8	34.2
50%	5.0	1.5	5.2	2.1	26.0	0.0	17.5	21.7	32.6

All of the options with the 6th bus coupler are robustly cheaper than those which include diesel generation.

The results also show that Option 2 can be considered similar in all but six of the sensitivities. These include the sensitivities in which the discount rate is changed, the exchange rate changes considerably and the cost of losses is only $60/ MWh.

It would be expected that relatively high capital cost options, such as Option 2, would appear cheaper using a low discount rate and more expensive using a high discount rate. Similarly, Option 2, which has a smaller component of foreign exchange than other options, is cheaper when the exchange rate weakens, but becomes more expensive when the exchange rate strengthens. Option 2 is not similar in the "cost of losses" sensitivity because transmission losses are a reasonably significant cost.

We believe this sensitivity analysis does not change our conclusion that Option 2 is preferred and demonstrates it is sufficiently robust to meet the requirements of the Investment Test.

As a further sensitivity, we have evaluated the Investment Test using the June 2011 MDS, rather than the modified MDS. These results are shown in Table 7-6.

Table 7-6: Expected net market cost (Present Value 2012 $m) relative to Option 6 by MDS using June 2011 MDS (excludes consultation submissions)

Option	Description	Expected Net Market Benefit relative to Option 6 (Present Value 2012 $m)						
		No gen	MDS1	MDS2	MDS3	MDS4	MDS5	Avg
1	BC6, refurb SVC3, Orari bussing	1.0	6.0	7.8	6.5	2.9	5.3	5.7
2	BC6, decomm SVC3, Orari bussing	-7.1	21.6	19.6	21.0	-5.4	-3.1	10.8
3	BC6, refurb SVC3, new SVCs	8.6	1.8	2.4	1.8	8.2	7.7	4.4
4	BC6, decomm SVC3, new SVCs	1.0	14.7	16.5	16.4	1.3	5.4	10.9
5	BC6, refurb SVC3, new sync cons, new SVCs	31.3	10.3	13.3	11.1	31.1	30.7	19.3
6	BC6, refurb SVC3, new STATCOMs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Diesel, decomm SVC3, Orari , new SVCs	17.7	30.5	32.2	31.5	14.7	19.9	25.8
8	Diesel gen, refurb SVC3, new SVCs	27.8	27.1	37.4	36.4	23.9	24.7	29.9

Option	Description	Expected Net Market Benefit relative to Option 6 (Present Value 2012 $m)						
		No gen	MDS1	MDS2	MDS3	MDS4	MDS5	Avg
9	Diesel gen, refurbish SVC3, new STATCOMs	35.6	30.0	33.9	31.8	35.6	38.5	34.0

This sensitivity shows that Option 3 is similar, but Option 2 is not. This is because new generation is built earlier in MDS 1-3, making Option 2 more expensive than in the modified MDS. It is worth noting that Option 2 is still favoured in MDS 4 and 5 where less new generation is built in the 2020s. Given our preliminary view on new generation, this does not change our conclusion.

7.7 Good electricity industry practice

The bus coupler is a cost effective option that reduces the need for reactive support. The HILP mitigations will improve resilience and ensure safety. Load monitoring will improve our understanding of the region's dynamic performance which will allow future investments to be further optimised. Preliminary works for Stage 2 further progresses a conventional solution consistent with good international practice that avoids some of the complexities of managing high levels of reactive support on the grid.

Overall the proposal reflects good electricity industry practice by being consistent with good international practice, demonstrating economic management, improving safety, and managing technology risks.

8| Investment Proposal Summary

The upper South Island does not have enough generation to meet electricity demand and the shortfall is supplied via our transmission lines into Islington and then further north.

Because the generation in the south is far from load, it is difficult to maintain voltage within an acceptable range following a fault or circuit outage on the grid and voltage support is required.

We have now completed an investigation, started in 2010, to consider whether further voltage support is required in the upper South Island to maintain a reliable supply of electricity.

Two synchronous condensers at our Islington substation, which currently provide voltage support, are to be decommissioned in 2014 and our technical analysis has determined that unless new generation is commissioned before then, investment in transmission or non-transmission solutions will be required by that time.

We consulted on assumptions for this analysis in June 2011, including assumptions about new generation in the upper South Island. Since then the environment for generation investors has changed – a slow-down in electricity demand growth means there is currently a surplus of generation. There has also been a move away from new hydro development because wind and geothermal are both more economic and socially acceptable. As a result, the June 2011 MDS seem overly optimistic regarding the amount of new generation which may appear in the upper South Island in the medium (before 2020) term.

We therefore modified the MDS to be more realistic and our proposal uses the modified MDS. The modified MDS were consulted on in our draft proposal consultation in May 2012. We incorporated the feedback from this consultation in the MDS as detailed in Attachment D.

By applying the Investment Test to the short-list derived from our June 2011 long-list consultation,, we have determined that investment in a bus coupler in our Islington substation is the most economic option for meeting the 2014 need.

NTSs are not viable for Stage 1 of this proposal, because the expected cost of the bus coupler is low, at $1.9 million, and cheaper than either diesel generation or demand-side response.

The bus coupler will provide 95 MW of voltage support, which replaces the capability of the synchronous condensers and meets demand growth until 2016, at which point, further voltage support. Our economic analysis shows that the following options are essentially the same from an economic point of view, either:

- installing a new SVC at Islington
- refurbishing the existing SVC3 at Islington
- installing a new transmission facility at Orari to bus four of the circuits into Islington.

In those MDS where significant new generation is built in the early 2020s, the SVC options are preferred. If no new generation is built until the 2020s, the Orari option is preferred.

Using unquantified benefits in our analysis, we have concluded that overall, building a new facility at Orari is the leading option of the three similar options. At an expected cost of $58 million, this option has several advantages.

- It insulates reliability of supply in the upper South Island from new generation uncertainty.
- It is a conventional transmission solution that actually reduces the need for voltage support, in contrast to options that install more voltage support devices to address an increasing need.
- It avoids some of the complexities in managing high levels of voltage support, as outlined in our Transmission Code.

Sensitivity analysis shows that the Orari option remains similar in all sensitivities except where the cost of that option increases significantly. However, there are several uncertainties in our assumptions which could affect our choice of leading option, namely:

- whether demand will recover to pre-earthquake levels
- whether new generation is likely to be commissioned in the upper South Island by 2020
- the cost to build a new transmission facility at Orari
- whether NTSs may be economic to defer or manage delivery risk for the 2016 investment.

For that reason we are deferring a decision on a proposal to meet the 2016 need until we have completed further work. We will submit a proposal for the 2016 need in 2013 – our Stage 2 proposal.

Orari bussing is currently the leading option for our Stage 2 development, but it has a minimum four year lead time, so if we want to ensure it is a viable option for 2016, we need to start the process now.

For that reason, we are including some preliminary costs for the Orari option in our Stage 1 Proposal. The expected cost for these preliminary costs is $2.14 million and would cover the detailed design and most of the consenting costs.

While our June 2011 consultation served as a RFI for non-transmission solutions (NTS) and we believe there are no economic alternatives to the 2014 need date, we are not satisfied that we have fully explored the viability of alternatives for 2016.

Given the 2016 investment is likely to be at least $11 million (the estimated cost to refurbish SVC3 and cheapest of the similar options), it may be economic to defer this investment or manage delivery risk of other investments using NTS. We will actively explore the viability of NTS ahead of the Stage 2 submission.

9| Major Capex Allowance

The expected cost of the Stage 1 Proposal is $12.10 million. We are seeking $13.65 million as the Major Capex Allowance. This covers the uncertainties in the project costs. Electricity consumers will only pay for actual costs incurred up to the Major Capex Allowance.

As we recover the costs once the project is commissioned (completed), the Major Capex Allowance is expressed in commissioning year dollars. This is shown in Table 9-1.

9.1 Major Capex Allowance

The relationship between the expected cost of the project and our Major Capex Allowance is shown in Table 9-1.

Table 9-1: Calculation of Major Capex Allowance

Project	Expected Cost (P50) (2012 $m)	Inflation	Financing costs	Expected Cost (P50) (2014-15 $m)	Major Capex Allowance (2014-15 $m)
6th Bus coupler	1.72	0.06	0.07	1.85	2.09
HILP measures	6.76	0.28	0.55	7.59	8.66
Load monitoring	0.65	0.02	0.03	0.70	0.76
Orari facility	1.86	0.04	0.06	1.96	2.14
TOTAL	10.99	0.40	0.71	12.10	13.65

10| Stakeholder engagement

An investigation into reliability in the upper South Island completed in 2008 determined that new investment would not be required until around 2014, assuming the two Islington synchronous condensers were refurbished. We committed to revisit and monitor the situation at timely intervals. This proposal has arisen out of that obligation and our studies confirming that refurbishing the condensers was not practicable.

We have engaged with industry stakeholders during this investigation.

We began the investigation in 2010 and in June 2011 released a Request for Information (RFI) regarding the assumptions to be used in our analysis and potential non-transmission solutions. A teleconference was held at the end of June 2011. Five submissions were received by the closing date:

- Orion New Zealand Limited
- Mighty River Power Limited
- Energy Response Pty Limited
- Trustpower Limited
- Metering Technology Limited

Some submissions offered specific answers to the 13 questions included in the RFI document while others were focussed on a range of non-transmission solutions including potential generation within the upper South Island and demand-side management.

Since that consultation, we have:

- considered and incorporated the feedback where appropriate
- further developed the short list options (as set out in this document)
- developed the economic approach (as set out in this report)
- applied the Investment Test
- analysed the results
- published a draft investment proposal for consultation
- considered and incorporated the feedback where appropriate.

See Table 10-1 for communications to date.

Table 10-1: Project communications to date

Date	Activity
September 2009	Upper South Island Lines Company and CEO Forum held, reopening the upper South Island investigation grid upgrade in line with the commitment we made to monitor the situation.
March 2010	Upper South Island workshop held, reopening the upper South Island investigation grid upgrade in line with the commitment we made to monitor the situation.

Date	Activity
November 2010	Upper South Island Lines Company technical meeting held to obtain input to verify the assumptions of our investigation.
June 2011	Publication of the initial RFI document. E-mail to recipients inviting to a teleconference on 30th June 2011.
July 2011	Submissions closed and summary published.
August 2011	Summary of submissions published.
May 2012	Publication of draft investment proposal for consultation.
May 2012	Submissions closed.
June 2012	Summary of submissions published with MCP.

11| Attachments

Further information supporting this consultation document is included in the following appendices:

Attachment A – Options and Costing Report

This document describes how the long list of options was reduced to a short list of options as well as detailing the cost assumptions for the short list options..

Attachment B – Technical Analysis

This document describes the power system analysis underpinning the need for investment in the Upper South Island.

Attachment C – Investment Test Analysis

This document provides detail of our application of the Investment Test.

Attachment D – Consultation on Options

This document summarises the submissions received to our June 2011 long list consultation and the May 2012 short list consultation. It includes our response to the points raised in those submissions.

Attachment E – Islington Substation HILP Event Study

This document summarises the analysis of the resilience of our Islington substation and the recommended remedial measures.

Attachment F – Meeting the Requirements of the Transpower Capital Expenditure Input Methodology Determination

This document describes how our proposal satisfies the requirements of the Transpower Capital Expenditure Input Methodology Determination and why we believe the Commerce Commission can approve it.

Data Files

The following data files have are included as part of this submission:

Data file	Filename	Description
USI MCP Datafile MCA	USI MCA Datafile_P50.xls	P50 calculation of Costs
	USI MCA Datafile_P90.xls	P90 calculation of Costs
	USI MCA Datafile_Orari MCA.xls	P90 Calculations of preliminary works at Orari
	USI MCP datafile instructions for powerfactory (dz) cases.docx	Digsilent instructions
	*.dz	Powerfactory input files
USI MCP Datafile Technical	USI MCP datafile development plans.xlsx	Powerfactory timing output
	USI MCP datafile generation dispatch.xlsx	Generation assumptions for Attachment A section 2.1.2

Data file	Filename	Description
	USI MCP datafile generation assumptions.xlsx	Profiles for USI MCP datafile generation dispatch.xlsx
	USI MCP datafile load composition matrices.xlsx	Translation from survey to Powerfactory input of static/motor load composition
USI MCP Datafile Investment Test	USI MCP datafile cost summary.xlsx	Cost-benefit inputs and calculation
	USI MCP datafile demand forecast outputs.xlsx	Demand Forecast
	USI MCP datafile limits by generation scenario.xlsx	Timing of each option under each MDS
	USI MCP datafile N minus 2 limits.xlsx	Expected unserved energy calculation by option and MDS
	USI MCP datafile unserved energy.xlsx	Input into USI MCP datafile N minus 2 limits.xlsx

