UPPER SOUTH ISLAND RELIABILITY MCP STAGE 1

ATTACHMENT A OPTIONS AND COSTING REPORT

Transpower New Zealand Limited

June 2012

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

TABLE OF CONTENTS

1| Executive Summary

This document is an Options and Costing report for the Upper South Island major capex investment proposal.

Long-List to Short-List process

The long-list includes a comprehensive range of transmission, generation, and non-transmission solutions (NTS) to meet the transmission need. New options suggested in the submissions received in response to the long-list consultation in June 2011 have been included in the long list.

Voltage stability issues are often resolved via the use of dynamic reactive sources such as SVCs and STATCOMs and static reactive devices such as capacitors and reactors. All these are included here. Reconfiguration of existing circuits can be of benefit; bussing of the four Waitaki to Christchurch circuits at Orari is also included, as is a 6th bus coupler at Islington.

The only NTS considered for the stage 1 short-list is diesel generation. Any demand-side NTS would be unlikely to be economic compared to the relatively low cost of investment required to meet the 2014 need date.

We have combined the short-list options into 9 separate development plans – the final list of investment test options. Each of these options increases the dynamic voltage stability limit to the point where it reaches the thermal capacity of the Waitaki Valley to Christchurch transmission lines. At this point, a new line is the most likely option and it forms the last element in each plan. The cost breakdowns for short-list options are included.

The Islington site survey identified a number of HILP issues, most with specific solutions within the site, so there are relatively few mitigation options. We discuss them here and provide a summary of the costs. Details are in Attachment E, HILP Analysis.

2| Introduction

2.1 Purpose

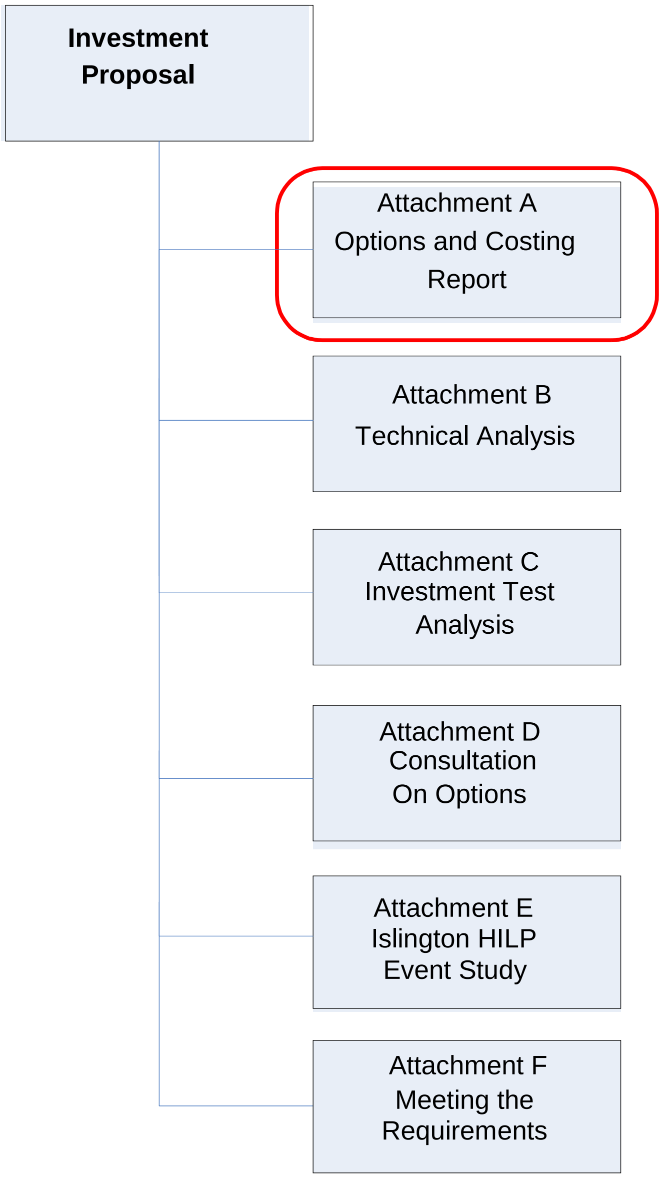
The purpose of this report is to:

- explain the Long Listing process
- identify the Short List options that address the identified need
- outline development plans for each of these options
- provide summarised costs for all options

2.2 Document Structure

This report forms part of the Upper South Island Reliability Investment Proposal, as set out in the diagram below:

Figure 2-1: Document structure



3| Long List of Options

The Long List includes a wide range of possible options for meeting the need, including options that reduce need by limiting load. Options other than transmission are called non-transmission solutions (NTS) and include demand-side and generation alternatives.

Through the Request for Information (RFI) issued in June 2011, we were able to ascertain whether there are NTS that could be used to defer the need for investment.

Our final Long List of options is shown in Table 3-1, grouped into NTS, transmission solutions – existing assets, and transmission solutions – new assets

Table 3-1: Long list and summary of short-listing

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 220kV 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

	Option	Short-Listed?	Reason
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
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

A set of high level screening criteria has been developed to eliminate those options that are not appropriate for consideration in the short list of options to which we apply the Investment Test.

The short-listing criteria for all investments are as follows:

A. Fit for purpose

- The design will assist meeting future energy demand growth
- The extent to which the option resolves the relevant issue.

B. Technical feasibility

- Complexity of option
- Reliability, availability and maintainability of the option
    - Is this proven technology (ie used commercially, internationally and/or with available data on performance, and expected life cycle)?
    - Does Transpower have experience with the technology?
    - Is there a low level of risk associated with implementing this technology (such as ongoing maintenance requirements and availability of after sales support and spare parts)?
- Future flexibility - Grid Development Strategy
    - To what extent does the option open up or foreclose future development options?
    - Could the investment be stranded under certain conditions?

C. Practicability of implementing the option

- It must be possible to implement the solution by the required dates (probability of proceeding)
    - How long will it take to implement this option? Consideration includes:
        - Property acquisition time
        - Likelihood of gaining required environmental approvals
        - Equipment lead time
        - T Time taken to build
    - Implementation risks, including potential delays due to property and environmental issues
    - Are there technical issues with access or available space for the works?
        - Implementation risks eg are outage constraints on the existing system going to impact on this option?
- The availability of proponent for or potential counterparty to a transmission alternative

D. Good electricity industry practice (GEIP)[1]

- Ensure safety
- Consistent with good international practice
- Minimise or mitigate environmental impacts
- Accounts for relative size, duty, age and technological status
- Manage technology risks

E. System security (additional benefit resulting from an economic investment)

- Improved system security
- System Operator benefits (controllability)
    - Does the option provide operational flexibility?

F. Indicative cost

- Whether an option will clearly be more expensive than another option with similar or greater benefits
    - The cost estimates, if used, are high level.

[1] refer Part 1 of the Electricity Industry Participation Code.

Any option that does not meet one or more of the criteria is removed from further investigation.

The overall assessment is indicated by a ✗ or ✓ in Table 3-1 above.

3.1 Long List Screening

Options have been grouped as follows:

- Non transmission solutions: generation and demand side
- Transmission: optimising existing assets
- Transmission: creating new assets

3.1.1 Non-transmission solutions

Submissions from the RFI consultation process in mid-2011 provided information about potential demand-side and generation options which could defer the need for investment.

While we think there benefit in exploring whether there is a viable NTS to defer the need for stage 2 transmission investment in 2016, we think that diesel generation is the only potential NTS that could be competitive with the relatively low-cost stage one transmission investment.

We intend to pursue NTS for stage 2 investment over the next year.

a) New market generation

Included in short-list: ✗

Reason: New generation investments reduce the power import into a region and provide fast acting voltage support with automatic voltage regulators (AVRs). New generation has the potential to defer transmission investment. Some new generation was proposed by Trustpower (Arnold at 25-45 MW) however it is not yet committed. New committed generation at Kawatiri and Amethyst is included in the analysis. The impact of new market generation will be considered in the economic analysis as a market development scenario.

b) Generation Grid Support Contract

Included in short-list: ✗

Reason: RFI submitters indicated a willingness to negotiate Grid Support Contracts around future developments. Specifically Mighty River Power highlighted early development plans for a wind farm proposal in the greater Cape Campbell area. However, no generation of sufficient capacity been offered which has not already been accounted for in the power system analysis.

c) Diesel Generation

Included in short-list: ✓

Reason: Orion offered installation of distribution network diesel generation as an alternative to transmission. The Belfast and Bromley diesel generation sites are both consented and could be implemented within 12 months. A demand-side response equivalent of up to two years of USI load growth (45 MW) is assumed available.

Therefore a diesel generation is considered as a short-list option for stage one.

d) Upper South Island load controller

Included in short-list: ✘

Reason: The USI load controller has been demonstrated to successfully manage peak load in the region. It primarily manages resistive hot water cylinder load and its effect is presently incorporated into the load forecast. The ongoing funding of the USI load controller has been secured via another avenue and therefore this option not carried through into the Short List.

e) Special Protection Scheme

Included in short-list: ✘

Reason: On the non-core grid, irrigation load and some industrial processing may be suitable for consideration as part of an SPS scheme to curtail demand during outages on the transmission system. However, no proponents for such were forthcoming. Voltage stability issues can occur rapidly and the use of an SPS to shed load following a contingent event may not be fast enough or reliable enough. Furthermore there is a risk that if too much load is shed an undesirable overvoltage condition could result.

f) Fuel switching

Included in short-list: ✘

Reason: This involves demand reduction potential that comes from switching from electricity to gas. Due to the scale of fuel switching required this is not considered a viable option.

g) Energy efficiency

Included in short-list: ✘

Reason: Demand reductions may be achieved through the promotion and installation of energy efficient heating, motors and appliances. This would require co-ordinated action from a number of third parties. Due to the scale of the demand reduction required, this action is not viable for this particular need.

h) Local network augmentation

Included in short-list: ✘

Reason: There are no known lines company augmentations that address the need for dynamic voltage support. There is an ongoing need for static reactive support from 2017 onwards. The static support compensates for steady state reactive power losses in the transmission lines, transformers, and loads. Lines company investments in power factory correction capacitors may defer the need for static support at the transmission level.

i) System operation improvements

Included in short-list: ✘

Reason: In 2011, we commissioned an advanced Reactive Power Controller (RPC) in Christchurch which provides a system operation improvement. The RPC automatically controls reactive plant to manage voltages and ensures sufficient dynamic reactive reserves. Any new reactive plant, or configuration changes, at Islington or Bromley substations will be incorporated into the RPC scheme. In addition, our proposed load monitoring initiative will allow us to improve models used in operations (and planning).

j) Ancillary Services

Included in short-list: ✘

Reason: An ancillary service in the voltage support context would be a generation grid support contract (GSC) which is already considered (and discarded) above.

k) Pre-contingency load shedding

Included in short-list: ✘

Reason: This option would mean shedding load in advance of a contingency; for reliability investment then pre-contingency load shedding shall be avoided.

This option will be discussed as part of the demand side alternative analysis.

3.1.2 Transmission: Optimising existing assets

We always seek to optimise the use of existing assets before deploying new assets.

a) Tee 220kV circuit near Bromley

- Reconfigure 220 kV circuits between Ashburton and Islington so they tee into Bromley.

Included in short-list: ✘

Reason: This option provides about 5 MW of benefit before additional investment is required and therefore provides only minor improvement in voltage stability. Teeing the circuits into Bromley costs $1m.

b) Reconductor existing transmission circuits

- Reconductor the 220kV transmission circuits from the Waitaki Valley into Islington.

Included in short-list: ✘

Reason: This option would be extremely expensive for the marginal improvement in voltage stability margins. Reconductoring a 100 km circuit is estimated at a high level to cost about $40m. Reconductoring doesn't significantly reduce line impedance and hence not an effective method for improving voltage stability.

3.1.3 Transmission: creating new assets

While a new transmission line from the Waitaki Valley, an HVDC tap-off, and possible conversion of an existing 220kV circuit, to say 330kV, may all improve voltage stability limits, they are generally options that will involve major capital expenditures in the orders of $100's of millions rather than $50-$70 million options that have made the Short List in this proposal.

However some transmission line options can have a significant impact on voltage stability limits such as bussing circuits to reduce post-contingent transmission impedances between the generation and remote load. Orari bussing is one such option which has made it through to the short-list.

a) Sixth bus coupler at Islington

- Bus coupler circuit breaker to sectionalise the existing Islington 'Bus D' and create a 6th bus section.

Included in short-list: ✓

Reason: This option avoids pairing the Tekapo B 220 kV circuit with a Kikiwa 220 kV circuit on the same bus section. Voltage stability is improved because loss of the Bus section A results in loss of Tekapo B circuit and interconnecting transformer T7 only. High level economic analysis suggests this should be in the Short List (see Section 3). The lead time for the sixth bus coupler is approximately 18 months (estimate based on Islington 5th bus coupler, commissioned 2009). The 6th bus coupler increases the transfer capacity by 4 years and in creating a new bus section provides option value for connecting future reactive plant. Space is available in the existing switchyard to install the 6th bus coupler.

b) Double breakering at Islington

- Connect 220 kV lines and interconnecting transformers simultaneously to two bus sections with circuit breakers.

Included in short-list: ✘

Reason: Except for the bay where it is proposed to install the 6th bus coupler, there are no free 220 kV bays to install new circuit breakers at Islington. Double breakering requires bays are made available in proximity to the equipment to be double breakered. The existing free bay could be employed to double breaker the Kikiwa circuit 3 which means loss of bus A only results in loss of Tekapo B circuit and T7. The cost is estimated at $2m and provides 4 years of benefit which is the same as the 6th bus coupler option. It is not short-listed because it doesn't provide any advantage over the 6th bus coupler option. There isn't any advantage in double breakering other components because the binding constraint is Bus A which is effectively a Tekapo B line outage.

c) Islington 220 kV bus tie circuit

- Tie circuit between the south and north ends of the Islington substation.

Included in short-list: ✘

Reason: This option provides greater security to load north of Christchurch during 220 kV bus section maintenance. However, the cost is about $10m and not expected to be justified by any reduction in un-served energy during bus maintenance

d) Pound Rd switching station

- new 220 kV substation south of Islington at Pound Rd
- connect in two lines from the Waitaki Valley in the south and a Kikiwa circuit in the north
- short tie lines into the existing Islington substation.

Included in short-list: ✘

Reason: This option provides some diversity and a location to connect future loads, reactive support, and transmission circuits. However, it provides only a relatively minor improvement in voltage stability. Establishing a new substation costs $10's of millions and hence represents a large capital investment. In addition, there are other more cost effective measures to mitigate HILP risk at Islington investigated separately.

e) STATCOM at Islington (or Bromley)

- +/-80 Mvar STATCOM at Islington (or Bromley) 220 kV bus

- STATCOM has short term overload capability of 1.25 pu.

Included in short-list: ✓

Reason: Increases the voltage stability transfer limit. High level economic analysis suggests this should be in the Short List (see Section 3). The lead time for a STATCOM is approximately 36 months (estimate based on Kikiwa STATCOM, commissioned in 2010).

f) STATCOM on Islington T6 and T7

- +/-40 Mvar STATCOMs on either one or both 11 kV tertiary windings of T6 and T7 interconnecting transformers.
- STATCOM has short term overload capability of 1.25 pu.

Included in short-list: ✓

Reason: A smaller size STATCOM may be appropriate if the need is not so great to require a larger 220 kV connected device. Alternative location to 220 kV connection. The lead time for a STATCOM is approximately 36 months (estimate based on Kikiwa STATCOM, commissioned in 2009).

g) SVC at Ashburton

- +150/-75 Mvar SVC at Ashburton 220 kV (or 66 kV) bus.

Included in short-list: ✗

Reason: In principle, an SVC connected at Ashburton 220 kV is as effective a location as Islington/Bromley. It is also attractive from the diversity perspective. However 220 kV bus reconfiguration work is required which would also require additional land purchase. The 66 kV connected option was also explored but was not as effective as other 220 kV (Bromley or Islington) options. This option was deemed too expensive when compared to others for similar benefit.

h) SVC at Islington (or Bromley)

- +150/-75 Mvar SVC at Islington (or Bromley) 220 kV bus.
- Or, alternatively, a +60/-50 Mvar SVC on an 11 kV tertiary winding

Included in short-list: ✓

Reason: Increases voltage stability transfer limit. High level economic analysis suggests this should be in the Short List (see Section 3). The lead time for a SVC is approximately 36 months (estimate based on Islington SVC9, commissioned in 2009).

i) Refurbish SVC3 at Islington

- Replace the indoor equipment (including control and protection, cooling systems, power electronic valves) for existing SVC3 connected on T3 11 kV tertiary at Islington.
- Retain building and outdoor equipment including reactors, capacitor banks, switchgear.

Included in short-list: ✓

Reason: SVC3 soon requires half life refurbishment or replacement. The cost of refurbishment is $12m which is less than full replacement cost of $16m.

j) New Synchronous condensers

- two +30/-18 Mvar (or a single 60 Mvar) synchronous condensers at Islington on an interconnecting transformer 11 kV tertiary winding.

Included in short-list: ✓

Reason: Synchronous condensers provide rotational inertia and have fast acting AVRs to provide fast dynamic voltage support. Though the steady state operating losses are higher than SVC's and STATCOM's it was decided to take this option through and compare with the other technology options. The lead time for a synchronous condenser is approximately 36 months.

k) STATCOMs on the West coast

- +/-10 Mvar STATCOM at Westport
- +/-25 Mvar STATCOM at Atarau
- STATCOMs have short term overload of 2.5 pu current.

Included in short-list: ✘

Reason: Motor loads on the West Coast are slowest to recover after a fault. However, the most severe contingency in the USI is currently a loss of ISL bus A (with no fault), meaning that small STATCOMs on the West Cost will provide very little benefit.

l) SVCs/STATCOMs north of Christchurch

- +150/-75 Mvar SVC (or +/-80 Mvar STATCOM) connected at Kikiwa (or Stoke)

Included in short-list: ✘

Reason: Not as effective at providing voltage support at other locations such as Islington or Bromley. Whereas a reactive device at Islington or Bromley covers around 6 years load growth, a device at the top of the South Island covers about 4 years.

m) Shunt capacitor banks

- 75 Mvar shunt capacitor banks connected at Islington 220 kV
- 10 Mvar shunt capacitor bank at Stoke

Included in short-list: ✓

Reason: As the load continues to grow additional static reactive support is necessary to maintain pre-contingent voltages within acceptable levels, while maintaining reactive reserves on dynamic plant. The lead time for a 75 Mvar 220 kV connected capacitor bank is approximately 18 months with a cost of about $2m. Shunt capacitor banks are common to all development scenarios considered.

n) Shunt reactor banks

- 30 Mvar shunt reactor bank connected to at 11 kV at Bromley or Islington

Included in short-list: ✓

Reason: The Bromley reactor is presently due to be decommissioned due to its aged condition. For development plans that do not have new SVCs or STATCOMs (for example Orari bussing), may require a replacement reactor to help manage high voltage issues during light load. The lead time for a reactor bank is approximately 18 months and has a cost of $2m.

o) Orari bussing

- New 220 kV substation near Orari
- New 220 kV double circuit line

The existing 220 kV circuits between the Waitaki Valley and Christchurch would be bussed where they converge just north of the Orari river, near Geraldine. This option effectively reduces the impact of an outage on the 220 kV circuits. There are two alternatives for implementing the bussing:

- At a single location that involves diverting Benmore – Islington A line to where the TWZ-CHH and ROX-ISL lines cross over; or
- two separate locations
  - one where the Christchurch-Twizel A and Roxburgh-Islington A lines cross over; and
  - one where the Benmore–Islington A and Roxburgh-Islington A lines come together.

The first option (requiring a diversion of Benmore – Islington line) is the alternative considered by this analysis.

Note that if we implemented Orari bussing in two separate locations we would still require a new transmission line (between the two stations).

Included in short-list: ✓

Reason: Increases the voltage stability transfer limit by reducing the impact of single line outages. It also provides a possible new supply point that may defer future capacity increases at other GXP. This is also a possible location for future reactive support, e.g. capacitors, SVC's and STATCOM's. High level economic analysis suggests this should be in the Short List (see Section 3). The lead time for Orari bussing is approximately 4 years.

p) Series capacitors

- Series capacitor at Tekapo B substation connected in the BEN-ISL line
- Series capacitors at Twizel substation connected in the TWZ-CHH lines
- Series capacitor at Livingston substation connected in the ROX-ISL line
- Series capacitor at Bromley substation connected in the ASB-BRY line

Included in short-list: ✘

Reason: Technically complex and costly project which affects multiple circuits and multiple substations. This option is considered marginally technically feasible and would be necessary on all four transmission lines from the south into Islington. At this stage it is considered that there are many technical issues that will require significant investigation to resolve, particularly with regard to protection design and operation. It is estimated that protection costs alone may exceed $15m, overall project cost in the region of $80m.

q) New AC transmission line from the Waitaki Valley to Christchurch

- New double circuit transmission line from the Waitaki Valley to Christchurch
- New substation near Christchurch
- New substation (or existing substation extension) in Waitaki valley

Included in short-list: ✘(✔)

Reason: While a new transmission line would increase the voltage stability transfer limit it is a major capital expenditure, in the order of $100’s of millions. It cannot be considered an economic option.

Once the voltage stability limit is raised sufficiently, more capacity into the region will require more thermal capacity from the Waitaki Valley to Christchurch circuits. At this point a new line is the most likely option – specifically a new double circuit line from Tekapo B to Christchurch, with the existing single circuit line dismantled. The existing line is 213 km long and, at $1.2 million per kilometre for the line and $1 million per kilometre for property, a rough order estimate for the new line is $500 million.

r) North Canterbury HVDC Tap-off

- Build a new HVDC converter station north of Christchurch, tapping off the existing HVDC line at Culverden or Waipara and connect to the existing 220 kV Islington-Kikiwa double circuit.

Included in short-list: ✘

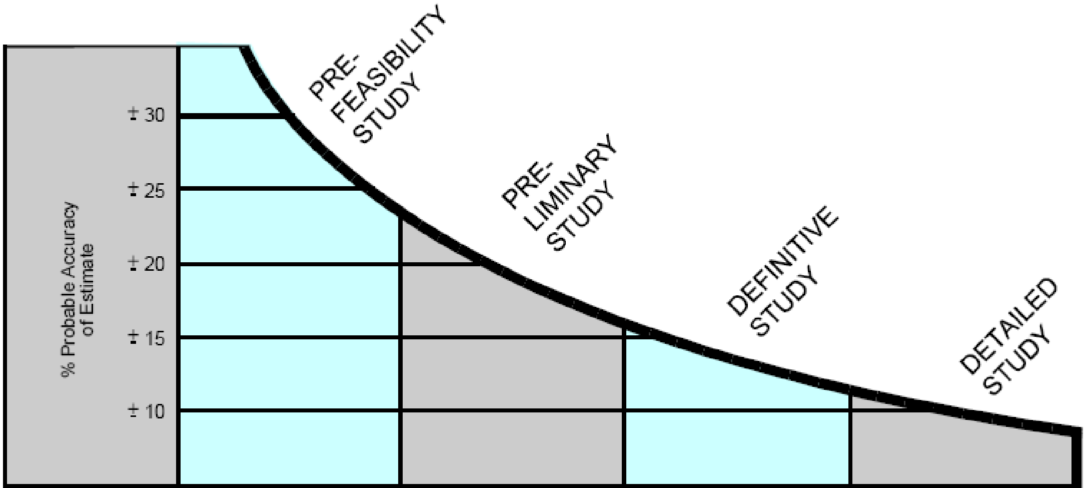
Reason: While a HVDC Tap-off would increase the voltage stability transfer limit it is a major capital expenditure, in the order of $100’s of millions, so cannot be considered an economic option.

4| Option Costing

4.1 Cost Methodology and Approach

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

Figure 4-1: Transmission costing process



Type of Estimate	Order of Magnitude	Preliminary	Definitive	Detailed
Provided Documentation	• Product capacity and Location • Cost Data on Similar Projects • Major Equipment List	• Preliminary Equipment List • Engineering Line Diagram • Plant Outline General Arrangement • Maps and Surveys • Bench Test Results • Nature of Facilities	• Equipment Specifications and Vendor Quotations • Construction Schedule • Electrical One Lines • Piping and Instrumentation Flow Diagrams • Soil Data and Architect Features • Site Survey and Labour Complete	• Bulk Material Specifications and Vendor Quotes • Construction Specification and Sub Contractor Quotations • Engineering Advanced Approximately 10%
Definition of Scope of Work	Conceptual	Approximate	Clearly Described Essentially Complete	Complete. Well Detailed
Estimating Procedure	Factoring	Combination of Factoring and Quantity Take-Off	Most Quantity Take-Off. Very little Factoring	Complete Quantity Take-Off
Use of Study	Comparison/ Rejection	Final Feasibility	Budget	Funding

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

The costs have been developed to an accuracy that is commensurate with the stage of the project and sufficient for the application of the Investment Test. Depending on the type of upgrade, the costs have been developed in one of either two alternative formats. The first is a High Level Cost (HLC) and the second is an Solution Study Report (SSR), which is technically more detailed cost breakdown and assessment then an HLC but not to the same level as a Detailed Design.

High Level Cost (HLC)

The HLC is a high level engineering assessment and cost report based on information held in Transpower's drawings and databases. An HLC is based on standard cost building blocks and a site inspection is not normally undertaken.

For this project, HLC studies were undertaken to assess the costs of the Long List and Short List options. The objective is to include the transmission line costs, substation costs, environmental and property costs and other significant costs that can be readily estimated. Note that at the HLC stage, detailed refinement of options is not possible. The options presented for high level analysis are only studied to the point that approximate scopes and costs can be determined.

System Study Report (SSR)

The SSR is a detailed engineering report on particular options. The objectives are to confirm option feasibility, to refine the engineering scope of work with particular attention to site conditions, and provide costs to a greater accuracy than at the HLC stage. Being of greater accuracy, SSR costs supersede the HLC costs. The scope typically includes the following:

- Determine the engineering requirements for transmission line reconductoing or new build
- Provide substation single line diagrams and equipment layouts
- Confirm substation site geotechnical conditions (if not known)
- Investigate electrical protection system upgrading and telecommunications requirements to enable each substation to interact with other parts of the national grid
- Provide materials lists and project schedule (timeline)
- Review existing cost estimates
- Provide a scope of work for the project management team

The SSRs commissioned to date are for a 220 kV shunt capacitor bank (2007), Sixth Bus coupler (2011) at Islington substation and Orari Switching Station (2008).

4.2 Cost Breakdown Items

Line and Substation capital costs

Transpower has considered the capital costs of the equipment together with project management costs that would be incurred up to and including the commissioning of each option. This includes substation, line works and telecommunication works required for each option. New transmission line costs are based on indicative costing corridors only. They include dismantling costs as required.

Initial costs have been based on construction programmes that assume it is possible to get the required outages. The timing of the development plans have taken into account the lead time required to commission the work needed to address the issues identified, this includes:

(a) awarding the construction contracts, incorporating any special conditions imposed by the consents and/or property rights agreements

(b) enabling contractors to plan the work and mobilise

(c) request outages

(d) implement work

Environmental costs scope

The establishment of any new assets will require the application of a robust site/route selection process to confirm an appropriate location and minimise environmental and community effects. Upgrading of existing substation and lines will also require a range of environmental approvals under the RMA and detailed assessments of potential environmental impacts (e.g. noise and visual impacts).

The costs associated with undertaking such environmental assessments, site/route selection processes and obtaining RMA and other environmental approvals have been taken into account and estimated for works contemplated in the short-list of options.

Property and easement costs

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

In relation to works on existing assets, property risk issues are not considered to be high and it is reasonably believed that the activities proposed will largely comply with the statutory test and the project will require the purchase of few easements.

In relation to the acquisition of property rights for new works (easements for new line sections and where additional land is required), property risk issues are considered to be somewhat higher and may result in additional cost to the project.

It is not anticipated that any property related activities will stop the project but there is a risk that land owner challenge or resistance may delay the project though contesting or preventing land access.

Operating and maintenance costs

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

Investigation costs

Transpower has included the sum of $387,300 for the costs that directly relate to Stage 1 of this proposal. These are for the costs that have been incurred, and will be incurred from the point at which the preferred option was identified. This includes the economic and technical analysis of the preferred option, the compilation of the Board Papers and Major Capex Proposal Document and any work required to support the Commerce Commission's review process over the coming months. It also includes the 6th Bus Coupler solution study report and the five HILP study reports.

Option costs

The table below summarises the short-listed options.

Also shown are

- the approximate effectiveness of the option expressed as the number of years delay of the need,
- the estimated total cost, and
- the source of the estimate.

Table 4-1: Short list options

Component	First available date	years of need met	Cost $M	Cost per year $M	Cost estimate source
Diesel Generation	2014	1 2	$2.4M	$1.2M	See section below
6th bus coupler	2014	4	$1.6	$0.4M	SSR
Refurbishing Islington SVC3	2015	2*	$11.1	$5.6M	HLC
Decommissioning SVC3	2014	N/A	$0.2		HLC
Small Tertiary connected SVC	2015	2	$15	$7.5M	HLC
Small Tertiary connected STATCOM	2015	2	$18	$9.0M	HLC
New synchronous condensers	2015	1	$25.2	$25.2M	HLC
Large SVC	2015	6	$31.9	$5.3M	HLC
Large STATCOM	2015	6	$24.8	$4.1M	HLC
Orari bussing	2016	12	$58.3	$4.9M	SSR
75 MVAR Shunt capacitors at Islington	2014	N/A	$2.1		HLC
10 MVAR Shunt capacitors at Stoke	2014	N/A	$1.4		HLC
30 Mvar Shunt Reactor at Bromley	2014	N/A	$1.6		HLC
* Refurbishing SVC3 does not give 2 years in the development plans below as it is assumed to be operating before refurbishment. Rather decommissioning it subtracts 2 years.					

Cost per year gives a measure of cost-effectiveness. The 6th bus coupler is particularly cost-effective. Next comes diesel generation. After that comes refurbishing SVC3, large STATCOMs and Orari bussing.

Table 4-2 overleaf breaks down the cost estimates by component

Table 4-2: Short list option cost

Cost of Components in $M	Demand response (Diesel)	6th bus coupler	Refurbishing Islington SVC3	Decommissioning SVC3	Small Tertiary connected SVC	Small Tertiary connected STATCOM	New synchronous condensers	Large SVC	Large STATCOM	Orari bussing	75 MVAR Shunt capacitors at Islington	10 MVAR Shunt capacitors at Stoke	30 Mvar Shunt Reactor at Bromley
Lines	-	-	-	-	-	-	-	0.5	-	16.4	-	-	-
Substations	2.9	1.1	10.8	0.2	13.8	15.9	24.8	28.9	21.6	24.7	1.8	1.1	1.6
Environment	-	-	-	-	-	0.0	-	0.0	0.0	-	0.0	-	-
Property	-	-	-	-	-	-	-	-	-	1.7	-	-	-
Protection	-	0.2	-	-	0.1	0.0	0.1	0.1	0.2	7.3	0.1	0.2	-
SCADA	-	0.1	0.0	-	0.0	0.0	0.0	0.1	0.1	0.2	0.0	0.0	-
Consenting	-	-	-	-	-	-	-	-	-	0.8	-	-	-
Communications	-	-	-	-	-	-	-	-	-	1.0	-	-	-
Transpower Overheads	-	0.1	0.3	-	0.7	1.8	0.1	2.1	2.6	1.6	0.1	0.1	-
Contractor Overheads	-	0.1	0.0	-	0.5	0.1	0.2	0.3	0.3	4.8	0.1	0.1	-
Total	2.9	1.6	11.1	0.2	15.0	18.0	25.2	31.9	24.8	58.3	2.1	1.4	1.6

5| Investment Test Options

5.1 Summary

The short-listed options are combined to create nine development plan options which cover the analysis period to 2050 assuming no new generation in the region. With no new generation, a new 220 kV line is constructed in 2028 between the Waitaki valley and Christchurch to increase the thermal capacity. With new generation this date extends out as late as 2045. Regardless of new generation, the next investment after a new line would be in 2050 or beyond, and is not considered here.

The nine development plans are then combined with five different market development scenarios (MDS) which gives a total of fifty four development plans. Depending on the quantity, location, and timing of new generation in the MDS transmission investment timing may also change. The investment test is then applied to the resultant fifty four development plans.

Table 5-1 summarises the results for the nine development plans.

Table 5-1: Development Plans

Option	2014	2016	2018 (if required)	2020s-2040s
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 Statcom		New Statcom, new line

The dates before 2020 are fixed as we do not expect any significant generation before 2020. The dates in the final column vary depending on generation development within each MDS.

All options require static reactive support in the form of shunt capacitor banks. There is an identified need for this by 2017. A total of 225 Mvars of shunt capacitors are required in all development plans, by the time of new line build. Two of the Orari bussing development plans require a shunt reactor to manage voltage at light load conditions.

A 6th bus coupler at Islington is common to many of the short-list development plans, as its cost-effectiveness permits the deferral of significant larger investments.

For details of the assumptions that drive the dates below see Attachment B, Technical Report.

5.2 Short List Options

The following subsections detail the nine development plan options assuming no new generation over the analysis period. New static capacitor banks, a total of 235 Mvars, are common for all the development plans.

5.2.1 Option 1 – Refurbish SVC3, Orari bussing

This option involves installing a 6th bus coupler, refurbishing the existing SVC3, and then Orari bussing.

Table 5-2: Option 1 – Refurbish SVC3, Bussing circuits at Orari

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	Refurbish Islington SVC3	
2017		75 Mvar at Islington
2018	Orari 4 circuit bussing	
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2026		75 Mvar at Islington
2028	New transmission line	

5.2.2 Option 2 – Decommission SVC3, Bussing circuits at Orari

This option involves installing a 6th bus coupler, decommissioning the existing SVC3, installing a 30 Mvar shunt reactor and then Orari bussing.

Table 5-3: Option 2 – Decommission SVC3, bussing circuits at Orari.

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	Decommission Islington SVC3 Orari 4 circuit bussing	30 Mvar Shunt reactor
2017		75 Mvar at Islington
2018		
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2026		75 Mvar at Islington
2028	New transmission line	

5.2.3 Option 3 – Refurbish SVC3, SVCs at Islington / Bromley

This option involves installing a 6th bus coupler, refurbishing the existing SVC3, and then building new SVCs at Islington followed by Bromley.

Table 5-4: Option 3 – Refurbish SVC3, then SVCs at Islington / Bromley.

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	Refurbish Islington SVC3	
2017		75 Mvar at Islington
2018	+150/-75 Mvar SVC at ISL	
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2024	+150/-75 Mvar SVC at BRY	
2026		75 Mvar at Islington
2028	New transmission line	

5.2.4 Option 4 – Decommission SVC3, SVCs at Islington / Bromley

This option involves installing a 6th bus coupler, decommissioning the existing SVC3, and then building new SVCs at Islington followed by Bromley.

Table 5-5: Option 4 – Decommission SVC3, SVCs at Islington / Bromley

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	Decommission Islington SVC3 +150/-75 Mvar SVC at ISL	
2017		75 Mvar at Islington
2018		
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2022	+150/-75 Mvar SVC at BRY	
2024		
2026		75 Mvar at Islington
2028	New transmission line	

5.2.5 Option 5 – Refurbish SVC3, New Synchronous condensers at Islington followed by SVCs

This option involves installing a 6th bus coupler, refurbishing the existing SVC3, and then building new synchronous condensers at Islington followed by SVCs.

Table 5-6: Option 5 - Refurbish SVC3, Synchronous condensers at Islington followed by SVCs

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	refurbish Islington SVC3	

Year	Upgrade	
2017		75 Mvar at Islington
2018	ISL new synchronous condensers	
2019	+150/-75 Mvar SVC at ISL	
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2022		
2025	+150/-75 Mvar SVC at BRY	
2026		75 Mvar at Islington
2028	New transmission line	

5.2.6 Option 6 – Refurbish SVC3, STATCOMs at Islington / Bromley

This option involves installing a 6th bus coupler, refurbishing the existing SVC3, then building a STATCOMs at Islington followed by Bromley.

Table 5-7: Option 6 – Refurbish SVC3, STATCOMs at Islington / Bromley

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	6th bus coupler at Islington 220	
2016	refurbish SVC3	
2017		75 Mvar at Islington
2018	+/-80 Mvar STATCOM at ISL	
2020		10 Mvar at Stoke
2021		75 Mvar at Islington
2024	+/-80 Mvar STATCOM at BRY	
2026		75 Mvar at Islington
2028	New transmission line	

5.2.7 Option 7 – Diesel generation, decommission SVC3, Orari bussing

This option involves diesel generation for 2 years, decommissioning the existing SVC3, and then Orari bussing, and a shunt reactor.

Table 5-8: Option 7 – Diesel generation, decommission SVC3, Orari bussing

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	Diesel generation (2 years growth)	
2016	decommission SVC3 Orari bussing	30 Mvar shunt reactor
2017		75 Mvar at Islington
2018		
2020		10 Mvar at Stoke

Year	Upgrade	
2021		75 Mvar at Islington
2022	+150/-75 Mvar SVC at BRY	
2026		75 Mvar at Islington
2028	New transmission line	

5.2.8 Option 8 – Diesel generation, refurbish SVC3, SVCs in Christchurch area

This option involves diesel generation for 2 years, refurbishing SVC3, and then SVCs in the Christchurch area.

Table 5-9 Option 8 – Diesel generation, refurbish SVC3, SVCs in Christchurch area

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	Diesel generation (2 years growth)	
2016	refurbish SVC3 +150/-75 Mvar SVC at BRY	
2017		75 Mvar at Islington
2018		
2020		10 Mvar at Stoke
2021	+60/-50 Mvar SVC at T6 tertiary. ISL	75 Mvar at Islington
2023	+150/-75 Mvar SVC at ISL	
2026		75 Mvar at Islington
2028	New transmission line	

5.2.9 Option 9 – Diesel generation, refurbish SVC3, STATCOMs in Christchurch area

This option involves diesel generation for 2 years, refurbishing SVC3, then STATCOMs in the Christchurch area.

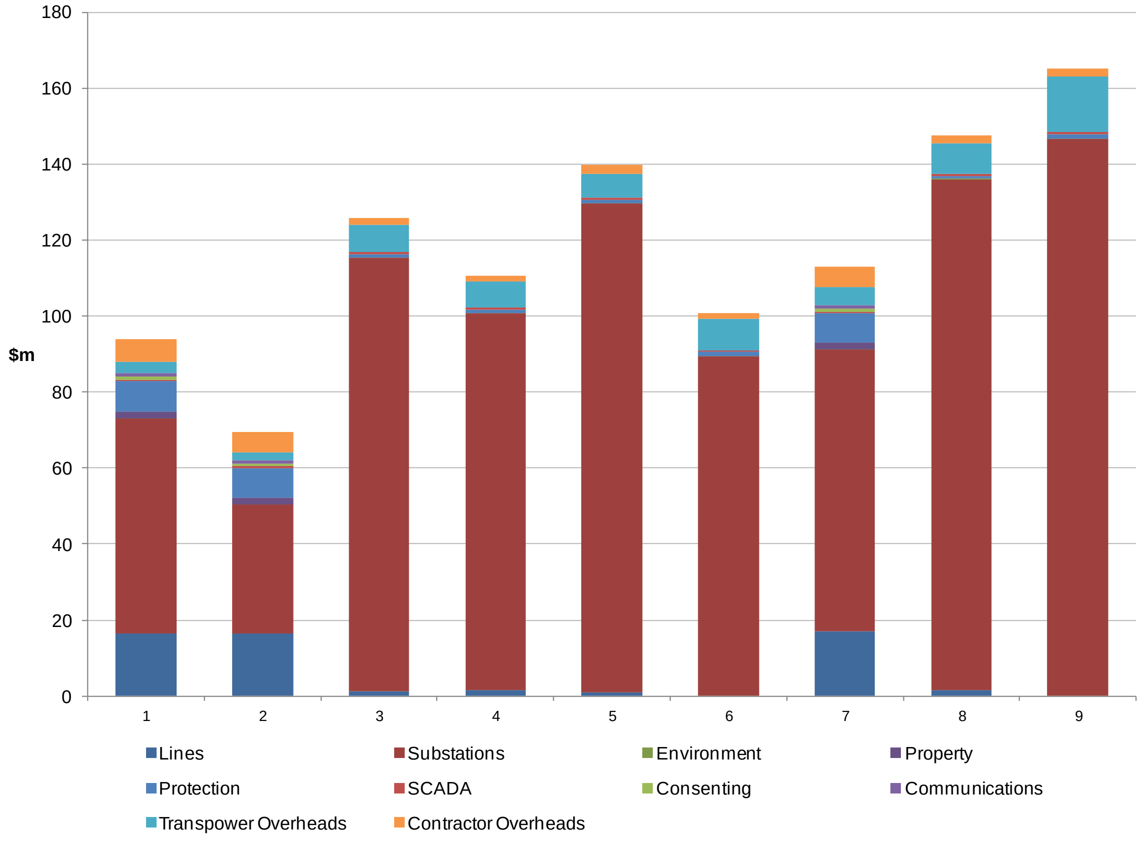
Table 5-10 Option 9 – Diesel generation, refurbish SVC3, STATCOMs in Christcurch area

Year	Upgrade	
	Dynamic	Shunt capacitor banks/ shunt reactors
2014	Diesel generation (2 years growth)	
2016	refurbish SVC3 +/-80 Mvar STATCOM at BRY	
2017		75 Mvar at Islington
2018	+/- 40 Mvar STC at ISL T6	
2020		10 Mvar at Stoke
2021	+/-80 Mvar STC at ISL	75 Mvar at Islington
2023		
2026	+/-40 Mvar STC at BRY11	75 Mvar at Islington
2028	New Transmission line	

5.3 Development Plan Costs

Adding the cost components from Table 4-2 for each item in the plans, produces the table overleaf. All values are in 2012 dollars and have not been adjusted for timing (i.e., not NPV). They are graphed in the chart below.

Figure 5-1 Development Plan Costs



All plan costs are dominated by the substation component. Options involving Orari bussing include significant line and property costs. Options 2, 4 and 6 have the lowest total costs.

Table 5-11 Breakdown of development costs by cost type

Cost Components in $M	1	2	3	4	5	6	7	8	9
	BC6, refurb. SVC3, Orari bussing	**BC6, decom. SVC3, Orari bussing**	**BC6, refurb. SVC3, new SVCs**	**BC6, decom. SVC3, new SVCs**	**BC6, refurb. SVC3, new STCs, SVCs**	**BC6, refurb. SVC3, new STCs**	**Diesel gen, decom. SVC3, Orari Bussing**	**Diesel gen, refurb. SVC3, new SVCs**	**Diesel gen, refurb. SVC3, new STCs**
Lines	16.4	16.4	1.4	1.5	1.0	0.0	17.0	1.5	0.0
Substations	56.8	34.0	113.9	99.2	128.6	89.4	74.2	134.5	146.6
Environment	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Property	1.7	1.7	0.0	0.0	0.0	0.0	1.7	0.0	0.0
Protection	7.9	7.8	0.9	0.8	1.0	1.0	7.7	0.7	1.2
SCADA	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Consenting	0.8	0.8	0.0	0.0	0.0	0.0	0.8	0.0	0.0
Communications	1.0	1.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Transpower Overheads	2.9	2.0	7.2	6.9	6.3	8.2	4.6	8.2	14.6
Contractor Overheads	5.7	5.3	1.8	1.5	2.1	1.6	5.5	2.2	2.0
Total	93.8	69.4	125.8	110.5	139.7	100.8	113.1	147.7	165.2

6| Non-Transmission Cost Assumptions

In this Section we estimate non-transmission option costs.

6.1 Demand-side Costs

To estimate the potential cost of engaging demand-side participation as a means of deferring the 6th bus coupler in 2014, we have made the following assumptions:

Table 6-1 Demand-side assumptions

	2014	2015
MW required	21	37
Hours above peak limit	1 – 4	10 – 15

We assume these peaks occur in the winter, covering a three month period.

We assume the costs of demand-side are:

- $10,000/month/MW availability fee
- $6,500/MW delivery cost for a 3 hour call

These costs were identified in the upper South Island demand-side trial in 2007. At the time these were thought to be reasonable and representative for low numbers of MWs. They represent the "low hanging fruit" cost.

The Auckland RFI in 2011 also gave us cost estimates, but they were higher.

Applying these assumptions we get:

Table 6-2 Demand-side calculation

2012 $ million	2014	2015
Number of calls	1	4
Availability fee	$0.630	$1.110
Delivery cost	$0.137	$0.962
Total	$0.767	$2.072

This gives a cost estimate for a two year deferral of $2.8 million.

6.2 Diesel Costs

We use the same assumptions as in Table 6-1 above. We assume that the generators need to run for approximately twice the time that the generation is required. In addition we assume the following parameters:

Table 6-3 Diesel assumptions

Fuel consumption	160l / MWh
Cost	$1.36 / l
Capital cost – generators	$500,000 / MW
Capital cost – other plant	$100,000 / MW
Annual return required	$10%

Lastly we assume that Orion expect to recoup 50% of the generator cost from this usage (the remainder being for other distribution related uses). This gives the following costs:

Table 6-4 Diesel calculation

2012 $ million	**2014**	**2015**
Variable costs	$128,000	$512,000
Capital costs	$630,000	$1,110,000
Total	$758,000	$1,622,000

The cost estimate for a two year deferral is $2.4 million.

The demand-side and diesel cost estimates are similar, as diesel generation partly established for another purpose may well be a competitive demand-side solution.

Note: We received feedback during the short-list consultation that our estimates of diesel generation costs are low. Hiring or capital costs and fuel costs are both higher than included in our calculations. We have not increased our cost estimates because diesel generation is already uneconomic using our low costs and no change would result.

7| HILP Mitigation Options

We are applying for funds to do three areas of work: seismic strengthening, fire suppression and LVAC Supply. Further details are in Attachment E, HILP Event Study.

7.1 Earthquake Strengthening (Seismic)

Seismic analysis of the Islington site has identified that significant strengthening work is required to bring the control building, and crane hall up to standard, at an expected cost of $1.5 million.

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

7.2 Fire Suppression

We have decided that the following recommendations from the Marsh fire suppression study, Attachment E, Appendix B, should be implemented without further delay:

- Sprinkler protection in the cable basement
- Upgrade fire doors
- Install smoke seals
- Apply intumescent coating to cables
- Installation early detection equipment
- Design & Installation of a hypoxic system for relay room

The economic justification is included in Attachment E.

7.3 Low Voltage Alternating Current (LVAC)

The Low Voltage Alternating Current (LVAC) system at Islington was also identified as a risk. 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.

7.4 Costs

A cost breakdown is included in Table 7-1.

Table 7-1 HILP Mitigation Cost Breakdown

Project	Expected Cost (2012 $m)	Inflation	Financing costs	Expected Cost (2014-15 $m)	Major Capex Allowance (2014-15 $m)
Seismic	2.08	0.09	0.17	2.34	2.61
Fire Suppression	2.86	0.11	0.23	3.20	3.81
LVAC Upgrade	1.82	0.08	0.15	2.05	2.24
TOTAL	6.76	0.28	0.55	7.59	8.66

8| Load Monitoring

We are applying for funding in our draft stage 1 proposal for additional instrumentation to better understand how the USI power system responds transiently to system events. This will improve our analysis on the future need for dynamic reactive support beyond stage 2. The nature of the load mix in the upper South Island is changing as the installation of heat pumps and motors continues, impacting on the need for further dynamic reactive support. The load monitoring equipment is portable and can therefore be readily moved around to gather data from different sites thereby building a comprehensive picture of load dynamics over time.

Table 8-1: Load monitoring costs

Project	Expected Cost (2012 $m)	Inflation	Financing costs	Expected Cost (2014-15 $m)	Major Capex Allowance (2014-15 $m)
Load monitoring	0.65	0.02	0.03	0.70	0.76
Total	0.65	0.02	0.03	0.70	0.76

