TRANSPOWER

# Inter-Island HVDC Pole 1 Replacement Investigation

## HVDC-TRAN-DEV-01

## GIT Consultation Document – Attachment E

## Options – Identification and Screening

Doc reference: Inter-island HVDC Pole 1 Replacement
Investigation/DC/Consult/004/Rev C

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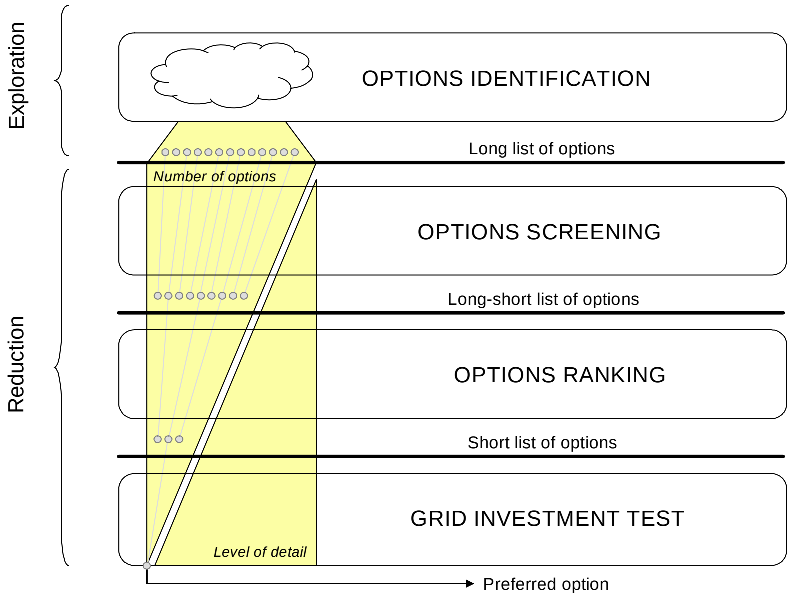
# Executive Summary

The purpose of this document is to set out the first phase of Transpower's analysis for the replacement of the Inter-Island HVDC Pole 1 (HVDC Pole 1 Replacement Investigation), i.e., the identification of all potential options and the screening of those options to derive a long short list. This is the first phase of Transpower's analysis, which includes option identification, option screening, option ranking and application of the grid investment test as shown below.



## Options Identification

A long list of all technically possible options has been identified regardless of any other factors such as their practicality or their economic viability. Transpower has grouped those options as HVDC, HVAC and Other options as shown below.

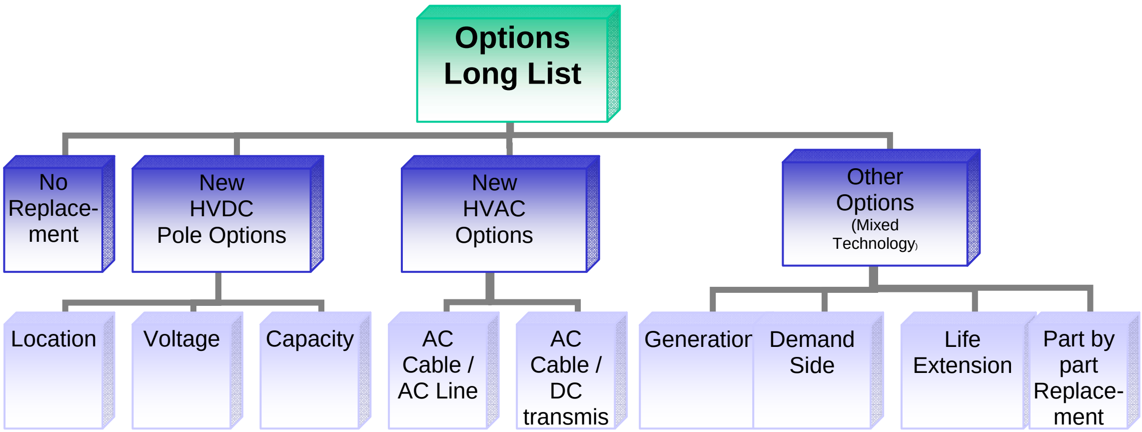


**Figure 0-1: Options Long List Overview**

## Options Screening

A set of screening criteria is then used to eliminate impractical options from this long list of options to produce a long short-list for further analysis.

The applicable set of screening criteria relevant to economic investments taking into consideration the requirements of the Electricity Governance Rules 2003 (Rules)[1] and good electricity industry practice are summarised below:

A. Fit for purpose
  - Purpose - Interconnection of the two island markets

B. Technical feasibility
  - Complexity of solution
  - Reliability, Availability and Maintainability of the solution
  - Future flexibility - Grid Development Strategy

C. Practicality of implementation
  - Solution implementable by required date (Probability of proceeding)
  - Property, environmental risks
  - Implementation risks

D. Good Electricity Industry Practice (GEIP)
  - Consistent with good international practice
  - Ensure safety and environmental protection
  - Accounts for relative size, duty, age and technological status
  - Prior industry experience with the technology
  - Low technology risks

E. System security ( additional benefit resulting from an economic investment)
  - Improved system security
  - System operator benefits (controllability)
  - Dynamic benefits (modulation features and improved system stability)

F. Enabling Renewables
  - Transport energy
  - Balancing MW transfer

Transpower applied the screening criteria above, ascribing a positive, neutral or negative outcome for each of the criteria for each of the options. Only the options that had positive or neutral outcomes for all of the screening criteria were retained in the long-short list to proceed to the second phase of analysis, i.e. the options ranking. The resulting long-short list of options is shown in Table 0-1 below.

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[1] Under the Rules, only those options that meet the definition of “proposed investment” or “alternative project” may be included in the application of the grid investment test. Accordingly, Transpower has screened the long list of options based on whether the options would meet either of these definitions.

| *Option No.* | *Description (1)* | *New Pole Termination* | | *Circuit Rating* | |
|---|---|---|---|---|---|
| | | **South Island** | **North Island** | **Voltage (kV)** | **Capacity (MW)** |
| **No new investment** | | | | | |
| LS1. | No new HVDC investment | N/A | N/A | N/A | N/A |
| **Direct Pole 1 replacement** | | | | | |
| LS2. | 300 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 270/350 | **300** |
| LS3. | 500 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 270/350 | **500** |
| LS4. | 700 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 350 | **700** |
| LS5. | 1000 MW, 350 kV Pole 1 Benmore-Haywards | Benmore | Haywards | 350 | **1000** |
| **Extend Pole 1 to Bunnythorpe** | | | | | |
| LS6. | 500 MW Pole 1 Benmore-Bunnythorpe | Benmore | Bunnythorpe | 350 | **500** |
| LS7. | 700 MW Pole 1 Benmore-Bunnythorpe | Benmore | Bunnythorpe | 350 | **700** |
| LS8. | 1000 MW, 350 kV Pole 1 Benmore- Bunnythorpe | Benmore | Bunnythorpe | 350 | **1000** |
| **Extend Pole 1 to Roxburgh** | | | | | |
| LS9. | 500 MW Pole 1 Roxburgh-Haywards | Roxburgh | Haywards | 350 | **500** |
| LS10. | 700 MW Pole 1 Roxburgh - Haywards | Roxburgh | Haywards | 350 | **700** |
| LS11. | 1000 MW, 350 kV Pole 1 Roxburgh -Haywards | Roxburgh | Haywards | 350 | **1000** |

**Table 0-1 Summary of long short list**

# Contents

# 1 Introduction

The purpose of this document is to set out the first phase of Transpower's analysis for the replacement of the HVDC Pole 1 Replacement Investigation, i.e., the identification of all potential options and the screening of those options to derive a long short list. This is the first phase of Transpower's analysis, which includes option identification, option screening, option ranking and application of the grid investment test as shown below.

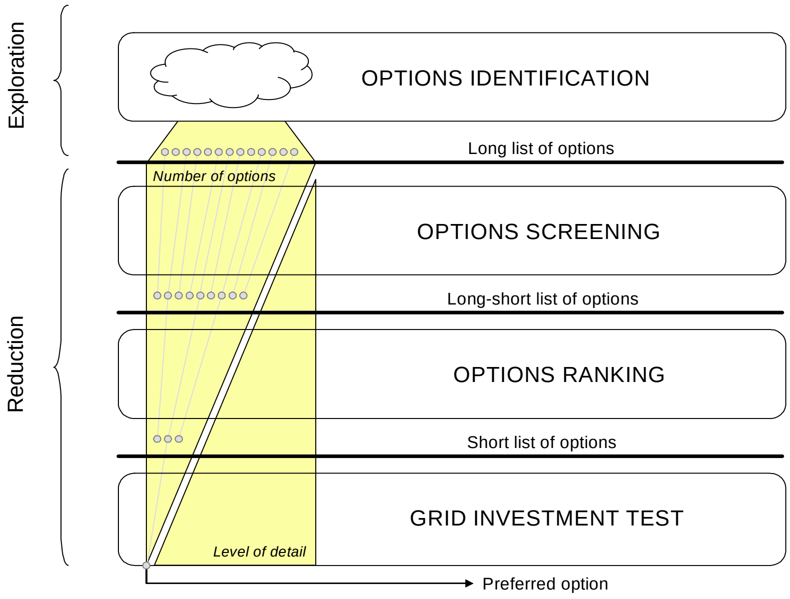


**Figure 1-1 Options reduction process**

# 2 Technical Assumptions

In order to derive a list of all technically possible options for replacing Pole 1 of the HVDC link certain technical assumptions are required. The technical assumptions used in creating these options are set out below.

1. Pole 2 will remain at Benmore and Haywards as at present. The cost of any relocation would be expected to exceed any benefit provided by relocation of Pole 2.
2. Similarly to Pole 2, the AC connections of a replacement Pole 1 (unless otherwise stated) are at the 220 kV bus. This enables synergies between Pole 1 and Pole 2 including common spare holdings.
3. Only line commutated (Classic) HVDC converter technology is considered as the proven technology option for HVDC. Voltage Sourced Converter (VSC) transmission systems are not considered. VSC transmission would be a standalone system and cannot be facilitated by the existing HVDC transmission line and cables, and would not be compatible with existing Pole 2. VSC transmission would require significant additional expenditure on new or modified transmission lines and cables when compared against classic HVDC converter technology of similar capacity.
4. Capacitor commutated converter option is considered an optimisation of the classic converter technology and reactive power management. Therefore, it is not explicitly mentioned as a distinct option.

5. Generation and demand side management alternatives are built into the generation scenarios as part of the Grid Investment Test (see Attachment B “Databook”). Therefore such options are not identified as distinct options.

# 3 HVDC Options Identification

A long list of all technically possible options has been identified regardless of any other factors such as their practicality or their economic viability. Those options fall within four broad categories:

- An option with no new investment;
- HVDC options - The 66 HVDC options reflect different combinations of HVDC terminal locations in the North Island and South Island and differing HVDC pole capacities;
- HVAC options - The 8 HVAC options reflect replacing the HVDC with HVAC, over a limited number of locations; and
- Other options - The 9 Other options represent alternatives to replacing Pole 1 of the HVDC with either HVDC or HVAC equipment.

## 3.1 No new investment

This option involves no reinstatement of the decommissioned Pole 1 of the HVDC link. Pole 2 is expected to continue to operate until 2025 and then be replaced with similar plant. This results in.

- a monopolar arrangement with a maximum HVDC capacity of 700 MW;
- if continuous ground current operation is not possible, a cable capacity limit of 500 MW. A new cable will be required to fully utilise the 700 MW transfer capacity of Pole 2; and
- the HVDC dispatch being determined by the ability to dispatch high DC transfer and the amount of spinning reserve costs.

## 3.2 HVDC variations

The following variations using existing HVDC technology were considered in identifying the long list of options:

- Converter terminal location options
- Converter pole capacity options
- DC voltage options
- Monopolar and bipolar termination options

### 3.2.1 Converter terminal location options

The existing Pole 1 has converter terminals at Haywards in the North Island and Benmore in the South Island. It may be possible to locate the site for new Pole 1 converter terminals in each Island with the result of a net market benefit. The converter locations in the North Island considered by Transpower were:

- **Haywards**: Haywards was identified as the most likely North Island site for a future replacement Pole 1 during the hybrid upgrade. Modification to the existing site at Haywards is required;

- **Bunnythorpe**: A new site would need to be established along with a new HVDC transmission line from Haywards to Bunnythorpe;
- **Whakamaru**: A new site would need to be established along with a new DC transmission line from Haywards to Whakamaru; and
- **Auckland**: A new site would need to be established along with a new HVDC transmission line from Haywards to Auckland.

The converter locations in the South Island considered by Transpower were:

- **Benmore**: Benmore was identified as the most likely South Island site for a future replacement Pole 1 during the hybrid upgrade. Modification to the existing site work at Benmore is required;
- **Roxburgh**: A new site would need to be established along with a HVDC transmission line from Benmore to Roxburgh; and
- **Invercargill**: A new site would need to be established along with a HVDC transmission line from Benmore to Invercargill.

A new HVDC transmission line or an extension from an existing converter station may be achieved by constructing a new line or converting an existing AC transmission line to DC depending on resulting system constraints.

### 3.2.2 Converter pole capacity options

Several pole capacities were considered for the replacement converters to provide a balanced or unbalanced operational condition and to make best use of the existing assets. An increase in rating beyond that of the existing DC circuits (lines and cables) will require further enhancements to the lines and cables. The following Pole 1 capacities were considered by Transpower:

- 300 MW: Provides a balanced bipole capacity of 600 MW or an unbalanced maximum capacity of 1000 MW;
- 500 MW: Provides a balanced bipole capacity of 1000 MW or an unbalanced maximum capacity of 1200 MW;
- 700 MW: Provides an ultimate balanced bipole capacity of 1400 MW. This would require an additional submarine cable to utilise the maximum capacity; and
- 1000 MW: Provides an ultimate balanced bipole capacity of 1400 MW or an ultimate unbalanced maximum capacity of 1700 MW. Sub options include:
    - A 350 kV option, which would require an additional cable to provide full capacity and investment in the HVDC transmission line to provide the required current rating; and
    - A 500 kV option, which would require new cables and new HVDC transmission line construction.

### 3.2.3 DC Voltage options

The existing Pole 1 operates at 270 kV. However, the HVDC transmission line is rated for 350 kV, having been reinsulated during the Hybrid Upgrade project in 1991. The three existing submarine cables and DC filters are also rated at 350 kV. Accordingly, Transpower considered the following voltage options:

- 270 kV DC: Existing HVDC transmission line, submarine cables and filters are rated for 350 kV but the transmission line current rating is limited to 2000 A. This means for pole capacities above 540 MW, major transmission line work would be required to increase the thermal rating of the line. Three cables would be required to provide 1000 MW capacity through this pole;

- 350 kV DC: Existing HVDC transmission line, submarine cables and filters are rated at this voltage. Minimal work is required for pole capacities below 700 MW. For a 1000 MW pole, major transmission line upgrade work would be necessary to increase the thermal rating of the line; and
- 500 kV DC: Not possible to use the existing HVDC transmission line, submarine cables and filters as they are not suitable at this voltage. Reconstruction of the existing line or constructing a new HVDC transmission line would be required.

### 3.2.4 Monopolar and bipolar termination (implications of converter terminal locations)

Depending on the choice of replacement and location of the new pole, monopolar or bipolar terminations of the inter-island HVDC link would result.

#### Monopolar terminations

With no replacements after the decommissioning of the mercury arc valve pole at Benmore and Haywards, there would be a monopolar configuration of the DC with only Pole 2 in service. This would result in a maximum possible capacity of 700 MW.

If at least one of the converter terminals of the replacement Pole 1 was shifted away from Benmore and/or Haywards, these would create monopolar terminations at the affected sites.

A monopolar arrangement could be operated with the ground return or metallic return mode. This means only one HV conductor bundle (includes HVDC transmission line and submarine cable) would be required if the ground return is acceptable. On the other hand, a metallic return configuration requires separate conductor bundles for the HV side and for the return conductor at ground potential.

#### Bipolar terminations

A bipolar configuration is feasible when the two poles are terminated closer to each other so a common current path between the two poles can be established.

### 3.2.5 North Canterbury HVDC Tap-off

This option involves constructing a new HVDC converter station north of Christchurch and connecting it to the existing 220 kV transmission lines from Islington to Kikiwa. Sub-options include:

- Tapping off the existing HVDC transmission line at Culverden or Waipara. This would reduce the HVDC capacity into the North Island;
- Upgrading the existing HVDC transmission line and converter station capacity to accommodate the Christchurch load and tapping it off at Culverden or Waipara. This would maintain the HVDC capacity into the North Island;

## 3.3 HVAC Options

An AC inter-island interconnection was considered as an alternative to the HVDC interconnection. The aim here would be to create a synchronous network including the whole of New Zealand's electricity market, albeit providing a weak AC link in parallel with Pole 2 DC interconnection.

Transpower considered both a 220 kV and a 400 kV AC cable interconnection across the Cook Strait. This is possible with a fully AC or hybrid AC/DC interconnection solution.

For the purpose of comparing to HVDC options, southern termination points may be considered as Benmore, Roxburgh or Invercargill. The northern termination point is Haywards.

### 3.3.1 Inter-island AC interconnection

These options require:

- AC cable terminations at both ends of the Cook Strait;
- 40 km submarine AC cables across Cook Strait; and
- an AC line to a North Island termination point. Sub options for the AC line include:
    - using existing 220 kV AC lines between the Lower and Upper South Island; and
    - constructing dedicated AC lines between the Lower and Upper South Island, at either 220 KV or 400 kV.

### 3.3.2 Inter-island AC/DC interconnection

It may be possible to terminate the HVDC transmission line in the Upper South Island and provide an AC cable connection across the Cook Strait. This option has been added in order to provide a synchronous interconnection between the north and south islands while making use of the existing HVDC transmission line.

Like the AC interconnection options, these options require:

- AC cable terminations at both ends of the Cook Strait;
- 40 km of submarine AC cable across Cook Strait; and
- an AC line to the North Island termination point. Sub options for the AC line include:
    - using the existing HVDC transmission line to the Upper South Island from Benmore with a HVDC terminal in the Upper South Island. The AC side voltage and cables considered were 220 kV AC and 400 kV AC.
    - establishing a new HVDC transmission line from Lower South Island to Upper South Island with a HVDC terminal in Upper South Island. The AC side voltage and cables considered were 220 kV AC and 400 kV AC.

## 3.4 Other Technology Options

### 3.4.1 Renewable/distributed generation technologies

These are options inherent in the generation scenario analysis and are assessed as a variable in the generation expansion optimisation.

### 3.4.2 Demand side management initiatives

These are options inherent in the generation scenario analysis and are assessed as a variable in the generation expansion optimisation. These may be in the form of the following technology options:

- Energy storage technology;
- Fuel switching to hydrogen or gas; and
- Demand side management.

### 3.4.3 Life extension of Pole 1

Life extension options involve the modified use or refurbishment of some of the existing equipment to extend the life of the existing Pole 1 and include:

- Maintaining one half pole at both Benmore and Haywards at current configurations (L79);
- Adding 100 kV thyristor converters series converters to increase the DC operating voltage (L81 & L82); and
- Retaining Benmore Pole 1 but replacing Pole 1 only at Haywards (L80 & L81).

The options associated with retaining elements of the existing mercury arc valve Pole 1 are listed below.

#### Maintain one half Pole at each end

This option involves maintaining one of the two half poles of the mercury arc valves at Benmore and Haywards. This would require adequate measures in place for continued operation of most of the aged equipment from the original mercury arc valve pole.

This option would not improve the line losses beyond current levels and would restrict the power rating to a maximum of 1024 MW, and result in an unbalanced bipole.

#### Maintain Benmore - replace new 270 kV Pole at Haywards

This option involves maintaining the mercury arc valve Pole 1 at Benmore and replacing the Haywards mercury arc valve converter pole with a new thyristor pole at 270 kV. This would require adequate measures in place for continued operation of Benmore Pole 1.

This option would not improve the line losses beyond current levels and would restrict the power rating to a maximum of 1240 MW, and result in an unbalanced bipole.

#### Maintain Benmore and Haywards add 100 kV converters in series

This option involves maintaining the mercury arc valve Pole 1 at Benmore and Haywards. The DC terminal voltages are raised to 350 kV by adding a 100 kV thyristor converter in series with the mercury arc valves at both ends. This would allow the mercury arc vales to be derated to 250 kV and allow the HVDC transmission lines to be used to the full rated voltage of 350 kV DC. This option would provide for a balanced operation up to a maximum of 1400 MW.

The main advantages with this option are a reduction in line losses and better use of submarine cables.

This option would require new thyristor converter equipment to be added in series with the mercury arc valves at Benmore and Haywards. This, therefore, requires keeping the old mercury arc valve pole intact while adding new equipment. This means adequate measures must be in place for the continued operation of existing Pole 1 equipment which is already over 40 years old.

#### Maintain Benmore - replace new 350 kV Pole at Haywards

This option involves maintaining the mercury arc valve Pole 1 at Benmore but replacing it with a thyristor pole at 350 kV at Haywards. The Benmore terminal voltage would be raised to 350 kV by adding a 100 kV thyristor converter in series with the mercury arc valves. This would allow the mercury arc valves to be derated to 250 kV and allow the HVDC transmission lines to be used to the full rated voltage of

350 kV DC. This option would provide for a balanced operation up to a maximum of 1400 MW.

The main advantages with this option are a reduction in line losses and efficient use of submarine cables.

This option would require new thyristor converter equipment to be added in series with the mercury arc valves at Benmore. This, therefore, requires keeping the old mercury arc valve pole intact while adding new equipment. This means adequate measures must be in place for the continued operation of existing Pole 1 equipment which is already over 42 years old.

By contrast, at Haywards, a complete replacement of a converter pole would be required, and the mercury arc valve equipment would be decommissioned. Some of the Haywards equipment could be shifted to Benmore as spares. However, critical items such as converter transformers from Haywards would not be suitable for use at Benmore.

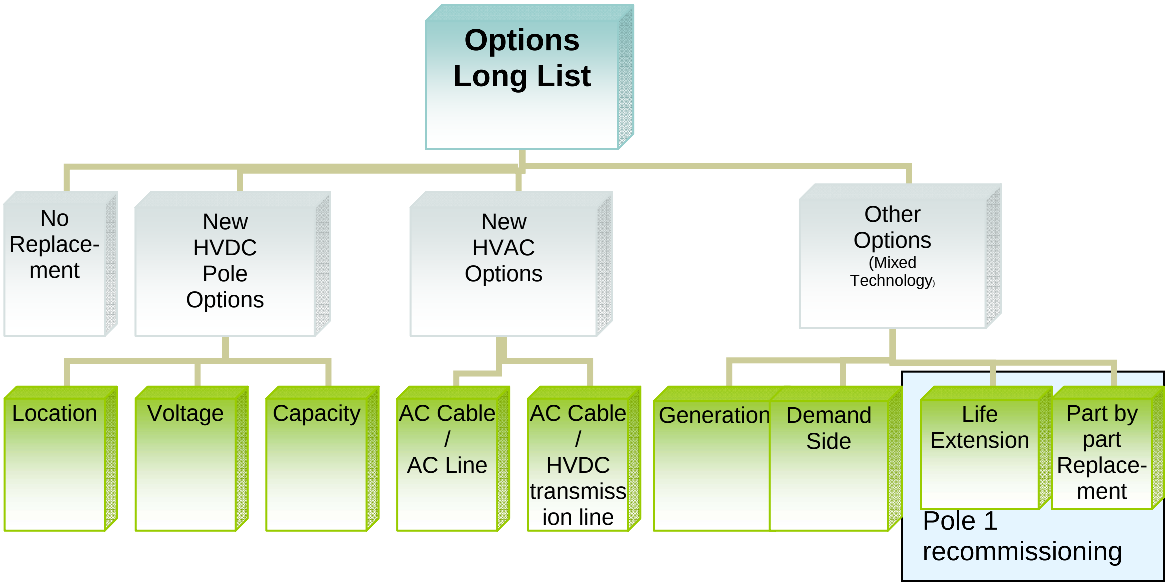
### 3.5 Part-by-Part Replacement

This option involves part-by-part replacement of the complete Pole 1 - with all Pole 1 equipment progressively replaced. Existing voltages and ratings would be retained on most equipment. The existing converter buildings and structures would need to be maintained and the transition would be made progressively by replacing converter transformers, mercury arc converters with thyristor valves, filters, and other AC and DC equipment. This option will require the existing ratings of most equipment to be maintained.

## 4 Summary of Long List of Options

The long list of options are grouped into four categories as shown in figure 4-1. These are further set out in the tables below.

**Figure 4-1 Summarised groups of long list of options**



## Table 4-1: New HVDC Options – DC Long list of options

| **Option No.** | | | **Terminal Locations** | | **Sub Options** | | | | | **Year commissioned** |
|---|---|---|---|---|---|---|---|---|---|---|
| **From** | **To** | **Group** | **From** | **To** | **New HVDC Pole Capacity MW/ (Voltage kV) 350 kV applies unless stated** | | | | | |
| L1 | | DC-Base | Benmore | Haywards | 0 | | | | | 2012 |
| L2 | L6 | DC-A | Benmore | Haywards | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L7 | L11 | DC-B | Benmore | Bunnythorpe | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L12 | L16 | DC-C | Roxburgh | Haywards | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L17 | L21 | DC-D | Roxburgh | Bunnythorpe | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L22 | L26 | DC-E | Benmore | Whakamaru | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L27 | L31 | DC-F | Benmore | Auckland | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L32 | L36 | DC-G | Roxburgh | Whakamaru | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L37 | L41 | DC-H | Roxburgh | Auckland | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L42 | L46 | DC-I | Invercargill | Haywards | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L47 | L51 | DC-J | Invercargill | Bunnythorpe | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L52 | L56 | DC-K | Invercargill | Whakamaru | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L57 | L61 | DC-L | Invercargill | Auckland | 300 | 500 | 700 | 1000 | 1000/(500) | 2012 |
| L62 | L66 | DC-M | Culverden | TAP | 250 | 500 | 700 | 1000 | 1000/(500) | 2014 |

## Table 4-2: New HVAC Options – long list

| **Option No.** | | | **Terminal Locations** | | **Sub Options** | | **Capacity (MW)** | **Year commissioned** |
|---|---|---|---|---|---|---|---|---|
| **From** | **To** | **Group** | **From** | **To** | **AC** | | | |
| L67 | L68 | AC | Benmore | Haywards | 220 kV | 400 kV | 700 | 2012 |
| L69 | L70 | AC-DC | Benmore | Haywards | 220 kV | 400 kV | 700 | 2012 |
| L71 | L72 | AC | Roxburgh | Haywards | 220 kV | 400 kV | 700 | 2012 |
| L73 | L74 | AC-DC | Invercargill | Haywards | 220 kV | 400 kV | 700 | 2012 |

## Table 4-3: Other Options – other options long list

| **Option No.** | | **Option Type** |
|---|---|---|
| L75 | OT-A | Generation technologies |
| L76 | OT-B | Demand side management initiatives |
| L77 | OT-C | Energy storage technology |
| L78 | OT-D | Fuel switching to hydrogen or gas |
| L79 | OT-E | Life extension of Pole 1 - Maintaining Half Poles at Benmore and Haywards |
| L80 | OT-F | Life extension of Pole 1 at Benmore - replace New 270 kV Pole at Haywards |
| L81 | OT-G | Life extension of Pole 1 at Benmore, Add 100 kV thyristor converter at Benmore - replace New 350 kV Pole at Haywards |
| L82 | OT-H | Life extension of Pole 1 at Benmore and Haywards. Add 100 kV thyristor converter in series at Benmore and Haywards to operate Pole 1 at 350 kV |
| L83 | OT-I | Part by part replacement of Pole 1 equipment at Benmore and Haywards. |

# 5 Options screening

The long list of options contains all technically possible options and does not consider any limitations such as costs and practical implementation.

Under the Rules, Transpower must apply the grid investment test reasonably to economic investments. The investments being contemplated by the HVDC Pole 1 Replacement Investigation Project are economic investments (i.e. it is an investment in the grid the main purpose of which is not to reduce expected unserved energy). For economic investments, the grid investment test requires a proposed investment to maximise the expected net market benefits compared with a number of alternatives projects and have expected net market benefits greater than zero.

Accordingly, to enable Transpower to compare a proposed investment with “alternative projects” under the grid investment test Transpower must first identify those options that fall within the definition of “alternative projects” under the Rules. “Alternative Projects” are defined in the Rules as follows:

> *any alternative transmission augmentation projects and* ***transmission alternatives*** *to the* ***proposed investment****, including any variant of the* ***proposed investment*** *that involves a non-negligible change in the timing of that* ***proposed investment****, that are:*
>
> *19.1. technically feasible;*
>
> *19.2. reasonably practicable having regard to the matters set out in clauses 8.1 to 8.4*[2]*;*
>
> *19.3. reasonably likely to proceed if neither the* ***proposed investment*** *nor any other* ***alternative project*** *proceeds and unlikely to proceed if the* ***proposed investment*** *does proceed;*
>
> *19.4. reasonably expected to provide similar benefits, in type but not necessarily in magnitude, to relevant nodes, as the* ***proposed investment;*** *and*
>
> *19.5. reasonably expected to enable the deferment of investment of the type contemplated by the* ***proposed investment*** *for a period of 12 months or more*

Therefore, only those options that meet the definition of “investment proposal” or “alternative projects” can proceed to application of the grid investment test and Transpower has used those definitions as the basis of its screening of long list options identified in section 4.

## 5.1 Options screening criteria

The applicable set of screening criteria relevant to economic investments taking into consideration the requirements of the Rules[3], good electricity industry practice (GEIP) and also those considerations relevant for the HVDC Replacement Investigation are summarised below:

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[2] The matters set out in clauses 8.1 to 8.4 include the grid reliability standards, any possible future scenarios set out in the statement of opportunities, the current state of the electricity industry and any reasonably expected future market developments.

[3] Under the Rules, only those options that meet the definition of “proposed investment” or “alternative project” may be included in the application of the grid investment test. Accordingly, Transpower has screened the long list of options based on whether the options would meet either of these definitions.

A. Fit for purpose
- Purpose - Interconnection of the two island markets

B. Technical feasibility
- Complexity of solution
- Reliability, Availability and Maintainability of the solution
- Future flexibility - Grid Development Strategy

C. Practicality of implementation
- Solution implementable by required date (Probability of proceeding)
- Property, environmental risks
- Implementation risks

D. Good Electricity Industry (GEIP)
- Consistent with good international practice
- Ensure safety and environmental protection
- Accounts for relative size, duty, age and technological status
- Prior industry experience with the technology
- Low technology risks

E. System security (additional benefit resulting from an economic investment)
- Improved system security
- System operator benefits (controllability)
- Dynamic benefits (modulation features and improved system stability)

F. Enabling Renewables
- Transport energy
- Balancing MW transfer

Each of these criteria are briefly described below.

### 5.1.1 Fit for purpose

The fit for purpose criteria ensures each of the options represents a credible alternative to the investment under consideration. For the HVDC Pole 1 Replacement Investigation, the purpose is to provide an interconnection between the transmission system in the North Island and the South island. If a particular option will not provide that interconnection it would not be expected to provide similar benefits to a proposed investment and will not meet the requirements of clause 19.4 of Schedule F4 of the Rules.

### 5.1.2 Technical feasibility

Clause 19.1 of Schedule F4 of the Rules specifies that alternative projects must be technically feasible. Solutions are technically feasible when they utilise proven technology that is readily available and is suitable for the planning horizon.

As part of the screening process, Transpower takes account of the technically feasibility which includes:

- Complexity of the solution
- Reliability of the solution
- Availability
- Maintainability
- Future flexibility and compatibility with Transpower's Grid Development Strategy[4]

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[4] See, Annual Planning Report 2007, Transpower New Zealand Ltd, 30 Mar 2007, pp 37-46.

### 5.1.3 Practicality of implementation

Practicality of implementation includes the ability to execute the option taking social, political and environmental factors into consideration.

The differentiation between technical feasibility and practicality of implementation is worth noting. A technically feasible solution (e.g. a 500 kV HVDC link between Invercargill and Auckland) may still not be practically implementable within the timeframe required.

Clause 19.3 of Schedule F4 of the Rules specifies that alternative projects must be "*reasonably likely to proceed if the proposed investment nor any other alternative project proceeds, and are unlikely to proceed if the proposed investment does proceed*". Inherent in whether an alternative is "reasonably likely to proceed" is the practicality of building the alternative, for example within the required need date.

Therefore, options are assessed against:

- the extent to which they are able to be implemented by the dates required. This may include consideration of central government legislation (such as the Resource Management Act), and/or local government requirements / bylaws (e.g. District Plan requirements);
- the ability to take existing assets out of service for the required duration (e.g. while reconductoring or thermal upgrading existing lines); and
- project lead times (approvals, equipment delivery times, and resource constraints).

A major consideration of any option is the property and environmental risk. Options involving transmission lines or establishment of a new substation may affect a large number of properties. Problems in securing property rights can present high risks towards implementing those options. Similarly, those options which require dealing with a large number of councils for the consenting/designation processes are faced with significant implementation and delay risks.

### 5.1.4 Good electricity industry practice (GEIP)

To qualify as a long short list option, an option must reflect good electricity industry practice. Good electricity industry practice is defined in the Rules to be:

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

Options are assessed in accordance with good electrical industry practice, including:

- Consistent with good international practice
- Ensure safety and environmental protection
- Accounts for relative size, duty, age and technological status
- Prior industry experience with the technology
- Low technology risks

### 5.1.5 System security benefits

Providing system security is not an essential criterion for economic investments. Nonetheless, some of these options will have positive contributions to system security and provide greater operational benefits. Options will be assessed for their ability to provide:

- improved system security;
- system operational flexibility; and
- dynamic benefits (such as modulation features and improving power system stability).

This economic investment is assessed primarily on energy transfer. The amount of dynamic benefit cannot be readily quantified other than where the cost of reserve generation or reactive support equipment can be identified, for example, the fast response of HVDC system and its ability to contribute to system stability.

Where two or more options provide similar economic benefits, the potential to provide additional dynamic benefits may be used as a differentiating factor.

### 5.1.6 Facilitating Renewable Generation

Clause 87B of the Government Policy Statement GPS (October 2006) states:

> *“The grid upgrade plan should also be consistent with statement of opportunity forecasts and wider government energy policy including applicable policies on renewable generation and climate change”*

Options are assessed for their ability and contribution to facilitating renewables. This ability may be expressed as:

- Transporting energy – the ability to transport energy from remote generation sources. This to some extent is valued as energy transfer benefits in the GIT.
- Balancing MW transfer - enabling bulk dispatch of renewable generation with fluctuating dynamic coverage from other sources of generation.

# 6 Screening the long list of options

Transpower applied the screening criteria identified in section 5 to each of the long list options set out in section 3. Transpower ascribed a positive, neutral or negative outcome for each of the screening criteria on each option. Only the options that have positive or neutral outcomes on all of the screening criteria are retained in the long-short list to proceed to the second phase of analysis, i.e. the options ranking.

## 6.1 New HVDC Options

### 6.1.1 Converter terminal locations: Whakamaru and Auckland

These options involve a single pole terminating at Whakamaru or Auckland in the North Island and are independent of the capacity of Pole 1.

The main expectation of a possible relocation of Pole 1 from Haywards to Whakamaru or Auckland would be the expected net market benefits resulting from linking remote South Island generation closer to the load centres in Auckland. However, total cost and implementation times for these options would be significantly impacted by the following:

1. The scale of these options is well beyond the scope of the purpose of the investment proposal. The cost of the project would be several times higher than a replacement at Haywards.
2. The minimum length of the HVDC transmission line would be over 1000 km to Whakamaru and over 1200 km to Auckland from Benmore. For these distances, the economic DC voltage for transmission would generally be much higher than

350 kV in order to manage transmission line losses. This may require the existing Benmore to Haywards HVDC transmission line and cables to be upgraded to above 350 kV.

3. Earth return operation of a monopole will produce lower line losses. However, due to environmental reasons it is not prudent to anticipate operating the link in continuous earth return mode. This would force the use of metallic return operation, increasing the line losses.
4. These options would be technically achievable but fraught with difficulties to implement in particular with respect to the property and environmental risks. The length of line would require interaction with a large number and a wide range of property owners and consenting authorities for permission to build. The cost of property purchase or designations would also be high. Transpower experience suggests that this scale of investment proposal poses a high risk of causing implementation delays resulting in a low probability of proceeding.

Given the risks to implementation with these options they are considered to have a negative outcome on the “practicality of implementation” criteria. On this basis, Transpower does not believe these options are reasonably likely to proceed and, therefore, do not qualify as “alternative projects”. Therefore, long list options L22 to L41 and L52 to 56 are discarded and do not proceed to the next phase of analysis, i.e. inclusion in the long short list of options for options ranking.

However, Transpower left it open that if the ranking process revealed significant economic advantage in moving the Pole 1 location from Haywards to Bunnythorpe, then Transpower would revisit Whakamaru as a terminal location for Pole 1. The options ranking process (refer to the “Option – Ranking” document attached to the GIT consultation documents) which includes a simplified grid investment test analysis did not include Bunnythorpe options within the short list and therefore no further analysis on the Whakamaru options is required.

### 6.1.2 Converter terminal locations: Bunnythorpe

Although some of the above arguments are also applicable to the options of relocating Pole 1 from Haywards to Bunnythorpe, Transpower has included some of these options in a long short-list for further analysis.

Transpower has considered Bunnythorpe as a potential terminal location for Pole 1 included in the long-short list of options (i.e., long list options L7 to L11. Options L17 to L21 are addressed in the following paragraphs and options L47 to L51 are treated separately under section 6.1.3). As part of the options ranking phase Transpower has performed a high level cost benefit analysis on those options with Bunnythorpe as a terminal location of Pole 1. The practicality of implementation risks are a significant disadvantage against these options and are included in the high level cost benefit analysis.

The options of extending to Bunnythorpe are not considered in conjunction with an extension of the existing HVDC transmission line beyond Benmore due to the practicality of implementation risk associated with two simultaneous large transmission line construction projects.

The options ranking high level economic analysis has subsequently shown that terminations at Bunnythorpe and Roxburgh are less attractive than Haywards and Benmore. Therefore then the option of extending both ways (north of Haywards and south of Benmore) is not expected to provide greater benefit and therefore it need not be evaluated. Consequently, the elimination of options L17 to L21 and L47 to 51 is reaffirmed. Sensitivity analysis within the application of the GIT has also shown that termination at Bunnythorpe and Roxburgh provide lower net market benefit than terminations at Haywards and Benmore respectively.

### 6.1.3 Converter terminal locations: Invercargill

These options involve a single pole terminating at Invercargill in the South Island and are independent of the capacity of Pole 1.

The main expectation of a possible relocation of Pole 1 from Benmore to Invercargill would be the expected net market benefits resulting from linking possible new remote South Island generation to North Island load centres. Compared with a terminal location for Pole1 at Roxburgh which would facilitate potential renewable generation from Otago and Southland, a terminal location at Invercargill will only produce benefit in connecting the lower probability generation projects in Southland. However, total cost and implementation times for these options would be significantly impacted by the following:

1. The scale of these options is well beyond the scope of the purpose of the investment proposal. The cost of the project would be several times higher than a replacement at Benmore.

2. The minimum length of the HVDC transmission line will be over 1000 km from Invercargill to Haywards. For these distances the economic DC voltage for transmission would generally be much higher than 350 kV in order to manage transmission line losses. This may require the existing Benmore to Haywards HVDC transmission line and cables to be upgraded to above 350 kV.

3. Earth return operation of a monopole will produce lower line losses. However, due to environmental reasons it is not prudent to anticipate operating the link in continuous earth return mode. This will force the use of metallic return operation, increasing the line losses.

4. These options would be technically achievable but fraught with difficulties in practicality of implementation; the main one being the property and environmental risks. The length of line would require dealing with a large number and a wide range of property owners and consenting authorities for permission to build. The cost of property purchase or designations will also be high. Transpower experience suggests that this scale of investment proposal poses a high risk of causing implementation delays resulting in a low probability of proceeding.

Given the risks to implementation with these options they are considered to have a negative outcome on the “practicality of implementation” criteria, Transpower does not believe these options are reasonably likely to proceed and, therefore, do not qualify as “alternative projects”. On this basis, long list options L42 to L61 are discarded and do not proceed to the next phase of analysis, i.e. inclusion in the long-short list of options for options ranking.

### 6.1.4 Converter terminal locations: Roxburgh

Although some of the above arguments are also applicable to options of relocating Pole 1 from Benmore to Roxburgh, Transpower has included some of these options in a long short-list for further analysis.

The main advantages of a terminal location of Pole 1 at Roxburgh would be to facilitate potential renewable generation from Otago and Southland.

Transpower has considered Roxburgh as a potential terminal location for Pole 1 included in the long-short list of options (i.e., long list options L17 to L21). As part of the options ranking phase Transpower performs a high level cost benefit analysis on those options with Roxburgh as a terminal location of Pole 1. The practicality of implementation risks are a significant disadvantage against these options and are included in the high level cost benefit analysis (i.e. options ranking).

These options of extending to Roxburgh will not be considered in conjunction with an extension of the HVDC transmission line beyond Benmore due to the practicality of implementation risk associated with two simultaneous large transmission line construction projects.

The options ranking high level economic analysis has subsequently shown that terminations at Bunnythorpe and Roxburgh are less attractive than Hayward and Benmore. Therefore then the option of extending both ways (north of Haywards and south of Benmore is not expected to provide greater benefit and therefore it need not be evaluated. Consequently, the elimination of options L17 to L21 is reaffirmed. Sensitivity analysis within the application of the GIT has also shown that termination at Bunnythorpe and Roxburgh provide lower net market benefit than terminations at Haywards and Benmore respectively.

| Converter Terminal Location | 1. Fit for purpose | 2. Technical feasibility | 3. Practicality of implementation | 4. Good Electricity Industry Practice | 5. System security | 6. Facilitating renewables | Result |
|---|---|---|---|---|---|---|---|
| **Auckland** | -1 | 1 | -1 | 1 | 0 | 0 | Fail |
| **Whakamaru** | -1 | 1 | -1 | 1 | 0 | 0 | Fail |
| **Bunnythorpe** | 0 | 1 | 0 | 1 | 1 | 1 | Pass |
| **Haywards** | 1 | 1 | 1 | 1 | 1 | 1 | Pass |
| **Benmore** | 1 | 1 | 1 | 1 | 1 | 1 | Pass |
| **Roxburgh** | 0 | 1 | 0 | 1 | 1 | 1 | Pass |
| **Invercargill** | -1 | 1 | -1 | 1 | 0 | 0 | Fail |
| Screening input | 1= Positive | | 0 = Neutral | | -1 = Fail | | |
| Screening output | Pass | | | | Fail | | |

**Table 6-1 Screening of HVDC converter terminal location options**

### 6.1.5 Converter pole capacity option: 300 MW Pole

As discussed in sections 6.1.1 and 6.1.3, any option that requires long HVDC transmission lines is not considered technically suitable due to the high capital cost compared to the maximum possible benefits. A 1000 km link regardless of the capacity will incur significant capital investment in the transmission line in excess of $150 million followed by further investment required for converters and the establishment of new sites. Therefore, a 300 MW pole, is only be considered as an option for terminal locations of Benmore and Haywards as no HVDC transmission line works and costs and risks associated with them are required. As such, long list options L7 to L12 do not proceed to the next phase of the analysis.

### 6.1.6 Converter pole capacity option: above 500 MW Pole

The existing HVDC transmission line between Benmore and Haywards and one submarine cable are suitable for 500 MW per pole operation at 350 kV. With two cables on Pole 2 this arrangement will provide a maximum bipole capacity of 1200 MW.

For locations other than Benmore or Haywards, extensions of the HVDC transmission line will be necessary. A monopolar metallic return configuration between any new converter location and the nearest existing converter location may be assumed for screening and ranking purposes as the establishment of any new earth electrode sites are not reasonable likely to proceed. A 500 MW pole is not ideal for extensions beyond Bunnythorpe or Roxburgh without increasing the line losses. The percentage of line losses to power transmitted will increase rapidly defeating the benefit achieved. This reaffirms the elimination of options L22 to L61.

| **Pole 1 Converter Capacity**<br>**Benmore - Haywards** | 1. Fit for purpose | 2. Technical feasibility | 3. Practicality of implementation | 4. Good Electricity Industry Practice | 5. System security | 6. Facilitating renewables | **Result** |
|---|---|---|---|---|---|---|---|
| **300 MW** | 1 | 1 | 1 | 1 | 0 | 0 | Pass |
| **500 MW** | 1 | 1 | 1 | 1 | 1 | 1 | Pass |
| **700 MW** | 1 | 1 | 1 | 1 | 1 | 1 | Pass |
| **1000 MW** | 1 | 1 | 0 | 1 | 1 | 1 | Pass |
| **Other Locations** | | | | | | | |
| **300 MW** | 0 | -1 | 0 | 1 | 0 | 0 | Fail |
| **500 MW** | 1 | 1 | 0 | 1 | 1 | 1 | Pass |
| **700 MW** | 1 | 1 | 0 | 1 | 1 | 1 | Pass |
| **1000 MW** | 1 | 1 | 0 | 1 | 1 | 1 | Pass |
| Screening input | 1= Positive | | 0 = Neutral | | -1 = Fail | | |
| Screening output | Pass | | | | Fail | | |

**Table 6-2 Screening of HVDC Pole 1 converter capacity options**

### 6.1.7 Converter Voltage Options: 270 kV

The present Pole 1 operates with a maximum voltage of 270 kV at the sending end (at Benmore). The initial installation of the HVDC transmission line was rated for ±250 kV and 1200 A operation. During the Hybrid Upgrade of the DC link the line was re-insulated for continuous operation at ±350 kV and 2000 A. Factors impacting continued use of 270 kV operation include the following:

1. The existing HVDC transmission line is rated for 2000 A operation. The capacity of the existing HVDC transmission line may be extended from a present maximum of 540 MW at 270 kV to 700 MW at 350 kV without needing significant redesign of the HVDC transmission line. This is a 30 % increase in line capacity at no additional cost in line upgrades.

2. The cables are rated at 350 kV and 1430 A, giving 500 MW maximum capacity. However, the two cables on Pole 1 presently operated at 270 kV. With an increase in operating voltage these two cables will be suitable for 700 MW operation. This is a 30 % increase in cable capacity at practically no additional cable cost.

3. At 270 kV operation of Pole 1 (with Pole 2 at 350 kV) with the existing three cables, the maximum bipole power capacity achievable will be limited to 1040 MW. This can be upgraded to 1240 MW when a new HVDC cable is installed. These maximums can be compared to those for 350 kV - 1200 and 1400 MW with three and four cables respectively. An increase of 160 MW at no significant cost.

4. The 270 kV DC options are considered practically feasible for replacing converter poles rated at 300 MW and 500 MW. The main constraint will be the HVDC transmission line which is rated to a maximum of 2000 A. The converter equipment budget costs would not show marked differences between 270 kV and 350 kV at this stage (without significant design optimisation). Ongoing cost of losses, however, will be higher for the 270 kV than for 350 kV. For 300 MW or 500 MW converter options, the voltages of 270 and 350 kV can be considered as inherent in the options [refer to reference 3].

5. At 270 kV, the new 700 MW and 1000 MW converter options will require the rating of the existing HVDC transmission line to be increased to 2600 A and 2860 A respectively. This would require a significant modification to the existing HVDC transmission line, resulting in a significant net market cost when compared to the same capacity options at 350 kV. This confirms that the practicality for implementation of 700 MW and 1000 MW capacity options would be limited to 350 kV, with 270 kV excluded.

6. The increase in operating voltage will reduce the line losses. For example, assuming a 10 ohm line resistance (approximate value based on Benmore-Haywards HVDC transmission line resistance), the line losses will be about 40 MW and 23.8 MW at 270 kV and 350 kV respectively at 540 MW (present Pole 1 maximum capacity). This corresponds to 7.4 % of HVDC transmission line losses at 270 kV compared to 4.4 % at 350 kV. If the line losses are valued say at $30/MWh at a 50 % utilisation during a year, the reduction in losses would amount to about $ 2 million/year.

7. There will be a further percentage reduction in losses in the converter plant at voltages higher than 270kV due to a reduction in current for the same MW capacity.

8. The converter and DC equipment costs are sensitive to current and voltage ratings. An increase in voltage will keep the current ratings lower. Hence the plant cost and losses would favour a 350 kV compared to a 270 kV voltage solution.

9. Transpower already has a pole which is rated at 350 kV. By maintaining 270 kV for Pole 1 it would not be possible to improve on the operational and maintenance cost savings, otherwise achievable with a common voltage operation of both poles at ±350 kV.

10. For those options where the length of the transmission line is expanded beyond Benmore or Haywards, the losses would increase for the 270 kV options much faster than the 350 kV option.

11. For new line constructions, the cost saving in material on line insulation for a 270 kV compared to a 350 kV line will be offset by the increased current rating and conductor requirements.

When taking all of these factors into account, the 270 kV option would not offer significant advantage over the 350 kV option. However, depending on the economic use of the link, the 270 kV may be considered as an inherent option for 300 and 500 MW capacity options, and hence retained on that basis. The selection of 270 kV as a preferred voltage for a new pole will depend on whether the total cost savings is higher than the overall savings from transmission losses at 350 kV.

The 270 kV option is limited to capacities equal or less than 500 MW and to converter stations at Benmore and Haywards. Outside these capacities or locations, 270 kV is not practical.

In summary, the 270 kV sub-option is eliminated from all options with the exception of L2 and L3.

### 6.1.8 Converter voltage options: 500 kV

For a long distance transmission link, increasing HVDC capacity would suggest an increase in DC voltage for apparent benefits as identified in section 6.1.7. Factors impacting the choice of a new DC pole for 500 kV operation include the following:

1. The existing HVDC transmission line is not suitable for 500 kV. To operate at 500 kV would require significant redesign of the line. This would require reconstruction of the existing line or construction of a new line. This means an additional cost of line upgrade to the project.
2. The two cables on Pole 1 at present are rated for maximum operating voltage of 350 kV and new cables would have to be purchased for the link to operate at 500 kV.
3. The increase in operating voltage will reduce the line losses. For example, assuming a 10 ohm line resistance, the line losses will be about 23.8 MW and 10.8 MW at 350 kV and 500 kV respectively at 540 MW (present Pole 1 maximum capacity). This corresponds to 4.4 % of HVDC transmission line losses at 350 kV compared to 2 % at 500 kV. If the losses are valued say at $30/Mwh at a 50 % utilisation during a year, the additional cost saving would amount to about $ 1.7 million/year.
4. There could be a further percentage reduction in losses in the converter plant at voltages higher than 350kV.
5. The converter and DC equipment costs are sensitive to current rating. An increase in voltage will keep the current ratings lower. An increase to 500 kV voltage would be beneficial for long distance DC links (say above 1000 km) with higher pole capacities (say above 1000 MW).
6. A 500 kV voltage option would only be worth considering for those options requiring new line construction with line lengths over 1000 km. Therefore, a 500 kV option would only be relevant for terminal locations further from Benmore and/or Haywards. Such a new line would have similar practicality issues and implementation risks as discussed in sections 6.1.1 and 6.1.3.
7. Transpower already has a pole which is rated at 350 kV. By using 500 kV for Pole 1 it would not be possible to improve on the operational and maintenance cost savings, otherwise achievable with a common voltage operation of both poles at ±350 kV.
8. For extensions of the existing line to Bunnythorpe or Roxburgh, it is not considered prudent to rebuild the existing line between Benmore and Haywards. These extensions when limited to 350 kV would involve lower implementation risks than rebuilding the whole line.

Given the risks to implementation and the high costs associated with implementing the 500 kV options, Transpower does not believe these options are reasonably likely to proceed and, therefore, do not qualify as “alternative projects”. On this basis, long list options L6, L11, L16, L21, L26, L31, L36, L41, L46, L51, L56, L61 and L66 are discarded and do not proceed to the next phase of analysis, i.e. not included in the long-short list of options for options ranking.

| Converter Voltage | 1. Fit for purpose | 2. Technical feasibility | 3. Practicality of implementation | 4. Good Electricity Industry Practice | 5. System security | 6. Facilitating renewables | Result |
|---|---|---|---|---|---|---|---|
| **270 kV (300/500MW)** | 0 | 1 | 1 | 1 | 1 | 1 | Pass |
| **270 kV (700/1000MW)** | -1 | 1 | -1 | 1 | 1 | 1 | Fail |
| **350 kV** | 1 | 1 | 1 | 1 | 1 | 1 | Pass |
| **500 kV** | -1 | -1 | -1 | 1 | 1 | 1 | Fail |
| **Other Links** | | | | | | | |
| **270 kV** | -1 | -1 | 0 | -1 | 1 | 1 | Fail |
| **350 kV** | 1 | 1 | 0 | 1 | 1 | 1 | Pass |
| **500 kV** | -1 | 0 | -1 | 1 | 1 | 1 | Fail |
| Screening input | 1= Positive | | 0 = Neutral | | -1 = Fail | | |
| Screening output | Pass | | | | Fail | | |

Table 6-3 Screening of HVDC converter voltage options for Pole 1

### 6.1.9 North Canterbury HVDC Tap-off

North Canterbury HVDC Tap-off options have been recognised and assessed as a potential grid development option within the South Island grid upgrade investigation. The South Island grid upgrade investigation has shown that the options of bussing at Geraldine or additional SVC's are the preferred South Island grid upgrade options thus eliminating all North Canterbury HVDC tap-off options. On their own, HVDC tap-offs would provide no material benefit for inter-island HVDC transfer, but would add significant cost to an inter-island HVDC Pole 1 replacement proposal. As such, Options L62 to L66 are therefore discarded and do not proceed to the next phase of the analysis.

## 6.2 New HVAC Options

Each of the HVAC options require AC submarine cables at 220 kV or 400 kV for the interconnection across the Cook Strait.

### 6.2.1 Inter-island AC interconnection

A full AC alternative involves synchronously linking the networks in the upper South Island and lower North Island. Given the purpose of this investment proposal to bring energy from Waitaki or lower South Island to the North Island a long distance bulk energy AC interconnection will be necessary.

This will require at least three single cored AC cables or one three-core cable as a minimum. A single three core cable may be an option if reliability of the AC link is traded off against the remaining HVDC Pole 2. For practical reasons a fourth single core cable may be added. A similar redundancy consideration is not easily made for a three-core cable due to the cost.

Substantial new AC transmission line lengths will need to be built from the lower South Island to the upper South Island. This may be a solution involving 220 kV, 400 kV or a mix of both voltage AC lines. Higher AC voltages may be more advantageous given the long transmission distances concerned. Regardless of the voltage chosen, the HVAC options are fraught with difficulties in practicality of implementation; the main one being the property and environmental risks. The length of line would require dealing with a large number and a wide range of property owners and consenting authorities for permission to build. The cost of property purchase or designations will also be high. Transpower experience suggests that this scale of investment proposal poses a high risk of causing implementation delays resulting in a low probability of proceeding. Ultimately, the investment involved will be significantly larger than utilising the existing HVDC transmission line.

In addition, a high capacity AC submarine cable circuit will be necessary. A submarine cable link may be in the order of 40 km (similar to the Cook Strait HVDC cables) which will present problems with reactive compensation. This may be in the form of high levels of compensation at both ends of the cable. The Cook Strait cable protection zone may mean there is not room for accommodating three or more new cables and one three-core AC cable may be required.

The cost of new transmission lines, cable terminals and AC cables will be very high compared to the use of existing HVDC transmission lines.

Given the risks to implementation and the high costs associated with implementing the HVAC interconnection options, Transpower does not believe these options are reasonably likely to proceed and, therefore, do not qualify as “alternative projects”. On this basis, long list options L67, L69, L71 and L73 are discarded and do not proceed to the next phase of analysis, i.e. inclusion in the long-short list of options for options ranking.

### 6.2.2 Inter-island AC/DC interconnection

A hybrid AC/DC alternative involves a synchronously linked network in the upper South Island and lower North Island.

These options will require the establishment of a DC termination point in the upper South Island. In addition, a high capacity AC submarine cable circuit will be necessary.

As set out above for the AC interconnection options, this will require at least three single cored AC cables or one three-core cable as a minimum. A single three core cable may be an option if reliability of the AC link is traded off against the remaining HVDC Pole 2. For practical reasons a fourth single core cable may be added. A similar redundancy consideration is not easily made for a three-core cable due to the cost.

While the additional transmission line is not required, a submarine cable link will be and may be in the order of 40 km (similar to the Cook Strait HVDC cables) which will present problems with reactive compensation. This may be in the form of high levels of compensation at both ends of the cable. The Cook Strait cable protection zone may mean there is not room for accommodating three or more new cables and one three-core AC cable may be required.

The additional cost of a converter station in Upper South Island, cable terminals and AC cables will be high compared to the use of existing DC cables.

Given the high costs associated with implementing the HVAC/DC interconnection options, Transpower does not believe these options are reasonably likely to proceed and, therefore, do not qualify as “alternative projects”. On this basis, long list options L68, L70, L72 and L73 are discarded and do not proceed to the next phase of analysis, i.e. inclusion in the long-short list of options for options ranking.

| **HVAC Inter-connection Options** | 1. Fit for purpose | 2. Technical feasibility | 3. Practicality of implementation | 4. Good Electricity Industry Practice | 5. System security | 6. Facilitating renewables | **Result** |
|---|---|---|---|---|---|---|---|
| **Inter-island AC** | 0 | 1 | -1 | 0 | 0 | 0 | Fail |
| **Inter-island AC/DC** | 0 | 1 | -1 | 0 | 0 | 0 | Fail |
| Screening input | 1= Positive | | 0 = Neutral | | -1 = Fail | | |
| Screening output | Pass | | | | Fail | | |

**Table 6-4 Screening of HVAC interconnection options across Cook Strait**

## 6.3 Other options

### 6.3.1 Generation and demand side options

Generation expansion and demand side management options are not distinct options but form an inherent part of the GIT analysis as defined by the market development scenarios (MDS) and the associated generation expansion schedules used within the GIT. Therefore these options L75 to L78 cannot be screened as part of this Phase or listed as distinct options in the long short-list. Consideration of these factors is inherently included within the GIT analysis.

### 6.3.2 Life extension of Pole 1

#### Overview

Transpower has been concerned for some time about the continued deterioration in the HVDC Pole 1 assets given the age of the plant and the risks identified in the 2005 GUP[5].

As part of the HVDC Pole 1 Replacement Investigation Project, Transpower needed to quantify the economics of continued Pole 1 operation. To that end, Transpower commissioned assessment from its insurance advisers in mid-2007 on the costs of insuring Pole 1. It was intended that these costs would then form part of the necessary GIT analysis for the replacement project.

Advice from Transpower's insurers was that the Pole 1 assets were uninsurable in their current state because of the potential consequences of failure and the age and condition of the assets[6]. Transpower subsequently commissioned further reports on mitigation costs and timings[7, 8].

After considering all the reports, Transpower decided on balance that it could not prudently continue to operate the Pole 1 assets other than in a limited mode of operation for a limited time without risking a high impact event. Transpower consequently announced that it intended to decommission one half-pole and look to make the other half pole available for limited northbound operation during peak demand periods only.

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[5] HVDC Grid Upgrade Plan, Sep 2005 submitted to the Electricity Commission [1]
[6] Risk Analysis Pole 1 HVDC Link, Marsh, 19 September 2007 [4]
[7] Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007 [5]
[8] Environmental Risk Analysis of Pole 1, Resource and Environmental Management Limited, 18 December 2007 [6]

### Pole 1 Assets Background

The existing Pole 1 commissioned in 1965 and use technology that is now obsolete. Spares are no longer available and Transpower has had to procure ‘used’ spares when other similar links overseas have been shut down. One other similar link remains in operation – but as a backup supply only.

The existing assets were built to different standards that are considered inadequate by modern standards, and pose consequential environmental risks that are very costly to mitigate and, in the case of mercury, remain intrinsic to the technology and cannot be fully mitigated.

Although robustly constructed at the time, the ageing assets have uncertain future performance and repairs and refurbishment are very expensive.

Even if some components are refurbished, many components are aged and expected to have increasing failure rates with failed components difficult to repair or replace. There is a risk that the refurbishment costs could be stranded if performance drops or a catastrophic failure occurs.

The above considerations have been key drivers in Transpower expediting the HVDC Pole 1 Replacement Investigation Project.

### HVDC Pole 1 Replacement Investigation Project

At the commencement of the HVDC Pole 1 Replacement Investigation Project into Pole 1 replacement, the economics of the existing Pole 1 continuing in some form in the future were considered.  To assist that analysis and determine whether it would be possible to continue operation of Pole 1 beyond 2010, Transpower engaged TransGrid Solutions to provide advice on the condition of the equipment and further engaged insurance advisers Marsh to advise on the cost of insuring against events relating to the aging Pole 1 assets. It was intended to use these costs in the GIT analysis for Pole 1 replacement.

### Professional Advice Received

In its initial report[9], Marsh advised that the Pole 1 assets, because of age and condition, had potential modes of failure with severe consequences. It was Marsh’s opinion that these assets were uninsurable in current operating condition.

The Marsh report was additional to the condition assessments of Pole 1[10,11] which highlighted the risks of continuing with 40+ year technology that was no longer supported by any manufacturer.  Those assessments resulted in Transpower limiting Pole 1 to northward flow only, to limit the stress to transformer windings from ‘arc backs’ during southward flow.

The initial Marsh report showed that Transpower could not prudently continue to operate the Pole 1 assets with the risks as reported and so Transpower initiated further work to quantify these risks and potential mitigation measures.

The second Marsh report[12] identified the mitigation works required to make the assets insurable. These works are significant and would take two or more years to complete.

Transpower also commissioned an environmental report[13] to address issues related to oil and mercury contamination. One of the conclusions of this report was that the assets should only be operated for ‘one to two’ more years (i.e. less than the period

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[9] Risk Analysis Pole 1 HVDC Link, Marsh, 19 September 2007 [4]

[10] HVDC Grid Upgrade Plan, Sep 2005 submitted to the Electricity Commission [1]

[11] Pole 1 Condition and Risk Assessment Reports, TransGrid Solutions, 3 October 2007 [7]

[12] Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007 [5]

[13] Environmental Risk Analysis of Pole 1, Resource and Environmental Management Limited, 18 December 2007 [6]

required for mitigation), and only in a limited mode of operation. Given these timeframes, the mitigation works described by Marsh[14] are not reasonable expected to enable the deferment of an investment of a new replacement Pole 1 for a period of 12 months or more. In addition, the probability of any significant benefit arising from the mitigation works is expected to be low.

On the basis of the identified risks, the costs of mitigation and the uncertain operating future of the aging assets and obsolete technology, Transpower has closed one half Pole 1[15]. This physically removes half the risk.

In order to mitigate potential supply security risks, Transpower is seeking to make the remaining half pole available until a new pole is operational. Operation would be restricted to periods of shortage and would avoid southward flow.

### High Impact Low Probability (HILP) events

Both Transpower and its advisors consider that there is a risk of a catastrophic failure if the existing assets are operated in an unrestricted manner for an indefinite period. This is due to the complexity of the assets, their age (and hence reliability) and technology.

Post-event analysis of a severe failure event would raise questions of prudence in operating aged and obsolete assets with known high impact failure modes.

While it may not be possible to determine whether an HILP event will occur, it is neither prudent nor good electricity industry practice (GEIP) to continue operation when it is known that an HILP event of the identified severity could occur.

### Conclusions

To some commentators, Marsh’s treatment of individual risks may appear overstated and, conversely, some risks may not appear to be addressed at all. Nevertheless, Transpower has concluded that on balance there are material risks that will be difficult and costly to mitigate and that some risks cannot be mitigated because of the technology used.

The consequences of a catastrophic failure cannot be ignored. Transpower cannot prudently continue to operate the Pole 1 assets other than in a safe mode of operation for a limited time without risking a high impact event.

Should Transpower continue to operate the existing Pole 1 assets and if a high impact were to occur, the knowledge of the risks enumerated in the Marsh and environmental reports would place Transpower in a position where it has not acted prudently and exercised an appropriate level of duty and care.

Operation of a half pole under limited conditions for short periods of time to meet system emergencies may be achievable because of the measures in place to limit the risk, such as the closure of (the other) half pole, the short exposure period and the removal of high risk modes of operation. This represents a balance between the consequences of not having a half pole available and risk of a high impact event.

The proposed restricted operation of the existing assets has the potential to deliver capacity benefits to the North Island for no additional investment. There is a risk that if the assets are run in an unrestricted mode, a failure could lead to the full shut down of Pole 1, potentially foregoing any further benefits of operating in a restricted manner.

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[14] Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007 [5]
[15] http://www.gridnewzealand.co.nz/n960.html

### Summary

Given the timeframes required to complete mitigation work on Pole 1 (i.e. two or more years) and the limited future remaining life of Pole 1 (i.e. one or two more years) mitigation works are not reasonable expected to enable the deferment of an investment of a new replacement Pole 1 for a period of 12 months or more. In addition, the probability of any significant benefit arising from the mitigation works is reasonably expected to be low.

Based on the above, implementation of mitigation works required to extend the life of the existing Pole 1 is:

- not reasonably practicable; and
- not considered reasonable likely to proceed.

In addition, Transpower does not considered it prudent nor good electricity industry practice (GEIP) to continue operation in full service when it is known that an HILP event of the identified severity could occur.

Therefore, the life extension options for Pole 1 (i.e. option L79, L80, L81 and L82) are screened out, do not qualify as long-short listed options and do not proceed to the next phase of analysis (i.e. Options Ranking).

### Subsequent Hypothesis Testing

Following a request from the Electricity Commission on 7 January 2008, Transpower has carried out economic analysis for a hypothetical situation where full service operation of the existing Pole 1, or half of Pole 1, is possible beyond the earliest likely commissioning date of a new Pole 1 (i.e. 2012). This represents a period of future operation which would be more than twice as long as the one to two years recommend within the environmental report.

The purpose of the economic analysis is to determine whether this hypothetical situation could reasonably provide benefit by hypothetically deferring the preferred HVDC Pole 1 replacement option as determine by the GIT. As such, the analysis attempts to identify whether there would be any significant net market cost in complying with the Environmental report's recommendations, without comprehensive regard to all of the practicalities that arise from of not carrying out the report's recommendations.

This analysis has been carried out and is presented in Attachment F of the GIT Consultation document.

## 6.3.3 Part-by-Part Replacement

The present state of Pole 1 as described Section 6.3.2 - Life Extension of Pole 1, also negatively impacts the feasibility of a part-by-part replacement option. Consequently, implementation of part-by-part replacement works required to extend the life of the existing Pole 1 and ultimately replace Pole 1 in its entirety is also:

- not reasonably expected to be practical; and
- not considered reasonable likely to proceed.

Further, a part-by-part option requires the existing ratings of most equipment to be maintained and any part-by-part replacement of the complete Pole 1 is subject to the following considerations:

1. All Pole 1 equipment would have to be progressively replaced
2. Unlike for a full replacement where the DC voltage can be increased to 350 kV, this option will limit the voltage to 270 kV. Thus the benefits of reducing

transmission line losses may not materialise. Given the size, duty and technological status of the existing pole and the complexity associated with the implementation of a part-by-part replacement option, Transpower does not consider that a complete part-by-part replacement of Pole 1 to be good electricity industry practice (GEIP).

3. In addition two of the existing cables could be required for a 540 MW capacity with this option due to high current requirements. Whereas, one existing cable will be adequate to provide 500 MW capacity for the 350 kV replacement options.
4. Even after replacement of all existing equipment, transmission losses would be similar to what it is at present due to the continuing need to operate at 270 kV.
5. Unless all components are replaced, the resulting Pole 1 would still not equal the reliability and availability of a new Pole 1.
6. The maximum capacity possible will be limited to 540 MW. The resulting Pole 1 would provide no capacity increase for future growth.
7. The total number of components would be double (compared to a new pole) and therefore the overall costs would be higher than a single pole, (as would maintenance requirements).
8. However, if an aggressive programme allowing major restructuring of the plants is considered the ratings may be improved.
9. On the other hand by increasing the voltage and current ratings the number of components can be reduced to one of the half poles and maintain the present capacity of Pole 1. This will prevent use of existing facilities such as valve hall total replacement of DC equipment. This case is no different to a full replacement pole except the process will be spread for several years. The net market benefits of such options are lower than any of the replacement options[16].

As detailed within the points above, Transpower considers that part-by-part replacement options:

- are not reasonably practicable;
- are not considered reasonable likely to proceed; and
- do not represent good electricity industry practice (GEIP) in this case.

Therefore a part-by-part replacement of the complete Pole 1 (i.e. option L83) is not considered a valid option to be included in the long short list of options and does not proceed to the next phase of analysis (i.e. Options Ranking).

| **Other Options** | 1. Fit for purpose | 2. Technical feasibility | 3. Practicality of implementation | 4. Good Electricity Industry Practice | 5. System security | 6. Facilitating renewables | **Result** |
|---|---|---|---|---|---|---|---|
| **Life extension** | -1 | 0 | -1 | -1 | 0 | 0 | 🟥 Fail |
| **Part by Part Replacement** | -1 | 0 | -1 | -1 | 0 | 0 | 🟥 Fail |
| Screening input | 1= Positive | | 0 = Neutral | | -1 = Fail | | |
| Screening output | 🟩 Pass | | | | 🟥 Fail | | |

**Table 6-5 Screening of Pole 1 life extension and part-by-part replacement**

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[16] Pole 1 Replacement Options [Transpower GUP 2005, Supporting Document 2] [1]

# 7 Summary of screening outcomes

| Major Options Group. | Sub Options Group | Carried to Long- Short List (Yes/No) | Options eliminated |
|---|---|---|---|
| **HVDC Locations** | Auckland | No | L27-L31, L37-41, L57 & L61 |
| | Whakamaru | No | L22-L26, L32-L36, L52-L56 |
| | Bunnythorpe | Yes (to BEN only) | L17-L21 |
| | Haywards | Yes | |
| | Benmore | Yes | |
| | Roxburgh | Yes (to HAY only) | L17-L21 |
| | Invercargill | No | L42-L61 |
| | North Canterbury tap-off | No | L62-L66 |
| **HVDC Capacity Options** | 300 MW | Yes (1) | L7, L12 |
| | 500 MW | Yes | |
| | 700 MW | Yes | |
| | 1000 MW | Yes (2) | |
| **HVDC Voltage Options** | 270 kV | Yes (3) | |
| | 350 kV | Yes | |
| | 500 kV | No | L6, L11, L16 |
| **HVAC Options** | AC Solution | No | L67, L68, L71, L72 |
| | AC/ DC Hybrid Solution | No | L69, L70, L73, L74 |
| **Other options** | Generation and demand side options | Yes(4) | |
| | Life extension of Pole 1 | No | L79-L82 |
| | Part by part replacement | No | L83 |

Notes:

(1) The 300 MW option is only relevant for Benmore-Haywards link consideration

(2) The 1000 MW option would be feasible if a new line construction or reconstruction/upgrade of existing HVDC transmission line is possible.

(3) The voltage option of 270 kV is inherent in the options of 300 and 500 MW but not suitable for 700 or 1000 MW capacity options for Benmore-Haywards link. It is not suitable for pole capacity higher than 500 MW pole or involving new converter locations.

(4) These options (i.e. factors) are inherently incorporated within the generation expansion modelling forming part of the GIT analysis.

# 8 Summary of Long short-list

The following is the long short-list resulting from the screening of options for the HVDC Pole 1 Replacement Investigation Project.

**Table 8-1 Summary of long short list**

| ***Long Short List Option No.*** | ***Option Description*** | ***New Pole Termination*** | | ***Circuit Rating*** | | ***Long List Option No.*** |
|---|---|---|---|---|---|---|
| | | **South Island** | **North Island** | **Voltage (kV)** | **Capacity (MW)** | |
| | | | | | | |
| LS1. | No new HVDC investment | N/A | N/A | N/A | N/A | L1 |
| | | | | | | |
| LS2. | 300 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 270/350 | 300 | L2 |
| LS3. | 500 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 270/350 | 500 | L3 |
| LS4. | 700 MW Pole 1 Benmore-Haywards | Benmore | Haywards | 350 | 700 | L4 |
| LS5. | 1000 MW, 350 kV Pole 1 Benmore-Haywards | Benmore | Haywards | 350 | 1000 | L5 |
| | | | | | | |
| LS6. | 500 MW Pole 1 Benmore-Bunnythorpe | Benmore | Bunnythorpe | 350 | 500 | L8 |
| LS7. | 700 MW Pole 1 Benmore-Bunnythorpe | Benmore | Bunnythorpe | 350 | 700 | L9 |
| LS8. | 1000 MW, 350 kV Pole 1 Benmore-Bunnythorpe | Benmore | Bunnythorpe | 350 | 1000 | L10 |
| | | | | | | |
| LS9. | 500 MW Pole 1 Roxburgh-Haywards | Roxburgh | Haywards | 350 | 500 | L13 |
| LS10. | 700 MW Pole 1 Roxburgh -Haywards | Roxburgh | Haywards | 350 | 700 | L14 |
| LS11. | 1000 MW, 350 kV Pole 1 Roxburgh -Haywards | Roxburgh | Haywards | 350 | 1000 | L15 |

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   *1.1 HVDC Pole 1 Condition and Risk Assessment [GUP 2005, Supporting Document 1]*

   *1.2 Pole 1 Replacement Options [GUP 2005, Supporting Document 2]*

2. Annual Planning Report 2007, Transpower New Zealand Ltd, 30 March 2007. http://www.gridnewzealand.co.nz/f41,2220/2220_grid-backbone.pdf

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