OTERANGA BAY TO HAYWARDS A LINE (CHURTON PARK SECTION) RECONDUCTORING

ATTACHMENT B: OPTIONS AND COSTING REPORT

TRANSPOWER NEW ZEALAND LIMITED

April 2018

Keeping the energy flowing




TRANSPOWER

Table of Contents

1 Introduction

This document is the Options and Costing report for the Churton Park section of the Oteranga Bay to Haywards A line reconductoring listed project application.

The condition of the line's conductor has reached replacement criteria and needs to be replaced.

1.1 Purpose

The purpose of this report is to:

- explain the long list to short list process
- identify the short list options that address the identified need
- provide summarised costs for all short list options
- present our cost-benefit analysis
- explain our listed project capital allowance.

1.2 Document Structure

This report forms part of the Oteranga Bay to Haywards A line reconductoring listed project application.

2 Moving from a long list of options to a short list

The long list of options that are alternatives to the project fall into three broad categories:

- Non-transmission solutions or alternatives to decrease or eliminate the need for a transmission investment through the use of such things as smart metering, demand response schemes etc.

- Transmission solutions: new assets
  - Building a new line
  - Using underground cable instead of over-head lines.

- Transmission solutions: existing assets
  - Maintain existing asset by patch fixing
  - Do nothing – run to failure
  - Replacing the conductor on the lines and increasing the capacity
  - Replacing the conductor on the lines and decreasing the capacity
  - Replacing the conductor on the lines and keep the same capacity - the "like for like" option
  - Dismantling the line and not replacing it.

Each of these long-list options has been assessed by considering their applicability to resolving the need, the likelihood they will be cost competitive with other equivalent options and the timeliness of the possible implementation.

We typically consider both transmission and non-transmission solutions (NTS) as options to meet transmission needs. However, due to the asset condition, safety, and asset criticality concerns associated with the existing conductor this option was not considered further as NTS solutions were not suitable options to meet the need for investment in this case.

2.1 Key requirements and assessment criteria

The long-list was evaluated using the following key requirements and assessment criteria:

1. Fit for purpose
    - The design will meet current and forecast energy demand
2. Technically feasible
    - Complexity of solution
    - Reliability, availability and maintainability of the solution
    - Future flexibility – fit with long term strategy for the Grid
    - Ideally the design can be staged and / or have flexibility to preserve options for future changes
3. Practical to implement
    - It must be possible to implement the solution by the required dates
    - Implementation risks, including potential delays due to property and environmental issues
4. Good electricity industry practice (GEIP)
    - Consistent with good international practice
    - Ensure safety and environmental protection
    - Accounts for relative size, duty, age and technological status
    - Technology risks
5. Provide system security (additional benefit resulting from an economic investment)
    - Improved system security
    - System operator benefits (controllability)
    - Dynamic benefits (modulation features and improved system stability)
6. Indicative cost
    - whether an option will clearly be more expensive than another option with similar or greater benefits
7. Feedback from consultation
8. Is economically neutral (or positive) for electricity consumers

Table 1 summarises our assessment of the long list options:

Table 1 - Assessment of Long List Options

Long List		Short Listed	Comments
Non Transmission Alternatives		X	The need (based on condition assessment and risk of conductor failure) is for a replacement conductor. As such, this option is not viable.
Transmission Solutions – New Assets	Building a new line	X	This option has been discarded. In 1992 OTB-HAY was diverted around Churton Park and consolidated into a new 'transmission corridor' obtained through a consent process. Therefore, it is unlikely there will be a better line route from a consenting perspective compared with the existing corridor.
	Using underground cable instead of over-head lines.	X	This option has been discarded based on the cost being higher than other options. Undergrounding is very expensive compared to overhead lines. The terrain is too steep and hilly for a cable within the transmission corridor; therefore, a new route is required.
Transmission Solutions – Existing Assets	Maintain existing asset by patch fixing	X	This option has been discarded. As the conductor continues to deteriorate, our ability to effectively maintain it will reduce over time to a point where it is no longer safe or cost effective to do so. Piecemeal removal or repair of widespread defects is not practicable for this line as required access is not possible or is excessively costly in many locations due to the steep and hilly terrain and under-crossings in span.
	Run to failure - wait until the conductor fails then replace either short sections or the entire line	X	This option has been discarded. This option comes with unacceptable risk to public safety. It would also result in an unplanned outage to one or both HVDC poles, which would result in major economic impacts to the electricity market.
	Replacing the conductor on the lines and increasing the capacity	X	This option has been discarded. An increase in rating on the Churton Park section of the HVDC lines will not increase HVDC capacity, as its capacity is constrained by the rest of the HVDC line between Benmore and Haywards.
	Replacing the conductor on the lines and decreasing the capacity	X	This option has been discarded. Decreasing the ratings of the OTB-HAY conductors would reduce the HVDC's capacity.
	Replacing the conductor on the lines and keep the same capacity - the "like for like" option	✓	This option has been included in the short list. This option meets all of our screening criteria (fit- for-purpose, technically feasible, practical, GEIP, system security, cost). A range of conductors are consistent with this option. The types of conductors that have been short listed are discussed below.
	Dismantling the line and not replacing it	X	This option has not been included as the there is a clear benefit provided by the HVDC to the NZ electricity system and market.

Reconductoring with a like-for-like or modern equivalent conductor is the only credible option from our long-list. We have considered a range of conductors within this short-listed option[1].

The conductors selected for the short-list needed to meet the current operating capacity of the HVDC (700 MW for Pole 3 and 500 MW for Pole 2), otherwise they would constrain the rest of the link.

In the below table, we summarise the reconductoring options considered in order to derive our short-list.

[1] Goat, Phosphorous and Selenium duplex conductors were eliminated because to achieve the required rating, they would exceed their recommended maximum operating temperature.

Drake and Dublin duplex conductors are still being trialled and the results will not be available in time for this reconductoring project

Table 2

Conductor	Meets load growth scenarios	Future TTU[2] upgrade possible?	Characteristics of options relative to Moa ACSR Duplex	Suitability to environ-ment	Standard conductor stock	Short list?
Moa duplex ACSR/AC (@65°C)	Yes	Yes	Maintains status quo. Some tower and engineering strengthening required for modern standards.	Yes	Yes	✓
Chukar duplex ACSR/AC (@61°C)	Yes	Yes	Blowout[3] slightly smaller than Moa. Loading significantly higher (20.5%CBL strung tension of conductor approx 8kN greater than that of existing Moa, and additional vertical loads from weight) meaning tower and foundation strengthening likely required. Wiring productivity slightly lower due to bigger conductor. Because of a larger conductor size, the bundle would be larger and could have structure internal clearance issues (which are already difficult to achieve for Moa) resulting in replacement cross arms with additional tower and foundation strengthening. Access costs increase substantially for cranes and concrete trucks to allow arm replacements and foundation strengthening.	Yes	Yes	✓
Zebra duplex ACSR/AC (@118°C)	Yes	No	Less wind load as conductor is smaller, but is lighter and will need greater tension to try to contain within easement resulting in increased likelihood of additional tower and foundation strengthening. Not all spans will be within existing easements so some expensive property easement costs are be expected. A smaller conductor means audible noise could be greater. Lighter conductor with high tensions could have internal clearance issues resulting in some replacement cross arms with additional tower and foundation strengthening. Access costs increase substantially for cranes and concrete trucks to allow arm replacements and foundation strengthening. Does not meet HVDC short term pole overload current rating.	Yes	Yes	✓
Zebra triplex ACSR/AC (@65°C)	Yes	Yes	Likely to have greater blowout to Moa at increased tension to stay within easement. Greater loads on tower and foundations, resulting in increased likelihood of tower and foundation strengthening. Not all spans will be within existing easements so some expensive property easement costs are be expected. A smaller conductor means audible noise could be greater - risk. Lighter conductor with high tensions could have internal clearance issues resulting in some replacement cross arms with additional tower and foundation strengthening. Access costs increase substantially for cranes and concrete trucks to allow arm replacements and foundation strengthening. Triplex bundle reduces ground clearance, requiring additional inverted V configurations. Wiring productivity is lower due to extra subconductor, sagging and space requirements.	Yes	Yes	✓
Goat triplex ACSR/AC (@80°C)	Yes	Yes	Likely to have greater blowout to Moa, so increased tensioning would be needed to stay within easement. Greater loads on tower and foundations, resulting in increased likelihood of tower and foundation strengthening. Not all spans will be within existing easements so some expensive property easement costs are be expected. A smaller conductor means audible noise could be greater - risk. Lighter conductor with high tensions could have internal clearance issues resulting in some replacement cross arms with additional tower and foundation strengthening. Access costs increase substantially for cranes and concrete trucks to allow arm replacements and foundation strengthening. Triplex bundle reduces ground clearance, requiring additional inverted V configurations. Wiring productivity is lower due to extra subconductor, sagging and spacering requirements.	Yes	Yes	✓
Sulphur duplex AAAC/1120 (@81°C)	Yes	No	Likely to have greater blowout compared to Moa. Loading could be slightly less (20.5% CBL strung tension of conductor approx 6kN less than existing Moa). Likely need for some taller tower replacements. Most spans will be outside existing easements and some substantial property easement costs should be expected. A smaller conductor means audible noise could be greater. Due to lighter tensions no major structure internal clearance issues are expected (mitigated with inverted V and existing 180kg weights). Access costs increase for cranes and concrete trucks to allow for new taller towers. Does not meet HVDC short term pole overload current rating.	Yes[4]	Yes	✓

[2] Tactical Transmission Upgrade, which for conductors relates to thermal uprating
[3] Blowout refers to the conductor moving in the wind.
[4] AAAC tends to perform better in polluted environments as there is no bimetallic corrosion.

2.2 Assessing optionality of short listed conductors

The following table shows the operating capacities of each conductor option.

Table 3: Unquantified Assessment of Conductor Capacity

	Capacity required with both poles operating			**Short term overload capacity required with pole 2 outage**		
Conductor	Real Power (MW)	Temp (°C)	Temp within conductor's operating limit?	Real Power (MW)	Temp (°C)	Temp within conductor's operating limit?
Moa duplex (Base)	873	65	✓	1008	78	✓
Chukar duplex	883	61	✓	1004	71	✓
Zebra duplex	873	118	✓	1001	152	X
Zebra triplex	873	65	✓	1006	78	✓
Goat triplex	881	80	✓	1001	97	-
Sulphur duplex	878	81	✓	1004	99	X

The continuous capacity of the HVDC circuits is 700 MW for Pole 3 and 500 MW for Pole 2. All conductor options meet this requirement. In a contingent event each pole can have a short-term overload, Pole 2 up to 840 MW and Pole 3 up to 1000 MW. Both Sulphur and Zebra duplex would exceed their recommended operating temperature if overloaded to 1000 MW. Zebra duplex is recommended to operate at below 120°C while Sulphur duplex at below 90°C.

If the HVDC link was further upgraded it could increase the short-term overload capacity of Pole 2 to 1000 MW, allowing the HVDC post-contingency capacity to increase from 840 MW to 1000 MW. This would also mean less (pre-contingency) reserves would need to be procured by the market. However, if Sulphur or Zebra duplex lines were installed, the post-contingent constraint in the HVDC system would remain at 840 MW, so the lines would need to be replaced in order to realise the full benefits from adding a fourth cable.

There is a reasonable likelihood of such an upgrade being required in the next 20 years (ie. within the useful life of the new conductors).

Sulphur and Zebra do not meet the short term overload rating for Pole 3 now (and for Pole 2 with a potential fourth cable) so score poorly in our unquantified benefit “Optionality for future upgrade”.

The final short-list of conductors are shown in the following table:

Table 4: Short list Options

Conductor Option	Type	Temp (°C)	MW
Moa duplex	ACSR/AC	65	873
Chukar duplex	ACSR/AC	61	883
Zebra duplex	ACSR/AC	118	873
Zebra triplex	ACSR/AC	65	873
Goat triplex	ACSR/AC	80	881
Sulphur duplex	AAAC/112	81	878

3 Short-List Option Costs

In this section we describe our approach to costing each of the options.

The cost of each short-listed option includes:

- the rectifications and strengthening anticipated to be required at each tower and foundation
- an assessment of how stringing the new conductor will be carried out taking into account aspects such as terrain, length of line, impact of circuit outages, resources etc
- equipment and materials required to complete the works
- the extent of any ancillary work, including access tracks to tower sites, foundation work for heavy lifting equipment, bridge strengthening (if transport is required) and additional work required for road, rail and other utility crossings
- an assessment of the uncertainty involved in each of these aspects, for example ground conditions and the strength of existing towers (dependant on the steel type and condition of the foundations)
- risks of delay due to weather conditions.

3.1 Purpose

Assumptions about each of these components have been made in order to compare options and the assessment of uncertainty is used to establish a Listed Project Capex Allowance (LPCA).

The various risks associated with each of these elements are described through each section.

To determine which conductors to evaluate in the short-list we started by considering the cost of a wide variety of conductors. Our cost estimates for the base case (Moa duplex) considered the following:

- Transpower Enterprise Estimating System (TEES) costings for construction using specific conductor types, and
- Transpower Business Case estimates derived from a high-level desk top study for duplex Moa installation (being the Base case), with an uncertainty range of -50%/+50%. The capital costs included:
    - Investigation and design
    - Materials (conductors, insulators & hardware)
    - Construction (conductors, structures, foundations, access and property)

For other short-list conductor options, material cost estimates were obtained for each, as were high level estimates of tower and foundation strengthening costs. All other construction costs were assumed to be the same as for Moa duplex installation. This may tend to favour options other than Moa duplex due to potential additional property costs, which we have considered within our unquantified benefit assessment.

A more accurate "Solution Study Report" (SSR) was subsequently undertaken for the preferred option (Moa). We have adjusted the previous estimated costs for the other conductor options to reflect this new cost information[5]. The new SSR Moa cost was approximately $5.5 million higher than the "old" cost estimate and can be seen in Table 5. As can be seen this change has been predominantly due to an increase in Access and Property costs which are common to all options. We have rescoped and priced the other short-listed conductor options considering their relative cost and scoping differences to Moa (as outlined in Table 2) and these 'new' costs have been used throughout this final listed project application proposal.

Table 5 – Changes to costs through project

Capex, real 2018, $000	SSR Cost March 2018	Desktop Cost December 2017	Change	
Investigation	0	544	-544	-100%
Design	876	1,270	-393	-31%
Conductor materials cost	915	959	-44	-5%
Insulators & Hardware	369	397	-28	-7%
Tower structural + foundations	405	1,040	-635	-61%
Access & property	7,372	923	6,450	699%
Stringing & other construction	9,959	10,221	-262	-3%
P50 risk allowance	1,858	0	1,858	0%
Reserve costs	0	900	-900	-100%
Total capex	**21,754**	**16,254**	**5,500**	**34%**

[5] New cost option A = Adjusted cost of Moa SSR based on estimated scope variation (ref Table 2) extrapolated from the loading and clearance information of the Moa SSR and input from our costing models.

3.2 Cost breakdown

3.2.1 Investigation & Design

Investigation costs are costs related to identifying our preferred solution and developing this proposal. Although these are a true project cost, they are common across all options and have already been allocated to Transpower as part of our current RCP2 Base Capex Allowance. Design costs are being included here, which cover the costs of detailed design and technical investigations and studies to implement the preferred solution.

3.2.2 Conductors & Material Cost

The cost of the conductor itself differs between the different options but the work involved to string the new conductor is common between the options. For example, the costs and materials are higher for options that are triplex.

3.2.3 Towers structural + foundations

Some tower and foundation strengthening is required for this project to meet the structural loads using current tower modelling techniques and foundation data. There are small changes required to increase clearances for safe working or for statutory requirements (e.g. NZECP 34). Most other options require a quantum of strengthening as tensions increase, with the larger Chukar conductor requiring all towers and foundations to be strengthened. A small number of tower replacements could also be required as well as cross-arm replacement to meet these heavier loads.

3.2.4 Access & Property

Most of the line section to be replaced passes over farmland with none directly over urban buildings, although four spans are less than 100m from houses in Churton Park. The crossing over the busy SH 1 Johnsonville-Porirua motorway and the electrified North Island Main Trunk Railway at span 58A - 59A pose a significant safety risk. There are also a number of significant crossings over 11 kV and 33 kV supply lines and minor roads. We have worked with the distribution asset owners to relocate or underground line crossings where possible. Replacing the conductor over the remaining crossings will require careful management to ensure public safety. Protection of these crossings will involve construction of safety-nets and supporting structures with dismantling following the stringing of the new conductor. Such crossings are both labour and time intensive.

We have planned for the use of scaffolding hurdles for the major State Highway 1 and Electrified NIMT crossings. This is because Catenary Support Systems are not yet sufficiently mature to be used with the much larger Moa conductor and duplex configuration in such a long span.

Costs to access the transmission line involve utilisation of existing access tracks, with some upgrades required to meet the loading of large stringing equipment and cranes used during construction. Each wiring site will have a flat platform constructed for wiring machines and conductor storage. These and temporary access tracks will be removed at completion – these costs have increased from our preliminary estimates since the SSR work has been undertaken. Construction will be challenging due to the hilly nature of the terrain, long access routes and multiple crossings. These costs include earthworks, benching, track upgrades, obtaining associated consents and landowner permissions and any reinstatement works required.

The work falls within allowable activities under the National Environmental Standards for Electricity Transmission (NES)[6] and Electricity Act. We also have some property issues that need to be rectified and we have included some funds to negotiate a resolution.

3.2.5 Insulators & Hardware, Construction & other

These cost categories capture all other major costs, construction costs such as stringing costs (the labour and associated tools and machinery hire), and insulators and hardware required to be replaced in order to upgrade the new conductor. These costs do vary a little across the different conductor types due to the slightly different work required on some options. This category also contains a small contingency to allow for weather delays – ie. wind speeds of greater than 80 km/hour will curtail work and >40 km/hour make sagging impossible. Analysis of local wind data suggests these wind conditions will prevail around 12% of the time, although this is variable year to year. The outages have been timed to coincide with the lowest wind months to minimise the adverse weather effects.

3.2.6 P50 Risk Allowance

As detailed design has not occurred for the options yet, there is a risk associated with the P50 estimate. This cost category accounts for additional tower strengthening and foundation work as well as stringing costs that are going to be encountered through the detailed design stage and implementation of our preferred option. The full extent of tower strengthening is subject to detailed design. The outage window is very tight with completion planned on the day before Easter Friday. Any delay during execution of the work will push the programme out past Easter.

[6] The NES sets out a national framework of permissions and consent requirements for activities on existing electricity transmission lines. Activities include the operation, maintenance and upgrading of existing lines.

Table 6: Capital costs ($2018, 000s)

Capex, real $2018, 000s	Moa duplex	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
Investigation & Design	876	876	876	876	876	876
Conductor material cost	915	1,063	627	883	769	659
Insulators & Hardware	369	369	369	369	369	369
Towers + foundations	405	2,898	1,209	2,898	2,898	2,345
Access & Property	7,372	7,997	7,537	7,997	7,997	7,572
Stringing + other construction	9,959	10,725	10,068	12,158	12,140	10,260
P50 risk allowance	1,858	1,858	1,858	1,858	1,858	1,858
Total P50 cost	**21,754**	**25,786**	**22,544**	**27,039**	**26,907**	**23,939**

3.2.7 Operating expenditure

We have assumed operating costs of $400k per annum, which is based on the average spend on this section of the line over the last 3 years. We don't expect there to be any material differences in the operating costs across the short-list options.

3.3 Electrical losses

In addition to the capital costs we have also considered the potential benefits resulting from lower electrical losses.

There are differences in the losses from each of the conductors. Larger conductors that run at lower temperatures will result in lower electrical losses. We have estimated the losses for each conductor under the five MBIE 2016 EDGS[7] scenarios:

1. Mixed renewables
2. High Grid
3. Global Low Carbon
4. Disruptive
5. Tiwai off

We have used SDDP[8] – a hydro-thermal dispatch optimisation model – to estimate flows on the HVDC under a range of hydrological conditions. SDDP takes 78 years of historical hydro inflow data and produces an optimal hydro dispatch profile given future demand, fuel/carbon price, and generation plant scenarios.

[7] Electricity Demand and Generation Scenarios
[8] Stochastic Dual Dynamic Programming

We have considered potential losses over 40 years using our “P50” expected demand forecast. These have been valued at $100/MWh and discounted using a 7% discount rate to determine the present value of losses associated with each option.

We found that in the Mixed renewables scenario northward transfers averaged around 2200 GWh in 2020, reducing to 1600GWh by 2040. In the “Tiwai off” scenario they averaged just over 6200 GWh in 2020, slowly reducing to around 4900 GWh by 2040[9]. For all scenarios, we took the average losses (from all the 78 inflow years).

We valued these losses using three different price assumptions:

- The short run marginal cost (SRMC) derived from our SDDP market model
- $50 per MWh sensitivity
- $150 per MWh sensitivity.

Table 7 shows the present value of the losses when averaged across the five EDGS scenarios, using a 7% pa discount rate. The expected life of the asset was assumed to be 40 years for valuing the losses.

Zebra duplex has the highest losses, while Chukar has the lowest.

Table 7: Present value of losses, average of 5 EDGS scenarios ($000)

PV $000	Moa duplex	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
$50 sensitivity	1,296	1,172	2,427	1,618	2,061	1,669
SRMC	2,546	2,303	4,768	3,179	4,050	3,216
$150 sensitivity	3,888	3,516	7,281	4,854	6,184	5,008

3.4 Total present value costs

The following table summarises the capital and operating costs, and also shows the present value (PV) of these costs.

Table 8: Conductor cost comparisons (P50 estimates)

$2018, 000s	Moa duplex	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
Capital cost	21,754	25,786	22,544	27,039	26,907	23,939
Annual opex (over life of asset)	400	400	400	400	400	400
Total present value (PV) cost	25,219	28,813	25,923	29,930	29,812	27,167

[9] Assuming that all lower South Island transmission constraints are alleviated.

The following table shows our overall analysis of options, including both costs and electrical losses.

Table 9: PV Costs and Losses showing preferred option

Option	**Moa duplex**	**Chukar duplex**	**Zebra duplex**	**Zebra triplex**	**Goat triplex**	**Sulphur duplex**
Total present value cost	25,219	28,813	25,923	29,930	29,812	27,167
Total present value losses	2,546	2,303	4,768	3,179	4,050	3,216
Total present value costs + losses	**27,765**	**31,116**	**30,691**	**33,109**	**33,862**	**30,383**
Net Benefit vs Base Case	**-**	**-3,351**	**-2,926**	**-5,344**	**-6,097**	**-2,618**
Rank	1	4	3	5	6	2

4 Listed Project Capital Allowance

Transpower is seeking approval from the Commission to increase the Base Capex Allowance by the estimated Listed Project Capital Allowance of the application.

Transpower estimates the expected cost of the application to be $21.8 million (+ HVDC Reserve Costs) in current (2018) dollars. With the addition of inflation and financing costs the total cost becomes $23.5 million (plus HVDC Reserve Costs) in 2020 when the conductor replacement is completed.

We have derived our proposed LPCA in a manner consistent with it being a standalone project, on the basis that our existing Base Capex Allowance was approved for other works, not including this project.

A summary of our LPCA calculation, including financing costs, inflation and exchange rate uncertainty (but excluding HVDC Reserve Costs) is shown in Table 10 and in Table 11 the annual break down is shown. As shown, the total LPCA we are applying for is $23.5 million. It is important to recognise that this amount excludes HVDC Reserve Costs.

We consider this amount to be our P50 estimate of the cost of the project – that is there is an equal chance that the project could be delivered for more or could be delivered for less. As with any project, and consistent with the incentive regime, we will attempt to deliver this project as efficiently as possible.

Table 10: Derivation of Listed Project Capex Allowance

LPCA application	Point selected within distribution (probability)	Cost applied for ($000)
Capex (real 2018$)	P50	21,754
Inflation		758
Exchange rates		-
IDC		952
Total LPCA (2020$)		**23,464**

Table 10: Listed Project Capex Allowance Annual Allocation

Cost by year	2018	2019	2020
Capex (real 2018$)	584	4,181	16,989
Inflation	1	93	664
Exchange rates	-	-	-
IDC	20	115	817
Total LPCA (2020$)	**605**	**4,389**	**18,471**

Per span costs

The costs of this project are higher than previous reconductoring works when compared on a per-span basis. These higher costs can be attributed to:

- the size and weight of the conductor and fittings when compared to typical Zebra conductor
- multiple wiring crews working at the same time to mitigate the length of the outage
- abnormally difficult terrain to work in
- a property easement remediation
- difficult and expensive hurdle crossings over SH1 and the electrified main trunk railway
- short 3km wiring runs which are not as efficient as a 6km run, and
- expensive undergrounding of local distribution company lines.

When these additions are accounted for, the project is comparable in cost with other reconductoring works we have completed.

5 HVDC Reserve costs

5.1 How reserve costs are allocated to Transpower

In the electricity market, reserves are required to protect against a sudden failure of a large generating plant or the HVDC link. This service is required to stop the resulting fall in frequency and allow the system frequency to recover promptly to 50 Hz. Reserves are provided by generation, or interruptible load. Reserve costs are paid by asset owners of generating units greater than 60 MW and the HVDC owner (being Transpower as the asset owner).

Costs are allocated on an island basis, proportional to the quantity of electricity injected by a generator or the HVDC transfer quantity.[10] With both poles in service Transpower's allocation of the reserve costs is reduced due to the ability for each pole to cover an outage of the other pole.

A simplified representation of the allocation of reserve costs is set out below for illustration[11]:

$$Share\ of\ reserves_t = reserve\ cost_t \times \frac{HVDC_{\ risk\ ,t} - 30\ MWh}{total\ reserve\ requirement_t}$$

where:

$HVDC_{\ risk\ ,t}$ is the at risk HVDC transfer in trading period t

$total\ reserve\ requirement_t$ is the total reserve requirement including that required from transmission and from generation units.

When both poles are in service $HVDC_{\ risk\ ,t}$ is significantly lower than the flow on the HVDC as one pole has the ability to cover the outage of the other pole reducing HVDC transfer at risk. When we are running a monopole, there is no self-coverage and all of the HVDC transfer is at risk. As a result, our allocation of the HVDC reserve costs will increase significantly as a result of undertaking this work.

5.2 How we modelled the impact on Transpower reserve costs

The same SDDP runs that were used to model the various outage options (see Attachment D) have been used to help analyse the potential impact on Transpower reserve costs. This provided generation, HVDC flows and short-run marginal cost of generation (SRMC) information.

However, SDDP is a least-cost optimisation, and the SRMC it produces is not necessarily the same as the market spot prices that may occur. For example, generators may be more risk adverse in a dry summer if there is a risk of low lake

[10] See clause 8.59 in the Code for details

[11] Note that this simple representation is for illustration purposes only and excludes some additional terms. See 8.59 for the full details.

levels leading into winter, resulting in higher summertime spot prices (than the SRMC of SDDP may imply). This is exactly the behaviour we observed this last summer in January 2018.

In order to better capture these market dynamics, we have supplemented the SDDP SRMC model outputs with a separate monte carlo simulation which produces a richer range of pricing outcomes. The parameters for the "shape" of spot prices over the year have been set so that it is consistent with the price patterns observed in the historical data.

We have assumed that reserve prices are a function of spot prices, and this relationship has been determined using least squares regression techniques. Volatility in reserve prices (that is unrelated to spot prices movements) is reflected in the Monte Carlo simulation.

We have also included in our simulation the potential impact of an unplanned CCGT outage (during the HVDC outage). We assume that *weekly average* spot prices would rise to at least $75/$125/$200 per MWh in a wet/normal/dry year, and that if the thermal outage occurred during the HVDC outage then prices would increase a further $50 per MWh. These assumptions reflect the type of marginal thermal plant that may be operating under each scenario.

5.3 The impact of outage on Transpower reserve costs

We intend to recover and capitalise the HVDC reserve costs as part of this project. However, the extent of these costs is heavily dependent on hydrological conditions. In wet years the flows on the HVDC are likely to be higher such that our allocation of the share of reserves will be higher. It is also likely less thermal generation plant will be operating which again is likely to increase our allocation of the total reserve costs. Our modelling suggests that the increase in Transpower reserve costs could be as low as $11 thousand or as large as $6 million with a 50th percentile of $1.9 million.

Table 11 summarises the range of reserve cost increases that we may be exposed to in different hydrological years[12]. It shows the increase in costs when there is just one pole operating, compared to the cost when both poles are operating. A negative number means that the share of costs has reduced under monopole operation.

We have excluded 10 days of VBE testing from our calculation, since those incremental costs cannot be attributed to this reconducting project.

Note that it is still possible for Transpower to be exposed to higher reserve costs (than we have modelled) if an extreme market event results in greater reserve market impacts than we have assumed. For example, we assume that in a dry year an appropriate price floor is $250 per MWh (weekly price), if there is an unplanned thermal

[12] In a wet year, the reserve cost per MWh will tend to be lower, however Transpower's share of the costs will be much higher due to the higher volume of HVDC transfers North. In a dry year the reserve cost per MWh will tend to be higher, so costs increase for all parties (both Transpower and generators).

outage during the HVDC outage. Its possible that a security of supply risk produces spot prices in excess of this for the week, resulting in very high reserve prices.

Table 11- Impact of outage on Reserve cost shares

Percentile	Transpower share $m	Generator share $m	Total market $m	Transpower % share
Mean	1,983	-355	1,628	122%
0%	11	422	433	2%
1%	499	128	627	80%
10%	908	-16	892	102%
50%	1,862	-433	1,428	130%
90%	3,142	-454	2,688	117%
99%	4,476	-491	3,986	112%
100%	5,954	-1,289	4,665	128%

Approving a P50 cost would leave us with a significant risk that we have little control over and few options to mitigate. There is no forward market for HVDC reserves to use to hedge our exposure. A partial mitigation option would have been to construct a by-pass line to reduce the outage length. However, as explained in this application this is not feasible within the timeframes for the need of this project, and would not be economic to implement.

5.4 Treatment of HVDC Reserve Costs within our Application

Given the high level of dependence on hydrology associated with reserve costs that is beyond our control, we consider that they should not be considered within the incentive regime (i.e. Base Capex expenditure adjustment).

This could be facilitated through use of the *g* term in Schedule B, Division 1 of the Capex IM. The Base Capex expenditure adjustment can be represented as:

$$base\ capex\ expenditure\ adjustment = a \times (b - c - g)$$

where:

a is the Base Capex incentive rate (33%)
b is the adjusted Base Capex Allowance
c is the actual Base Capex cost capitalised
g is the net Base Capex for which the incentive does not apply.

For example, if our listed project is approved, the approved amount will increase the "*b*" term. The actual cost of the project will be capitalised and included in the "*c*" term, and would include any increase in reserve costs. If our reserve costs were not included in our proposed increase to our Base Capex Allowance (i.e. the "*b*" term") but instead captured in the "*g*" term to offset their appearance in the c term, then they would "net-out" and not impact on the Base Capex expenditure adjustment.

In this case we would not be penalised if the weather was such that we faced high reserve costs or stand to gain if we faced very low reserve costs. Given this arrangement we would expect the reserve costs to be excluded from the approved increase to the Base Capex Allowance as they would not be subject to the incentive calculations.

The actual costs associated with reserves and stand-down costs would be captured in the *c* term for this project but then could be subtracted out using the g term such that they net out and are removed from the Base Capex expenditure adjustment.

Table 12 shows the range of incremental reserve costs that could occur, across a set of 78 historical inflow years. Either wet or dry hydro conditions could cause Transpower reserve costs to increase above the 90th percentile. We propose that once the hydro conditions in 2020 have transpired, the reserve cost impact is recalculated using the "actual" hydro conditions.

Table 12 – Transpower reserve cost risk

Percentile	**0%**	**10%**	**50%**	**90%**	**100%**
Increased cost (real 2018$)	11	908	1,862	3,142	5,954
Inflation	0	37	76	128	243
IDC	0	22	46	77	146
Total contingency for reserve costs (2020$)	**11**	**967**	**1,983**	**3,348**	**6,344**

