CHURTON PARK SECTION OF OTERANGA BAY TO HAYWARDS A LINE RECONDUCTORING

LISTED PROJECT APPLICATION

Transpower New Zealand Limited

May 2018

Keeping the energy flowing

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Executive Summary

This document is our application to the Commerce Commission seeking approval to increase our Base Capex Allowance for the costs to replace the conductor on the Churton Park section of our Oteranga Bay to Haywards A line (OTB–HAY A line).

The OTB–HAY A line is 37 km long and forms part of our HVDC (High Voltage Direct Current) link between Benmore in the South Island and Haywards in the North Island. The Churton Park section of this line spans 25 sections and is approximately 9.5 km long.

Project at a glance

This reconductoring project was identified as a "listed project" in the Commerce Commission's Transpower Individual Price Quality Determination 2015[1]. As a listed project, we can apply to the Commission for an increase to our Base Capex Allowance to cover the costs of this project. The details of this project are summarised below:

Proposal at a Glance	
What:	Replace the existing conductors on the Churton Park section of the OTB–HAY A line with ACSR/AC Moa duplex, rated to operate at 65°C.
When:	Commence work in Q4 2019 and complete by Q2 2020
How much:	Transpower is seeking approval: a. to add $23.5 million to our Base Capex Allowance (excludes HVDC Reserve Costs); and b. recover the actual HVDC Reserve Costs we incur as a result of the project, and those costs not to be subject to the incentive regime.

Need for this project

Conductor condition assessment has shown that the existing duplex Moa[2] conductor requires replacement.

As the conductor continues to deteriorate, our ability to maintain it effectively will reduce over time, to a point where it is no longer safe or cost effective to do so. If no action is taken, this ongoing deterioration will increase the risk of conductor failure. The consequences associated with a conductor failure may include fire, property damage, electrocution, or harm from physical impact, as well as, the unavailability of the HVDC impacting on the electricity market.

[1] http://www.comcom.govt.nz/dmsdocument/14912
[2] Moa is the name given to existing ACSR conductor. Duplex refers to the configuration of the Moa conductor. A duplex configuration has two conductors on the same circuit.

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Option assessment

We have considered a range of options for replacement of the existing duplex Moa conductor. Table A summaries the results. The duplex Moa conductor has the highest net electricity market benefit – $2.7 million higher than the next best option, a sulphur duplex conductor. It also has the highest unquantified benefits as it allows for future upgrade options, is likely to minimise disruption, is least likely to cause property issues, amongst others.

Table A: Quantitative and Qualitative ranking of options

Item	Moa duplex	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
Expected Net Electricity Market Benefit relative to replacing with Moa duplex ($000s)	0	-3,351	-2,926	-5,344	-6,097	-2,681
Net benefit as % of Base Case	0.0%	12.1%	10.5%	19.2%	22.0%	9.7%
Ranking based on quantified benefits (QB)	1	4	3	5	6	2
Ranking based on unquantified benefits (UQB):	1	2	3	4	4	4
Overall ranking QB + UQB	1	2	2	5	6	4

Management of outages

Each Oteranga Bay to Haywards circuit connects one HVDC pole to the AC system at Haywards. Therefore, an outage of one Oteranga Bay to Haywards circuit will require one of the two HVDC poles[3] to be out of service (monopole operation).

To complete the reconductoring work and replace the Valve Based Electronic equipment associated with HVDC Pole 2, we estimate there will need to be an outage for 13.3 weeks[4]. We understand stakeholders are concerned about the length of this outage. Within our construction programme we have attempted to minimise the length of the outage required through use of multiple line reconductoring crews. We also intend to coordinate this outage with an outage needed to replace electronic control equipment on the HVDC link and its associated testing, reducing the need for multiple outages.

[3] HVDC capacity can be maximised by ensuring Pole 2 is always the pole that is out of service; however, this is likely to increase the number of bi-pole outages required.
[4] 10 days of this outage relates to testing associated with replacing the Valve Based Electronics of Pole 2.

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We have considered a range of alternative ways to mitigate the outage length but in most hydrology conditions they cannot be justified.

A full bypass line could reduce the length of the outage. Our market modelling has found that under most hydrology conditions, the benefits from installing the by-pass would be less than its costs – it would cost in excess of $12m. Importantly, the bypass would not be feasible to implement by 2020.

Based on feedback, we also investigated the use of partial bypass lines with the aim of reducing the overall outage time length. Again, the extra expense cannot be justified in most hydro conditions.

Other alternative outage approaches we have considered include conducting the work over multiple years, or during different months. In our view, it would be more efficient to complete this work in one year and in the planned January to April window.

Overall, we still consider our base case option is the best option. In some more extreme hydrological sequences we recognise the outage length could have a material impact on generation dispatch costs. We cannot predict the type of hydrology that will exist in 2020. Therefore, we have based our decision on the likely conditions based on historical hydrological inflows.

Our intent is to continue to undertake a 13.3 week outage. We consider this provides generators with some certainty over our plans and the ability to hedge positions and manage lake levels based on this information. However, we will review this position closer to the time of the outage and in view of hydrological conditions. If, for some reason, the System Operator declared a grid emergency or if system security was challenged, we would consider deferring the outage, following our normal procedures, and based on actual conditions at that time.

We have not included any provision to stand-down crews and return both poles to service for several weeks part way through the outage within this application as our intent is to proceed with the 13.3 week outage. We do not consider that this cost, or other such deferral costs, are likely and would only be incurred in exceptional hydrological conditions.

HVDC Reserve Costs

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.[5] With both poles in service,

[5] See clause 8.59 in the Electricity Industry Participation Code 2010 (the Code) for details

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Transpower's allocation of the reserve costs is reduced due to the ability for each pole to cover an outage of the other pole.

With one of the poles out of service for 13.3 weeks Transpower will be exposed to higher reserve costs. We believe that the reserve costs attributed to the line upgrade is a capex cost and should be recovered by the project. However, the exact amount of that exposure is completely dependent on hydrology. Our modelling has indicated that these costs could range between $11 thousand > $6 million with a P50 figure being $1.9m. The very high costs for Transpower tend to occur in either very wet or very dry hydro years[6].

Within our application this represents a significant uncertainty.

Expenditure not subject to the incentive

We request that the Commission exclude reserve costs from the Base Capex expenditure adjustment. Approving a P50 cost relating to reserves would leave us with a significant risk that we have little control over and few options to mitigate. There is no forward market for 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 above this is not feasible within the timeframes for the need of this project, and would not be economic in the majority of cases.

One option to facilitate this would be through use of the *g* term in the Base Capex expenditure adjustment (i.e. Schedule B, Division 1 of the Capex IM). This term can be used to capture Capex costs to which the Base Capex expenditure adjustment does not apply and could be used to capture the actual cost of reserves in such a way as to "net" them out of the calculation. Another option would be to amend the adjusted Base Capex Allowance ex-post based on actual reserve costs in such a way as to "net" the reserve costs out of the calculations. We are happy to discuss with the Commission what is the most appropriate mechanism to exclude these costs from impacting the expenditure adjustment.

Under such an arrangement 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.

[6] 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). The 10 days of outage associated with VBE testing for Pole 2 has been excluded from these figures.

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1 The Proposal

This proposal concerns a section of the OTB–HAY A line, a part of the 350 kV HVDC link between the South and North Island. The line section in focus is known as the Churton Park section.

The Churton Park section of the OTB–HAY A line is a 9.5 km long, 25 span, section constructed in 1992 to deviate the existing line around the Churton Park residential area.

Conductor condition assessment has shown the conductor requires replacement. Conductor inspection and testing has confirmed there is exposed steel on the aluminium-clad core wires and that galvanic corrosion is now occurring at an accelerated rate.

This proposal concerns reconductoring the 9.5 km Churton Park section of the line. We replaced the conductor for the remainder of the OTB–HAY A line in 2008 and 2012, due to its then condition with a duplex Moa conductor.

The components in the box below are the grid outputs to be delivered by the project.

Grid Outputs

- Procuring, installing and commissioning conductors on the Churton Park section of the OTB–HAY A line with ACSR/AC Moa duplex, rated to operate at 65°C.
- Associated works on the towers and foundations to enable the Moa conductor to be operated at 65°C.
- Obtaining property rights and environmental approvals as required for these works.
- To undertake this work an increase in our Base Capex Allowance of $23.5 million (plus HVDC reserve costs)
- Approval to capitalise the actual HVDC Reserve Costs incurred but those costs not to be subject to the Base Capex expenditure adjustment.
- Expenditure outgoings up to $23,464,000 (plus HVDC Reserve Costs):

Year	$ Amount
2018	605,000
2019	4,389,000
2020	18,471,000
Total	**23,464,000 (plus HVDC Reserve Costs)**

with commissioning occurring in 2019/20 year.

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Reconductoring of the Churton Park section of the OTB–HAY A line was put forward in our RCP2 proposal with a provisional estimate of $28m. This reconductoring project was identified as a “listed project” in the Commerce Commission’s Transpower Individual Price Quality Determination 2015[7]. As a listed project, we are required to apply to the Commission for an increase to our Base Capex Allowance to recover the costs of this project.

The expected cost of reconductoring the Churton Park section (including contingencies, inflation and interest) will be $23.5m (plus HVDC Reserve Costs) once commissioned. We are seeking approval to increase our Base Capex Allowance by $23.5m plus the costs of reserves incurred by us (with reserve costs to be excluded from the application of the Base Capex expenditure adjustment).

We believe that the use of the *g* term in Schedule B, Division 1 of the CapexIM is an appropriate mechanism to facilitate the HVDC Reserve Costs being excluded from 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.

Alternatively, there may be another mechanism more appropriate for dealing with these costs that the Commission would prefer to use. We are happy to discuss with the Commission the most appropriate mechanism for the treatment of these costs.

[7] http://www.comcom.govt.nz/dmsdocument/14912

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2 The Need

2.1 Background

The OTB–HAY A line is 37 km long and is part of the 350 kV HVDC link between the South and North Island. The Churton Park section of the OTB–HAY A line runs from Tower 45A to Tower 68. This 25 span section was constructed in 1992 to deviate the existing line around the Churton Park residential area. It is strung with six Moa ACSR/AC (Aluminium Clad Steel Reinforced/Aluminium Clad) conductors, two for each of the two circuits (due to the duplex configuration of each circuit), and two for the earth return electrode line.

This section of line is in a severe corrosive environment due to airborne salts from the coast nearby. The rest of the line has already had the conductor replaced due to poor condition between 2008 and 2012. This proposed work would complete the reconductoring of the entire OTB–HAY A line.

Figure 1 and Figure 2 below illustrate the line.

Figure 1: Oteranga Bay to Haywards A line, towers 45 to 68

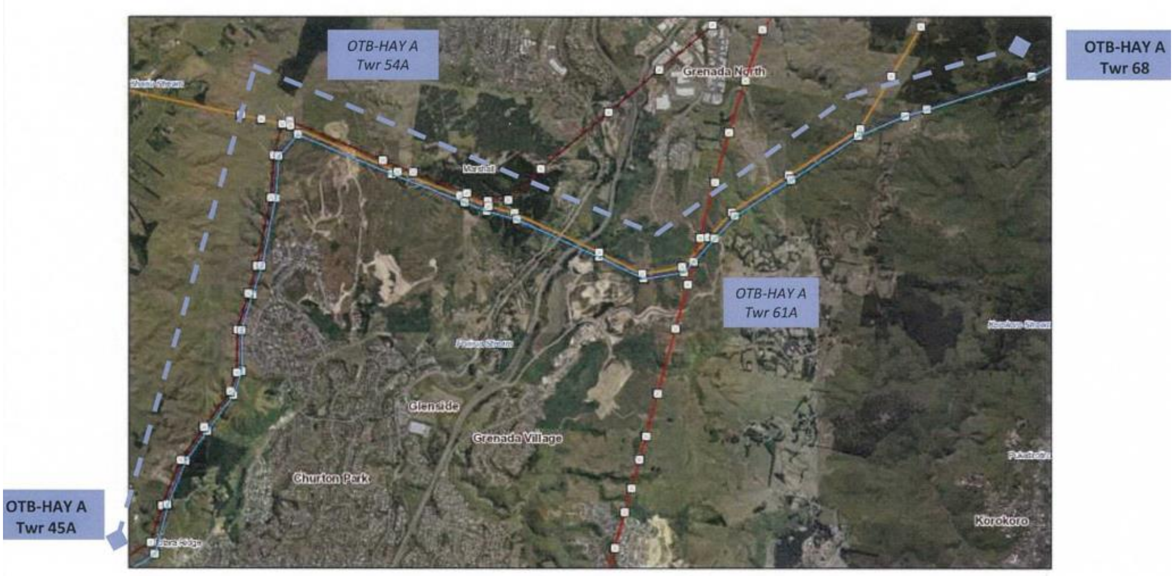

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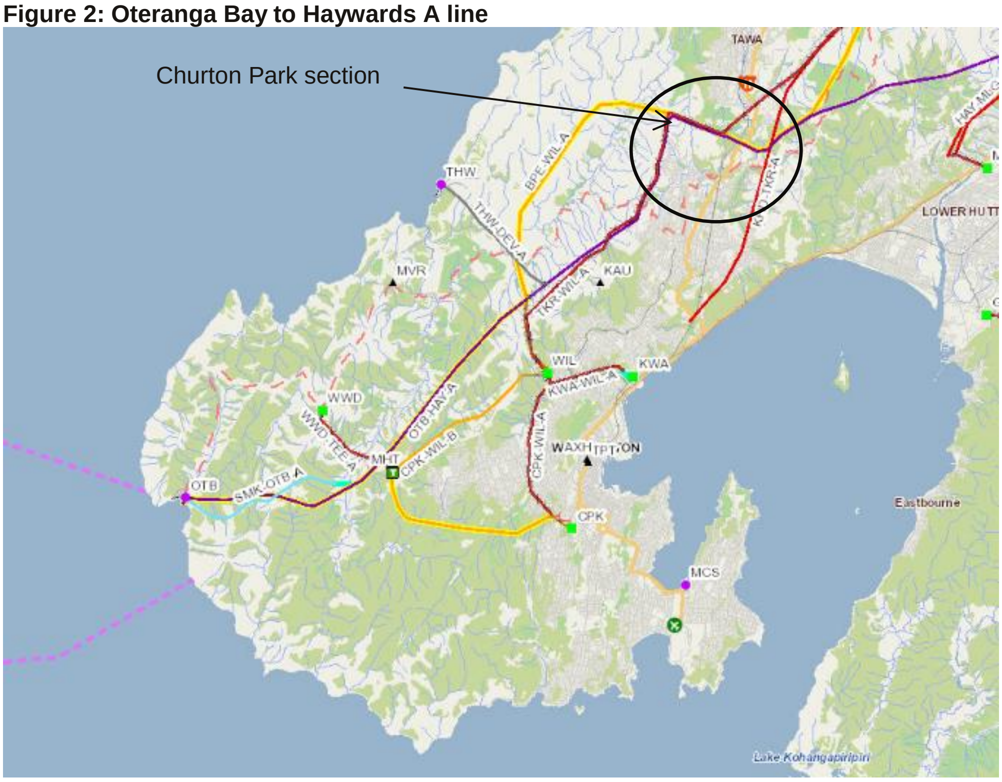
Figure 2: Oteranga Bay to Haywards A line



2.2 Need

The need to replace the existing conductor is driven by three factors:

- Asset condition
- Safety
- Criticality

2.2.1 Asset condition

Inspection and testing to date has identified conductor defects beyond Transpower replacement criteria and general conductor degradation indicating that accelerated corrosion is likely to be occurring on many spans in this line section.

All tests competed to date show relatively high degradation rates, and support the conclusion that this conductor needs to be replaced.

The photographs in Figure 3 and Figure 4 below show corrosion of the Oteranga Bay – Haywards A conductor and degradation of the ACSR conductor.

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Figure 3: Conductor defect on span 54A-55A shows extent of white corrosion product on the underside of the conductor before removal from the line

Figure 4: Exposed steel on aluminium-clad steel core wires (span 67A – 68)

A number of close aerial surveys carried out since submission of the RCP2 proposal has verified the need for replacement due to condition deterioration. During the 2017 inspection, we have identified a number of areas showing obvious signs of corrosion and the number of detectable bulges have increased. Bulging indicates our replacement criteria has been exceeded – it also implies the likelihood of bulging in other areas is likely to follow soon. Corman Eddie Current tests are also confirming that undetected internal corrosion is occurring within the conductor which cannot be seen in the close aerial surveys at this time.

On-going inspections and maintenance will be required to ensure the likelihood of a conductor failure is appropriately managed until the existing Moa conductor is replaced. The other sections of this line have been reconductored with duplex Moa consistent with the rest of the HVDC line.

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2.2.2 Safety

As the conductor continues to deteriorate, our ability to maintain it effectively will reduce over time, to a point where it is no longer safe or cost effective to do so. If no action is taken, this ongoing deterioration will increase the risk of conductor failure. Safety is an important consideration when setting our replacement criteria.

If a conductor failed due to poor condition, it is likely to fall onto the ground below. Potential consequences associated with such an event include fire to vegetation and property, electrocution, or harm from physical impact. Most of the line section passes over farmland. The relevant section of the line does not pass directly over urban buildings, although four spans are less than 100 meters from houses in Churton Park. The crossing over the busy State Highway 1 Johnsonville-Porirua motorway and the electrified North Island Main Trunk Railway at span 58A - 59A poses a significant safety risk.

2.2.3 Criticality

The Churton Park section of the OTB–HAY A line makes up a small section of the HVDC link.

The HVDC is the only connection between the North and South islands. It provides a number of critical benefits to New Zealand, including:

- reduced electricity generation costs by allowing greater utilisation of low cost hydro energy to be transferred from the South Island to the North, which displaces higher cost thermal generation;
- security of supply via transfer of energy from the North to South Islands during dry hydrological conditions, which allows stored water in the South Island to be rationed if necessary;
- greater competition in the wholesale energy, reserves, and retail electricity markets.

A conductor failure would cause an unplanned outage to one or both HVDC poles. This would cause disruption to the electricity market and have a major economic cost to New Zealand. Although an unplanned HVDC outage would not usually have immediate security of supply implications, a failure may threaten security of supply if it occurred during dry hydrological conditions in the South Island.

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3 Options, costs and benefits

3.1 The options

3.1.1 Long-list of options

We initially compiled a long list of options, which fell into three broad categories:

- Non-transmission solutions or alternatives
- Transmission options: New assets
    - New overhead line – different route
    - New underground cable
- Transmission options: Existing assets
    - Maintain existing asset by patch fixing
    - Do nothing (run to failure)
    - Reconductor: increase line rating
    - Reconductor: decrease line rating
    - Reconductor: like-for-like or modern equivalent
    - Dismantle

3.1.2 Assessment of Long-list options

A short-list of options was then derived by applying screening criteria.

We have included our assessment of the long-list to short-list process, in preparing this application, as Attachment B, and have summarised the key points below.

- × **Non-transmission solutions** – or alternatives to decrease or eliminate the need for a transmission investment through the use of such things as smart meeting, demand response schemes etc.
    - × Due to asset condition, safety, and asset criticality concerns associated with the existing conductor, non-transmission solutions were not suitable for meeting the need for investment.
- × **Transmission solutions – new assets** - considered options that involved investing in new transmission assets.
    - × New overhead line – different route. The A line could be re-built using a different route, however it is unlikely there will be a better line route from a consenting perspective compared with the existing corridor. Long consenting and construction processes would increase the risk of conductor failure before the construction is completed. This option is also unlikely to be economically justifiable.
    - × New underground cable. 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. Long consenting and construction processes would increase the risk of conductor failure before the construction is completed. This option is also unlikely to be economically justifiable.
- × **Transmission solutions – existing assets** - considered options that involve work with existing transmission assets.

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- × Maintain existing asset by patch fixing. The conductor on this line has reached replacement criteria more quickly than originally expected so it isn't feasible to undertake patch repairs for any extended period of time. The whole section is considered to be in the same condition. The access required for patch replacement is not possible in some locations and is excessively costly in any locations due to the steep and hilly terrain and under-crossings in span.
- × Do nothing – run to failure. This option comes with unacceptable risk to public safety from conductor drop. 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.
- × Reconductor – increase the rating. This option will not increase HVDC capacity, as its capacity is constrained by the rest of the HVDC line between Benmore and Haywards. So it is difficult to justify additional cost unless there were plans to upgrade the HVDC in the near-future.
- × Reconductor – decrease the rating. This option would reduce the HVDC's capacity. We consider that any cost savings from installing a smaller conductor are likely to be small and there is strategic value in not limiting the capacity of the line by installing a smaller conductor on this small section of line. Therefore, it is unlikely to be an economic option. Not fit for purpose if does not meet future demand growth.
- ✓ Reconductor – like-for-like or modern equivalent. 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.
- × Dismantle. Not practical or economic. Losing the ~2,500 GWh pa transferred North on HVDC each year would result in major economic impacts to the electricity market (~$200m pa).

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.

3.1.3 The short-list

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. The short-list of conductors are shown in Table 1:

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Table 1: 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

It is worth noting, while Zebra duplex and Sulphur duplex provide enough capacity to not constrain the HVDC in normal operating conditions, they have less overload capacity and could constrain flows. This is outlined further in Section 4.

Attributes and further details of the short-listed conductors can be found in the Options and Costing Report in Attachment B.

3.1.4 The Base Case option

Like-for-like reconductoring with duplex Moa is our Base Case option. As explained in Section 3.1.2, doing nothing is not a feasible option as this line section forms part of the critical 350 kV HVDC link. Piecemeal replacement of smaller sections of the line over several years has also been ruled out since the whole section is in the same condition.

3.2 The costs

3.2.1 Capital expenditure

In our analysis of the short-list we have included both capital and operational costs. Our initial capital costs were derived from a high-level desk top study for duplex Moa installation. The capital costs include:

- investigation and design
- materials (conductors, insulators & hardware)
- construction (conductors, structures, foundations, access and property)
- incremental reserve costs.

For this application we have commissioned a more accurate “Solution Study Report” (SSR) to be undertaken for the preferred option (duplex Moa). We have adjusted the “old” costs for the other conductor options to reflect this new cost information[8]. The new SSR Moa cost (present value) was approximately $5.5 million higher than the “old” cost estimate, which is predominantly due to increased costs related to complexity in property and access for construction. More detail can be found in section A.2 of this document. We have used the information identified in the SSR to produce new

[8] New cost option A = New cost Moa SSR plus a scope variation extrapolated from the loading and clearance information of the Moa SSR and input from our costing models.

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comparable costs for the other options (as much of the cost increase would be common to all options) and re-run the investment test analysis with this new information. The relative cost differences between the options have not changed materially in light of the SSR study.

Table 2: 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**

Sulphur and Zebra duplex are the cheapest conductors, but are more expensive overall because they have greater foundation or tower strengthening work required. Moa duplex is the cheapest option compared to other alternatives.

3.2.2 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.

3.2.3 Total present value costs

Table 3 summarises the capital and operating costs, and also shows the present value (PV) of these costs.

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Table 3: Cost of Options $000

$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

We discuss our approach to outages in undertaking this work in more detail in Section 6.

3.3 The Benefits

3.3.1 Economic assumptions

The assumptions used in this analysis are consistent with our long-list consultation:

- We have used a 7% pre-tax real discount rate as outlined in the Capex IM
- We have used a 40 year analysis period for valuing losses, given the long life of the asset.
- The cost of transmission losses are based on the marginal cost of generation as determined using our market dispatch model.
- Our generation plant assumptions are based on MBIE's 2016 Electricity Demand and Generation Scenarios (EDGS)[9].
- Our energy demand forecast is based on Transpower's 2016 Transmission Planning Report (TPR). The demand forecast also incorporates electric vehicle and solar photovoltaic uptake assumptions which are consistent with MBIE's EDGS.
- We have assumed that replacement of the conductor takes place in in 2020.

3.3.2 System dispatch and reliability benefits

All conductor options being considered in the short-list meet the continuous operating capacity requirements of the HVDC. We therefore assume they all provide the same level of system dispatch and reliability benefits during the years they are operating (i.e. we have not quantified any system dispatch benefits for the options). However, two of the conductors have a lower "overload" capacity which would constrain the line if there is an outage, or if there were to be a future upgrade to 1,400 MW (refer to section 2.2

[9] http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/edgs-2016

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in Attachment B, Options and Costing Report). We have considered this in our unquantified benefit analysis.

3.3.3 Loss benefits

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[10] scenarios:

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

We have used SDDP[11] – 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.

We found that in the mixed renewables scenario, northward transfers averaged around 2200 GWh in 2020, reducing to 1600 GWh by 2040. In the “Tiwai off” scenario they averaged just over 6200 GWh in 2020, slowly reducing to around 4900 GWh by 2040[12]. 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 4 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 4: 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

[10] Electricity Demand and Generation Scenarios
[11] Stochastic Dual Dynamic Programming
[12] Assuming that all lower South Island transmission constraints are alleviated.

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3.3.4 Expected net electricity market benefit

Table 5 shows the net market benefits for each conductor option relative to a Moa duplex option[13]. Moa has the highest net benefit of all the short-list options.

Table 5: Present value of costs and losses (2018 $000)

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

3.3.5 Robustness of the results

We have undertaken sensitivity analysis to determine the robustness of our quantified option assessment.

Table 6 shows the net benefit / (cost) relative to our Base Case (Moa duplex). It shows the difference in the Present Values of each option under low and high sensitivities:

- Capital costs - /+30%, except
  - Enabling works for Chukar, Zebra, Goat and Sulphur assume +/-50% (these other options have not had a detailed study undertaken)
- Transmission losses at $50/MWh or $150/MWh
- Change in discount rate -/+3%

Each row shows the impact from changing only that single cost driver.

[13] We have not presented the results relative to a "do nothing" option as for safety reasons we would look to dismantle this section of the line. We have also not presented the results relative to dismantling this section of line. This would mean the HVDV link would not operate, and cause generation dispatch costs to increase at a high level by approximately $200m pa. We do not consider such an option is sensible or economic. However, if this was used as the base case reconductoring the line would result in a expected net electricity market benefits in excess of $2 billion over 40 years.

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Table 6: Sensitivity of net benefit (PV $000)

Net benefit/(cost) PV $000	Moa	Chukar	Zebra	Zebra	Goat	Sulphur	Base case quant rank
P50	0	-3351	-2926	-5344	-6097	-2618	1
Low sensitivities							
Conductor capex	0	-3312	-3003	-5354	-6137	-2687	1
Tower + foundation capex	0	-2166	-2494	-4159	-4911	-1680	1
Stringing & other construction	0	-1289	-1141	-2647	-3406	-755	1
Losses	0	-3471	-1835	-5033	-5359	-2321	1
Disc rate	0	-3528	-2961	-5577	-6323	-2714	1
High sensitivities							
Conductor capex +30%	0	-3390	-2849	-5335	-6057	-2549	1
Tower & foundation capex +30%	0	-4537	-3358	-6530	-7283	-3557	1
Stringing & other construction	0	-5418	-4712	-8043	-8788	-4485	1
Losses @ $150/MWh	0	-3223	-4097	-5678	-6889	-3068	1
Disc rate +3%	0	-3187	-2894	-5130	-5887	-2529	1

The low and high capex sensitivities reflect the uncertainty in our current cost estimates. Moa duplex remains the best option under both the low and high capex sensitivities.

The ranking of our options also does not change when we flex the discount rate or the low and high losses sensitivity.

3.4 Unquantified benefits:

We have further assessed the suitability of the conductors against each other using a variety of other considerations.

Our qualitative assessment is described in Table 7 below. The benefit for each option has been qualitatively ranked between ✓ and ✓✓✓, where ✓✓✓ means more benefit than ✓. Of the full list of unquantified benefits we consider, the following are relevant to this analysis:

> **Optionality to further upgrade –** how easy will it be to further increase capacity if required? This benefit recognises the inherent optionality in some options from

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being able to increase capacity if our demand and/or generation assumptions prove to be inaccurate.

Consumer benefits through enhanced competition – to what extent will the option enhance competition in the New Zealand electricity market and create competition benefits? The more competitive a market is, the closer nodal prices will be to SRMC. Higher transfer capacities, both northward and southward will enhance market competition. This benefit is not captured in our modelling.

Minimises disruption – to what extent will the local community be disrupted by the implementation of an alternative? Replacing conductor and working on towers creates disruption and often inconvenience to the local community. Over time, lower capacity or incremental upgrades are more disruptive to communities because we will have to undertake our upgrading activities more often.

Operational benefits – to what extent are there operational benefits not reflected in the economic analysis?

Asset life – to what extent will the options differ in expected life? These effects are not recognised in our analysis.

Property impacts – to what extent will the options differ on their impact on property in the vicinity of the asset?

Table 7: Unquantified assessment of benefits

Item	**Moa duplex (Base Case)**	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
Optionality to further upgrade	✓✓✓	✓✓✓	-	✓✓✓	✓✓✓	-
Consumer benefits through enhanced competition	✓✓✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓	✓✓✓
Minimises disruption	✓✓✓	✓✓	✓✓✓	✓	✓	✓✓✓
Operational benefits	✓✓✓	✓✓	✓✓	✓	✓	✓✓
Asset life	✓✓	✓✓	✓✓	✓✓	✓✓	✓✓✓
Visual impacts	✓✓✓	✓✓✓	✓✓✓	✓✓	✓✓	✓✓✓
Property impacts	✓✓✓	✓✓	✓✓	✓✓	✓✓	-
Total ticks	20	17	15	14	14	14
Unquantified benefits (UQB) ranking:	1	2	3	4=	4=	4=

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Optionality for future upgrade: Which options allow for future upgrades in the future?

- Sulphur and Zebra duplex meet the load requirements under normal operating conditions, however, they would be operating near their maximum temperature rating, hence there is no optionality for a future thermal upgrade. Their limited overload capacity would also reduce Pole 3's current overload capacity following the unplanned loss of Pole 2. This is a significant dis-benefit associated with these options. This is discussed in more detail in Section 2.2 in Attachment B Options and Costing report.

Consumer benefits through enhanced competition: Are there any competition benefits associated with any of these options?

- Our assessment is that all options provide similar levels of competition.

Minimises disruption

- Disruption is minimised by installing duplex Moa, Sulphur or Zebra. The length of the HVDC outage could be longer for triplex installation since they are more difficult to sag than duplex, and Chukar is a heavier conductor than Moa so may take longer to install[14].

Operational benefits

- There are operational benefits from installing Moa since the same maintenance schedule and procedures can be used as for other sections of the line.

Asset life

- Asset life is also expected to be similar for all options. All Aluminium conductors may have a longer life, but we have not had these in service for sufficient time to determine if this the case. Modern manufacturing techniques and monitored grease application have improved the service life of ACSR (Moa) significantly.

Visual impact

- We do not consider there is a meaningful difference in visual impact between options.

Property impacts:

- Sulphur duplex conductor configuration is lighter than Moa and hence could have a blow-out[15] more than the existing duplex Moa. This has a significant risk of causing property impacts with associated cost and time implications.

Overall our assessment is that Moa duplex has the most unquantified benefits and strongly outperforms a duplex Chukar conductor.

[14] Sulphur and Zebra duplex could also impose further disruption in the future, which we discuss in section 2.2 of Attachment B: Options and Costing Report - relating to overload capacity and a potential 4th cable.

[15] "Blow-out" is conductor movement under wind

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4 Selecting the investment proposal

To select our preferred option we considered both our quantified and unquantified analysis.

Table 8 summarises the quantitative and qualitative analysis. The unquantified benefits deriving from a Moa installation are far superior to other options as described in our assessment of unquantified benefits above.

Table 8: Quantitative and Qualitative ranking of options

Item	Moa duplex	Chukar duplex	Zebra duplex	Zebra triplex	Goat triplex	Sulphur duplex
Total cost PV ($000s)	-27,765	-31,116	-30,691	-33,109	-33,862	-30,383
Expected Net Electricity Market Benefit ($000s)	0	-3,351	-2,926	-5,344	-6,097	-2,618
Net benefit as % of Base Case	0.0%	12.1%	10.5%	19.2%	22.0%	9.4%
Ranking based on quantified benefits (QB)	1	4	3	5	6	2
Ranking based on unquantified benefits (UQB):	1	2	3	4	4	5
Overall ranking QB + UQB	1	2	2	5	6	4

We consider this demonstrates that Moa duplex conductor has the best overall ranking, is sufficiently robust under sensitivity analysis to satisfy the requirements of the Investment Test and it therefore becomes our proposal.

4.1 Good electricity industry practice

The proposed replacement of the Churton Park section of the OTB–HAY A line with Moa duplex conductor removes safety risk and better utilises existing assets. Overall the proposal reflects good electricity industry practice by being consistent with good international practice, demonstrating economic management, and improving safety.

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5 Stakeholder engagement

Table 9 summaries our engagement with stakeholders.

Table 9: Stakeholder engagement to date

Date	Activity
December 2016	Request for Information and Long-list of Options
December 2017	Consultation on our draft Listed Project Application
February 2018	Outage options forum
April 2018	Outage modelling and capital cost update

In December 2016 we published our Long-list consultation document[16] entitled *Long-list: Oteranga Bay to Haywards A line (Churton Park section) reconductoring.*

We received three submissions. All submitters were supportive of the need for the reconductoring work to be carried out. However, all submitters raised the issue of the outage length and timing, and commented on how best to mitigate the market impact of the outages.

In Attachment C, we provide Transpower's responses to the feedback received from this consultation.

Following receipt of that feedback we:

- undertook analysis around spreading the work and outages over two summers
- investigated the benefits of a third lines crew working, rather than two crews.

We did not find any net market benefit in changing our approach to the options raised. We published the findings of our analysis in our *Preferred Option Consultation* in December 2017. The options considered are summarised in Section 5 of this document.

In December 2017 we published our *Preferred Option Consultation*.

We received two responses – one from Contact Energy and one from Meridian.

The submissions agreed with Transpower's condition assessment and the need to reconductor the Churton Park section of the OTB–HAY A line. They also agreed with the replacement option selected. They also supported Transpower coordinating other work associated with the HVDC during this project to minimise the impact of outages in the future.

[16] The consultation paper, the non-confidential submissions and this document are available at https://www.transpower.co.nz/oteranga-bay-haywards-churton-park-section-reconductoring-investigation

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Contact expressed concerns about the duration of the 13.3 week outage and the effect it will have on potential spill. It requested Transpower ensure the outage can be deferred if market conditions prove unfavourable prior to its commencement, such as high forecast spill levels or energy shortfalls or in a security of supply situation.

Contact also suggested we consider any partial bypass options. Meridian was of the view that a partial bypass option would likely provide a net market benefit. They considered limits on HVDC transfer under monopole operation are now greater given national reserve sharing and the thin North Island reserves market. They submit that even short periods of bi-pole operation during the project would provide greater flexibility to manage hydro storage and avoid spill.

On Friday 23rd February 2018 we hosted an *Industry Forum* to present our analysis of outage option alternatives to interested parties. The notes from this session can be found on our project website[17].

In early April 2018, we published an update of our outage modelling and the capital costs for this project.

Full details of our consultation and comments can be found in Attachment C.

[17] https://www.transpower.co.nz/oteranga-bay-haywards-churton-park-section-reconductoring-investigation

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6 Mitigating the impact of outages for construction works

Each Oteranga Bay to Haywards circuit connects one HVDC pole to the AC system at Haywards. Therefore, an outage of one Oteranga Bay to Haywards circuit will require one of the two HVDC poles[18] to be out of service (monopole operation).

To undertake this proposed project work, we require the HVDC to run on monopole operation for 13.3 weeks. Within the first 6 weeks we have coordinated this work with other work required to replace the Valve Based Electronics (VBE) on Pole 2. During the VBE replacement, Pole 2 will be out of service.

We have received support for the project[19]. However, submitters raised the issue of the outage length and timing, and have commented on how best to mitigate the market impact of the outages (e.g. partial by-pass lines, breaking up outages, deferring work if constraints would be high etc).

The costs presented in Section 3.2 of this document assume there is a 13.3 week continuous outage of one pole, from 7 January 2020 to 9 April 2020. It should be noted that:

- The actual outage lengths may vary depending on the impact of weather.
- Our costs assume an average year adverse weather contingency based on NIWA data (construction is mainly affected by high wind speeds).
- Any variations in outage timing will also be dependent on us aligning with outages to replace electronic equipment associated with the HVDC link which would itself require a single pole outage of at least 4 weeks, and testing activity of up to 10 days.

Additionally, there is also the need for 8 hour bi-pole outages on 4 separate days. The outages are now loaded onto the shared industry POCP outage notification website.

6.1.1 Analysis of outages

We have undertaken options analysis to try and establish ways to minimise the outage length required to undertake this project. Stakeholder feedback has led to more options that we have also considered in the analysis.

In our Long-list consultation we ruled out a bypass line since we considered its significant cost ($12m) outweighed any generation dispatch benefits it provided from reducing the outage length in most hydro conditions. In addition, the long lead-in time to build a bypass would mean that the project would not be completed in time to meet the need for this project, and therefore increase the risk of the conductor failing.

[18] HVDC capacity can be maximised by ensuring Pole 2 is always the pole that is out of service; however, this is likely to increase the number of bi-pole outages required.
[19] Ref Section 5 Stakeholder Engagement

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A number of other outage alternatives were also considered based on further consultation feedback, all of which were considered by their costs and benefits as allowed by the Investment Test – including a partial bypass as well as stopping the work midway should market conditions be unfavourable.

The outage alternatives analysed are summarised in Table 10.

Table 10- Outage Options considered

Outage Option	**Expected benefit** (normal" hydro conditions)	Comment
1. Base Case: Complete the work in one summer over January to April 2020	$0	
2. Complete the work in one summer but start in December 2019	-$1950k	Enabling works need to be completed in spring, so earliest month work can commence is Nov/Dec. Crews need to break for Christmas which introduces inefficiencies in the staging of the work, and remobilisation. Results in longer outage period.
3. Hire more linesman to reduce the outage length	-$1800k	The initial constructability investigation considered adding a third wiring crew, but this only reduced the outage length by 4 days. 2 wiring crews is the most productive and cost efficient option.
4. Complete the work over two separate summers	-$1350k	Would result in lower system cost impact, however this is outweighed by the significant re-mobilisation costs in the following year. In a wet hydro year it could be justified economically, however, there is no guarantee that hydro conditions the following year will be "normal".
5. Two-week break in the outage period	-$1150k	Additional construction costs (standing down the crew for 2 weeks) only justified economically in a wet year (1 in 5).
6. Last minute (unplanned) delay due to market conditions	-$2650k	Would result in lower system cost impact, however this is far outweighed by the significant re-mobilisation costs in the following year, and the last minute crew stand down costs. Would have major impact on delivering other reconductoring projects.
7. Full pole bypass	-$3850k	Infeasible to construct by 2020 Likely to cost $12+m to reduce outage length by 9 weeks (outage still required during VBE replacement). Uneconomic in 90% of hydro years
8. Partial bypass	-$2800k	Infeasible to construct by 2020. Likely to cost $6m to construct the partial bypass, but outage period only reduced by 2 weeks.

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9. Electrode bypass	Less than partial by-pass	Infeasible to construct by 2020 if external to the line easement as will be similar design to a full bypass. Impinges safety clearances and interferes with construction activities if strung on the existing towers. One pole would still have to be taken out of service to allow the safe reconductoring of the electrode line.

Overall we still consider our base case option is the best option. In some more extreme hydrological sequences we recognise the outage length could have a significant impact on generation dispatch costs. We have no certainty as to the type of hydrology that will exist in 2020. We have based our decision on our modelling which looks at the conditions across 78 hydrological years.

Our intent is to continue to undertake a 13.3 week outage. We consider this provides generators with some certainty over our plans and the ability to hedge positions and manage lake levels based on this information. However, we will review this position closer to the time of the outage and in view of hydrological conditions. If, for some reason, the System Operator declared a grid emergency or if system security was challenged, we would consider deferring the outage, following our normal procedures, and based on actual conditions at that time.

If we were to stand-down crews for two weeks we would be exposed to additional costs we estimate at $1 million plus. As this cost is an exceptional cost that would only be incurred in exceptional hydrological conditions we do not feel it reasonable to request this funding as part of this proposal.

The full details can be found in Attachment D.

6.1.2 Effect of Tiwai Closure

In the unlikely event Tiwai were to close before the re-conductoring commences, the expected market costs from a single pole outage would increase since there would be higher transfers from South Island generation. However, transmission constraints in the lower South Island would need to be alleviated before the full market capacity could be realised. These constraints would take up to 3 years to complete[20] so the current outage plan for the re-conductoring would occur before the constraints are alleviated.

Nevertheless, the closure would warrant a review of the re-conductoring and outage program. The VBE replacement would still need to proceed because of the risk presented to HVDC availability by the failing oil filled snubber capacitors and obsolescence of the VBE system.

In order to minimise the risk of clashing with a Tiwai announcement, we have looked at bringing the project timing forward. However, the planning, procurement and enabling work prior to an outage will take approximately 18 months to complete, so November 2019 is the earliest we could commence re-conductoring.

[20] https://www.transpower.co.nz/clutha-upper-waitaki-lines-project-and-tiwai-future-faqs

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7 HVDC Reserve costs

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.[21] 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[22]:

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

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 for 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.

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 reserve costs could be as low as $11 thousand or as large as $6 million with a 50th percentile of $1.9 million[23].

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[21] See clause 8.59 in the Code for details
[22] Note that this simple representation is for illustration purposes only and excludes some additional terms. See 8.59 for the full details.
[23] 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

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Section 7 summarises the range of reserve costs that our analysis suggests that we may be exposed to in different hydrological years.

Table 11- Impact of outage on Reserve costs[24]

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%

As we outline in Section 8 we ask that the Commission exclude these costs from the incentive regime. 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 Section 6 this is not feasible within the timeframes for the need of this project, and would not be economic to implement.

year the reserve cost per MWh will tend to be higher, so costs increase for all parties (both Transpower and generators).

[24] Note that these costs do not include IDC and inflation. See Attachment B for further details.

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8 Application to the Commerce Commission

This project is a listed project within the Capex IM as detailed in Transpower Individual Price-Quality Determination 2015[25] for RCP2. The listed project status means that we need to submit an application to the Commerce Commission seeking approval to add to our Base Capex Allowance (i.e. base capex[26]) to account for this work.

Listed projects are large projects that had uncertain scope and cost at the time of our RCP2 application. The listed project mechanism was developed to allow our Base Capex Allowance to be amended when the scope and cost of these projects was more certain. We are also required to consult on our application of the Investment Test set out in the Capex IM, and this process has been outlined in this document.

The OTB–HAY A line is part of the HVDC link. Revenue for the HVDC link is recovered from South Island generators under the Transmission Pricing Methodology (TPM).

8.1 Proposal and Grid Outputs

This is an application to the Commerce Commission for:

Proposal at a Glance	
What:	Replace the existing conductors on the Churton Park section of the OTB–HAY A line with ACSR/AC Moa duplex, rated to operate at 65°C.
When:	Commence work in Q4 2019 and complete by Q2 2020
How much:	Transpower is seeking approval: a. to add $23.5 million to our Base Capex Allowance (excludes HVDC Reserve Costs); and b. recover the actual HVDC Reserve Costs we incur as a result of the project, and those costs not to be subject to the incentive regime.

[25] See schedule I in http://www.comcom.govt.nz/dmsdocument/12769.

[26] Defined in the Capex IM.

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Grid Outputs

- Procuring, installing and commissioning conductors on the Churton Park section of the OTB–HAY A line with ACSR/AC Moa duplex, rated to operate at 65°C.
- Associated works on the towers and foundations to enable the Moa conductor to be operated at 65°C.
- Obtaining property rights and environmental approvals as required for these works.
- To undertake this work an increase in our Base Capex Allowance of $23.5 million (plus HVDC reserve costs)
- Approval to capitalise the actual HVDC Reserve Costs incurred but those costs not to be subject to the base capex expenditure adjustment.
- Expenditure outgoings up to $23,464,000 (plus HVDC Reserve Costs):

Year	$ Amount
2018	605,000
2019	4,389,000
2020	18,471,000
Total	**23,464,000 (plus HVDC Reserve Costs)**

with commissioning occurring in 2019/20 year.

8.2 Listed Project Capex Allowance

If this proposal is approved by the Commerce Commission, an amount will be added to our RCP2 Base Capex Allowance. We have called this the Listed Project Capex Allowance (LPCA).

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 12 and in Table 13 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 (as outlined in Section 6.1.1).

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.

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Table 12 – Derivation of Listed Project Capex Allowance ($000)

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 13 – Listed Project Capex Allowance Annual Allocation ($000)

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**

8.3 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

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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 HVDC reserve 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 14 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 14 – Transpower reserve cost risk ($000)

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**

8.4 Effect on transmission charges

If the Commerce Commission approves this investment proposal and we complete the conductor replacement as outlined, transmission charges will increase. The costs of the HVDC link are currently recovered from South Island generators as set out in the Transmission Pricing Methodology (TPM).

Table 15 shows the estimated annual increase in Transpower HVDC revenue, which equates to the increased costs our HVDC customers will face. These calculations assume P50 reserve costs are incurred.

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Table 15: Increase in Transpower HVDC revenue

Year	Base Case (P50)
2020	842,474
2021	1,565,978
2022	1,626,255
2023	1,677,090
2024	1,719,427
2025	1,754,117
2026	1,781,923
2027	1,803,535
2028	1,819,571
2029	1,830,590
2030	1,837,093

Note: The revenue calculation in Table 18 uses our current best estimate of the vanilla WACC from RCP3 onwards (at 6.13%), because the project commissions at the end of RCP2. It assumes a conductor life of 56 years.

Table 16: Pro-rata increase in 2025 costs for HVDC customers ($)

HVDC customer	Base Case (P50)
Alpine Energy	2,156
Aurora Energy	10,173
Buller Electricity	13
Contact Energy	384,308
Electricity Ashburton	0
Genesis Energy	101,032
Meridian Energy	1,256,410
PowerNet	12,642
TrustPower	31,633
Westpower	1,633
Total	1,800,000

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Note: The numbers in Table 16 are based on 2018/19 HVDC customer charges, pro-rata, assuming an incremental HVDC charge of $1.8M. The charges below are calculated using our last published customer charges Information Disclosure. They are indicative only, being calculated by assuming the same HVDC charges as those underlying the 2018/19 HVDC charges.

Table 17 shows the resulting increase in cents per annum on an “average” consumer bill in 2025. We define an “average” consumer as a household using 7,600 kWh per annum.

Table 17 Increase in 2025 consumer cost (cents per annum)

2025 consumer bill, cents pa	Base Case (P50)
An “average” consumer (7,600 kWh)	35c

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A.1 Capex IM requirements

In the below table we outline how this application meets the requirements to be approved by the Commerce Commission under the Capex IM.

Table A.1-1 – Capex IM checklist

Capex IM section	Report cross reference
2.2.3 Listed Project	
(2) Listed project definition (a) (i) capex > $20 million (ii) to be commissioned in the regulatory period (b) replacement/ refurbishment (c) commencement date within the regulatory period (d) not already in base capex	Section 1 The Proposal 8.1 Proposal and Grid Outputs
3.2.4 Approval of base capex in addition to the base capex allowance	
(1) Due by June twenty-two months before the end of a regulatory period	Submission expected in April 2018 (due before June 2018)
(2)(a) reason for project, technical evidence	Section 2 Attachment A
(2)(b) options considered	Section 3.1 The options Attachment B
(2)(c) scope & grid outputs	Section 1 The Proposal 8.1 Proposal and Grid Outputs
(2)(d) technical & costing info & risks	Section 3 Attachments B & D
(2)(e) costs by year & assumptions	Supporting spreadsheet 8.1 Proposal and Grid Outputs
(2)(f) cost-benefit & sensitivity	Section 3.2 The costs Section 3.3 The Benefits Section 4 Selecting the investment proposal
(2)(g) consultation	Section 5 Stakeholder engagement Attachment C Attachment D
(2)(h) Board & CEO sign-off	Attachment E
(4)(a) consultation process as per base capex	Section 5 Stakeholder engagement Section 6 Mitigating the impact of outages for construction works Attachment C Attachment D
(4)(b) evaluated as per base capex criteria, incl Sched A where relevant: - follow Transpower policies & planning standards for grid / base capex; - cost-effective; - reasonable assumptions (method); - risk-based good asset management, - grid output dependencies - deliverability; - reasonable asset replacement models (inputs & method); - reasonable demand forecasts (inputs & method); - scope for efficiency gains	Section 2 The Need Section 3 Attachment A https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transpower%20National-Regional%20Peak%20Demand%20Forecasts%20Feb-2015%20Information%20Document.pdf
(5)(a) forecast CPI used for base capex in reg period; (b) forecast FX rates used for base capex for reg period; (c) percentage of foreign capex	Supporting spreadsheet

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A.2 Changes in costs from prior estimates

In our preferred option consultation, we provided cost-estimates for the options derived from a high-level desktop study for duplex Moa installation, with an uncertainty range of -30%/+30%.

The investment test analysis found Duplex Moa to be the preferred option.

We have subsequently undertaken a more accurate Solution Study Report (SSR) for Duplex Moa. Our Capital Cost estimate has increased by $5.5m, predominantly due to an increase in access and property costs on this section of the OTB–HAY A line that had been underestimated across all options. This category also contains costs to remedy a property easement issue where line swing under some wind conditions is greater than the easement width.

The SSR also identified cost changes associated with accessing the OTB–HAY A line. We will be utilising existing access tracks, with more upgrades, and construction of temporary access tracks (which will be removed at completion). Construction will be challenging due to the nature of the terrain and variety of structures.

We have re-run these cost changes through the Investment Test analysis (this proposal document). The cost changes did not change our preferred option.

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
- increased resources (i.e. two crews) working in parallel to mitigate the length of the outage
- the inclusion of costs to widen a property easement
- steep terrain and access constraints
- 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
- undergrounding of local distribution company line crossings.

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

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A.3 Attachments

Further information supporting this application is included in the following attachments:

Attachment A – Condition assessment

Attachment B – Options and Costing report

Attachment C – Consultation Summary

Attachment D – Outage Modelling Report

Attachment E – Board approval and CEO certification

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