TRANSPOWER

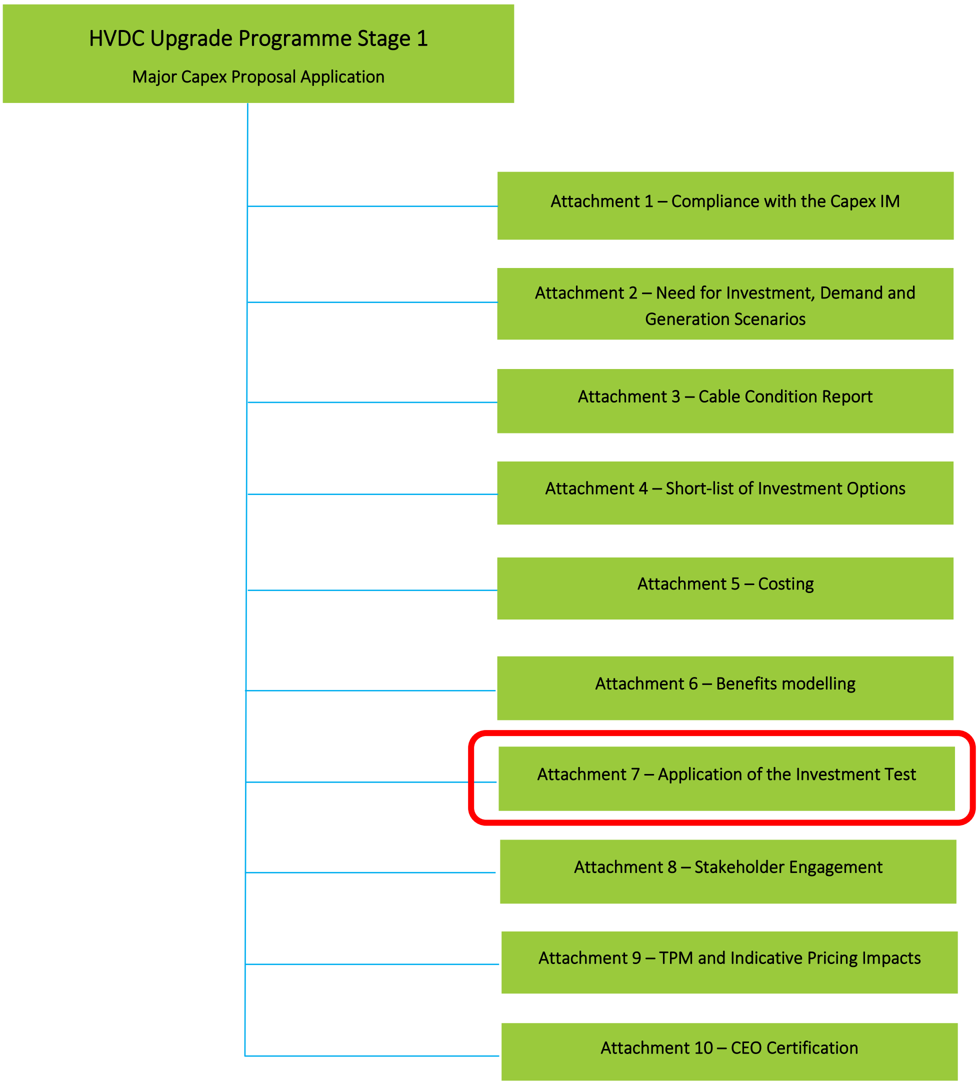
HVDC Link Upgrade Programme Major Capex Proposal (Stage 1)

Attachment 7: Application of the Investment Test

September 2025

Purpose

This document sets out our application of the Investment Test (i.e., cost-benefit analysis) for this HVDC Link Upgrade Programme Stage 1 Major Capex Proposal (**MCP**). It includes our application of the Investment Test to identify our proposed investment.



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1 Introduction

The Capex IM investment test (**Investment Test**) is an economic cost-benefit analysis that uses the real value of costs and benefits over time to calculate the expected net electricity market benefit of an investment option.[1] As the proposed investment is an economic investment, for the proposed investment to satisfy the Investment Test it must:

- be the investment option that maximises expected net electricity market benefit,
- have positive expected net electricity market benefit, and
- be sufficiently robust under sensitivity analysis.

In the Investment Test, expected net electricity market benefit is the difference between expected electricity market benefits and costs. Electricity market benefits and costs are those received or incurred by consumers in the electricity market. In this analysis we have considered the following such benefits and costs:

- capital costs of the investment options and modelled transmission projects,
- operating and maintenance costs of the investment options,
- changes in generation capex,
- changes in generation operational costs, e.g., the cost of generating electricity,
- changes in emissions costs, such as carbon pricing,
- changes in costs associated with voluntary and involuntary demand curtailment, e.g., deficit costs, and
- changes in instantaneous reserve costs, reflecting the cost of maintaining system reliability.

Details about the methodologies we have used to quantify these benefits and costs can be found in this document and Attachments 5 (Costing) and 6 (Benefits modelling).

This document sets out our Investment Test parameters and the results of the Investment Test to identify our proposed investment.

1 The Investment Test is defined in Schedule D of the Capex IM.

2 Investment Test parameters

This section sets out the key assumptions that are critical to application of the Investment Test. We set out standard values for each of these, and, where relevant, specify our rationale for using an alternate value.

2.1 Scenario weightings

The Investment Test uses a weighted average of net electricity market benefits under each demand and generation scenario. Details of the demand and generation scenarios used in this analysis are given in Attachment 2.[2]

Under the default approach in the Capex IM, each of the five scenarios would be given equal weighting. However, upon reviewing the demand growth rates for the Global and Reference scenarios, we found their demand growth to be particularly low. Between 2030 and 2050 the Global scenario projects national demand growth of just 0.6% per annum, and the Reference scenario 0.8% per annum. These rates are low in the context of ongoing electrification and decarbonisation trends, which are expected to drive higher electricity demand.

As the Reference scenario already represents a conservative outlook, including both low-growth scenarios would over-represent the low-growth end of the range. We therefore exclude the Global scenario from this analysis. This adjustment retains a sufficiently low-growth demand case while better reflecting a plausible range of future demand.

For this analysis, the four remaining scenarios are weighted equally.

Table 1: Scenario weightings

Weighting set	Usage	Global	Reference	Growth	Environmental	Disruptive
1 (Default)	20% each	20%	20%	20%	20%	20%
2 (Preferred)	Adjusted	0	25%	25%	25%	25%

Feedback received during the short-list consultation generally supported this approach. Fonterra considered it overly conservative, suggesting that the Environmental scenario more accurately reflects New Zealand's likely energy future and should receive a 50% weighting. Vector queried whether there was a weighting bias to higher growth scenarios, but this is not the case as all scenarios are weighted equally. While this balanced approach across a

2 The scenarios used are based on EDGS 2019 but include necessary variations that were detailed in Transpower's NZGP1 major capital proposal (NZGP Latest updates | Transpower) along with updates to reflect updated electricity distribution company views of demand growth. In Capex IM language, the scenarios are demand and generation scenario variations because they are variations on EDGS 2019 (and the EDGS 2019 Global scenario is not used). We note that while the EDGS were updated in 2024 these scenarios are not yet being used by Transpower for the Investment Test.

range of potential energy futures may lean conservative, we believe that an equal weighting approach provides a prudent and balanced basis for assessing long-term investments. It ensures that the proposed investment demonstrates value across a wide range of plausible futures, not just those with high demand growth.

2.2 Calculation period

The Capex IM specifies that a calculation period should be used that captures significant electricity market benefit or cost elements. The default calculation period for the Investment Test is 20 years. For this analysis we propose using a 30-year period from the commissioning date of the proposed Stage 1 investment (2031 to 2060).

The submarine cables have an expected installed life of 40 years. Using a calculation period to 2060 covers three-quarters of the submarine cables' assumed 40-year life.

To ensure fair comparison across options, we have calculated the Equivalent Annualised Cost (**EAC**) over the full lifetime of the asset (i.e., 40 years for submarine cables). This involves applying an annuity factor to the present value of the investment costs. Additionally, annualised costs are truncated at 2060 to align with the modelled benefits.[3]

Feedback from our short-list consultation did not raise any objections to the 30-year calculation period. Therefore we consider that 30 years, along with the inclusion of EAC, to be an appropriate balance between capturing the long-term benefits of investment and managing the uncertainty of distant future benefits.

2.3 Discount rate

We have used the standard pre-tax real rate of 5%, and a sensitivity range of 3% to 7%. No issues with this approach were raised during our short-list consultation.

3 Investment Test application

This section sets out our application of the Investment Test.

As set out in Section 1, as the proposed investment is an economic investment, for the proposed investment to satisfy the Investment Test it must:

- be the investment option that maximises expected net electricity market benefit,
- have positive expected net electricity market benefit, and

3 For cost annualisation, we have applied an asset life of 40 years for most assets including the replacement submarine cables. Exceptions include buildings, which are allocated a 60-year lifespan, and control systems and STATCOMS, which are assigned a 20-year lifespan.

- be sufficiently robust under sensitivity analysis.

3.1 Costs

We use Transpower's Enterprise Estimating System (**TEES**) to estimate the cost of all capex projects. TEES produces cost estimates for a project based on the historical rates from past projects or known current rates, as well as information from consultants and/or potential vendors (e.g. RFPs, concept design and solution study exercises). Where possible, our cost estimates are informed by our internal experience with past projects, ensuring a reasonable level of accuracy for this stage of the analysis.

Cost breakdown and considerations

- **Capital costs of investment options:** Tables 2, 3 and 4 present the expected P50 capital cost estimates for the three investment options,
- **Capital costs of modelled projects:** These are future projects (in this case transmission projects) expected to occur during the calculation period that are outside the investment options but their likelihood, nature and timing is affected by an investment option proceeding. Table 2 sets out the modelled projects and their modelled commissioning year and expected capital costs we have included in our analysis (for both Options 2 and 3, except as noted in the table). We have not included any modelled project capital costs for the base case (Option 1) in our analysis as we have assumed none of the modelled projects (including neither of the first two) will go ahead in the base case,[4]

Table 2: Modelled projects

Modelled projects	Modelled commissioning year	Expected capital cost ($m, undiscounted)
Approved HVDC NZGP1.1 projects (Reactive plant, filter banks, associated equipment)	2028	84.4
Pole 3 mid-life refurbishment	2032	89.0
Dismantle Pole 2	2041	57.5
Replace Pole 2 with Pole 4	2041	1150.0
Dismantle Pole 3	2057	57.5
Replace Pole 3 with Pole 5	2057	1150.0

4 If this assumption is incorrect then the costs of the base case are significantly under-estimated. Correcting for that would not affect the outcome of the Investment Test.

Modelled projects	Modelled commissioning year	Expected capital cost ($m, undiscounted)
Control system replacement	2051	253.5
Filter bank at BEN 2055 (Option 3 only)	2056	19.7

- **Operational and maintenance (O&M) costs of investment options:** While there is no significant O&M cost difference between the 1200 MW and 1400 MW cable replacement options (Options 2 and 3), the no investment and decommissioning option (Option 1) has considerably lower O&M costs because these costs cease after the HVDC link is decommissioned. We have assumed annual O&M costs for the HVDC link of $20m, based on the average forecast O&M spend on the HVDC link over the next 30 years.[5] We consider this is a to be a reasonable P50 estimate of annual O&M costs for Options 2 and 3,
- **Cable recovery and disposal costs:** These are the costs related to recovering the three existing HVDC submarine cables. This is treated as a capital cost and reflects the net cost of asset removal, factoring in potential scrap value from decommissioned materials,
- **Estimated decommissioning costs:** In the base Case (Option 1) we have estimated the costs to decommission the HVDC link equipment (including both poles). However, we have not estimated the additional costs required to reinforce the AC transmission network if the HVDC link is removed. As a result, the true capital costs for the base case would be significantly higher than estimated.

Table 3: Base case (Option 1) – No investment – P50 capital cost breakdown(undiscounted)

Capex component	Expected P50 cost (real 2025 $m)
Recovery and disposal of decommissioned existing submarine cables	131.8
Decommission all HVDC link equipment	360.0
Total	**491.8**

[5] We are not seeking any allowance for O&M costs for the proposed Stage 1 investment. Any required O&M funding is incorporated into our base expenditure forecasts and will be submitted to the Commerce Commission for approval in each regulatory control period.

Table 4: Option 2 – Like-for-like replacement, 1200 MW – P50 capital cost breakdown (undiscounted)

Stage	Capex component	Expected P50 cost (real 2025 $m)
Stage 1	Supply and installation of three submarine cables	651.4
Stage 1	Cable termination stations replacements (3 cables)	132.8
Stage 1	Establishment of new submarine cable storage facility	11.6
Stage 1	Project investigation costs	19.5
Stage 2	HVDC control system replacement	253.5
Stage 2	Recovery and disposal of decommissioned existing submarine cables	131.8
Stage 2	Provision for recovery and disposal of new submarine cables	131.8
	Total	1,332.5

Table 5: Option 3 – Increased capacity, 1400 MW – P50 capital cost breakdown (undiscounted)

Stage	Capex component	Expected P50 cost (real 2025 $m)
Stage 1	Supply and installation of four submarine cables	760.4
Stage 1	Cable termination stations replacements (4 cables)	134.5
Stage 1	Benmore filter bank to enable 1400 MW	19.7
Stage 1	Pole 2 overload scheme	12.7
Stage 1	Establishment of new submarine cable storage facility	11.6
Stage 1	Project investigation costs	19.5
Stage 2	HVDC control system replacement	253.5

Stage 2	Recovery and disposal of decommissioned existing submarine cables	131.8
Stage 2	Provision for recovery and disposal of new submarine cables	131.8
	Total	**1,475.4**

3.1.1 Present value project costs

Future expenditure is discounted at a rate of 5% per annum, reflecting the time-value of money, as discussed in section 2.3. Table 6 presents the present value of costs for each investment option through to 2060. Assessing present value costs allows us to compare the options fairly.

The fourth column shows the discounted costs of the modelled projects - future projects that are outside the investment options but their likelihood, nature and timing is affected by an investment option proceeding. They are included to provide a more complete picture of the cost of the continued operation of the HVDC link to 2060. The fifth column captures O&M costs, while the sixth column shows the total costs of each investment option.

The seventh column shows each investment option's total costs difference relative to Option 2 (like-for-like replacement) to provide clearer insights into the relative costs of each option.

Table 6: Short-list P50 present value costs at 5% discount rate (2025 $m)

Option	Description	Capital Cost *A*	Modelled projects capital cost *B*	O&M costs *C*	Total costs *A+B+C*	Relative total costs
1	No investment	267.3	0.0	207.9	475.2	-1520.2
2	Like-for-like replacement, 1200 MW	1002.8	645.1	347.5	1995.4	0.0
3	Increased capacity, 1400 MW	1113.2	646.5	347.5	2107.2	111.8

The base case (Option 1) has the lowest total costs, as it involves no further investment in the HVDC link, including submarine cables and control systems. In the base case, the entire HVDC link will be decommissioned in 2038. While this option avoids the cost of submarine cable replacement, there are capital costs associated with decommissioning the HVDC link and removing the existing submarine cables. The capital cost for the base case is underestimated, as it does not reflect the investments required in the AC network should the HVDC link be removed.

Options 2 and 3 involve replacing the existing submarine cables and undertaking the associated upgrades, with Option 3 increasing the cable capacity to 1400 MW north. These options have the highest capital costs and share similar ongoing O&M costs.

3.2 Benefits

The following benefit categories have been quantified in our analysis. Detail of how the benefits are calculated for each investment option are presented in Attachment 6 – Benefits modelling.

I. **Reduction in generation capex**. The HVDC link allows efficient energy transfer between the North and South Island, reducing the need for new local generation infrastructure to meet demand. By enabling integration of generation resources between the North and South Islands, the HVDC link can defer or reduce investment in new local power generation sources, leading to long-term capital cost savings;

II. **Reduction in generation operational costs.** Generation operating costs are influenced by generation dispatch strategies in each option. The HVDC link facilitates efficient access to diverse generation resources, enabling optimal dispatch that prioritises lower-cost renewable generation over more expensive thermal plants. Operating costs include fuel and variable operation and maintenance expenses but exclude emission costs, which are accounted for separately;

III. **Reduction in emission costs.** Emissions from fossil fuel combustion and geothermal steam have an associated cost, depending on the carbon price. Optimising generation dispatch and increasing access to renewable energy through maintaining or enhancing the HVDC link capacity can help reduce overall carbon emissions and associated costs;

IV. **Reduction in deficit costs**. Deficit costs arise when electricity demand cannot be met due to supply constraints. These might occur during very high peak demand periods or low hydro inflows. Although these deficits are typically infrequent and short-lived, they can have significant financial and operational consequences. In these situations, consumers will be forced to curtail demand or find alternative ways of being supplied with electricity. Enhancing the capacity of the HVDC link can reduce deficit amounts and associated costs by facilitating access to firm generation during periods of tight supply;

V. **Reduction in instantaneous reserves costs**. Instantaneous reserves are required to mitigate the impact of unplanned outages. Sufficient reserves must be procured to cover defined contingencies, such as the loss of the largest generating unit in each island or the failure of a single HVDC link pole. These reserves can be provided by generation, batteries, or interruptible load. The required reserve levels include additional reserves to cover HVDC link pole outages, which are directly attributable to HVDC link operation. Enhancing the capacity of the HVDC link increases the extent to which the link can self-cover its reserve requirements, which leads to a saving in reserve costs.

Table 7 shows the total present value benefit for each investment option through to 2060. As with the costs, we have shown the expected net electricity market benefits relative to the like-for-like replacement option (Option 2) to provide a clearer comparison.

Table 7: Benefits, present values at 5% discount rate (2025 $m)

Option	Description	Total benefits present value	Relative total benefits present value
1	No investment	0.0	-4747.2
2	Like-for-like replacement, 1200 MW	4747.2	0.0
3	Increased capacity, 1400 MW	4925.2	178.0

3.3 Expected net electricity market benefit

Table 8 presents the quantified expected net electricity market benefit for each of the investment options. The expected net electricity market benefit of an option is calculated as the difference between total benefits and total costs for the option. The expected net electricity market benefit of each option is shown relative to the like-for-like replacement option (Option 2) to provide a clearer comparison.

The results show that Option 3 has the highest expected net electricity market benefit, and its expected net electricity market benefit is positive.

Based on this analysis, Option 3 is our proposed investment.

Table 8: Quantified expected net electricity market benefits, present values at 5% discount rate (2025 $m)

Option	Description	Total costs *A*	Total benefits *B*	Expected net electricity market benefit *B-A*	Relative expected net electricity market benefit
1	No investment	475.2	0.0	-475.2	-3226.9
2	Like-for-like replacement, 1200 MW	1995.4	4747.2	2751.7	0.0
3	Increased capacity, 1400 MW	2107.2	4925.2	2818.0	66.3

4 Sensitivities

Sensitivity analysis considers the impact of parameter variations on the quantum of expected net electricity market benefits. The Capex IM requires sensitivity analysis to be carried out on specified parameters, except when not reasonably practical nor reasonably necessary. Our approach to the Investment Test sensitivity analysis is set out in Table 9 below.

Table 9: Sensitivities considered

Sensitised parameters	Comment
Forecast demand	Expected net electricity market benefits are reported for each of the four scenarios used in the Investment Test (100% weighting).
Size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question	Either reflected in scenarios or included in +/- 30% capital cost sensitivity.
Capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects	Sensitivities of +/- 30% capital cost are considered.
Timing of decommissioning, removing or de-rating of decommissioned assets	Not relevant
Value of expected unserved energy	Not relevant. We have not included reliability benefits in our application of the Investment Test.
Discount rate	Sensitivities of 3% and 7% discount rates are considered.
Range of hydrological inflow sequences	Reflected in scenarios.
Relevant demand and generation scenario probability weightings	Expected net electricity market benefits are reported for each of the four scenarios used in the Investment Test (100% weighting).
In relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies	Not relevant.
Other variable: Total benefits	Sensitivities of +/- 30% total benefits are considered.

The results of this analysis are shown in Table 10. The investment option with the highest expected net electricity market benefit under each sensitivity is highlighted in green.

Table 10: Quantified expected net electricity market benefits, sensitivity analysis (present value, 2025 $m)

	Base case (Option 1)	Option 2 Like-for-like, replacement 1200 MW	Option 3 Increased capacity, 1400 MW
Low discount rate (3%)	-573	5,118	5,263
Base discount rate (5%)	-475	2,752	2,818
High discount rate (7%)	-398	1,354	1,372
Capital increase (130% of base)	-555	2,257	2,290
Capital decrease (70% of base)	-395	3,246	3,346
Benefits increase (130% of base)	-475	4,176	4,296
Benefits decrease (70% of base)	-475	1,328	1,340
Reference	-475	1,600	1,630
Environmental	-475	3,813	3,936
Disruptive	-475	2,735	2,829
Growth	-475	2,859	2,877

Across all sensitivities, Option 3 (1400 MW cable upgrade) delivers the highest expected net electricity market benefit. This confirms that the proposed investment meets the Investment Test requirement of being "sufficiently robust under sensitivity analysis."

Deliverability risks

During our May 2025 short-list consultation, Vector recommended that Transpower test the impact of potential schedule delays and compare deliverability risks across the short-listed options. We agree that deliverability is a critical consideration – particularly given current constraints in global supply chains for HVDC link equipment and the complexity of marine works in Cook Strait. Our assumed delivery programme reflects current global lead times for cable manufacture, testing, vessel mobilisation, and consent planning. These assumptions are a key reason for seeking approval now – to secure capacity and reduce exposure to timing-related risks.

We acknowledge that a one-year delay would defer benefit realisation and increase interest during construction. However:

- This risk is not unique to Option 3. Option 2 also faces exposure to marine weather windows, consenting uncertainty, supplier capacity, and vessel availability,
- As Option 1 involves no works, these risks are not relevant for that option,
- The Investment Test is inherently long-term in nature, and our modelling shows that even with a 30% capital cost increase (a proxy for delivery risk), Option 3 still delivers the highest expected net electricity market benefit.

In summary, deliverability risks are real but manageable, and the proposed investment remains robust.

4.1 Proposed investment

Option 3 provides the highest expected net electricity market benefit compared to the other investment options, has positive expected net electricity market benefit and is robust under sensitivity analysis. We conclude that Option 3 passes the Investment Test and is our proposed investment.

Our proposed investment received widespread support as the best solution during our short-list consultation.

5 Good electricity industry practice

The Capex IM requires this MCP to include a description as to how consistent with good electricity industry practice (**GEIP**) the proposed investment is.

The definition of GEIP in the Electricity Industry Participation Code is:

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

We have ensured that the planning and performance standards used to determine the investment options, and the proposed investment, reflect GEIP.

The proposed investment – replacing aging HVDC submarine cables and increasing their transmission capacity – aligns with GEIP for several reasons:

- **Asset condition and lifecycle management:** The existing submarine cables, installed in the early 1990s, are nearing the end of their operational life. International practice and asset management standards support proactive renewal of critical infrastructure assets before end-of-life failure risks escalate. The proposed investment reflects prudent lifecycle asset management, consistent with GEIP expectations;
- **Security of supply and system resilience:** The HVDC link is a critical part of New Zealand's transmission grid, enabling the transfer of electricity between the North and South Islands. Replacing and upgrading the submarine cables improves security of supply, enhances network resilience, and reduces the risk of unplanned outages — all of which are central to prudent transmission planning under GEIP;
- **Future proofing long-life infrastructure:** The investment increases the link's capacity, supporting expected growth in electricity demand and enabling more efficient transfer of renewable generation. This forward-looking approach reflects the level of foresight and strategic planning expected under GEIP, particularly when investing in long-lived infrastructure assets.

The shortlist consultation process did not identify any stakeholder concerns that the proposed investment was inconsistent with GEIP. Stakeholders recognised the need to replace the aging assets and to future-proof the HVDC link.

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