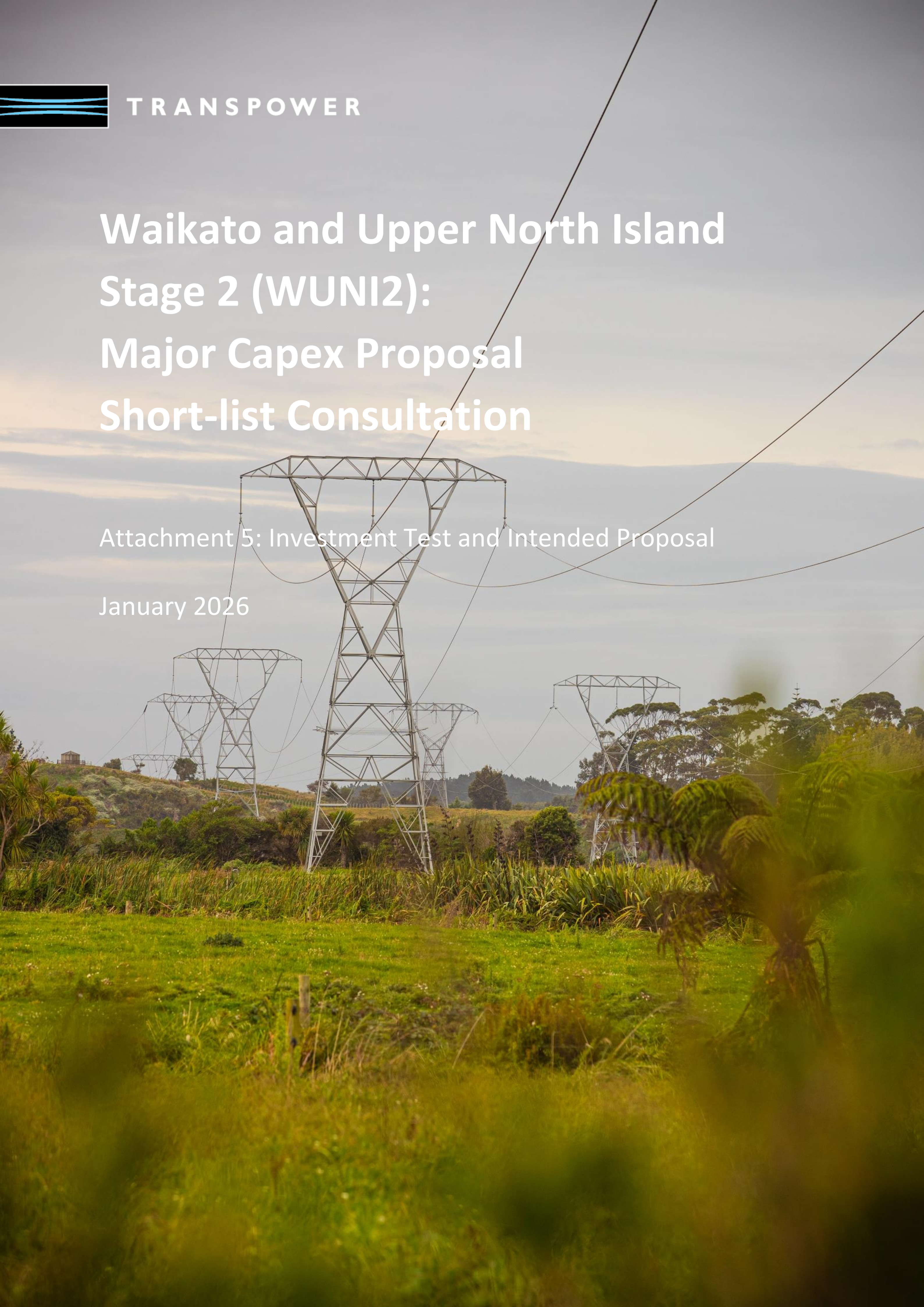
TRANSPOWER

Waikato and Upper North Island Stage 2 (WUNI2): Major Capex Proposal Short-list Consultation

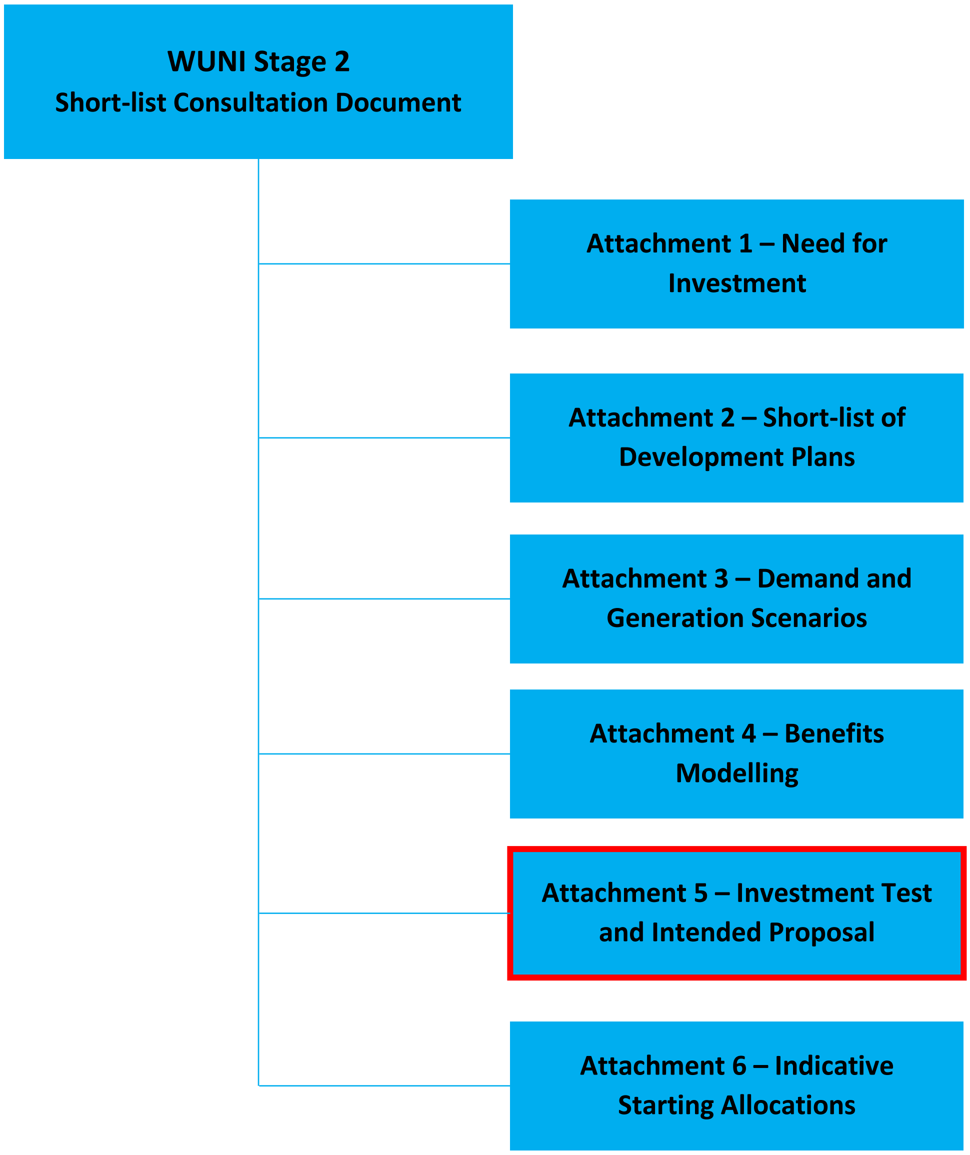
Attachment 5: Investment Test and Intended Proposal

January 2026



Purpose

This Attachment sets out an overview of our Waikato and Upper North Island (**WUNI**) Stage 2 options analysis and our approach to the Investment Test for this short-list consultation. It includes our preliminary application of the Investment Test and identifies our draft preferred option that we intend to submit to the Commerce Commission (**Commission**). Our analysis may be refined based on feedback from this consultation and further analysis.



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1 Introduction

The Investment Test is an economic cost-benefit analysis that uses the expected value of costs and benefits over time to calculate the net benefits of an option.[1] As the considered investment options are on the core grid, for an option to satisfy the Investment Test[2] it must be:

- the option that maximises expected net electricity market benefit (although this net benefit may be negative), and
- sufficiently robust under sensitivity analysis.

Electricity market costs and benefits are those received or incurred by consumers of the electricity market. In this analysis we have included the following:

- fuel costs e.g., the cost of generating electricity,
- cost of involuntary demand curtailment e.g., non-supply of electricity
- capital costs of modelled projects e.g., future assets that are likely to exist whose nature and timing is affected by an investment option, for instance new generation,
- relevant operation costs e.g., costs of existing assets, options and modelled projects,
- cost of losses, including transmission and local losses.

The benefits and the methodologies used to quantify these can be found in Attachment 4.

This Attachment sets out our proposed variations to standard Investment Test parameters and the results of the Investment Test. We also include our intended proposal to the Commission, subject to feedback from this consultation.

Feedback to this consultation will inform where we should modify our development plans and analysis. Should the option continue to pass the Investment Test, a major capex proposal (**MCP**) will be prepared and submitted to the Commission.

2 Investment Test Parameters

This section sets out the key assumptions that are critical to the 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. The assumptions used in this provisional analysis are consistent with the consultation requirements for major capex projects.

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1 The Investment Test is defined in Schedule D of the Capex Input Methodology (**Capex IM**).

2 The net benefit of an option in the Investment Test is its aggregated electricity market benefit minus its aggregated project cost. For more detail on terms used in the Investment Test, refer to Division 2 of Schedule D of the Capex IM.

2.1 Scenario Weightings

The Investment Test uses a weighted average of benefits under each demand and generation scenario.

The default position is for scenario weightings to be equal, meaning with five scenarios, each would typically receive a 20% weighting. However, as indicated in Attachment 3, we consider three of the five scenarios are sufficient to model a range of high and low scenarios. Given this, we believe it is reasonable to adjust the weightings of certain scenarios. We have adopted the following approach:

- *Global Scenario: weighted at 0%* – We consider the Reference scenario to adequately represent a lower bound for demand growth, rendering the Global scenario unnecessary.
- *Disruptive Scenario: weighted at 0%* – The Disruptive scenario is within the range of the three selected scenarios and therefore does not provide additional insights.
- *Growth scenario increased to 60%* – The Growth scenario is assumed to be a medium demand growth scenario, sitting between Reference (low demand growth) and Environmental (high demand growth). We consider it appropriate to increase the Growth scenario to 60% because it represents the mid-point of the different scenarios.

We adopt these weightings for our Investment Test analysis, i.e., we are using three scenarios – Environmental, Growth, and Reference – while excluding two of the original five. We have also considered an equal weighting of these three scenarios as a sensitivity. This approach centres our focus on three demand forecasts – low, medium, and high – paired with generation expansion plans based on comparable input assumptions.

Table 1: Scenario weightings

Weighting set	Usage	Disruptive	Environmental	Global	Growth	Reference
0	Default	20%	20%	20%	20%	20%
1	**Preferred**	**0%**	**20%**	**0%**	**60%**	**20%**
2	Equal (Sensitivity)	0%	33%	0%	33%	33%

Q9. Do you consider our proposed weighting of the scenarios to be appropriate?

2.2 Calculation Period

The Capex IM specifies that a calculation period should be used that captures significant electricity market benefits or cost elements. The default calculation period for the Investment Test is 20 years.

Our analysis uses a 22-year period from 2034 to 2055. This is because the last asset delivered in Stage 2 of the Option 4 variants is commissioned in 2033, and we need to capture the cost elements associated with Option 3, which includes a future investment planned for commissioning in 2054.

Assets with economic lives that extend beyond 2055 will retain residual value at the end of the calculation period. To ensure fair comparison across options, we have included a terminal benefit, which effectively reduces the asset's cost by capturing its remaining value. A linear depreciation approach is used to decrease the cost of the asset over its expected lifetime.

We consider this calculation period, and the inclusion of terminal benefits, to be an appropriate trade-off between assessing benefits over the full economic life of an option and the uncertainty regarding far off benefits.

2.3 Discount Rate

We propose to use the standard discount rate (pre-tax, real) of 5%, and a sensitivity range of 3% to 7%. This is consistent with the Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination 2023.

Q10. Do you consider our use of a calculation period of 2034-55 and a standard discount rate of 5% to be appropriate?

3 Investment Test Application

This section sets out our preliminary application of the Investment Test. It sets out the costs for each of the investment options, the benefits, and the results of the Investment Test, i.e., the expected net electricity market benefit.

3.1 Electricity Market Costs and Benefits

Electricity market cost and benefit elements are those received or incurred by consumers during the calculation period relative to the base case, and which will affect net electricity market benefits. The benefits and the methodologies used to quantify these can be found in Attachment 4.

3.2 Project Costs

Project costs are those costs reasonably incurred prior to or during the calculation period, in undertaking a major capex project.

The WUNI investigation has been undertaken to determine a transmission development plan to 2055 to support a reliable electricity supply into the region. The development plan contains costs associated with those development plan investments.

The cost of Transpower's investment options was estimated using concept design reports, budgetary offers, or internal cost data, depending on the level of information available. The estimation process incorporated benchmarking against historical projects, utilization of our cost library, and inclusion of budgetary equipment pricing. Where information was incomplete or unclear, reasonable assumptions were applied. An appropriate cost classification was assigned to each option based on the accuracy, confidence level, and quality of information available for this analysis.

While operational expenditure was considered for each short-listed option, we found no significant differences across the options. Therefore, operational costs were not factored into the preliminary application of the Investment Test, other than allowances for the mid-life refurbishment of the STATCOM and series compensation assets after 20 years of operation.

3.3 Sensitivity Analysis

Sensitivity analysis considers the impact of parameter variation on the quantum of benefits and costs, except when not reasonably practicable nor reasonably necessary. Our approach to the Investment Test sensitivity analysis examines the effect of varying key assumptions. These variations are set out in Table 2.

Table 2: Sensitivities considered

Sensitised parameters	Comment
Forecast demand	Net benefits are reported for each of the EDGS scenarios used in the Investment Test (100% weighting).
Relevant demand and generation scenario probability weightings	Results are presented using both the preferred weighting (20% Environmental, 60% Growth, 20% Reference) and an equal weighting across these scenarios.

Sensitised parameters	Comment
Size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question	Reflected in scenarios.
Timing of decommissioning, removing or de-rating of decommissioned assets	Not relevant.
Huntly Rankine units’ retirement timing	Sensitivity of delaying the retirement of Huntly Rankine units from 2030 to 2035 is considered for the Growth scenario.
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.
Capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects	Sensitivities of +/- 30% of capital costs are considered.
In relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies	Not relevant.

4 Preliminary Application of the Investment Test

Our analysis incorporates both the project costs and electricity market benefits associated with each of our short-listed development plans. By including these costs and benefits, we ensure that the option delivering the highest expected net electricity market benefit is identified.

4.1 Quantified Assessment

The Investment Test is a cost-benefit analysis that uses the expected aggregated value of both costs and benefits over time. To account for the time value of money, future costs and benefits are discounted at an annual rate of 5%. Table 3 provides an overview of the present value of the total project costs for each short-listed option.

Although the cost-benefit analysis encompasses the full calculation period, we are currently only proposing to seek approval for investments through to 2033 in our draft proposal. Any further investments identified in the preferred option development plan would require separate approvals (refer section 5.1). As a result, the project cost values presented here are higher than those presented in our draft proposal (refer section 5.3).

Table 3 includes the total discounted project cost for each short-listed option over the period to 2055.

As mentioned in Attachment 2, the anticipated need for condition-based reconductoring of the Ōtāhuhu–Whakamaru A and B lines (southern section between Ohinewai and Whakamaru) can be avoided in options 3 and 4. To work out the expected costs, we have assumed the like-for-like (simplex) reconductoring happens in two stages in 2032 and 2039. The present value of these avoided costs is shown in Table 3.

We have considered two variants of Option 4, varying the order of series compensation and duplexing, as described in the Overview document and in Attachment 2. While the investment components and the respective costs (in real terms) in Options 4a and 4b are the same, the discounting to a present value leads to a small difference in the Stage 2 value. Further details of the development plans, their components and timings can be found in Attachment 2.

Table 3: Cost estimates of short-listed development plans, 2025 present values at 5% discount rate[3]

	Option 1 Series Comp + Tee	Option 2 Series Comp + Cable	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
Stage 2 investments ($m)	276.8	494.1	274.1	404.0	403.7
Future stages and modelled projects ($m)	139.9	95.5	161.3	60.1	60.1
Avoided reconductoring cost ($m)	-	-	-64.7	-64.7	-64.7
Total costs ($m)	**416.7**	**589.7**	**370.8**	**399.4**	**399.2**

Option 3 (Duplex + STATCOMs) incurs the lowest costs. This option avoids series compensation on the Brownhill–Whakamaru lines but requires later investments in additional STATCOMs.

Types of benefits quantified as part of our analysis include terminal benefits, transmission loss benefits and deficit benefits:

- **Terminal benefits:** the economic lifespan of some investments considered extend beyond the calculation period, meaning that the assets will retain value at the end of 2055. We have accounted for this as a terminal benefit, which effectively reduces the overall asset cost. It is assumed that the asset value decreases linearly over its lifetime.
- **Modelled benefits:** calculated by applying a hydro-thermal dispatch optimisation package called SDDP.[4]
  - **Transmission loss benefits:** represent the reduced electricity needed to be generated due to lower electrical losses over the transmission network under

[3] Discounted project costs, including mid-life refurbishment costs for STATCOM and series compensation assets after 20 years of operation.

[4] SDDP is an electricity market modelling tool used to determine economic benefits, see Attachment 4.

different asset configurations of the grid. These transmission losses are converted to loss costs by multiplying the losses by the Island short-run marginal cost.

- **Deficit benefits:** if no transmission investment is made, we will be unable to supply all forecast electricity demand. In this situation consumers will be forced to curtail demand or find alternative ways of being supplied with electricity. This electricity shortfall is primarily valued at $600 per MWh.[5]

Further details of the benefits and the calculation methods are described in Attachment 4.

Table 4 outlines the quantified benefits for each of the shortlisted options.

Table 4: Quantified benefits, 2025 present values at 5% discount rate

	Option 1 Series Comp + Tee	Option 2 Series Comp + Cable	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
Terminal value benefits ($m)	84.0	107.6	81.9	71.7	72.9
Modelled market benefits ($m)	318.7	365.1	335.3	422.1	422.1
Total benefits ($m)	**402.7**	**472.8**	**417.2**	**493.9**	**495.0**

Option 4b (Duplex + Series Compensation) offers the highest quantified benefits among the short-listed options. The modelled market benefits of Options 4a and 4b are identical in the calculation period (2034-55), but there is a small difference in the terminal values due to the varied timing of the investments.

The Investment Test identifies the option with the highest net electricity market benefit as the preferred option. Table 5 outlines the quantified net benefits (total benefits minus total costs) for each of the shortlisted options.

Table 5: Quantified net benefits, 2025 present values at 5% discount rate

	Option 1 Series Comp + Tee	Option 2 Series Comp + Cable	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
Total benefits ($m)	402.7	472.8	417.2	493.9	495.0
Total costs ($m)	416.7	589.7	370.8	399.4	399.2
Net benefits ($m)	-14.0	-116.9	**46.4**	**94.5**	**95.8**

The cost-benefit analysis indicates that Option 4b (Duplex + Series Compensation) not only delivers a positive net benefit but also achieves the highest quantified net benefit among all options. However, Option 4a (Series Compensation + Duplex) delivers a similar net benefit and can therefore be considered as an alternative preferred option.[6]

[5] Deficit cost has been valued using cost tranches, see Attachment 4.

[6] Capex IM clause D1(2)(a) states that a similar expected net electricity market benefit is one where the difference in quantum is 10% or less of the aggregate project costs of the investment option.

Q11. Do you have any feedback on our cost-benefit analysis for this project?

4.2 Sensitivities

The sensitivities analysed in this assessment are outlined in section 3.4.

For an option to satisfy the Investment Test for core grid reliability investments like this one, it must be the option that maximises net benefit, although the net benefit may be negative. The results of the sensitivity analysis are presented below, with green highlights indicating the option with the highest expected net market benefit for each sensitivity scenario.

Table 6: Quantified net benefits, sensitivity analysis, 2025 present values ($m)

	Option 1 Series Comp + Tee	Option 2 Series Comp + Cable	Option 3 Duplex + STATCOMs	Option 4a Series Comp + Duplex	Option 4b Duplex + Series Comp
Low discount rate 3%	134.7	65.8	209.9	294.1	296.6
Base discount rate 5%	-14.0	-116.9	46.4	94.5	95.8
High discount rate 7%	-94.8	-216.2	-47.0	-21.8	-21.4
Capex increase (130% of base)	-139.0	-293.8	-64.8	-25.4	-23.9
Capex decrease (70% of base)	111.0	60.0	157.7	214.3	215.6
Equal scenario weighting	-50.3	-151.5	7.9	54.8	56.2
Environmental only	-49.4	-143.1	7.3	64.2	65.6
Growth only	40.4	-65.0	104.3	153.9	155.3
Reference only	-141.8	-246.3	-87.9	-53.7	-52.3

The sensitivity analysis indicates that Options 4a and 4b consistently deliver the highest net benefit across a wide range of assumptions. In the sensitivity cases with high discount rate and Capex increase, the net benefit turns slightly negative. Also, in the Reference scenario with a low demand increase, the net benefit is negative.

Consequently, we consider Options 4a and 4b are robust to uncertainties in the key input parameters and remains a robust choice under diverse future energy scenarios.

Q12. Do you agree that our preferred option remains robust under sensitivity analysis?

4.3 Recommendation of Preferred Option

Our cost-benefit analysis identified Option 4b as having the highest net-benefit to meet the N-1 reliability standard on the core grid. The sensitivity analysis reinforces the robustness of Option 4b, showing that it maintains the highest net benefit across a wide range of input uncertainties and diverse future energy scenarios. Option 4a has a similar net benefit to Option 4b.

Based on our preliminary application of the Investment Test, we conclude that Option 4b is our preferred option, subject to feedback from this consultation and any further analysis required as a result. Option 4a is considered as an alternative preferred option.

As discussed in Attachment 2, Option 4b (duplexing by 2030) provides future optionality and possible staging opportunities, as the investment in series compensation can potentially be delayed if the forecast load growth does not eventuate. However, there are risks with the deliverability of duplexing by 2030. This option therefore brings risk if, for example, high demand growth eventuates or if generation is on the lower side of our assumptions (particularly at Huntly). This is discussed further in Attachment 1.

Option 4a (duplexing by 2033) provides more time for duplexing to be delivered because it builds series compensation in 2030. However, the duplexing cannot be deferred further even if the forecast load growth does not eventuate. This option commits us to the full cost of both the series compensation and duplexing by 2033.

Deliverability of duplexing by the 2030 need date will be further considered, and along with consultation feedback on demand growth and generation, will feed into our final option selection.

In addition to the quantified benefits, we believe that Options 4a and 4b are prudent investments for Transpower to ensure a reliable and resilient electricity supply to the WUNI region. In a future likely to see increased electrification, new generation could potentially reduce the need for transmission infrastructure investment. However, the most likely future generation sources in the region are inherently intermittent and cannot consistently meet regional energy requirements. Moreover, voltage stability challenges cannot always be addressed through new generation alone, due to technical and locational constraints.

Options 4a and 4b effectively address these challenges by enabling a robust transmission network that supports the integration of intermittent generation while ensuring a reliable and stable electricity supply for consumers as demand for electrification grows. These factors strongly support the case for Options 4a and 4b as a necessary and forward-looking investment to meet the N-1 reliability standard on New Zealand's core electricity transmission grid.

Q13. Is our selection of the preferred option (4b) reasonable? How do you view the benefits of the potential for staging in the context of the delivery challenges of duplexing by 2030? Do you support the consideration of an alternative preferred option (4a), as the feasibility of 4b is dependent on consultation feedback and further consideration of duplexing deliverability by 2030?

5 Intended Proposal to the Commission

This project is a stage of a Major Capex Project (Staged) under the Capex IM. The major capex project status means that we will submit an MCP to the Commission seeking approval to recover the costs of the option chosen to meet the need. Before making any such proposal, we are seeking feedback from stakeholders on our preferred option (Option 4b) and alternative option (Option 4a). In particular, we are interested in receiving feedback regarding available generation in the region and its impact on the need date for duplexing or series compensation. Please refer to Q3 in Attachment 1. Your feedback, as well as further work by Transpower on the deliverability of Option 4b, will influence whether Option 4a or 4b is the eventual preferred option.

Due to uncertainties at this stage regarding available generation in the region and deliverability of Option 4b, and because Options 4a and 4b are similar in terms of net benefit, we have presented summaries below of the proposed staging, what an MCP proposal would include, and the Major Capex Allowances for both Options 4a and 4b. This is to highlight the similarities and differences between the two variants.

5.1 Project Staging

We have a high level of confidence in the immediate investment horizon, but this confidence diminishes as we look further into the future due to the inherent uncertainties in demand and generation forecasting. While we are certain about the near-term investment needs into the mid-2030s, there is still some uncertainty regarding the exact timing, location, and nature of future components.

For this MCP, our focus is primarily on the investments required in the near-term, within the immediate investment horizon (between 2028 and 2033), while keeping in mind the longer-term development path extending to 2055. Any additional investments in thermal and voltage management that may be needed after the early 2030s will be addressed either in a subsequent stage of the Major Capex Project (Staged) or through separate major or base capex projects.

5.2 Major Capex Allowances

The proposed Stage 2 investments for Options 4a and 4b and their costs are outlined in Table 7.

Table 7: Proposed WUNI Stage 2 investments, Option 4a and Option 4b (in real 2025 dollars)[7]

WUNI Stage 2 investments (Option 4 variants)	Expected P50 cost ($m)	Expected commissioning date (Option 4a)	Expected commissioning date (Option 4b)
100 Mvar shunt capacitor (PAK)	13.3	2028	2028
±150 Mvar STATCOM (HEN)	80.3	2029	2029
Series compensation on BHL–WKM circuits at Hangawera Road	185.9	2030	2033
100 Mvar shunt capacitor (Auckland region)	13.3	2031	2031
100 Mvar shunt capacitor (Auckland region)	13.3	2031	2031
100 Mvar shunt capacitor (Auckland region)	13.3	2032	2032
2x75 Mvar shunt capacitors (OHW)	21.3	2032	2032
Duplex OTA–WKM A&B circuits (OHW–WKM section) and connect at OHW	174.9	2033	2030
Total	**515.6**		

The estimated Major Capex Allowances (including inflation and interest during construction) for Options 4a and 4b are provided in Table 8. Although the expected costs (in real terms) for the Option 4 variants are identical, differences in the investment timing led to small variations in the draft Major Capex Allowances.

Table 8: Draft Major Capex Allowance (WUNI Stage 2)

	Expected P50 cost (real 2025 $m)	Draft Major Capex Allowance (nominal $m)
Transpower Capital Projects (Option 4a)	515.6	605.0
Transpower Capital Projects (Option 4b)	515.6	606.7

5.3 Proposal

This section describes the key grid outputs for Options 4a and 4b that would be included in an MCP to be submitted to the Commission.

The WUNI project is a Major Capex Project (staged). Stage 1 was approved by the Commission in 2020. This short-list consultation focuses on Stage 2, covering a STATCOM, series compensation, various shunt capacitors in the immediate investment horizon, and duplexing of the OTA–WKM

7 Substation acronyms: Henderson (HEN), Brownhill Road (BHL), Whakamaru (WKM), Ōtāhuhu (OTA), Ohinewai (OHW), Pakuranga (PAK)

circuits south of Ohinewai. A subsequent Stage 3 would address any future investments, should they eventuate.

Table 9: Intended WUNI Stage 2 proposal at a glance (Option 4a)

Intended proposal at a glance	
What:	Maintain the grid reliability standards in the WUNI region in the immediate investment horizon by: • Installing a ±150 Mvar STATCOM at Henderson (2029) • Installing series compensation on BHL–WKM circuits (2030) • Connecting the OTA–WKM A&B circuits at Ohinewai and duplexing the OHW–WKM section (2033) • Installing shunt capacitors at various locations. We are not seeking approval of the future Stage 3 components at this time.
When:	Commence work as soon as funding approved.
How much:	Transpower intends – subject to feedback from this consultation – to seek approval from the Commerce Commission for the second stage of a Major Capex Project (Staged) with a total Major Capex Allowance of $605.0 million.

Table 10: Intended WUNI Stage 2 proposal at a glance (Option 4b)

Intended proposal at a glance	
What:	Maintain the grid reliability standards in the WUNI region in the immediate investment horizon by: • Installing a ±150 Mvar STATCOM at Henderson (2029) • Connecting the OTA–WKM A&B circuits at Ohinewai and duplexing the OHW–WKM section (2030) • Installing series compensation on BHL–WKM circuits (2033) • Installing shunt capacitors at various locations. We are not seeking approval of the future Stage 3 components at this time.
When:	Commence work as soon as funding approved.
How much:	Transpower intends – subject to feedback from this consultation – to seek approval from the Commerce Commission for the second stage of a Major Capex Project (Staged) with a total Major Capex Allowance of $606.7 million.

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