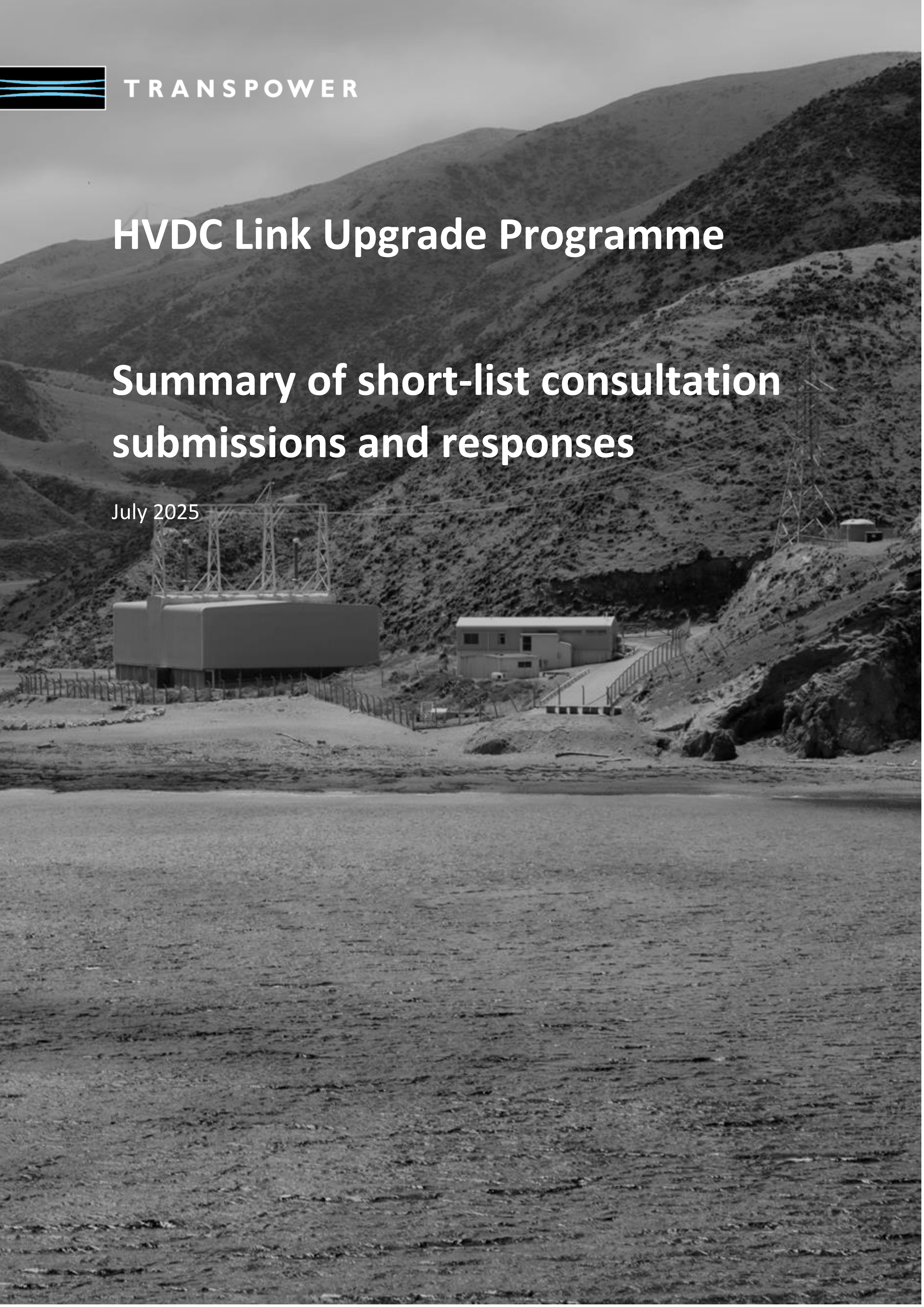
TRANSPOWER

HVDC Link Upgrade Programme

Summary of short-list consultation submissions and responses

July 2025



1. Executive summary

This document provides a summary of submissions received on Transpower's *HVDC Link Upgrade Programme short-list consultation* of May 2025 (the consultation paper)[1]. The consultation sought feedback on the proposed investment options to replace ageing High Voltage Direct Current (HVDC) infrastructure and our preferred option to increase the capacity of the HVDC link to 1400 MW.

Transpower received submissions from eleven organisations and one individual, representing a broad cross-section of the electricity sector, including generators, distributors, major industrial users, and policy bodies. We thank all submitters for their considered input and engagement.

In this document we have endeavoured to summarise the key points raised by submitters. For more comprehensive information, please refer to the original submissions. We have also taken the opportunity to provide a response to the submissions, where appropriate.

Key themes and feedback:

- The majority of stakeholder strongly support the need for HVDC investment to maintain system reliability, support decarbonisation, and meet future demand.
- Option 3 (1400 MW capacity via four cables) received widespread support as the best solution.
- There was support for bundling related HVDC upgrades to minimise outages and maximise efficiency.
- Stakeholders expressed no concerns with our treatment of non-transmission solutions in the short-list consultation, and no alternative solutions were proposed.
- Vector proposed a staged approach to cable installation. Transpower had earlier assessed this variant but excluded it due to higher costs, procurement risks, and reduced net benefits.
- Submitters called for greater clarity on transmission pricing and Benefit-Based Investment (BBI) charges. As indicated in our consultation material Transpower commits to providing further information and estimated charges as part of our proposal to the Commission.

Please feel free to contact us at grid.investments@transpower.co.nz if you have any questions or further feedback.

1 The consultation, the submissions and this document are available at HVDC link upgrade programme – short-list consultation | Transpower

2. Submissions received

Submissions were received from:

- Business Energy Council **(BEC)** – a cross-sector energy forum focused on promoting informed energy policy and dialogue.
- Electricity Engineers' Association **(EEA) –** a key industry organisation representing the electricity supply sector.
- Electricity Networks Aotearoa **(ENA)** – the industry associating representing electricity distribution businesses in New Zealand.
- **Fonterra** – a significant industrial electricity consumer, operating multiple diary processing facilities across the country.
- Infrastructure New Zealand **(INZ) –** a body representing public and private sector Infrastructure stakeholders
- Contact Energy **(Contact)**, a major electricity generator and retailer.
- Major Electricity Users' Group **(MEUG)** – an association representing the interests of large industrial and commercial electricity users.
- Meridian Energy (**Meridian**), a major electricity generator and retailer.
- Transpower **(**as **System Operator)** – providing a submission in its regulated role as System Operator, distinct from its role as Grid Owner.
- New Zealand Steel **(NZ Steel)** – a major electricity consumer operating energy-intensive manufacturing facilities.
- **Vector** – the electricity distributor for greater Auckland region.

We also received a submission from Logan Fenton in their private capacity.

3 Submissions on questions raised, with Transpower's responses

This section provides a summary of each submission. Transpower welcomes the opportunity to incorporate feedback into our HVDC Link Programme Major Capex Proposal (MCP).

Submitters generally answered the specific questions asked only, although some general comments were made. This section includes the most significant submitter responses to the 10 questions asked in the consultation paper, along with additional general comments relevant to these questions. We provide our response to each issue raised in blue text.

Q1.	**Are there any additional factors we should consider regarding our identified investment need?**

Several stakeholders have provided valuable perspectives that reinforce the investment need.

- Fonterra supports the investment and underscores the importance of aligning it with New Zealand's broader decarbonisation trends. They note that their own electrification plans may exceed the assumptions used in Transpower's scenarios, suggesting a need for more ambitious planning to accommodate increasing industrial demand.
- Contact emphasises the HVDC link's critical role in ensuring national energy security and maintaining market functionality. They point to the increasing unreliability and cost of thermal generation – particularly due to the decline of New Zealand's gas market – as a key justification for the investment.
- Meridian agrees that the investment is necessary to address the ageing HVDC infrastructure and mitigate the significant risk of failure. They stress that prolonged outages would have unacceptable consequences for electricity supply and the wider economy.
- MEUG highlights the importance of timely investment to sustain HVDC performance. They also raise concerns about rising electricity costs and advocate for careful consideration of affordability and equitable cost recovery mechanisms.

Q2. Do you have any additional information that could materially affect our electricity demand forecast or generation assumptions?

Several submitters provided insights that suggest Transpower's current assumptions may underestimate future electricity demand:

- Fonterra highlighted that Transpower's scenarios may underestimate electrification, particularly due to industrial decarbonisation. They recommended revising some specific assumptions to reflect an earlier decommissioning of cogeneration plants.
- Meridian Energy questioned the continued use of EDGS 2019 (particularly regarding gas availability and solar uptake). They acknowledge Transpower's updates may address some or all of these outdated assumptions but encouraged Transpower to adopt the EDGS 2024 as the basis for modelling, noting that these more accurately reflect current market conditions.
- BEC referenced the TIMES-NZ 2.0 model, which projects that electricity demand could double by 2050 due to widespread electrification of transport and industry. They stressed that an upgraded HVDC link is essential to integrate the expected surge in renewable generation, warning that without it, the grid may struggle to accommodate future renewable generation capacity.

Transpower response:
We appreciate the thoughtful feedback from stakeholders and acknowledge the importance of using up-to-date demand projections in our modelling.

Transpower has used an updated version of the 2019 EDGS to inform its analysis as at the time the modelling commenced it was the most recent version of the EDGS available and was consistent with the TPM Assumptions Book. The updated version used is based on an extensive process of updating the 2019 EDGS to reflect future views of electricity demand and generation that occurred in 2020 and

2021. This included several online panel discussions with industry experts and formal consultation. We subsequently reviewed and updated the scenarios based on more recent information. Following the release of the 2024 EDGS we reviewed the demand growth paths at a high-level. Our view is that they are broadly like those that we have used. On that basis we consider the existing scenarios we have used are reasonable and appropriate for assessing this project.

Nevertheless, we do intend to move to using the 2024 EDGS as a basis for demand and generation modelling for future projects. Work is already underway to update the Transmission Pricing Methodology (TPM) Assumptions Book to reflect this. We plan to consult on the revised Assumptions Book later this year.

Q3. Do you agree with our application of short-listing criteria?

There was broad support among stakeholders for the short-listing criteria, as reflected in their endorsement of Option 3, Transpower's preferred option.

Q4. Do you agree that we should be incorporating other related HVDC projects due at the same time with the cable replacement?

There was broad support among stakeholders for bundling related HVDC upgrades to maximise efficiency, reduce costs, and minimise disruption to the electricity system:

- Contact and the System Operator strongly endorsed a coordinated approach, highlighting the importance of integrated outage planning. Contact noted that aligning procurement and delivery timelines presents an opportunity to upgrade HVDC capacity alongside cable replacement, thereby reducing market impacts and enhancing security of supply.
- MEUG supported consolidating all HVDC-related work into a single programme. They emphasised the benefits of cost efficiencies, streamlined planning, and reduced disruption to the sector.
- Meridian agreed with the logic of combining projects to minimise outage periods but sought clarity on how outage-related costs have been factored into the cost-benefit analysis. They cautioned that bundling could lead to earlier or extended outages, potentially increasing short-term costs.
- NZ Steel questioned the necessity of removing decommissioned cables, given the high associated costs, and suggested this aspect of the project warrants further scrutiny.

Transpower response:

We appreciate the strong stakeholder support for a coordinated approach to HVDC upgrades. Undertaking these projects separately would require multiple outages – particularly for the cable replacement and the control system upgrade – each with its own market and operational impacts.

By integrating these works into a single, coordinated programme, we aim to minimise outage durations and reduce disruption to the electricity system. We believe there will be benefits in bringing forward the control system upgrade by two years (currently scheduled for replacement in 2033) to align with the cable replacement, if it is in the best interests of consumers and the market.

While detailed outage planning and durations are not yet available, our intent is that bundling these projects will not result in longer outages. However, due to limited information at this stage, we have not attempted to quantify the specific benefits of coordinated outages in our cost-benefit analysis. We undertake to engage with the market and stakeholders on the outages required for this important piece of work as soon as possible.

We acknowledge that the cost of removing decommissioned cables is not insignificant. Transpower considers this is the right course of action. As a responsible infrastructure owner, we recognise that removing these assets that are no longer being used aligns with our environmental responsibilities and supports our social license to operate; their removal may also be a regulatory or consenting requirement. Reflecting our commitment to environmental stewardship and public expectations, we intend to include this activity in our proposal to the Commerce Commission as a subsequent stage once we have undertaken further investigation to confirm the need, scope and costs of their removal.

Q5. Do you agree with the options we've shortlisted?

Submissions generally supported the shortlisted options, with Option 3 receiving broad endorsement.

- Contact agreed that there is no complete non-transmission alternative that could viably replace the HVDC works. They noted that North Island battery energy storage systems (BESS) will complement Option 3 but cannot provide long-term, firm capacity needed to meet sustained energy and peak capacity demands.
- Vector emphasised the importance of maintaining flexibility in infrastructure planning. They suggested that committing to all four HVDC cables upfront removes the opportunity to defer part of the investment until demand is more certain. Vector recommended that Transpower assess the option value of a staged approach – installing three cables initially and a fourth later – to reduce upfront costs while preserving flexibility for future expansion.

Transpower response:

We appreciate stakeholder support for the shortlisted options and acknowledge the importance of considering flexibility and alternative delivery approaches.

We see benefits from the fourth cable as soon as it is installed. In response to Vector's suggestion, we had earlier considered a variant involving the installation of three cables now (delivering 1200 MW), with the fourth cable deferred until demand increases. However, this variant was not included in the shortlist or Investment Test analysis because it will result in higher overall costs and lower net benefits compared to both the 1200 MW and 1400 MW options.

Key reasons for excluding the staged variant include:

- *Procurement and supply chain risks: Our market engagement indicates that future procurement of a single HVDC cable may be infeasible or highly risky due to limited global supply and increasing demand. There are few suppliers capable of producing cable compatible with our HVDC system, and future availability cannot be guaranteed. Therefore the fourth* *cable would still need to be ordered now, shipped to New Zealand, and stored – incurring additional costs for handling, storage infrastructure, and risk management.*

- *Additional mobilisation costs: Installing the fourth cable later would require a second mobilisation of a specialised cable-laying ship, adding significant cost and logistical complexity. Securing vessel availability in the future for a relatively small project also introduces uncertainty and potential risks.*
- *Project integration and outage impacts: Deferring the fourth cable would necessitate a separate future project for installation, testing, and HVDC control system integration. This would require additional outages and configuration, increasing costs and market disruption.*
- *Limited capital savings: Key enabling infrastructure (such as cable termination stations) must still be built to accommodate all four cables, limiting opportunities for meaningful capital cost deferral. Some components (e.g. Benmore filter bank) could be deferred, they would still be required later - likely at higher cost.*

While deferring investment can offer theoretical option value, in this particular case, the additional costs and reduced capacity outweigh any flexibility benefits. Delaying the fourth cable would reduce HVDC transfer capacity in the 2030s, potentially requiring more expensive North Island generation to meet demand.

Our assessment is that this is Transpower's only real opportunity of delivering all four cables. Doing so as part of a single, coordinated project avoids these additional costs and complexities and ensures full 1400 MW capacity is available from 2031. Our Investment Test analysis confirms that Option 3 delivers a positive net benefit, and delaying the fourth cable would reduce the net benefit by deferring benefit realisation without a commensurate reduction in cost.

We have engaged with Vector to discuss these points and how we can strengthen our proposal.

Q6. Do you consider our proposed weighting of the scenarios to be appropriate?

Most stakeholders supported the proposed scenario weightings, though some raised some concerns:

- Fonterra considered the current approach overly conservative. They recommended assigning a 50% weighting to the Environmental Scenario, arguing that it most accurately reflects New Zealand's likely energy future, particularly given strong decarbonisation trends and industrial electrification.
- Vector indicated a view that the scenario weighting was imbalanced and recommended a more balanced weighting approach.

Transpower response:

We appreciate the feedback and acknowledge the importance of scenario weighting in ensuring robust investment decisions.

To clarify, we have applied equal weighting to all four scenarios used in our analysis. There is no weighting bias toward higher-growth scenarios.

We acknowledge Fonterra's view that a higher weighting on the Environmental Scenario could better reflect emerging trends in electrification and decarbonisation. In more localised situations where a high, medium and low demand scenario has been considered we have weighted the central scenario higher. However, for this investment we believe that an equal weighting approach provides a balanced basis for assessing long-term investments.

Our sensitivity analysis (see Table 9 in Attachment 5 of the short-list consultation) presents Investment Test results for each scenario individually, including how each option performs under a 100% scenario weighting. Option 3 performs well across all scenarios, reinforcing the robustness of the preferred option.

In response to Vector's request for more detailed benefit timing, Figure 13 in Attachment 4 provides an annualised view of modelled benefits under each scenario. These benefits begin to accrue from around 2031, when the new cables are assumed to be in service and Option 3 enables an increase in northward HVDC transfer capacity to 1400 MW.

It's important to note that:

- *Figure 13 presents benefits in real (undiscounted) terms.*
- *The Investment Test applies discounting, which places less weight on benefits occurring further into the future (particularly post-2040).*

The benefits of Option 3 are most significant during periods of high demand and low North Island wind generation, when the additional 200 MW of firm transfer capacity enables greater use of South Island hydro resources. Without this capacity, higher-cost thermal generation would be required, and in some scenarios, energy deficits could occur.

We have engaged with Vector to discuss their submission.

Q7. Do you consider the use of a 30-year calculating period and a standard discount rate of 5% to be appropriate?

Fonterra and INZ expressed support for the proposed 30-year calculation period and the use of a 5% discount rate. Other stakeholders did not specifically address this question in their submissions.

Q8. Do you have any feedback on our analysis of the quantified costs and benefits for this project?

Stakeholders generally supported the analysis, particularly the emphasis on long-term economic and reliability benefits:

- Contact and BEC highlighted the significant economic and system reliability advantages of the proposed investment. Contact specifically noted that the additional capacity under Option 3

would deliver clear and material benefits to North Island consumers by enabling access to low-cost renewable peaking generation. This would reduce reliance on increasingly scarce and expensive thermal peaking generation, thereby enhancing security of supply.
- Contact also identified the increase in self-covering reserve capacity as a substantial market benefit, as it would lower reserve costs and make more generation available in the energy market.
- The System Operator acknowledged that some operational costs – such as Over-Frequency Reserve (OFR) and Automatic Under-Frequency Load Shedding (AUFLS) – were not included in the analysis. However, they did not consider these omissions to be material to the overall conclusions.

Q9. Is our conclusion, that Option 3 (replacing the cables with 1400 MW capacity) offers the greatest net benefit, reasonable?

There was strong consensus among stakeholders that Option 3 offers the greatest net benefit:

- EEA, BEC, and Contact expressed strong or unequivocal support for Option 3, citing its alignment with the scale and urgency of change in the electricity sector. Many submitters noted that the other shortlisted options would not be fit for purpose given the pace of electrification and the need for long-term resilience.
- Meridian and Vector also supported Option 3, while requesting clarification on several points raised in their submissions. These points are summarised throughout this document, along with Transpower's responses to them where applicable.
- INZ endorsed Option 3 as a model of best practice in long-term infrastructure planning. They described it as a "blueprint" for other sectors such as transport and water, noting that a future-ready HVDC link will enhance national connectivity, support community aspirations, and ensure a resilient, renewable-powered electricity system for decades to come.

Q10. Are there any additional sensitivities that we should test?

Most stakeholders did not propose specific additional sensitivities. However, several clarifications and considerations were raised – such as demand assumptions, outages, and staged investment options – which are addressed in other sections of this summary.

Vector raised two key suggestions:

- Concern that the modelling may unrealistically assume all utility-scale batteries are continuously available for instantaneous reserves
- A request for a high-level comparison of the cost and effectiveness of delivering similar benefits through large-scale battery storage or other non-network alternatives.

Transpower response:

We appreciate Vector's feedback and would like to clarify our modelling approach.

First, the modelling does not assume that all utility-scale batteries are continuously available to provide instantaneous reserve across all trading periods. Instead, batteries are dispatched based on co-optimisation of energy and reserves reflecting how the electricity market operates in real time. Batteries are dispatched to provide either energy (via arbitrage) or reserves, depending on system needs and prevailing market conditions. Their participation is governed by economic efficiency and technical feasibility, including state of charge and operational constraints.

We also distinguish between battery types in the model:

- *Utility-scale BESS are explicitly represented in the model, with operational constraints such as charge/discharge rates and energy capacity.*
- *Distributed batteries (e.g. behind-the-meter or within distribution networks) are reflected indirectly through demand forecasts. These are not assumed to contribute to system-wide capacity or instantaneous reserve provision.*

The level of battery capacity also varies significantly across the modelled EDGS scenarios. For instance, by 2050, North Island utility-scale BESS capacity ranges from 350 MW to 1,000 MW, and South Island capacity from 40 MW to 350 MW.

While a detailed cost-effectiveness comparison of large-scale battery storage and other non-network options was not the primary focus of this assessment, we note that these alternatives are incorporated into our modelling through EDGS scenarios and our model that co-optimises energy and reserves – consistent with how the real-time electricity market operates. The role of North Island BESS installations is recognised as complementary. For example, Contact Energy's submission supports the value of batteries while acknowledging their limitations – they cannot provide the long-duration, firm inter-island transfer needed to address structural energy or peak capacity gaps.

We have engaged with Vector to discuss this and clarify our modelling approach.

4 Other points raised

1. **Salt spray buildup and termination station location**
   Meridian and NZ Steel raised concerns about recent outages caused by salt spray accumulation on insulators at HVDC cable termination stations. This operational issue poses risks to long-term reliability and maintenance costs. Both parties queried whether Transpower had considered relocating these stations further inland to reduce exposure to coastal conditions and mitigate this recurring risk.

Transpower response:
We acknowledge the risks associated with salt spray in this challenging coastal environment. Our current design locates the new termination station adjacent to the existing buildings, on a site that we already own and have designated for this purpose.

To address salt-related risks, the design incorporates several mitigation measures:

- *Use of more pollution-resistant equipment, including longer and larger HV bushings*
- *Application of anti-salt buildup coatings*
- *Installation of permanent washdown facilities and provision for more frequent cleaning*

We are also looking into the effectiveness of a seaward-facing screen to protect roof bushings. We will continue to assess the cost-benefit trade-offs of further relocating the termination station as the project progresses, balancing technical, environmental, and economic considerations.

2. **HVDC southward transfer constraint**
   Vector noted that Transpower's modelling assumes unconstrained southward power transfers, whereas in practice, the HVDC link is limited to 950 MW southward until additional AC grid upgrades are completed. They argued that this assumption may overstate the immediate benefits of the upgrade and requested that Transpower re-run the modelling with this real-world constraint reinstated.

   Contact Energy emphasised the importance of completing these AC system upgrades prior to the HVDC upgrade. Contact believes these upgrades are essential to fully realise the benefits of Option 3, particularly for transferring additional power to northern load centres and avoiding the stranding of generation in the Lower South/Southland region.

Transpower response:
We appreciate feedback from Vector and Contact and recognised the importance of accurately reflecting system constraints in our modelling.

To clarify, Vector's interpretation of our modelling assumptions is not correct. Our benefits modelling does not assume that the full 1400 MW capacity of the upgraded HVDC link is available for southward transfers. While the upgrade enables up to 1400 MW of transfer capability, the effective southward limit remains constrained by the AC transmission system in the lower North Island – not by the HVDC system itself.

As detailed in Attachment 4: Benefits Modelling (page 23) of the short-list consultation, our modelling retains the 950 MW cap for southward flows. The increased capacity to 1400 MW is only applied to northward transfers in our modelling. This approach ensures that the benefits assessment reflects the physical limitations of the AC network and avoids overstating benefits.

We acknowledge Contact's point regarding the importance of complementary system upgrades. While such upgrades could unlock additional benefits, such upgrades are outside the scope of the current HVDC proposal – and any costs and benefits related to these additional works are not included. Any investigation into relieving these AC constraints would be considered as part of a separate project.

3. **Deliverability and environmental risk**
   Vector raised concerns about deliverability risks associated with the proposed HVDC project, including:
   - Long global lead times for submarine cables and specialised ships
   - Environmental permitting challenges and iwi engagement requirements
   - The potential for greater environmental and cultural scrutiny with the four-cable option, due to increased seabed disturbance.

They recommended that Transpower assess the sensitivity of project outcomes to delays and provide a comparison of deliverability risks across the short-listed options to allow stakeholders to better assess which options are genuinely most robust to the uncertainties that lie ahead

Transpower response:
We acknowledge that deliverability is a critical consideration – particularly for infrastructure of this scale in a complex marine environment like the Cook Strait. Our programme assumptions are based on the best available information, including current global supply chain lead times for submarine cables, engagement with suppliers and environmental and consenting requirements.

These inputs have informed our decision to seek approval for the project now, to secure delivery windows and mitigate future timing risks.

We acknowledge the concern around a one-year delay. While any delay would defer benefits and result in additional interest during construction, this risk is not unique to the four-cable (option 3) solution. Similar risks – including supply chain constraints, marine conditions, or consenting delays – also apply to the three-cable (option 2) alternative. What differs is the scale of the benefit foregone during any delay, which is greater for a lower-capacity option. As such, it does not materially affect the relative timing or cost comparison between options.

Importantly, the Investment Test is inherently long-term in nature and is designed to assess robustness across a range of future scenarios. Our modelling shows that even with a 30% capital cost increase due to risk, the four-cable option remains robust and continues to deliver the highest net benefit. A delay would not materially change the relative economic ranking of options, given the long duration and magnitude of benefits.

Regarding the marine installation scope of four-cables compared to the three-cable option, we do not consider this a material increase in deliverability risk. The cables would be installed as a bundled package, and installation durations and sequencing will be managed within a structured programme. Importantly, the fourth cable provides future flexibility, reducing the likelihood of further disruptive marine works later in the asset lifecycle.

On environmental and cultural considerations, we are actively engaging with iwi and other stakeholders. Cultural, environmental, and regulatory requirements are being integrated into our planning and consenting strategies from the outset. The project is specifically listed in Schedule 2 of the Fast-track Approvals Act 2024, recognising its national significance and enabling us to apply directly for fast-track consenting through an expert panel should we decide to do so. This proactive approach is intended to mitigate potential risks and ensure the project aligns with community expectations, statutory obligations and our social license to operate.

We have engaged with Vector to clarify these points.

4. Transmission pricing and transparency

Several stakeholders – including MEUG, Vector, Meridian, Fonterra, and NZ Steel – raised concerns about the transparency and fairness of cost allocation under the proposed Benefit-Based Investment (BBI) framework. Key points included:

- A lack of transparency in BBI charge allocations, making it difficult for stakeholders to assess their likely financial contributions.
- A call from Vector for early and detailed disclosure of indicative charges across all short-listed investment options.
- NZ Steel's concern that the current Transmission Pricing Methodology (TPM) disproportionately allocates costs to North Island consumers and South Island generators.
- Suggestions from Fonterra and MEUG that as energy flows become more balanced between islands, cost allocation should also be more evenly distributed.

Transpower response:
We acknowledge the importance of pricing transparency in enabling meaningful stakeholder engagement under the TPM. A central objective of the TPM is to align transmission investment costs with those who benefit from them.

In this short-list consultation, we have provided indicative benefit-based charge (BBC) allocations – expressed as broad percentage ranges – for the preferred investment option only. These allocations offer a high-level view of how charges may be distributed, based on expected benefit patterns.

We consider it reasonable to expect that the beneficiaries of the current proposal (replacing the HVDC cables and control systems to maintain and expand inter-island transfer capability) will be broadly similar to those of the earlier Pole 2 converter transformer replacement – given the shared objective of maintaining long-term HVDC operability.

We understand the request for indicative dollar-value BBCs across all short-listed options. However, we have not provided these at this stage due to:

- ***TPM charges not being a selection criterion:*** *Under the Capex IM, our responsibility is to identify and consult on the investment option that delivers the highest expected net benefit to New Zealand. The TPM determines how the costs of that investment are recovered once a decision is made. Indicative pricing is therefore a consequence of the investment decision, not an input into it. Publishing comparative indicative BBCs at this stage could risk confusion about the role of pricing in the option selection process.*
- ***Expected similarity of beneficiaries:*** *As Vector has observed, the parties that would benefit from the 1200 MW and 1400 MW options are likely to be largely the same, given the shared location, function, and system-wide impact of the proposed investment. While the scale of benefits may vary slightly between options (due to differences in timing, capacity, or duration of constraints relieved), the pattern of beneficiaries is not expected to change materially.*

That said, we acknowledge the intent behind these requests and remain committed to improving transparency.

A full consultation on proposed starting benefit-based investment (BBI) customer allocations – including engagement on customer-specific pricing outcomes – will occur following the submission and any approval of the MCP to proceed with the preferred investment.

5. **Clarification on existing HVDC BBI charges**
   Meridian requested clarification on whether BBI charges for existing HVDC assets will cease when those assets are replaced. They asked Transpower to provide a breakdown of the assets currently covered by HVDC BBI charges and explain whether new charges will replace or be additional to existing charges following the proposed investment.

Transpower response:
Transmission charges for existing HVDC BBIs will continue for as long as the associated assets remain in the Regulatory Asset Base (RAB). Once these assets are removed from the RAB—typically when they are decommissioned or replaced—the corresponding transmission charges will cease.

We have not provided a detailed breakdown of the specific HVDC assets currently included in the RAB and subject to BBI charges at this stage. The timing of when these assets will be removed from the RAB, and when new assets will be added, is yet to be confirmed.

In principle, any new HVDC investments approved through the Commerce Commission's Capex IM process will be added to the RAB once commissioned. These new assets will then attract their own BBI charges, which will be separate from and not additional to the charges for assets they replace. However, during any transition period where both old and new assets are in the RAB, there may be an overlap in charges. We note that most of the HVDC assets being refurbished (such as the Pole 2 transformers) or replaced (such as the HVDC cables) have already been fully depreciated so currently hold no value in the Regulated Asset Base (RAB).

6. **Operational questions**
   Meridian sought clarification on whether the proposed HVDC investments would alleviate current operational limitations, such as reserve sharing constraints linked to cable discharge times and other physical traits. They asked whether control system improvements are included in the scope of the upgrade alongside the planned capacity increase.

Transpower response:
Pole 2 is currently limited to 500 MW due to its connection to a single cable, whereas Pole 3 is connected to two cables. With the installation of a fourth cable, the limiting factor will shift to the rating of the Pole 2 converter transformers, which is 700 MW. Increasing the Pole 2 15 minute overload capability to 150% (840 MW) will ease current reserve-sharing limitations between Pole 2 and Pole 3 and delivers significant benefits, which have been quantified in our analysis.

The new cables will have the same discharge performance requirements as the existing cables they are replacing. These discharge times are designed to reduce electrical stress and maximise cable lifespan – shortening the discharge time would reduce asset life.

We also plan to include round power functionality within the scope of the new control system, enabling seamless and flexible transfer capability in either direction — from South to North or vice versa.