TRANSPOWER

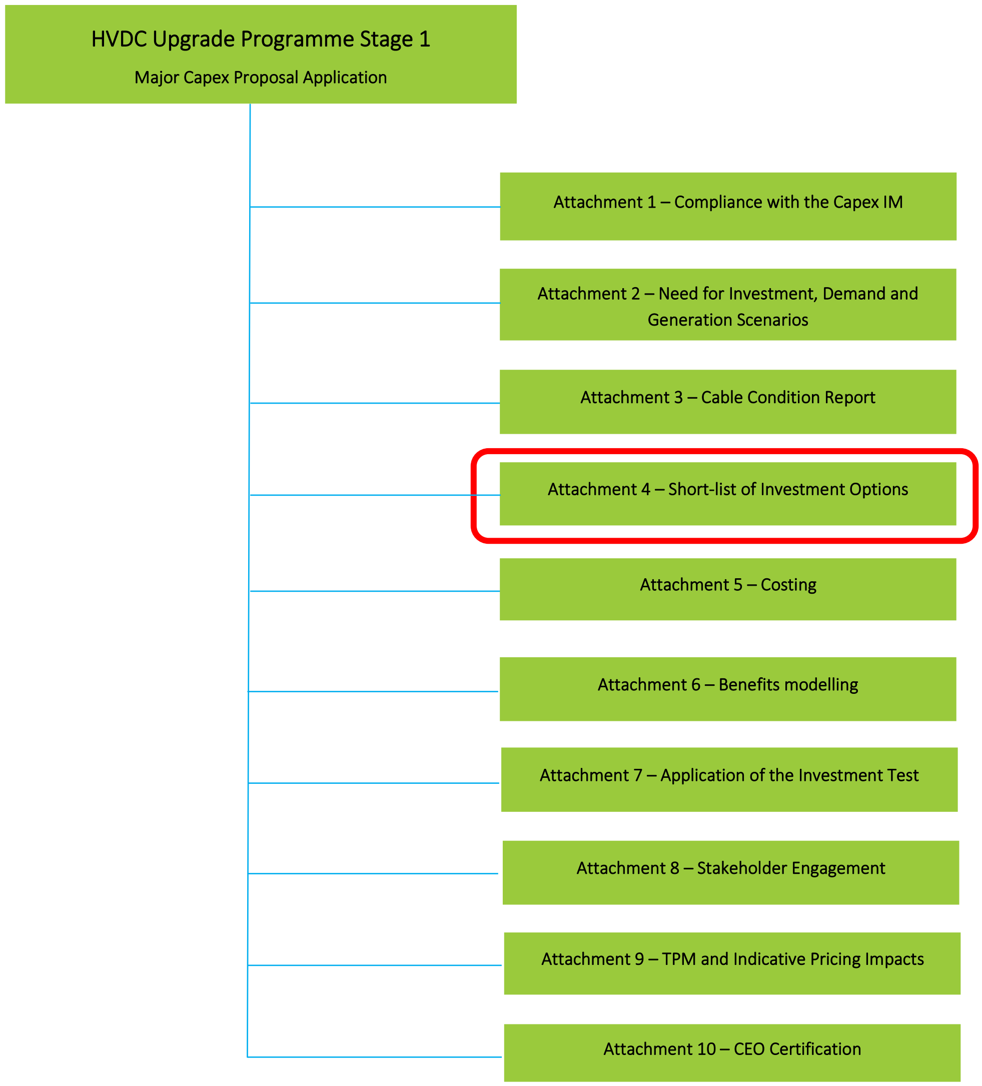
HVDC Link Upgrade Programme
Major Capex Proposal (Stage 1)

Attachment 4: Short-list of investment options

September 2025

Purpose

This document is part of our HVDC Link Upgrade Programme Stage 1 Major Capex Proposal (MCP). Its purpose is to outline our approach to developing options to assess, detailing how we applied our short-listing criteria to our initial long-list to derive a final short-list of investment options.



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1.1 Long-list of investment options

Acknowledging the condition-based need for investment, we initially compiled a long-list of options, which fell into three broad categories:

1. **Non-transmission options**
    - Alternatives aimed at decreasing or eliminating the need for a transmission investment.
2. **Transmission solutions: Existing assets: maintain, upgrade, enhance, modify**
    - <u>Do nothing:</u> allow the cables and associated equipment to run to failure,
    - <u>Like-for-like replacement:</u> Replace the cables and associated equipment with a capacity of 1200 MW, maintaining current capacity,
    - <u>Capacity increase:</u> Replace the current three cables and associated equipment with the addition of a fourth cable to support increased capacity (e.g. 1400 MW),
    - <u>Capacity decrease:</u> replace the cables and associated equipment with lower capacity.
3. **Transmission options: new assets**
    - Constructing a completely new HVDC link.

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

Our long-list of options, and an assessment of whether each was short-listed, is outlined in Table 1. Each short-listed investment option represents options to meet the need.

2 Assessment of the long-list of options

2.1 Short-listing criteria

Our long-list of options was evaluated using high-level screening criteria. These criteria were used to eliminate options that were not appropriate for consideration in the short-list, to which we apply the Investment Test. The outcome of applying the shortlisting criteria is reflected in Table 2. The screening criteria are described further below:

1. Fit for purpose
   - The design will meet current and forecast energy demand
   - The extent to which the option resolves the relevant issue

2. Technically feasible
   - Complexity of solution
   - Reliability, availability, and maintainability of the solution
   - Future flexibility – fit with long term strategy for the grid
   - Ideally the design can be staged and/or has flexibility to preserve options for future changes

3. Practical to implement
   - It must be possible to implement the solution by the required dates
   - Implementation risks, including the likelihood of obtaining any necessary outages and potential delays due to property, social, and environmental issues, are manageable

4. Good electricity industry practice (GEIP)
   - Ensures safety
   - Consistent with good international practice
   - Accounts for relative size, duty, age, and technological status
   - Technology risks

5. Provides system security
   - Improves resilience of the power system
   - Has benefits for system operation (e.g., controllability)

6. Indicative cost
   - Whether an option will clearly be more expensive than another option with similar or greater benefits.

Table 1 provides an overview of the long-list of options and our assessment of the long-list of options after applying our screening criteria. Table 2 provides a summary of the options that have been short-listed.

Table 1: Long-list of components

Component	Type	Sub-type	Details	Considered further
Non-Transmission Options				
A1	Non-transmission solutions (NTS)	Non-transmission solutions	Options that involve load management or additional supply in both the North and South Island.	X Does not meet criteria 1 and 2. Condition assessments indicate that cable replacement is necessary to ensure the ongoing operation of the HVDC link and to maintain supply-demand balance between islands. Without replacement the risk of cable failure increases and the risks are intolerable. Non-transmission solutions do not address the fundamental need for replacement cables. This option is not technically feasible, as NTS cannot fully replace the functions that the HVDC link provides. Refer section 2.1.
Transmission option: Existing assets: maintain, upgrade, enhance, modify				
B1	Cable replacement	Like-for-like replacement	Replace cables and associated equipment with a 1200 MW capacity, maintaining current transfer capability. *Location: Cook Strait* *Delivery timeline: 48-55 months delivery after planning investigations (i.e., procurement and design completion, etc).*	✓

Component	Type	Sub-type	Details	Considered further
B2	Cable replacement	Capacity increase	Replace the cables and associated equipment to support increased capacity (e.g. 1400 MW). *Location: Cook Strait* *Delivery timeline: 48-55 months delivery after planning investigations (i.e., procurement and design completion, etc).*	✓
B3	Cable replacement	Capacity decrease	Replace the cables and associated equipment with lower capacity (i.e., less than 1200 MW). *Location: Cook Strait* *Delivery timeline: 48-55 months delivery after planning investigations (i.e., procurement and design completion, etc).*	*X* Does not meet criteria 1 and 2. Decreasing HVDC link capacity would not support New Zealand's net zero goals or expected demand growth. The potential cost savings would be minimal, as cable manufacturing and installation costs dominate overall project expenses.

Component	Type	Sub-type	Details	Considered further
B4	Run to failure	Run to failure	No investment is made to replace the existing cables and associated equipment, and the cables and associated equipment are run to failure. This results in the decommissioning of the entire HVDC link. *Delivery timeline: N/A*	*X* *(included as base case)* Does not meet criteria 1 and 2. This option does not resolve the need or meet long-term needs. However, we are including this as a base case to illustrate the economic value of maintaining the HVDC link within the New Zealand electricity system.
Transmission option: New transmission assets				
C1	New HVDC	New HVDC	Decommission the existing HVDC infrastructure and construct a new HVDC link and associated cables along a similar route *Delivery timeframe: 7-10 years (depending on property rights acquisition, consenting and preferred technology)*	*X* Does not meet criteria 3 and 6. A completely new HVDC link would be very complex to implement and significantly more expensive than replacing only the cable, control system and minor components of the existing system. This option does not eliminate the need for future cable procurement to span the Cook Strait to connect the North and South islands.

Component	Type	Sub-type	Details	Considered further
C2	New AC inter-island link	New HVAC transmission line and cables, decommission HVDC link	Decommission the existing HVDC link infrastructure and construct a new HVAC link and associated cables along a similar route *Delivery timeframe: 10-15 years (depending on property rights acquisition, consenting and preferred technology*	*X* Does not meet criteria 3 and 6. A completely new HVAC link would be significantly more expensive than replacing only the cable, control system and other minor components of the existing HVDC link system. It would be technically challenging due to distance and grid integration issues. This option does not eliminate the need for future cable procurement to span the Cook Strait to connect the North and South islands.

2.1.1 Early stakeholder engagement and option development

In March 2024 we initiated early engagement with stakeholders ahead of our formal HVDC Link Upgrade Programme consultation process. This proactive approach helped shape the long-list of options and informed the short-listing. Feedback received supported replacing the cables by the early 2030s to mitigate failure risks, with broad agreement on increasing capacity to 1400 MW during replacement – recognising the significant costs and long lead times associated with later upgrades. Some submissions supported an increase beyond 1400 MW.

2.1.2 Evaluation of our long-list of options

The evaluation determined that:

- The only credible options involve replacing the cables with either like-for-like capacity or with increased capacity,
- Lower-capacity replacements or decommissioning the HVDC link were not considered fit for purpose. Lower capacity alternatives or decommissioning would undermine the HVDC link's role in supporting New Zealand's future energy demands.

Because of the condition-related need to replace the submarine cables due to intolerable risk of failure, there are limited options available. As a consequence, Transpower considers the Base Case and short-listed options (do nothing, like-for-like replacement, capacity increase) are appropriate in both number and technology to meet the investment need.

Maintaining the existing cables indefinitely is not a viable option

Maintaining the existing cables indefinitely and not replacing is not a viable option. The 'do nothing' base case included in the short-list is effectively a run-to-failure strategy, rather than a genuine maintenance alternative. The undersea cables are reaching end-of-life and, unlike overhead assets, cannot be proactively maintained or reactively repaired once deterioration begins. Cable failures would result in prolonged outages and significant disruption. The risk of cable failure increases beyond 2031, as well as the likelihood that those failures are irreparable.

A key driver throughout this process has been the increasing failure risk because of the deteriorating condition of the existing HVDC submarine cables. By 2031 the risk of failure will increase significantly as the cables approach the end of their operational life. Beyond this point, the likelihood and consequence of failure become intolerable, making continued reliance on the existing cables untenable. Replacement is the only viable solution to mitigate this risk and ensure the ongoing reliability of the HVDC link.

Additionally, the control systems are approaching obsolescence, with critical components no longer supported by manufacturers or available in the market. Continued reliance on these systems poses a high risk of unplanned failure, and there is no viable strategy for life extension. Without targeted investment in a control system replacement, the HVDC link cannot continue to operate reliably.

For this reason, a 'maintain without investment' option was not short-listed.

Consideration of staged cable replacement

During the May 2025 short-list consultation Vector queried whether a staged cable installation to 1400 MW had been considered. We assessed the variant involving the installation of three cables now (delivering 1200 MW), with a fourth added later (to deliver 1400 MW).

This variant was not short-listed because it will result in higher overall costs and lower net benefits compared to installing all four cables together. The benefits of the fourth cable are realised soon after commissioning. Market engagement indicates that future procurement of a single HVDC submarine cable may be unfeasible or highly risky due to limited global supply and increasing demand. Few suppliers manufacture cables compatible with our HVDC link, and future availability is uncertain as the world electrifies.

Consequently, if staged, the fourth cable would still need to be ordered now, shipped to New Zealand, and stored – incurring significant handling, storage, and risk management costs. In addition, a second vessel mobilisation would further increase costs (including additional outages), effectively negating any option value. In summary, a staged installation of a fourth cable was not short-listed.

2.2 Inclusion of other related projects

In addition to the planned HVDC link submarine cable replacement, we have identified two closely related projects that present opportunities for efficiency and cost savings when delivered as a coordinated package. This integrated approach received widespread support during our May 2025 short-list consultation.

The first of these is the planned works at the cable termination station buildings. Rather than attempting to retrofit and upgrade the existing buildings to meet current engineering and seismic requirements, we propose constructing two new buildings adjacent to the existing. This approach will meet modern seismic performance requirements and avoid long-duration construction-related outages.

The second is the replacement of the HVDC control systems which are critical for the operation of the HVDC link. These systems, commissioned in 2013 to manage both Pole 2 and Pole 3, are approaching the end of their 15-to-20-year operational lifespan. Obsolescence of both hardware and software components is expected by the early 2030s. They were originally scheduled for replacement in RCP5 (2030-2035) which is around the same time as we are planning to commission the new cables in 2031.

Our review of procurement, interface, and outage planning requirements for the cable replacement has highlighted benefits in delivering these projects concurrently. As with the cable replacement, global demand for HVDC control systems and the complexity of integration work means we must begin market engagement, procurement, and design now to ensure timely delivery and minimise system disruption.

By integrating these projects into a single programme, we can commence planning needed to manage the long lead times, streamline the regulatory approval process, and engage stakeholders on a holistic system upgrade rather than through a fragmented, project-by-project approach. Completing these projects together is expected to deliver cost savings to the electricity market and enhance the long-term resilience and reliability of the HVDC link.

Integration of control system replacement with cable programme

The HVDC control systems are bespoke, complex, and critical to the HVDC link's operation. Without them, the HVDC cannot function. Their obsolescence by the early 2030s makes replacement unavoidable if the HVDC is to remain in service. Our base case (Option 1) quantifies the decommissioning of the HVDC link following failure of the control system in 2038.

Although replacing the HVDC control systems was originally planned for 2033, there are strong benefits in aligning this work with the 2031 cable replacement programme. For the purposes of the Investment Test, we have included an estimate of the cost for the control system replacement. However, we are not seeking approval for this expenditure until Stage 2, as significant elements of scope and cost require further refinement over the next year to ensure a robust proposal.

Why integration makes sense

- Linked drivers: Control system replacement, already planned in RCP5, is fundamental to maintaining a reliable, long-term HVDC link,
- Unavoidable investment: The control systems will be obsolete and non-operational soon after the cables are replaced. Replacement is required irrespective of cable decisions if the HVDC is to continue operating,
- Considerable risk in a staggered approach: Attempting to connect new cables to an aging unsupported control system introduces material technical and operational risks. New hardware is no longer available so the use of available spares would be required to support connection of new cables to new cable termination stations, depleting the remaining spares. Manufacturer support will progressively reduce or cease over the next decade,
- Procurement timing risk: Global demand for HVDC control systems is high, similar to that for cables. If approval to replace the control systems is delayed until RCP5, it will likely be too late to secure design, equipment and delivery slots for a timely replacement,
- Better outcomes if aligned: Analysis shows that replacing cables and control systems together in 2031 delivers higher expected net electricity market benefits, specifically as a result of:
    - Reduced outages: Coordinated works avoid multiple shutdowns and minimises disruption to HVDC transfer, with more efficient delivery of engineering, testing and commissioning. Industry and consumers are likely to have low appetite for multiple major HVDC link outages a few years apart,
    - Avoided re-work costs: Avoids the inefficiency of first connecting new cables to the old control system, then reconnecting them to a new system a few years later,
    - Efficient delivery: Enables timely procurement, design, and integration of both systems as a single coordinated programme of outages and related works.

Value of integration

Although programme, outage, and cost requirements for the control system replacement are still being refined – and will depend heavily on final outage requirements and hydrology conditions – current analysis conservatively estimates that combining works in 2031, compared with deferring control system replacement to 2033 delivers additional expected net electricity market benefits of approximately $10–$150 million.

In summary, control system replacement is unavoidable to keep the HVDC link operational. Integrating this investment with the 2031 cable programme minimises costs and outage impacts, avoids technical and procurement supply risks, and ensures a coordinated, value-for-money upgrade of the HVDC link.

2.3 Non-transmission solutions

Considering the condition-based need to replace the HVDC submarine cables and the scale of the load, we believe that NTS are unlikely to provide a viable alternative to transmission for the HVDC link as a backbone grid asset. Unlike local distribution networks, electricity flow on the backbone grid is driven by national market operations rather than localised demand fluctuations. This dynamic makes it challenging to identify peak usage periods, which are critical for driving investment decisions.

During NZGP1.1 we issued a high-level Request for Information (RFI) alongside our long-list consultation. While we received some responses, most of the interest expressed by proponents was general support for the concept of NTS rather than specific project proposals or technologies capable of replacing or deferring transmission investments.

In the future, as North Island thermal generation is retired, peak demand may become increasingly dependent on intermittent renewable sources such as wind and solar, which are inherently less predictable due to variations in wind strength and cloud cover. Despite these uncertainties, NTS could help mitigate operational risks associated with the temporary unavailability of grid assets during project delivery. We will continue to assess the feasibility and effectiveness of NTS as part of our ongoing asset management planning to enhance grid resilience and reliability.

During our May 2025 consultation Contact Energy 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 a 1400 MW option but cannot provide long-term, firm capacity needed to meet sustained energy and peak capacity demands.

3 Short-list of investment options

In earlier sections we outlined the process of deriving a short-list of investment options. Table 2 provides a summary of our short list of investment options. The following subsections provide a detailed overview of the short-listed options.

Table 2: Summary of short-listed options

Option[1]	Description
Base case (Option 1)	No investment • The HVDC submarine cables, control systems and termination stations would not be upgraded. Over time, as critical components fail, the HVDC link would be decommissioned.
Option 2	Like-for-like replacement, 1200 MW • Replacement of the three submarine cables with 1200 MW capacity, along with necessary seismic and engineering upgrades to the termination stations and the HVDC control system replacement.
Option 3	Increased capacity, 1400 MW • Replacement of the three submarine cables with four submarine cables to support 1400 MW north capacity, accompanied by necessary seismic and engineering upgrades to the termination stations, overload capacity and the HVDC control systems replacement.

This investigation has not considered the benefits of an HVDC link larger than 1400 MW, as this is the maximum capacity of the existing HVDC infrastructure. However, a future investigation would be worthwhile to explore the potential benefits of additional transfer capacity or potentially a second HVDC link. Such a study would assess the conditions under which these options could become economically viable.

3.1 Base case (Option 1) – No investment

The base case assumes a run-to-failure approach where no investment is made to replace the HVDC submarine cables, control systems or termination stations. While cable failures are expected over time, the primary driver of the decommissioning date is the obsolescence of

1 The location of all three options is the Cook Strait.

the existing HVDC control systems, which become non-operational without upgrades by 2038.[2]

The timing for control system obsolescence aligns closely with the projected end-of-life for the existing submarine cables. This base case assumes a single cable failure in 2031 and a second in 2039. For modelling purposes, it is assumed that all HVDC system components, including the control system, will continue operating until they fail in 2038 without further investment. This assumption is optimistic given the assets' nominal lifespans, but it provides a suitable base case for comparison.

This option is not viable in practice. It is included only because the Investment Test requires us to define a base case to assess cost and benefit differences when evaluating alternative investment options. Typically, we have chosen a base case that assumes no new / minimal new investment in the grid.

In this base case, all HVDC assets would be dismantled following decommissioning in 2038.

For further detail and the HVDC transfer capacity changes please refer to Attachment 6, Benefits Modelling, Section 2.1.1.

3.2 Option 2 – Like-for-like replacement, 1200 MW

Option 2 involves replacing the three existing submarine cables with three new cables, maintaining the current northward transfer capacity of 1200 MW in 2031.

To enhance system reliability and resilience while minimising HVDC link outages, the following critical upgrades will be undertaken alongside the cable replacement:

- **HVDC control systems replacement** to address obsolescence and reliability concerns, as the existing platform will be 20 years old by 2031 and no longer supported,
- **Replacement of termination station buildings** at Ōraumoa/Fighting Bay and Oteranga Bay to ensure compliance with current seismic and engineering standards,
- **Development of a specialised cable storage facility** to accommodate spare submarine cable lengths. This will require constructing a storage turntable and supporting infrastructure to ensure the long-term integrity of the spare cable.

Delivery timeline: 48-55 months delivery after planning investigations (i.e., procurement and design completion, etc).

3.3 Option 3 – Increased capacity, 1400 MW

Option 3 involves replacing the existing submarine cables with four new cables, to support an increased northward capacity of 1400 MW in 2031.

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2 While this requires optimistic assumptions about system performance beyond nominal lifespans, we consider this to be reasonable and plausible for the purposes of a base case after consideration of alternatives.

As with Option 2, to enhance system reliability and resilience while minimising HVDC outages, the following critical upgrades will be undertaken alongside the cable replacement:

- **HVDC control systems replacement** to address obsolescence and reliability concerns, as the existing platform will be 20 years old by 2031 and no longer supported,
- **Implementation of a Pole 2 overload scheme** to enhance operational flexibility and reserve self-cover as transfer capacity increases,
- **Installation of filter banks at Benmore substation** that are required to support the 1400 MW transfer between islands,
- **Replacement of termination station buildings** at Ōraumoa/Fighting Bay and Oteranga Bay to ensure compliance with current seismic and engineering standards, and to provide the space needed for the additional cable,
- **Development of a specialised cable storage facility** to accommodate spare submarine cable lengths. This will require constructing a storage turntable and supporting infrastructure to ensure the long-term integrity of the spare cable.

Delivery timeline: 48-55 months delivery after planning investigations (i.e., procurement and design completion, etc).

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