TRANSPOWER

Net Zero Grid Pathways 1

Major Capex Project (Staged) updated

Attachment C: Options Report

Date: 25 September 2023

Contents

Glossary

Capex IM	Transpower Capital Expenditure Input Methodology Determination, New Zealand Commerce Commission[1].
Code	Electricity Industry Participation Code 2010.
Connection Asset	A grid asset that connects a customer to the interconnected transmission network.
Connection Charge	The sum of the annual asset, maintenance, operating and (injection for generation customers) cost components for a connection asset over that pricing year. The charge recovers part of Transpower's AC revenue.
Exempt Major Capex	The amount of the major capex allowance (MCA) to which the major capex incentive rate does not apply.
EDGS	Electricity Demand and Generation Scenarios.
GEIP	Good electricity industry practice.
GIP	Grid injection point.
Grid Reliability Standards	The Grid Reliability Standards (GRS) are a set of standards against which the reliability performance of the existing grid (or future developments to it) can be assessed.
GXP	Grid exit point.
Interconnection Charge	Recovers the remainder of Transpower's AC revenue and is based on a customer's contribution to Regional Coincident Peak Demand (RCPD).
Investment Test	The Capex Input defines the 'Investment Test' (IT), being the detailed economic assessment required for Major Capex Projects.
Major Capex Incentive Rate	Major Capex Incentive Rate means 15% or an alternative rate specified by the Commission in respect of an approved major capex project.
MBIE	Ministry of Business, Innovation and Employment.
MCA	Major Capex Allowance, as defined by the Capex IM.
MCP	Major Capex Proposal, as defined by the Capex IM.
MW	Megawatt, one million watts, being the power conveyed by a current of one ampere through the difference of potential of one volt.
MWh	Megawatt hour of electrical energy.
N-1	A security standard that ensures with all facilities in service Transpower's transmission system remains in a satisfactory state following a single fault (e.g., a circuit outage).
P50	Expected peak demand forecast. P50 is the 50th percentile of the peak demand forecast probability distribution.

[1] See https://comcom.govt.nz/regulated-industries/input-methodologies/transpower-ims

	Also, P50 means the estimated aggregate project costs where the probability of the actual project cost being lower than that estimated is 50%
Present Value	Future costs discounted to a present value using a discount rate specified in the Capex IM.
Prudent forecast	Prudent peak demand forecast. P90 is the 90th percentile of our peak demand forecast for the first seven years, then grows at the same rate as the expected for all remaining years in the analysis period.
RFI	Request for information.
RFP	Request for proposal.
SDDP	Stochastic dual dynamic programme – a dispatch model used to determine the optimal dispatch of hydro, thermal and other renewable generation.
SRMC	Short run marginal cost.
TPM	Transmission Pricing Methodology, defined in Schedule 12.4 of the Code.
TTU	Thermal Transmission Upgrade (TTU): tower strengthening and ground clearance improvements as necessary to allow an existing line to carry more electricity.
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the national grid).

1.0 Introduction

This attachment provides an overview of our assessment of options for the Net Zero Grid Pathways 1.1 (NZGP1.1) Major Capex Proposal (MCP) application.

This document explains how we have assessed options and applied the Investment Test specified in the Commerce Commission's Capex IM[2]. It is one of the supporting attachments to our main report (Net Zero Grid Pathways 1 Major Capex Proposal (staged), updated to reflect a correction to the Central North Island circuits operation and maintenance costs, and should be read in conjunction with our Investment Proposal.

[2] Consolidated Transpower capital expenditure input methodology determination as at 1 June 2018.

Investment Proposal

- Attachment A – Compliance Requirements
- Attachment B – Power Systems Analysis
- Attachment C – Options Report
- Attachment D – Scenario & Modelling
- Attachment E – Costing Report
- Attachment F – Expected Impact on Transmission Charges
- Attachment G – Indicative transmission charges
- Attachment H – Summary of Submissions
- Attachment I – Summary of Commerce Commission RFIs
- Attachment J – CEO Certification

2.0 Options Assessment Approach

To assess options, we have used our internal Options Assessment Approach. This involves four key stages of investigation designed to systematically identify the best option, as illustrated in Figure 1 below.

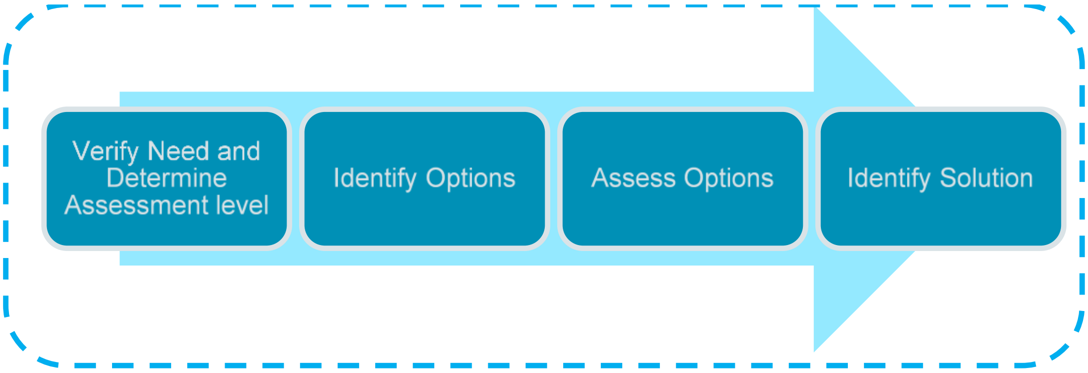

Figure 1: Option Assessment Approach stages

Verify Need and Determine Assessment level – This step focuses on confirming the need for the project and determining an appropriate level of assessment given its complexity and cost.

Identify Options – This step involves defining a long-list of potential solutions to the identified need, and then reducing this to a short-list for further analysis.

Assess Options – This step analyses the short-listed options and quantifies costs, benefits, and unquantified benefits.

Identify Solution – This step involves identifying our preferred option, based on our analysis.

The *Verify Need* determination for this investigation is outlined in the main report and Attachment B – Power System Analysis Report.

We summarise the remaining steps in turn below.

2.1 Refinement since the short-list consultation

In June 2022 we released our short-list consultation[3]. Since that time, we have considered feedback on our short-list consultation and have continued to work on our analysis. This has resulted in us refining some of our work. Since our short-list consultation we have:

- Refined the list of options considered for both the HVDC, CNI and Wairakei Ring
- Refined our pricing of the options for the HVDC, CNI and Wairakei Ring

[3] NZGP1: Short list consultation.

- Undertaken further modelling of the benefits of investment into the HVDC, CNI and Wairakei Ring
- Reconsidered our approach to non-transmission solutions (NTS) for this proposal

In refining our list of options, we started to formalise some of the strategic considerations identified in undertaking this particular investigation and our NZGP project more generally. These have guided some of our choices. Those considerations are described in more detail in Section 4.0.

2.2 Integrated transmission plan

Our most recent integrated transmission plan[4] (ITP) identified the need for enhancements to the grid due to anticipated increased demand from electrification and supply from renewable generation. The ITP describes how additional investment is required for connecting new load and generation and interconnection investments under our long-term roadmap “Net Zero Grid Pathways”.

Our Whakamana i Te Mauri Hiko work outlined the need for a long-term roadmap for the transmission grid, going out to 2050 and which clearly articulates the key enabling projects for electrification and renewable energy. The NZGP project will consider the grid upgrades required, including those for large step-loads such as the NZ Battery Project, when details emerge.

The need, short-list options, and proposed investment as described in this proposal are therefore consistent with this ITP.

3.0 Identify options

Following verification of the need we developed a long-list of components to address the issues which make up the need. It contained a wide range of possible components which individually contribute to meeting that need. It included both transmission and non-transmission solutions (NTS) and our preferred option consists of a development plan made up from the components. For this reason, we refer to the long-list as a long-list of components, rather than the usual terminology of a long-list of options.

This section describes several long-lists of components:

Table 1 includes the first long-list, which are components to bypass the existing grid and not upgrade it. Two components are included.

- The first utilises the existing HVDC assets to their maximum capacity of 1400 MW as far as Haywards. At Haywards, 700 MW is converted to AC and injected into the AC grid, while a new HVDC line is built to Whakamaru, where a new 700 MW converter is installed.

[4] 2022 Integrated Transmission Plan - RCP4 Consultation..

- The second component reflects a new link being built entirely between the North and South Islands. Such an option might be required if a large Lake Onslow scheme is developed, and it could also meet our overall need. New HVDC converters would be installed in the South Island, a new HVDC line built to the Nelson region, new undersea cables would be installed between there and the Taranaki south coast, a new HVDC line would be built with Taranaki to the west and Ruapehu to the East, as far as Huntly, where new HVDC converters would be installed.

Table 2, Table 3 and Table 4 are the remaining long-lists of components, which include potential upgrades of the existing assets, including new assets, for the existing HVDC, CNI and Wairakei Ring successively. In each table, the right-hand column indicates whether that option has been considered further or dismissed.

We consulted on our draft long-list of components in August 2021[5].

[5] NZGP1 Long-list Consultation

3.1 NZGP1 Long-List Components

Table 1: Components that could potentially meet the overall need

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)				YES
Transmission Components - new assets					
B1	New North Island HVDC Option	**Extend the HVDC from Haywards to Whakamaru.** Requires a new HVDC line. (Duration of works to be confirmed)	Enhance the Cook Strait capacity from the existing 1200 MW link to 1450 MW. Build a new (700 MW capacity) HVDC line from Haywards to Whakamaru. Retain 700 MW of HVDC converter capacity at Haywards and install a new 700 MW converter at Whakamaru.	This option would require enhancement to the existing Cook Strait cable capacity, a new line from Haywards to Whakamaru and a new 700 MW HVDC converter to be installed at Whakamaru.	YES This option would meet the overall need and avoid the need to upgrade the existing grid
B2	New inter-island HVDC option	**Install a new HVDC converter in South Island, new undersea cables from Nelson region to Taranaki region, new HVDC line to Huntly and new HVDC converter at Huntly.** Requires new assets. (Duration of works to be confirmed)	Install a new HVDC converter/s (700 MW to 1400 MW) in the South Island (location depending upon application (could be in the north of the South Island, or as far south as Lake Onslow), new line to Nelson region, undersea cables to south Taranaki, new HVDC line to Huntly and new HVDC converters at Huntly.	This option would require new assets entirely but would provide resilience in supply between the North and South Islands. Such a configuration would meet the overall need, avoiding the need to upgrade the existing grid.	YES This option would meet the overall need and avoid the need to upgrade the existing grid

3.2 HVDC Long-List Components

Table 2: HVDC components that could potentially meet all or a part of the need. This list may contain "tactical" options, which meet the need in the short-term need, but are followed by another component to meet long-term need

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)		Keeping the existing HVDC capacity (1200 MW N / 850 MW S)	Existing HVDC Cook Strait cables will require replacement circa 2032	YES
Non-transmission solution					
B1	Expansion	**Enhanced STATCOM**	Install enhanced STATCOM. Run the HVDC in unbalanced mode with enhanced STATCOM providing the higher reserve requirement when transfers are above 800 MW.	An enhanced STATCOM is a STATCOM with battery capability.	NO Market participants will decide if providing or purchasing higher reserves to enable an unbalanced HVDC mode is economic.
Improve availability					
C1	Improve availability	**HAY & BEN reactive support**	Installation of reactive support devices to provide improved link availability		NO
C2	Improve availability	**HAY & BEN reactive support with redundancy**	Installation of reactive support equipment to provide improved link availability, including installation of additional devices to create redundancy. Would target to lift the historic average availability from 1071 MW to close to 1200 MW.		YES
Expansion - fourth cable					

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
C1	Expansion	**Fourth Cook Strait Cable** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 700 MW (+60 MW) HVDC Target Capacity: 1200 MW N/ 850 MW S	Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 700 MW. Shifts threshold for dependence on NI instantaneous reserve up to 700 MW (from 640 MW).	NO Only provides small increase in capacity as an isolated option
C2	Expansion	**Fourth Cook Strait Cable with an increase Pole 2 overload capacity** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 1000 MW for 15 minutes. HVDC Target Capacity: 1200 MW N/ 850 MW S	Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 100 MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 100 MW (from 64 MW). Requires replacement of some Pole 2 equipment	NO Only provides small increase in capacity as an isolated option
C3	Expansion	**Fourth Cook Strait Cable, increase Pole 2 overload capacity and additional reactive support equipment at Haywards/Benmore** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 1000 MW for 15 minutes. Increases Bipole capacity to 1400 MW N (+200 MW) and 950 MW S (+100 MW) HVDC Target Capacity: 1400 MW N / 950 MW S	Increases Bipole transfer capacity (+200 MW) Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 1000 MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 1000 MW (from 640 MW). Requires replacement of some Pole 2 equipment Requires installation of reactive support equipment HAY and BEN. Requires augmentation or reconfiguration of the lower NI AC 110 kV network for increased South transfer	YES Improves Bipole capacity, reduces receiving IR requirements, improves equipment redundancy levels
C4	New additional HVDC link (duration to be confirmed)	**New Pole 700 MW N/ 500 MW S** (duration to be confirmed)	Total HVDC Target Capacity: 2100 MW N / 1550 MW S	Some scenarios (Onslow and/or significant increased SI demand) show a requirement for additional 700 MW N / 700 MW S. (Total 2100 MW N / 1550 MW S) Existing assets have theoretical maximum capacity for 1480 MW N and 950 MW S. Increasing HVDC transfer capacity above 1200 MW N and 850 MW S requires additional reactive support and augmentation of the lower NI AC transmission network (to supply load in Wellington and increase HVDC transfer South. Additional link to consider converter locations in relation to AC network requirements and termination points for submarine cable/s	YES Is the same as option B2 where the existing grid is bypassed

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
			Modify/upgrade		
D1	Incremental Improvement	**Increase HVDC Operating Current or Voltage** (duration 12-18 mths)	Increase Pole nominal operating limits approx. 10 MW (per pole). Increases Pole 2 ramp up (reserve) capacity to 650 MW (+10 MW) HVDC Target Capacity: 1200 MW N/ 850 MW S	Minor improvement to HVDC utilisation by increasing Pole 2 ramp up / overload capacity to 650 MW (+10 MW). Requires use of technology to enhance assessment of local ambient conditions. Shifts threshold for dependence on NI instantaneous reserve up by 10 MW to 650 MW.	NO This option would place strain on equipment and is not a viable long-term option
D2	Utilise Pole 2 ramp up (reserve) capacity	**Utilise Pole 2 to ramp up capacity (reserve) for energy transfer** Operational change	Allows Pole 2 dispatch to full asset capability of 500 MW for energy transfer (from 420 MW). HVDC Target Capacity: 1200 MW N/ 850 MW S	Requires additional instantaneous reserve (+130 MW) in receiving island provided by others. Increase in reserve costs (HVDC risk setter).	NO This option does not provide the required benefits, The option does not contribute to overall transfer capacity and would increase receiving island reserve requirements

3.3 CNI 220 kV Long-List Components

Table 3: CNI Components that could potentially meet all or a part of the need. This list may contain "tactical" options, which meet the need in the short-term need, but are followed by another component to meet long-term need

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
A1	Do Nothing (Counterfactual)			The need to enable efficient dispatch for new generation and reliable supply of future demand growth can't be addressed with this option.	YES
Non-Transmission Options					
B1	Battery Storage	**Battery installed north of constraint** (Duration of works to be confirmed**)**	A battery would need to act as a generator and/or only discharge on command, requiring a SPS system to work with the battery. If it only discharges on command: a SPS would detect a Tokaanu–Whakamaru circuit overload and ramp up the output of the battery while ramping down generation south of Whakamaru.	Market impacts have not been revised, as this solution would have to be accepted by the industry participants and regulator, including the development of protection grade communications and other SPS associated investments. A battery could potentially also provide reserves for the HVDC but not voltage support.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
B2	Generation Redispatch	**Automatic Generation Controller (AGC)** (duration of works to be confirmed)	Automatic scheme to detect overloading of Tokaanu–Whakamaru circuits and automatically and concurrently reduce demand north of Whakamaru and generation south of Whakamaru to remove the overload.	Viability depends on the level of interest from demand and generation customers to facilitate such an SPS. This is technically a lot more challenging than installing an AGC as there isn't the ability to precisely control demand like generation. If possible, this could potentially be a partial solution to defer transmission options	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
B3	Load Shedding	**Automatic scheme to concurrently reduce demand north of Whakamaru and generation south of Whakamaru post contingency to resolve grid overloads** (duration of works to be confirmed)	Regulated operation, where the load acts like a generator, allowing to minimise cost through controlled dispatch (start and stop electricity consumption) and when the load will only disconnect on instruction and remain off until the System Operator restores the grid back in a secure state.	Viability depends on the level of interest from demand and generation customers to facilitate such an SPS. This is technically a lot more challenging than installing an AGC as there isn't the ability to precisely control demand like generation. If possible, this could be a partial solution and it would require the acceptance of the market. This is technically more challenging than installing a generation redispatch SPS as demand not able to be precisely controlled.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
Transmission options - existing assets: maintain, upgrade, enhance, modify					
C1	Bussing existing line	**Bus the three Central North Island lines at an optimal point to improve load sharing between them**. (1 year of consenting + 3 years to build)	A new switching station where the three lines run adjacent to each other to bus them between Bunnythorpe and Whakamaru/Wairakei. Bussing can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them.	High level load flow analysis shows there to be no benefits as all three lines are already well utilised.	NO Little benefit was found by undertaking as the circuits are already well balanced
C2	Line upgrade	**Duplexing reconductoring of existing 220 kV Bunnythorpe-Whakamaru A and B lines** (2 years consenting and planning + 4 years build]	Converting the existing simplex Goat to an uprated duplex conductor.	Duplexing both existing Bunnythorpe-Whakamaru A&B lines will require strengthening key structures and foundations throughout the line. Duplexing provides the largest thermal capacity increase for the Central North Island corridor under the Line Upgrade sub-category. It also minimises system impedance which generally improves system performance during system events. Duplexing can be split into 2 stages with: • Stage 1- duplexing Tokaanu–Whakamaru sections • Stage 2 – duplexing Bunnythorpe–Tokaanu sections	YES This option provides largest thermal capacity as an upgrade and is reasonably fast to deliver
C3	Line upgrade	**Simplex reconductoring of existing 220 kV Bunnythorpe-Whakamaru A and B lines** [2 years consenting, and planning + 4 years build]	Reconductor existing simplex Goat with a larger conductor in a simplex configuration.	Reconductoring with a larger conductor would still likely require strengthening the towers and foundations, but not on the level of D2. Reconductoring with a larger conductor in simplex configuration provides some increase in thermal capacity but not to the extent of duplexing. It only provides a small reduction in system impedance which would generally improve system performance during system events. Reconductoring can be split into 2 stages with: • Stage 1- reconductoring Tokaanu–Whakamaru sections • Stage 2 – reconductoring Bunnythorpe–Tokaanu sections	NO Does not provide as much benefit as duplexing and due to the higher conductor impedance could cause voltage stability issues
C4	Line upgrade	**HTLS reconductoring of existing lines**[6] [2 years consenting, and planning + 4 years build]	Converting the existing simplex Goat to a high-temperature low-sag (HTLS) conductor	HTLS is currently being trialled by Transpower on sections of a recently reconductored line but it's performance and deliverables are not currently verified, particularly in regions with colder temperatures (snow). The capacity gains for this option may mean that it is only a partial solution. Reconductoring with a HTLS conductor in simplex configuration may not provide material increase in thermal capacity as it is unlikely to reduce the impedance of the upgraded lines which would otherwise offload parallel lower capacity lines. It also does not materially reduce system impedance which would generally improve system performance during system events. Therefore, further studies	NO This option is inferior to the duplex reconductoring options

[6] HTLS is not yet approved for widespread use in the network. The information required to progress on this option is outside of the timeframe required to address the needs.

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
				are required to check that voltage stability limits do not limit the benefits of this option. Voltage support equipment, if required, adds cost to this option. HTLS conductors are also higher resistance therefore transmission losses will be higher. Reconductoring can be split into 2 stages, similarly to D3.	
C5	Line upgrade	**Thermally upgrading of existing 220 kV lines** (3 years to build)	Upgrade the maximum operating temperature of existing 220 kV Bunnythorpe–Whakamaru A and B lines (also known as thermal upgrade) to achieve more capacity.	Thermal upgrades could provide similar benefits to reconductoring with HTLS conductor in simplex configuration but won't be as beneficial to reconductoring with a larger conductor in simplex configuration or duplexing. Thermal upgrades do not reduce system impedance which would generally improve system performance during system events. Therefore, further studies are required to check that voltage stability limits do not limit the benefits of this option. Voltage support equipment, if required, adds cost to this option. Thermal upgrades can be split into 2 stages with: • Stage 1 – thermal upgrading Tokaanu–Whakamaru sections • Stage 2 – thermal upgrading Bunnythorpe–Tokaanu sections Thermal upgrades (one or both stages) could be a good option to defer more significant transmission upgrades	YES This option is worth exploring further due to its low cost
C6	Variable Line ratings	**Apply Variable Line Ratings (VLR) on existing 220 kV lines** (3 years to build)	Apply VLR to existing Bunnythorpe–Whakamaru and Bunnythorpe–Wairakei lines. Variable line ratings use historical weather data to provide more granular ratings depending on the time of day and year. This generally increases ratings in the mornings and evenings where ambient temperatures are typically lower.	Some lines work is required prior to the application of VLR. On the interconnected grid, capacity needs depend on the most economic dispatch of generation. Therefore, the periods where VLR provides better ratings may not coincide with periods where the market would benefit from the additional capacity.	YES VLR is a low-cost option and will be combined with thermal uprating
C7	Series reactor	**Install series reactors on constraining Central North Island circuits** (2 years for build + 1 year for consenting)	Install series reactors on the constraining Tokaanu–Whakamaru circuits to reduce power flowing through them. Series reactors can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them	Series reactors do provide a small increase in transmission capacity as it forces more power to flow north through the Taranaki region. However, the benefits are contingent on some thermal generation retirements (e.g., the Stratford combined cycle generator) in the Taranaki region to free up transmission capacity in the region.	NO Similar to option C1, circuits are already well balanced so this option would not provide additional capacity
C8	Dynamic Line Rating	**Apply dynamic line rating (DLR) on existing 220 kV lines** (2 years for build)	Apply DLR to existing Bunnythorpe–Whakamaru and Bunnythorpe–Wairakei lines. Dynamic line ratings allow line ratings to be calculated in real-time based weather condition measurements. This typically provides higher ratings for transmission lines when compared with static ratings that are calculated using assumptions that may be conservative for a large portion of the time.	Requires investments in weather monitoring stations, communications network, and data processing systems to enable real time rating calculations. Potentially requires Code changes by the Electricity Authority to enable market and tools to be compatible with real time ratings. Requires Market tools to be developed to be compatible with real time ratings. Market participants will need to be consulted as real time ratings is not something the market has had to deal with in the past. On the interconnected grid, capacity needs depend on the most economic dispatch of generation. Therefore, the periods where DLR provides better ratings may not coincide with periods where the market would benefit from the additional capacity.	NO Dynamic line rating would require code changes in the market. High flows on CNI can be driven by hydro/wind in the SI and lower NI. It is unlikely that a clear correlation between high ratings and high flows will exist

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
Transmission components - new assets or replacing existing assets					
D1	New Line	**New 220 kV line between Bunnythorpe and Whakamaru** [8 years property acquisition and consenting + 5 years build]	A new 220 kV double circuit duplex line between Bunnythorpe and Whakamaru	Following the existing Bunnythorpe-Whakamaru A&B routes, a new double circuit 220 kV duplex line could be constructed. As the new line would likely pass through nationally significant areas, which are volcanically active, the time for property acquisition and consenting poses a risk to this option. This is a long-term solution and would require a partial solution in the interim to achieve the required capacity in 5 years from now.	YES This is a long-term option that will be further examined. Specific areas and routes will be analysed in phase 2 of NZGP
D2	New Line within the Taranaki transmission corridor	**New 220 kV line Bunnythorpe-Stratford-Huntly** [10 years property acquisition and consenting + 7 years build]	A new 220 kV double circuit duplex line between Bunnythorpe - Stratford - Huntly	This new line can be developed in stages: • Stage 1 – a new double circuit line between Huntly–Stratford 2. • Stage 2 – a new double circuit line between Bunnythorpe–Stratford. This stage could be deferred by upgrading existing lines between Bunnythorpe–Stratford. The new Bunnythorpe–Stratford route would follow the existing Brunswick-Stratford A and Bunnythorpe-Brunswick A lines. A new route is probably required from Stratford to Huntly. Of all the new line options this covers the longest distance and presents the most difficult terrain to cover, particularly between Huntly and Stratford.	YES This new line option combines with option D1 for further analysis in NZGP phase 2
D3	New Line within the Hawkes Bay transmission corridor	**New 220 kV line between Bunnythorpe-Woodville-Waipawa-Fernhill-Redclyffe-Wairakei** [10 years property acquisition and consenting + 5 years build]	A new 220 kV double circuit duplex line between Bunnythorpe - Woodville - Waipawa - Fernhill - Redclyffe-Wairakei	This option, if northern end terminates at Wairakei, will exacerbate the Wairakei Ring needs, and requires Wairakei Ring needs to be resolved first. Likely to require the line to be built from Wairakei towards Bunnythorpe end due to system needs. This increases the lead time before addition capacity is available for export of generation out of Bunnythorpe. The existing 110 kV Bunnythorpe-Woodville A and Fernhill-Woodville A lines would provide the route; however, the terrain would need some deviations. Only a partial solution, as the Wairakei-Whirinaki A line may still also need to be uprated.	YES This new line option combines with option D1 for further analysis in NZGP phase 2
D4	New Line within the existing Central North Island transmission corridor	**Replace the existing Bunnythorpe–Whakamaru-A and B lines to 400 kV** (10 years property acquisition and consenting + 5 years build)	Replace the existing 220 kV Bunnythorpe-Whakamaru A & B lines with 400 kV lines.	Requires 220/400 kV interconnection at either ends of the lines. Existing towers are not 400 kV capable therefore this option is equivalent to building new lines. However, costs and outage requirements for this option make it less feasible than building a new line (new lines are higher voltage class and existing lines have to be dismantled to re-use the route).	NO Under the present scenarios this level of capacity is not seen to be necessary

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
D5	New Line within the existing Central North Island transmission corridor	**Triplexing existing 220 kV Bunnythorpe–Whakamaru A and B lines** [8 years property acquisition and consenting + 5 years build]	Triplex the existing 220 kV simplex Bunnythorpe–Whakamaru A&B lines.	Existing towers are only designed for simplex loads, therefore triplexing requires significant tower and foundation strengthening, making this option similar to building a new line from a cost perspective. The outages to replace and strengthen these lines make this option less feasible than building a new line.	NO This option would require significant tower and foundation strengthening and would not be cost effective
D6	New Line within the Central North Island transmission corridor	**Upgrade Bunnythorpe-Ongarue A to 220 kV and terminate into Whakamaru** [8 years property acquisition and consenting + 5 years build]	Upgrade the existing 110 kV Bunnythorpe–Ongarue-A to 220 kV.	The existing Bunnythorpe–Ongarue A line is not 220 kV capable therefore this option is equivalent to building a new line. Requires alternate supply options for Mataroa, Ohakune, National Park and Ongarue substations that are currently supplied by the existing Bunnythorpe–Ongarue A line.	NO This is a high-cost option that would be unlikely to pass the investment test
D7	New Line within the Central North Island transmission corridor	**Upgrade Bunnythorpe-Ongarue A to 220 kV and terminate into Taumarunui and upgrade capacity between Huntly-Taumarunui** (10 years property acquisition and consenting + 7 years build)	Upgrade the existing 110 kV Bunnythorpe–Ongarue A to 220 kV and terminate the circuit into Taumarunui. Upgrade the capacity of the existing Taumarunui to Huntly 220 kV line or build a new line in parallel.	The existing Bunnythorpe–Ongarue A line is not 220 kV capable therefore this option is equivalent to building a new line. Requires alternate supply options for Mataroa, Ohakune, National Park and Ongarue substations that are currently supplied by the existing Bunnythorpe–Ongarue A line. If a new line between 220 kV Taumarunui and Huntly is built, it may defer investments between Whakamaru and the Waikato and upper North Island region	NO This is a high-cost option that would be unlikely to pass the investment test
D8	New Line within the Central North Island transmission corridors	**Build a new 220 kV cable between Bunnythorpe and Whakamaru** (10 years property acquisition and consenting + 7 years build)	Build a new 220 kV cable between Bunnythorpe and Whakamaru	This option is technically challenging as long cables have very high charging currents. Charging currents reduces available capacity to carry power and causes high voltages (exceeding designed limits) at the opened end. A common solution to tackle this issue is to install shunt reactors to compensate the charging currents. Multiple substations with shunt reactors will be required along the cable route which increases cost. This option will be of many magnitudes (in the order of 5-10x) more costly than building a new 220 kV overhead line.	NO This is a high-cost option that would be unlikely to pass the investment test
D9	HVDC transmission option	**Extend the HVDC NI terminal to Whakamaru** (10 years property acquisition and consenting + 7 years build)	Build a new 350 kV HVDC line between Haywards and Whakamaru and install a new convertor station at Whakamaru	Although new HVDC lines are slightly cheaper to construct than 220 kV HVAC lines, the HVDC line length is significantly more as it needs to cover Haywards to Bunnythorpe section as well. This coupled with the cost of a convertor station will make this option significantly more expensive than a new 220 kV line option.	NO This option would be prohibitively expense and would not pass the investment test. Should MBIE announce the construction of a large Onslow, this could be revisited

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered Further
D10	HVDC transmission option	**Extend the HVDC NI termination to Huntly** (10 years property acquisition and consenting + 10 years build)	Build a new 350 kV HVDC line between Haywards and Huntly and install a new convertor station at Huntly	Although new HVDC lines are slightly cheaper to construct than 220 kV HVAC lines, the HVDC line length is significantly more as it needs to cover Haywards to Bunnythorpe section as well. This coupled with the cost of a convertor station will make this option significantly more expensive than a new 220 kV line option. Transmission losses will be higher than a HVAC option due to the significant length (high resistance) and relative low voltage (high currents) Some 220 kV HVAC lines between Whakamaru and the Waikato and Upper North Island region may be repurposed for HVDC operation.	NO This option would be prohibitively expense and would not pass the investment test. Should MBIE announce the construction of a large Onslow, this could be revisited

3.4 Wairakei Ring Long List Components

Table 4: AC Components that could potentially meet all or a part of the need. This list may contain "tactical" options, which meet the need in the short-term need, but are followed by another component to meet long-term need

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)		Assumes reactor at 19.5 ohms		YES
Non-Transmission Components					
B1	Battery Storage	**Battery installed north of constraint** (Duration to be confirmed**)**	A battery would need to act as a generator and/or only discharge on command, requiring a SPS system to work with the battery. If it only discharges on command: a SPS would detect a Tokaanu–Whakamaru circuit overload and ramp up the output of the battery while ramping down generation south of Whakamaru	This solution would have to be accepted by the industry participants and regulator, including the development of protection grade communications and other SPS associated investments. Such a battery would need to be large but could potentially also provide reserves for the HVDC but not voltage support. HVDC could set the capacity (MW) needs of the battery and the minimum energy (MWh) needs while CNI adds in the energy needs that it could justify Such a battery could potentially also address other constraints south of Whakamaru such as on the CNI	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
B2	Generation Redispatch	**Automatic generation controller (AGC)** (Duration to be confirmed**)**	AGC would detect overloading of Wairakei Ring circuits and automatically reduce generation in the Wairakei/Eastern Bay of Plenty/Hawkes Bay regions while increasing generation north of Whakamaru to remove the overload.	This would require agreement between affected asset owners and would be subject to compatibility of different assets to facilitate such a scheme. Such an arrangement may be more likely to be acceptable for a short term, e.g., to defer transmission or assist with obtaining requisite outages.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
B3	Load shedding	**Automatic scheme to concurrently reduce demand and generation to resolve grid overloads** (Duration to be confirmed**)**	Automatic scheme to detect overloading of Wairakei Ring circuits and automatically and concurrently reduce demand north of Whakamaru and generation in the Wairakei/Eastern Bay of Plenty/Hawkes Bay regions to remove the overload.	This would require agreement between affected demand and generation customers to facilitate such an SPS. This is technically more challenging than installing AGC as there is no ability to precisely control demand like generation. Such an arrangement may be more likely to be acceptable for a short term, e.g., to defer transmission or assist with obtaining requisite outages.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
Transmission components - modifying and upgrading existing assets					
C1	Line upgrade	**Thermally upgrade Wairakei–Whakamaru A line, Wairakei–Whakamaru C line and Eastern Bay of Plenty 220 kV circuits (Edgecumbe–Kawerau–Ohakuri 220 kV)** (Approximately 3 years to build + 2-years for consenting and planning)	High level of uncertainty on the cost and time required to thermally upgrade Wairakei–Whakamaru A line and Edgecumbe–Kawerau–Ohakuri 220 kV circuits (currently at 50°C). This option does not materially resolve Wairakei Ring constraints but is an option to relieve constraints on Eastern Bay of Plenty generation.	Thermal upgrade of Wairakei–Whakamaru C line is possible.	NO Grease migration temperature of the A line conductor means uprating the line temperature is not feasible
C2	Reconfiguration	**Reconfigure Atiamuri–Ohakuri reactor impedance and thermally upgrade the Wairakei-Whakamaru C line.** (3 years to build + 2 years for consenting and planning)	Thermal upgrade of Wairakei–Whakamaru C line is possible. This option is likely to only provide a modest increase in capacity on the Wairakei Ring.	Thermal upgrade of the WRK–WKM C line is limited to 100 deg C due to the annealing temperature of the conductor	YES Although the capacity increase from this option would be modest, the price is also small so the investment may be economic
C3	Reconfiguration	**Reconfigure the Wairakei 220 kV bus and split the network to potentially increase load sharing on the Wairakei 220 kV circuits** (Duration to be confirmed**)**	Reconfigurations will involve investments which could be significant if the 220 kV bus must be rebuilt. Reconfigurations may also reduce transfer capacity on the CNI corridor.	There is no obvious reconfiguration option to further increase capacity through the Wairakei Ring.	NO There is no option to reconfigure that would provide additional capacity

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
C4	Bussing C line	**Bussing C Line** (Duration to be confirmed**)**	Bussing can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them.	High level load flow analysis shows there to be no benefits as all three lines are already well utilised. Would require designation/NOR and regional consents. Need to avoid SNA. Time and cost to secure approvals. To consider archaeology and cultural impact.	NO There is no capacity increase gained through this option
C5	Line Compensation	**Active Line Compensation** (Duration to be confirmed**)**	Install active line compensation devices to actively optimise impedance of Wairakei Ring circuits to maximise transfer capacity	Technically feasible but the Electricity Market currently operates with a static power system. Active Line compensation will require the Market and the Market tools to be adapted to work with a dynamic power system. This option is unlikely to be achievable in the 0-5-years' timeframe as code changes may be required in addition to tool upgrades etc (similar challenges to DLR).	NO This option would require the development of market tools in conjunction with the Electricity Authority and is outside the scope of this investigation
Transmission components - new assets					
D1	HVDC	**HVDC terminal** [5 years property acquisition and consenting + 7 years build]	Tap into HVDC that is on the way to Whakamaru. If the preferred option for CNI and HVDC is to extend the HVDC to Whakamaru, tap into HVDC at Wairakei if the HVDC traverses the site or deviate the HVDC to Wairakei if it doesn't.	This option will require it to align with HVDC and CNI projects as the proposal is to tap into new HVDC lines headed north towards Whakamaru. Tapping into HVDC, or building new HVDC, require converter stations that are in the order of ~$250m each. Suggest this makes these options infeasible.	NO The CNI preferred solution is not to build additional HVDC assets
D2	HVDC	**Back-to-back HVDC terminal** [2 years consenting and planning +5 years build]	Install back-to-back HVDC between Atiamuri–Ohakuri plus thermal upgrade Wairakei–Whakamaru C line.	This option will allow the power flow across the Wairakei Ring to be coordinated (using the back-to-back HVDC to steer power flow), allowing the maximum capacity of the Wairakei Ring to be used (i.e., 100% utilisation of all three circuits) Likely to be more costly than line upgrades (due to short lengths) while offering less capacity as it is still limited by the capacity of existing circuits.	NO This option is cost prohibitive when compared to HVAC construction options and would not pass the investment test
D3	HVDC	**HVDC Light system between Wairakei–Whakamaru** [3 years property acquisition and consenting + 5 years build]	Install HVDC light between Wairakei–Whakamaru by converting existing HVAC line to HVDC operation (maybe one of the Wairakei–Whakamaru C line circuits)	HVDC light is smaller scale HVDC systems that are often the result of conversions of HVAC assets into HVDC operation. The idea is that converting HVAC lines to HVDC will increase the power transfer limits between two or more points that are currently served by HVAC lines that are nearing or at capacity and obtaining another transmission corridor is much more expensive or impractical. HVDC is usually more cost effective for transmission over long distances, so it is unlikely to be the most cost-effective approach to address the Wairakei Ring constraints.	NO This option is cost prohibitive when compared to HVAC construction options and would not pass the investment test

Component Type	Component sub-type	Component (duration of works)	Details	Comments	Considered further
D4	New Line	**Connect into 400 kV lines between Bunnythorpe and Whakamaru** [3 years property acquisition and consenting + 10 years build]	Connect into 400 kV lines between Bunnythorpe and Whakamaru. If the preferred option for CNI and HVDC is to build a 400 kV line between Bunnythorpe and Whakamaru, bus the line at Wairakei if it traverses the site or deviate the line into Wairakei if it doesn't. A new 400 kV substation is required at Wairakei.	This is a long-term solution and would require a partial solution in the interim to achieve the required capacity in 5 years from now.	NO The CNI preferred solution is not to build additional HVDC assets
D5	New Line	**New line from Ohaaki (OKI) to Atiamuri and new Atiamuri–Whakamaru double circuit to replace current section of the A line** [3 years property acquisition and consenting + 7 years build]	New 220 kV line from Ohaaki to Atiamuri and upgrade existing Atiamuri–Whakamaru section of the Wairakei-Whakamaru A line to a 220 kV double circuit line	This option increase security of supply to the Bay of Plenty region It may be more economic to build a new line between Atiamuri–Whakamaru and then dismantle that section of the Wairakei–Whakamaru A line due to the length of outage required to upgrade it to a double circuit.	NO This option has been further refined since longlisting and is now shown as option D5A
D5A	New Line	**New line from Wairakei to Ohakuri and Duplex Ohakuri to Whakamaru** [2 years consenting, and planning + 4 years build]	New 220 kV line from Wairakei to Ohakuri and upgrade existing Ohakuri–Whakamaru section of the Wairakei-Whakamaru A line to a 220 kV duplex line	This option may prove to be an economic balance of new and upgraded lines and would provide sufficient capacity.	YES This option would also include the C line TTU option and should be explored further
D6	New Line	**Third line in the Wairakei Ring transmission corridor** [2 years consenting, and planning + 4 years build]	New double circuit 220 kV line between Wairakei–Whakamaru in parallel to the existing lines	This option could increase security of supply/resilience to the Bay of Plenty region if it connects into Atiamuri. However, the preferred transmission corridor may not allow this to be the case. A double circuit line is preferred as it creates optionality for the future.	YES This option provides additional capacity and should be explored further
D7	New Line	**New 220 kV line** [2 years consenting, and planning + 4 years build]	New double circuit line to replace the A line (duplex Sulfur at 75 deg C), second circuit bypassing Ohakuri	This option increase security of supply to the Bay of Plenty region It may be more economic to build a new line between Atiamuri–Whakamaru and then dismantle the Wairakei-Whakamaru A line due to the length of outage required to replace it.	YES This option provides additional capacity and should be explored further

3.5 Short-listing approach

Our long-list of components were evaluated using different combinations of:

- High-level screening criteria
- Economic analysis
- NZGP strategic considerations

The HVDC long-list was evaluated using high-level screening criteria and reduced to two options for further analysis.

The CNI long-list was evaluated using high-level screening criteria to produce intermediate list options, which were then evaluated using economic analysis and NZGP strategic considerations to derive a short-list of options for final Investment Test analysis. There were 11 options on the intermediate list, and this was reduced to 3 options.

The Wairakei Ring options were evaluated using NZGP strategic considerations to derive a short-list of options for final Investment Test analysis. There were 7 options, and this was reduced to 3 options.

This approach was necessary to make the Investment Test analysis tractable. In all, the short-list of options consists of 2 x HVDC, 3 x CNI and 3 x Wairakei Ring options. We have applied the Investment Test to all combinations of these options, meaning 18 options overall.

3.5.1 High-level screening criteria

The screening criteria are used to eliminate those components that are not appropriate for consideration in the short-list and subsequent development plans, to which we apply the Investment Test. The outcome of applying the short-listing criteria is reflected in Tables 5 and 6.

We applied the following short-listing criteria:

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 and environmental issues, are manageable

4. Good electricity industry practice (GEIP)
    - Ensures safety
    - Consistent with good international practice

- Ensures environmental protection
- 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)
    - Improves voltage stability (e.g., has modulation features or improves system stability)

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

3.5.2 Economic analysis for evaluating the intermediate long-list

The economic analysis we used for evaluating the CNI options was similar to the Investment Test. It considered the five varied EDGS, but not all options. Rather it used a sampling approach.

3.5.3 NZGP strategic considerations

Our NZGP investigations have identified several key factors that inform the strategy involved in choice and timing of investments.

Error! Reference source not found. shows the strategic considerations that have emerged thus far i n NZGP, but there may be more as we explore NZGP Phase 2. They describe various considerations which are appropriate to consider when long term planning in such an uncertain environment.

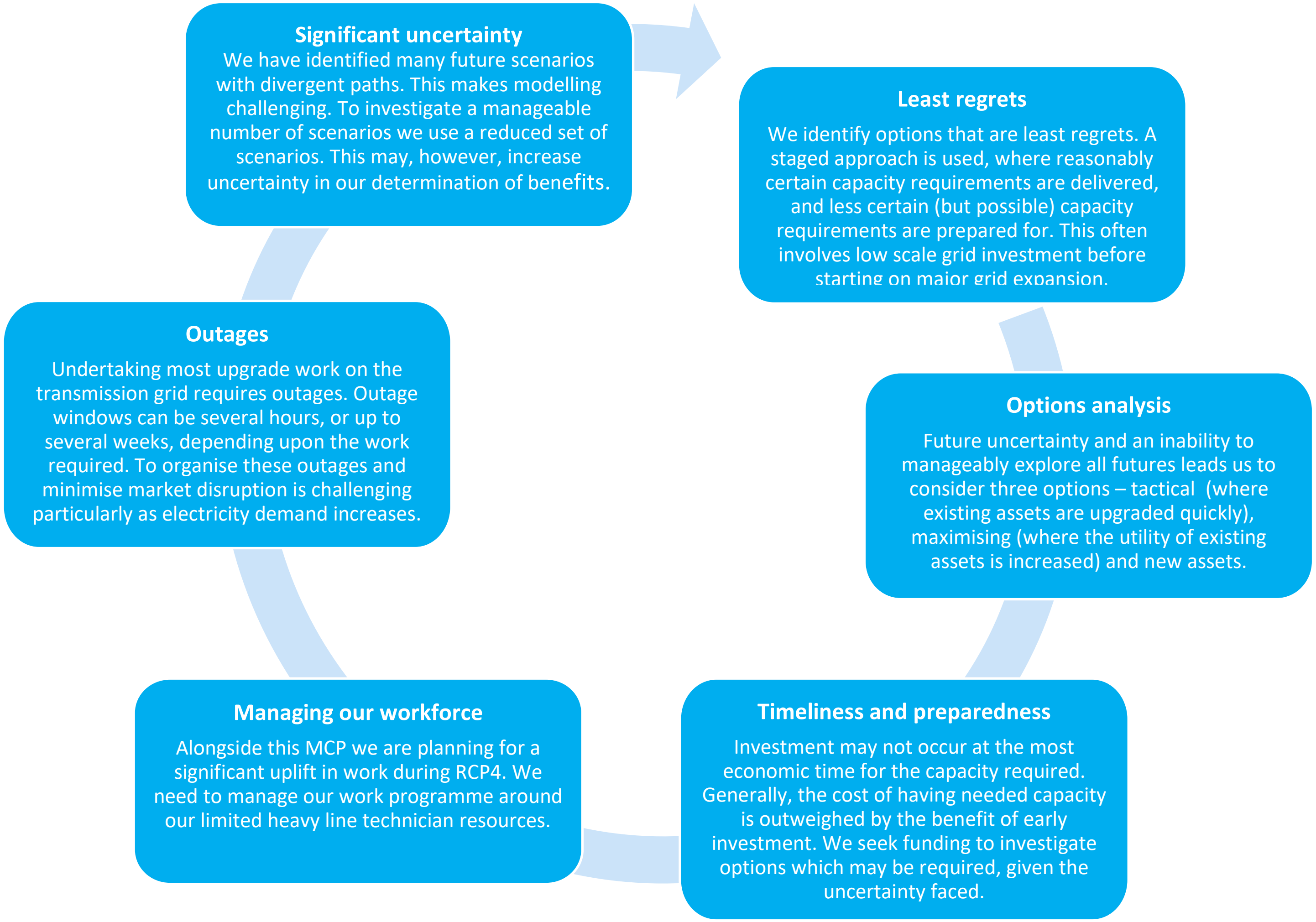

Figure 2: Strategic considerations for NZGP

3.5.4 Use of non-transmission solutions within investment options

Transpower is committed to exploring the application of non-transmission solutions (NTS) to replace, defer, or enable transmission investment, where economically feasible. Our NZGP1 long-list consultation posed a number of questions regarding how NTS could be incorporated into the development plans created by NZGP1. We received limited responses and of the responses received, there were none that appeared sufficient to meet the investment need in its entirety.

Electricity flows over the backbone grid differ considerably to those elsewhere in the grid. They are less determined by electricity demand peaks and troughs than market operation. Being the platform for operation of our electricity market, flows are dependent on operation of that market and at times peak flows even occur at off-peak demand times. As a result, it is difficult to predict when they will occur. If anything, they are more aligned to hydrology than demand. In the future, when the North Island thermal generation is closed, they may become more aligned with the strength of the wind and cloud cover, which is even less predictable.

We have formed a view that due to such issues it is unlikely NTS would be a viable substitute to the projects covered in this MCP.

However, NTS may be able to help manage operational risk due to unavailability of grid assets during delivery of the investments included in this proposal and we will explore opportunities for this once those are known.

Our experience to date with contracting NTS for major projects has been hindered by process. We have evaluated NTS as long-list or short-list options, but often several years ahead of the need for such NTS. Our understanding is that, not surprisingly, NTS proponents have been reluctant to commit to services that far ahead. The process we follow is a regulatory requirement, but it was developed when neither ourselves nor the regulator had experience with NTS.

For that reason and to ensure NTS providers are offered a reasonable opportunity, we are proposing this MCP without having fully assessed NTS, but with an undertaking to explore the use of NTS at the relevant time. For NZGP1.1 this would likely be during the delivery phase of any approved works.

3.5.5 Use of Area Wide Special Protection and Runback Schemes

A Network Control Special Protection Scheme (SPS) comprises tools that maintain the power system in a satisfactory operating state following a contingency and are usually additional to conventional power system control and protection schemes. An SPS is generally implemented to prevent the thermal overloading of transmission network elements following a specified contingency, with the selection of load or generation to be tripped dependent on the location of the transmission element to be protected.

By contrast, Run Back schemes can be delineated from SPS in that their action is aimed at alleviating localised issues though reductions in generation or transmission circuit flows, where they are controllable. Run Back schemes would probably be better characterised as transmission line loading controllers[7].

Transpower currently relies on several SPS, runback and inter-trip schemes as an alternative to transmission line upgrades and added interconnection capacity, by preventing circuit overload or

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[7] Special Protection Schemes.

transient instability following specific circuit outages. These schemes protect less utilised lines including Kawerau, Waipipi and the Tokaanu inter-trip; operating locally to reconfigure the grid and redistribute electricity flows.

SPS are well suited where there is a need to operate a transmission corridor at more than its N-1 capacity, and when it is not economic to install additional transmission capacity. In an application for tripping generation "the SPS may be feasible due to the intermittent or limited amount of time that the additional transmission capacity is required, and other generation is available to meet system peak demand."

In the instance where this is used for tripping load, the first challenge is to identify customers that are willing to have load tripped. Again, more conducive to a local network control solution, rather than installing on a complex grid backbone, where maintaining both market and generator developer confidence needs to be considered.

The one exception on the New Zealand grid is the HVDC link. Its control system is programmed with multiple runbacks and inter-trips and requires support from a dedicated technical team, a complex control system and simulator to allow exhaustive testing of control sequences and outcomes. While HVDC operation draws on the availability and status of grid equipment and responds accordingly, it relies on the impact of system frequency to cover rebalancing supply and demand, rather than sending direct commands to generators to compensate for changes in output.

We have not explicitly consulted on the use of automatic schemes to reduce generation (or reconfigure the grid) as an alternative to either deferring or avoiding investment in core grid transmission upgrades. These schemes can reduce the effect of constraints on electricity transfer to avoid overloading other transmission lines when a transmission line is out of service...

However, our proposal enhances an existing Inter-trip Scheme at Tokaanu substation that aids transfer through the CNI in conjunction with the upgrading of the CNI lines. The scheme reconfigures the substation connection arrangement of the Tokaanu–Whakamaru lines should one line trip. The redesigned scheme will also operate for the unexpected loss of the also upgraded Bunnythorpe to Tokaanu lines.

A generator runback scheme was considered as an alternative to increase capacity through the Wairakei Ring. We identified instead that a Tactical Thermal Upgrade (TTU) of the Wairakei–Whakamaru C line at a cost of $2.9m will deliver a further 200 MW or 20% transfer through the Wairakei Ring. This is in addition to $6m expenditure already funded for a device (Series Reactor) currently being installed at Atiamuri, that balances electricity flow across the lines into Whakamaru. The TTU is a simpler solution, frequently used as an early-stage measure ahead of more significant investment and is part of this proposal on several lines. It is achieved by in-field modifications and remedying of any ground clearance infringements of the transmission line conductors. It is a relatively simple solution and does not require the additional specialist control systems needed for generator runback schemes.

In summary, area wide SPS schemes are by nature complex, requiring significant time to design and commission, as well as a dedicated team to ensure their ongoing reliability and availability. For this reason, we have not included an area wide SPS option in the longlisting of NZGP1. We do however remain open to their applicability and will further evaluate as a possible option in the context of the larger scale transmission investment under consideration in our NZGP Phase 2 work programme.

3.5.6 Intermediate analysis

We reduced the long-list of components for each staged project using the high-level screening criteria initially and combined them into development plan options, as shown in Table 5. We have called these intermediate options. They contain an intractable number of combinations:

- Two HVDC options
- Eleven CNI options
- Seven Wairakei Ring options

If we considered each combination for all five scenarios, that would result in excess of 700 SDDP runs plus a Base Case for each scenario, which is unmanageable.

In order to reduce the number of SDDP runs required, we applied economic analysis and our strategic considerations to combined HVDC and CNI options and separately to Wairakei Ring options. This intermediate analysis approach was possible because we had observed that although linked, the ranking of the Wairakei Ring options was constant under different HVDC/CNI option combinations. Using this approach, we were able to reduce the options to a short list of:

- Two HVDC options
- Three CNI options
- Three Wairakei Ring options

This still resulted in 90 SDDP runs plus a Base Case for each scenario, which is a large number of SDDP runs, but nevertheless we have applied the Investment Test to this shortlist.

Diagrammatically, our entire process from long-list to Proposal is summarised in Figure 3.

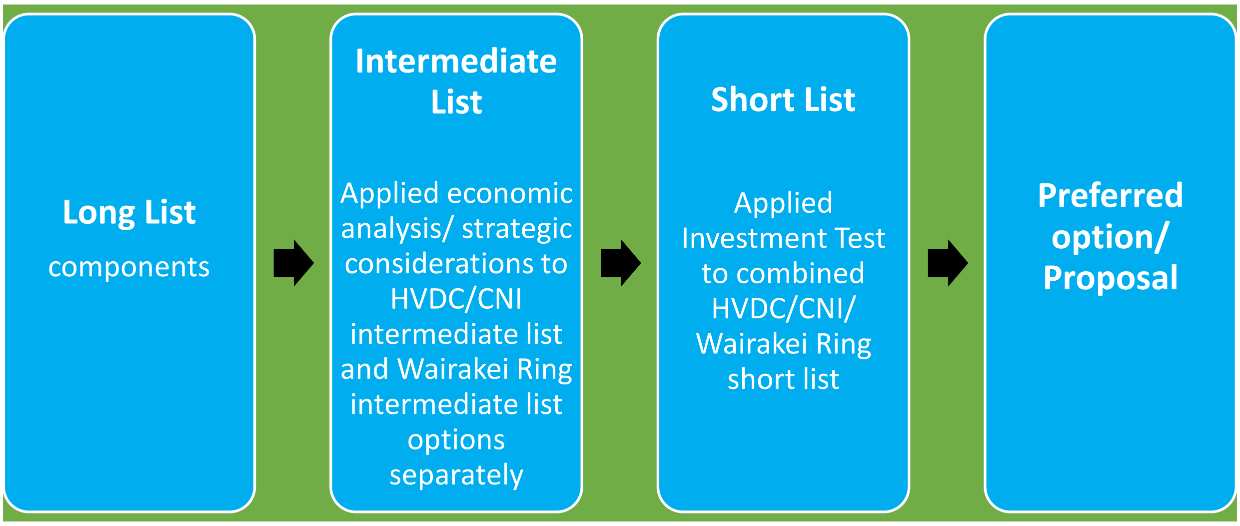

Figure 3: Long list to Preferred Option process

3.6 Intermediate development plan options

In general, the development plan options include combinations of components, commissioned at different times. In some instances, the development plan options consist of a tactical response only, e.g., thermally upgrading an existing transmission line. Such an option often does not provide a significant increase in capacity, but it can be less costly and undertaken quickly. In other instances, the development plan options consist of a tactical response and a long-term response, e.g., thermally upgrading an existing transmission line, followed by building a new transmission line. The tactical option may be a Stage 1 project and the new line a Stage 2 project. A full list, in summary form, of the intermediate development plan options is shown in Table 5.

Table 5: List of Intermediate development plan options matrix

List of intermediate development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to meet the overall need and bypass the existing grid									
	New North Island HVDC	New inter-island HVDC							
Option B1	✓								
Option B2		✓							
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2	✓	✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C1	✓	✓	✓	✓					
Option C2	✓	✓	✓	✓	✓				
Option C3	✓	✓	✓	✓		✓			
Option C4	✓	✓	✓	✓	✓	✓			
Option C5	✓	✓	✓	✓			✓		
Option C6	✓	✓	✓	✓	✓		✓		
Option C7	✓	✓	✓	✓	✓		✓	✓	
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Option C10	✓	✓	✓	✓	✓	✓			✓
Option C11	✓	✓	✓	✓	✓		✓	✓	✓
Options to enhance Wairakei Ring capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A Option D5A	Replace WRK-WKM A Option D7	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓		✓					
Option W2	✓	✓	✓						
Option W3	✓	✓	✓	✓					

Option W4	✓	✓		✓	✓				
Option W5	✓			✓		✓		✓	
Option W6	✓	✓		✓		✓			
Option W7	✓			✓			✓	✓	

3.6.1 Short-listed development plan options

Following evaluation of the intermediate list of options using economic analysis and our strategic considerations, we identified the following short-list of development plan options. For completeness, we included the two which bypass the existing grid altogether, options B1 and B2, but these were dismissed based on cost and were not analysed using the Investment Test. The remaining options were studied further using the Investment Test. Our rationale for the short-list and then choice of Proposal, is described in Section 3.0.

Table 6: Short list development plan options

List of shortlisted development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to meet the overall need and bypass the existing grid									
	New North Island HVDC	New inter-island HVDC							
Option B1	✓								
Option B2		✓							
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2	✓	✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C6	✓	✓	✓	✓	✓		✓		
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Options to enhance WRK capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A plan A	Replace WRK-WKM A plan B	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓		✓					
Option W4	✓	✓		✓	✓				
Option W7	✓			✓			✓	✓	

4.0 Assess options

Our options analysis applies economic modelling in the intermediate analysis and then the Investment Test to the short-list of options. The Investment Test is a cost-benefit test, with the net benefit being determined for each short-listed option. Demand and generation scenarios are considered in the Investment Test and the net market[8] benefit of each short-listed option is determined for each scenario. The option which maximises the expected net market benefit (applying expected scenario weightings) passes the Investment Test.

In the sections below, we describe various aspects of the inputs to the Investment Test, then our intermediate analysis and then our application of the Investment Test.

We quantify costs and benefits where possible, but as allowed in the Capex IM[9], we treat some costs and benefits as unquantified. This is where we cannot calculate an expected value with sufficient certainty due to the extent of uncertainties in underlying assumptions, or where the cost of calculating its quantum is likely to be disproportionately large relative to the quantum. Section 3.2 describes our quantified costs and benefits and or unquantified benefits.

4.1 Demand and generation scenarios

As per the requirements of the Capex IM, the demand and generation scenarios considered in our analysis are based on the Electricity Demand and Generation Scenarios (EDGS) published by MBIE.[10]

The EDGS are hypothetical future situations relating to forecast electricity demand and generation and are developed by MBIE, specifically for the purpose of investigating major capex proposals. The Investment Test does allow for demand and generation scenario variations to be used, where the variations are of the EDGS and have reasonable regard to the views of interested persons.

Using demand and generation scenarios helps to ensure economic analysis is robust to future uncertainty around both electricity demand growth and generation expansion. Some investigations do not warrant the use of scenarios, but this investigation does. A demand and generation scenario includes assumptions about:

- future electricity demand;[11]
- existing, decommissioned and future new generation connected to the transmission network;
- capital and operating costs for existing and future new generation;
- fuel availability for generation;
- fuel and carbon costs for generation; and
- grid-connected energy storage.

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[8] Net benefit and net market benefit are equivalent. The term “net market benefit” is used within the Investment Test because only electricity market costs and benefits are considered.
[9] See Schedule D, Clause D1(2)(b) of the CapexIM here.
[10] Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz).
[11] Including assumptions regarding base demand, electric vehicle uptake, solar PV uptake, distributed energy storage, etc.

The latest EDGS were published by MBIE in 2019. However, there have been several relevant and important energy industry changes since then which are not reflected. These include, but are not limited to:

- COVID-19 effect on electricity demand;
- MBIE generation cost stack update, which describes potential new generation plant information;
- potential closure of the Tiwai aluminium smelter (and subsequent effect on North Island thermal generators);
- investor interest in grid-scale batteries; and
- Government investigation of the Onslow pumped hydro scheme, i.e., the NZ battery project.

We therefore considered it necessary to vary the EDGS for the purposes of this investigation. To ensure we reflected the views of interested persons, we used a consultative approach. A description of our consultations can be found on our website at: https://www.transpower.co.nz/NZGP.

We initially used a panel of external (to Transpower) experts to review the EDGS in late 2020. Recordings of the online meetings are available at the web link above. Conclusions from those meetings were included in a written consultation paper, which was published on our website in December 2020. That consultation closed in February 2021. Feedback confirmed that we had good information to produce reasonable EDGS variations in terms of demand scenarios, but insufficient information regarding generation scenarios.

We concluded that demand and generation scenario variations should be determined separately.

We therefore undertook further consultation, via a written consultation paper, regarding generation scenarios, in May 2021.[12] This targeted potential generation investors but was open to all stakeholders. The six-week consultation period closed in June 2021. Feedback suggested there is too much uncertainty regarding future generation possibilities for grid-connected generation in Aotearoa New Zealand, to reflect in just five nationally determined scenarios, as per the published EDGS.

As well as uncertainty around future generation technologies and where it will be built, we identified several large step-load uncertainties which are too significant to spread across the EDGS:

- Tiwai closure date and any Southland replacement demand.
- The possibility of Taranaki development, including offshore wind being built.
- Peaking and dry year reserve options, including:
    - South Island (Lake Onslow) development;
    - North Island (with gas peaking allowed); and
    - North Island (100 per cent renewables – some combination of generation overbuild, batteries, demand response, green peakers, pumped hydro, hydrogen).

We then published our first formal NZGP1 document – the long-list consultation document – in August 2021. That six-week consultation closed in October 2021. The submissions we received (excluding two that were provided on a confidential basis) are published on our website.

In the long-list consultation document, we described a possible approach to developing scenarios suitable for NZGP1 Investment Test analysis. The approach involved developing a matrix of

[12] Link to our NZGP1 scenario consultation paper.

scenarios and selecting a sample of relevant scenarios from the matrix, according to the investigation being undertaken. While this approach reasonably reflected the considerable uncertainty regarding new generation and the largely binary uncertainties we face, it was complex.

Although a suitable approach for our NZGP project, we consider it would be difficult to demonstrate to the Commission that the resultant scenarios are reasonable variations of EDGS 2019. We therefore changed our approach, and the scenarios we have used for this NZGP1.1 investigation, are more obviously aligned with the EDGS. We have used the same five scenarios, but with updated inputs. The differences between scenarios is very similar to the EDGS. We are calling our scenarios NZGP1.1 scenarios to differentiate them as variants of the EDGS. The five scenarios are:

1. Reference - Current trends continue.
2. Growth - Accelerated economic growth.
3. Global - International economic changes.
4. Environmental - Sustainable transition.
5. Disruptive - Improved technologies are developed.

A full description of our NZGP1 scenarios was published in December 2021 and can be found on our website.[13]

A consequence of this approach is that our analysis has not evaluated the full range of generation and/or supply uncertainty possible in New Zealand. One effect of this is that there is more uncertainty than normal in the benefits we identify. We discuss this further in the sections below. This does support our use of a staged MCP, because some of the uncertainties may have further resolved by the time we get to Stage 2 and are reflected in the scenarios.

4.1.1 Scenario weightings

The Investment Test requires we determine the expected net electricity market benefit for each option considered. The expected net electricity market benefit for an option is the weighted average of the net electricity market benefit under each NZGP1 scenario. Schedule D, Division 2 clause D2 (1) of the Capex IM requires that:

> *"…each relevant demand and generation scenario is accorded the explicit or implicit weighting assigned to it by the party who developed the scenario, unless Transpower considers that alternative weightings should apply and has consulted on these as part of its consultation on the short list of investment options."*

The original scenarios were developed by MBIE and did not address the issue of how each scenario should be weighted in the context of the Capex IM. The Capex IM assumes the scenarios should be equally weighted, unless Transpower considers otherwise. Any alternative scenario weightings need to be justified to the Commerce Commission.

Therefore, the starting point is that each of the five scenarios should be weighted 20 per cent in the determination of expected net electricity market benefit.

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[13] Link to document.

In our short-list consultation, we argued that the Global and Reference scenarios had low demand growth, were not consistent with the extent of electrification required for Aotearoa New Zealand to achieve net zero carbon by 2050 and should therefore be weighted zero.

This view was an assumption we have been unable to corroborate. It is plausible that electricity demand growth could be very low due to global economic conditions, or other reasons and yet some extent of electrification occurs.

For that reason, we are no longer suggesting that the Global and Reference scenarios should be weighted zero and our analysis assumes the default weightings of 20 percent for each scenario in our Investment Test application.

4.2 Investment Test parameters

4.2.1 Key parameters

The Investment Test is a cost-benefit analysis and, as such, several parameters need to be defined. The parameters we have used are consistent with those defined in the Capex IM, as described in our long-list and short-list consultation and as supported by submissions.

4.2.2 Calculation period

The Capex IM states the default calculation period for costs and benefits is 20 years. It does, however, allow for this to be altered if benefits can be better captured using a different period. Some transmission assets have lives greater than 20 years, so relative benefits will continue to accrue after a 20-year calculation period has ended. The effect of discounting future benefits to present values does diminish this effect, but nevertheless they can be significant. We have used a calculation period to 2055 to reflect the net zero by 2050 carbon target and better capture the costs and benefits for some options over their useful life.

Although this is not the full economic life of some options, we consider this to be an appropriate trade-off between assessing benefits over the full economic life and assessing uncertain future benefits. We have not included a terminal benefit in 2055 for any option.

4.2.3 Value of expected unserved energy

The Value of Lost Load (VoLL – also known as Value of Expected Unserved Energy), is the assumed value to consumers of losing electricity supply as the result of an unplanned outage. We use this value to assess reliability benefits, in situations where different options deliver differing levels of reliability of supply. The Electricity Industry Participation Code specifies that VoLL should be $20,000/MWh. This value was determined in December 2004 and reflecting inflation, equates to approximately $29,500/MWh in $2022. VoLL is not relevant to this analysis and the value has not been used in our Investment Test analysis.

4.2.4 Discount rate

The Capex IM defines a standard real, pre-tax discount rate of 7 per cent, with low and high sensitivities of 4 per cent and 10 per cent respectively. The discount rate of 7 per cent was set at a time when that rate was close to Transpower's WACC. It may be high today, but we note that the sensitivity values of 4 per cent and 10 per cent cover the range of alternatives that some parties argue should be used (4 per cent is close to a Social Rate of Time Preference discount rate and 10 per cent is close to a commercial discount rate). We are therefore satisfied that, provided the sensitivities are considered, the range of discount rate arguments is addressed.

The Commission have proposed to amend the Capex IM discount rate from 7% to 5%, particularly given current economic conditions, so we also report Investment Test results for a 5% discount rate.

4.2.5 Quantified electricity market costs and benefits

Electricity market costs and benefits are those received or incurred by consumers of the electricity market during the calculation period, and which will affect net electricity market benefits. We have quantified the following costs and benefits for each option.

- Fuel costs, e.g., the cost of generating electricity
- Cost of involuntary demand curtailment, e.g., the cost of lost load
- Cost of demand-side management
- 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 and maintenance costs, e.g., costs of existing assets, options and modelled projects
- Cost of losses, including transmission and local losses

4.2.6 Project costs

Project costs are costs reasonably incurred by Transpower prior to or during the calculation period in undertaking a major capex project. These include, but are not necessarily limited to:

- Capital expenditure, including capital expenditure for land purchased for an option
- Costs payable to a third party for testing
- Costs payable for commissioning of assets
- Operating, maintenance, and dismantling costs
- Compliance costs relating to applicable legislation and administrative requirements.

These are calculated on a P50 estimate of cost for the project – there is equal chance that the project could be delivered for more or could be delivered for less. Since the long-list consultation, all project streams excluding new line options on the central North Island, HVDC and Wairakei ring mentioned in this document have been costed via the engagement of concept design and/or solution study reports as appropriate. New line options have been costed using our internal knowledge of past projects, and we feel that this will be an acceptable level of accuracy for the Investment Test, noting that any final application for construction costs of new lines would likely form part of a stage 2 MCP application.

To this end, it should be noted that price of new line construction sits across a continuum of potential final cost when considering the variability we would face depending on line length and route, property types impacted and line configuration (both in terms of conductor configuration and the potential for different tower and/or pole setups). Any application as part of this Stage 1 MCP, for new lines, is for funding to further investigate options and potentially start on a process to define corridors and potential routes to allow construction costings to be more accurately defined, in order that such costs allow greater accuracy in subsequent Investment Test analyses.

For the HVDC cable upgrade, a Request for Pricing (RFP) process was undertaken with international vendors, seeking pricing for the manufacture, transport, and installation of appropriate undersea cables. We had a good response to this process and are comfortable with the price accuracy. We are also considering how timings can be co-ordinated with the end-of-life replacement of our current HVDC cables, which is expected around 2032. A large portion of the cable pricing is for manufacturing setup and ship mobilisation to New Zealand. It is highly possible that any final investment decision into the installation of additional HVDC cable capacity would be made in parallel with an investment decision to replace the three current cables in order to achieve the economies of scale available and reduce the costs faced if we were to proceed with the two projects independently. As further analysis into the economics of bringing forward the replacement of the current cables has not yet been completed , we have analysed the HVDC 1400 MW option as carrying the full mobilisation costs and reported a sensitivity where this option is deferred until the other cables are replaced and at an incremental cost.

General advice from respondents indicated that the lead time from placement of order until commissioning was four to five years[14], due in part to New Zealand's isolated location and the demand for undersea cables from large northern hemisphere projects. Due to the commercial sensitivity of such costs, we will not be providing detail of the estimated HVDC upgrade cost publicly, but will provide details to the Commission under commercial confidence, as part of the submission of this MCP.

Given this long lead time, we further tested with suppliers the viability of booking manufacturing capacity to await a trigger point (such as the confirmed closure of NZAS Tiwai point) in an effort to establish a reduced lead time to installation. This process was unsuccessful with little engagement from the RFS respondents.

In some options, where existing transmission lines would be upgraded, the outages required to implement parts of the option would have a market cost. Where the outages are significant, we have determined an approximate market cost using a dispatch tool, rather than include the cost of a bypass line. A bypass line is a temporary transmission line, erected to avoid outages. We recently used a bypass line when undertaking maintenance on the HVDC line from the North Island cable termination station to Haywards. Further analysis since the shortlisting consultation has determined that the construction of bypass lines for the CNI projects is technically unachievable. We are however confident that rather than build a bypass line we could enter into a contract or contracts with market participants, were that to cost less than our assessed market cost.

4.2.7 Unquantified electricity market costs and benefits

Some electricity market benefits are unquantified. This occurs when the cost of calculating its quantum is likely to be disproportionately large relative to the quantum, or when its expected value cannot be calculated with an appropriate level of certainty due to the extent of uncertainties in underlying assumptions or calculation approaches. Examples of such benefits relevant to this proposal are:

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[14] Although subsequent discussions indicate that due to global demand, the lead time is more likely to be in the vicinity of 5-10 years.

Competition effects and benefits fall into this category, because subjective assessments of market behaviour are required to determine their magnitude.

Resilience benefits also fall into this category. Currently we do not have a suitable methodology for determining these to an appropriate level of certainty, yet they may be large, especially where an option includes building a new, geographically diverse line. Recognising that uncertainty, but supposing they can be quantified, we have included a request for funding in our Stage 1 MCP to develop a suitable quantification methodology for use in Stage 2 analysis.

Reliability of supply improvements to Bay of Plenty electricity consumers are also currently unquantified. One of our potential Stage 2 projects for the Wairakei Ring would improve reliability of supply to Bay of Plenty electricity consumers by ensuring they have n-1 security when maintenance outages are required on some lines. This remains an unquantified benefit in this Stage 1 analysis, but will be quantified for Stage 2 analysis.

4.2.8 Determining net electricity market benefit

The Investment Test requires that we determine the net benefit for each option studied. In this case the net benefit is:

Net electricity market benefit = Electricity market benefits – Electricity market costs

We have compared the before (investing in the transmission option) cost of meeting electricity demand, with the after cost of meeting electricity demand, for each option and each scenario to 2050.

Formulaically, this could be represented as:

Before cost

$$= (A+B)_{existgen} + (A+B)_{existgridnm} + (A+B)_{existgridmb} + C_{existgen} + D_{before}$$

After cost

$$= (A+B)_{existgen} + (A+B)_{newgen} + (A+B)_{existgridnm} + (A+B)_{existgridma} + (A+B)_{newgrid} + C_{existnewgen} + D_{after}$$

and the net benefit

$$= (A+B)_{existgen} + (A+B)_{newgen} + (A+B)_{existgridnm} + (A+B)_{existgridma} + (A+B)_{newgrid} + C_{existnewgen} + D_{after} - (A+B)_{existgen} - (A+B)_{existgridnm} - (A+B)_{existgridmb} - C_{existgen} - D_{before}$$

$$= (A+B)_{newgen} + (A+B)_{existgridma} - (A+B)_{existgridmb} + (A+B)_{newgrid} + C_{existnewgen} - C_{existgen} + D_{after} - D_{before}$$

where:

A = Respective capital costs

B = Respective operating and maintenance cost

C = Dispatch costs

D = Unserved energy costs

$existgen$ = existing generation

existgridnm = existing grid not modified

existgridmb = existing grid modified, before modification costs

existgridma = existing grid modified, after modification costs

newgen = new generation

newgrid = new grid

existnewgen = Existing and new generation

before = before modification

after = after modification

4.2.9 Passing the Investment Test

An investment option satisfies the Investment Test if:

- it has the highest expected net electricity market benefit compared to other investment options;
- it has a positive expected net electricity market benefit, unless it is designed to meet an investment need the satisfaction of which is necessary to meet the deterministic limb of the grid reliability standard; and
- it is sufficiently robust under sensitivity analysis.

The Capex Input Methodology recognises the inherent uncertainty in estimating costs and benefits in Investment Test analysis. Where the difference in expected net benefit between two investment options is within 10% of the project cost of the option which passes the Investment Test, the options are considered “similar”. All “similar” options pass the Investment Test, and the Capex IM then allows unquantified benefits to be used to identify a preferred option.

4.2.10 Sensitivity analysis

Sensitivity analysis means consideration, except where not reasonably practicable nor reasonably necessary, of the effect on quantum of variations in the following parameters:

- forecast demand
- size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question
- capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects
- timing of decommissioning, removing or de-rating decommissioned assets
- the value of expected unserved energy
- discount rate
- range of hydrological inflow sequences
- relevant demand and generation scenario probability weightings
- in relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies
- any other variables that Transpower considers to be relatively uncertain.

4.3 Intermediate analysis to define a short-list of options

4.3.1 High level analysis of Options B1 and B2

We undertook a high-level economic analysis of Options B1 and B2 to determine whether further, more detailed analysis is required.

As shown in Table 7, Options B1 and B2 both include building new HVDC links between different parts of the grid.

In option B1, the new North Island HVDC option, we retain the existing inter-island HVDC link, but build a new HVDC line from where the Cook Strait cables come ashore, or Haywards, to Whakamaru. This would bypass the existing Haywards to Whakamaru AC lines, avoiding the need to upgrade these lines, as well as providing more resilience to the electricity system by virtue of providing another line route. Our high-level cost estimate for this option is $2 billion.

In option B2, the new inter-island HVDC option, a new HVDC line is built in the South Island, possibly to somewhere in the Nelson region, a new set of undersea cables is laid to the North Island, possibly in the Taranaki region, and a new HVDC line is built in the North Island, possibly all the way to Huntly. New HVDC converters are also installed in both the North and South Islands. This possibly provides the most resilient electricity system overall, at a high-level estimated cost of $4 billion.

Neither of these options improve capacity on the Wairakei Ring and we would need to undertake our proposed works for the Wairakei Ring as well.

Our similarly high-level cost estimate to upgrade the existing AC grid (including Stage 1 and Stage 2 projects, where the CNI option is a new line north of Bunnythorpe) is $1.2 billion, which includes our proposed works for the Wairakei Ring.

Although we have not attempted to quantify the resiliency benefits of options B1 and B2, in our view they are unlikely to outweigh the extra cost and this analysis is sufficient to demonstrate that upgrading the existing grid is more economic and no further analysis is required on these options. Neither option B1 or B2 is therefore carried forward for Investment Test analysis.

Table 7 - Options to bypass the existing grid

Option	High level cost, $b	Comments
Upgrade existing grid - preferred	$1.2	Includes all Stage 1 and 2 costs
New North Island HVDC Option	$2.0	Requires new HVDC line from HAY to WKM plus new HVDC converters at WKM
New inter-island HVDC Option	$4.0	Requires new HVDC lines in North and South Island plus new HVDC converters in South Island and HLY, plus new inter-island cables

4.3.2 HVDC and CNI intermediate list analysis

To evaluate the intermediate list of combined HVDC and CNI options, we sampled the list of combinations – not for the purposes of determining a preferred option, but in order to help reduce the intermediate set of options to a manageable short-list.

Our preliminary intermediate list analysis is described first.

Preliminary intermediate list analysis

We published our preliminary intermediate list analysis in our short-list consultation document. In that document we summarised our calculation of the net benefit for each intermediate list option, as shown in Table 8.

Table 8: Net benefit of intermediate list of HVDC and CNI options

Net benefit of intermediate list of HVDC and CNI options										
	Scenario									
PV net benefit, $m	Global		Reference		Growth		Environmental		Disruptive	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option										
C1	-$10	$36	-$110	-$86	$266	$280	$42	$84	-$251	$147
C2	-$54	-$7	-$153	-$130	$222	$237	-$2	$39	-$291	$105
C3	-$38		-$140		$237		$12		-$282	
C4	-$78	-$28	-$180	-$155	$202	$205	-$27	$15	-$321	$76
C5	-$43	$1	-$134	-$111	$244	$259	$25	$69	-$241	$142
C6		-$25		-$143		$222		$37		$101
C7	-$17	-$110		-$215		$151		-$24		$40
C8	-$141	-$92	-$227	-$195	$158	$169	-$55	-$6	$-335	$54
C9		-$265		-$352		$12		-$149		-$97
C10	-$355	-$304	-$434	-$397	-$46	-$36	-$256	-$201	-$550	-$155
C11		-$342		-$429		-$65		-$226		-$174

We then developed and published Table 9 showing expected net market benefit for the various options, using a range of scenario weightings.

Table 9: Expected net benefit, intermediate list of HVDC, CNI options, various scenario weightings, $PV net benefit, $m

Expected net benefit, intermediate list of HVDC, CNI options, various scenario weightings, $PV net benefit, $m								
Scenario weighting	Weighting set 1 20/20/20/20/20		Weighting set 2 5/10/25/30/30		Weighting set 3 0/10/30/30/30		Weighting set 4 0/0/33/33/33	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option								
C1	-$13	$92	-$8	$133	$6	$145	$19	$170
C2	-$56	$49	-$51	$89	-$37	$101	-$24	$127
C3	-$42		-$38		-$24		-$11	
C4	-$81	$23	-$76	$62	-$62	$73	-$49	$99
C5	-$30	$72	-$19	$117	-$5	$130	$9	$157
C6		$39		$82		$94		$120
C7		-$31		$16		$29		$56
C8	-$120	-$14	-$107	$32	-$93	$46	-$77	$72
C9		-$170		-$119		-$105		-$78
C10	-$328	-$218	-$314	-$170	-$299	-$157	-$284	-$130
C11		-$247		-$196		-$182		-$155

In Table 9, cells with negative net benefits are shaded in pink. The option with the highest net benefit is shown in the darkest green. The next lightest shade of green indicates net benefits which are “similar” under the Capex IM[15] and the other green cells indicate net benefits which are also “similar”, if the 10% parameter is raised to 15%.

We considered scenario weightings of 0%/0%/33%/33%/33% for the Global, Reference, Growth, Environmental and Disruptive scenarios respectively, but as explained in Section 3.1.1, we can no longer justify the rationale for those weightings, hence are applying the default weightings of 20%/20%/20%/20%/20%.

[15] The Capex IM recognises the inherent uncertainty in inputs to the cost-benefit analysis required by the Investment Test. Where the difference in net benefit between the option with the highest net benefit and another option is 10% or less of the aggregate project cost of the option with the highest net benefit, the options are considered “similar” and unquantified costs and benefits may be taken into account in order to identify a preferred option.

As shown in **Error! Reference source not found.**:

- The only options with a positive net benefit occur when the HVDC capacity is upgraded to 1400 MW
- Of those options, CNI option C1 has the highest net benefit

Using the default scenario weightings:

- With option C1 having a project cost of $412m, CNI option C5 has a “similar” net benefit and if the 10% parameter is raised to 15%, CNI options C2 and C6 can also be considered “similar”.

Despite the HVDC only having positive net benefits when upgraded to 1400 MW, we are not recommending reducing the short list of HVDC options to one, but rather will carry both the 1200 MW and 1400 MW options forward.

With regard to the CNI options, in our view, CNI option C1 would not enable a wide range of futures. The benefits do not include a large amount of unserved energy, so in those futures it has been possible to find a generation expansion plan which works - but it is restricted. The fact that a generation expansion plan works for this option, reflects the abundance of wind and solar generation that New Zealand has access too. The MBIE generation stack includes some 10 GW of potential wind projects alone and the fact that CNI option C1 is feasible, is likely a result of that abundance.

If we compare the benefits for CNI options C1 and C11 (CNI option C11 would have the highest transmission capacity, we note that the benefits for CNI option C11 are approximately $130 million, on a present value basis, higher than for CNI option C1. Only a small fraction of that benefit difference arises from a difference in capital costs (the projects on the MBIE generation stack reflect a similar cost), whereas a large fraction arises from dispatch costs in the North Island. Our modelling tells us that enough generation could be built in both options, but the generation built under CNI option C1 incurs higher dispatch costs.

We also note that our analysis has considered EDGS variations, although these are not specified for any intermediate analysis in the Capex IM. These do not cover the full range of future electricity demand and generation uncertainty. If Lake Onslow is developed, for instance, electricity flows over the backbone grid in the lower North Island would be significantly higher.

We consider the long-term interest of consumers is best served by at least acknowledging the possibility of other futures and not limiting the possibilities for generation investors. Instead we should reasonably ensure those investors can build generation where they would prefer. In our view, the increase in competition benefits as a result of increasing accessibility to new generation, is an unquantified benefit which could be used to differentiate “similar” options.

Although intermediate analysis is not reflected in the Capex IM, we have used an Investment Test-like approach. The Capex IM allows the Commission to vary the 10% parameter and we have varied this parameter to 15% in these circumstances. In our view, the uncertainties arising in which new generation projects are built are large and criteria used by generation developers in deciding whether their project should proceed or not are not all reflected just in a capital cost comparison. As mentioned, we have also confined our analysis to just five scenarios which are reasonable EDGS variations when, in our view a wider range would be required to fully capture future supply uncertainty faced in the electricity industry. The result is a larger than normal uncertainty in our benefit determinations, meaning a higher than 10% parameter could be justified for this analysis.

Accepting that, then CNI options C1, C2, C5 and C6 are all similar and since CNI option C6 enables the most competitive generation investment market, it is preferred over option C1.

Using NZGP strategic considerations to define a short-list

Our NZGP investigations have identified several key factors that inform the strategy involved in choice and timing of investments.

These considerations are described in section 2.5.3.

The relevant consideration here is that:

Future uncertainty and an inability to manageably explore all futures leads us to consider three options – a tactical option where existing assets are upgraded quickly, an option which maximises the utility of existing assets and a new asset option.

We have determined our short-list of options for the HVDC and CNI Investment Test analysis using this consideration. The preferred option from our intermediate list analysis is our tactical option C6. The quickest upgrade we can make to the HVDC is to install a STATCOM, filter bank and bus-works, boosting availability of the HVDC converters and providing a level of redundancy for future outages of synchronous condenser and filter banks. This is Stage 1 of the works required to increase HVDC capacity to 1400 MW. Stage 2 requires the installation of a fourth Cook Strait cable and we believe we could possibly install this as early as 2028. The work to our existing transmission lines in Option C6 occurs in steps, but all of it could be delivered by 2028.

The option which maximises the utility of our existing assets, is Option C8. This option builds on Option C6 by also duplexing the BPE-TKU lines and thermally upgrading the BPE-WRK line.

Once that work is undertaken, the only way of providing more transfer capacity north is by building new assets. In the case of the CNI this would entail a new transmission line north from BPE. Options C9, C10 and C11 are all possibilities. For the sake of our analysis, we have chosen the cheapest, being Option C9.

Therefore, our short-list of options for HVDC and CNI are those shown in Table 10.

Table 10: List of shortlisted development plan options for HVDC and CNI

List of shortlisted development plan options for HVDC and CNI									
Base Case									
Option 0	Do not enhance existing grid								
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2	✓	✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C6	✓	✓	✓	✓	✓		✓		
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓

4.3.3 Wairakei Ring intermediate list analysis

As with the intermediate list of options for the HVDC and CNI, we have an intermediate list of Wairakei Ring options which results in too many combinations for Investment Test analysis. As previously stated, we sampled the list of HVDC and CNI and Wairakei Ring combinations and found that although benefits for combinations of HVDC, CNI and Wairakei Ring options do vary with Wairakei ring options, the ranking of Wairakei Ring options does not vary as HVDC and CNI combinations are changed. This suggests we can reasonably evaluate the Wairakei ring options on their own – not for the purposes of determining their overall benefits, but in order to reduce the options to a short-list. We undertook a similar process for the Wairakei Ring options and using the default scenario weightings, the expected net market benefit for each option is as a shown in Table 11.

Table 11: Net benefit of Wairakei Ring intermediate options list using default scenario weightings, $PV net benefit, $m

Net benefit of intermediate list of Wairakei Ring options using default scenario weightings, $PV net benefit, $m	
Wairakei Ring option	
W1	$7
W2	-$28
W3	-$28
W4	-$24
W5	-$36
W6	-$42
W7	-$5

The analysis shown is the same as undertaken for the short-list consultation. It has not been updated, because there is no significant new information and the short-list of three options was reasonably clear.

In Table 11, cells with negative net benefits are shaded in pink. The option with the highest net benefit in each scenario is shown in green. It might appear that only one option has a positive net benefit, but that is misleading. This analysis has been undertaken using a limited set of benefits and is for ranking purposes only. The Investment Test considers the synergies between HVDC, CNI and Wairakei Ring and overall, benefits are higher.

Option W1 is to thermally uprate the existing WRK–WKM C line only and has a positive net benefit. Option W1 would also be the quickest option to implement.

Option W7 reflects building a new WRK–WKM D line. It has the least negative net benefit of the other options, would possibly deliver the biggest capacity increase, but would take the longest to implement.

Our NZGP strategic considerations reflect having three options:

- A tactical option where existing assets are upgraded quickly – Option W1 is suitable
- An option which maximises the utility of existing assets
- A new asset option – Option W7 is suitable

Option W4 has the next least negative benefit and involves the TTU in option W1, plus replacing the existing WRK–WKM A line. It is a suitable candidate for an option which maximises the utility of our existing assets.

Hence, our short-list of Wairakei Ring options is options W1, W4 and W7.Short list of development plan options

From the sections above, our completed short-list of options for Investment Test analysis is therefore:

Table 12: List of shortlisted development plan options

List of shortlisted development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2	✓	✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C6	✓	✓	✓	✓	✓		✓		
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Options to enhance WRK capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A plan A	Replace WRK-WKM A plan B	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓		✓					
Option W4	✓	✓		✓	✓				
Option W7	✓			✓			✓	✓	

4.4 Application of the Investment Test

4.4.1 Short-list Investment Test analysis

For the purposes of applying the Investment Test, we combined the options in Table 12 into the following list of short-list options as shown in Table 13.

Table 13: Short-list for Investment Test analysis

Shortlisted option	HVDC option	CNI option	Wairakei Ring option
Option 1	H1	C6	W1
Option 2	H1	C6	W4
Option 3	H1	C6	W7
Option 4	H1	C8	W1
Option 5	H1	C8	W4
Option 6	H1	C8	W7
Option 7	H1	C9	W1
Option 8	H1	C9	W4
Option 9	H1	C9	W7
Option 10	H2	C6	W1
Option 11	H2	C6	W4
Option 12	H2	C6	W7
Option 13	H2	C8	W1
Option 14	H2	C8	W4
Option 15	H2	C8	W7
Option 16	H2	C9	W1
Option 17	H2	C9	W4
Option 18	H2	C9	W7

We then undertook the SDDP runs required to determine the benefits of each option and determined the following costs and benefits for each short-list option across each varied EDGS, as shown in Table 14. The net benefit of each option, per scenario is shown in Table 15.

Table 14: Short-list option costs and benefits, PV $m

Option costs and benefits, PV $m						
		Scenario				
Shortlisted option	Option costs	Global benefits	Reference benefits	Growth benefits	Environmental benefits	Disruptive benefits
Option 1	$296	371	295	209	205	434
Option 2	$357	399	327	250	249	492
Option 3	$354	417	351	279	276	528
Option 4	$355	415	341	280	287	486
Option 5	$417	447	375	316	327	540
Option 6	$413	461	398	344	356	575
Option 7	$629	469	393	335	343	522
Option 8	$692	498	427	368	380	579
Option 9	$687	512	451	398	406	615
Option 10	$393	743	485	476	449	691
Option 11	$454	760	515	515	489	741
Option 12	$451	777	545	544	519	775
Option 13	$452	786	541	533	519	747
Option 14	$514	811	570	570	558	785
Option 15	$510	827	597	600	585	816
Option 16	$726	850	603	591	589	801
Option 17	$788	871	630	627	623	838
Option 18	$784	887	650	655	646	871

Table 15: Short-list option net benefits for each scenario, PV $m

Option net benefits, PV $m					
	Scenario				
Shortlisted option	Global	Reference	Growth	Environmental	Disruptive
Option 1	$75	-$1	-$87	-$91	$138
Option 2	$42	-$30	-$107	-$108	$135
Option 3	$63	-$3	-$75	-$78	$174
Option 4	$60	-$14	-$75	-$68	$131
Option 5	$30	-$42	-$101	-$90	$123
Option 6	$48	-$15	-$69	-$57	$162
Option 7	-$160	-$236	-$294	-$286	-$107
Option 8	-$194	-$265	-$324	-$312	-$113
Option 9	-$175	-$236	-$289	-$281	-$72
Option 10	$350	$92	$83	$56	$298
Option 11	$306	$61	$61	$35	$287
Option 12	$326	$94	$93	$68	$324
Option 13	$334	$89	$81	$67	$295
Option 14	$297	$56	$56	$44	$271
Option 15	$317	$87	$90	$75	$306
Option 16	$124	-$123	-$135	-$137	$75
Option 17	$83	-$158	-$161	-$165	$50
Option 18	$103	-$134	-$129	-$138	$87

By applying the default scenario weightings, we determine the expected net benefit for each option as presented in Table 16.

Table 16: Expected net benefit for investment options

Short-listed option	Expected net benefit PV $m
Option 1	$7
Option 2	-$14
Option 3	$16
Option 4	$7
Option 5	-$16
Option 6	$14
Option 7	-$217
Option 8	-$242
Option 9	-$211
Option 10	$176
Option 11	$150
Option 12	$181
Option 13	$173
Option 14	$145
Option 15	$175
Option 16	-$39
Option 17	-$70
Option 18	-$42

This demonstrates that several short-list options do not have a positive net benefit. Options 10-15 are the most economic, with Option 12 maximising expected net benefit. Options 10-15 comprise the combinations of HVDC, CNI and Wairakei Ring options summarised in Table 17.

Table 17: Combinations of HVDC, CNI and Wairakei Ring options for various shortlisted options

Shortlisted option	HVDC option	CNI option	Wairakei Ring option
Option 10	H2	C6	W1
Option 11	H2	C6	W4
Option 12	H2	C6	W7
Option 13	H2	C8	W1
Option 14	H2	C8	W4
Option 15	H2	C8	W7

From Table 14, Option 12 has an overall project cost of $451m on a present value basis, so projects within $45.1m of the expected net benefit for Option 12, can be considered similar. This includes Options 10, 11, 13, 14 and 15. All options include uprating the HVDC to 1400 MW.

Option 10 reflects our tactical option for the CNI – a thermal uprating of the Bunnythorpe to Tokaanu section of the A&B lines, plus duplexing the Tokaanu to Whakamaru section of the A&B lines – plus our tactical option for the Wairakei Ring – a thermal uprating of the Wairakei to Whakamaru C line- plus our tactical option for the HVDC - Stage 1 increases the availability near to

1200 MW transfer. Option 10 also includes the probable addition of a fourth Cook Strait cable as a Stage 2 project for the HVDC.

Option 11 is similar to Option 10 but includes a replacement of the existing Wairakei–Whakamaru A line as a Stage 2 for the Wairakei Ring. The logic applied to the CNI options in section 4.3.2, also applies to the Wairakei Ring and the works in Option 10 may not provide sufficient transmission capacity in some possible futures not evaluated in this analysis. There is merit in including a potential Stage 2 for the Wairakei Ring. We have not done enough work yet to decide whether replacing the existing Wairakei–Whakamaru A line would be more economic than building a new Wairakei–Whakamaru D line, as shown in Option 12, however that would be studied in Stage 2. Replacing the existing A line includes an unquantified benefit in that it ensures Bay of Plenty consumers will have n-1 security of supply at all times. At the moment the Bay of Plenty only has n security when maintenance is undertaken on existing lines. If we undertake a Stage 2 investigation for the Wairakei Ring we would quantify this benefit. Our preference is to proceed with the tactical upgrade and also study which of those two options is most economic. Therefore, we prefer Option 11 over both Option 10 and Option 12.

Option 13 is similar to Option 10 but includes a Stage 2 for the CNI lines which squeezes the most out of those assets. It is not yet clear whether any Stage 2 should be implementing the second stage of Option 13 or building a new CNI line entirely, but that would be studied in a Stage 2 investigation. However, Option 13 does not include a Stage 2 project for the Wairakei Ring.

Option 14 includes a tactical project for each of the HVDC, CNI and Wairakei Ring, plus a Stage 2 project for each as well. Given the uncertainties around the need for Stage 2 projects, but their potential benefit if required, this option has an advantage over other options. It includes a tactical response for each of the HVDC, CNI and Wairakei Ring and reflects an investigation into the need and justification for any Stage 2 projects.

Option 15 does not include a tactical response for the Wairakei Ring and jumps straight to a new D line option. We have not yet undertaken enough work to determine whether replacing the existing A line, or building a new D line is more economic. Replacing the existing A line includes an unquantified benefit in that it ensures Bay of Plenty consumers will have n-1 security of supply at all times. At the moment the Bay of Plenty only has n security when maintenance is undertaken on existing lines. If we undertake a Stage 2 investigation for the Wairakei Ring we would quantify this benefit.

Given the extra flexibility of Option 14 to deal with future uncertainty, we prefer this option over all of Options 10, 11, 12, 13 and 15. It is similar to the option with the highest expect net market benefit, Option 12 and the unquantified benefits from the extra flexibility mean it is an appropriate choice for preferred option. The main components of Option 14 are described in Table 18. Please note our application is to recover the costs of Stage 1 only.

Table 18: Our NZGP1.1 proposed works for HVDC, CNI and Wairakei Ring[16]

	Stage 1 MCP (NZGP1.1)		Possible Stage 2 MCP (NZGP1.2)	
	Project	**Expected $m**	**Project**	**Expected $m**
HVDC	Haywards reactive support	84.4	New Cook Strait cable	120
CNI	TTU/Duplex TKU-WKM A&B TTU BPE-TKU A&B	208.0	Reconductor BRK-SFD A line Duplex BPE-TKU A&B TTU BPE-WRK A	75 189 55
Wairakei Ring	TTU WRK-WKM C TTU EDG-KAW 220 kV line	20.7	New/replaced WRK-WKM line	92
Supporting projects		3.5		
Stage 2 preparatory		10.2		

4.4.2 Sensitivity analysis

As required by the Capex IM, we have varied the magnitude of key variables and assumptions by an amount reflecting their uncertainty to determine the sensitivity of the Investment Test result to that variable or assumption. The Capex IM requires the following sensitivities to be undertaken, unless not relevant:

- forecast demand;
- size, timing, location, fuel costs, and operating and maintenance costs relevant to existing assets, committed projects, modelled projects, and the investment option in question;
- capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects;
- timing of decommissioning, removing, or de-rating decommissioned assets;
- the value of expected unserved energy;
- discount rate;
- range of hydrological inflow sequences;
- relevant demand and generation scenario probability weightings;
- in relation to any competition effects associated with an investment option, generator offering, and demand-side bidding strategies; and
- any other variables that Transpower considers to be relatively uncertain.

[16] Please note that our application to the Commerce Commission is to recover the funds required for Stage 1 plus investigation costs for Stage 2. We are not seeking to recover the forecast costs for Stage 2 in this proposal.

For this application of the Investment Test, we consider the sensitivities in **Error! Reference source n ot found.** to be relevant. The other sensitivities referred to in clause D7 of the Capex IM are not reasonably necessary.

Table 19: Investment Test sensitivities

Parameter sensitised	Comment
Forecast demand	Reflected in scenarios (see Table 15)
Size, timing, location, fuel costs, operating & maintenance costs relevant to existing assets, committed projects, modelled projects, investment option in question	Either reflected in scenarios or included in +/-30% operating cost sensitivity
Capital cost of proposed investment option (incl. variations up to proposed MCA) and modelled projects;	Capital cost sensitivity where capital costs are varied +/- 30% are reported
Timing of decommissioning, removing, or de-rating decommissioned assets	Not relevant
Value of expected unserved energy	Not relevant
Discount rate	Sensitivities of 4 , 5 and 10 per cent are reported
Range of hydrological inflow sequences	Our results reflect averages hydrological flows
Relevant demand and generation scenario probability weightings	A range of scenario weightings are presented
Competition effects associated with an investment option, generator offering, and demand-side bidding strategies	Not relevant
Other variables that Transpower considers to be relatively uncertain	Tiwai closure date of 2034 sensitivity reported

Table 17 shows how expected net market benefit varies for the short-listed options, for all except the Tiwai closure date of 2034 sensitivity, which is considered separately.

Table 17: Sensitivity of expected net benefit to various sensitivities, PV, $m

Sensitivity of expected net benefit to various sensitivities, PV, $m											
	Sensitivity										
	Investment Test	-30% capital cost	+30% capital cost	-30% ongoing costs	+30% ongoing costs	4% discount rate	5% discount rate	10% discount rate	Scenario weighting 5/10/25/30/30	Scenario weighting 0/10/30/30/30	Scenario weighting 0/0/33/33/33
Option 1	7	94	-80	6	9	212	125	-84	-3	-11	-13
Option 2	-14	93	-121	-14	-14	210	114	-112	-20	-27	-27
Option 3	17	121	-88	15	18	258	156	-92	13	6	7
Option 4	7	134	-120	27	-13	283	165	-114	2	-5	-4
Option 5	-16	130	-162	5	-37	277	152	-143	-18	-25	-23
Option 6	14	157	-130	34	-6	325	193	-123	15	9	12
Option 7	-217	-35	-398	-224	-209	-4	-98	-293	-223	-230	-229
Option 8	-241	-40	-442	-247	-234	-11	-112	-322	-244	-250	-249
Option 9	-211	-13	-409	-219	-203	37	-72	-303	-211	-217	-214
Option 10	176	290	62	172	180	545	390	1	154	141	146
Option 11	150	283	16	147	153	533	372	-29	133	121	127
Option 12	181	312	51	177	186	583	415	-8	167	155	162
Option 13	173	327	20	191	156	609	425	-30	155	142	148
Option 14	145	318	-28	164	126	594	404	-62	129	117	124
Option 15	175	345	5	192	158	641	445	-41	162	150	157
Option 16	-39	169	-247	-49	-29	342	179	-202	-59	-71	-66
Option 17	-70	157	-298	-79	-62	322	153	-236	-87	-99	-92
Option 18	-42	183	-267	-53	-32	366	191	-217	-56	-67	-60

This sensitivity analysis differs from other MCP investigations we have undertaken. For most of our previous MCP's the sensitivity analysis has overwhelmingly supported the choice of our preferred option. In this case that is not so because of future uncertainty, supporting the use of a staged MCP. Whilst it is important we invest in the grid now and provide more choices to generation developers, it is not perfectly clear which is the most economic option. The sensitivity analysis indicates that any of options 10, 12 or 15 may maximise net benefit, depending upon the circumstances. Option 12 maximises net benefit in the most number of sensitivities.

From one point of view, it might appear that either Option 12 or 15 should be preferred option choices over Option 14. Neither Option 12 or 15 includes a Stage 2 investigation for each of the HVDC, CNI and Wairakei Ring, which is why they are not preferred. Option 14 has a similar net benefit for several sensitivities and it remains our preferred option because it does include a Stage 2 investigation for each of the HVDC, CNI and Wairakei Ring, and we consider that once the currently unquantified benefits of Option 14 are quantified (the benefit of providing full n-1 security to Bay of Plenty consumers), they will demonstrate that Option 14 is preferred to Options 12 and 15. It should also be noted that Stage 1 outputs do not change between the short-listed options.

Since the EDGS do not reflect the full range of future electricity demand or generation uncertainty, it is important that there is a Stage 2 investigation for each of the HVDC, CNI and Wairakei Ring.

We note the sensitivity of the economic outcome of Option 14 to higher capital cost but would point out that this option includes an unquantified benefit (provision of full n-1 security to the Bay of Plenty), which we would expect to lower this sensitivity.

We also note that using a discount rate of 5% would increase the net benefits of our proposal.

In summary, our preference for Option 14 is sufficiently supported by sensitivity analysis and it remains our preferred option.

4.4.3 Tiwai closure date sensitivity

Our analysis assumes Tiwai aluminium smelter closes at the end of 2024. That appears to be a conservative assumption based on current market information, nevertheless remains our assumption, as a prudent grid owner. To assist regulatory decision-makers, we have undertaken sensitivities to consider alternative Tiwai closure possibilities:

- Tiwai closes at the end of 2034 (perhaps by negotiating a longer term electricity supply contract) and we defer installation of a fourth Cook Strait cable until 2032/34
- Tiwai closes at the end of 2034 (perhaps by negotiating a longer term electricity supply contract) and we defer installation of the HVDC Stage 1 works and installation of a fourth Cook Strait cable until 2032/34

In the sensitivities , we assume all Cook Strait cables are replaced at once since the existing three are expected to be at end-of-life in 2034. This reduces the cost of the fourth cable considerably, as we only require a cable laying ship once, instead of twice.

The sensitivity results are:

Table 18: Sensitivity of expected net benefit of proposal to Tiwai closure assumption

Tiwai closure option	Preferred option	Expected net market benefit, $m
Tiwai closes in 2024, Stage 1 in 2027 and 4th cable in 2027	Option 14	145
Tiwai closes in 2034, Stage 1 in 2027 and 4th cable deferred until 2032	Option 14	66
Tiwai closes in 2034, Stage 1 and fourth cable in 2032	Option 14	65

As shown, the expected net market benefit is maximised if Tiwai closes in 2024 and we respond to upgrade South Island to North Island transfer capability as soon as possible, possibly by winter 2027.

If Tiwai closure is deferred until 2034, then it is more economic to defer installation of a fourth cable until the existing cables are replaced, nominally in 2032. Not only is capital expenditure deferred, but deferring the need for a cable laying ship until the existing cable are replaced, means the fourth cable can be installed at an incremental cost, much lower than undertaking such an installation on its own.

If Tiwai closure is deferred until 2034, it is still economic to undertake the HVDC Stage 1 works as soon as possible. The reason for this is that, during RCP4, we are planning to undertake life extension works on the Haywards synchronous condensers and the presence of a new STATCOM will lift the overall transfer capability of the HVDC during that time.

As Table 21 shows, the expected net market benefit of maintaining the HVDC Stage 1 works asap, is marginally higher than if they were deferred. In addition, there is an unquantified benefit in that the grid is more prepared for uncertain futures should the future not unfold as per the EDGS.

A more fulsome description of the analysis is included in Appendix A of Attachment C to this proposal.

5.0 Identify solution

5.1 Preferred solution

Our Investment Test analysis, using similarity, assesses Option 14 as having the highest expected net benefit when future, currently unquantified benefits, are taken into account.

Our sensitivity analysis confirms that Option 14 is sufficiently robust to sensitivity analysis.

Therefore, we conclude that Option 14 passes the Investment Test and is reasonable to form the basis of this Investment Proposal to the Commerce Commission.

6.0 Appendix A: Impact of synchronous condenser refurbishment and HVDC Stage 1 timing

This appendix describes additional modelling undertaken to better understand the impact of the RCP4 Haywards synchronous condenser refurbishment and HVDC upgrade alternative delivery dates.

We show:

- Average gross benefits, shown in Table 1, across all scenarios decrease if either the STATCOM or Fourth Cable is delayed. This applies to both Tiwai leaving in 2024 and 2034.
- If Tiwai leaves in 2034, the magnitude of the reduction in average gross benefits if the HVDC upgrades are delayed is lower than if Tiwai leaves in 2024. Also, if Tiwai leaves in 2034, the relative benefits of delaying the HVDC upgrades varies by scenario.
- If the HVDC upgrades are delayed, in general, Northwards transfers across the HVDC are reduced during the later half of the 2020s. Of note, the STATCOM helps to not only increase HVDC maximum capacities but also mitigates against the loss in maximum capacity because of the Haywards synchronous condenser outages. Differences in HVDC Northwards transfers, in turn, drives the differences in gross benefits observed.
- Gross benefits are very sensitive to different hydro inflow sequences. Gross benefits will increase if the wet years (with high hydro inflows) occur during 2027 to 2029.

	Updated HVDC install dates	**Delayed Fourth Cable**	**Delayed STATCOM and Fourth Cable**
STATCOM install date	May 2027	May 2027	Jan 3031
Fourth Cable	May 2028	Jan 2032	Jan 2032
	Gross benefits, $m, NPV to 2022, 7% discount rate		
Unweighted average across scenarios, **Tiwai leaves 2024**	668	622	540
Unweighted average across scenarios, **Tiwai leaves 2034**	523	512	484

Table 1: Summary of modelling results

6.1 Assumptions and Methodology

6.1.1 Modelling Assumptions

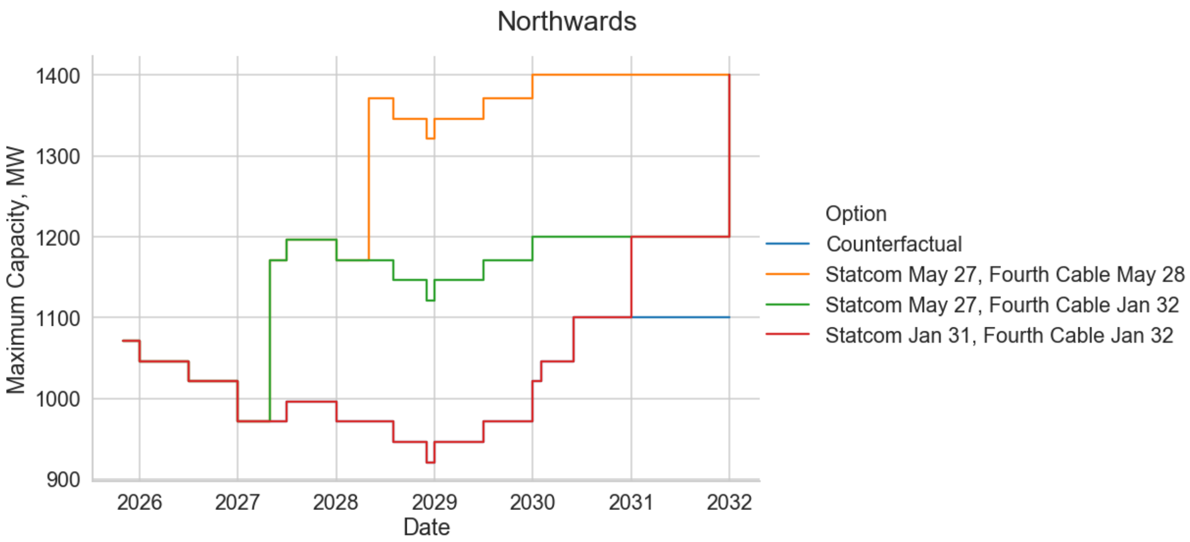
The additional modelling considered alternative HVDC upgrade delivery dates described in Table 1 for both Tiwai leaves in 2024 and our proposal sensitivity, where Tiwai leaves in 2034.

		Additional Modelling		
	Application Proposal	**Updated HVDC install dates**	**Delayed Fourth Cable**	**Delayed STATCOM and Fourth Cable**
STATCOM, Stage 1	January 2026	May 2027	May 2027	January 2031
4th cable, Stage 2	January 2027	May 2028	January 2032	January 2032

Table 2: Additional modelling HVDC upgrade delivery options

The Haywards synchronous condenser refurbishment is scheduled to occur during Transpower's RCP4 (April 2025 – March 2030) programme of work. We estimate that the synchronous condenser outages required for this work will reduce the maximum capacity of the HVDC by up to 125 MW Northwards and 75 MW Southwards, on average, for extended periods. The extent of this reduction varies according to the number of synchronous condensers that are on outage and whether STATCOM has been installed.

The additional modelling uses the maximum HVDC capacities shown in Figure 1. For our counterfactual we assume that after the synchronous condenser refurbishment there will be an improvement of 29 MW Northwards and 20 MW Southwards in HVDC maximum capacity for ten years. The work on the synchronous condensers is primarily focused on life extension and it is uncertain if there will be sustained improvements in reliability that would lead to improved HVDC maximum capacity. For this reason, our counterfactual can be considered conservative in this regard.



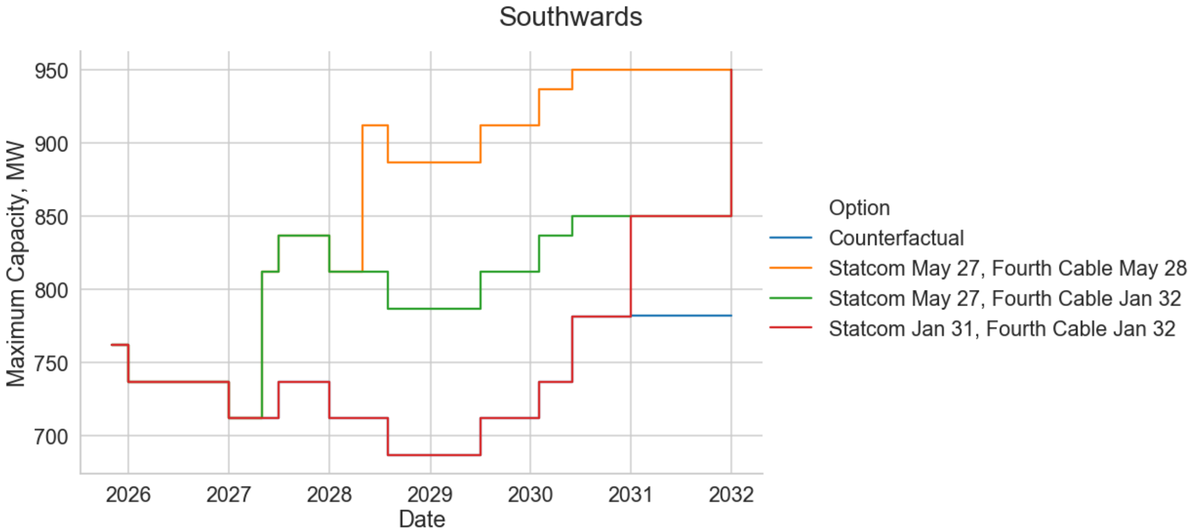


Figure 1: Assumed HVDC maximum capacities for additional modelling

The additional modelling considers AC transmission Option 14, with updated dates as described in Table 2.

Transmission upgrade	**Application proposal, commissioning date**	**Updated commissioning date**[17]
TKU-WKM TTU	Dec-23	Dec-24
TKU-WKM duplex	Jun-27	Jun-28
BPE-TKU TTU	Dec-25	Dec-26
BPE-TKU duplex	Feb-30	Same
BPE-WRK TTU	Nov-31	Same
WRK-WKM C TTU	Jan-29	Same
WRK-WKM A rebuild	Jan-28	Same
BPE-ONG split	Jan-24	Jan-25
SFD-HLY protection	Jan-24	Jan-25
TKU SPS	Jun-27	Jun-28
BRK-SFD reconductor	Jan-30	Same
EDG-KAW 110kV split	Jan-23	Jan-24

Table 3: Option 14 AC transmission upgrade commissioning dates

[17] As modelled. The as proposed commissioning dates vary for the WRK-WKM C TTU (2025), BPE-ONG split (2026), SFD-HLY protection (2026), TKU SPS (2026) and the EDG-KAW 110kV split (2025). These changes will have only a very minor impact of our modelled gross benefits.

6.1.2 Modelling Methodology

We have used the same modelling methodology as described in Attachment D of the modelling methodology.

New generation expansion plans were developed to account for the different HVDC upgrade delivery dates for both Tiwai leaves in 2024 and 2034. As a simplification the new generation expansion plans and counterfactual generation expansion plan ignore the RCP4 synchronous condenser outages. We consider this is reasonable as, in our view, the impact of these outages on investment decisions should be relatively minimal. RCP4 synchronous condenser outages are included in our detailed dispatch modelling.

6.2 Gross Benefits

Gross benefits for our additional modelling options are shown in Tables 3 and 4, with Tiwai leaving in 2024 and 2034 respectively. Gross benefits include electricity system thermal, emission, deficit, and line loss costs and exclude transmission investment costs. Gross benefits are derived by subtracting factual electricity system costs from counterfactual electricity system costs.

Average gross benefits across all scenarios decrease if either the STATCOM or Fourth Cable is delayed. This applies to both Tiwai leaving in 2024 and 2034. If Tiwai leaves in 2034 the magnitude of the reduction in average gross benefits if the HVDC upgrades are delayed is lower than if Tiwai leaves in 2024. Also, if Tiwai leaves in 2034, the relative benefits of delaying the HVDC upgrades varies by scenario:

- For the Reference and Growth scenarios, the highest gross benefits are where the fourth cable is delayed.
- The Environmental scenario is the only scenario where delaying both the STATCOM and fourth cable is beneficial with respect to gross benefits.

	Updated HVDC install dates	**Delayed Fourth Cable**	**Delayed STATCOM and Fourth Cable**
STATCOM install date	May 2027	May 2027	Jan 3031
Fourth Cable	May 2028	Jan 2032	Jan 2032
Scenario	*Gross benefits, $m, NPV to 2022, 7% discount rate*		
Reference	514	496	338
Global	753	738	640
Growth	625	573	510
Environmental	661	594	513
Disruptive	786	711	698
Unweighted average	**668**	**622**	**540**

Table 3: Gross benefits for Tiwai leaves 2024

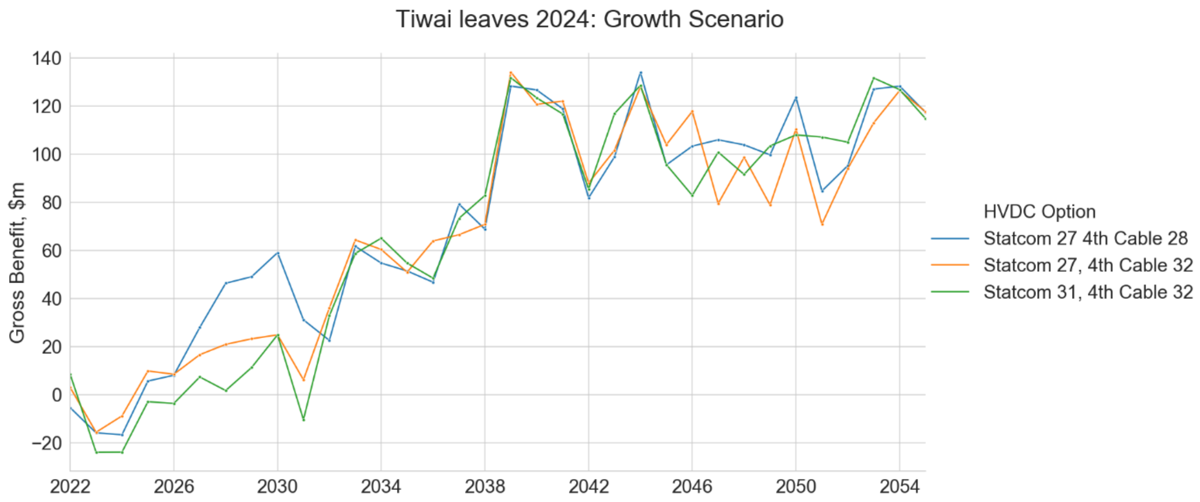
	Updated HVDC install dates	**Delayed Fourth Cable**	**Delayed STATCOM and Fourth Cable**

STATCOM install date	May 2027	May 2027	Jan 3031
Fourth Cable	May 2028	Jan 2032	Jan 2032
Scenario	*Gross benefits, $m, NPV to 2022, 7% discount rate*		
Reference	378	442	429
Global	541	496	460
Growth	523	531	470
Environmental	580	593	603
Disruptive	591	498	459
Unweighted average	**523**	**512**	**484**

Table 4: Gross benefits for Tiwai leaves 2034

6.3 Gross benefits over time: Growth Scenario

Undiscounted gross benefits over time for the Growth scenario are shown in Figures 2, with Tiwai leaving in 2024 and 2034 respectively. These figures show that for the most part differences in gross benefits occur during the latter half of the 2020s when the RCP4 synchronous condenser work has been scheduled. These differences are sensitive to Tiwai leaving. Similar trends are observed for the other scenarios.



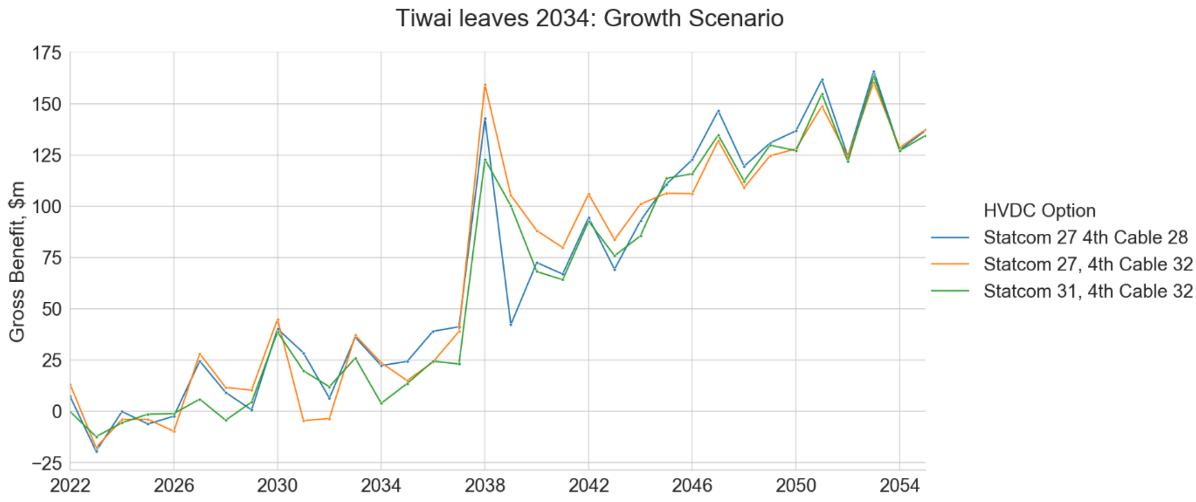


Figure 2: Undiscounted gross benefits by time for the growth scenario

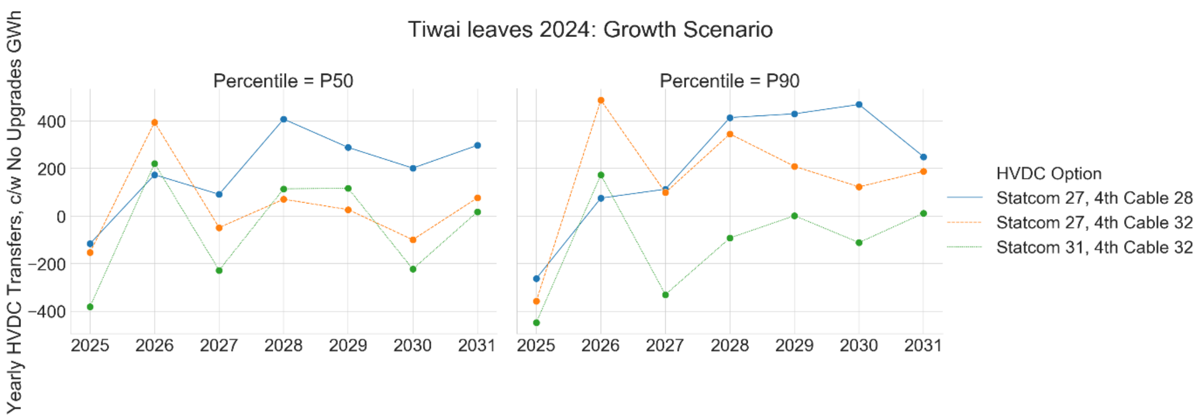
6.3.1 HVDC transfers: Growth Scenario

Yearly, P50 and P90, HVDC transfers for the Growth scenario are shown in Figures 3, with Tiwai leaving in 2024 and 2034 respectively. Transfers are Northwards and are differences with respect to the counterfactual. A positive Northwards transfer is where transfers are greater than the counterfactual. We show the period between 2025 and 2031, as this covers the period where gross benefits vary for our additional modelled options. Similar trends are observed for other scenarios.

Northwards HVDC transfers are generally lower if the HVDC upgrades are delayed. The relative difference is more significant for P90 transfers – when flows across the HVDC are high. This indicates that Northwards flows across the HVDC can be constrained, and that the frequency of these constraints will be reduced if the proposal's HVDC upgrades are not delayed.

Higher Northwards flows across the HVDC will be associated with both higher South Island hydro generation and reduced North Island thermal generation. This relationship drives the differences in observed gross benefits between our modelled options.

Northwards HVDC transfers differences between our modelled HVDC upgrade options are less pronounced if Tiwai leaves in 2034. With the smelter operating there is less opportunity for South Island hydro to export energy Northwards during the second half of the 2020s. Northwards HVDC transfers are the lowest where both the Statcom and Fourth cable are delayed.



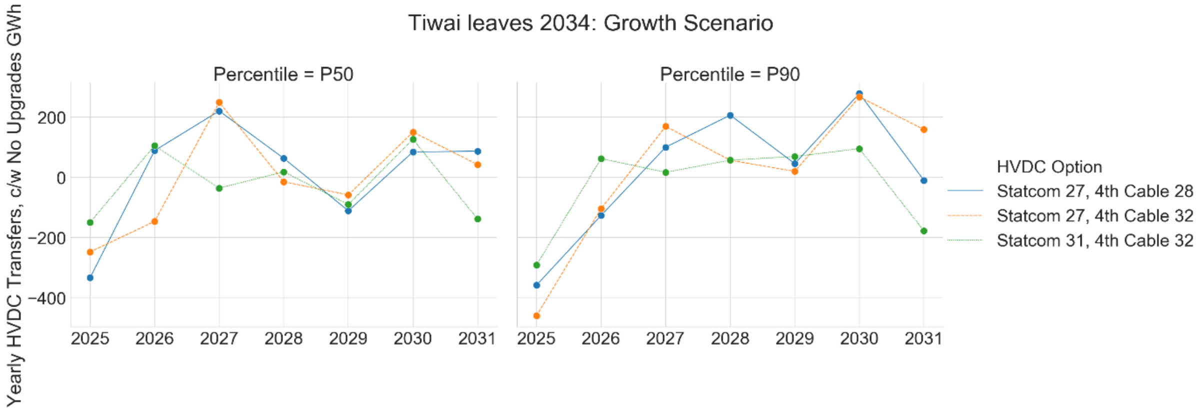


Figure 3: Yearly, P50 and P90, HVDC transfers, relative to the counterfactual, for the Growth scenario

6.3.2 Sensitivity of costs to hydro inflows

Gross benefits are very sensitive to different hydro inflow sequences. A wet year sequence in 2027 through to 2029 could have a material impact on modelled dispatch benefits. To illustrate this, we look at the distribution of undiscounted thermal dispatch benefits for 2028, for both Tiwai leaves options and for the Growth scenario, as shown in Figure 4. Thermal dispatch benefits contribute, very approximately, around half of the total dispatch benefit change observed. Figure 4 shows that wet year thermal dispatch benefits for 2028 can significantly exceed the total average dispatch benefits (over 2026 through to 2030), particularly for where Tiwai leaves in 2034.

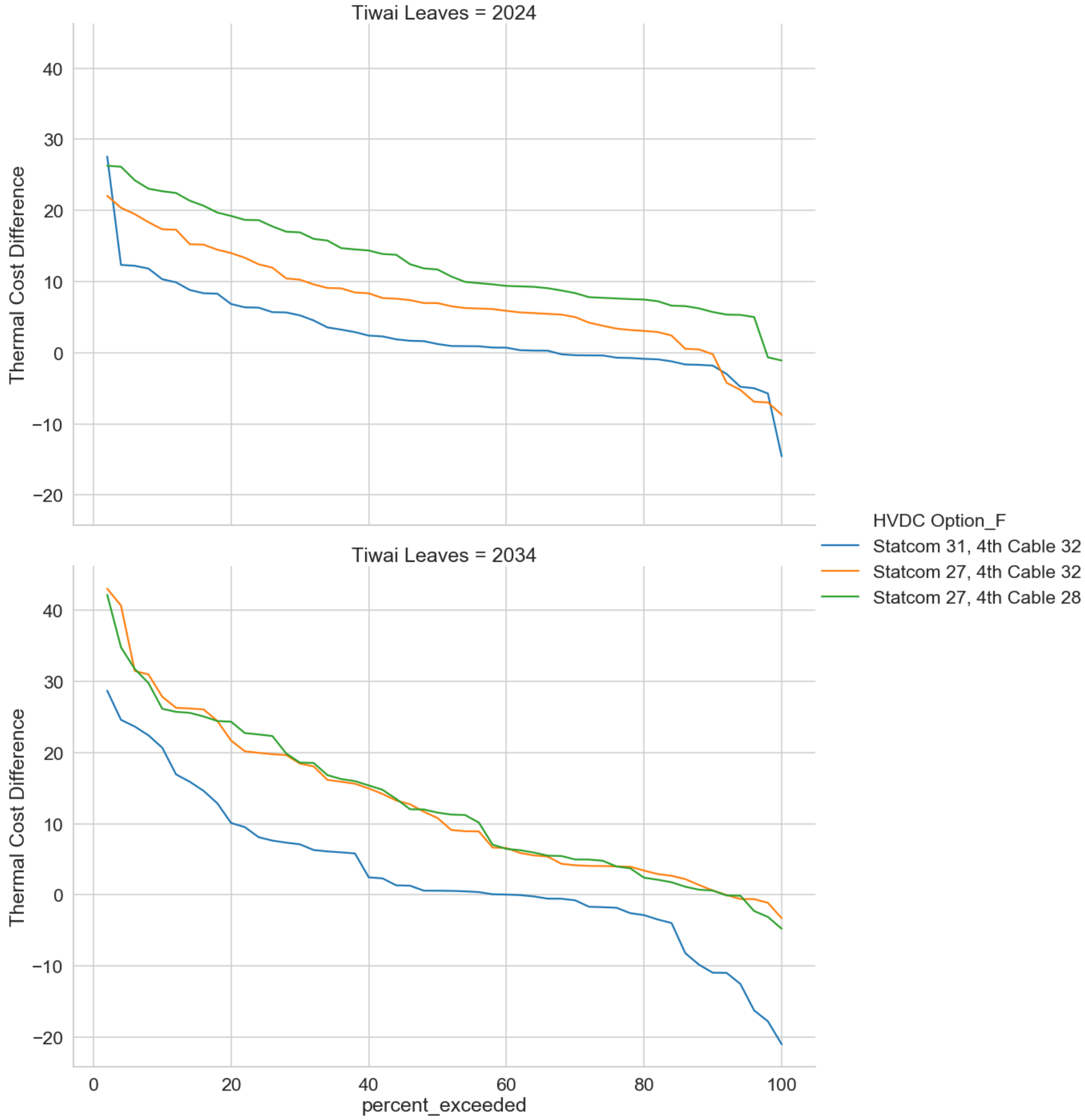


Figure 4: Distribution of undiscounted thermal costs for 2028: Growth scenario

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