TRANSPOWER

HVDC Link Upgrade Programme Major Capex Proposal (Stage 1)

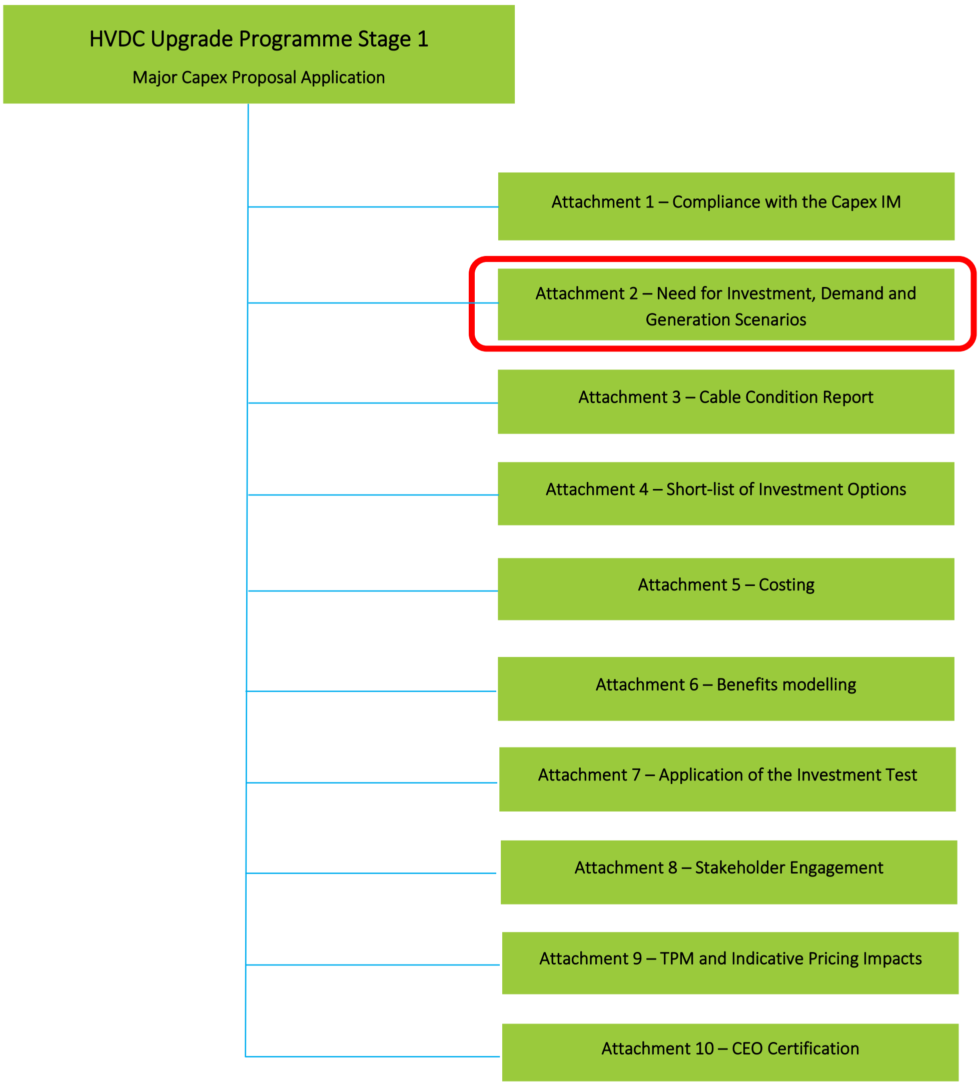
Attachment 2: Need for investment, demand and generation scenarios

September 2025

Purpose

This document forms part of our HVDC Link Upgrade Programme Stage 1 Major Capex Proposal (MCP).

The purpose of this document is to describe the investment need and to outline the demand and generation scenarios that we have used for our project analysis and application of the Investment Test. The need for investment is driven by the condition of the existing submarine cables and other HVDC Link equipment, as well as our assumptions about future demand and generation. This attachment outlines the key demand and generation assumptions underpinning our analysis.



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1 Need for investment

1.1 Background

The high-voltage direct current (HVDC) link electrically connects the North and South Islands of New Zealand and is a vital piece of the nation's energy infrastructure. This link enables electricity generated on either island to flow to the other, supporting the balance of supply and demand. Given the North Island's larger population and higher electricity consumption, the HVDC link typically transfers electricity northward during the day and southward overnight. However, this flow pattern can shift, such as when South Island hydro lake levels are low and/ or when wind generation in the North Island is high.

Commissioned in 1965 by the New Zealand Electricity Department, the HVDC link was developed to meet the growing electricity demand in the North Island by utilising the South Island's abundant hydro resources.[1] At the time of its construction, the HVDC link was considered a groundbreaking achievement in engineering.

The construction posed significant challenges, particularly crossing Cook Strait, known for its deep waters, strong currents, and unpredictable weather. Despite these hurdles, the project was a huge success and paved the way for many HVDC links globally. Today, HVDC technology is widely regarded as the preferred solution for bulk electricity transmission, both onshore and offshore, with numerous projects planned worldwide.

The original HVDC link, spanning 570 kilometres between Benmore in the South Island and Haywards in the North Island, had an initial capacity of 600 MW.[2] This link included the installation of submarine cables to traverse Cook Strait, a critical component of the system (see Figure 1 and 2).[3]

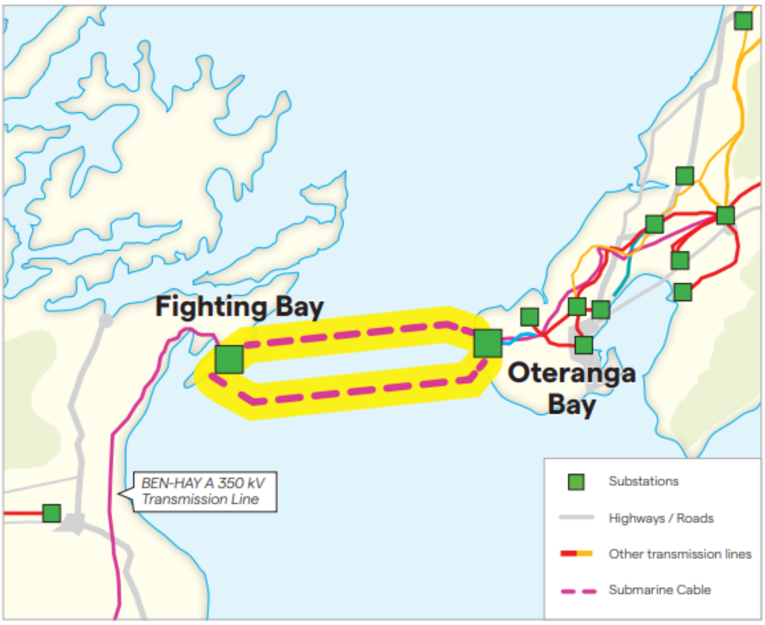
1 'White Diamonds North', Chapter 3, Transpower, 1990.

2 600 MW is the power required for approximately 300,000 electric kettles.

3 The HVDC link comprises a 535 km overhead transmission line between Benmore and Fighting Bay (Marlborough), three 40 km submarine cables across Cook Strait between Fighting Bay and Oteranga Bay, and a further 37 km overhead transmission line to Haywards substation north of Wellington. Both Haywards and Benmore substations have AC/DC converter stations.

Figure 1: Overview of the New Zealand Transmission Network showing the HVDC link

Figure 2: Geographic view of the HVDC Cook Strait link



1.2 The role of the HVDC link in New Zealand's electricity system

The HVDC link plays an indispensable role in New Zealand's electricity system. Our recent investigations have demonstrated the ongoing need for HVDC capacity between the North and South Islands until at least 2060. Industry forecasts[4] predict an average increase in electricity demand by 2050 of 66%, with some scenarios predicting an increase of over 80%. A significant proportion of this demand will be met by renewable sources, notably wind and solar generation.

The benefits of the HVDC link to New Zealand include:

- **Diversity of supply:** The HVDC link benefits North Island consumers by enabling access to (lower cost) South Island hydro generation and South Island consumers by enabling access to North Island generation (required in what we call 'dry years', when the South Island hydro-electric storage lakes are low). The HVDC link is also becoming more critical in supplying the North Island at winter peak. We are relying more on the link to meet North Island demand as New Zealand's generation mix changes,
- **Firming of intermittent generation.** In a highly renewable generation mix, South Island hydro will play a crucial role as firming generation, compensating for the intermittent nature of wind and solar generation,
- **Promoting competition:** The link also enables greater competition for electricity supply. Connecting the North and South Island power systems increases the overall pool of competing generators in a single national wholesale electricity market. This also widens the geographic area for potential new generation investment. Together this increased competition helps drive more efficient market outcomes and lower generation investment costs,

The existing HVDC link comprises several critical components:

- ***Thyristor bipole converters**: Two ±350 kV thyristor bipole converters (Pole 2 and Pole 3), each rated at 700 MW, with converter stations and protection and control systems at Benmore (South Island) and Haywards (North Island).*
- ***Bipolar transmission lines**: A 535 km 350 kV transmission line from Benmore to Ōraumoa/Fighting Bay (South Island) and a 37 km line from Oteranga Bay to Haywards (North Island).*
- ***Submarine cables**: Three 350 kV, 500 MW, 40 km submarine cables connecting to termination stations at Fighting Bay and Oteranga Bay.*
- ***Electrodes**: A land electrode at Bog Roy near Benmore and a shore electrode at Te Hikowhenua near Haywards to ensure safe and efficient current return paths.*
- ***AC filters**: AC filters to reduce harmonic distortion and provide static reactive support at both Benmore and Haywards.*
- ***Reactive support systems**: Eight synchronous condensers and a STATCOM at Haywards to supplement the dynamic reactive support available from the AC transmission system.*
- ***HVDC Control Systems**: bespoke systems that control the management of link operations, including frequency keeping control and roundpower.*

4 Including MBIE's recently updated Electricity Demand and Generation Scenarios [Electricity Demand and Generation Scenarios (EDGS) 2024]

- **Providing a National Reserves Market**: Upgrades to the HVDC link over the last 60 years have included added controls to allow South Island generation to instantly provide extra power into the North Island following the tripping of a North Island generator (and vice-versa). As part of our Pole 3[5] upgrade in 2013, this inter-island reserve sharing functionality was enhanced to always be available using "roundpower". This enables the seamless direction change from north to south and vice-versa,[6]
- **Frequency management:** Another cost in operating the grid is the payment to generators of maintaining the grid frequency at 50 Hz in each island. During the Pole 3 upgrade, controls were also added to tie the North and South Island grids in such a way that the frequency keeping role provided by generators can be shared between the islands, reducing the overall costs of frequency keeping to consumers.

As demand grows and generation becomes more renewable, the HVDC link's utilisation will increase. Any outages on the link will have a much larger impact on New Zealand electricity consumers and system security. Maintaining the HVDC link's availability and ensuring appropriate levels of capacity will be essential to ensuring secure and efficient electricity transmission.

1.3 Overview of the need for investment

The primary driver for our proposed investment is **the deteriorating condition of the HVDC submarine cables** (as they approach the end of their design life) and the **control systems have reached obsolescence and will no longer be supported by the manufacturer**. These submarine cables and the control systems will require replacement by the early 2030s to mitigate risks of failure and ensure the sustained reliability of New Zealand's electricity grid.

In parallel with the cable replacement, Transpower has also assessed potential enhancements to the HVDC link's capacity. Upgrading the cable capacity while undertaking the condition-based replacement could deliver economic and operational benefits by increasing the link's Northward capacity to align with the full capability of its converters.[7] Potential enhancement of HVDC link capacity was identified as part of our NZGP1 (staged) programme of investments to address the future capacity needs of New Zealand's main transmission grid backbone. NZGP1 aims to optimise capacity to enable efficient dispatch of forecast new generation and a reliable supply for future demand growth across the interconnected grid.[8]

We have reviewed other upgrade and replacement projects on the HVDC link that are due around the same time as the cable replacement. The projects are:

- **HVDC control systems.** The control systems that control the HVDC link are nearing the end of their operational life and are due for replacement around this time,

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5 Each pole contains the necessary equipment to convert alternating current (AC) to direct current (DC) for transmission, and then back to AC at the receiving end.

6 Frequency keeping control and roundpower information | Transpower

7 The HVDC south transfer capability is limited to 950 MW though actual transfers are limited by constraints in the AC transmission grid. While additional investment could remove the southward constraint, we have assumed the 950 MW limit remains in place in our modelling.

8 Transpower Net Zero Grid Pathways (NZGP1.1) Proposal -25 September 2023, page 11.

- **Cable termination stations.** The cable termination station buildings enclose the cable terminations at each end of the submarine cables. These buildings require upgrades to meet modern engineering and seismic requirements as well as modifications to accommodate the new termination requirements of the replacement cables. We are planning to work on the termination stations alongside the cable replacement, as both tasks are interdependent,
- **Cable store replacement.** The existing cable storage facility is no longer fit for purpose. A new facility is required to store spare submarine cables from the replacement project, ensuring they remain accessible for future maintenance and repairs by cable repair ships.

Additionally, increasing HVDC link capacity to 1400 MW north would also benefit from the link covering a larger share of its own reserve requirements by increasing Pole 2’s short term overload, reducing the costs associated with procuring other reserves.

Our investigations have shown that combining these projects will minimise outages and costs, and limit disruption to the electricity sector. Although the Control System replacement is included in our Investment Test analysis, this MCP (Stage 1) does not seek its approval; we anticipate doing so in a subsequent stage application.

1.3.1 Submarine cable condition

There are three existing submarine cables, each rated at 500 MW (see Section 1.3.2). According to our inspections and asset health data, these submarine cables will reach the end of their operational life around 2032, which aligns with their original design life.

Continuing to operate the submarine cables beyond this date significantly raises the risk of failure. Such failures could disrupt HVDC link operations and compromise electricity supply, particularly during dry years when South Island hydro generation supports North Island demand. Our Cable Asset Health Index (AHI) modelling shows that the condition of the submarine cables is steadily deteriorating, and the risk of defects continues to rise. Even if the worst sections were replaced (assuming they are technically repairable), the next most at-risk sections would likely require attention soon after.[9] Therefore targeted repair is not a sustainable or cost-effective long-term strategy.

Maintaining the submarine cables beyond 2032 through reactive repairs is not viable. The risk of one or more cable failures will continue to rise which could result in unplanned outages of one or both HVDC poles. Repair times vary – depending on fault location, type, cable depth, vessel availability, required cable length and weather – but can range from 6 to 18 months or longer. In some cases, reactive repair may not be possible at all.

While a short-term unplanned HVDC link outage may not have immediate security of supply implications, such a failure may threaten security of supply if it occurred during dry hydrological conditions in the South Island or during periods of capacity shortage in the North Island.

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[9] Attachment 3 details more information on the condition of the HVDC submarine cables and our asset health assessments.

If the damage is irreparable, the lead time for procuring and installing a replacement cable stands at approximately 7-10 years. This extended duration poses a significant challenge as full HVDC link capacity cannot be restored until a replacement cable is installed.[10] Such a scenario would disrupt the electricity market and result in significant economic losses to New Zealand.

The growing global demand for undersea HVDC submarine cables, driven by inter regional network development and offshore wind development, has made it more difficult, and more expensive, to secure cable manufacturing and installation. Cable installation requires specialist vessels.

Recognising the importance of securing our position in the supply and installation queue for these future works, in 2024 we began work to secure suppliers. At the end of 2024 we entered into a capacity and reservation agreement with global cable solutions supplier Prysmian for submarine cable manufacture and installation, which provides us with a procurement pathway for the submarine cables.

Any investment to replace the HVDC submarine cables would require HVDC link outages. Should we proceed with a cable replacement option, we will engage with customers and stakeholders through our usual channels as we develop the programme of required outages, with sufficient notice to minimise potential impacts.

A HVDC cable on the sea floor of the Cook Strait

10 'HVDC Submarine Cable Replacement and Enhancement Investigation (NZGP) – HVDC Submarine Cables Q&A', Transpower, 6 April 2023.

1.3.2 Capacity of the HVDC link

The HVDC link comprises of two converter stations which are referred to as Pole 2 and Pole 3,[11] each with a converter rating of 700 MW. Providing a combined capacity of 1400 MW.

The three 500 MW submarine cables across Cook Strait impose practical constraints on capacity: two cables are connected to Pole 3, and one to Pole 2. This configuration limits the end-to-end capacity of Pole 2 to 500 MW, resulting in a maximum combined operational capacity of 1200 MW for the HVDC link.[12] Our economic analysis has consistently shown that increasing the HVDC link's capacity to 1400 MW north through the addition of a fourth cable would give a material positive net electricity market benefit under various demand growth scenarios. The benefits primarily arise from the South Island hydro providing firming as North Island intermittent renewable generation (i.e., wind and solar) increases.

Increasing the capacity of the HVDC link at the same time as replacing the existing submarine cables is likely our best practical opportunity to do so. Significant delivery efficiencies can be gained if we use a single cable-laying ship and coordinate the work. A large portion of the cable pricing is attributed to manufacturing setup and ship mobilisation to New Zealand.

To support operation at 1400 MW, an additional filter bank will be required at Benmore. HVDC converter systems generate significant harmonic currents due to the switching action of thyristors. Without adequate filtering, these harmonics can distort voltage, interfere with nearby equipment, and increase losses and heating across the network. Filter banks are designed to suppress specific harmonic frequencies and provide reactive power support. They are critical to maintain compliance with power quality requirements in NZECP36, which sets strict limits on harmonic distortion. Transpower has an obligation to meet these limits.[13]

Studies confirm that increasing HVDC link transfer capacity to 1400 MW at Benmore will exceed the current harmonic filtering capability, and therefore, an additional filter bank is required to meet Transpower's design and planning standards. This ensures that the full increase in HVDC link transfer capacity to 1400 MW north can be made available to the market.

No additional filters are needed at Haywards, where an extra filter was recently approved and funded through the Net Zero Grid Pathways (NZGP) Major Capex Proposal (MCP). At both converter stations, filter banks are configured in multiple switched units, which allows

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11 Pole 2 and Pole 3 each convert electricity between direct and alternating current.

12 The maximum Northward capacity of 1200 MW is only achieved in unbalanced bipole mode (Pole 2 at 500 MW and Pole 3 at 700 MW). Although maximum transfer capability of the HVDC assets is continuously available (notwithstanding outages), the maximum energy transfer achieved at any point in time is dependent on market energy and reserve offers, and the capacity of the surrounding AC networks in the North and South Islands to supply regional loads and support both AC and HVDC energy transfer requirements.

13 NZECP 36:1993. This electrical Code of Practice sets acceptable levels of harmonic voltages and currents which may be introduced into an electricity supply system.

continued HVDC link operation if one filter bank is offline due to faults or planned maintenance. Each filter bank typically requires around one week of maintenance per year.

1.3.3 HVDC control systems, termination stations and cable store

HVDC control systems

The HVDC control systems, commissioned in 2013 alongside Pole 3, are critical to the operation of the HVDC link. These bespoke systems manage both Pole 2 and Pole 3, as well as the associated AC reactive power controls, and are uniquely tailored to the operational demands of New Zealand's two-island power system.[14] The HVDC link cannot operate without the control systems.

Unlike the core converter infrastructure, HVDC control systems have a much shorter lifecycle, typically 15 to 20 years, due to the rapid pace of technology change and software/hardware obsolescence.[15] By 2033 the current systems will be 20 years old and at the end of their expected life. The hardware platform it relies on is already being phased out by the manufacturer, with spare parts no longer produced and component-level repairs no longer viable. Once manufacturer support ends, Transpower will be unable to resolve critical failures, increasing the risk of prolonged and potentially system-critical outages.

Transpower has considered alternatives to full replacement of control systems, including staged upgrades and partial replacements. These were found to be infeasible due to:

- the bespoke and tightly integrated nature of the current system,
- incompatibility with modern platforms,
- lack of supported spares and repair options, and
- limited supplier willingness or ability to reprogramme legacy systems after 2025.

In parallel, the planned commissioning of a fourth cable in 2031, would necessitate reprogramming of the control systems. Attempting to modify the legacy system for this purpose would require significant internal engineering effort, HVDC link outages, and ultimately result in redundant work if the system is replaced shortly afterwards, with much of this integration effort and associated outages needing to be repeated.

Replacing the control system is a complex, high-risk undertaking. It is not a standard upgrade – it involves integrating new controls with legacy converter infrastructure from different manufacturers, requiring deep technical expertise, rigorous testing, and close coordination with a limited pool of global HVDC suppliers. Lead times are long, and global demand for HVDC control systems is high. Our current estimates are that outages of 3 to 6 months will be required to install a new system.

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14 The HVDC control system plays a critical role in managing link operations, including frequency keeping control and roundpower

15 International standards such as CIGRE Technical Brochure 649 and IEC Technical Report 62978-2017 indicate a typical service life of 7 years for the human machine interface (HMI) and 12-15 years for digital control systems.

Although the control system replacement was initially scheduled for around 2033, Transpower is now planning to integrate this work into the broader cable replacement programme. This coordinated approach includes the following key benefits:

- Early market engagement and procurement planning, securing supplier capacity in a globally constrained environment,
- Reduced total outage duration by combining commissioning windows and minimising system outages,
- Avoided costs associated with redundant reprogramming and HMI replacement costs that would otherwise be repeated within a short timeframe,
- Improved project delivery through shared planning, resource coordination and risk management,
- Additional expected net electricity market benefits of approximately $10–$150 million, based on current analysis, by combining works in 2031 rather than deferring control system replacement to 2033. While programme, outage, and cost requirements are still being refined, these estimates remain conservative given uncertainties around outage timing and hydrology conditions.

In summary, all viable alternatives to replacing the control systems have been considered. A full replacement of the control systems is the only technically and operationally sound solution. We also believe that there are benefits with aligning this upgrade with the 2031 cable replacement – reducing overall outage duration, avoiding redundant costs, and ensuing a more efficient, coordinated delivery.

As the scope and cost of the HVDC control system replacement are still being refined, we are not seeking approval for this component as part of the Stage 1 proposal.[16] Approval will be sought in a subsequent stage once further work is complete. Estimates of the control system costs for Stage 2 have been included in the Investment Test analysis.

Cable Termination stations

At each end of the HVDC submarine cables are termination station buildings that house critical systems to protect the cable terminations and maintain a clean, controlled environment for sensitive components. These buildings are positively pressurised to prevent dust or salt ingress.

Originally built in 1965 and upgraded in 1992, the existing buildings at Oteranga Bay and Fighting Bay were already forecast to require modifications in order to accommodate the new termination specifications of the new replacement submarine cables. We have long anticipated that the cable replacement and associated termination station upgrades would be an interdependent package of work.

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16 As part of Stage 1 we are seeking preparatory funding to undertake work that will refine the scope and cost estimates for the control system. This will inform the Stage 2 investment application.

The cable termination stations are classified as IL4 (Importance Level 4) structures due to their critical role in maintaining inter-island electricity transfer.[17] Recent seismic assessments indicate the existing buildings no longer meet current seismic and engineering standards. Recent assessments indicate that their seismic capacity is around 34% of the new seismic loading requirements, far below the 75% required by Transpower's compliance and engineering standards for Importance Level 4 (IL4) structures. The integrity of these buildings is critical to the operation of the HVDC link. IL4 requirements ensure that the buildings can experience minor damage while remaining operational or be quickly restored following a major seismic event.

An independent study commissioned by Transpower evaluated both upgrade and rebuild options. The study set out the key challenges with existing sites and considers engineering solutions to overcome those challenges. It also provided examples of new-build stations that could overcome the challenges. It concluded that seismic strengthening would involve extensive work to the floors, walls, roof, and foundations, requiring prolonged outages. Critically, due to safety risks, this work cannot be performed above or around live HVDC equipment. It is estimated that to do this work would require a 6-12 month outage of both HVDC poles.

The current buildings are configured for three cables. Upgrading to 1400 MW north by installing a fourth cable would require extensions to accommodate an additional cable bay as part of any strengthening effort.

Given these factors, the study recommended full replacement as the preferred option. Constructing new termination stations adjacent to the existing facilities (within the existing designation) provides multiple advantages:

- Allows construction and connection of the new cables to occur without interrupting operation of the HVDC link,
- Minimises outage windows during commissioning,
- Improves safety by avoiding work in live environments, and
- Delivers a fit-for-purpose facility that meets modern seismic and engineering standards.

After careful consideration, we have determined that the most effective long-term solution is to construct new termination stations adjacent to the existing buildings.

Cable store

Given our geographical location, we plan to procure and store 10km of spare cable to enable possible future repairs. Any contract for supply and installation of replacement submarine cables will also include the supply of spare HVDC submarine cable lengths. Due to the weight and handling requirements of the cable, a dedicated cable storage facility with suitable cable storage turntables must be established to ensure the spare cable remains in optimal condition.

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17 Under NZS 1170.0: Structural design actions – General principles, IL4 (Importance Level 4) is defined as: *"Buildings or facilities that must be operational immediately after a major disaster or whose failure would lead to significant loss of life, disruption to critical services, or significant economic or environmental consequences."* This includes major electricity substations, control centres, and key infrastructure.

The current cable storage facility in Wellington is no longer fit for purpose. The existing Miramar cable store is dependent on the use of the adjacent Miramar wharf, which was closed in 2015 and is now condemned, with no plans for repair or replacement. In addition, there are new airport flight path restrictions limiting the height of repair vessels that would be offloading the spare cable and loading the cable in the event of a repair. As a result, loading and accessing spare cable from this store is no longer feasible. While we could retrieve the cable in an emergency, doing so would be highly impractical.

In preparation for delivery of the replacement submarine cables, Transpower plans to develop a new cable storage facility.

1.3.4 HVDC link Pole 2 short-term overload

Short-term overload occurs when the HVDC link temporarily exceeds its normal operating capacity. Currently Pole 2's overload capacity is limited to 700 MW north, due to the capacity constraint of the single cable. However, after cable replacement and the addition of a second cable connected to Pole 2, its short-term overload limit could be increased to 840 MW. Pole 3, by comparison, can reach 1000 MW as its converter transformers were designed with this capacity at commissioning – unlike Pole 2, which was not initially designed with such an overload.

The investment would allow Pole 2 to absorb additional load for up to 15 minutes in the event of a Pole 3 trip, improving overall network stability. Increasing Pole 2's short-term overload capacity would also reduce the need for pre-contingency reserves by allowing the HVDC link to cover a larger portion of its own reserve requirement. This would improve market efficiency

South Island HVDC cable termination station at Ōraumoa / Fighting Bay in the outer Marlborough Sounds.

and lower the costs associated with procuring reserves. We have identified that increasing the Pole 2 overload limit to 840 MW is expected to lead to net electricity market benefits.[18]

1.4 Integrated transmission plan

The need to replace the HVDC submarine cables and HVDC control systems, based on asset condition and risk, has been identified in Transpower's Integrated Transmission Plan (ITP). The ITP is a suite of documents that outlines our plans for the regulated transmission network over a 10-year horizon and includes the Transmission Planning Report.

In the most recently published Transmission Planning Report 2023, Section 6.10 describes the HVDC link and key information relating to the submarine cables and control systems. Specifically, sections 6.10.2 to 6.10.3 discuss HVDC link capacity considerations and outline potential upgrade options. These are driven by the need to enable future grid development in response to increasing electricity demand and growing renewable generation – a core component of our Net Zero Grid Pathways programme. These assumptions remain unchanged and will carry through to our next ITP, scheduled for release in September 2025.Accordingly, the need for investment, the short-listed options, and the proposed investment described in this MCP are consistent with the direction set out in the ITP.

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18 With additional investment, Pole 2's overload capacity could be increased further to match that of Pole 3. Our analysis has shown that while there are benefits associated with increasing the overload capacity to 1000 MW they are unlikely to outweigh the associated costs.

2 Approach to developing demand and generation scenarios

We conduct economic evaluations of options using a range of market development scenarios, i.e, demand and generation scenarios under the Capex IM. A market development scenario is an internally consistent set of input assumptions that represents a plausible future of the electricity system. Using market development scenarios ensures that our economic analysis considers a range of different demand and generation futures.

A market development scenario includes assumptions about:

- future electricity demand, including assumptions regarding base demand, electric vehicle (EV) uptake, solar photo-voltaic (PV) uptake, distributed energy storage, etc,
- existing, decommissioned and future new generation connected to the national grid,
- capital expenditure and operating costs for both existing and future generation assets,
- availability of fuel for generation,
- fuel and carbon costs associated with generation, and
- grid-connected energy storage solutions.

The Investment Test uses the *market development scenarios* produced by the Ministry of Business, Innovation and Employment (MBIE) or reasonable variations of its scenarios. MBIE's scenarios are called the Electricity Demand and Generation Scenarios (EDGS).[19]

For this MCP we have based our analysis on the 2019 EDGS with several updates and variations. We updated the 2019 EDGS to reflect consultation we undertook as part of the Net Zero Grid Pathways 1 (NZGP1) workstream in 2021 (which we refer to as the NZGP1 EDGS Variations).[20] These updates aimed to ensure the EDGS reflected the potential for rapid change in New Zealand's energy sector and are plausible futures to use in our evaluation of investment proposals.

The EDGS focus on national and island level demand, meaning we must use a variety of allocation mechanisms to allocate the national and island level information to the regional and Grid Exit Point (GXP) levels to complete our analysis. To do this, we also incorporate information from electricity lines companies about GXP level growth.

The 2019 EDGS and our 2019 EDGS Variations consist of five scenarios:

1. **Reference:** Current trends continue,
2. **Growth**: Accelerated economic growth,

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19 See Consultation on EDGS 2019 Variations to develop generation scenarios | Transpower

20 The scenarios used are based on EDGS 2019 but include necessary variations that were detailed in Transpower's NZGP1 major capital proposal (NZGP Latest updates | Transpower) along with updates to reflect updated lines company views of demand growth. In Capex IM language, the scenarios are demand and generation scenario variations because they are variations on EDGS 2019.

3. **Global:** International economic changes,
4. **Environmental:** Sustainable transition,
5. **Disruptive:** Improved technologies are developed.

Additionally, we have updated certain generation assumptions to ensure they reflect the most current information. Our generation assumptions are largely consistent with the TPM Assumptions Book 2.0, which we consulted on in October 2024.

In July 2024, MBIE released a new version of EDGS. We have continued to base our analysis for this project on the 2019 EDGS Variations we have developed and consulted on as the foundation of our analysis. Our view is that the 2019 EDGS Variations and our assumptions presented below provide a suitable basis for assessing this project. We note that the long-term national energy demand forecast range is broadly similar between the 2024 EDGS and the 2019 EDGS variations.

In our May 2025 short-list consultation,[21] most stakeholders appeared supportive of the weightings, though some raised some concerns:[22]

- Fonterra considered the current approach overly conservative. They recommended assigning a 50% weighting to the Environmental Scenario, arguing that it most accurately reflects New Zealand's likely energy future, particularly given strong decarbonisation trends and industrial electrification. We acknowledge Fonterra's view that a higher weighting on the Environmental Scenario could better reflect emerging trends in electrification and decarbonisation. In more localised situations where a high, medium and low demand scenario has been considered we have weighted the central scenario higher. However, for this investment we believe that an equal weighting approach provides a balanced basis for assessing long-term investments,
- Vector indicated a view that the scenario weighting was imbalanced and recommended a more balanced weighting approach. We have since clarified that they had misinterpreted our weightings.

Following this feedback we have decided to not amend the weightings, which are set out in Table 1 of Attachment 7. Our sensitivity analysis (see Table 8 in Attachment 7) presents Investment Test results for each scenario individually, including how each option performs under a 100% scenario weighting. Option 3 performs well across all scenarios, reinforcing the robustness of the preferred option.

21 Attachment 8 summarises our stakeholder consultations.

22 Individual submissions, including a summary of these submissions can be found at [HVDC link upgrade programme - short-list consultation | Transpower]

3 Demand assumptions

This section presents the HVDC link market development demand forecasts we have used for this MCP. These are largely consistent with the assumptions we have used for the recent Upper South Island and Western Bay of Plenty major capex proposals.

3.1 Regional forecasts and assumptions

Figure 3 presents our proposed energy demand forecasts for the North and South Island, respectively, for each of the five EDGS scenarios. Table 1 and Table 2 present the energy forecasts from 2025 through to 2060, broken down by the factors that are contributing to that growth:

- Base growth – this relates to the underlying growth in demand driven by "business-as-usual" growth factors,
- Step loads – this relates to new demand that might appear in the future from new developments, such as new commercial and residential developments, and informed by feedback from electricity distribution businesses (EDBs),
- EV – this relates to the uptake of EVs and the "smartness" of their charging,
- Solar – this relates to the uptake of residential and commercial solar photovoltaic panels,
- Battery – this relates to the uptake of residential and commercial battery storage packs,
- Industrial electrification – this relates to the electrification of industrial processes such as the conversion of coal and diesel boilers to electric boilers.

Each scenario has different assumptions relating to each of these factors that leads to the overall variation in the forecasts. We explain our approach to determining each of these factors in more detail below.

Figure 3: Gross energy demand forecast, TWh

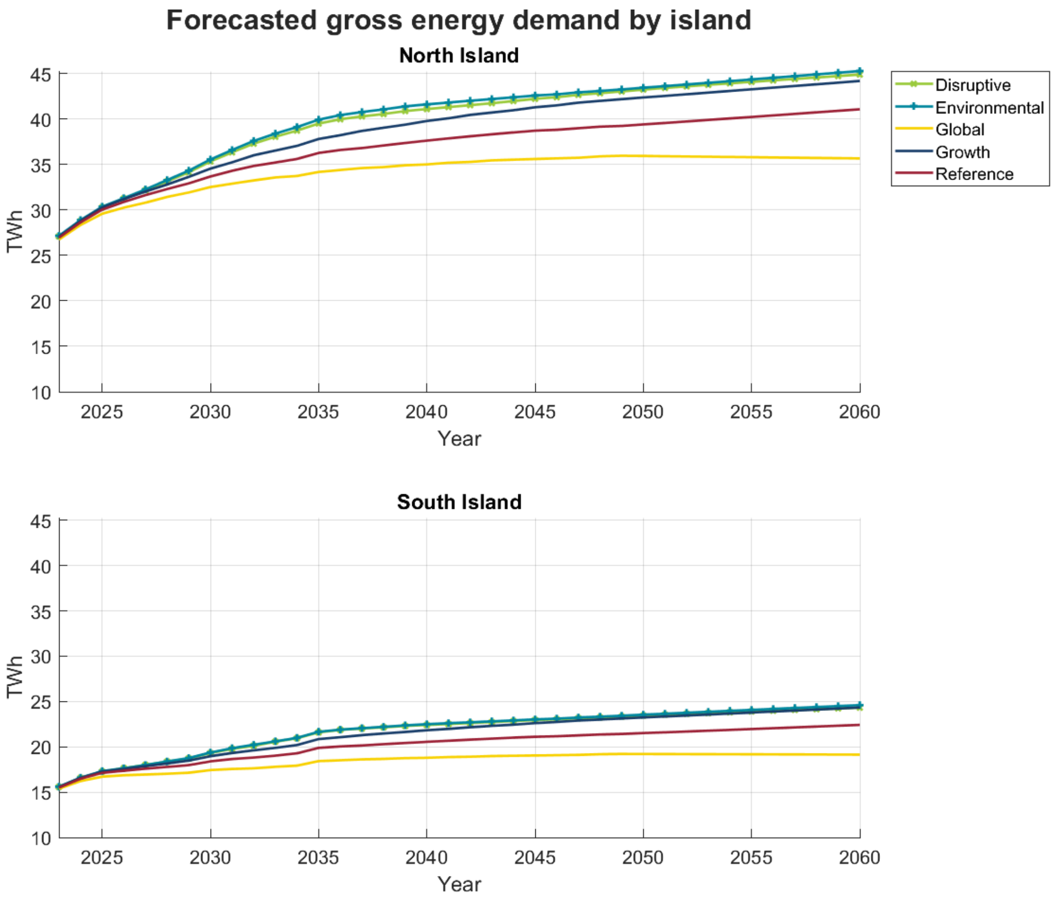


Table 1: North Island energy demand forecast assumptions – Summary, GWh

Scenario	Year	Total energy demand	Base	Step loads	EV	Solar	Installed battery capacity[23]	Electrified process heat
Disruptive	2025	30300	26300	3600	500	-200	0.01	200
	2030	35300	26800	5900	1500	-600	0.04	1700
	2050	43200	29000	6400	7700	-4500	3.46	4500
	2060	44900	30100	6500	9900	-6200	4.64	4500
Growth	2025	30300	26600	3600	200	-200	0.01	100
	2030	34600	27500	5900	700	-400	0.02	800
	2050	42400	31600	6500	4800	-2700	2.1	2200
	2060	44200	33800	6500	6700	-5000	3.87	2200
Environmental	2025	30400	26500	3600	400	-200	0.01	200
	2030	35600	27300	5800	1400	-600	0.04	1600
	2050	43500	30700	6300	6500	-4500	3.46	4300
	2060	45300	32500	6300	8200	-6200	4.64	4300
Reference	2025	30000	26400	3600	200	-200	0.02	100
	2030	33700	27000	5900	600	-300	0.04	500
	2050	39400	29900	6400	3900	-2200	0.95	1400
	2060	41100	31300	6400	5800	-3900	1.59	1400

[23] Here we present the total installed capacity rather than energy due to charge and discharge cycles. This gives a clearer indication of the different battery assumptions between the scenarios

Scenario	Year	Total energy demand	Base	Step loads	EV	Solar	Installed battery capacity[23]	Electrified process heat
Global	2025	29600	25900	3600	200	-200	0.01	100
	2030	32500	26100	5800	600	-200	0.01	300
	2050	35900	26600	6200	3000	-800	0.61	900
	2060	35700	26900	6300	3000	-1300	1.04	900

Table 2: South Island energy demand forecast assumptions – Summary, GWh

Scenario	Year	Total energy demand	Base	Step loads	EV	Solar	Installed battery capacity[24].	Electrified process heat
Disruptive	2025	17300	15500	1500	200	-100	0	200
	2030	19300	15800	2300	600	-200	0.02	800
	2050	23400	17100	2800	3000	-1900	1.51	2300
	2060	24300	17800	2800	3900	-2600	2.02	2300
Growth	2025	17300	15700	1400	100	-100	0	200
	2030	19000	16200	2100	300	-200	0.01	500
	2050	23200	18700	2400	1900	-1100	0.91	1400
	2060	24300	19900	2400	2600	-2100	1.69	1400
Environmental	2025	17300	15600	1400	200	-100	0	200
	2030	19400	16100	2100	600	-200	0.02	800
	2050	23500	18100	2400	2600	-1900	1.51	2200

Scenario	Year	Total energy demand	Base	Step loads	EV	Solar	Installed battery capacity[24].	Electrified process heat
	2060	24600	19200	2400	3200	-2600	2.02	2300
Reference	2025	17100	15600	1400	100	-100	0.01	200
	2030	18400	15900	2000	200	-100	0.02	400
	2050	21500	17600	2200	1500	-900	0.41	1100
	2060	22400	18500	2200	2300	-1600	0.69	1100
Global	2025	16700	15300	1200	100	-100	0	200
	2030	17400	15400	1600	200	-100	0	300
	2050	19200	15700	1800	1200	-300	0.27	800
	2060	19100	15900	1800	1200	-600	0.45	800

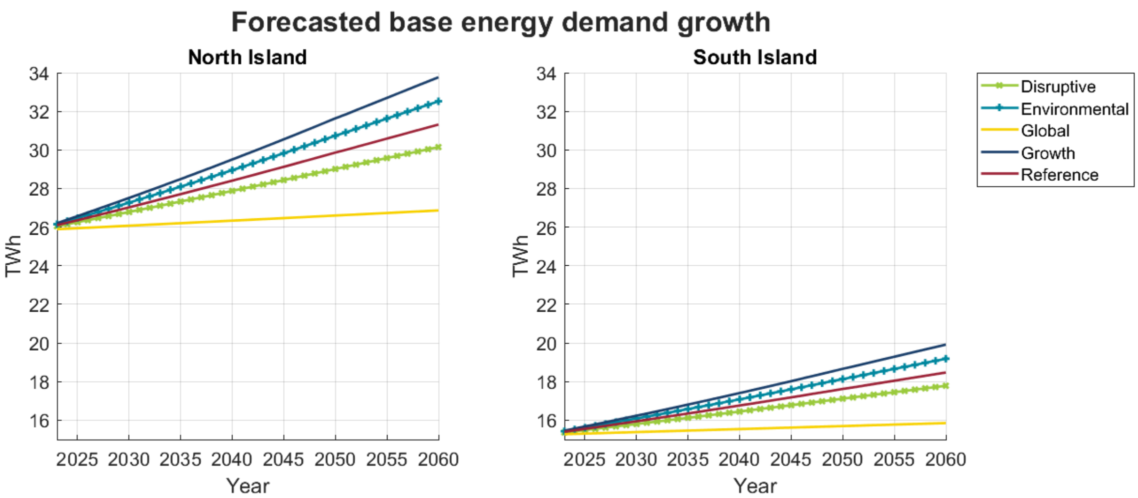
3.1.1 Base demand

Base level demand relates to underlying demand we expect to occur. For example, economic and population growth will drive demand. As shown in Table 1 and Table 2, it is the primary contributor to overall demand growth. The base growth assumptions are encapsulated by the Compound Annual Growth Rates (CAGRs) specified in Table 8.

We model base demand by combining national and island level base demand energy forecasts informed from our NZGP1 EDGS variations, with local electricity distribution businesses' (EDB's) GXP level peak base demand forecasts. We do this through a reconciliation process where we create half-hourly GXP demand profiles that sum nationally and by island to close to national and island NZGP1 EDGS forecasts of base demand and still aligning well with the GXP level forecasts provided by distribution businesses. Aligning with GXP forecasts is given higher weighting in the reconciliation process in early years to place higher value on EDBs' nearer term information. Modelling demand profiles is important as factors such as EV charging and residential/commercial battery use will have a significant impact on future peak demand.

Figure 4 shows the resultant base energy demand forecasts for the North and South Island. It is notable that the growth associated with the Global scenario is very low reflecting the low national growth rate associated with this scenario in the EDGS.

Figure 4: Base demand growth, TWh



3.1.2 Step loads

New step loads are expected to play a major role in driving growth in New Zealand over the next 10 years. These relate to new developments expected to occur that will lead to a step increase in electricity demand. Table 1 and Table 2 show that step loads are a significant driver of forecast growth, contributing up to 5.9 TWh to the North Island energy demand growth by 2030.

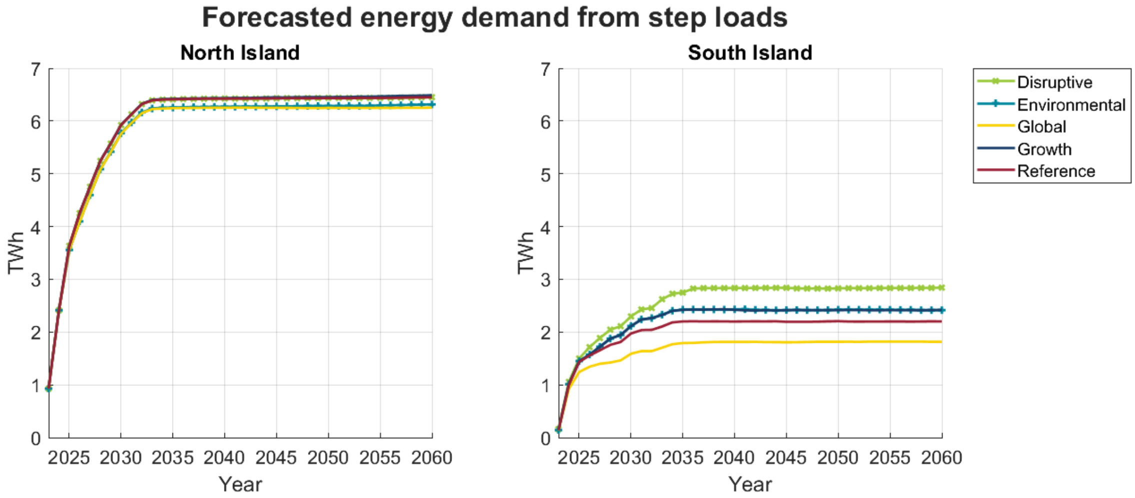
We model step changes by assigning a half-hourly demand profile to each step change based on the type of demand expected (e.g., industrial, residential etc.) and then scaling so that the peak of the profile aligns with the expected peak demand of the step load. We then add this profile to the existing forecast base demand at the GXP where the step is expected.

EDBs and industrial companies have provided us with details of the step loads expected around the country. We have also included possible electrification of boilers identified in the thermal fuel transition impact assessment reports.[24] Where a step load appears to be also captured in another modelled component (e.g. process heat) we reduce the other modelled component by the size of the step change to reduce the chance of double counting.

We have included some variation of the step loads across the scenarios.

Figure 5 shows the contribution of step loads to the forecast electricity energy growth in each island. Note the demand due to steps loads is the same in the Growth and Environmental scenarios.

Figure 5: Step load growth, TWh



3.1.3 Electric vehicles

We have aligned our national EV assumptions closely with our NZGP1 EDGS variations.

We model the impact of EVs by first adopting the assumed national uptake rates of EVs as given by each NZGP1 EDGS variation scenario. National uptake rates are then allocated to a regional level using historical light passenger vehicle kilometres travelled in each region, and to GXP level using the number of relevant Installation Control Points (ICPs) behind each GXP. Figure 6 shows EVs' annual electricity demand resulting from our uptake assumptions.

It is also critical for peak demand forecasts to make assumptions about when EVs will be charged. We model the timing of EV charging by assuming some proportion of EVs have a fixed profile (e.g., they tend to charge after work or when it is convenient) and the remaining proportion have a "smart" profile, and charge in a way that avoids regional peaks. In our

24 Regional Energy Transition Accelerator (RETA)

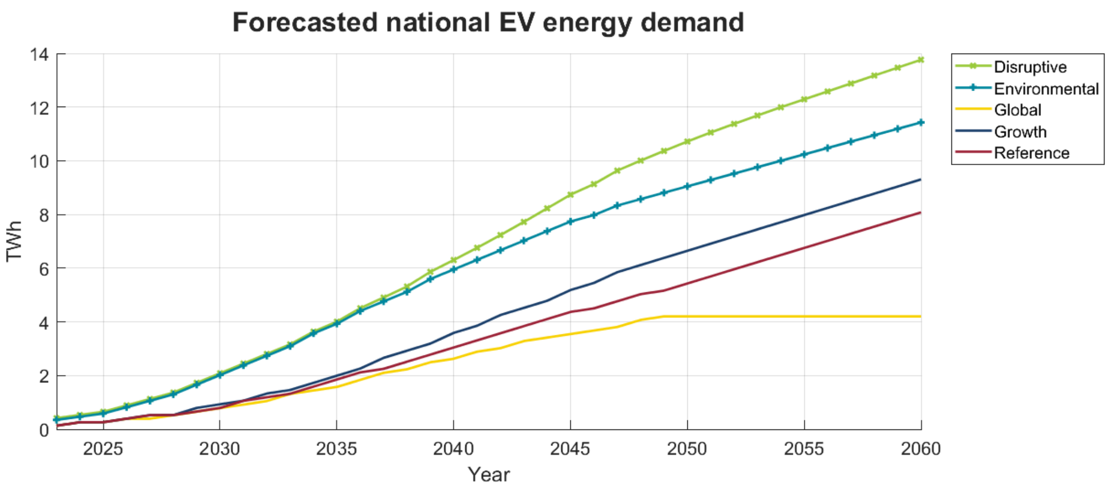
demand forecasting models the charging of "smart" EVs is moved to avoid peak periods. In this way "smartness" reduces our peak demand forecasts.

We have aligned our "smartness" assumptions with our NZGP1 EDGS variations except we have reduced the "smartness" in the Disruptive scenario from 60% to 50%, such that 50% of all EV demand is "smart" charging by 2050. We have done this to create some additional diversity in our forecasts and to recognise that there are risks that EV charging may be less smart. Table 3 summaries the "smartness" assumptions for all scenarios.

Table 3: EV Smartness Assumptions, by scenario, by 2050[25]

	Disruptive	Growth	Environmental	Reference	Global
Proportion smart charging %	50 %	50 %	60 %	40 %	20 %

Figure 6: Electric vehicle demand growth, TWh



3.1.4 Solar uptake

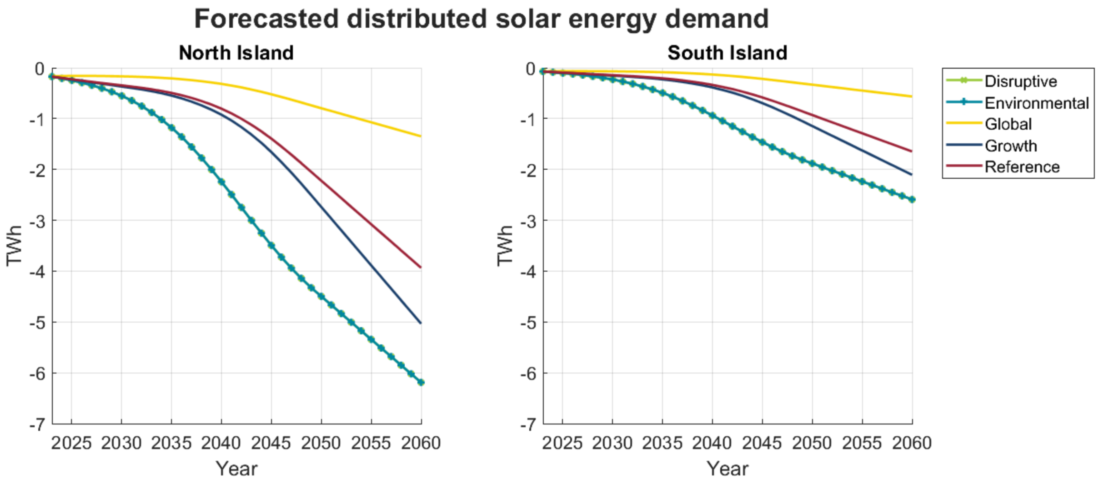
We have aligned our national level solar and residential/commercial uptake rates with the assumptions we consulted on in developing the NZGP1 EDGS variations. We then allocate the national uptake rates to a GXP level using the number of ICPs behind each GXP and the solar propensities for each region.

25 NZGP1 Scenarios Update December 2021

We use solar irradiance data at a regional and hourly level to estimate the amount of solar generation that is being produced at a half-hourly level.

Figure 7 shows the contribution of new residential/commercial solar installations to each island's energy (TWh) demand. Note that solar generated electricity reduces GXPs' demand (i.e., solar uptake reduces demand forecasts during the times of day solar can produce electricity). As shown below, the Disruptive and Environmental scenarios have the same solar uptake.

Figure 7: Distributed solar demand growth production contribution to demand, TWh



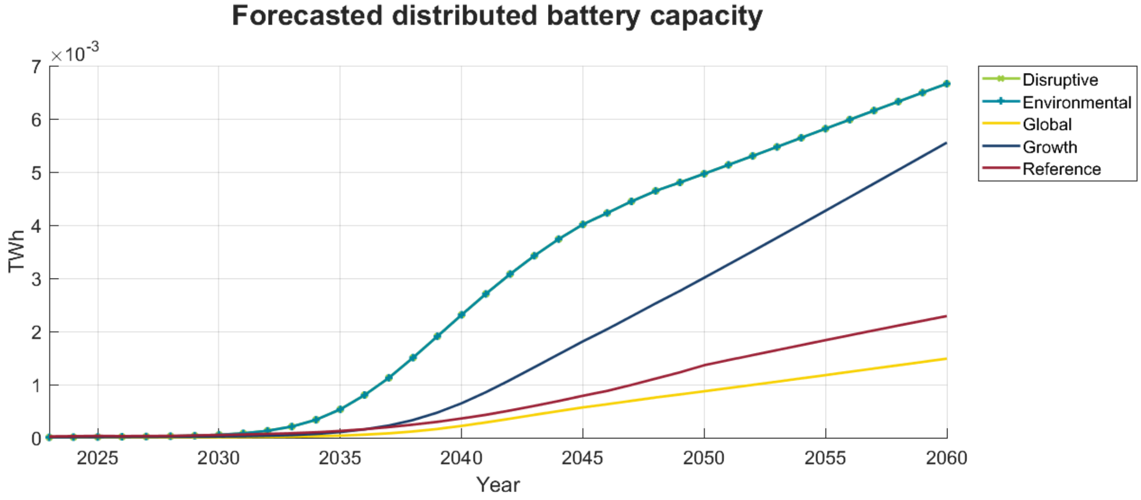
3.1.5 Battery uptake

We have aligned our battery uptake with the approach taken in our NZGP1 EDGS variations and set it as a percentage of solar update. We assume that the battery allocation at a GXP level is the same as the solar allocation. We also assume that EV batteries are available to reduce peak demand. In

Figure 8 we show the total TWh installed for each demand scenario.

We assume batteries are charged in trough periods and discharged in peak periods in such a way as to reduce the overall peak demand. In our modelling, batteries are assumed to reduce the daily peak load at a GXP.

Figure 8: Total storage capacity of battery installations, TWh



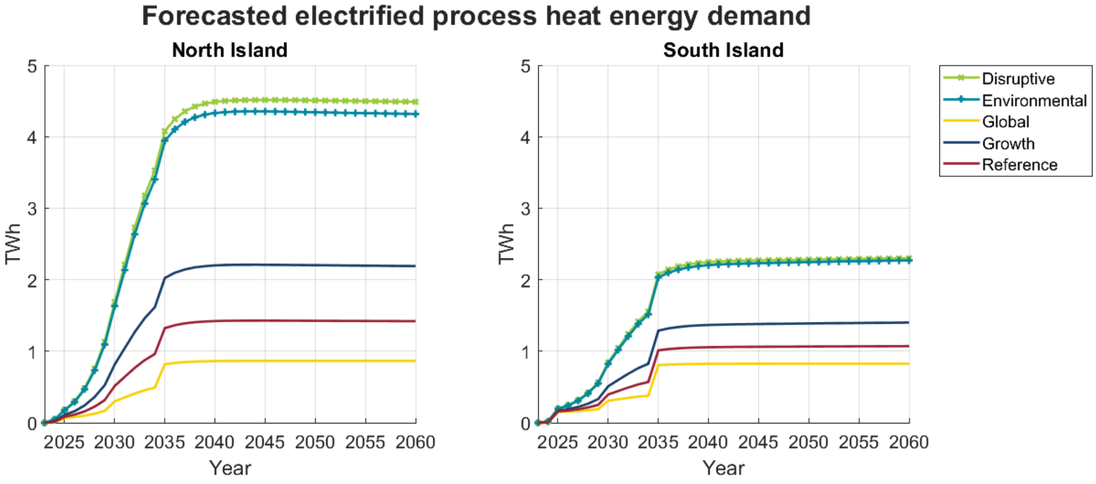
3.1.6 Process heat

We have aligned our process heat 2060 totals closely with our NZGP1 EDGS variations.

However, we have updated the trajectory of heat electrification to follow an S-curve. An S-curve is a more common form of uptake for new products. It has some period of ramp up in uptake followed by a flattening in uptake. Additionally, we have excluded high-temperature process heat from the Disruptive scenario (the only scenario that included this), which is utilised in industries needing heating above 300°C, such as chemical manufacturing and metal melting. We note there is potential for new demand from such processes but have not accounted for it in this analysis.

We model heat electrification by allocating national totals for different temperature heat electrification to a region using data on energy use by sector, fuel type and technology. We allocate the heat load at a GXP level using boiler databases, knowledge of major plants on the grid and by identifying any step loads which are electrifying process heat. By using step loads to allocate process heat, we ensure that we avoid double counting process heat electrification.

Figure 9: Process heat demand growth, TWh



3.1.7 Updates from NZGP1

We have based our assumptions on those made as part of our NZGP1 project. However, we have made some refinements to the data and approach we used since deriving forecasts for our NZGP1 project. These include:

- updating data based on more recent historical information and feedback from EDBs,[26]
- decreasing the "smartness" of EV charging in the Disruptive scenario from 60% to 50%,
- amending the uptake rate of process heat to be a S-curve and removing the conversion of high temperature heat from the Disruptive scenario,
- assuming the Tiwai Point aluminium smelter remains open throughout the forecast horizon.

26 As modelling work began a year ago, we based the forecasts on the last consulted on forecasts that incorporated customer feedback from 2023.

4 Generation assumptions

This section presents information relating to the generation assumptions we have used for this project. Generation assumptions apply to our:

- Dispatch model, **SDDP**, which simulates the wholesale electricity market by calculating a least cost optimal dispatch over the study horizon,
- Generation expansion plan model, **OptGen**, which determines the location, timing, and technology of new (modelled) generation.

We use these models to evaluate the electricity market benefits for different investment options. For more information on this modelling refer to Attachment 6.

4.1 Basis of our assumptions

Generation assumptions for our SDDP and Optgen modelling are based on the Benefit-Based Charges (BBC) Assumptions Book v.2.0 ("Assumptions Book")[27] which was published in November 2024 following consultation.

The Assumptions Book is a near complete reference for our generation modelling assumptions and should be referred to for detailed information. This attachment gives a high-level overview of our modelling assumptions and details variants to the Assumptions Book which have been applied for this MCP. Note that our generation scenario assumptions are not equivalent to the NZGP1 EDGS variants.

4.2 Scenario assumptions

Our market development scenario assumptions (the EDGS) have been designed to promote diversity in terms of demand and generation. This makes them appropriate for testing the benefits of transmission investment, considering a range of future uncertainty.

The key generation scenario assumptions vary in terms of fuel and carbon costs, generation cost reductions and the emission intensiveness of geothermal generation. The generation assumptions are summarised in Table 4.

[27] See the Assumptions Book site.

Table 4: Key generation scenario assumptions

	Reference	Growth	Global	Environmental	Disruptive
New generators	Moderate cost declines for geothermal, wind, solar, batteries	Moderate cost declines for geothermal, wind, solar, batteries	Conservative cost declines for geothermal, wind, solar, batteries	Advanced cost declines for geothermal, wind, solar, batteries	Advanced cost declines for geothermal, wind, solar, batteries
Geothermal generation	No reinjection assumed	Reinjection of 50% of greenhouse gas emissions and additional 20% capital cost reduction	No reinjection assumed		
Gas generation	Use of fossil gas			Gas turbine generators able to convert to biofuel when economic to do so (around 2040).	Use of fossil gas
BESS development alongside solar	Battery Energy Storage System (BESS) projects are not paired with solar developments**				
Carbon prices	Use "low" carbon price	Use "medium" carbon price	Use "low" carbon price	Use "high" carbon price	Use "medium" carbon price

** Differs from AB, as noted in Table 10.

4.3 Existing generation

We include existing grid-connected hydro, wind and solar generation and all thermal generation >10MW in our model. We also include 'embedded generation' greater than 10 MW. Smaller embedded generation (<10 MW) is included in the demand forecasts as a reduction in gross demand.

4.4 Generation retirements and repowering

During our modelling horizon which extends to 2060 much of the existing generation base and generation which is currently being developed will reach the end of its technical or economic life. In our generation expansion plan modelling we therefore need to consider plant retirement and replacement. We have a variety of approaches for this depending on the generation type. The assumed plant changes are summarised in Table 5.

For existing thermal generation, we assume a decommissioning year based either on the owner's stated intention, or independent estimates. For geothermal generation we assume the retirement of the existing generation at Wairākei by 2031, and the partial replacement of this capacity by Te Mihi Stage 2, and an optional uplift of capacity with Te Mihi Stage 3. We assume all other existing and future geothermal generation and all hydro generation continues to operate until the end of the modelled horizon. We assume that existing wind generation is repowered at the end of its technical life with an uplift in capacity.

Table 5: Assumed changes for existing generation

Year	Thermal generator decommissioning	Geothermal changes	Wind repowering
2023	TeRapa (-44MW)		
2026	TaranCC (-377MW)		
2027		Partial replacement of Wairakei with Te Mihi Stage 1 (+30.4MW)	
2029	Whirina (-155MW)		TRrHau (+40.5MW) TaraW1 (+35.7MW)
2030	HuntC1 (-250MW) HuntC2 (-250MW) HuntC4 (-250MW) *See note in text below*		TRrHau3 (+41MW)
2031		Wairakei decommissioning	TRrHau4 (+40MW)
2033	Edgcmb (-10MW)		
2034			TaraW2 (+36.3MW)

Year	Thermal generator decommissioning	Geothermal changes	Wind repowering
			TeApiti (+94.2MW)
2035	SFDOCGT (-210MW)		
2036	BRBPkr (-0MW)		
2037	E3p (-403MW)		TaraW3 (+11MW) WhtHll (+39MW)
2038	Hawera (-68MW) McKee (-100MW)		
2039			WstWnd (+65.4MW)
2040	Kapuni (-25MW)		
2041			Mahiner (+4MW) TeUku (+29.6MW)
2044			MillCrk (+28MW)
2045	JnctnRd (-100MW)		

For wind, solar and BESS which is developed in our generation expansion plans we assume aged-based retirements at the end of a plants specified operational life. We assume a 15-year lifetime for BESS, 25 years for solar and 30 years for wind. These durations mean that much of the existing wind/solar generation and that which is built in the early years of the study will be retired before the end of the horizon.

The timing of future generation retirements is uncertain, and the assumptions above reflect the best information available at the time of our last assumptions book update. We note that since this time:

- Fonterra have announced the staged decommissioning of the Whareroa and Edgecumbe co-generation plants (Hawera and Edgcmb in Table 5) with a planned retirement in

2026[28]. We considered updating our modelling assumptions to align with this earlier retirement, however, we have elected not to as we judged this assumption to not be material to our benefits modelling. This is because the grid injection of these cogeneration plants is significantly less than their nameplate capacities, and their retirement will be compensated for with other generation build in our modelling,

- An agreement has been reached between Genesis, Mercury, Meridian, and Contact to establish a strategic energy reserve at the Huntly Power Station[29]. This agreement is still subject to regulatory approval, but if approved, it is likely to extend the operation of the Huntly Rankine units (HuntC1, HuntC2, HuntC4 in Table 5) to 2035. We considered updating our modelling to align with this emerging agreement, however the extension of the Rankine units is likely to be compensated for by an earlier retirement of gas generation (e.g the 403 MW E3p gas turbine generator at Huntly)[30]. This is because the Rankine units can run on coal and so the Rankine extension is a consequence of a deteriorating gas supply situation.

4.5 Committed generation and BESS

In our generation expansion modelling we include 'committed' generation and grid scale battery projects which we judge as likely to proceed. The timing of these builds is exogenously specified in the generation expansion model based on publicly reported development schedules, or expert judgment. The criteria for classifying a project as 'committed' are specified in the clause D8(1) in the Capex IM.[31]

The assumed committed generation for this project is summarised in Table 6[32]. Our assessment is that there is considerable committed generation development underway, and we expect over 1,000 MW of this generation, and 300 MW of BESS to be installed in the 2025, 2026 and 2027 calendar years.

Table 6: Committed generation and BESS projects

Commissioning year	Generation type	Name	Installed capacity (MW)
2024	Geothermal	Tauhara2a	174
2024	Solar	RangitaikiLS	32

28 Fonterra submission on Transpower HVDC Link Upgrade - June 2025.pdf.
29 Agreements signed, Huntly capacity to support national energy security | Genesis NZ.
30 Fonterra advised that the baseload gas thermal generation plant availability post-2030 should be revisited as there remains a strong likelihood that baseload gas thermal plant will be fully decommissioned by 2030. Fonterra submission on Transpower HVDC Link Upgrade - June 2025.pdf
31 Transpower Input Methodologies Determination - consolidated as of 23 April 2024.
32 Note that the committed build is specified from 1 Jan 2023 and includes projects which have now been commissioned. The reason for this is we normally begin our modelling on 1 Jan 2023 to give a period for the model to set up a representative hydro storage.

Commissioning year	Generation type	Name	Installed capacity (MW)
2024	Wind	Harapaki	176.3
2024	Wind	KaiwDwns1	43
2025	BESS	Ruakaka	100
2025	Geothermal	TeHuka	51.4
2025	Solar	Solar_ASB_1	47
2025	Solar	Lodestone3	35
2026	BESS	Glenbrook_2h	100
2026	Geothermal	Ngatamariki2	46
2026	Geothermal	Kawerau2	50
2026	Solar	Solar_WHU_1	147
2026	Solar	FNSF_WAI	58
2026	Solar	Helios_EDG	115
2026	Solar	Solar_DVK_1	25
2026	Solar	Solar_EDG_1	29
2026	Solar	Solar_OHW_1	119
2026	Solar	Solar_OHW_2	152
2026	Solar	KowhaiPark	150
2026	Solar	Whitiannga	24

Commissioning year	Generation type	Name	Installed capacity (MW)
2027	BESS	HLY_PS2h	100
2027	Solar	Solar_BRB_1	120
2027	Solar	RangitaikiT1	150
2027	Wind	KaiwDwns2	155
2027	Wind	Kaiwaikawe	77

4.6 Potential generation

There is significant potential for the development for additional wind, solar, geothermal, thermal, and hydro generation projects in New Zealand. Potential geothermal and thermal projects are known for the North Island, but there is excellent potential for other generation types in both islands.

4.6.1 Generation stack

Our generation stack is a list of candidate projects which are included in the generation expansion model. The model determines a capacity expansion plan from these candidate projects based on a least cost optimisation condition (i.e., the capacity expansion plan provides the lowest cost mix of generation which can meet demand).

Table 7 summarises the generation candidate projects which are included in our generation stack across all regions of New Zealand. The basis for our generation stack is the generation stack reports procured by MBIE in 2020[33]. We have expanded this stack with other projects as we become aware of them.

33 New Zealand generation stack updates | Ministry of Business, Innovation & Employment (mbie.govt.nz)

Table 7: Generation stack summary (with costs expressed in 2021-dollar[34] values)

Island	Type	Capacity (MW)	Minimum capital cost ($/kW)	Maximum capital cost ($/kW)
North Island	BESS	7,679	1,451	4,424
	Geothermal	1,274	4,930	9,767
	Hydro	200	5,100	5,100
	Solar	8,770	1210	1,692
	Thermal	2,960	1,542	1,542
	Wind	10,675	1,685	3,042
South Island	BESS	2,780	1,451	4,424
	Hydro	2,086	5,100	5,100
	Solar	7,214	1210	1,534
	Wind	4,047	1,685	2,602

34 SDDP produces values in 2021-dollar values which we inflate to 2025-dollars for the Investment Test

Appendix A: Proposed EDGS and BBC Assumptions Book variations

Below we summarise the main EDGS and BBC Assumptions Book variations we intend to use with this project.

EDGS variations

Table 8: Demand variations

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>Tiwai closure</td><td>Tiwai stays open in all scenarios. The reference scenario has a sensitivity case where Tiwai closes in 2030.</td><td>Tiwai remains operational in all scenarios.</td><td>A range of foreseeable futures are covered by EDGS scenarios.</td></tr>
<tr><td>Base energy growth rate</td><td><table><tr><td>Scenario</td><td>CAGR (%)[35]</td></tr><tr><td>Reference</td><td>0.8</td></tr><tr><td>Growth</td><td>1.2</td></tr><tr><td>Global</td><td>0.2</td></tr><tr><td>Environmental</td><td>0.9</td></tr><tr><td>Disruptive</td><td>0.7</td></tr></table></td><td><table><tr><td>Scenario</td><td>CAGR (%)</td></tr><tr><td>Reference</td><td>0.5</td></tr><tr><td>Growth</td><td>0.7</td></tr><tr><td>Global</td><td>0.1</td></tr><tr><td>Environmental</td><td>0.6</td></tr><tr><td>Disruptive</td><td>0.4</td></tr></table></td><td>Consistent with NZGP1</td></tr>
<tr><td>Electrification of Process heat</td><td>2050 energy demand:<table><tr><td>Scenario</td><td>2050 demand by temperature (TWh)</td></tr><tr><td>Reference</td><td>Low: 1.2</td></tr><tr><td>Growth</td><td>Low: 1.9</td></tr><tr><td>Global</td><td>Low: 1.2</td></tr><tr><td>Environmental</td><td>Low: 1.9
Med: 4.6</td></tr><tr><td>Disruptive</td><td>Low: 1.9
Med: 4.9
High: 6.5</td></tr></table></td><td>2050 energy demand:<table><tr><td>Scenario</td><td>2050 demand by temperature (TWh)</td></tr><tr><td>Reference</td><td>Low: 4</td></tr><tr><td>Growth</td><td>Low: 5.1</td></tr><tr><td>Global</td><td>Low: 3.2</td></tr><tr><td>Environmental</td><td>Low: 5.1
Med: 3</td></tr><tr><td>Disruptive</td><td>Low: 5.1
Med: 3.2
High: 0</td></tr></table>Process heat electrification has been modelled using an updated S-curve.</td><td>The amount of low and medium temperature process heat is consistent with NZGP1. Conversion of high temperature heat has since been removed. High-temperature process heat is highly localised to specific regions, so we believe it is best to assess these on a case-by-case basis. A S-curve has been used to better reflect the likely path of electrification.</td></tr>
</table>

35 Compound Annual Growth Rate.

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>EV demand</td><td>2050 energy demand by scenario (No assumptions around smartness given)
<table>
<tr><td>Scenario</td><td>2050 EV demand (TWh)</td></tr>
<tr><td>Reference</td><td>4.1</td></tr>
<tr><td>Growth</td><td>5.0</td></tr>
<tr><td>Global</td><td>3.2</td></tr>
<tr><td>Environmental</td><td>7.6</td></tr>
<tr><td>Disruptive</td><td>7.6</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>2050 EV demand by smartness (TWh)</td></tr>
<tr><td>Reference</td><td>Fixed: 3.2
Smart: 2.3</td></tr>
<tr><td>Growth</td><td>Fixed: 3.2
Smart: 3.5</td></tr>
<tr><td>Global</td><td>Fixed: 3.3
Smart: 0.9</td></tr>
<tr><td>Environmental</td><td>Fixed: 3.5
Smart: 5.6</td></tr>
<tr><td>Disruptive</td><td>Fixed (Light): 3.4
Smart (Light): 5.6
Fixed (Heavy): 1.7</td></tr>
</table></td><td>Consistent with NZGP1 with minor updates.</td></tr>
<tr><td>EV charging smartness</td><td>Not specified</td><td>Smartness by 2050:
<table>
<tr><td>Scenario</td><td>Smartness by 2050 (%)</td></tr>
<tr><td>Reference</td><td>40</td></tr>
<tr><td>Growth</td><td>50</td></tr>
<tr><td>Global</td><td>20</td></tr>
<tr><td>Environmental</td><td>60</td></tr>
<tr><td>Disruptive</td><td>50</td></tr>
</table></td><td>The smartness in all scenarios except the Disruptive scenario is consistent with NZGP1. The smartness in the Disruptive scenario is set to 50% to better reflect uncertainties in EV charging.</td></tr>
<tr><td>Solar generation</td><td><table>
<tr><td>Scenario</td><td>Generation in 2050 (TWh)</td></tr>
<tr><td>Reference</td><td>3.1</td></tr>
<tr><td>Growth</td><td>3.9</td></tr>
<tr><td>Global</td><td>1.1</td></tr>
<tr><td>Environmental</td><td>6.4</td></tr>
<tr><td>Disruptive</td><td>6.4</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>Generation in 2050 (TWh)</td></tr>
<tr><td>Reference</td><td>2.3</td></tr>
<tr><td>Growth</td><td>2.8</td></tr>
<tr><td>Global</td><td>0.9</td></tr>
<tr><td>Environmental</td><td>4.6</td></tr>
<tr><td>Disruptive</td><td>4.6</td></tr>
</table></td><td>Consistent with NZGP1</td></tr>
<tr><td>Residential solar uptake</td><td><table>
<tr><td>Scenario</td><td>Number of 3 kW solar installations in 2050</td></tr>
<tr><td>Reference</td><td>531,620</td></tr>
<tr><td>Growth</td><td>655,330</td></tr>
<tr><td>Global</td><td>190,210</td></tr>
<tr><td>Environmental</td><td>1,076,300</td></tr>
<tr><td>Disruptive</td><td>1,076,300</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>Number of 3 kW solar installations in 2050</td></tr>
<tr><td>Reference</td><td>797,420</td></tr>
<tr><td>Growth</td><td>983,000</td></tr>
<tr><td>Global</td><td>285310</td></tr>
<tr><td>Environmental</td><td>1,614,440</td></tr>
<tr><td>Disruptive</td><td>1,614,440</td></tr>
</table></td><td>Consistent with NZ GP1</td></tr>
</table>

While not part of the EDGS assumptions, our demand forecasts for this project reflect:

- Updated information on step changes
- Updated historical demand
- Updated Base peak demand across all scenarios to be more in line with EDB's GXP level forecasts.

Table 9: Generation variations

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>Generation stack</td><td>Details in generation stack not specified e.g., capital costs, named projects, capacity factor</td><td>Incorporate information from the 2020 generation stack updates, recent Transpower connection queries and news articles as outlined above.</td><td>To incorporate newer and more detailed information.</td></tr>
<tr><td>Wind repowering</td><td>Wind repowering not mentioned in EDGS</td><td>Assume that all existing wind farms are repowered at the end of their 30-year lifetime (with increased capacity), or earlier if indicated by developers.</td><td>Assumption is consistent with those specified in the BBC Assumptions Book 2.0.</td></tr>
<tr><td>BESS (batteries)</td><td>Grid scale batteries not mentioned in EDGS</td><td>Include two, four and eight-hour batteries in our generation stack, based on cost information from NREL.</td><td>To add an alternative peaking option. Assumption is consistent with the BBC Assumptions Book 2.0.</td></tr>
<tr><td>New generation cost decline</td><td>LRMC changes by 2050 are specified for wind and solar generation.

<u>Solar</u>
<table>
<tr><td>Scenario</td><td>Change</td></tr>
<tr><td>Reference</td><td>-50%</td></tr>
<tr><td>Global</td><td>-50%</td></tr>
<tr><td>Disruptive</td><td>-45%</td></tr>
</table>
<u>Wind</u>
<table>
<tr><td>Scenario</td><td>Change</td></tr>
<tr><td>Reference</td><td>-13%</td></tr>
<tr><td>Global</td><td>-7%</td></tr>
<tr><td>Disruptive</td><td>-27%</td></tr>
</table></td><td>Use future cost decline scenarios from National Renewable Energy Laboratory's (NREL's) 2023 annual technology baseline (ATB) to scale capital and fixed O&M (FOM) costs of generation stack projects. Wind, solar, geothermal and BESS projects costs are scaled and the cost decline is varied by scenario. The change in the costs by 2050 compared with 2021 are given in the tables below.

<u>Solar</u>
<table>
<tr><td></td><td>FOM change</td><td>CAPEX change</td></tr>
<tr><td>Environmental Disruptive</td><td>-50%</td><td>-63%</td></tr>
<tr><td>Reference Growth</td><td>-23%</td><td>-58%</td></tr>
<tr><td>Global</td><td>-13%</td><td>-47%</td></tr>
</table>
<u>Wind</u>
<table>
<tr><td>Scenario</td><td>FOM change</td><td>CAPEX change</td></tr>
</table></td><td>Assumption is consistent with the BBC Assumptions Book 2.0.</td></tr>
</table>

		Environmental Disruptive -53% -38% Reference Growth -48% -31% Global -38% -15%	
Geothermal emission	Not mentioned in EDGS but provided in 2020 geothermal generation stack.	Reduce emission rates from geothermal generation stack by 50% in the Growth scenario.	To account for the potential of CO2 reinjection.
Biofuel	Not mentioned in EDGS.	Add biofuel as a potential fuel source in our thermal generation stack	To add an alternative dry year and peaking option.
Long-term carbon price	NZ$66/t by 2050, except Environmental scenario (NZ$154/t by 2050)	For the Growth and Disruptive scenarios, we use long-term carbon prices from CCC[36] i.e., NZ$250/t by 2050. For the Environmental scenario we use the carbon price from the International Energy Agency's Net Zero Emissions scenario[37]. For the Global and Reference scenarios we assume the carbon prices falls to a floor of $44/tCo2. This is based on MBIE's 2024 EDGS assumptions.	Significant diversity in future carbon prices. Assumption is consistent with the BBC Assumptions Book 2.0

36 Climate Change Commission Demonstration Path
37 Net Zero Emissions by 2050 Scenario (NZE) – Global Energy and Climate Model – Analysis - IEA

BBC Assumptions Book variants

A summary of the main variants to the Assumptions Book are provided below:

Table 9: Assumption Books variations

Assumptions Book Paragraph / Section	BBC Assumptions Book, Version 2.0	Variation	Rational
2.3.4.9	Taranaki Combined Cycle (TCC) generator retires in 2025	TCC retires in 2026	Updated market information[38]
	Reserves are not modelled	Instantaneous reserves are modelled	Reserves are relevant for this investigation due to their interaction with the HVDC.
2.3.2.2	Assume HVDC limits of 1400 MW north and 950 MW south from 2032	Assume HVDC limits of 1400 MW north and 950 MW south from 1 April 2031 for investment option 3. Assume transfer capacities for other investment options as detailed in Attachment 6.	Targeted installation date for replacement submarine cables.
2.3.4.3	Whirinaki and Stratford peakers are modelled as single plants, with a min generation of 0 MW	Whirinaki and Stratford peakers are modelled as units (e.g., 3 Whirinaki and 2 Stratford units), each with a min generation of 5 MW	To support reserve modelling. Each of the units can provide reserves, but they need to be generating to do so.
2.3.8.3	Future thermal plants OTOpeaker_s1, OTOpeaker_s2, OTOpeaker_s3 have a minimum generation of 0 MW	Future thermal plants OTOpeaker_s1, OTOpeaker_s2, OTOpeaker_s3 have a minimum generation of 5 MW	To support reserve modelling. Each of the units can provide reserves, but they need to be generating to do so.

38 https://contact.co.nz/-/media/contact/mediacentre/2024/contact-to-keep-tcc-available-in-2025.ashx?la=en

Assumptions Book Paragraph / Section	BBC Assumptions Book, Version 2.0	Variation	Rational
2.3.4.6	Retirement of new wind farms (2023 onwards) is not considered	New wind farms are retired after 30 years of operation.	As the generation expansion and dispatch modelling extends to 2060 it is necessary to consider plant end-of-life.
2.3.4.7	Retirement of solar farms is not considered	Solar farms are retired after 25 years of operation.	As the generation expansion and dispatch modelling extends to 2060 it is necessary to consider plant end-of-life.
2.3.4.8	Retirement of BESS is not considered	BESS is retired after 15 years of operation.	As the generation expansion and dispatch modelling extends to 2060 it is necessary to consider plant end-of-life.
2.3.8.8	Solar plants are paired with BESS	Solar plants are not paired with BESS.	Explicit modelling of reserves provides additional revenue stream for BESS reducing the rationale for pairing BESS with solar.
2.3.8.8	In the Disruptive scenario we reduce BESS costs by an additional 50% below the NREL Advanced cost decline scenario.	The Disruptive scenario BESS costs are not discounted below the NREL Advanced cost decline scenario	The discounting was to proxy the additional value that BESS can offer through ancillary services. This is not relevant as we are directly modelling reserves for this investigation.
2.3.8.2	Committed generation build is specified	Assume updated committed build as detailed in Section 4.5	Incorporate recent market announcements from developers.
2.3.8.2	Transpower connection pipeline BESS projects classified as 'Application received' can be built by Optgen 3 years after current year (2025)	Transpower connection pipeline BESS projects classified as 'Application received' AND all 2hr and 4hr BESS which can provide reserves can be built by Optgen 3 years after current year (2025).	It is only practical to model a subset of BESS projects as reserve backing. Assume that these BESS projects can be built as early as other BESS.

Assumptions Book Paragraph / Section	BBC Assumptions Book, Version 2.0	Variation	Rational
2.3.8.5	We assume future geothermal plants Te Mihi 2 and Te Mihi 3 are 100 MW in capacity and cost $5440/kW (2021 NZD) with an emissions factor of 21 gCO2eq./kWh. For the Growth scenario the Capex is 4352 $/kW and 10.5 gCO2e/kWh.	We assume future geothermal plants Te Mihi 2 and Te Mihi 3 are 101.4 MW in capacity and cost $5973/kW (2021 NZD) with an emissions factor of 2.2 gCO2eq./kWh For the Growth scenario the Capex is 4778 $/kW and 1.09 gCO2e/kWh.	Align with market announcement by developer Contact Energy[39]
2.3.4.5	The aggregate generation from the Wairākei fields is unchanged following the commissioning of Te Mihi 2	The aggregate generation from the Wairākei fields increases by 30.4 MW following the commissioning of Te Mihi 2	Align with market announcement by developer Contact Energy
2.3.8.6	The capacity of the potential future wind farm Kaiwaikawe is 73 MW	The capacity of the potential future wind farm Kaiwaikawe is 77 MW	Align with market announcement by developer Mercury[40]

39 NZX market announcement - Contact Energy

40 NZX market announcement - Mercury Energy

Appendix B: Demand forecast data

For each of the demand forecast figures presented in section 3, we have provided the raw data in a spreadsheet.

HVDC - Attachment 2 - Appendix B - Demand figure data.xlsx

TRANSPOWER