TRANSPOWER

Net Zero Grid Pathways 1

Major Capex Project (Staged) Investigation

Long-list consultation and non-transmission solution request for information

Date: 20/8/21

Executive Summary

Purpose of this document

This document discusses our current investigation into options to enable the efficient dispatch of new generation and reliable supply of future demand growth over the interconnected grid.

This investigation is a part of our Net Zero Grid Pathways (NZGP) project, to support New Zealand's pathway towards greater renewable electricity generation and electrification of our energy consumption in our pursuit of being net-zero carbon by 2050.

We seek feedback on our long list of options to meet the need, our approach to reducing that to a short-list and assumptions we will use to analyses the short-list.

Background

Electricity demand will increase as we transition away from fossil-fuel based energy consumption. Electricity generation will increase to meet this growth in demand and at the same time our fossil-fuelled generation will be replaced by renewables (hydro, geothermal, wind and solar).

Transpower sees itself as having a role in enabling that future, by ensuring parties can connect to the transmission grid where and when they want. This investigation relates to our enabling role.

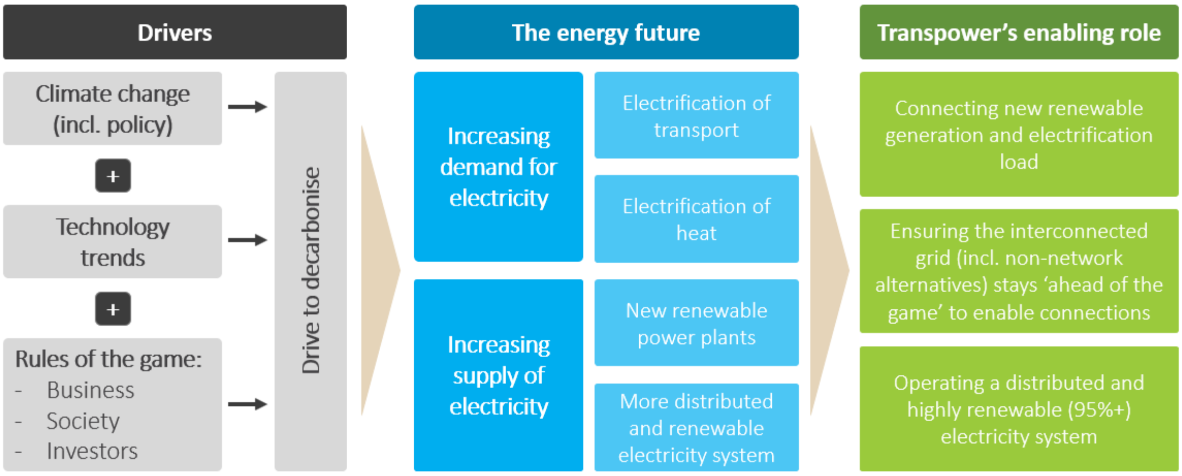

Figure 0-1 – Transpower's enabling role in support of New Zealand pursuing net-zero carbon by 2050

We are undertaking NZGP in two phases. Phase 1 is focused on the timeframe to 2035 and is primarily considering enhancing the grid backbone, either through upgrades to existing routes or where justified, new transmission lines[1]. We are keen to ensure New Zealand's transmission grid will be fit for purpose and our priority is to ensure the grid backbone is fit for a range of possible futures. Phase 2 will look out to 2050 and will look to identify how the grid backbone needs to develop to provide the require reliability and resilience with added routes that enable future connections. We will start engaging with industry on Phase 2 later in 2022.

The output from the NZGP project will be a long-term transmission plan, showing how we envisage the transmission system being developed between now and 2050. This is important information for

[1] We use the term grid backbone, rather than core grid, on purpose. Although similar, "core grid" has a very specific and slightly different meaning under the Electricity Industry Participation Code (EIPC).

potential new electricity demand and generation investors as it provides surety about future transmission grid capacity.

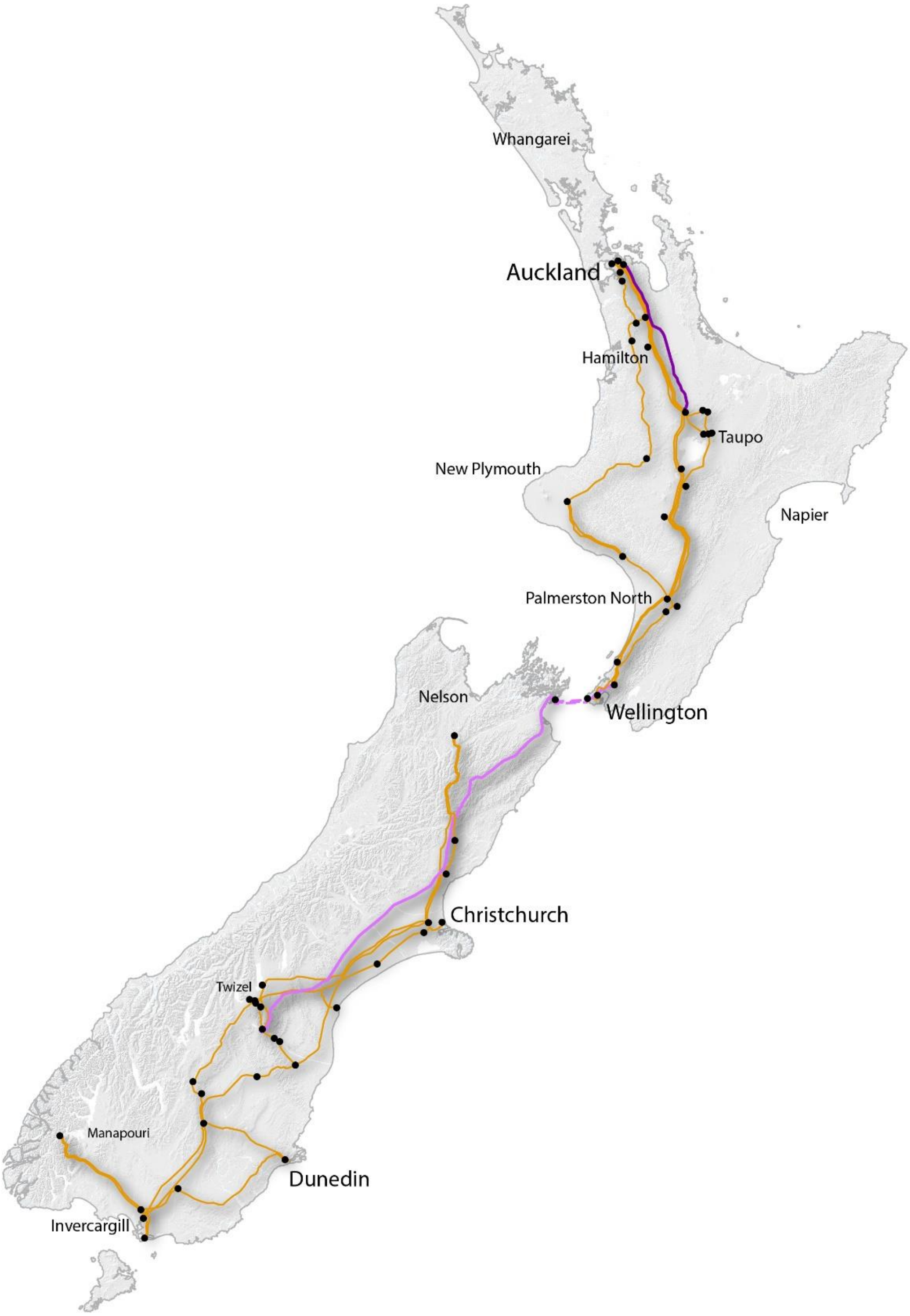

Figure 0-2 – New Zealand transmission grid backbone – the focus of NZGP Phase 1

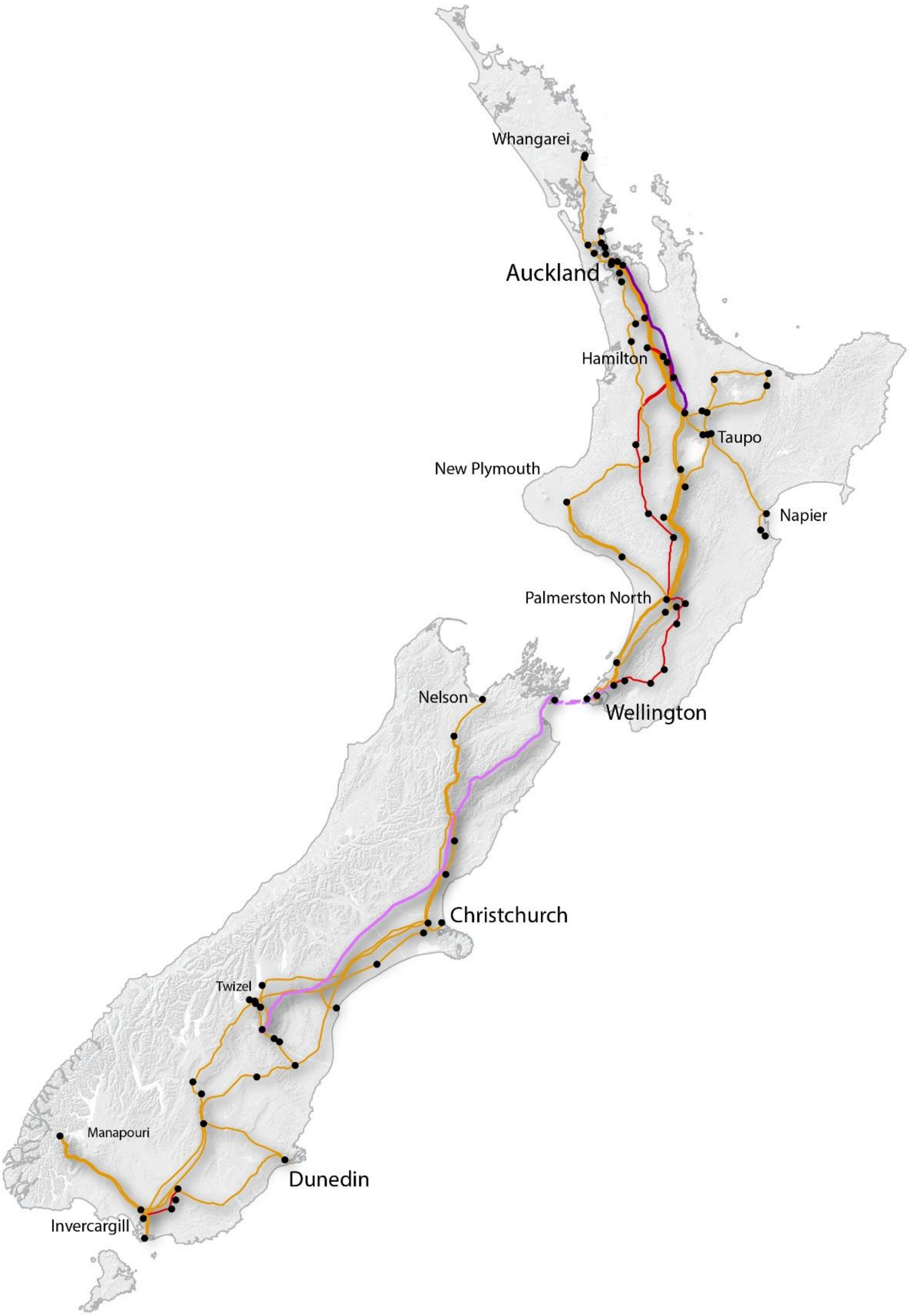

Figure 0-3 – New Zealand transmission grid backbone and interconnected regional grids – the focus of NZGP Phase 2

Work undertaken in late 2020 identified that the grid backbone across Cook Strait and as far north as Whakamaru (including the Wairakei Ring), is likely to constraint first as electricity demand and generation grows.

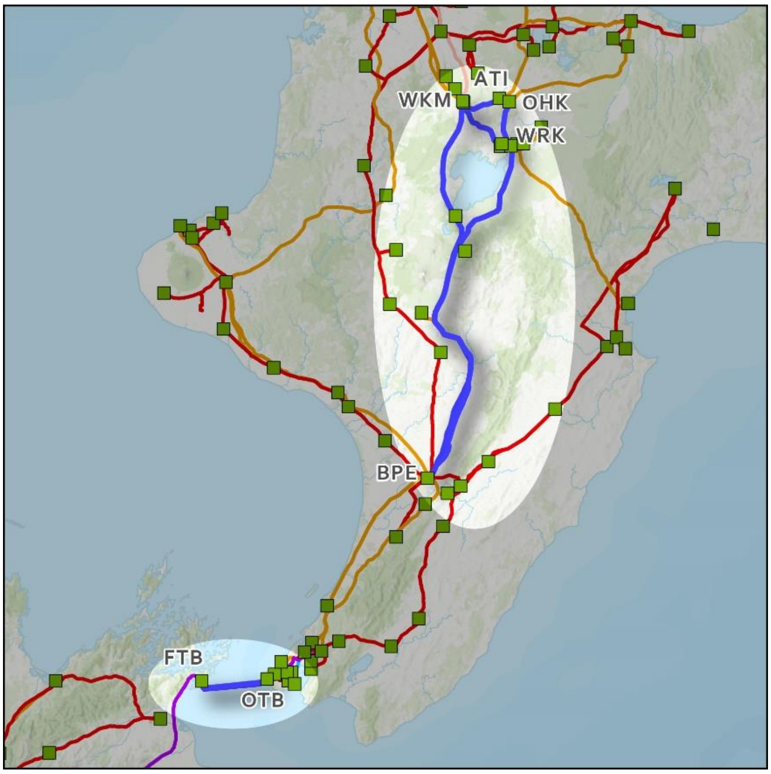

Figure 0-4 – Those parts of the grid backbone (in blue) which constrain first as electricity demand and generation grow

The entire grid backbone in that region does not constrain, but capacity across Cook Strait (the High Voltage Direct Current (HVDC) link between the North Island and South Island), the 220kV grid between Bunnythorpe and Whakamaru (CNI) and the 220kV grid around the Wairakei Ring all constrain at similar times[2].

Recognising that the cost of relieving this constraint will exceed $20 million, we are undertaking this investigation consistent with the requirements for a major capex project (staged) (MCP), as defined by the Commerce Commission in their Capital Expenditure Input Methodology (Capex IM)[3].

The investment need is to **enable the efficient dispatch of new generation and reliable supply of future demand growth over the interconnected grid**.

There are two main approaches to relieving the overall constraint in this part of the grid. One is to consider new transmission options which largely bypass the existing grid between the top of the South Island and Whakamaru (including the Wairakei Ring) and the second is to consider upgrading parts of the existing grid. This may be more beneficial. The existing grid between Haywards and Bunnythorpe does not constrain over our time horizon and is already matched in capacity to enhanced Cook Strait HVDC capacity.

Cook Strait cable capacity, the grid between Bunnythorpe and Whakamaru and the grid around the Wairakei Ring all constrain as new generation is developed but may reach their limits at different years in the future. Our investigation will consider the work required to these parts of the grid individually, but our analysis will consider them collectively, acknowledging their interdependency.

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[2] Some parts of the 110kV network in the lower and central North Island also constrain. These will be dealt with separately and are assumed to be in place for the purposes of this investigation.

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

The investigation will require a common set of assumptions and as required by the Capex IM, our analysis will be based upon variations of the current Electricity Demand and Generation Scenarios (EDGS) developed by the Ministry of Business, Innovation and Employment (MBIE).

We began developing EDGS variations in 2020 and a summary document describing our consultation process and conclusions will be published on our website shortly.

This long-list document is:

- a consultation with interested parties on the key assumptions to be used in the investigation
- a draft long list of options to address the need for investment
- a request for information (RFI) for non-transmission solutions (NTS), which could defer or replace the need for investment in transmission.

We are calling the MCP investigation NZGP1, because it is possible that more investment opportunities, potentially requiring further investigation through major capex projects, will be identified as the project progresses.

We are investigating both transmission and NTS to meet the need.

Our draft long-list of options includes both short-term solutions, which could be implemented quickly, and which would provide enhanced transmission capacity for up to 5 years and long-term solutions which may take longer to implement, but which provide more enhanced transmission capacity. Any proposal to the Commerce Commission may include a mixture of short-term and long-term solutions. Apart from being relatively quick to implement, the short-term solutions may be least-regrets, in that they defer higher levels of capital, allowing some uncertainties time to resolve, or at least become clearer before we need to commit to that capital.

The stages for this MCP, as notified to the Commerce Commission, are:

- HVDC capacity
- CNI capacity; and
- Wairakei Ring capacity

Those stages are based on the possibility that upgrading parts of the existing grid will be more beneficial than a new transmission option bypassing the existing grid. If the latter turns out to be the most economic, we do have flexibility, under the Capex IM, to change the stages notified to the Commerce Commission.

Process to date

Under the Capex IM, we are required to submit an application to the Commerce Commission if we want to recover the full costs of a MCP from our customers. This document is intended to meet the requirements of a long-list consultation, as described in Schedule I of the Capex IM.

Non-transmission solutions

Transpower is committed to the consideration of NTS in our investment decisions. Some of the need could be met by, or components could be provided as NTS through, a grid support contract with Transpower.

This consultation paper is also an RFI for NTS to meet the identified needs. Specific information, relevant to some forms of NTS, is included in Appendix D.

Demand and generation forecasts

We propose using the demand forecasts and generation scenarios outlined in this document as the basis for our analysis.

Our scenarios are based on the EDGS as published by the MBIE. Our proposed scenarios are variations of the EDGS, to ensure the scenarios are up to date, are relevant to the regions of interest and to reflect the latest information about likely new generation projects.

This consultation

We will provide updates on this project on our website: www.transpower.co.nz. Following consultation, we will:

- publish the submissions on www.transpower.co.nz. Unless otherwise requested by you, we will include both your name and your full submission on the website
- consider the feedback received in submissions
- develop a short-list of options taking account of the information received in response to this consultation
- if appropriate, request more detail of viable non-transmission solutions from proponents. This will be via a Request for Proposal (RFP) that will include more detail of our requirements
- evaluate the short-list of options in a manner consistent with the Commerce Commission's Investment Test (IT)
- identify a preferred option if any options pass the IT
- consult on our application of the IT and preferred option
- submit an MCP application to the Commerce Commission, if required.

Your feedback

We seek written feedback by 1 October 2021. Responses should be in electronic form, in either Microsoft Word or PDF format, and emailed to nzgp@transpower.co.nz.

If there is any aspect of your submission that is confidential, please:

- clearly mark the sections you consider confidential and indicate why,
- indicate whether we can share the confidential information with the Commerce Commission.

Transparency is important in this process and we may not be able to rely on confidential information to justify an investment proposal.

A number of questions are asked throughout this document and these are summarised below. These are intended to aid your response. You are not obliged to answer all or any of these questions and are welcome to raise other issues, which you believe might be relevant.

We will acknowledge all submissions. Please note late submissions may not be considered.

Table 0-1 – Consultation questions

No.	Question	Relevant section
1	Is our need description for this investigation reasonable?	**1.1**
2	Should Transpower be looking to enable investment in new generation and demand ahead of when that generation or demand is confirmed?	**1.1**
3	Are our long-list options (B1 and B2 in Table 3.1) to meet the overall need for this investigation, reasonable?	**3.1**
4	Are our long-list options for enhancing capacity of the HVDC reasonable?	**3.2**
5	Are our long-list options for enhancing capacity of the CNI 220kV corridor reasonable?	**3.3**
6	Are our long-list options for enhancing capacity of the Wairakei Ring reasonable?	**3.4**
7	Are there other criteria we should consider when evaluating our long- list of options and reducing it to a short-list?	**4.1**
8	Is our process for developing relevant scenarios reasonable?	**5.2**
9	Are our proposed NZGP1 demand forecasts reasonable?	**5.4**
10	Is our proposal to identify base scenarios and sensitivity scenarios reasonable?	**5.5**
11	Is our process for identifying potential generation scenarios reasonable?	**5.5**
12	Is our approach to determining an appropriate number of scenarios reasonable?	**5.5**
13	Is our choice of scenarios to include in our analysis reasonable?	**5.6**
14	Is our set of sensitivity scenarios reasonable?	**5.7**
15	Is our approach to determining the weighting for each scenario appropriate?	**5.8**
16	Would interested parties support the use of a discount rate for Investment Test analysis, closer to Transpower's current WACC?	**5.9**
17	Are there any other costs or benefits we should consider in our Investment Test analysis?	**5.9**

Contents

1.0 Need for investment

1.1 Existing system

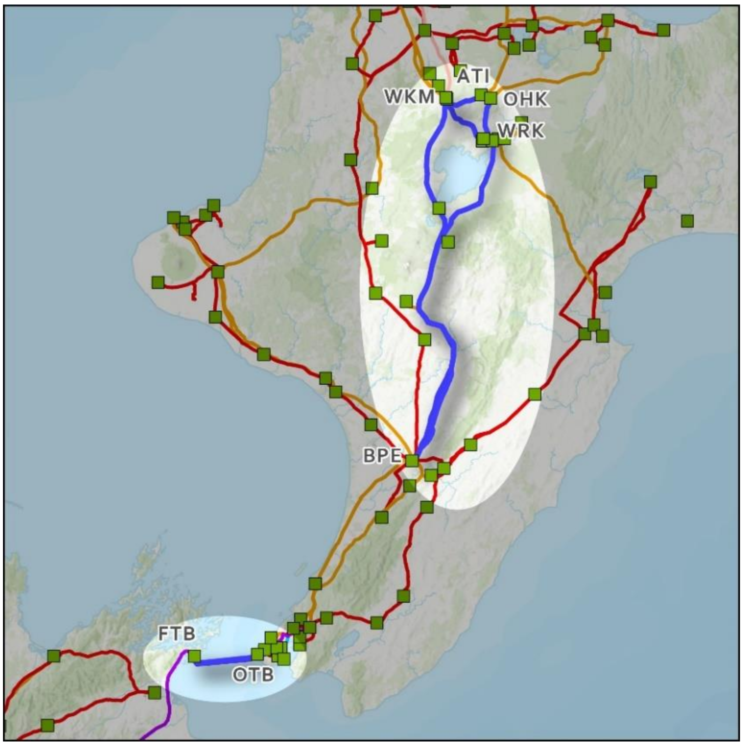
In this section we discuss the existing system and its capabilities.

Net Zero Grid Pathways (NZGP) Phase 1 is focused on identifying and investigating potential constraints on the grid backbone to enable the efficient dispatch of new generation and reliable supply of future demand growth over the interconnected grid, for the period out to 2035. This is our investment need.

In December 2020, we undertook work[4] to consider the effect of Rio Tinto's announcement to wind-down, and eventually close, the Tiwai Point aluminium smelter (Tiwai), on the transmission system. That study identified transmission constraints on the High Voltage Direct Current (HVDC) link and the North Island 220kV Alternating Current (AC) network between Bunnythorpe and Whakamaru (CNI) as being the most restrictive and relieving them would provide the highest benefit to consumers.

Although Tiwai closure has now been deferred, it will still likely to have a significant effect when it does occur, and we need to be as prepared as possible. Also, as explained later in this document, we have consulted with generation investors on where new generation might be built between now and 2050 and approximately 2/3 is likely to be built south of Whakamaru or be connected on our Wairakei Ring 220kV network.

Therefore, we are investigating the transmission constraints identified in our December 2020 work in this investigation, along with the Wairakei Ring. Together, they potentially result in an overall constraint, between the top of the SI and Whakamaru, including the Wairakei Ring.



[4] Accessing Lower South Island Renewables December 2020.pdf

Figure 1-1 – The existing transmission network between the top of the South Island and Whakamaru, including the Wairakei Ring

This investigation will consider a single solution for this part of the entire network, as well as upgrading individual parts of the existing grid. With an expectation that upgrading individual parts of the existing grid may be the most beneficial, we have advised the Commerce Commission (Commission) that this investigation is for a Major Capex Project (staged) (MCP). This will best allow us to take a least regrets approach and commit to significant expenditure with the maximum amount of certainty. The stages for this MCP, as notified to the Commerce Commission, are:

- HVDC capacity
- CNI capacity; and
- Wairakei Ring capacity

The rest of this section comprises a description of the HVDC link, the 220kV transmission between Bunnythorpe and Whakamaru and the Wairakei Ring. These descriptions are abbreviated, and more information can be found in our Transmission Planning Report[5].

> **Question 1:** Is our need description for this investigation reasonable?
>
> **Question 2**: Should Transpower be looking to enable investment in new generation and demand ahead of when that generation or demand is confirmed?

1.11 HVDC

The HVDC link is a key component of the New Zealand transmission network. The existing HVDC link comprises on:

- Two ± 350 kV thyristor bipole converters, Pole 2 rated at 700 MW and Pole 3 rated at 780 MW, with converter stations and protection and control systems at Benmore in the South Island and Haywards in the North Island. *(these are the continuous ratings offered to the market).*
- Two 350 kV bipolar transmission lines. These comprise a 535 km length from Benmore to Fighting Bay (on the shore of Cook Strait in the South Island) and a 37 km length from Oteranga Bay (on the shore of Cook Strait in the North Island), to Haywards
- Three 350 kV, 500 MW, 40 km long undersea cables, with cable terminal stations at Fighting Bay and Oteranga Bay
- A land electrode at Bog Roy near Benmore in the South Island and a shore electrode at Te Hikowhenua near Haywards in the North Island
- AC filters to reduce harmonic distortion and provide static reactive support at both Benmore and Haywards
- Eight synchronous condensers and a STATCOM at Haywards to supplement the dynamic reactive support available from the AC transmission system.

[5] Link to the Transmission Planning Report 2020 | Transpower

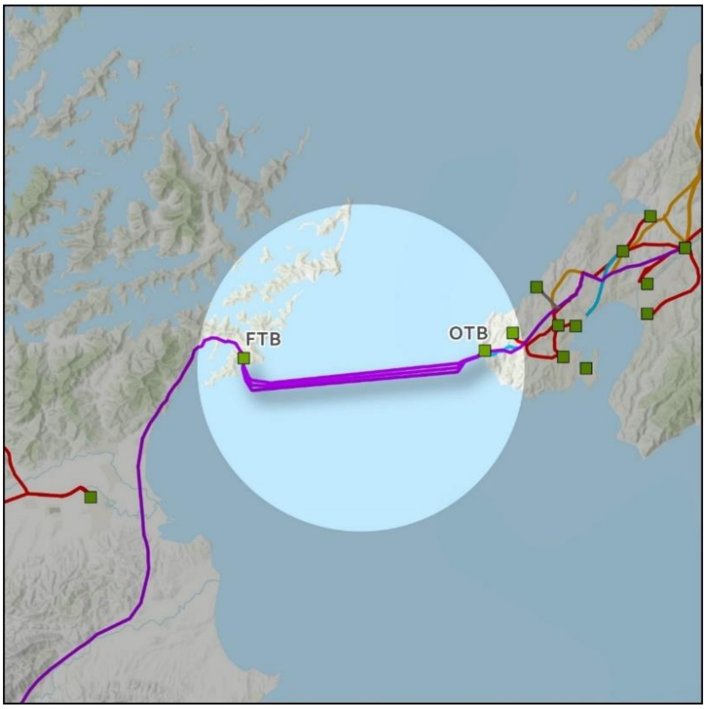


Figure 1-2: Geographic view of the HVDC Cook Strait link

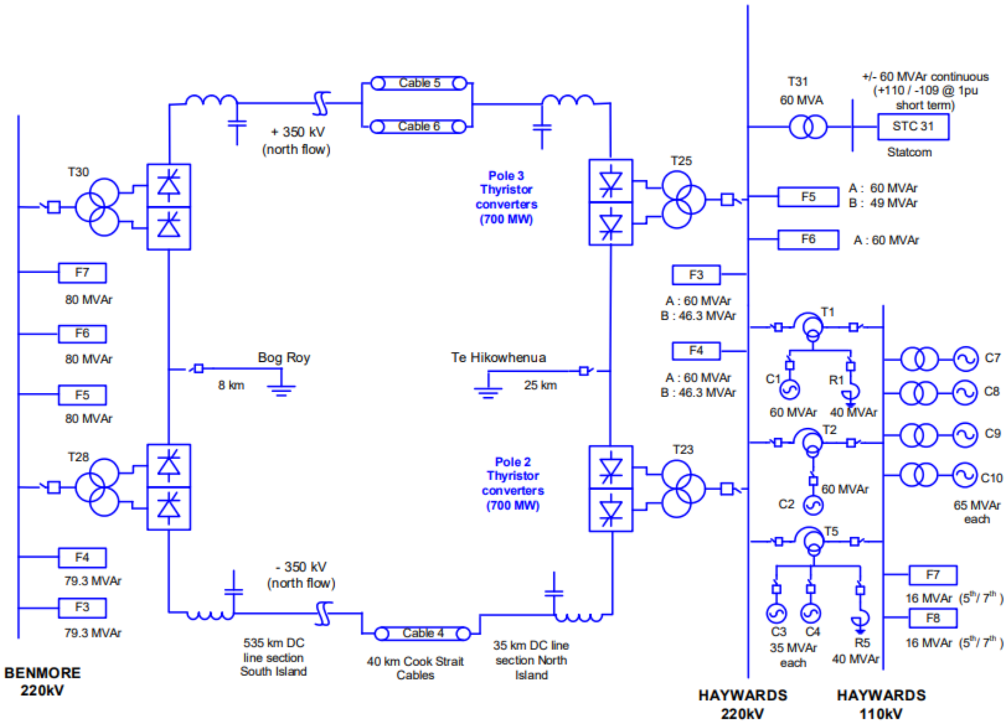


Figure 1-3: Simplified schematic of the existing HVDC link

1.12 Central North Island (CNI)

The CNI 220 kV transmission system consists of the 220 kV Bunnythorpe–Whakamaru A and B lines and the 220 kV Bunnythorpe–Wairakei A line.

The direction of power flow through the region, north or south, is determined by generation, direction of HVDC flow and demand outside of the region.

These 220 kV circuits form part of the grid backbone. The lower North Island also has a 110kV network, which is mainly supplied through the 220/110 kV interconnecting transformers at Bunnythorpe.

The CNI region is a main corridor for 220 kV transmission circuits through the North Island. This corridor connects the Central North Island to the Wellington region to the south, the Taranaki region to the west, the Waikato region to the north, and the Hawke's Bay region to the east.

A geographic view of the CNI is shown in **Error! Reference source not found.**-4 and the single line diagram is shown in **Error! Reference source not found.**.

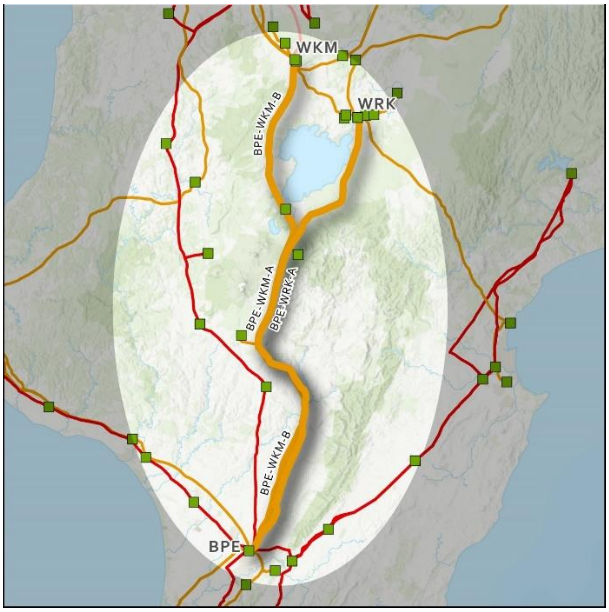


Figure 1-4: Geographic view of the Central North Island region transmission network

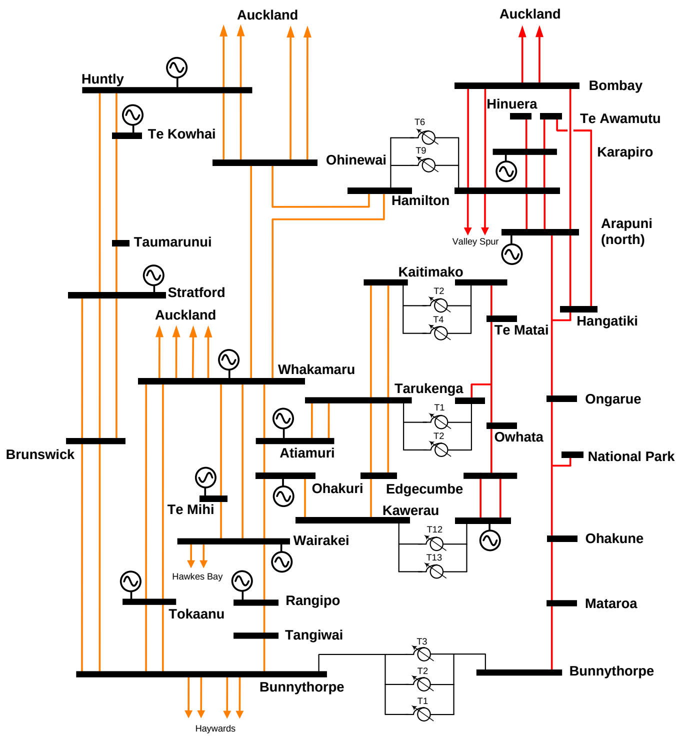


Figure 1-5: Single Line Diagram of the Central North Island (including Wairakei Ring) transmission network

1.13 Wairakei Ring

The Wairakei Ring connects the generation rich regions of the Central North Island with the high load centres of the upper North Island, Waikato and Bay of Plenty via two 220 kV transmission lines (a single and a double circuit line). A single line diagram of the Wairakei Ring is included in Figure 1-5.

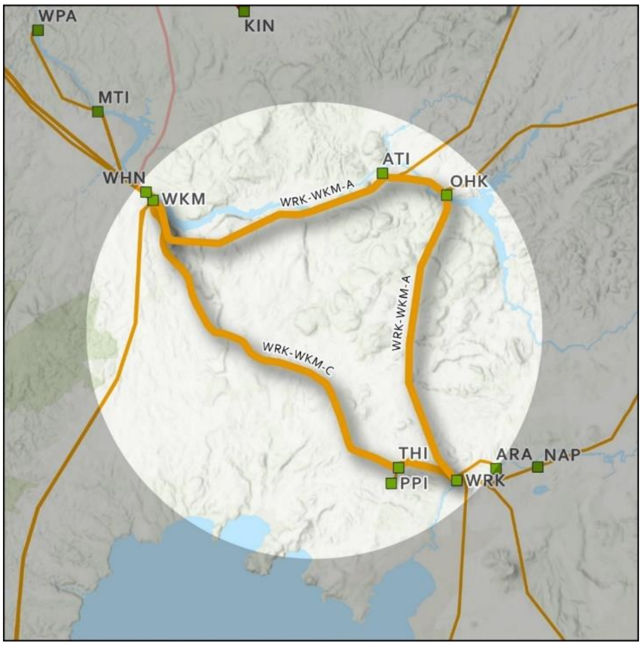


Figure 1-6: Geographic view of the Wairakei Ring

1.14 Other North Island constraints

There are some other North Island constraints which can limit north flow.

The Huntly-Stratford 220kV line constrains in some circumstances, with the frequency and severity depending upon generation within the Taranaki region. The announced retirement of the Stratford combined cycle generator in 2023 will reduce the frequency of this constraint.

Rebuilding the line is one option and is included in our long list of options, but there are also less expensive options (such as lifting the protection limit) which would relieve the constraint in the short term.

Notwithstanding this line, some lower North Island 110kV circuits can also constrain north flow – the Bunnythorpe-Mataroa and Masterton-Mangamaire circuits. We have plans being developed to relieve these constraints by installing system splits to prevent through-transmission when grid flows are high. There is already equipment in place to enable a system split on the Masterton–Mangamaire circuit, but not on the Bunnythorpe–Mataroa circuit.

These projects will cost less than $20 million each and will be funded from Commerce Commission approved Base Capex Enhancement & Development funding.

In this project, our analysis will assume these works have been completed.

1.2 Overview of the need for investigation and investment

As new generation is built and demand grows, a number of constraints emerge on the transmission grid between the top of the South Island and Whakamaru (including the Wairakei Ring). We expect it would be beneficial to resolve these by 2035 as New Zealand pursues its net zero carbon by 2050 goal. Relieving these constraints would provide some surety to generation investors that new generation could be economically dispatched and hence ensure the generation investment market remains competitive.

We could enhance parts of the existing network – the HVDC, our CNI 220kV network and the Wairakei Ring, or if justified, build a new line/s between these points.

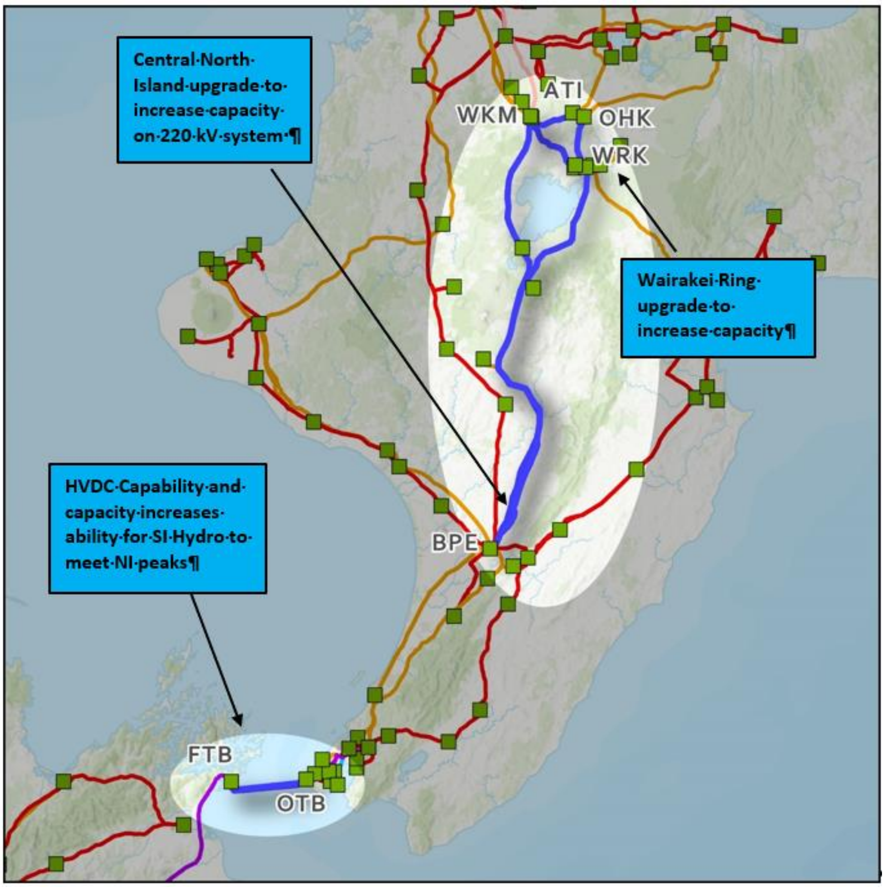


Figure 1-7: Initiatives being investigated in NZGP1

1.21 HVDC capacity

The nominal rating of the Pole 2 converter is 700 MW. However, the nominal end-to-end capacity of Pole 2 is limited to 500 MW by the rating of the single HVDC cable across Cook Strait, connected to the pole. The nominal rating of the Pole 3 converter is 780 MW. Two 500 MW Cook Strait cables are connected to Pole 3, so the nominal end-to-end capacity of Pole 3 is 780 MW.

In total, the HVDC link therefore has a capacity of up to 1,000 MW in balanced 500/500 MW bipole operation and up to 1,200 MW[6] in unbalanced 500/700 MW bipole operation. These are north flow capacities, with south flow being limited to 850MW.

HVDC transfer at any point in time is determined by energy market outcomes. However, periods of high North transfer are typically characterised by moderate to high South Island hydro storage levels coinciding with reduced availability of North Island generators. Conversely periods of high South transfer are typically characterised by low to very low South Island hydro storage levels coinciding with high availability of North Island generators.

[6] Although maximum transfer capability of the HVDC assets is continuously available (not withstanding 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.

The surrounding AC transmission network and the availability of instantaneous reserves in the receiving island also play an important part in determining HVDC transfer limits at any point in time.

This investigation will consider options for increasing HVDC Cook Strait capacity, in order to access the higher available existing HVDC converter capacity. Increasing both north and south transfer between the islands will be considered.

1.22 CNI 220kV

North flow transmission through the CNI region is close to being constrained at times and if any significant new generation south of Bunnythorpe emerged, we would likely see significant constraints. Tiwai Point smelter closure, for instance, would result in significant constraints.

Separately, if generation in the Taranaki region is higher this will result in lower transfer limits on the circuits north of Bunnythorpe. The announced retirement of the Stratford combined cycle plant in 2023 will affect CNI transfer levels and this will be monitored closely.

Previous analysis indicates that the two Tokaanu – Whakamaru 220 kV circuits and the Huntly – Stratford 220 kV circuit can constrain north flow through the CNI region in various scenarios. If constraints are removed on these circuits via upgrade work, then the two Bunnythorpe – Tokaanu 220 kV circuits would then become the limiting constraint.

1.23 Wairakei Ring

The capacity of the Wairakei–Ohakuri–Atiamuri–Whakamaru circuits (see Fig 1-6) may cause a transmission constraint during high generation in the Wairakei Ring, eastern Bay of Plenty or Hawkes Bay areas. This constraint would be exacerbated if there is a reduction in industrial load in the Bay of Plenty region, or if additional generation is developed around the Wairakei, Bay of Plenty, or Hawkes Bay regions. To a smaller extent, through-transmission from the Central North Island to the WUNI region also exacerbates the Wairakei Ring constraint.

No further thermal uprating is possible on the limiting circuits in the Wairakei Ring transmission corridor and they already have variable line ratings applied, so there is no scope to further increase the transmission capacity using these techniques. As part of our investigations, we will assume the series reactor on the Wairakei–Ohakuri–Atiamuri– Whakamaru line (to balance flows on the Wairakei Ring circuits), has been installed.

1.3 Asset condition

1.31 Condition of Pole 2 Equipment and HVDC Cables

The Pole 2 Converters and three Cook Strait cables were commissioned in 1991 and have performed very well to date.

The converter transformers and valves are generally in good order and another 25 years of service is to be expected if critical items are refurbished at this half-life point in their lifecycle. Preparations are now in progress for these refurbishments during the remainder of Regulatory Control Period 3 (RCP3) and RCP4.

Pole 2 control systems which have a shorter (20 year) lifecycle due to obsolescence were replaced during the Pole 3 project in 2012.

Critical Valve Base Electronics equipment (part of the control system) not able to be replaced during the Pole3 project was replaced in 2020 along with all snubber capacitor assemblies within the valves.

With these refurbishments, we expect Pole 2 will last until beyond 2040.

The three Cook Strait submarine cables which have a 40-year design life, are anticipated to reach the end of their design life in approximately 2031.

The Cook Strait environment is one of the worlds harshest for submarine cables, with extreme tidal flows. In general, the condition of the protective outer layer of the Cook Strait cables remains sound, however in localized places the outer protective layer has worn through exposing the underlying layers. Remedial works are used wherever possible, but we expect the effects of constant abrasion and corrosion of the protective outer layers will ultimately determine timing for cable end of life.

A study is underway into the replacement of existing cables and it may be that installation of an additional fourth cable could be undertaken at the same time, if justified. Replacement of the existing cables will be funded through Replacement & Refurbishment capital expenditure, to be considered by the Commerce Commission in our RCP4 and/or RCP5 proposals.

2.0 Regulatory process for the approval of investments

2.1 Regulatory Process

Should this investigation determine that the preferred option is to enhance the service provision of the existing grid, the cost will exceed $20 million and we will submit a MCP to the Commission, in order to recover the costs of the project from transmission customers. Commission approval will allow us to either recover the costs as operating expenditure should the investment be a recoverable cost, or to include the investment on our regulated asset base and recover the cost through the Transmission Pricing Methodology (TPM).

The TPM is currently under review by the Electricity Authority and a new TPM will likely apply for this project. Under the new TPM we expect that costs will be recovered from those parties identified as beneficiaries of the investment/s (potentially both offtake and generator customers).

The process we are using for this investigation is consistent with the requirements of the Commerce Commission's Capex IM, but rather than consult twice[7] as required by the Capex IM, we will consult three times. The first consultation is a long-list consultation, which is the purpose of this document and includes consultation on:

- investment need
- long-list of options to be considered
- request for information relating to NTS
- key assumptions we will use in our assessment.

In parallel, we are developing the processes required for an expected new TPM and although the Electricity Authority's review will not be complete, our intention is to consult further, after this long-list consultation, but before the short-list consultation required by the Capex IM.

The purpose of that consultation will be to outline some of the key assumptions to be used in allocating the costs of major capital investments approved by the Commerce Commission. Although some assumptions are outlined in this long-list consultation document, the second consultation will describe them in more detail – detail not required for investigation purposes, but which are important from the point of view of cost allocation.

The insertion of this consultation, along with conclusions on our EDGS variations, result in a departure from the level of detail included in this document in relation to relevant demand and generation scenarios, as compared to previous long-list consultation documents. See section 5.1 to 5.8 for more detail. Although different, this new approach is still consistent with the requirements of section I2 of Schedule I of the Capex IM.

Our third consultation will be a short-list consultation, consistent with the requirements of the Capex IM, outlining the reduction of the long-list to a short-list, our application of the Investment Test (IT) to the short-list options and any draft MCP.

[7] Depending upon the efficacy of NTS. If an NTS is likely to be economic, we may run a RFP for NTS, requiring adjustments to the timetable and effectively resulting in an additional consultation

3.0 Long-list of options

This section describes several long lists of options.

Table 3-1 includes the first long list, which are options which do not use the existing AC grid in the North Island. Two options are included.

The first utilises the existing HVDC assets to their maximum capacity of 1450 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 news 700 MW converter is installed.

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

Tables, 3-2, 3-3 and 3-4 are the remaining long lists of options, which include potential upgrades of the existing assets, or new assets, depending on the capacity required.

These tables do not include indicative costs for each long-list option, but these will be derived prior to short-listing.

3.1 NZGP1 Long List Options

Table 3-1 Options that could potentially meet the overall need.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
A1	Do Nothing (Counterfactual)			
Transmission options - 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 1200MW link to 1450MW. 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. Such a configuration would meet the overall need, avoiding 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.

Question 3: Are our long-list options (B1 and B2 in Table 3.1) to meet the overall need for this investigation, reasonable?

3.2 HVDC Long List Options

Table 3-2 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 option to meet long-term need.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
A1	Do Nothing (Counterfactual)		Keeping the existing HVDC capacity (1200MW N / 850MW S)	Existing HVDC Cook Strait cables will require replacement circa 2031
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.	Further description is provided in the RFI for NTS
Expansion - fourth cable				
C1	Expansion	**Fourth Cook Strait Cable** (duration 2-5 yrs)	Allows Pole 2 operation up to 700MW (+200MW). Increases Pole 2 ramp up (reserve) capacity to 700MW (+60MW) HVDC Target Capacity: 1200MW N/ 850MW S	Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 700MW. Shifts threshold for dependence on NI instantaneous reserve up to 700MW (from 640MW).
C2	Expansion	**Fourth Cook Strait Cable with an increase Pole 2 overload capacity** (duration 2-5 yrs)	Allows Pole 2 operation up to 700MW (+200MW). Increases Pole 2 ramp up (reserve) capacity to 1000MW for 15 minutes. HVDC Target Capacity: 1200MW N/ 850MW S	Improves HVDC Bipole utilisation by increasing Pole 2 rampup / overload capacity to 1000MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 1000MW (from 640MW). Requires replacement of some Pole 2 equipment
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 700MW (+200MW). Increases Pole 2 ramp up (reserve) capacity to 1000MW for 15 minutes. Increases Bipole capacity to 1400MW N (+200MW) and 950MW S (+100MW) HVDC Target Capacity: 1400MW N / 950MW S	Increases Bipole transfer capacity (+200MW) Improves HVDC Bipole utilisation by increasing Pole 2 rampup / overload capacity to 1000MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 1000MW (from 640MW). 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 110kv network for increased South transfer

Option Type	Option sub-type	Option (duration of works)	Details	Comments
C4	New additional HVDC link (duration to be confirmed)	**New Pole 700MW N/ 500MW S** (duration to be confirmed)	HVDC Target Capacity: 2100MW N / 1550MW S	Some scenarios (Onslow and/or significant increased SI demand) show a requirement for additional 700MW N / 700MW S. (Total 2100MW N / 1550MW S) Existing assets have theoretical maximum capacity for 1480MW N and 950MW 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
Modify/upgrade				
D1	Incremental Improvement	**Increase HVDC Operating Current or Voltage** (duration 12-18 mths)	Increase Pole nominal operating limits approx 10MW (per pole). Increases Pole 2 ramp up (reserve) capacity to 650MW (+10MW) HVDC Target Capacity: 1200MW N/ 850MW S	Minor improvement to HVDC utilisation by increasing Pole 2 rampup / overload capacity to 650MW (+10MW). Requires use of technology to enhance assessment of local ambient conditions. Shifts threshold for dependence on NI instantaneous reserve up by 10MW to 650MW.
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 500MW for energy transfer (from 420MW). HVDC Target Capacity: 1200MW N/ 850MW S	Requires additional instantaneous reserve (+130MW) in receiving island provided by others. Increase in Transpower's reserve costs (HVDC risk setter).

Question 4: Are our long-list options for enhancing capacity of the HVDC reasonable?

3.3 CNI 220kV Long List Options

Table 3-3 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 option to meet long-term need.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
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.
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.
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
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.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
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.
C2	Line upgrade	**Duplexing reconductoring of existing 220kV 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: 1. Stage 1- duplexing Tokaanu–Whakamaru sections 2. Stage 2 – duplexing Bunnythorpe–Tokaanu sections
C3	Line upgrade	Simplex reconductoring of existing 220kV 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: 1. Stage 1- reconductoring Tokaanu–Whakamaru sections Stage 2 – reconductoring Bunnythorpe–Tokaanu sections

Option Type	Option sub-type	Option (duration of works)	Details	Comments
C4	Line upgrade	**HTLS reconductoring of existing lines**[8] [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 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: 1. Stage 1 – thermal upgrading Tokaanu–Whakamaru sections 2. Stage 2 – thermal upgrading Bunnythorpe–Tokaanu sections Thermal upgrades (one or both stages) could be a good option to defer more significant transmission upgrades

[8] 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.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
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.
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.
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.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
Transmission options - new assets or replacing existing assets				
D1	New Line	**New 220kV line between Bunnythorpe and Whakamaru** [8 years property acquisition and consenting + 5 years build]	A new 220kV double circuit duplex line between Bunnythorpe and Whakamaru	Following the existing Bunnythorpe-Whakamaru A&B routes, a new double circuit 220kV 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.
D2	New Line within the Taranaki transmission corridor	**New 220kV line Bunnythorpe-Stratford-Huntly** [10 years property acquisition and consenting + 7 years build]	A new 220kV double circuit duplex line between Bunnythorpe - Stratford - Huntly	This new line can be developed in stages: 1. 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.
D3	New Line within the Hawkes Bay transmission corridor	**New 220kV line between Bunnythorpe-Woodville-Waipawa-Fernhill-Redclyffe-Wairakei** [10 years property acquisition and consenting + 5 years build]	A new 220kV 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 110kV 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.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
D4	New Line within the existing Central North Island transmission corridor	**Replace the existing Bunnythorpe–Whakamaru-A and B lines to 400kV** (10 years property acquisition and consenting + 5 years build)	Replace the existing 220kV Bunnythorpe-Whakamaru A & B lines with 400kV 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).
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 220kV 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.
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 110kV Bunnythorpe–Ongarue-A to 220kV.	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.
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 110kV Bunnythorpe-Ongarue A to 220kV.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

Option Type	Option sub-type	Option (duration of works)	Details	Comments
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 causes two main issues, 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.
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.).
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.

Question 5: Are our long-list options for enhancing capacity of the CNI 220kV corridor reasonable?

3.4 Wairakei Ring Long List Options

Table 3-4 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 option to meet long-term need.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
A1	Do Nothing (Counterfactual)			
Non-Transmission Options				
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	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. 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 A battery could potentially also address other constraints south of Whakamaru such as on the CNI
B2	Generation Redispatch	**Automatic generation controller (AGC)** (duration to be confirmed**)**	An AGC to 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.	Viability depends on consent from affected asset owners and the compatibility of different assets to facilitate such a scheme. If possible, this could potentially be a partial solution to defer transmission options.
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.	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

Option Type	Option sub-type	Option (duration of works)	Details	Comments
Transmission options - modifying and upgrading existing assets				
C1	Line upgrade	**Wairakei-Whakamaru A line, Wairakei-Whakamaru C line and Eastern Bay of Plenty 220 kV circuits (Edgecumbe-Kawerau-Ohaakuri 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-Ohaakuri 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. There is a risk that it might not be achievable in 0-5 years.
C2	Reconfiguration	**Reconfigure Atiamuri-Ohaaki reactor impedance and thermal 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 and the Wairakei-Whakamaru A line will still constrain capacity in this corridor	
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.
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.
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).

Option Type	Option sub-type	Option (duration of works)	Details	Comments
Transmission options - 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. Suggest this makes these options infeasible.
D2	HVDC	**Back to back HVDC terminal** [2 years consenting and planning +5 years build]	Install back to back HVDC between Atiamuri-Ohaakuri 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.
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.
D4	New underground cable	**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 the 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.
D5	New Line	**New line from Ohaaki 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.

Option Type	Option sub-type	Option (duration of works)	Details	Comments
D6	New Line	**Third line in the Wairakei Ring transmission corridor** [2 years consenting, and planning + 4 years build]	New 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.
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 75degC), second circuit bypassing Ohaakuri	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.
D8	New Line	**New double cct line** [2 years consenting and planning + 4 years build]	New double circuit line Wairakei-Ohaakuri-Atiamuri only, replaces existing section of the A line	This option was one of the future development paths for the Wairakei Ring analysis that justified the Wairakei-Whakamaru C line. However, this option is not suitable today as the Bay of Plenty region's demand is not large enough to consume much of the generation from Wairakei. This option does not increase the ability to export Wairakei generation to Whakamaru which is what we need today
D9	Upgrade the Central Corridor	**Duplex reconductoring existing 220 kV lines** 2 years consenting and planning + 4 years build]	Duplex reconductoring Wairakei-Whakamaru A line (duplex Sulfur at 75degC)	Scope for duplexing may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the duplexing work may also impact the economics of this option does not increase the security of supply to the Bay of Plenty region like new line options that terminate at Atiamuri
D10	Upgrade the Central Corridor	**Simplex reconductoring existing 220 kV lines** [2 years consenting and planning + 4 years build]	Simplex reconductoring Wairakei-Whakamaru A line (simplex Chukar at 90degC) plus thermal upgrading the Wairakei-Whakamaru C Line	Scope for simplex reconductoring with a larger conductor may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the reconductoring work may also impact the economics of this option does not increase the security of supply to the Bay of Plenty region like new line options that terminate at Atiamuri
D11	New Line	**New 220 kV line plus reconductoring existing 220 kV lines** [2 years consenting and planning + 4 years build]	New single cct line between Wairakei-Atiamuri and reconductor (duplex) between Atiamuri-Whakamaru, keep existing A line	Increases security of supply/resilience to the Bay of Plenty region. Scope for reconductoring with a larger conductor may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the reconductoring work may also impact the economics of this option
D12	New Line	**New 220 kV line** [2 years consenting, and planning + 4 years build]	New single cct line between Wairakei-Atiamuri-Whakamaru, keep existing A line (duplex Sulfur at 75degC)	This option is a variation of option D6. A new 220kV line will not offer future flexibility that a new double circuit line does

Question 6: Are our long-list options for enhancing capacity of the Wairakei Ring reasonable?

3.5 Long-list development plan options

The options evaluated in the Investment Test will be the short-listed options. These will either be from Table 3.1, or will be combinations of the short-listed options from Tables 3.1, 3.2, 3.3 or 3.4.

The combined options are referred to as development plan options and may include combinations of more than one short-listed option, where the short-listed options are commissioned at different times. For instance, where a short-listed option has a long lead-time e.g. building a new transmission line, we may also include a “tactical” option to enhance capacity until such time as a new line can be commissioned.

4.0 Short-listing criteria

4.1 Short-listing

We propose to evaluate our long list of options using a set of high-level screening criteria. The screening criteria will be used to eliminate those options that are not appropriate for consideration in the short-list and subsequent development plans, to which we apply the Investment Test. Broadly, we intend to use six criteria for screening:

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

Question 7: Are there other criteria we should consider when evaluating our long- list of options and reducing it to a short-list?

5.0 Options analysis

5.1 Investigation Approach

The diagram below sets out the general process followed by this investigation. We are at the 'Option Identification' stage.

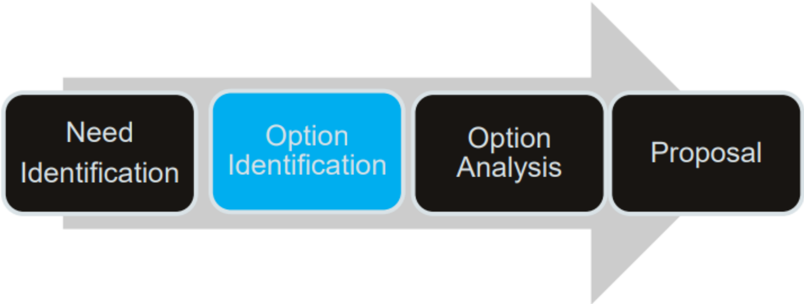


Figure 5-1 – Transpower's standard investigation approach

Once we have received feedback to this consultation, we will amend and finalise the long-lists of options, then reduce them to short-lists, using the criteria outlined in section 4.0.

We will then produce development plan options, by combining the short-listed options in a manner which meets the need in a single option.

Then we enter the Options Analysis stage of our investigation by assessing the development plan options using the Investment Test, as prescribed in Schedule D of the Capex Input Methodology[9]. In addition to quantifiable benefits, our assessment may also consider a range of unquantified benefits.

Sensitivity analysis will be undertaken to test the robustness of the IT result and should any option pass the IT we will prepare a draft MCP, which will form the basis of a short-list consultation.

5.11 Relationship with the new Transmission Pricing Methodology

The Electricity Authority released its final decision on its transmission pricing review and published new TPM Guidelines (Guidelines) on 10 June 2020. A key component of the Guidelines is a new benefit-based charge which applies to any expenditure in the interconnected grid after 30 June 2019. The benefit-based charge (BBC) aims to allocate the cost of this expenditure to those customers who are expected to benefit from the investment. For investments with a capital cost of greater than $20m (high-value investments), the modelled costs and benefits used to produce these allocations are aligned with electricity market benefit or cost elements under the Investment Test.

Following consultation with customers on options for the BBC (and other aspects of the new TPM), Transpower proposed a new TPM that is consistent with the Guidelines and the other

[9] Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination), 1 June 2018

requirements under Part 12 of the Electricity Industry Participation Code 2010 (the Code) on 30 June 2021.

The Electricity Authority is currently assessing our proposal, referring aspects of it back to us for consideration. Once this process is complete the Electricity Authority may make further changes to the proposed TPM. When it is satisfied it complies with the Code, it will consult on a full proposed TPM later in 2021.

5.12 The role of the TPM

The Commerce Commission determines how much revenue Transpower, as the owner and operator of the National Grid owner, can recover from its customers according to its regulation of Transpower under Part 4 of the Commerce Act. The TPM determines how that amount of allowable revenue is recovered from (or allocated to) each of Transpower's customers in each pricing year.

Once Transpower's capital expenditure proposal has been approved by the Commerce Commission, whether as major capex or base capex, that spend (and an allowable return on investment) may be recovered through the TPM.

The Commerce Commission has noted:

The new TPM guidelines and the new TPM Transpower develops under them will not affect the regulatory approval process for assessing the [Major Capex Proposal] under the Capex IM or the amount Transpower can recover in transmission charges for the investment.[10]

The TPM Guidelines require the allocations for high-value benefit-based investments are aligned with the costs and benefits assessed through the Investment Test. One or more of the solutions to meet the need of this project will be high value. Therefore, the assumptions and scenarios that we use in the application of the Investment Test are likely to be used to determine allocations for one or more components of this project under the new TPM, unless we consider these will result in allocations that are not broadly proportional to expected positive net private benefit.

We intend to consult on more detailed assumptions applying to this investigation, that will be used for both the IT and TPM, prior to the short-list consultation – ideally before the end of 2021. At the same time as any short-list consultation is undertaken, we also intend to consult on indicative pricing under the proposed TPM for any preferred options identified through this investigation.

5.2 Demand and generation scenarios

The IT requires that we consider demand and generation scenarios in our analysis.

Demand and generation scenarios are a description of a hypothetical future situation relating to forecast electricity demand and generation, as published by the MBIE, specifically for the purpose of investigating major capex proposals. These demand and generation scenarios are called the EDGS[11].

[10] Commerce Commission Decision and reasons on Transpower's Bombay Otahuhu Regional MCP, 19 March 2021, paragraph 27.

[11] Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz)

The IT does allow for demand and generation scenario variations to be used, where the variations are of the EDGS and they have reasonable regard to the views of interested persons.

Using demand and generation scenarios helps to ensure our economic analysis is robust to future uncertainty around both electricity demand growth and generation expansion. A demand and generation scenario include assumptions about:

- future electricity demand[12]
- existing, decommissioned and future new generation connected to the national grid
- capital and operating costs for existing and future new generation
- fuel availability for generation
- fuel and carbon costs for generation
- grid-connected energy storage

The latest EDGS were published in 2019 but reflecting the rapid pace of change in New Zealand's energy sector at the moment, there have been several relevant and important changes which are not reflected in the EDGS 2019. 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
- Tiwai aluminium smelter announcement to close in 2024 (and subsequent effect on North Island thermal generators)
- Investor interest in grid-scale batteries
- Government investigation of Onslow pumped hydro scheme i.e. the NZ battery workstream

We therefore consider it necessary to vary the EDGS 2019 for the purposes of this investigation. To ensure we reflect the views of interested persons, we have used a consultative approach to review the EDGS.

A full description of our interactions with stakeholders in reviewing the EDGS 2019 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 November and December 2020. Recordings of the online meetings we held with them are available at the web link above. The conclusions from those meetings were then included in a written consultation paper, which was published on our website in December 2020. That consultation was open for 8 weeks, closing in February 2021.

Feedback confirmed that we had good information to produce reasonable EDGS variations in terms of demand scenarios, but not enough information regarding generation scenarios.

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

We then undertook further consultation, via a written consultation paper, regarding generation scenarios, in May 2021. This targeted potential generation investors but was open to all stakeholders. That consultation was open for 6 weeks and closed in June 2021. Feedback re-

[12] Including assumptions regarding base demand, electric vehicle uptake, solar PV uptake, distributed energy storage, etc.

confirmed there is too much uncertainty regarding future generation possibilities for grid-connected generation in 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 uncertainties which are too significant to spread across the five EDGS:

- Tiwai closure date and any Southland replacement demand
- The possibility of Taranaki offshore wind being built
- Peaking and dry year reserve options:
    - South Island (Onslow) – small (5 TWh), medium (8-10 TWh) and large (12 TWh) are 3 variants worth considering
    - North Island (with gas peaking allowed)
    - North Island (100% renewables with a combination of generation overbuild, batteries, demand response and perhaps pumped hydro or hydrogen)
- A higher proportion of grid-connected solar generation compared to wind generation

This has led us to propose having "base scenarios" which reflect the five EDGS demand variations and generation build uncertainty only, with each of the uncertainties above considered in separate scenarios termed "sensitivity scenarios".

We outlined a possible approach in our December 2020 consultation document to developing suitable scenarios for investigations and following mostly supportive feedback, we are proposing to use a slightly improved version for our NZGP1 MCP. The process is shown in Figure 5-2.

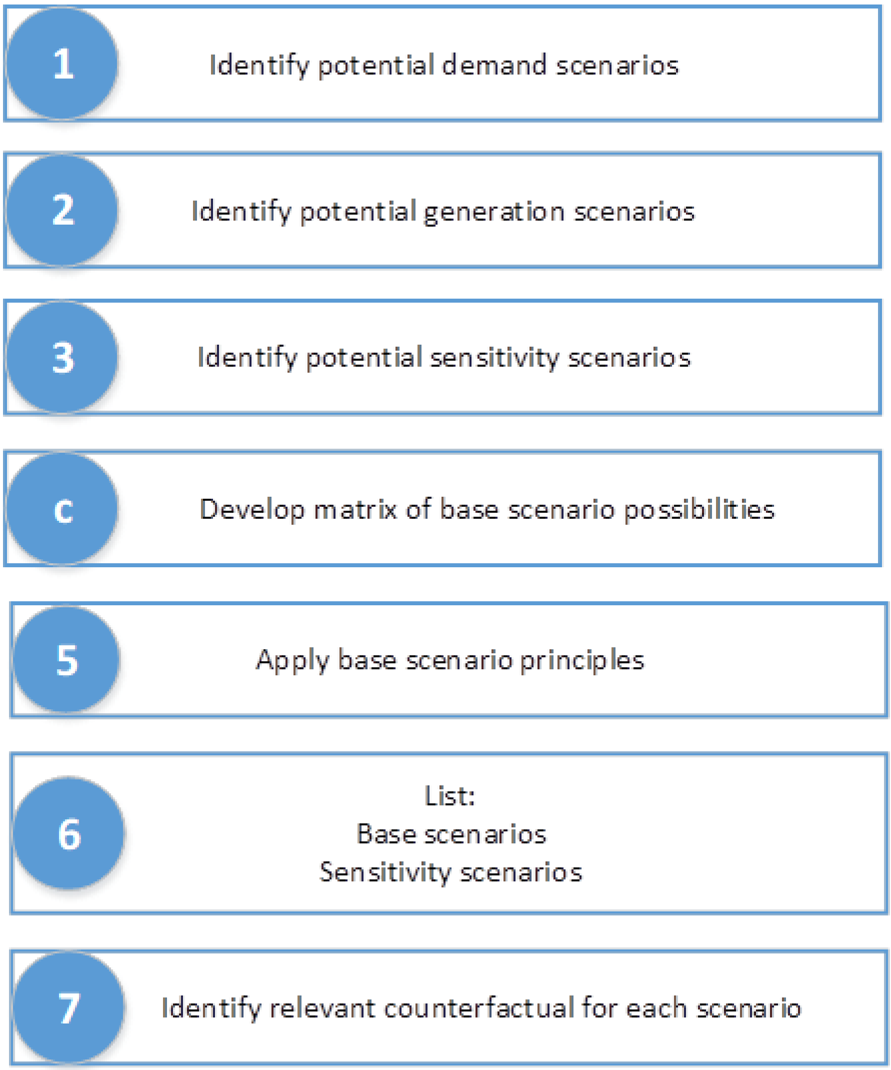


Figure 5-2 – Process for developing relevant scenarios

Question 8: Is our process for developing relevant scenarios reasonable?

Our application of this process, for this investigation, is included in sections 5.4 to 5.7.

5.3 EDGS 2019

The EDGS 2019 include five scenarios as follows:

1. Reference: Current trends continue

   The "Current trends continue" scenario is scenario is one view of how the electricity system could evolve under current policies and technology trends if no major changes occur.

2. Growth: Accelerated economic growth

   This scenario assumes the past decade of slow growth in labour productivity is an aberration rather than the norm. Higher economic growth drives higher immigration while policy and investment focus on priorities other than the energy sector. The economy is transformed to put emphasis on high technology. The commercial sector grows to be larger than in the Reference scenario and higher income growth leads to higher uptake of electric vehicles. This scenario provides an assessment of what level electricity demand could reach if the economy is doing well.

3. Global: International economic changes

   In this scenario New Zealand's economy is battered by international trends, leaving little room for local growth or innovation. Some aspects are opposite to the Accelerated economic growth scenario such as the uptake of EVs. This scenario also includes a higher cost for wind turbines and solar power than in the Reference scenario.

4. Environmental: Sustainable transition

   The New Zealand government targets more ambitious emissions reduction levels than in the Reference scenario. Strong environmental leadership, including the use of regulation and incentives (rather than technology) provides the change reflected in this scenario. Policies are introduced to support the electrification of both transport and process heat. This scenario focuses on decarbonising the economy.

5. Disruptive: Improved technologies are developed

   In this scenario, the electricity demand and supply implications of more advanced and sophisticated technological progress in the energy sector are reflected. A faster reduction in technology costs results in a higher uptake of both EVs and solar more electrification of process heat.

Figure 5-3 shows the EDGS 2019 national demand[13] forecasts by scenario, but with Tiwai exiting in 2024. In their most recent advice, Rio Tinto announced that the aluminium smelter at Tiwai has an electricity supply contract until 2024 and its future after that is uncertain. As discussed above, our approach to that uncertainty is to reflect a common assumption that Tiwai closes in 2024, in our base scenarios, with closure uncertainty reflected in a sensitivity scenario.

[13] The EDGS reports gross national demand, being the total electricity used by consumers. It is defined as electricity demand measured as exiting the grid at our GXP's' less distribution losses plus generation embedded behind our GXP's. Our EDGS 2019 variations also report gross national demand.

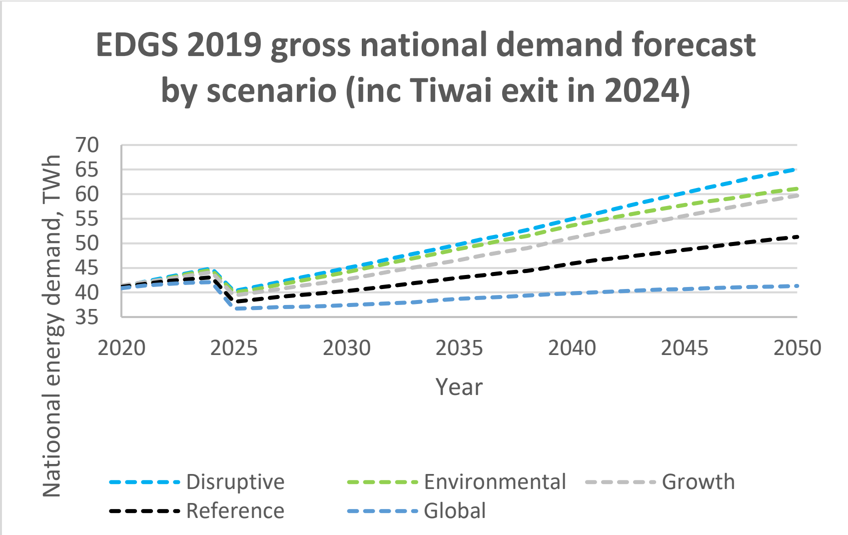


Figure 5-3 - EDGS 2019 national demand forecasts by scenario

5.4 Identifying NZGP1 demand scenarios

We consulted with the industry on reasonable[14] variations to the EDGS 2019 demand forecasts, to ensure they were up to date.

Since those EDGS 2019 variations were developed, there have been other changes affecting our forward view of electricity demand, so we have made some minor adjustments We have:

- updated the historical data that informs our base load demand forecast
- updated our view of future demand at each Grid Exit Point (GXP) through discussion with our customers. This is a regular and annual process used to inform demand forecasts for our TPR. We discuss long term demand growth and demand step-jumps as a result of known increases. The most significant change is in Auckland where some step-jumps in new demand are occurring
- included replacement of the Marsden Point oil refinery by a storage terminal
- included retirement of Kawerau pulp and paper mill

We are calling these our NZGP1 demand forecasts and are proposing these for our NZGP1 MCP analysis.

Table 5-1 shows the original EDGS 2019 gross national demand forecast in 2050 (TWh), the changes included in the EDGS 2019 variations and the changes since then which make up our proposed NZGP1 gross national demand forecast in 2050.

[14] The changes need to be considered reasonable in the sense that the revised EDGS 2019 forecasts can be used in place of the EDGS 2019 forecasts for evaluating investment decisions.

Table 5-1 – Original EDGS 2019 gross national demand forecast in 2050 (TWh)

	EDGS scenario				
Gross national demand in 2050, TWh	Reference	Growth	Global	Environmental	Disruptive
EDGS 2019	57	65	47	67	71
Tiwai closure	-5	-5	-5	-5	-5
Variations due consultation	0	-4	2	-2	-2
EDGS 2019 variations	52	56	44	60	64
NZGP1 variations					
- Baseload forecast	-0.64	0.33	0.20	0.14	0.77
- Auckland step-jumps	0.45	0.45	0.45	0.45	0.45
- Marsden Point closure	-0.32	-0.32	-0.32	-0.31	-0.31
- Kawerau closure	-0.47	-0.47	-0.47	-0.46	-0.46
NZGP1	51	56	44	60	64

A table of the gross national demand proposed for the NZGP1 scenarios, by scenario, by year is shown in Appendix C.

Diagrammatically, the original EDGS 2019 demand forecasts are shown in Figure 5-4 and Figure 5-5 along with our published EDGS 2019 variations and our proposed NZGP1 forecasts. Figure 5-5 shows the same data as in Figure 5-4, but all series are included on the same graph.

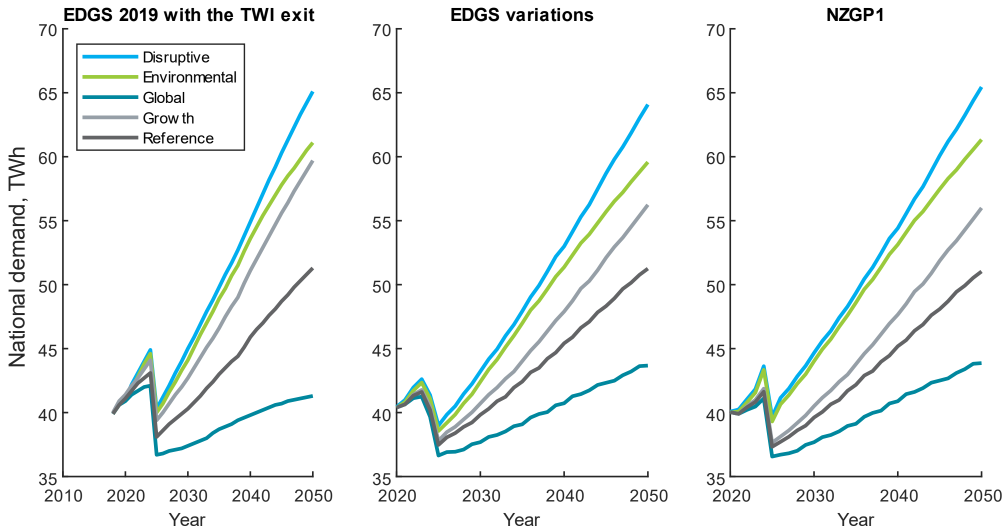


Figure 5-4 – Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

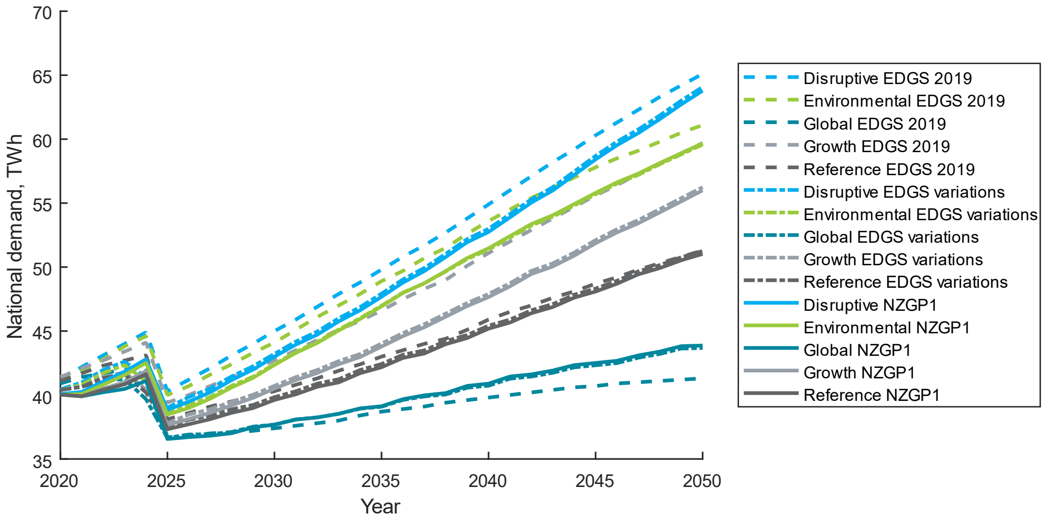


Figure 5-5 – Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

5.41 Comparing the EDGS to other demand forecasts

Several New Zealand organisations produce electricity demand forecasts at present, focusing on different aspects of New Zealand's electricity future.

For comparison, we show our proposed NZGP1 demand forecasts with the Climate Change Commission's (CCC's) forecasts and Transpower's own Whakamana I Te Mauri Hiko (WiTMH) forecasts in Figure 5-6 below.

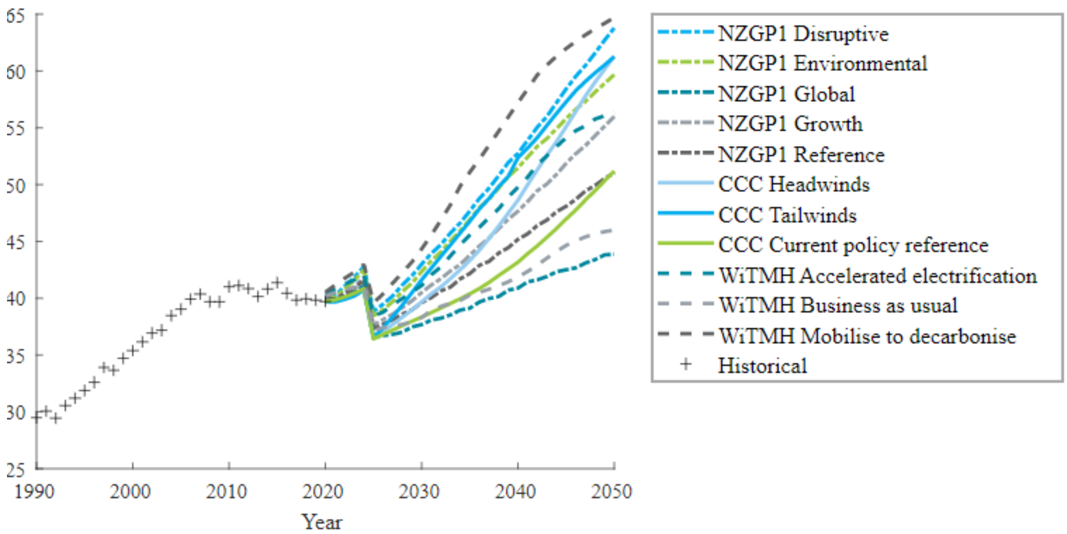


Figure 5-6 Comparison of NZGP1 demand forecasts, with CCC and WiTMH forecasts

Question 9: Are our proposed NZGP1 demand forecasts reasonable?

We can make several interesting observations from Figure 5-6:

1) The range of gross national demand forecasts in our proposed NZGP1 scenarios cover the full range of demand uncertainty between the other scenarios in Figure 4.
2) We note that most of the EDGS, the CCC's Current Policy Reference scenario and the WiTMH Business as Usual scenario, are not aligned with a net zero carbon by 2050 target, whereas the other scenarios are. The weighted average demand of our proposed NZGP1 forecasts (varied EDGS forecasts) is 55 TWh. The average of the CCC's aligned scenarios (Headwinds and Tailwinds) scenarios is 61 TWh and the weighted average of the WiTMH aligned scenarios (Accelerated electrification and Mobilise to decarbonize) scenarios is also 61 TWh.
3) Therefore, the national energy demand reflected in our Investment Test analysis will be below that forecast to be consistent with a net zero carbon by 2050 target as forecast by others.
4) However, we also note that the national energy demand forecast in the NZGP1 environmental scenario (varied EDGS) is 60 TWh and that this scenario is closely aligned with a net zero carbon by 2050 target.
5) In our Investment Test analysis, we will study each scenario separately, and so will pay attention to, and report, the outcome from using the NZGP1 Environmental scenario.

These are expected forecasts, meaning that they are P50 forecasts of future electricity demand. We use expected forecasts in our analyses, except to determine preferred timing, in which we use a prudent, or P90 forecast. This is explained further in section 5.43. The expected gross national demand forecast proposed for the NZGP1 scenarios, by scenario, by year, is shown in Appendix C.

5.42 Solar PV forecasts

As mentioned, the difference between gross demand and GXP demand (which is primarily used in our analysis), is distribution losses and embedded generation. A part of the embedded generation is rooftop solar PV. We did discuss the forecast uptake of solar PV in our panel meetings and decided to increase the uptake compared to EDGS 2019. For information and comparison, we show the how our resultant NZGP1 solar PV forecasts compare with the original EDGS 2019 in Figure 5-7. The left plot shows the EDGS 2019 forecasts and the right plot shows the variations that we consulted on along with the updated uptakes that we are proposing for NZGP1. The solid lines represent the proposed NZGP1 forecast and the dashed lines represent the EDGS 2019 variations.

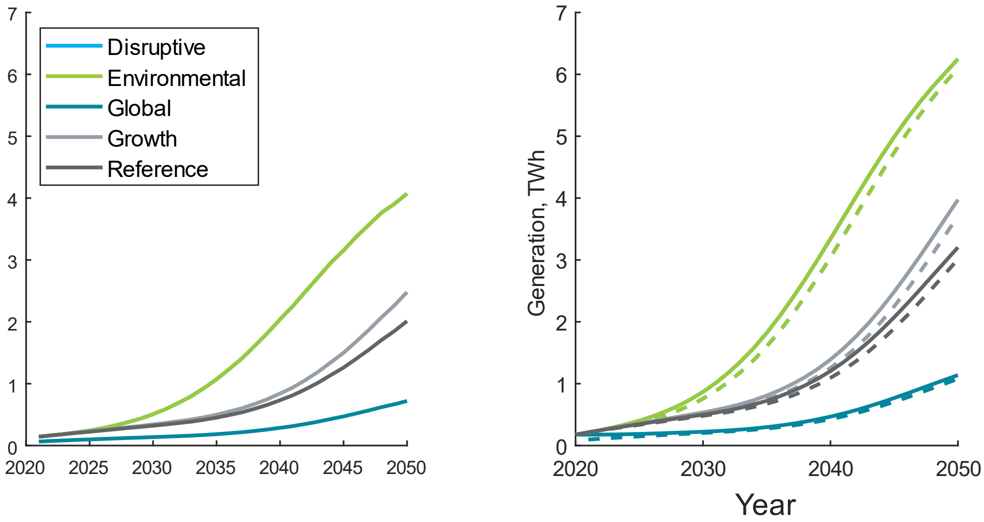


Figure 5-7: Solar demand for the three variations of the EDGS

5.43 Peak demand assumptions

The EDGS 2019 demand forecasts are primarily forecasts of electricity energy demand. They do not contain profiles, showing how demand varies throughout the day. These forecasts are called peak demand forecasts and are used in much of our analysis to ensure we provide enough transmission capacity for the peak times of the day. To that end, we produce peak demand forecasts that are consistent with the EDGS 2019.

We produce two versions of peak demand forecasts. One is the "expected" forecast and this aligns with the EDGS. The EDGS 2019 are P50 forecasts, in that they represent the 50th percentile from a distribution of forecasts. We use these in our economic analysis to determine a preferred option.

The other is a "prudent" peak demand forecast. This is a higher demand forecast, where we use the P90 forecast, representing the 90th percentile of the demand forecast distribution for the first 7 years, revering to the P50 forecast after that. Prudent forecasts recognise that demand forecasts are a distribution, it takes time to commission new assets, and that the risks from delivering a project late could be high, particularly if demand growth is higher than expected. We use these to determine the preferred commissioning date.

The expected and prudent gross national peak demand forecasts proposed for the NZGP1 scenarios, by scenario, by year are shown in Appendix C.

5.5 Identifying NZGP1 generation scenarios

As explained in section 5.2, we decided it was necessary to consult further, in respect to generation scenarios, following our December 2020 consultation. This further consultation used a written consultation paper published on our website in May 2021. The consultation targeted potential generation investors but was open to all stakeholders.

Feedback to that consultation re-confirmed there is too much uncertainty regarding future generation possibilities for grid-connected generation in New Zealand, to reflect in just five nationally determined scenarios, as per the EDGS 2019.

As well as uncertainty around such issues as which generation technologies will be built and where, our consultation highlighted there are several large uncertainties which are too significant to spread across the five EDGS:

- Tiwai closure date and any Southland replacement demand
- The possibility of Taranaki offshore wind being built
- Peaking and dry year reserve options:
  - South Island (Onslow) – small (5 TWh), medium (8-10 TWh) and large (12 TWh) are 3 variants worth considering
  - North Island (with gas peaking allowed)
  - North Island (100% renewables with a combination of generation overbuild, batteries, demand response and perhaps pumped hydro or hydrogen)
- A higher proportion of grid-connected solar generation compared to wind generation

Our proposed approach is to have "base scenarios" which reflect our five EDGS demand variations and generation build uncertainty only, with each of the uncertainties above considered in separate scenarios termed "sensitivity scenarios".

The sensitivity scenarios consider uncertainties which would have a significant effect on the transmission grid required, but they are not confirmed, nor are likely enough to include in our base scenarios. These will be studied, just as our base scenarios are, in order to understand their impact if they did occur, but we will reserve our opinion on whether they should be included in our Investment Test analysis until as late as possible. This will allow as much time as possible for uncertainty to resolve. Where they are included, we will need to assign a weighting to the sensitivity scenario. Weighting scenarios is discussed in section 5.7.

Question 10: Is our proposal to identify base scenarios and sensitivity scenarios reasonable?

5.51 Generation cost stack

The timing and location of future new generation is extremely difficult to predict.

Wind and grid-scale solar generation are prevalent and appear likely to be the cheapest source of new generation in the future, but they are also intermittent. Eventually, some may appear with storage, but that seems less likely in the near future, hence some firming generation will also be required. The available firming technologies are natural gas, geothermal and hydro, but the first two are (to varying degrees) in conflict with our greenhouse gas emissions target and large-scale hydro power developments face public opposition on environmental grounds.

Our approach to forecasting new generation is to use a least-cost generation expansion model, which looks to find a generation expansion plan which results in the lowest cost electricity overall. The model uses a stack of potential generation projects provided by MBIE. The EDGS 2019 generation scenarios were developed using a generation stack developed in 2011, but MBIE updated the generation stack in 2020. The new generation stack is more reflective of current and forecast generation costs and generator intentions and we have used it to develop our proposed NZGP1 generation scenarios. The EDGS 2019 did not use the new generation stack, however the new stack was produced by MBIE and we have consulted widely on its use, so we are still referring to our generation scenarios as EDGS 2019 variations.

The MBIE 2020 generation stack update[15] highlights the abundance of economic wind and solar resource right across New Zealand, with at least 20 GW being available and much of it being a similar cost. That information drove our most recent consultation with generation developers, which sought information to help prioritise the new wind and solar generation we should enable. The result is our so-called Table 5-2, which shows the wind and solar generation we will look to enable as a part of our NZGP study, by region and decade, out to 2050.

[15] Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz)

Table 5-2 New grid scale wind and solar generation Transpower will plan on enabling in NZGP1

Revised Table 2 - New grid-scale wind and solar generation Transpower will consider enabling in NZGP project, by region and decade												
	MW		Committed	2021-2030		2031-2040		2041-2050		2021-2050		Total
	Region			Wind	Solar	Wind	Solar	Wind	Solar	Wind	Solar	
1	Far North		0	100	150	0	150	100	0	200	300	500
2	Northland		0	100	150	400	150	200	0	700	300	1000
3	Auckland		0	100	25	0	0	200	0	300	25	325
4	Waikato		0	500	50	400	150	0	0	900	200	1100
5	BOP-Taupo		0	250	300	500	0	350	200	1100	500	1600
6	Eastland		0	0	50	0	50	150	50	150	150	300
7	Central Plateau		0	200	0	0	0	400	0	600	0	600
8	Hawkes Bay		176	0	100	0	0	0	200	176	300	476
9	Taranaki		133	100	50	100	0	100	0	433	50	483
10	Manawatu		222	150	0	200	50	100	50	672	100	772
11	N Wairarapa		0	500	50	500	50	100	50	1100	150	1250
12	S Wairarapa		0	0	0	0	50	100	50	100	100	200
13	Wellington		0	0	0	100	0	100	0	200	0	200
14	Marlborough		0	0	0	200	50	0	50	200	100	300
15	Nelson		0	0	0	0	50	0	50	0	100	100
16	West Coast		0	0	0	0	0	0	0	0	0	0
17	N Canterbury		93	200	0	0	50	0	50	293	100	393
18	S Canty/N Otago		0	0	100	0	150	0	200	0	450	450
19	C Otago/S Otago		0	150	0	100	50	400	50	650	100	750
20	Southland		0	100	0	150	0	400	0	650	0	650
			624	2450	1025	2650	1000	2700	1000	8424	3025	11449

This version of Table 2 is an output of our recent generation consultation. The numbers in red are different to those in our consultation paper and reflect feedback received.

Table 5-2 reduces the available wind and solar our generation expansion model can build. All the projects included in Table 5-2 are included in the 2020 generation stack, but not all the 2020 generation stack projects are included in Table 2.

Table5- 2 includes more wind and solar generation than will be required under any of our demand forecasts, but by enabling this amount we will ensure the generation investment market remains competitive.

5.52 Process for identifying an appropriate set of generation scenarios

There is considerably more uncertainty around future new generation build than when MBIE developed the EDGS 2019 and this is reflected in our process for developing an appropriate set of generation scenarios. Our process is shown diagrammatically in Figure 5-8 and sections 5.53 to 5.55 describe our application of this process for this NZGP1 MCP.

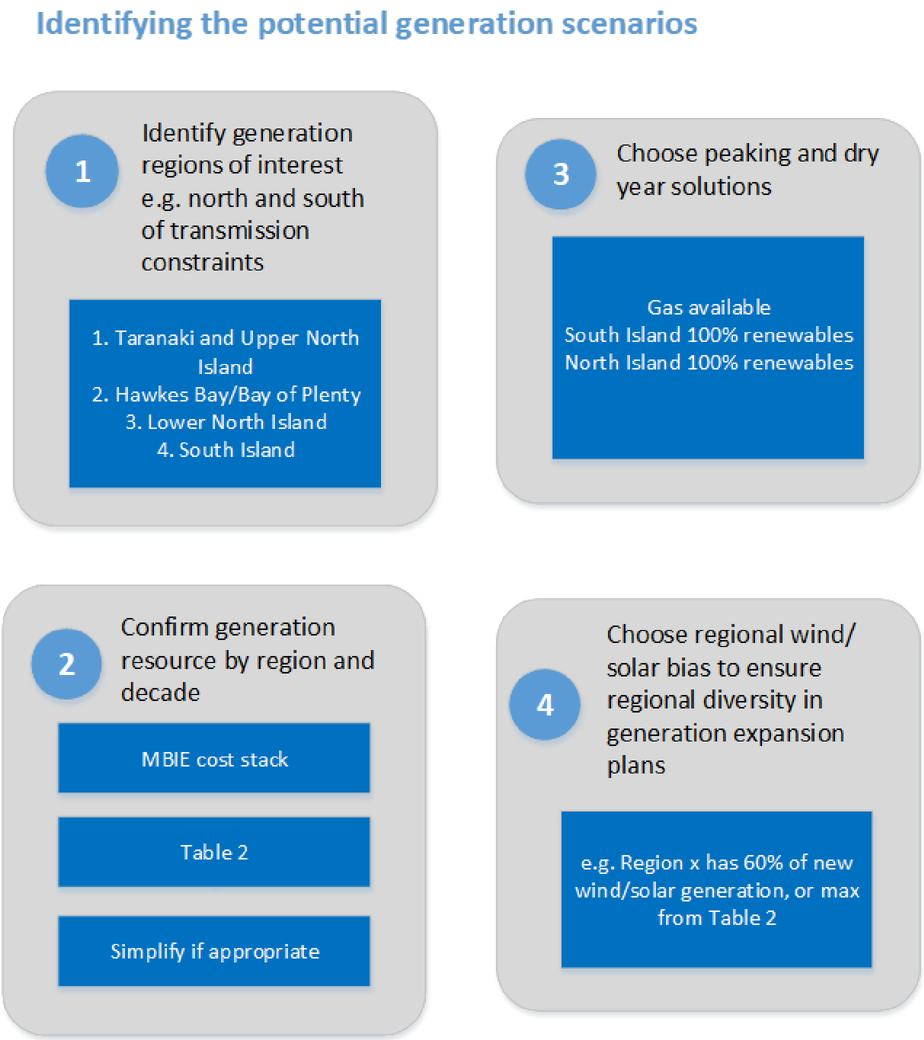


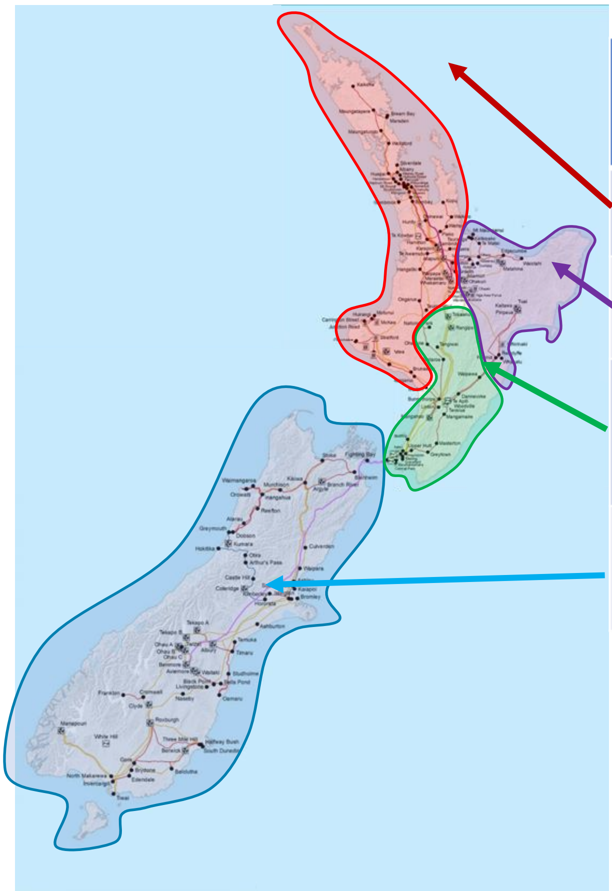
Figure 5-8 Process for identifying potential generation scenarios

Question 11: Is our process for identifying potential generation scenarios reasonable?

5.53 Identify regions

To identify relevant generation scenarios, we begin by identifying regions wherein any generation development will lead to distinct transmission implications for the part of the grid under investigation (from the top of the South Island to Whakamaru (including the Wairakei Ring), in this instance). In this way, we need only consider scenarios where generation expansion differs at an *inter-regional* level and reduce the number of relevant generation scenarios. Scenarios that only differ at an *intra-regional* level will not lead to significantly different transmission implications and therefore need not be considered independently.

Our assumptions and rationale for regional definitions, for the NZGP1 investigation are shown in Figure 5-9 below.



	Rationale
Region 1	Region 1 contains significant North Island demand centres. Generation expansion within this region is likely to reduce the need for upgrades in the Central North Island, Wairakei ring, and on the HVDC.
Region 2	Region 2 includes the Bay of Plenty, Taupo volcanic zone, and Hawkes bay. Generation expansion within this region is likely to exacerbate the transmission constraint on the Wairakei ring while reducing the need for upgrades in the Central North Island and on the HVDC.
Region 3	Region 3 includes the lower North Island, stretching up to Tokaanu. Generation expansion within this region is likely to primarily exacerbate the transmission constraint in the Central North Island. The Wairakei ring is also exposed to additional flows but to a lesser extent. Generation expansion within this region has potential to reduce the need for upgrades on the HVDC.
Region 4	Region 4 includes the entire South Island. This region has the potential for significant step changes in both load and generation. Any such step change is likely to have an immediate impact on the capacity requirement of the HVDC. Any increase in the net export of this region would also likely exacerbate the transmission constraint in the Central North Island.

Figure 5-9 Relevant regions for generation scenarios

Generation scenarios which bias generation build toward each of these regions will help assess the benefit of investing in the grid. This would result in four different scenarios, biasing build in region 1, 2, 3 and 4r respectively.

As a comparison we propose also including a scenario where a region's wind/solar expansion is correlated with demand growth in that region up to the Table 2 maximum. Such a scenario reflects a neutral generation build.

5.54 Identify the technology and resource availability by region

Next, we identify the technology and resource availability by region. Our assumptions around this are shown in Table 5-4.

For interest, our Table 5-2 reduces to the following table for the purposes of these regions.

Table 5-3 Table 2 can be reduced to this table for the purposes our NZGP1 investigation

MW	Committed	2021-2030	2031-2040	2041-2050	Total
NZGP1 Region					
1	176	1483	1442	783	3841
2	133	542	459	767	1943
3	222	900	950	950	3022
4	0	550	800	1200	2643
	531	3475	3650	3700	11449

Table 5-4 Generation technology and resource availability by region

	Wind	Solar	Hydro	Geothermal	Gas (and other thermal generation)
Region 1	✓	✓	✗	(✓)	✓
Region 2	✓	✓	✗	✓	✗
Region 3	✓	✓	✗	✗	✗
Region 4	✓	✓	✓	✗	✗

Key
- ✓ Abundant and economic
- (✓) Limited availability
- ✗ Unavailable and/or uneconomic

This approach can be used to simplify the analysis and highlight potential important scenarios. For this investigation:

a) We should consider only the Table 5-2 amounts of wind and solar-connected generation in each region
b) We will exclude the small amount of hydro in Region 2 in order to simplify the modelling
c) We should consider a scenario which considers a high geothermal build in Region 2.

Otherwise the technology availability is per MBIE's 2020 generation stack.

5.55 Identify peaking and dry year solutions

Next, we consider the availability of firming or peaking capacity and dry year reserve in a scenario. This is a critical consideration in the electricity supply mix and for the generation expansion model. Trade-offs between security, environmental sustainability, and energy equity (the three corners of the trilemma) exist between different options, making it difficult to predict likely approaches. Our consideration of available technologies, along with a brief rationale, are shown in Table 5-5.

Gas	Hydro	Batteries	Flexible demand	Pumped hydro	Generation overbuild	Hydrogen
Pros: Resilient Flexible Relatively cheap **Cons**: Carbon emissions	**Pros**: Economic long-term Zero carbon emissions **Cons**: Dry year vulnerability Environmental impact	**Pros**: Low to zero carbon emissions Can support grid stability **Cons**: Emerging technology Currently uneconomic	**Pros**: Zero carbon emissions **Cons**: Uncertainty around availability and economics Potential resilience issue	**Pros**: Zero carbon emissions **Cons**: Expensive Environmental impact Uncertain economics	**Pros:** Zero carbon emissions **Cons:** Expensive Environmental impact Uncertain economics	**Pros:** Zero carbon emissions **Cons:** Emerging technology Currently uneconomic
Current solution and assumed to be available in our futures	Large scale considered unlikely, excepting expansion of existing plants	Likely and may play a minor part in some scenarios	Likely and likely to play a minor part in some scenarios	High expected cost Considered as a sensitivity only	High expected cost Considered as a sensitivity only	High expected cost
Peaking	Peaking	Peaking	Peaking	Peaking	Peaking	[Peaking]
Dry year reserve			[Dry year reserve]	Dry year reserve	Dry year reserve	[Dry year reserve]

Table 5-5 Table comparing various technologies for providing peaking generation and dry year reserve

These technologies combine into three main relevant peaking and dry year solutions for New Zealand:

1) North Island gas peakers allowed. The CCC consideration of the energy dilemma resulted in them recommending to the government that gas peakers should be allowed through to 2050. Although this does not achieve a 100% renewable electricity future, it results in a 96-98% renewable electricity future and is far cheaper. Given their recommendation and the difficulties, including cost, of achieving a 100% renewables future, we propose to include this solution in all our base scenarios.
2) Lake Onslow is developed. The New Zealand battery project is currently considering this option and several versions of it, but their work is not well enough developed to understand the feasibility. We propose considering 3 possible variants of Lake Onslow development as sensitivity scenarios:
    - A smaller Lake Onslow development, which manages South Island dry winter risk only. This variant would not manage North Island peaking requirements (approx 5 TWh).
    - A medium Lake Onslow development, which manages South Island dry winter risk and includes some limited transfer to the North Island for balancing renewables (approx 8 TWh).
    - A large Lake Onslow, which manages South Island dry winter risk and North Island intermittency risk (approx 12 TWh).

3) A North Island 100% renewables solution is developed – we would expect this to be a mixture of technologies, including generation overbuild, batteries, flexible demand and possibly pumped hydro and hydrogen. Currently there is no such option and it is unclear whether market participants, responding to appropriate signals, would develop this themselves. As with Lake Onslow development this solution is not well developed enough to include in our scenarios.

   We propose including evaluation of these as sensitivity scenarios.

5.56 Principles for identifying an appropriate and tractable set of demand and generation scenarios

For this NZGP1 investigation and as described below, we have identified 4 geographic regions of interest and at least 4 generation technologies which need to be varied. In combination with the 5 demand scenarios and likely minimum of 6 short-listed development plan options, that could mean a total of 480 combinations to be evaluated if we consider them all.

We consider it impractical to consider this number of combinations in our investigations and we do not consider it necessary to reach a robust result. Although we must investigate the full range of potential uncertainties in our analysis, we consider 10 scenario combinations would be the maximum practical. Multiplied by the likely minimum of 6 short-listed development plan options, that still means 60 combinations need to be evaluated.

As discussed above, we have identified some potential futures which will be analysed as sensitivity scenarios. We propose 7 sensitivity scenarios, which would give a total of 67 combinations.

Despite the practical difficulties that presents, we also recognize the unprecedented future uncertainties the electricity industry face at the moment and acknowledge the need to be thorough and analyse a wide range of possible futures.

In order to determine a reasonable range of scenarios, we have developed some principles that will be applied in each investigation, which attempt to balance rigour and practicality:

- Regions relevant to the investigation should be represented.
- All generation scenarios which might require significantly different transmission options should be included.
- All combinations of demand and generation scenarios which might require significantly different transmission options should be included.
- Choose a selection of scenario combinations which cover a wide range of uncertainty regarding both demand and generation.
- The minimum number of scenarios to be analysed should be 5.
- For practical purposes, the maximum number to be analysed should be 10, excluding sensitivity scenarios.

Question 12: Is our approach to determining an appropriate number of scenarios reasonable?

5.6 Identifying scenarios - matrix of possible scenario combinations

The sections above identified a range of possible scenarios which should be considered. Combining these into a matrix of possible demand and generation scenarios, we get the matrix shown in Table 5-6 below.

Table 5-6 Table of possible demand and generation scenario combinations for NZGP1

	Global	Reference	Growth	Environmental	Disruptive
Region 1 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind: solar capacity (MW) split is 75:25					
Region 2 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
Region 3 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
Region 4 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
A region's wind/solar expansion is correlated with demand growth in that region up to the Table 2 maximum. Our national wind:solar capacity (MW) split is 75:25.					
Geothermal expansion plays an significant role in the long term generation expansion[16]					

[16] We have observed that geothermal generation is not preferred by Optgen. This is related in part to the inclusion of gas peakers within the model. In addition, the model struggles to accurately quantify the difficulties relating to intermittency of wind and solar. From the models perspective, wind and solar has more of a "base-load" role (equivalent to geothermal, but significantly cheaper), whereas in reality this is not the case. For these reasons we consider geothermal expansion as a separate scenario.

For this NZGP1 investigation, we have identified 4 geographic regions of interest and 2 other generation driven scenarios which should be varied. In combination with the 5 demand scenarios and a likely minimum of 6 short-listed development plan options, that could mean a total of 180 combinations to be evaluated if we consider them all.

Along with 7 sensitivity scenarios, a total of 187 combinations. This an impractical number, so we apply our principles:

Regions relevant to the investigation should be represented

The 4 regions identified in section 5.53 are all relevant as different flows between these regions will determine the benefit of investing in the transmission grid. All should be included.

All generation scenarios which might require significantly different transmission options should be included.

If we test the 4 regions identified and compare that to a neutral generation expansion plan, we will identify the minimum and maximum benefit for each transmission grade option, so the neutral generation expansion scenario should also be included.

The 4 regions identified will not test the benefits if a high geothermal expansion occurs. For that reason, the high geothermal expansion scenario should be included.

All combinations of demand and generation scenarios which might require significantly different transmission options should be included.

One area we can rationalise the number of combinations is in our choice of demand forecasts. Rather than test all 5 demand scenarios, we propose that testing just, a relatively high scenario and a relatively low scenario, will provide good information. We propose the Reference demand scenario being a lower scenario and the Environmental scenario as the higher scenario. As noted in section 5.41, the Environmental scenario is close to the mid-range demand forecasts produced in the CCC and WiTMH forecasts.

Choose a selection of scenario combinations which cover a wide range of uncertainty regarding both demand and generation.

By using all generation scenarios and a high and low demand scenario, we are covering a wide range of uncertainties. We recommend analysing the neutral generation expansion scenario across all demand scenarios, as a base.

The minimum number of scenarios to be analysed should be 5.

This results in 15 demand and generation combinations, which is more than 5.

For practical purposes, the maximum number to be analysed should be 10, excluding sensitivity scenarios.

We have identified a preferred number of 15 demand and generation combinations. This is more than the recommended maximum in our principles, but it is difficult to see how the number could be reduced to 10 and still cover a robust range of futures.

We propose to analyse the scenarios shown in green in the table below.

Table 5-7 Table of proposed demand and generation scenario combinations for NZGP1

	Global	Reference	Growth	Environmental	Disruptive
Region 1 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
Region 2 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
Region 3 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
Region 4 incurs 60% of national wind/solar expansion out to 2035 or max from Table 2. The remaining 40% is split equally among other regions. Beyond 2035, the expansion is correlated to regional demand. Our national wind:solar capacity (MW) split is 75:25					
A region's wind/solar expansion is correlated with demand growth in that region up to the Table 2 maximum. Our national wind:solar capacity (MW) split is 75:25.					
Geothermal expansion plays an significant role in the long term generation expansion					

There are a total of 15 scenarios in the table above, which when combined with our expected 6 short-listed development options and 7 sensitivity scenarios, gives a total of 97 combinations. This close to being intractable, but such a set will allow us to robustly deduce the net benefit of each investment option and identify a preferred overall option.

Question 13: Is our choice of scenarios to include in our analysis reasonable?

We note that each scenario combination requires a counterfactual to test it against. The counterfactual is a "Do Nothing" option, which in this case means determining a reasonable generation expansion plan if investment in the transmission grid does not occur. It is not clear to us at this stage, how many counterfactuals will be required. The worst case (from the point of view of tractability of the analysis), would be that each scenario requires its own counterfactual. This would double the amount of analysis required. The best case (from the point of view of tractability of the analysis), is that a single counterfactual will be suitable for all scenarios. This is unlikely, but until we undertake the analysis, we will not know.

5.7 Sensitivity scenarios

As discussed above, there are several large uncertainties which are too significant and too uncertain to spread across the five EDGS:

- Tiwai closure date and any Southland replacement demand
- The possibility of Taranaki offshore wind being built
- Peaking and dry year reserve options:
    - South Island (Onslow) – there are 3 variants worth considering
    - North Island (with gas peaking allowed)
    - North Island (100% renewables with a combination of generation overbuild, batteries, demand response and perhaps pumped hydro or hydrogen)
- A higher proportion of grid-connected solar generation compared to wind generation

Each of these would have a significant impact on the requirements of the transmission grid and if some emerged, they may mean we should not proceed with this investigation, but rather should be developing an alternative option. However, all are uncertain and none of them are developed enough to include in the base scenarios we use for Investment Test analysis.

It is important we understand the transmission implications of these scenarios occurring and so are proposing to consider them as sensitivity scenarios. We will publish our findings from analysing them but will reserve our opinion on whether they should be included in our Investment Test analysis until as late as possible. This will allow as much time as possible for uncertainty to resolve. Where they are included, we will need to assign a weighting to the sensitivity scenario. Scenario weightings are discussed in section 5.8.

Table 5-8 Table of proposed sensitivity scenarios for NZGP1

	Sensitivity scenario	Description
1	Southland sensitivity	Tiwai closes in 2030 and Manapouri's production is fully utilized by a hydrogen exporting plant
2	Taranaki offshore wind	1 GW of offshore wind is developed in the Taranaki region. Most of the electricity is used onshore for hydrogen manufacture, but a 300 MW connection is made to the transmission grid, so the plant can participate in the market when it chooses
3	Onslow 1	Small
4	Onslow 2	Medium
5	Onslow 3	Large
6	North Island 100% renewables solution	
7	50:50 wind/solar generation outcome	

Question 14: Is our set of sensitivity scenarios reasonable?

5.8 Scenario weightings

The Investment Test requires that 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 demand and generation scenario.

The default position for scenario weightings is that they are equally likely.

Our approach to managing the number of potential scenarios, however, involves choosing a range of scenarios, some of which are more extreme, to ensure we analyses the boundaries of future uncertainty. The question then arises as to whether the scenarios we are using are still equally likely. They may have different likelihoods and not be equally weighted.

The panel agreed with that view when we raised it in our panel meetings late in 2020, but we did not discuss how to determine suitable weightings.

We did include a section on scenario weightings in our written consultation document issued in December 2020 but did not receive substantive feedback.

In this document we will not attempt to assign weightings to our recommended set of scenarios. Rather we will publish proposed weightings in our next consultation. Instead we would like to repeat our proposed approach to determining scenario weightings and seek further feedback.

Although the EDGS 2019 are equally weighted by default, we have developed EDGS 2019 variations for NZGP1 demand scenarios and would see the direction of their weighting moving as shown in Table 5-9.

Table 5-10 shows our view of how the likelihood of generation technologies has moved since EDGS 2019 and Table 5-11 shows our view of the relative likelihood of peak and dry year reserve options compared to an equal weighting.

Table 5-9 How we view relative weightings between demand scenarios might have changed since the EDGS 2019

Demand scenario	Global	Reference	Growth	Environmental	Disruptive
EDGS 2019	20%	20%	20%	20%	20%
EDGS 2019 variations	↓	↑	↓		↑

Table 5-10 How we view relative weightings between generation technologies might have changed since the EDGS 2019

Generation technology likelihood	Hydro	Geothermal	Wind	Solar
Equal weighting	20%	20%	20%	20%
Current view on likelihood	↓		↑	↑

Table 5-11 How we view relative weightings for peaking and dry year reserve options

Peaking and dry year	Thermals	Onslow	North Island 100% renewables
Equal weighting	33%	33%	33%
EDGS 2019 variations	↑	↓	↓

We are not proposing any more exact weightings at this time but will leave that to our second consultation.

We note that assigning weightings is a subjective exercise and may be contentious. For that reason, we are considering the use of “likelihood bands” as follows:

Table 5-12 How likelihood bands could be used so that precise, yet subjective, weightings are not required

Likelihood band	Likelihood	Scenario weighting
A	0-20%	10%
B	10-30%	20%
C	20-40%	30%

Using this approach each scenario would be classified as A, B or C, assigned a 10%, 20% or 30% weighting initially and then these would be scaled to equal 100%. This purpose of this approach is to recognise that some scenarios are less or more likely and to minimise subjective discussions.

Question 15: Is our approach to determining the weighting for each scenario appropriate?

5.9 The Investment Test Parameters

5.91 Calculation period

The Capex IM states the default calculation period for costs and benefits is 20 years but allows for it to be altered if benefits can be better captured using a different period. Some transmission assets have long lives, greater than 20 years, so relative benefits will continue to accrue for some options after 20 years. The effect of discounting future benefits to present values does diminish their effect, but nevertheless they can be significant. We propose a calculation period out to 2050 to better capture the costs and benefits over the useful life of some options in this analysis. 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.

5.92 Value of expected unserved energy

The Value of Lost Load (VoLL), which is also known as Value of Expected Unserved Energy) is the assumed value to consumers 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 Code specifies that VoLL should be $20,000/MWh. This value was determined in December 2004 and including inflation, equates to $26,200/MWh in $2021. We propose to reflect this value in our analysis in 2019, we completed a VoLL study which determines VoLL by GXP9. This reflects the fact that each GXP has a different mix of domestic/commercial/industrial load, each of which has a different VoLL. We are not proposing to use these VoLL's in this study due to the national nature of the grid backbone and its components.

5.93 Discount rate

The Capex IM defines a standard real, pre-tax discount rate of 7%, with low and high sensitivities of 4% and 10% respectively. The discount rate of 7% was set at a time when that rate was close to Transpower's WACC and it seems a high rate to use today. We are considering using an alternative discount rate, closer to our current WACC, with sensitivities of +/-3%.

Question 16: Would interested parties support the use of a discount rate for Investment Test analysis, closer to Transpower's current WACC?

5.10 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. These include, but are not necessarily limited to:

- 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 eg costs of existing assets, options and modelled projects
- Cost of ancillary services
- Cost of losses, including transmission and local losses
- Third party contributions to the cost of a project
- Subsidies or other benefits provided under or arising pursuant to all electricity-related legislation and electricity-related administrative determinations
- Competition effects

5.11 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

5.12 Expected net electricity market benefit

We will determine the net electricity market benefit for each short-listed option, for each demand and generation scenario, being its aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost.

The expected net electricity market benefit, for each option. is the weighted average of the net electricity market benefit under each demand and generation scenario, where the weighting is that determined for each demand and generation scenario, as discussed in section 5.8.

5.13 Passing the Investment Test[17]

An investment option satisfies the IT 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.

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

The Capex IM recognises the inherent uncertainty in estimating costs and benefits in Investment Test analysis and 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.

5.14 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.

[17] For more detail on terms used in the Investment Test, refer to Division 2 of Schedule D in the Capex IM.

Question 17: Are there any other costs or benefits we should consider in our Investment Test analysis?

Appendix A Request for Information from proponents of non-transmission solutions

Request for Information from proponents of non-transmission solutions

One purpose of this long-list consultation is to seek expressions of interest from proponents of non-transmission solutions (NTS) in providing a service which could help meet the need. The following descriptions are intended to guide proponents of NTS and assist them in deciding whether to offer a suitable service. They are not intended to be exhaustive and may be inaccurate, as we are not experts in NTS. They do represent our current thinking, but we would be more than happy to discuss other alternatives with potential NTS providers.

NTS are an alternative to a transmission investment in the grid, which might:

- avoid or defer a transmission investment
- manage operational risks due to unavailability of grid assets during a major capex project.

In our view, for this need, NTS are more likely to be economic to defer investment in transmission, or to help manage operational risks during the transmission outages needed to implement a transmission solution. The descriptions that follow relate to NTS for upgrading parts of the existing grid, rather than meeting the overall need, as we could not think of a NTS that might be suitable for the overall need.

However, as already stated, we would welcome other ideas from proponents of NTS, the potential NTS described below relate to:

- NTS to increase HVDC transfer capacity across Cook Strait to 1400 MW; and
- NTS to increase transfer capacity between Bunnythorpe and the Wairakei Ring to Whakamaru (being two separate capacity increases that have synergies).

To provide material benefits, a NTS will likely need to be 100 MW or greater. Recognising how restrictive that is, we are interested in hearing from proponents of smaller NTS, as it is possible, they could be aggregated.

High level requirements

In general, the NTS would be expected to respond to commands from a grid scheme that automatically redispatches the system to remove transmission overloads following an event on the grid (an event in this case would mean a circuit has been disconnected due to a fault in the system).

Some of these descriptions are concepts only at this stage and if there are proponents interested, we would need to validate their efficacy through modelling and possibly discuss the impact on the market with regulators, before they would advance.

HVDC Cook Strait capacity

Unbalanced HVDC operation, above 1200 MW and without an extra Cook Strait cable, will require a higher level of instantaneous reserves to be purchased by the System Operator. Currently, the amount of reserves in the North Island is limited, so for options where we are able to extend HVDC transfer capacity above 1200 MW, a NTS may be where Transpower pays a participant to enable their demand to participate in the reserves market. Such participants would then have an obligation to offer into the reserves market.

Battery as an NTS for HVDC

Another mechanism for enabling more instantaneous reserves, would be a payment to a battery owner to provide such a service.

A charged battery, in the North Island, could provide North Island instantaneous reserves.

We note that HVDC operation above 1200 MW, however that capacity is provided, would also require new reactive response (which could be from a device such as a STATCOM), but could also be provided from an appropriately specified battery.

To be effective for this requirement, the battery would need to be installed at or south of Bunnythorpe and be directly connected to the grid. The most effective Transpower locations would be Haywards or Wilton. There is insufficient space at those Transpower locations for a battery, however there would be room to install a battery at either our Linton or Bunnythorpe sites. We would be prepared to consider a third-party battery installation at those sites.

A battery providing instantaneous reserves only could be installed anywhere in the North Island.

CNI and Wairakei Ring capacity

Flexible demand as an NTS for CNI and Wairakei Ring

We have identified two potential modes of operation, for deferring the need to upgrade the CNI and Wairakei Ring circuits. Both transmission corridors potentially constrain flows from Bunnythorpe and Wairakei to Whakamaru respectively (i.e. south to north flow constraints on both corridors):

- A potential pre-contingency mode were there upper North Island consumers who would be prepared to reduce demand during high CNI or Wairakei Ring flow periods.
  - If so, CNI or Wairakei Ring flows could be smoothed and avoid the need to upgrade capacity. This could potentially be an NTS where such consumers would respond to “calls” from Transpower, in a similar manner to how other demand response operates now, but perhaps with a shorter call window.
  - This NTS may appeal more to consumers who have flexible demand i.e. demand which can be turned down, or turned off, at short notice, as required.

- Post-contingency, where a Special Protection Scheme (SPS) will detect an overload on one of the constraining circuits and instruct demand north of Whakamaru to disconnect and generation at or south of Tokaanu and Wairakei to ramp down until the overload is removed.
  - Reducing generation at or south of Tokaanu will address CNI constraints while reducing generation electrically at or south of Wairakei will address Wairakei Ring constraints.
  - The controlled demand and generation will remain off until the System Operator restores the grid back to a secure state and provides confirmation that it can be restored.
  - An example would be where a Tokaanu–Whakamaru circuit outage occurs, overloading the remaining circuit. Demand north of Whakamaru could be reduced and generation at or south of Tokaanu reduced to remove the circuit overload until the System Operator redispatches the system to a secure state.
  - The demand and generation will need to be automatically controlled and is typically required to reliably respond within 5-10 seconds when instructed.

- The feasibility and design of the SPS depends on the characteristics of the load and generation that are connected to the scheme (e.g. if the load cannot be disconnected at a similar rate to the ramp rate of the controlled generation then the scheme may not produce the desired outcome as generators elsewhere will respond to the deviation in system frequency).
- Note that this is only discussed as a concept, we have not confirmed such a scheme can be implemented nor do we have agreements with generators that may partake in such a scheme. Studies will need to be undertaken once interested parties provide details of their proposals to confirm it is feasible, but before an RFP is issued.
- For this NTS, the demand and generation do need to be matched and we would prefer hearing from proponents with matched pairs. We will consider unmatched demand or generation, but please be aware that unless a match is also indicated, the unmatched demand or generation may not progress.

Flexible demand to assist with implementation outages

If upgrading the existing CNI or Wairakei Ring circuits provides the highest net benefit compared to other options, we will need circuit outages to implement the upgrade/s. Flexible load in the upper North Island could assist with outages by reducing load on the remaining circuits at peak times. The need for such a service has not yet been confirmed, so we would ask potential proponents to register their interest and we would issue a RFP closer to the time.

Battery (and rampable generation) as a NTS for CNI and Wairakei Ring

A battery, or rampable generation, could operate in a similar manner to flexible demand in this instance. We have identified two potential modes of operation:

- A potential pre-contingency mode, where an upper North Island battery, or rampable generator, acts like a generator during high upper North Island demand periods and when flows on the CNI or Wairakei Ring circuits is high. The battery, or rampable generation would effectively smoothing out flows on the CNI or Wairakei Ring transmission corridors. Note that we would contract any rampable generation through our Grid Support Contract (GSC) and so the conditions of that contracting would apply.

- Post-contingency, where a SPS will detect an overload on one of the constraining circuits and instruct the battery/rampable generation north of Whakamaru to ramp up power output and generation at or south or Tokaanu and Wairakei to ramp down until the overload is removed. The controlled battery and generators will maintain its output until the System Operator redispatches the system to a secure state (this is expected within 15 minutes). An example would be where a Te Mihi–Whakamaru circuit outage occurs, overloading the Atiamuri–Ohakuri circuit. The SPS instructs the battery/rampable generation north of Whakamaru to increase its power injection and generation at or south of Wairakei to reduce its output until the overload is removed and these setpoint is maintained until the System Operator redispatches the system to a secure state. Similarly to the flexible demand option, this is a concept only and feasibility and design of the SPS depends on the characteristics of the battery and generators. However, a battery/rampable generation is typically more controllable than demand and is more likely to be a feasible option compared to flexible demand.

Battery to assist with implementation outages

If upgrading the existing CNI or Wairakei Ring circuits provides the highest net benefit compared to other options, we will need circuit outages to implement the upgrade/s. A battery in the upper North Island could assist with outages by reducing load on the remaining circuits at times of peak flow on those circuits. The need for such a service has not yet been confirmed, so we would ask potential proponents to register their interest and we would issue a RFP closer to the time.

Synergies between projects and with WUNIVM

Transpower is also currently seeking expressions of interest in NTS to assist with meeting the voltage stability need in the WUNI region. That RFI is more specific than for this project, but we are aware that synergies may exist with some solutions being able to support the needs of multiple projects. We would be happy to consider NTS for multiple projects.

Process for progressing NTS

At this long-list stage, we do not have costs for any transmission options and correspondingly, are not expecting proponents of NTS to provide costing information. The purpose of this RFI is to provide information to potential proponents of NTS and encourage those proponents to submit an expression of interest to Transpower. The examples mentioned above are not intended to be exhaustive and we would welcome new ideas. We are open to receiving information about one solution or a combination of these solutions to meet the need.

Following any expression of interest, our process will be to discuss potential use of the NTS with the proponent in more detail and mutually decide whether to proceed to a Request for Proposal (RFP). Detailed technical information and costing would be required in response to a RFP, so Transpower can compare the NTS against transmission options using the Investment Test.

Transpower would intend to contract any suitable NTS through our Grid Support Contract (GSC).

Other information

Other information applicable to Transpower use of a NTS is provided below. It is in no particular order, but is provided for interest.

Battery solutions

There may be some space available to support NTS solutions on Transpower owned land at existing grid connection sites. Transpower would be open to exploring this possibility with potential proponents in order to facilitate NTS options that may otherwise be unable to proceed.

Demand reductions

To minimise the overhead of managing multiple contracted parties, we are limiting the minimum demand reduction capability of an NTS offer to 10 MW.

Composition of demand reduction

For demand management, we would like to know the type of demand being reduced (e.g. commercial refrigeration, residential, industrial process etc.).

Contracting with generation

As stated above, we would contract with a NTS provider using our GSC[18]. GSCs allow for a limited scope of market generation procurement. GSC procurement is restricted to services that contribute MW and/or MWh that would otherwise not be available without such a contract being in place. We assume the generator would participate in the wholesale market once the GSC is in place, but not

[18] See Grid Support Contracts (transpower.co.nz) for more information.

with the portion of generation contracted through the GSC. To be a viable NTS, generation would need:

- an ability to ramp up or down quickly
- to be available as and when required ie the generation capacity offered for use as a NTS would not be able to participate in the wholesale market – at least at times of peak load on the grid.
- to provide a high level of reliability, which may mean providing redundancy in generating units.

For this type of NTS, Transpower will not provide payment for supplying real power (MW) or MWh, but rather though a preparation payment we may incentivise generation:

- to increase the available capacity above that which would otherwise occur, or
- to increase the reliability of a generating unit relative to that which would otherwise occur

Any new generation commitment will need to comply with the System Operator's generator connection requirements and generation requirements specified in the Code (e.g. generator ride through criteria).

Common requirements

The following requirements would be common to all types of NTSs.

Availability and expected operation

A pre-contingent NTS must be available to operate during all demand periods. Unlike demand response, which is most useful at times of high demand, this demand response would be subject to dispatch patterns and times of high flow may not be related to demand.

A shorter notice period may also be required in order to correspond with the determination of dispatch instructions by the System Operator. Yet to be determined, but the notice period may only be 30 minutes.

Given uncertainty inherent in determining optimal dispatch instructions, it is also uncertain how often and how long we would require an NTS to operate.

Technologies

Although we are technology agnostic, we are seeking proven technology that will deliver the described service requirement. The NTS should ideally have been proven on a high-voltage transmission network and the information provided would support this.

Service level

For a NTS to be a viable alternative to transmission it must be both available and reliable. In the event of non-delivery of the procured service there are likely to be contractual penalties against the provider.

Transpower's planning guidelines ensure a resilient and robust supply of electricity to consumers following major unexpected events (or high-impact, low-probability HILP events). Any contracted NTS would be expected to operate to similarly high levels of reliability (available ~98% of the time during contracted periods).

To ensure the necessary levels of reliability, all NTSs will be required to undertake commissioning and routine tests as specified and required by the System Operator [19].

Other terms

We are seeking NTS as a means of deferring the need for transmission equipment or assisting during the installation of transmission equipment.

Our expectation for an NTS that defers the need for transmission equipment, is that the contract term would be 1-3 years, although it may be longer depending upon cost.

Our expectation for an NTS that assists with the installation of transmission equipment is that the contract term would be 1-5 years.

We are considering payment for the proposed solution through one-off establishment payments, availability payments ($/month or $/year) and delivery payments ($/hour) (except for generation commitment NTSs, for which we only intend to make establishment and/or availability payments). We are seeking comments on these indicative payment structures.

Information sought

The information can be provided in the form of either a word or PDF document or supported by technical brochures if it a provides answers to the questions. If providing a brochure, please refer to the brochure name and reference that provides the detail in your response.

We are seeking the following information on any nominated NTS:

- Details of proposed solution describing how it would meet the need and high-level technical specifications.
- Proposed location of solution and whether there is an interest in exploring the use of Transpower owned land to facilitate the solution.
- An indicative installation programme, showing the steps and how long installation would take following commercial agreement with Transpower.
- A list of your experience in installing and/or operating the NTS.

We would also welcome any suggestions on how you may work with Transpower to minimise costs and / or increase efficiency.

Our timeframes and receipt of information process

We would like your information by 5:00pm NZ time, 1 October 2021 in either PDF or MS Word format.

If you feel that you would like to provide some information but can't make that date, please let us know at the contact details below.

Project timeframe

Transpower is expecting to have completed its analysis of interest in providing any potential NTS, by 1 December 2021.

[19] Indicative testing processes can be found in this document: https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/GL-EA-010 Companion Guide for Testing of Assets.pdf

If the information shows there are potentially economic NTS then we would expect to undertake more detailed discussions with a view to deciding whether to start a formal procurement and/or engagement process.

The principles of this RFI

This RFI process is an information gathering exercise. It does not form any part of a procurement selection and by submitting information you understand there is no obligation formed to engage in any formal or informal procurement process as a result.

We ask that any information you provide is; relevant and factual at time of submission, relates to your operation and does not impinge anyone's intellectual property rights. We will use this information to form our overall project strategy.

The information requested can be of a general nature and need not contain any commercially sensitive information. If, however, you have included commercially sensitive information which should not be published, please let us know so that we can adequately protect it.

Following completion of our review, we will provide feedback to respondents in the form of general information and comments relating to their response.

Appendix B Proposed NZGP1 national demand forecasts

Table B-1. Proposed NZGP1 expected gross national electricity demand (TWh)

Year	Disruptive	Environmental	Global	Growth	Reference
2020	40.1	40.0	40.0	40.0	40.0
2021	40.2	40.1	39.9	39.9	39.9
2022	41.0	40.8	40.2	40.5	40.4
2023	41.8	41.6	40.5	41.0	40.8
2024	42.8	42.5	41.1	41.9	41.6
2025	38.8	38.5	36.6	37.7	37.3
2026	39.5	39.0	36.7	38.1	37.7
2027	40.2	39.7	36.8	38.6	38.1
2028	41.2	40.6	37.0	39.2	38.6
2029	42.0	41.3	37.5	39.8	39.0
2030	43.0	42.3	37.7	40.5	39.6
2031	43.9	43.3	38.1	41.2	40.1
2032	44.7	44.1	38.2	41.7	40.6
2033	45.8	45.0	38.5	42.4	41.0
2034	46.6	45.9	39.0	43.0	41.7
2035	47.7	46.9	39.1	43.8	42.2
2036	48.8	48.0	39.7	44.6	42.9
2037	49.7	48.7	40.0	45.3	43.2
2038	50.8	49.7	40.2	46.1	44.0
2039	51.9	50.7	40.7	47.0	44.5
2040	52.7	51.5	40.9	47.7	45.2
2041	53.9	52.4	41.4	48.5	45.7
2042	55.0	53.4	41.6	49.5	46.4
2043	56.0	54.1	41.9	50.0	46.9
2044	57.2	54.9	42.3	50.9	47.6
2045	58.4	55.8	42.5	51.9	48.1
2046	59.5	56.6	42.7	52.7	48.7
2047	60.5	57.3	43.1	53.4	49.4
2048	61.6	58.1	43.4	54.3	49.9
2049	62.7	58.9	43.8	55.1	50.5
2050	63.8	59.7	43.9	56.0	51.0

Table B-2. Proposed NZGP1 expected gross national peak demand (MW)

Year	Disruptive	Environmental	Global	Growth	Reference
2020	6632	6622	6625	6624	6623
2021	6671	6648	6628	6627	6626
2022	6800	6768	6688	6726	6713
2023	6902	6869	6726	6790	6766
2024	7032	7000	6823	6913	6879
2025	6598	6565	6325	6449	6405
2026	6669	6639	6353	6504	6452
2027	6743	6738	6371	6560	6502
2028	6829	6855	6404	6621	6557
2029	6881	6959	6469	6671	6597
2030	6946	7097	6505	6739	6668
2031	6998	7221	6560	6796	6708
2032	7040	7323	6590	6837	6775
2033	7117	7443	6638	6907	6811
2034	7161	7534	6690	6949	6885
2035	7231	7591	6697	7024	6920
2036	7290	7616	6739	7097	6978
2037	7327	7569	6732	7141	6988
2038	7383	7523	6702	7209	7031
2039	7431	7476	6710	7274	7040
2040	7447	7428	6687	7308	7084
2041	7506	7433	6711	7366	7101
2042	7570	7462	6707	7425	7153
2043	7612	7477	6713	7450	7177
2044	7691	7524	6748	7504	7232
2045	7773	7579	6755	7563	7257
2046	7860	7645	6762	7621	7311
2047	7920	7684	6800	7652	7366
2048	8010	7752	6810	7711	7390
2049	8113	7817	6850	7773	7443
2050	8204	7880	6854	7834	7467

Table B-3. Proposed NZGP1 prudent gross national peak demand (MW)

Year	Disruptive	Environmental	Global	Growth	Reference
2020	6632	6622	6625	6624	6623
2021	6671	6648	6628	6627	6626
2022	7166	7133	7049	7088	7074
2023	7315	7280	7128	7196	7170
2024	7483	7450	7259	7356	7319
2025	7088	7054	6795	6928	6880
2026	7193	7161	6852	7015	6959
2027	7295	7291	6893	7097	7034
2028	7387	7416	6928	7163	7093
2029	7443	7529	6998	7216	7136
2030	7513	7677	7037	7289	7212
2031	7568	7811	7096	7350	7255
2032	7613	7921	7128	7394	7326
2033	7695	8051	7179	7469	7365
2034	7742	8149	7235	7515	7445
2035	7818	8210	7242	7595	7483
2036	7880	8236	7286	7673	7545
2037	7920	8185	7279	7721	7555
2038	7980	8134	7246	7794	7601
2039	8031	8082	7254	7864	7611
2040	8047	8030	7228	7900	7657
2041	8111	8035	7253	7963	7676
2042	8179	8066	7249	8026	7731
2043	8225	8081	7255	8052	7756
2044	8309	8132	7293	8110	7816
2045	8398	8191	7299	8174	7842
2046	8491	8261	7307	8236	7900
2047	8555	8303	7348	8269	7960
2048	8691	8376	7358	8332	7985
2049	8848	8446	7400	8399	8042
2050	8954	8514	7405	8464	8067

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