TRANSPOWER

Transmission Expansion and Upgrade Options

Te Kanapu Technical Approach

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DOCUMENT REVIEW AND APPROVAL

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Contents

1.0 Background and overview

1.1 Background

The Te Kanapu Technical Approach suite of documents outline how Transpower is working to develop its draft future grid blueprint. By publishing these documents, we are sharing all the data, inputs and information being used in this process, for review and feedback.

Within this suite of documents are publications we have completed within Transpower and work that has been commissioned from others. For an outline of all the documents published under our technical approach, please see *Technical Approach Summary.*

This document, *Transmission Expansion and Upgrade Options*, covers a key input into our methodology. In it we outline a range of options available to us, to feasibly increase transmission capacity across Aotearoa, both at an inter-regional level and a national level. Where it is possible, we have also provided indicative costs.

While every effort has been made to ensure this information is of the highest possible quality, many assumptions are made across our work. This information should not be used for any purpose other than to inform discussions on a future grid blueprint.

The possible options mentioned throughout this document are concepts only to help guide conversations.

We want to hear from you

The approach we are taking is collaborative: we are developing this future grid blueprint by gathering feedback and we welcome your input into this work.

Please get in touch by emailing feedback@transpower.co.nz.

Publishing feedback

We will publish a summary of the feedback we receive throughout this process on www.transpower.co.nz/our-work/te-kanapu; especially where we have changed our approach as a result of the feedback we hear.

Transparency is important in this process. Unless requested by you, we will include both your name and any information you provide as part of your feedback, on our website.

If there is any aspect of your feedback that is confidential, please make this clear to us.

For more information

Visit the Te Kanapu section on the Transpower website to find out more. There you will find the background to our work, previous and current consultations, and additional data and analysis that has been used in our work to date.

www.transpower.co.nz/our-work/te-kanapu

1.2 Overview

The future grid blueprint will guide Transpower in its ‘low regrets’ investments in the grid; investments that ensure it is affordable, reliable, resilient, adaptive and supports the way we need to manage the electricity system.

One of the key inputs to our analysis, as well as future electricity demand and the generation to serve that demand, are options to increase the capacity of our transmission network.

In this document, we outline a range of options available to feasibly increase transmission capacity across Aotearoa, and how those options could be applied to add capacity between regions and if required across the entire grid backbone. Where it is possible, we have also provided indicative costs.

This document is structured as follows:

Section 1: Background and overview

Section 2: Here we outline the three different categories of options we are presenting and how they have been costed. Our categories are:

- adding transmission capacity
- maximising existing transmission capacity
- emerging new solutions

Section 3: North Island inter-regional upgrade options. Existing transmission system limits between adjacent regions in the North Island and initial options we have identified to increase them.

Section 4: South Island inter-regional upgrade options. Existing transmission system limits between adjacent regions in the South Island and initial options we have identified to increase them.

Section 5: Holistic transmission investments. Potential inter North and South Island options and larger scale inter North and South Island transmission options across multiple regions.

As we run the methodology and do the analysis for each potential future demand scenario we may identify the need for other options. For instance, most initial options we have identified in sections 3, 4 and 5 are from category one, adding transmission capacity. Power system analysis of the transmission needs under a specific demand scenario with its associated generation mix, may identify the opportunity to apply category two and three solutions.

Crucially, the methodology co-optimises the build of both generation and transmission. So, in addition to the transmission options listed in this document, we consider and compare options to build generation in a region.

Nothing in this document should be seen as an implied decision on the preferred future transmission grid technology or architecture (e.g. upgrading the network to 400 kV high voltage alternating current (HVAC)). Nor should it be considered an expression of any commitment to build new lines between specific locations mentioned as options in sections 3-5. These options are listed purely for the purpose of helping identify the optimal grid blueprint for that demand scenario.

The optimal grid blueprint for each demand scenario will then inform our overall first grid blueprint and the low regrets investments needed in the 2030s and into the 2040s. This will draw on the common transmission investments identified across scenarios and implications for the future architecture of the transmission grid in the context of the wider power system.

2.0 Option categories

2.1 Summary of option categories

The future grid blueprint will guide Transpower in its ‘low regrets’ investments in the grid; investments that ensure it is affordable, resilient, adaptive and supports the way we need to manage the electricity system.

In this section, we outline a range of options available to us, to feasibly increase transmission capacity across Aotearoa. Where it is possible, we have provided indicative costs.

The transmission network today is predominantly a high voltage alternating current (HVAC) system on the North and South Islands, operating at a range of voltages from 66 kV to 220 kV, plus the inter-island high voltage direct current (HVDC) system ±350 kV.

These option categories are grouped into the following:

1. Adding transmission capacity
    - Upgrading existing lines
    - New overhead alternating current (AC) transmission lines
    - New underground cables
    - New HVDC transmission
2. Maximising existing transmission capacity
    - System reconfiguration
    - Directing flow on transmission circuits
    - Increasing transmission stability
3. Emerging new solutions
    - Consumer Energy Resources (CER) and demand flexibility
    - Smart grid solutions
    - Virtual transmission lines using batteries

In our options we are also considering 400 kV HVAC transmission, as well as new HVDC links within and between the North and South Islands. Both may be a valuable addition to the power system, to meet forecast future electricity demand in our scenarios.

2.1.1 Estimating costs and capacity

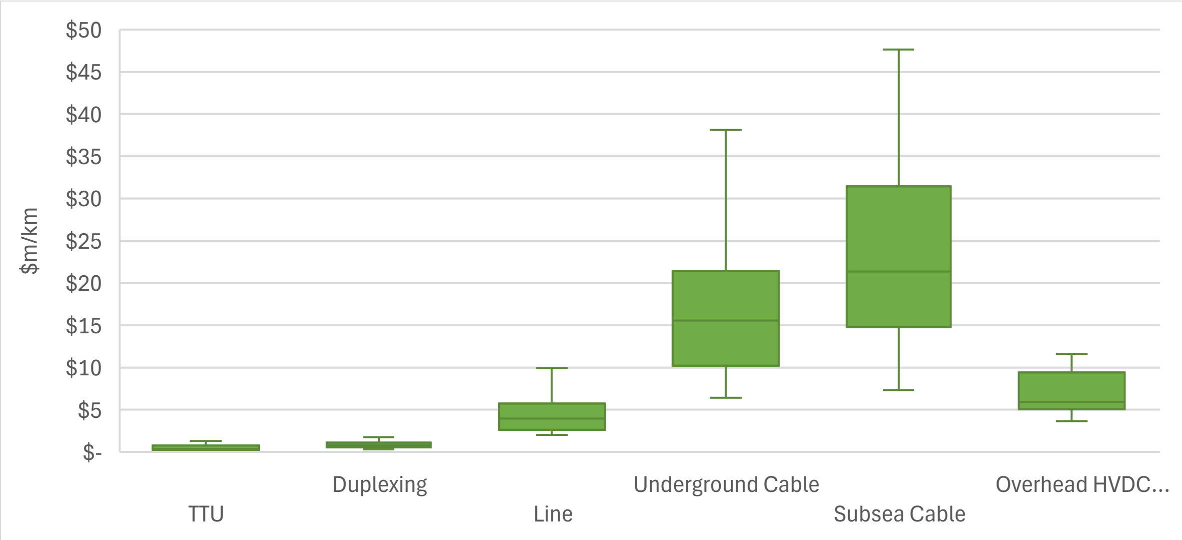
We used the Transpower Enterprise Estimating System (TEES) as a core input for estimating costs in this document. This is a tool used to maintain a database of cost information to create cost estimates for capital and maintenance projects.

Models were created to estimate the costs of the major upgrade types discussed under Category One: Adding transmission capacity. There are tactical thermal upgrades (TTUs), reconductoring/duplexing, new transmission lines, new HVDC transmission, and new cables. All costs are expressed in nominal New Zealand Dollars (2025).

The cost estimates have an Association for the Advancement of Cost Engineering (AACE) Class 5 estimate classification; this means the maturity level of project defining deliverables are 0-2% complete and the accuracy range is expected to be -50% to +100%.

The distributions in **Figure 1** and **Figure 2** were determined by adjusting the model inputs across various voltage levels, while also factoring in the full potential range of accuracy (i.e.-50% to +100%). The box and whisker charts show the maximum and minimum expected values, the box indicates the range between the expected 25th and 75th percentile. **Figure 1** shows the range of costs that the models predict for each upgrade type[1].

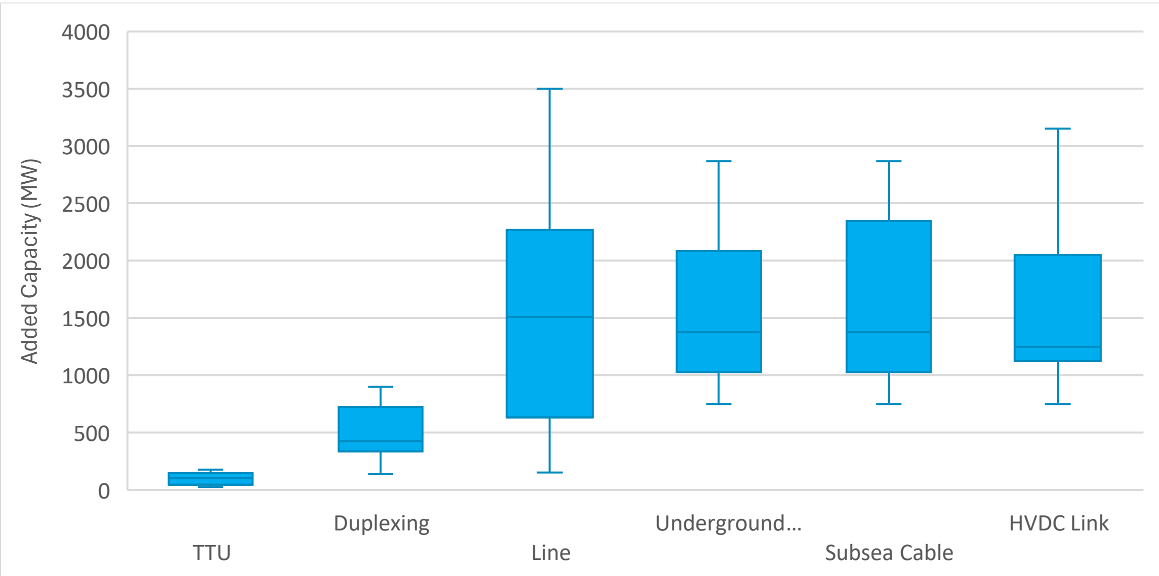
Figure 1: Cost per kilometre for upgrade types considered, presented in millions of NZD



Cost estimates show significantly higher costs for cables compared to alternative upgrade types.

Each upgrade type offers a different level of capacity gain. TTUs and reconductoring/duplexing are incremental upgrades to existing assets and there is a limit to the capacity gains that can be achieved this way. The capacity gains available are much higher for new assets.

Figure 2: Potential capacity gains achievable for the different upgrade types



New transmission lines and cables offer more additional capacity than incremental upgrade types.

[1] For the Overhead HVDC Link, the cost estimate includes two converter stations.

2.2 Category one: Options to add transmission capacity

2.2.1 Upgrading existing lines

Tactical thermal upgrades

A tactical thermal upgrade (TTU) means we upgrade our lines so the conductor system can be operated at a higher temperature. While this means they can carry more electricity, it also causes conductors to sag more, potentially getting too close to the ground, vegetation or structures.

To avoid this, we may need to make towers taller, adjust how conductors are held at the tower, or complete earthworks or foundations strengthening. We also need to check other assets like joints can handle the new higher operating temperature and check that substation equipment is adequately rated to ensure the full capacity of the upgraded line can be utilised.

Estimating the cost of this additional work can be challenging because it is heavily dependent on the existing equipment and location. We have analysed some previous projects and our engineering models to help us generate cost estimates for this upgrade type.

Tactical thermal transmission line upgrades range from $0.2-0.9M per kilometre[2]. Increasing the capacity of a transmission line usually does not require substation equipment at each end of the line to be upgraded. In some cases, minor upgrades of substation equipment is required at a cost of up to $2M at each substation.

Reconductoring and duplexing

The conductor system (wires) on a transmission line dictates how much power it can carry. Key aspects that contribute to a line's capacity are the size of conductor and whether its bundled (i.e. how many wires per phase is utilised). For some existing transmission lines, replacing the conductor system, known as reconductoring, would result in a substantial increase in transmission capacity.

As with TTUs, we need to ensure that all supporting assets (such as towers) can also withstand the increased loads. If not, additional strengthening is required. Understanding the extent of strengthening required is critical to determining the cost of this type of upgrade. Our transmission lines have a lot of variation in environment and structure type, which influences the cost of reconductoring.

We must also ensure equipment within our substations is adequately rated; if not, equipment upgrades will also be required.

Our estimates price this work at around $0.5–1.1M per kilometre. This cost excludes substation upgrades which could range from $2M for the line bays at either end of the circuit to $10M if more significant upgrades are required to the substation buses at either end.

[2] These estimates reflect an upper bound that does not account for cases requiring significant strengthening, remediation, modifications, etc.

2.2.2 New overhead AC transmission lines

New overhead transmission lines come in different shapes and sizes, each with different capacities. The capacity of a transmission line is dependent on the voltage, whether it's a single circuit or double circuit line, and the conductor system. These are critical inputs for determining both cost, capacity and resilience of new lines.

We have considered three voltage levels for new AC transmission: 110 kV, 220 kV, and 400 kV. We have also included options for single or double circuit transmission lines, and different conductor system options (e.g. simplex conductor, duplex conductor etc).

Other inputs include: the type of structure (towers or poles) used to support the lines, the type of foundations needed, the earth wire required, enabling works, and property costs. While these do not impact a line's capacity, these inputs are factors in determining the total cost of a transmission line.

By combining the cost components of a new transmission line together, we estimate that a new line may cost between $2.7-5.7M per kilometre.

There are also costs associated with connecting new lines to existing substations, and potentially the need for new substations to create new connection points. These costs are highly variable and could range from $22M per double circuit line (for new switchgear only) to $45-75M if a new substation is required.

2.2.3 New underground cables

Underground cables do the same job in moving electricity as overhead lines but are typically buried underground and out of sight[3]. There are a range of factors that influence cost and capacity of transmission cables. These include: the voltage, type of cable, number of terminations, enabling works, and how the cable is installed.

Types of cable installation could be a cable trench, ducts, direct buried, or sub-sea direct laying. The type of installation used is dictated by the cable route, location, and voltage.

In this work we have only costed sub-sea and cable trench installation of cables. These two give us a sufficiently broad understanding of the costs involved for other types of cable installation. We anticipate a new underground cable costing between $10.3-21.5M per kilometre, while sub-sea cables are estimated to cost between $15.0-31.5M per kilometre.

New underground cables will also require either upgrades to existing substations or potentially new substations to connect the new cable to the rest of the grid.

With underground cables typically utilised in urban areas, our urban substations may need to utilise gas insulated switchgear (GIS) rather than air insulated switchgear (AIS). GIS typically costs 70% more than AIS. GIS is more compact and typically is installed within a building whereas AIS is installed outdoors and relies on adequate physical spacing of equipment to provide insulation of live parts to ground which makes its footprint larger. Long cables also need compensating shunt reactors to manage charging currents which adds to the footprint and cost.

[3] An important consideration around underground cables is that the repair time of a faulty cable is much longer than that of an overhead line. However, cables are less prone to faults.

2.2.4 New HVDC transmission

An HVDC system typically consists of converter stations at either end of an HVDC line or cables. HVDC systems require less line or cables to transmit the same amount of power when compared to a HVAC system, but the required convertor stations are very costly.

Therefore, HVDC connections are typically used for point-to-point power transmission over very long distances where the added costs of converter stations are offset by the lower cost of transmission lines or cables. It can also be used to interconnect different HVAC systems in close proximity; however, this is not relevant to Aotearoa as we do not have interconnections with other countries or have HVAC systems that operate at different frequencies. HVDC could also be used for the transmission of offshore wind generation which is >20-30 kilometres away from shore, because at these distances HVAC cables reach their technical limit as their charging current becomes excessive. There could also be new applications in future for relatively short point-to-point subsea transmission as gaining transmission corridors on land becomes too costly or impractical.

There are two categories of HVDC systems with the converter technology being the key difference. Line commutated converter (LCC) HVDC systems utilise thyristors for switching and voltage source converters (VSC) HVDC systems utilise insulated-gate bipolar transistor (IGBT) for switching. The two technology have different applications and depending on the transmission need, one technology will be more favourable than the other. Broadly speaking for high-capacity predominantly bipolar transmission needs, LCC systems are generally preferred, whereas VSC technology would be generally preferred for lower capacity predominantly monopolar or multi terminal transmission needs. Our Te Kanapu work is agnostic to the HVDC technology choice, and we will select a technology that suits our expected transmission needs. Our cost estimates provided are based on projects that utilise VSC technology which is the predominant technology in new HVDC systems due to its cost advantages for connecting large amount of inverter-based generation such as offshore wind.

If we were to construct a new overhead HVDC link, we expect this would cost around $3.0-5.9M per kilometre. A second sub-sea HVDC inter-island link would carry greater cost at about $14.4-31.5M per kilometre.

These costs are exclusive of the required converter stations at each end of the link; substantial additional costs estimated to range from $0.6-1.5B per converter station.[4]

[4] Te Kanapu is currently receiving external support to refine these HVDC cost estimates in a New Zealand context.

2.3 Category two: Options that maximise existing transmission capacity

There are many areas of the transmission grid where we have several transmission lines operating in parallel that may have been installed decades apart. These lines have varying voltage levels and routes which means their impedance and ratings can be significantly different. As a result, some circuits can overload while others operating in parallel, still have spare capacity.

2.3.1 System reconfiguration

In some cases, there is the potential to reconfigure the transmission system to enable greater use of existing assets.

The transmission system has been evolving for decades, meaning we have older transmission assets (typically at 110 kV or lower voltage levels) operating in parallel with our 220 kV grid.

In some cases, these older assets can limit the ability to transfer power between two regions.

A pragmatic solution to resolve these types of constraints is to reconfigure the transmission system which typically entails splitting the network to allow more power to flow through our high capacity 220 kV network. These system reconfigurations can be done as a permanent reconfiguration or as a temporary solution for times when capacity is constrained. This involves employing a special protection scheme to automatically apply the reconfiguration when capacity is constrained. Splits might cause a reduced level of service to some customers.

System reconfigurations are relatively low cost; permanent reconfigurations could be done with no capital investment or cost up to $1M if upgrades are needed. Special protection schemes typically cost in the range of $1-2M.

Options to decommission or divest existing assets are also considered.

2.3.2 Directing flow on transmission circuits

Flexible AC transmission systems (FACTS) can maximise the utilisation of our existing transmission lines by distributing the power flow across different lines to the load more evenly, or by addressing power system stability risks that arise from higher power transfers across the existing transmission lines.

FACTS can be installed at substations or on some circuits to 'steer' power from overloaded circuits to ones with spare capacity. This is known as series compensation.

There are many technologies that can be employed for series compensation, outlined below.

Series compensation options:

- **Fixed and variable series reactors**: typically increase the impedance of the overloaded circuit(s) to force more power through other, higher capacity circuits. This technology is typically the lowest cost per unit. However, increasing the impedance on a transmission line lowers the stability limit across the line so other investments may be required to rectify these issues which may make it impractical or uneconomic. Fixed series reactors could cost in the range of $10-20M.

- **Phase shifting transformers**: can be applied to overloaded circuits to force power away or applied to high-capacity circuits to encourage power to flow on the circuit. It's logical to apply this technology to lower-rated circuits to minimise the size and cost of the phase shifting transformer. This technology is relatively expensive and could be impractical for high-capacity circuits; it also has a relatively high maintenance requirement which could materially impact the availability of the circuits it is added to.

- **Fixed and variable series capacitors**: typically reduce the impedance of high-capacity circuits to encourage more power to flow on them. This technology can be employed where series reactors are not viable either due to the number of lower-capacity circuits that otherwise need compensation or stability limitations due to added impedance from reactors. This technology is more expensive per unit compared to series reactors. Series capacitors could introduce other risks that require careful management such as protection coordination, sub-synchronous resonance, and control and stability issues. Risk management could add significant cost to a series capacitor installation or make it impractical. Series capacitors could cost in the range of $50-400M.

- **Power electronics-based series compensation**: VSCs can be applied to overloaded circuits to force power away or to high-capacity circuits to encourage power to flow on the circuit. This technology is relatively new with limited suppliers and is costly compared to the traditional forms of series compensation. However, it does allow maximum flexibility as the compensation amount can be varied across a range to adapt to system needs. It could also address some of the power system risks introduced by series compensation. However, due to costs, these technologies are more likely to be cost effective on applications where only a small level of compensation is required, i.e. typically on shorter transmission lines.

Note: the use of variable compensation, rather than fixed, presents challenges for our current electricity market systems. The value of variable series compensation cannot be adequately captured. Future evolution of our market systems and regulations may open the door to these types of solutions.

2.3.3 Increasing transmission stability

New Zealand's grid is geographically very long and on both the North and South Islands, with generation on one end, load on the other and a relatively high impedance transmission system. The stability limit of a transmission network is largely driven by its impedance which, in turn, is related to the number of transmission lines connecting load and generation at a given voltage. The most common stability issue Transpower needs to manage, and therefore invest in, is the voltage stability limit; the ability for the voltage to recover to tolerance following a system event.

There are broadly two categories of voltage stability:

- **Static:** the adequacy of reactive power support to ensure voltage can recover to tolerance following a system event

- **Dynamic:** the ability for voltages at generation and load buses to remain within a prescribed envelope immediately following a system event

Two forms of grid augmentation can be employed to resolve voltage stability issues:

- **Static reactive support equipment:** this includes shunt capacitors or reactors. Capacitors are primarily used to provide reactive power to ensure voltages do not fall below allowable limits. Reactors are used to absorb excessive reactive power to ensure voltages do not go above allowable limits.

- **Dynamic reactive support equipment:** this includes static synchronous compensators (Static Var Compensators (SVCs) and STATCOMs) and synchronous condensers. These technologies are more costly than static reactive support equipment and are only employed when there is a dynamic voltage stability issue where static reactive support equipment cannot be applied. SVCs were the first form of static synchronous compensators but STATCOMs are becoming cheaper and generally have better performance than an SVC for resolving voltage stability issues due to their faster response times and wider capability envelope. Therefore, STATCOMs are now the primary equipment used for dynamic reactive support. Synchronous condensers are costly and, as rotating machines, have a much higher operating cost and lower availability compared to a STATCOM. Synchronous condensers are not typically employed to resolve voltage stability issues alone but could be employed if system strength (inertia) is an issue.

2.4 Category three: Emerging new solutions

2.4.1 Consumer energy resources and demand flexibility

The widespread adoption of consumer energy resources (CER) is changing the nature of the power system making it more decentralised. This from the increasing adoption of rooftop solar, sometimes with batteries along with greater demand flexibility due to smart home solutions and price response.

We will account for this in each demand scenario through adjusting parameters such as the smartness of electric vehicle (EV) charging, residential photovoltaic (PV) and battery energy storage system (BESS) penetration levels, that reflect the nature of the scenario and the extent it is likely to rely on centralised our decentralised generation sources and demand flexibility. These parameters allow us to produce as realistic as possible peak demand forecasts under the different scenarios. Arrangements to efficiently utilise CER and demand flexibility to reduce peak demand and better utilised transmission and distribution networks are important as the peak demand is the primary factor when it comes to optimising the sizing the transmission grid.

2.4.2 Smart grid solutions

There are a range of other operational measures including fully utilising the actual real time rating of grid equipment given the environmental conditions at the time – such as wind, temperature and solar gain – known as dynamic ratings. Most equipment has a static rating based on a predetermined set of conditions that is fixed or might only vary by season (summer or winter).

In the late 2000s Transpower explored the use of dynamic ratings to maximise the use of our transmission line capacity. We adopted variable line ratings rather than fully dynamic ratings, here the ratings of transmission lines being operated near their limits vary every two hours based on analysis of historic environmental conditions in the vicinity of the line. This works well with our current electricity market design.

We will continue to evaluate the case for dynamic ratings and other smart grid solutions. As such the wider use of these solutions has not been factored into our options

2.4.3 Virtual transmission lines using batteries

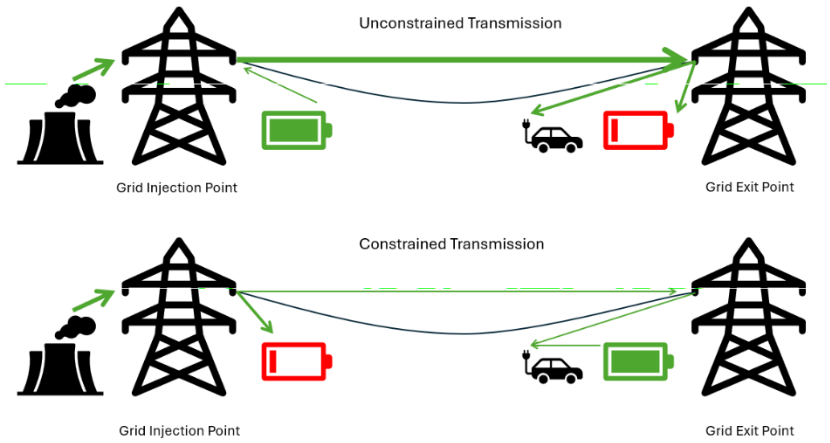
Virtual transmission using batteries is the coordinated operation of two BESSs at either end of a transmission corridor. This can enable electricity to move (virtually) around the grid, without relying on physical transmission networks.

If a major transmission line becomes constrained, virtual transmission may be able to help. When the line is unconstrained, electricity can flow freely between the grid injection point (GIP) and grid exit point (GXP), charging the BESS at the GXP. During peak periods, the line may become constrained. The BESS at the GXP can discharge to meet demand, while the normally curtailed generation can charge the BESS at the GIP. The coordinated approach enables the indirect transfer of electricity without needing to upgrade transmission lines. Of course, batteries can run out of power, rendering the virtual transmission line useless.

Figure 3 illustrates how electricity may flow in both constrained and unconstrained transmission cases.

The cost of this system is dependent on the required capacity of each battery. Battery costs are estimated within the 2025 Generation Stack.

Figure 3: Demand is met by generation in the unconstrained case



Once the line becomes constrained it is met by the grid-scale BESS at the GXP.

2.5 Lead times for implementation

Implementing changes or additions to the grid can involve significant lead times. We measure lead time as being from the time we decide to proceed with an option until the time it is in service. Factors that impact lead time include consenting, engagement, procurement, market coordination challenges and construction. **Table 1** presents an indicative range of lead times based on the type of option being implemented.

Table 1: Lead times for different option types

Option type	Lead time
Tactical thermal upgrades	1-2 years
Reconductoring and duplexing	1-5 years
New overhead AC transmission lines	5-12 years
New underground cables	3-5 years
New HVDC transmission	8-12 years

The lead time of option category 3, emerging new solutions, may be less than other options. For example virtual transmission lines may have a lower consenting timeframe, as less landowners would be impacted. However, there is considerable uncertainty (including applicability, cost, technology maturity, etc) around this option category, and the lead time will be assessed on a case-by-case basis.

Options may include preparatory works that reduce lead times. These will be explored at a later stage of our analysis.

3.0 North Island inter-regional upgrade options

3.1 North Island inter-regional upgrade options

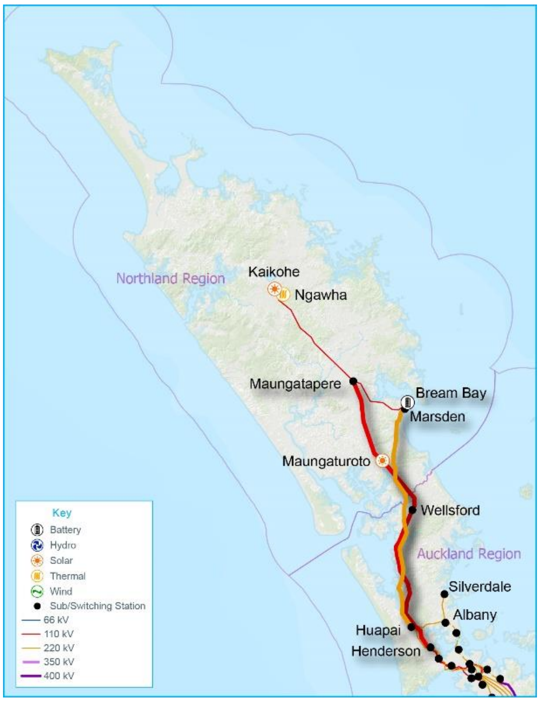
In this section we explore the transmission options that exist within the North Island as we understand them, today. Each option and assumed cost, calculated using the TEES, is discussed. Regions are not included where we have been unable to identify any feasible upgrade options.

The options listed here are not exhaustive. For simplicity, we have limited them to circuits which cross regional boundaries and have only shown summer (minimum) ratings. This is to highlight the inter-regional focus of Te Kanapu. In certain regions, intra-regional circuits may constrain inter-regional flows. We will consider these within the options assessment approach.

3.1.1 Northland to Auckland

The Northland region is supplied by a 220 kV double-circuit "main" line from Huapai and a 110 kV double-circuit "backup" line from Henderson. These circuits are effectively in parallel.

Power is imported from the central North Island through the Auckland region almost all the time to supply Northland load. The amount imported can drop significantly in the middle of the day when solar farms in Northland, are generating. In the Far North, local generation can exceed load, particularly in summer months when solar generation is high and loads are lower, therefore power is being exported towards Whangarei on the 110 kV Kaikohe-Maungatapere line.



Existing installed line capacity is 1055 MVA in summer through the four circuits from Henderson and Huapai

Circuit	Summer capacity (MVA)
Huapai–Marsden 1	610
Bream Bay–Huapai 1	333
Henderson–Maungatapere 1	56
Henderson–Maungatapere 2	56

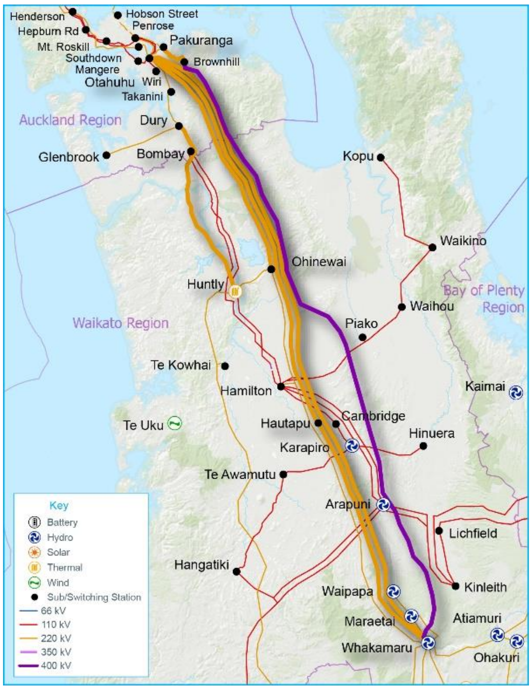
Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermal upgrade Henderson–Marsden A and Bream Bay–Deviation A to 100°C	160 MVA	$18.5-74M	1-2 years
• Duplex Bream Bay–Huapai 1 section of Henderson–Marsden A	660 MVA	$35-138M	2-3 years
• Reconductor Henderson–Maungatapere A with Nobellium	125 MVA	$52-207M	2-3 years
New transmission			
• A new 220 kV double circuit line between Silverdale - Maungatapere	2050 MVA	$518M-2.07B	5-12 years

3.1.2 Auckland to Waikato

The Auckland region is the largest load centre, connected by eight high-capacity 220 kV circuits from Whakamaru (the generation-rich centre of the North Island), Huntly and Taranaki. Voltage support is needed to ensure stability. This is provided by dynamic reactive plant, static capacitors and shunt reactors spread across substations in the region.

The power flow on the lines/circuits connecting Waikato and Auckland are exclusively northwards, supplying the Auckland and Northland regions with electricity from wind, hydro and geothermal generation in the Waikato region and south of it, and thermal generation at Huntly and Taranaki.



Existing installed line capacity is 5462 MVA in summer through eight circuits

Circuit	Summer capacity (MVA)
Pakuranga–Whakamaru 1	1129
Pakuranga–Whakamaru 2	1129
Otahuhu–Hautapu–Whakamaru 1	293 (VLR[5])
Otahuhu–Hautapu–Whakamaru 2	293 (VLR)
Ohinewai–Otahuhu 1	615
Ohinewai–Otahuhu 2	615
Drury–Bombay–Huntly 1	694
Drury–Bombay–Huntly 2	694

Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Otahuhu–Hautapu–Whakamaru A/B between Ohinewai and Whakamaru and bus the two circuits at Ohinewai	290 MVA	$75-300M	3-5 years
New transmission			
• Bus the Otahuhu–Whakamaru A & B lines at Ohinewai and replace Ohinewai–Whakamaru sections with a new double circuit 220 kV line[6]	1470 MVA	$347M-1.39B	5-12 years
• Bus the 220 kV lines at Brownhill and install a new 220 kV Brownhill–Otahuhu cable	768 MVA	$102-407M	3-5 years
• Install a new 220 kV cable between Pakuranga–Penrose–Hobson Street–Wairau Road–Albany	735 MVA	$319M-1.28B	5-10 years
Other upgrade			
• Install series capacitors on Brownhill Road–Whakamaru North A	~200 MVA	$126-270M	3-5 years

[5] Variable line rating (VLR) assigns a different rating to a circuit every two hours of the day for each month, based on the historic wind, ambient temperature and solar gain for each two-hour period.
[6] Cost includes the dismantling of the Ohinewai-Whakamaru section.

3.1.3 Waikato to Bay of Plenty

The 220 kV Atiamuri–Whakamaru and Ohakuri–Wairakei circuits connect the region to the rest of the national grid. The Bay of Plenty load is predominantly supplied through these two circuits, and the region will be on n security whenever one of these circuits is out of service. These two circuits are part of a grid backbone area known as the Wairakei Ring.

The regional 220 kV grid runs in parallel with the Atiamuri–Ohakuri circuit and forms a longer 220 kV route between those two substations via Kawerau, Edgecumbe and Tarukenga. Therefore, there are mutual interactions between the grid backbone and the Bay of Plenty regional grid. There is also a low capacity 110 kV Tarukenga–Kinleith–Arapuni line that connects the Bay of Plenty to the Waikato 110 kV regional network. In normal operation this connection is split at Arapuni to prevent overloading.

Existing installed line capacity is 1019 MVA in summer through five circuits

There are five transmission circuits feeding the Bay of Plenty region from Waikato:

Circuit	Summer capacity (MVA)
Kawerau - Ohakuri 1	239
Atiamuri – Tarukenga 1	333
Atiamuri – Tarukenga 2	333
Lichfield – Tarukenga 1	51
Lichfield – Tarukenga 2	63

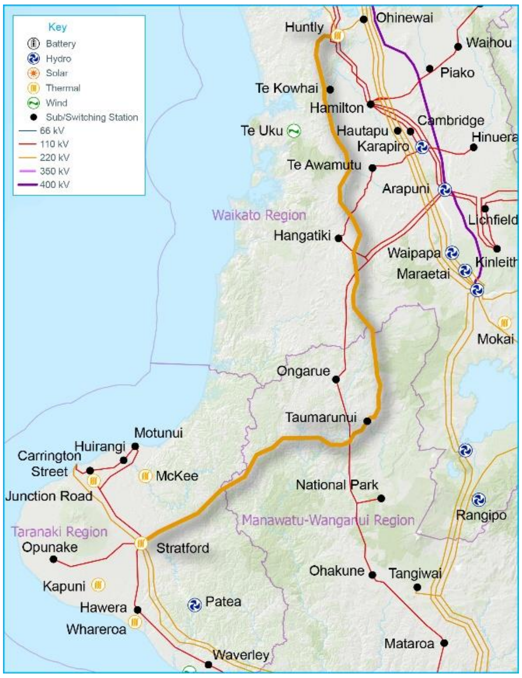
Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Atiamuri–Tarukenga A	660 MVA	$19-77M	2-3 years
• Duplex Ohakuri–Edgecumbe A and Kawerau–Deviation A	240 MVA	$32-130M	3-5 years
• Duplex Edgecumbe–Tarukenga A	480 MVA	$29-117M	3-5 years
New transmission			
• New 220 kV double circuit line between Wairakei–Whakamaru	2050 MVA	$143-572M	5-12 years
• New 220 kV double circuit line between Edgecumbe–Kawerau	2050 MVA	$59-236M	5-12 years
• New 220 kV double circuit line between Ohakuri–Kawerau	2050 MVA	$168-673M	5-12 years
• New 220 kV double circuit line from Okere Tee–Te Matai–Kaitemako	2050 MVA	$100-401M	5-12 years

3.1.4 Waikato to Taranaki

The Taranaki transmission system supplies the city of New Plymouth (from the Carrington Street and Huirangi grid exit points) and other towns in the Taranaki region including Stratford, Hawera, Waverley and Whanganui. Taranaki has been a focus for wind generation (both onshore and offshore) over recent years, with Waipipi Wind Farm leading the charge and several onshore wind farms being actively investigated.

The Taranaki region connects to Waikato through 220 kV circuits that run north-east to Huntly. Local generation can exceed regional demand and any excess power is exported to other parts of the country via the national grid



Existing installed line capacity is 823 MVA in summer through two circuits

There is one transmission circuit connecting Waikato and Taranaki directly. Another circuit connects via Taumarunui in the Manawatu-Wanganui region:

Circuit	Summer capacity (MVA)
Huntly–Stratford 1	354 (current project to increase rating to 469 MVA)
Stratford–Taumarunui 2	469

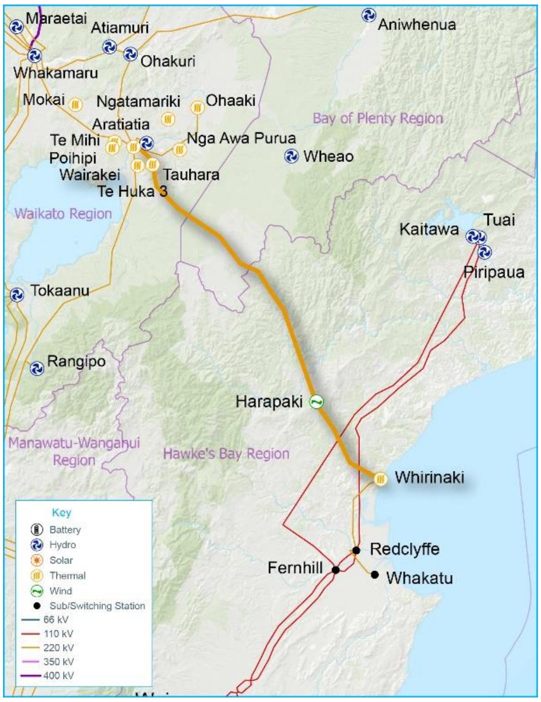
Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Stratford–Taumarunui A	940 MVA	$46-185M	2-3 years
New transmission			
• New 220 kV double circuit line from Stratford to Huntly	2050 MVA	$588M-2.35B	5-12 years
• New 220 kV double circuit line from Taumarunui–Whakamaru	2050 MVA	$190-760M	5-12 years

3.1.5 Waikato to Hawke’s Bay

Hawke’s Bay is home to significant regional cities and heavy industry. It also has the grid connection point to supply the Gisborne region through Firstlight Network. Waikato is a generation rich region, primarily from hydro and geothermal sources. The Waikato region also hosts the transmission into Auckland, the largest load centre in the country.

Transmission into the Hawke’s Bay from Waikato is via two 220 kV circuits from Wairakei that directly supply the Whirinaki and Whakatu loads, and two 220/110 kV interconnecting transformers at Redclyffe.



Existing installed line capacity is 956 MVA in summer through two circuits

There are two transmission circuits connecting the Hawke’s Bay and Waikato:

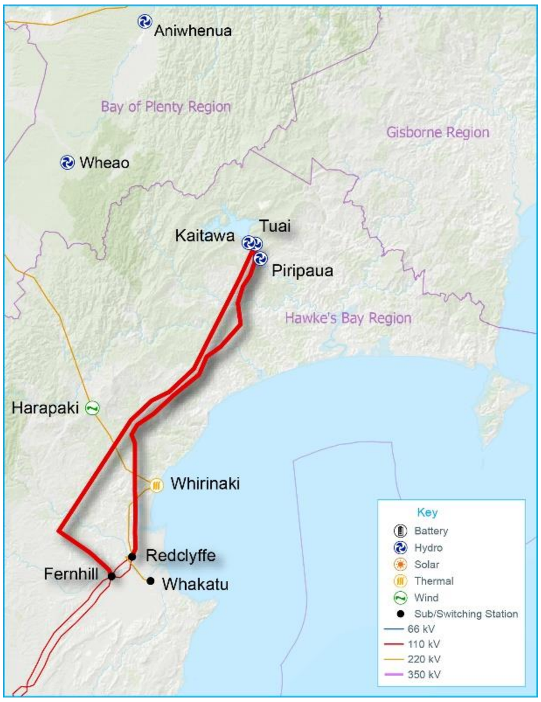
Circuit	Summer capacity (MVA)
Wairakei–Whirinaki 1	478
Wairakei–Whirinaki 2	478

Options include new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
New transmission			
• New 220 kV transmission line from the Taupo area to Redclyffe	2050 MVA	$420M-1.68B	5-12 years

3.1.6 Hawke’s Bay to Gisborne

Gisborne is connected to the national grid through our substation at Tuai. Electricity distribution within the Gisborne region sits under Firstlight Network’s distribution system. Tuai substation also connects the Waikaremoana hydro scheme. Power is exported from Gisborne to Hawke’s Bay during high hydro generation at Waikaremoana and imported when generation is low.



Existing installed line capacity is 215 MVA in summer through three circuits

Firstlight Network Limited connect to Transpower’s network at Tuai Substation. Tuai is connected to the rest of Hawke’s Bay via three 110 kV transmission circuits:

Circuit	Summer capacity (MVA)
Redclyffe–Tuai 1	57
Redclyffe–Tuai 2	57
Fernhill–Tuai 1	101

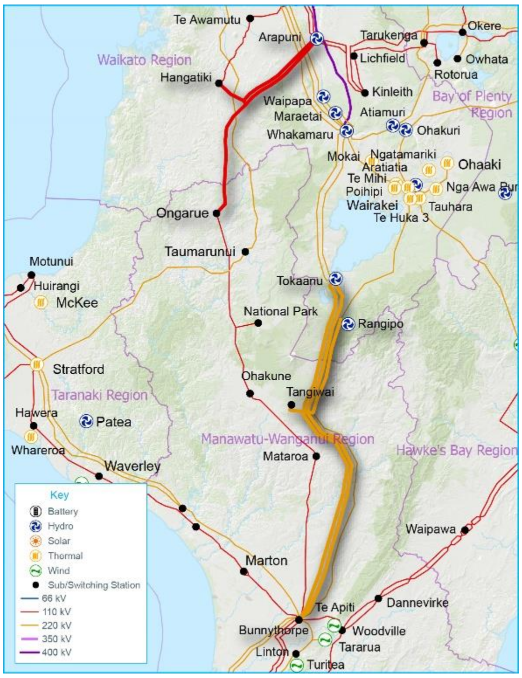
Options include reconductoring

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Reconductor Fernhill–Redclyffe A and B	100 MVA	$4.2-16.7M	1-2 years
• Reconductor Redclyffe–Tuai A	120 MVA	$38-152M	2-3 years

3.1.7 Manawatu-Wanganui to Waikato

Manawatu-Wanganui and Waikato are the two largest regions in the North Island by land area. The direction of power flow through these regions, north or south, is determined by generation, direction of HVDC flow and loads outside the region.

Waikato and Manawatu-Wanganui is the main corridor for 220 kV transmission circuits through the North Island. The 220 kV transmission system 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.



Existing installed line capacity is 912 MVA in summer through four circuits

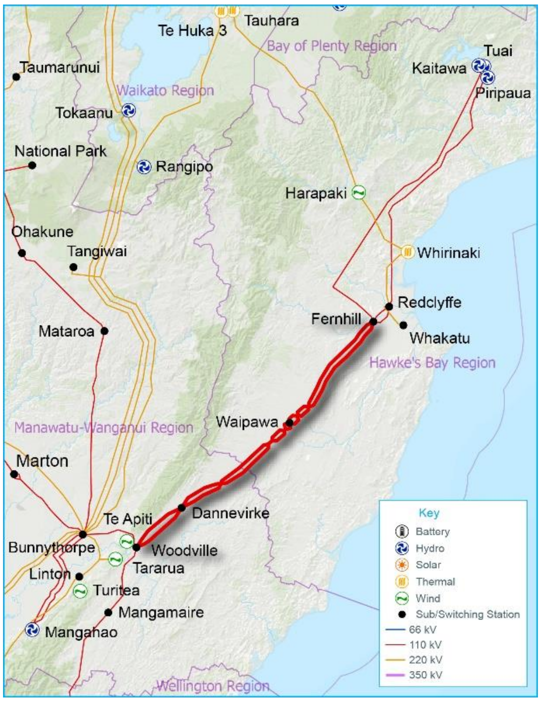
Circuit	Summer capacity (MVA)
Bunnythorpe–Tokaanu 1	308 (current project to increase rating to 358 MVA)
Bunnythorpe–Tokaanu 2	308 (current project to increase rating to 358 MVA)
Tangiwai-Rangipo 1	239
Ongarue–Hangatiki–Arapuni 1	57

Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Bunnythorpe–Tokaanu section of Bunnythorpe–Whakamaru A/B lines	930 MVA	$99-395M	2-3 years
• Duplex Bunnythorpe–Wairakei A line	480 MVA	$96-383M	3-5 years
New transmission			
• New 220 kV double circuit line from Bunnythorpe to Whakamaru	2050 MVA	$551M-2.20B	5-12 years

3.1.8 Hawke's Bay to Manawatu-Wanganui

Hawke's Bay is home to significant regional cities and heavy industry. Manawatu-Wanganui is home to a crucial substation for the North Island, Bunnythorpe. There is a low-capacity 110 kV transmission line connecting these regions. However, the 110 kV system is normally split at Waipawa to avoid constraints on the low capacity 110 kV line.



Existing installed line capacity is 102 MVA in summer through two circuits

There are two transmission circuits connecting the Hawke's Bay to Manawatu-Wanganui. These circuits connect to Waipawa where there is an operational system split:

Circuit	Summer capacity (MVA)
Fernhill–Woodville 1	51
Fernhill–Woodville 2	51

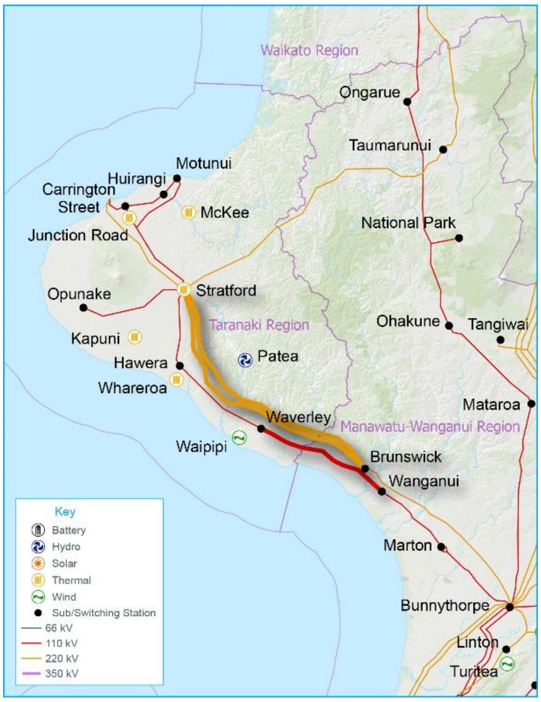
Options range from reconductoring to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Reconductor Bunnythorpe-Woodville-Dannevirke-Waipawa-Fernhill-Redclyffe circuits and closing the 110 kV system split at Waipawa	120 MVA	$78-311M	3-5 years
New transmission			
• New 220 kV double circuit line Bunnythorpe to Redclyffe via Woodville	2050 MVA	$329M-1.32B	5-12 years
• New 220 kV double circuit transmission line from Haywards to Redclyffe via Wairarapa	2050 MVA	$587M-2.35B	5-12 years

3.1.9 Manawatu-Wanganui to Taranaki

Taranaki is home to major oil and gas facilities including both upstream and downstream facilities. Due to the region's gas resources, a significant portion of the country's remaining thermal generation is in Taranaki.

Taranaki connects to Manawatu-Wanganui through the three 220 kV Brunswick–Stratford circuits, and a 110 kV Wanganui–Waverley circuit. The Taumarunui substation in the Manawatu-Wanganui region only supplies KiwiRail so the Stratford-Taumarunui 220 kV connection is not considered a transmission connection between these two regions.



Existing installed line capacity is 849 MVA in summer through four circuits

Circuit	Summer capacity (MVA)
Brunswick–Stratford 1	232
Brunswick–Stratford 2	232
Brunswick–Stratford 3	232
Wanganui–Waverly 1	153

Options range from thermal upgrades to new transmission lines

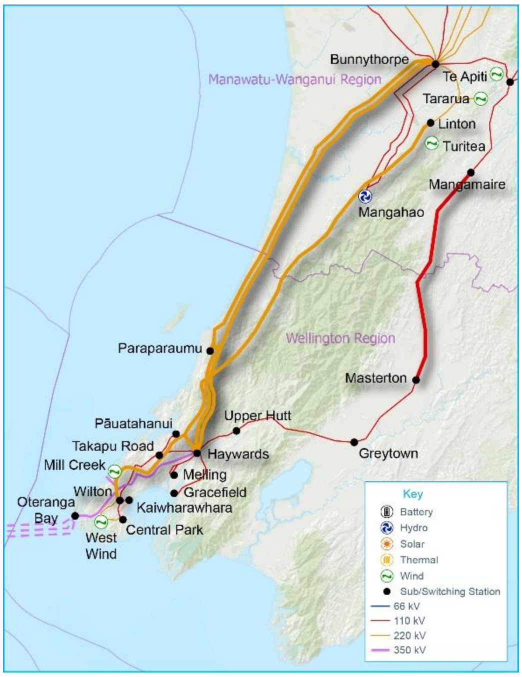
Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermal upgrade Brunswick–Stratford A to 90°C	270 MVA	$18-73M	2-3 years
• Reconductor Brunswick–Stratford A with a higher capacity conductor	480 MVA	$35-140M	3-5 years
New transmission			
• New double circuit 220 kV transmission line from Bunnythorpe to Stratford	2050 MVA	$407M-1.63B	5-12 years
• Replace Brunswick–Stratford B with double circuit 220 kV line[7]	1810 MVA	$249-$997M	5-12 years

[7] Cost includes the dismantling of the existing transmission line.

3.1.10 Manawatu-Wanganui to Wellington

Wellington is a critical through point for HVDC flows, it plays a key role in getting electricity from generating sites from one island to the other.

The Wellington region is connected to Manawatu-Wanganui through four 220 kV circuits to Bunnythorpe. It is a main corridor for through-transmission between the North and South Islands. The loading of these circuits is primarily driven by HVDC power flow and Central North Island generation. Additionally, a 110 kV transmission line connects to Manawatu-Wanganui via Wairarapa.



Existing installed line capacity is 2233 MVA in summer through five circuits

There are five transmission circuits connecting Manawatu-Wanganui to Wellington:

Circuit	Summer capacity (MVA)
Bunnythorpe–Haywards 1	355
Bunnythorpe–Haywards 2	355
Haywards–Wilton–Linton 1	694
Haywards–Wilton–Linton 2	694
Mangamaire–Masterton 1	135

Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermal upgrade Bunnythorpe–Paraparaumu–Haywards A and B	152 MVA	$46-185M	2-3 years
• Reconductor Haywards–Upper Hutt – Masterton–Mangamaire–Woodville–Bunnythorpe line with a higher capacity conductor	100 MVA	$72-290M	3-5 years
• Duplex Bunnythorpe–Paraparaumu–Haywards A and B	615 MVA	$71-283M	3-5 years
New transmission			
• New 220 kV double circuit transmission line from Haywards to Bunnythorpe via Wairarapa	2050 MVA	$349M-1.40B	5-12 years

4.0 South Island inter-regional upgrade options

4.1 South Island inter-regional upgrade options

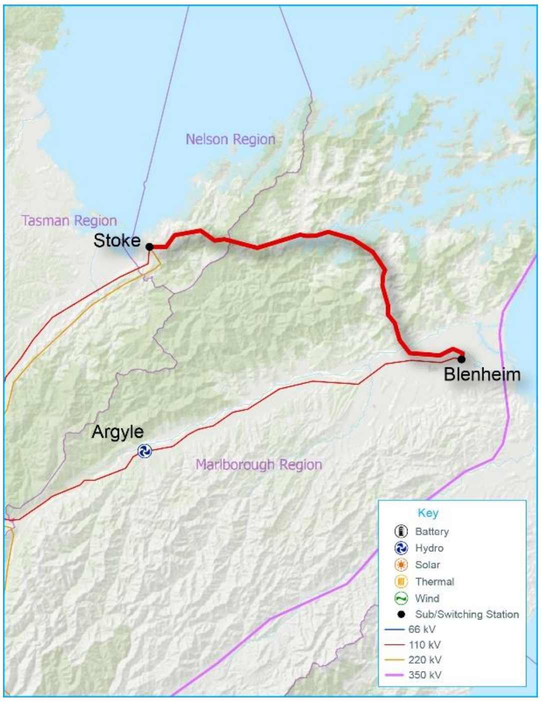
In this section we explore the transmission options that exist within the South Island as we understand them, today. Each option and assumed cost, calculated using the TEES, is discussed. Regions are not included where we have been unable to identify any feasible upgrade options.

The options listed here are not exhaustive. For simplicity, we have limited them to circuits which cross regional boundaries and have only shown summer (minimum) ratings. This is to highlight the inter-regional focus of Te Kanapu. In certain regions, intra-regional circuits may constrain inter-regional flows. We will consider these within the options assessment approach.

4.1.1 Nelson to Marlborough

The Nelson region is the largest load centre with Nelson being the largest city in the upper South Island. The Nelson region hosts our Stoke substation which supplies the region with electricity as well as provide through transmission into neighbouring regions Marlborough and Tasman.
The Marlborough region is also a major load centre in the upper South Island. The region hosts our Blenheim substation which primarily supplies the region's load but also connects local generation within the distribution network and at Argyle.

Transmission between Nelson and Marlborough comprises 110 kV circuits from Blenheim to Stoke. The two regions are also connected via 110 kV circuits forming a 'triangle' between Stoke, Kikiwa (Tasman region) and Blenheim. Interconnection between the 220 kV and 110 kV networks is provided by a single transformer at Stoke, and a second transformer at Kikiwa, which together provide N-1 security to the 110 kV transmission network.



Existing installed line capacity is 206 MVA in summer through two circuits

There are two transmission circuits connecting Nelson and Marlborough:

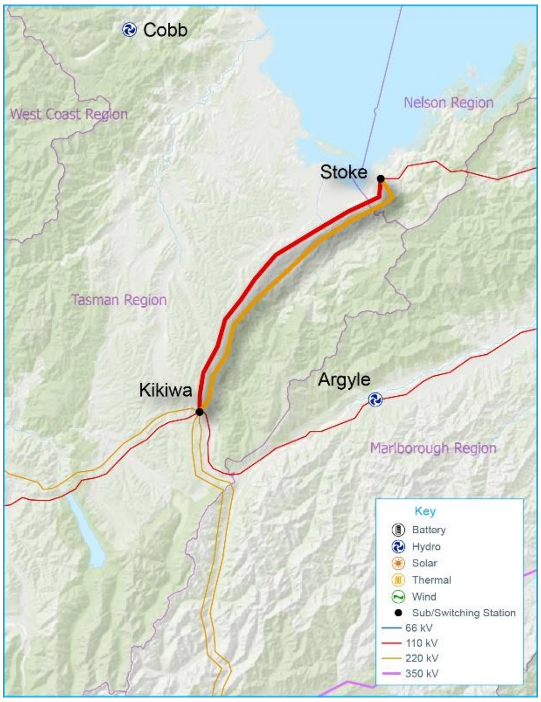
Circuit	Summer Capacity (MVA)
Blenheim–Stoke 1	101
Blenheim–Stoke 2	105

Options include thermal upgrades

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermally upgrade Blenheim–Stoke A	168 MVA	$36-146M	2-3 years

4.1.2 Nelson to Tasman

Nelson is predominantly supplied with three circuits from Kikiwa in the Tasman region. Two of these circuits operate at 220 kV, with the third at 110 kV. The circuits from Kikiwa are connected to the rest of the grid via 220 kV lines through to Islington. Interconnecting transformers at Kikiwa and Stoke enable N-1 security to the Marlborough region.



Existing installed line capacity is 534 MVA in summer through three circuits

There are three transmission circuits connecting Nelson and Tasman:

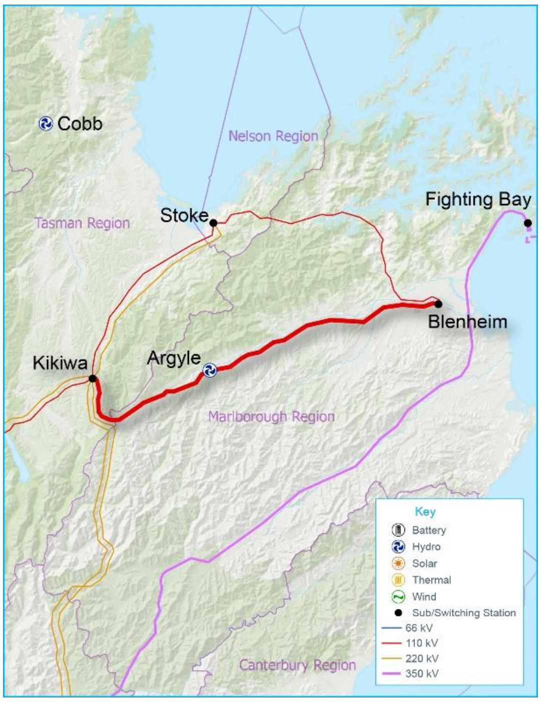
Circuit	Summer capacity (MVA)
Kikiwa–Stoke 1	239
Kikiwa–Stoke 2	239
Kikiwa-Stoke 3	56

Options range from thermal upgrades to reconductoring

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermally upgrade Kikiwa–Stoke A	265 MVA	$10-41M	1-2 years
• Reconductor Kikiwa–Stoke B	63 MVA	$13-52M	2-3 years

4.1.3 Tasman to Marlborough

Tasman and Marlborough are connected via a single 110 kV transmission line. Between Blenheim and Kikiwa. The 110 kV line along with the 110 kV line through Nelson enables N-1 security to the Marlborough region.



Existing installed line capacity is 56 MVA in summer through one circuit

Circuit	Summer Capacity (MVA)
Blenheim–Kikiwa 1	56

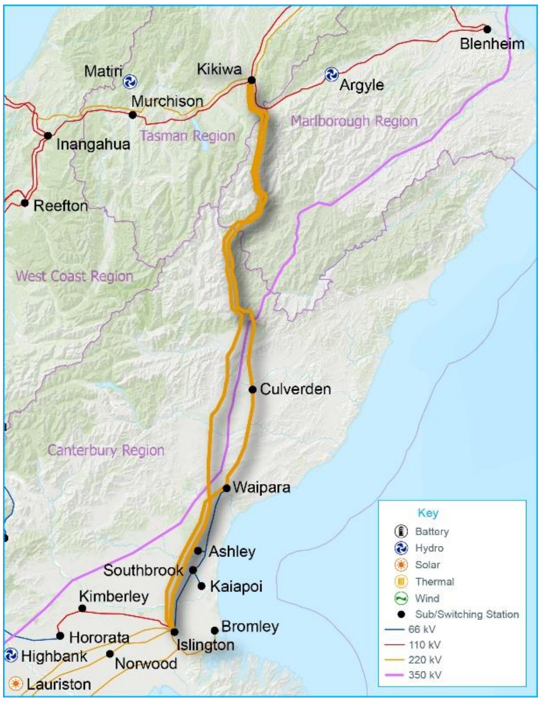
Options range from thermal upgrades to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermally upgrade Blenheim–Kikiwa A	42 MVA	$34-138M	2-3 years
• Reconductor Blenheim–Kikiwa A	63 MVA	$39-158M	2-3 years
New transmission			
• New 220 kV double circuit transmission line from Blenheim to Kikiwa	1570 MVA	$364M-1.4B	5-12 years

4.1.4 Tasman to Canterbury

The Tasman region is connected to the National Grid at Kikiwa via three 220 kV circuits from Islington. Kikiwa is a major transmission node for the upper South Island, which provides transmission connection to Nelson, Marlborough and the West Coast regions.

The regions supplied from Kikiwa far exceeds local generation so most of the load is supplied via 220 kV circuits from the Waitaki Valley, which also supply significant load in the South Canterbury and Canterbury regions. This shared capacity from the Waitaki Valley is important for supply security to the upper South Island.



Existing installed line capacity is 859 MVA in summer through three circuits

There are three transmission circuits connecting Tasman and Canterbury:

Circuit	Summer capacity (MVA)
Islington–Kikiwa 1	239
Islington–Waipara–Culverden–Kikiwa 2	310
Islington–Waipara–Culverden–Kikiwa 3	310

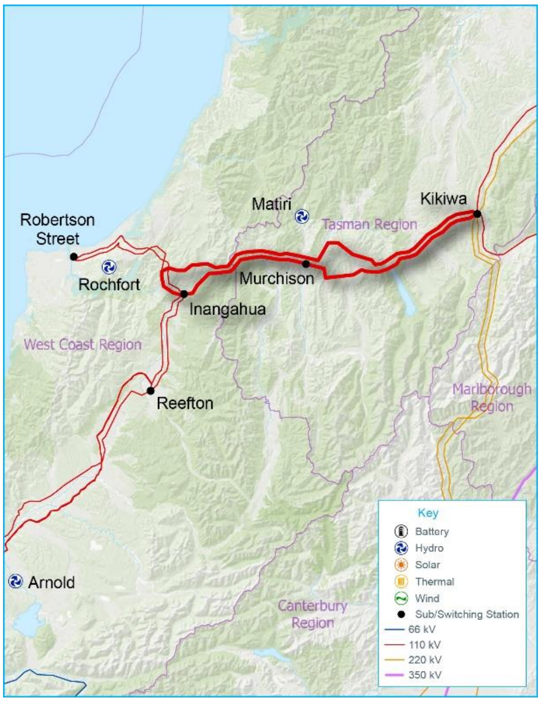
Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermal upgrade Islington–Kikiwa A to 75°C	90 MVA	$30-119M	2-3 years
• Duplex Islington–Kikiwa B	690 MVA	$103-413M	3-5 years
• Duplex Islington–Kikiwa A	238 MVA	$71-379M	2-3 years
New transmission			
• Replace Islington–Kikiwa A with a new double circuit 220 kV line[8]	880 MVA	$578M-2.31B	5-12 years

[8] Cost includes the dismantling of the existing transmission line.

4.1.5 Tasman to West Coast

The West Coast region is connected to Tasman via two 110 kV circuits from Kikiwa. The amount of generation in the West Coast and Nelson-Marlborough regions, combined, is much less than their combined demand. Significant imports are required, most of which is supplied from remote generation in the Waitaki Valley, with significant load off take in the South Canterbury and Canterbury regions.



Existing installed line capacity is 148 MVA in summer through two circuits

There are two transmission circuits connecting Tasman and the West Coast:

Circuit	Summer Capacity (MVA)
Inangahua–Kikiwa 1	56
Inangahua–Kikiwa 2	92

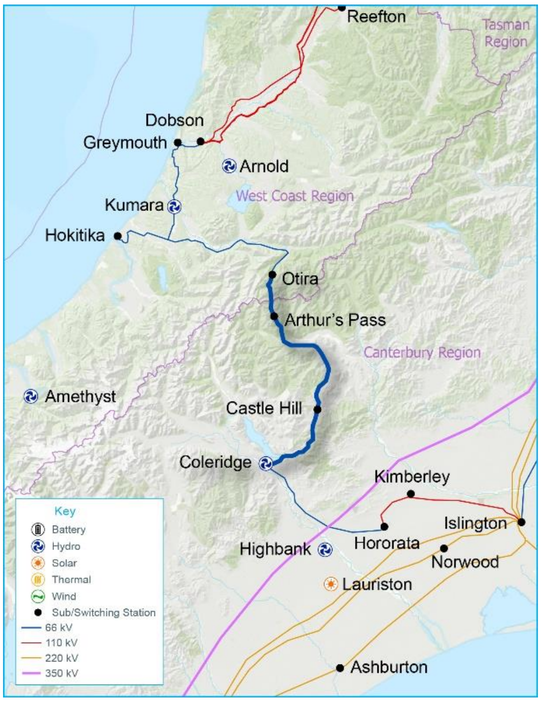
Options include thermal upgrades

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Thermally upgrade Inangahua–Kikiwa A	30 MVA	$18-71M	2-3 years

4.1.6 Canterbury to West Coast

The West Coast region is connected to Canterbury via the 66 kV Coleridge–Otira transmission line. This connects the West Cost to hydro generation at Lake Coleridge and further afield to Islington substation in the heart of Canterbury's transmission network.

These are relatively low-capacity transmission circuits when comparing to the other West Coast supply point through the 110 kV transmission through Tasman.



Existing installed line capacity is 54 MVA in summer through two circuits

There are two transmission circuits connecting Canterbury to the West Coast:

Circuit	Summer capacity (MVA)
Coleridge–Otira 1	27
Coleridge–Otira 2	27

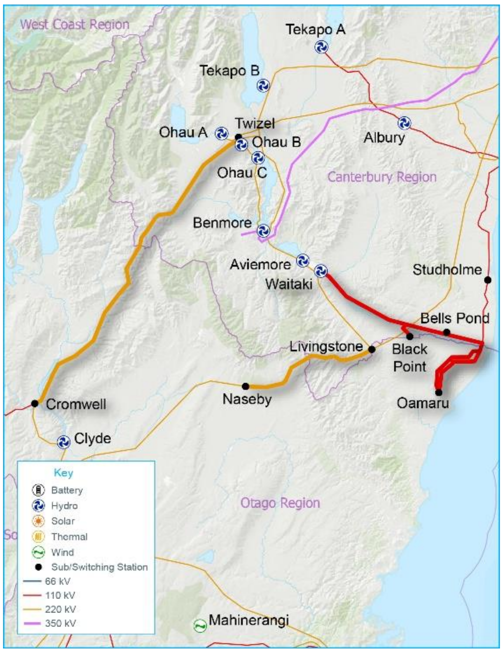
Options range from reconductoring to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Reconductor 66 kV lines between Islington-Hokitika	82 MVA	$95-379M	2-5 years
New transmission			
• New 110 kV double circuit transmission line from Christchurch to the West Coast	333 MVA	$255M-1.02B	5-12 years

4.1.7 Canterbury to Otago

The Canterbury region is the South Island's major load centre. It includes the city of Christchurch together with smaller rural localities.

The Canterbury region has some of the South Island's highest load densities, but relatively low levels of local generation. As a result, most of Canterbury's electricity demand is supplied by generation located in South Canterbury and Otago, via four 220 kV transmission circuits – three from Twizel and one from Livingstone.



Existing installed line capacity is 1829 MVA in summer through five circuits

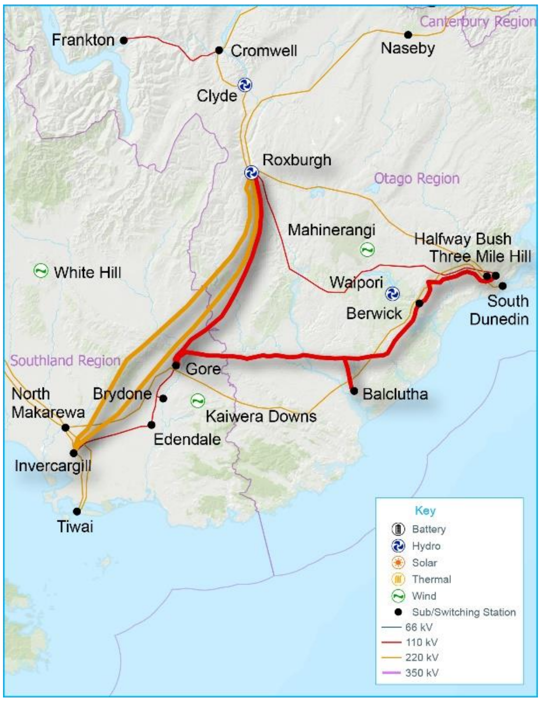
There are five transmission circuits connecting Canterbury to Otago:

Circuit	Summer capacity (MVA)
Cromwell–Twizel 1	561
Cromwell–Twizel 2	561
Oamaru–Blackpoint–Waitaki 1	48
Oamaru–Waitaki 2	50
Livingstone–Naseby 1	609

Options range from duplexing to new transmission lines

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Clyde–Twizel section of Roxburgh–Twizel A	770 MVA	$60-242M	2-5 years
New transmission			
• New double circuit 220 kV line from the Waitaki Valley to Christchurch	570 MVA	$556M-2.22B	5-12 years
• New double circuit 220 kV line from the Waitaki Valley to Orari/Rangitata switching stations	1570 MVA	$271M-1.09B	5-12 years
• New double circuit 220 kV line from Aviemore to Roxburgh	1570 MVA	$315M-1.26B	5-12 years

4.1.8 Otago to Southland



The Otago-Southland regions include a mix of provincial cities (Dunedin and Invercargill) together with the smaller but significant tourist and rural service centres of Queenstown, Wanaka, and Cromwell. New Zealand's largest electricity consumer is the New Zealand Aluminium Smelter at Tiwai Point, located in Otago-Southland.

Three 220 kV circuits and two 110 kV circuits connect the Southland region to Otago. The regions have substantial hydro generation, much of which is consumed locally. During wet periods, significant amounts of power are exported to the Waitaki Valley. During dry periods, power may be imported from the Waitaki Valley to Otago and Southland.

Existing installed line capacity is 1502 MVA in summer through six circuits

There are six transmission circuits connecting Otago to Southland:

Circuit	Summer capacity (MVA)
Gore–Roxburgh 1	63
Gore–Three Mile Hill 1	347
Gore–Three Mile Hill 2	347
Invercargill–Roxburgh 1	347
Invercargill–Roxburgh 2	347
Balclutha–Gore 1	51

Options include duplexing

Description	Added capacity (MVA)	Cost ($M)	Lead time (years)
Line upgrade			
• Duplex Invercargill–Roxburgh A	350 MVA	$42-166M	2-3 years
• Duplex Invercargill–Roxburgh B	350 MVA	$37-148M	2-3 years
• Duplex North Makarewa–Three Mile Hill A	690 MVA	$84-335M	3-5 years

5.0 Holistic transmission investments

5.1 Holistic transmission investments

In this section we explore the transmission options that exist across both islands, or between the North and South Island, as we understand them, today. Each option and assumed cost, calculated using the TEES, is discussed. Regions are not included where we have been unable to identify any feasible upgrade options.

5.1.1 New inter-island HVDC link

HVDC systems are typically more cost effective when transporting electricity across long distances (within a synchronised system). HVDC systems needs to have convertor stations at either end of the link which brings significant cost, but the benefit is that fewer lines are required between the nodes when compared to a HVAC system. Our current HVDC link is over 600km long consisting of overhead HVDC lines on both islands and HVDC cables across the Cook Strait.

North Island terminal options

There can be several HVDC terminal options in the North Island and it is a complex task to pick an optimum location without extensive studies. The optimum location depends on the level of HVAC transmission upgrades it could potentially offset which, in turn, depends on load and generation scenarios.

In the absence of the detailed studies, we have selected several potential locations based on our understanding of the current transmission grid capacity and likely future transmission constraints.

Bunnythorpe

The 220 kV grid backbone between the Central and Lower North Island converges at Bunnythorpe. An inter-island HVDC terminal at Bunnythorpe would allow generation from these regions to flow south and also South Island generation to flow north via existing and potentially upgraded HVAC grid between Bunnythorpe and Whakamaru. This option could avoid major HVAC grid upgrades South of Bunnythorpe.

Whakamaru

Whakamaru hosts six of the eight 220 kV circuits (on four transmission lines) supplying the Waikato and Upper North Island region. This option could allow South Island generation to flow into Whakamaru which potentially avoids major HVAC grid upgrades between Haywards (existing inter island HVDC terminal on the North Island) and Whakamaru.

Otahuhu

Otahuhu is a major transmission node for the Auckland region, which also provides through transmission to the Northland region. This option could allow South Island generation to flow directly into the Auckland region which potentially avoids major North Island HVAC grid upgrades south of Otahuhu.

Huapai

Huapai is the northern most 220 kV GXP in the Auckland region and has diverse 220 kV connections to Henderson and Albany which supplies major load centres in North Auckland (Northshore). This option could allow South Island generation to flow directly North of Auckland which potentially avoids HVAC grid upgrades through Auckland which requires a cabled network and a second harbour crossing. This option could also avoid major North Island HVAC grid upgrades south of Otahuhu.

Figure 4: location of potential North Island terminal options

South Island terminal options

The South Island hosts a big portion of the hydroelectric schemes in Aotearoa and most of the available storage. That is the basis of the existing Benmore HVDC terminal which is situated in the head of the Waitaki hydroelectric scheme.

As more solar and wind generation is added to our power system, the South Island hydroelectric schemes will play a bigger role in providing peaking services. Therefore, we can expect to see increased frequency of south flows across the inter-island HVDC system as the South Island imports power during high wind and solar generation periods in the North Island. A new HVDC terminal on the South Island could be strategically located to minimise investments on the South Island HVAC system to facilitate the export of hydro generation during North Island peak load periods and import of excess wind and solar generation from the North Island.

Islington

Islington is a major node in Christchurch that provides the bulk of the city's supply and provides through transmission into the upper South Island region. This option could allow North Island generation to flow directly into Christchurch which is the largest load centre in the South Island. However, most of South Island's hydroelectric schemes are south of Islington so the ability to send hydro power north could be constrained by the HVAC grid south of Islington.

Benmore

Benmore is a central node for the Waitaki hydroelectric scheme which is the largest both from a capacity and energy storage perspectives. This option has the same benefits of the existing Benmore HVDC node and HVAC grid upgrades northwards to Christchurch and southwards towards the Otago-Southland region is still required to allow power to flow to the major load centres and Otago-Southland hydro generation to flow north.

Roxburgh

Roxburgh is a major interconnection node between Otago-Southland and the Waitaki Valley. All 220 kV HVAC circuits between the two regions connects into Roxburgh. This option allows excess North Island solar and wind generation to be connected to the Otago-Southland region and hydro power to be sent northwards during North Island peak load periods. This option could avoid major HVAC upgrades between the Otago-Southland region and the Waitaki Valley.

Invercargill

Invercargill is a major transmission node for the Southland region. The region connects the Manapouri hydro power station, the largest by capacity in the country and the Tiwai aluminium smelter which is the largest direct connected load in the country. The Southland region has a lot of existing industrial loads and the potential for more industrial and data centre loads in future. There are also significant amounts of onshore wind potential in the region and offshore wind has also been considered. This option allows excess North Island solar and wind generation to be connected to the Southland region to power its industrial demand. Excess wind and hydro generation can also be exported during North Island peak load periods. This option could potentially minimise HVAC grid upgrades between the Otago-Southland region and the Waitaki Valley and minimise HVAC grid upgrades within the Southland region itself, e.g. between Invercargill and Roxburgh.

Figure 5: location of potential South Island terminal options

5.1.2 New intra-island HVDC links

Intra-island HVDC links can be an option to provide bulk power transmission between regions that are geographically far apart. HVDC links can allow subsea cabled transmission or minimises the overhead transmission corridor requirements which could be a more cost-effective method than utilising a HVAC network.

Taranaki to Auckland

Taranaki has the potential for significant amounts of wind and solar generation. Major HVAC grid upgrades are required to get the potential generation into the Auckland region which is the largest load centre in the country. This option could allow subsea cables instead of an overhead system or potentially converting existing overhead HVAC lines to HVDC.

Manawatu-Wanganui to Auckland

The Manawatu-Wanganui region sits in between hydro and geothermal generation in the Waikato region and solar and wind generation in the Wellington region. The Manawatu-Wanganui region itself also consists of significant existing hydro and potential for wind and solar generation. Auckland is the largest load centre in the Country. Therefore, a HVDC link between these two regions would connect generation in the lower north Island directly to the load in Auckland. This option could avoid or minimise HVAC upgrades in the North Island.

Otago to Canterbury

The Otago and Southland regions have significant existing hydro generation and the potential for significant onshore and offshore wind generation. The Canterbury region is the largest load centre in the South Island. Connecting these two regions allows generation in the Otago-Southland region to be directly connected to the load in the Canterbury region. This option could avoid HVAC upgrades between Otago and Canterbury.

Southland to Canterbury

The Otago and Southland regions have significant existing hydro generation and the potential for significant onshore and offshore wind generation. The Canterbury region is the largest load centre in the South Island. Connecting these two regions allows generation in the Otago-Southland region to be directly connected to the load in the Canterbury region. This option could avoid HVAC upgrades between Southland, Otago and Canterbury.

5.1.3 New HVAC 400 kV grid backbone

The main driver to transition to a higher voltage system is to provide large increases in transmission capacity between regions without needing too many additional transmission lines.

Transpower already owns a 400 kV capable line (Brownhill-Whakamaru A) currently operated at 220 kV. It was built with the long-term objective of establishing 400 kV transmission between Whakamaru and Auckland: connecting generation in the Central North Island to the country's largest load centre.

The country's transition to a 400 kV grid backbone could happen gradually as the need arises and the 400 kV system would likely operate in parallel with our existing 220 kV system. This would mirror the country's transition from a 110 kV system to a 220 kV system which has been occurring since the mid-1980s. The Brownhill-Whakamaru A line is an example where we already have four 220 kV lines and several more 110 kV lines connecting into the region. It is not cost effective nor practical to build more 220 kV lines into the region as demand grows, therefore a decision was made to plan for the eventual transition to a 400 kV system where we can transmit more power through an existing corridor.

The build out of the 400 kV grid could take two broad approaches:

- building new 220 kV HVAC circuits at 400 kV
- gradually adding 220/400 kV interconnecting transformers to allow 400 kV capable lines to be operated to their designed rating

The ability to stage makes these options potentially better than intra-island HVDC links where transmission needs are uncertain or ramp up over a long period.

The most logical introduction of 400 kV is by adding 220/400 kV at Whakamaru (north) and Brownhill substations to allow the existing Brownhill-Whakamaru A line to be operated at its designed voltage rating. However, new lines Transpower is considering in the short to medium term such as between Whakamaru-Wairakei (Wairakei Ring) could also be built to 400 kV to allow the 400 kV grid to be expanded towards the Taupo region where geothermal energy resources are concentrated. In the longer term, new HVAC lines between the Manawatu-Wanganui/Taranaki regions and the Waikato region could be viable and they could be built at 400 kV but initially operated at 220 kV until there is a need to convert their operation to 400 kV.

There are currently no 400 kV capable lines in the South Island. However, in the medium to long term, it may be economic to build new lines between Canterbury-Otago and Otago-Southland. These can also be built to 400 kV but initially operated at 220 kV and only converted to 400 kV when the need arises.

The challenges with migrating to a 400 kV grid include:

- being able to justify the incremental costs of building 400 kV lines upfront. There is a 10% increase in costs for building at 400 kV over 220 kV so it could be uneconomic if the need date for 400 kV is too far away.
- maintaining security and resilience during the transition process which could be over a very long period. For example, if we operated the existing Brownhill-Whakamaru circuit at 400 kV, the existing 220 kV network may also need upgrading to ensure the upper North Island is resilient to a tower failure event on the 400 kV Brownhill-Whakamaru A line. The original plan, under a relatively high demand growth forecast, was for a second 400 kV line between Auckland and Whakamaru to provide capacity and add resilience.

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