TRANSPOWER

Net Zero Grid Pathways 1

Major Capex Proposal (Staged)

2 December 2022

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1.0 Executive Summary

1.1 Key messages

Figure 1: Key messages

To successfully meet the climate change challenge Aotearoa New Zealand will need significant investment in electricity transmission infrastructure between now and 2050

Significant uncertainties around how demand and supply will ramp-up, make it challenging to plan and develop new infrastructure

We have identified a series of tactical upgrades to extract capacity from the existing grid backbone. These tactical upgrades are relatively low-cost grid investments that our analysis indicates are low regrets under a range of plausible future scenarios

When the benefits of these upgrades are combined, they provide options and confidence for investors in generation that would not exist if we focused on a smaller incremental investment

Progressing these investments as a package enables forward work planning to ensure timely delivery, and allows Transpower to work on planning, consenting, and developing any larger investments that may be required post 2030

1.2 Context

Aotearoa New Zealand is on a journey towards a net zero future, working to respond and adapt to climate change. Meeting the country's 2050 net zero target will require rapid transformation of the energy sector which will affect almost all aspects of our daily lives. Transpower is committed to playing our part in the transition while continuing to deliver reliable electricity for New Zealanders. We are a critical enabler for other sectors to reach their net zero emissions objectives. We have roles in enabling both electrification demand and the connection of renewable energy.

For Aotearoa New Zealand to shift away from fossil fuel-based energy, consumers and industry need confidence that electricity will be reliable and affordable. Significant (large scale) investment in transmission infrastructure is likely to be necessary to achieve the least cost transition to a net zero emissions economy.

Aotearoa New Zealand's electricity system is market-led rather than centrally planned. For generation to meet future demand at the lowest cost, investors in new generation need us to provide long term transmission grid development plans and information on those plans to make their investment decisions.

The Government has endorsed our role, stating in a letter from the Minister of Energy:

"We continue to expect Transpower to invest ahead of transmission demand in order to ensure that there is capacity for competitive investment by generators in distant load renewables, including intermittent renewables. Transpower's work in this area, and in facilitating the decarbonisation of industrial heat and transport, will help support the Government's targets to achieve 100 per cent renewable electricity by 2030, and reach net zero emissions by 2050."[1]

1.3 The project

Net Zero Grid Pathways (NZGP) is our project to develop plans for evolving the transmission grid as New Zealand pursues a goal of achieving net zero carbon emissions by 2050.

Industry forecasts, including our own *Whakamana i Te Mauri Hiko* (WiTMH), point toward a 60-80 per cent increase in electricity demand by 2050. This demand will be supported by renewable generation. However, the role that various energy sources such as electricity, hydrogen and biomass will play in our future energy mix is not yet clear.

Making a case for, planning, and developing new transmission infrastructure for the expected ramp up of demand and supply from 2025 is an intensive task. The challenge is deepened by key uncertainties. Whether the New Zealand Aluminium Smelter at Tiwai Point closes or not, when and where the next renewable generation projects will be built, decisions around the NZ Battery Project, and whether offshore wind will be developed in New Zealand, will affect what transmission investment is needed. The speed of uptake of electric vehicles, the reduction in fossil fuelled production of process heat, and the evolution of distributed energy resources will also have an impact on transmission investment decisions. The changes to the Resource Management Act and other regulatory amendments also contribute to uncertainty around how we can best ensure a reliable and safe network within a net zero emissions future.

This level of uncertainty is challenging. Whatever future plays out, the overarching demand pathway is clear and Transpower needs to increase the capacity of some parts of the main grid backbone in the medium term to ensure capacity is available to deliver the benefits of further investments in low-cost renewable generation.

It is clear that we need to develop the grid flexibly, in a proactive manner. We need to minimise the risk of over-build while ensuring the grid is fit-for-purpose. This will allow Aotearoa New Zealand to handle any of the wide variety of futures we could face.

As detailed in the recent *The Future is Electric* report from Boston Consulting Group:

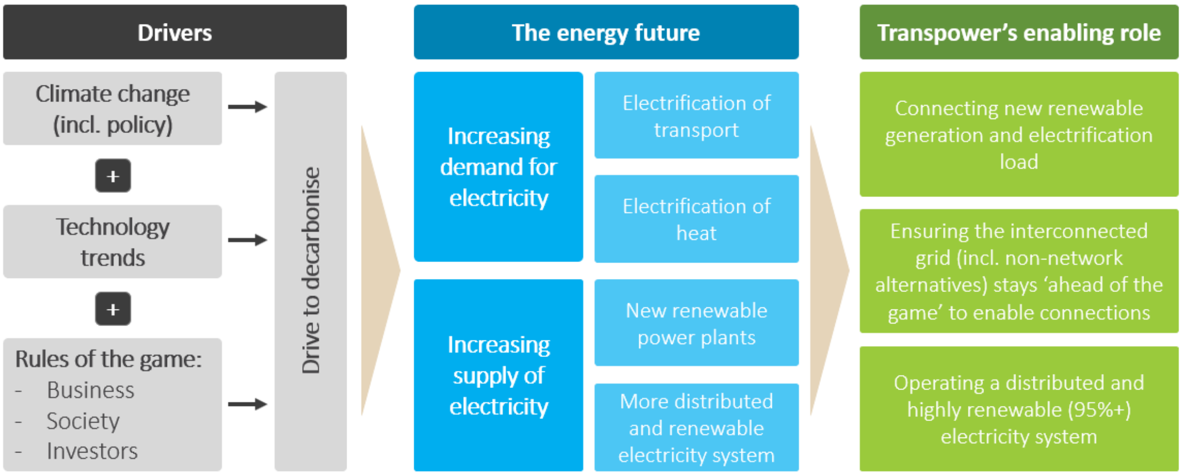
"This will require unprecedented levels of investment but will lead to flat household electricity bills and declining household energy bills…. Delivering this will require a much smarter, more flexible electricity system that saves $10 billion in net present value terms by 2050."

The NZGP proposal documented here is the first Major Capital Proposal to be submitted to the Commerce Commission for approval in this area. It covers the first stage of the first phase of

[1] Letter of Expectations 2022/23 from the Responsible Minister - Transpower New Zealand Limited (treasury.govt.nz)

NZGP including improvements to the inter-island capacity of the HVDC, Central North Island 220 kV capacity between Bunnythorpe and Whakamaru, and Wairakei Ring capacity.

Figure 2: Transpower's enabling role in support of goal to reach net-zero carbon by 2050



1.4 Net Zero Grid Pathways

Electricity flow over the backbone grid is determined by electricity market operations rather than local demand peaks and troughs. As a result, the peaks, which drive our investment, are difficult to predict. In the future, when North Island thermal generation is retired, peak usage may become more aligned with the strength of the wind and cloud cover, which is even less predictable.

Net Zero Grid Pathways (NZGP) considers Transpower's investment in the backbone of Aotearoa's electricity transmission grid. NZGP aims to ensure the grid backbone has enough capacity to accommodate new renewable generation and maintain a secure and reliable supply of electricity. It has two phases:

1. enhance the existing grid backbone to 2035
2. address the likely need for a larger grid backbone with new interconnections beyond 2035 (including regional grid developments)

Our investigations have now identified the least regrets, tactical investments needed for the first step in phase one. These are least regrets as they are beneficial under a range of scenarios and mitigate the risk of not having sufficient capacity out to 2035. Importantly, the investments provide generators with confidence to make their own choices about investment. This would not be the case with smaller incremental investment. It also allows us to separately develop, approve, and consent work on the larger future investments that may be required post 2035.

Processing these investments as a package enables forward work planning to ensure timely delivery, reduces the churn in sequential approvals, and captures economies of scale.

"Although waiting to invest may appear to be an efficient way to save money, investing in transmission too late stalls the development of low-cost renewable generation, and can therefore increase net prices and emissions."[2]

[2] The Future is Electric p97

1.4.1 Staging

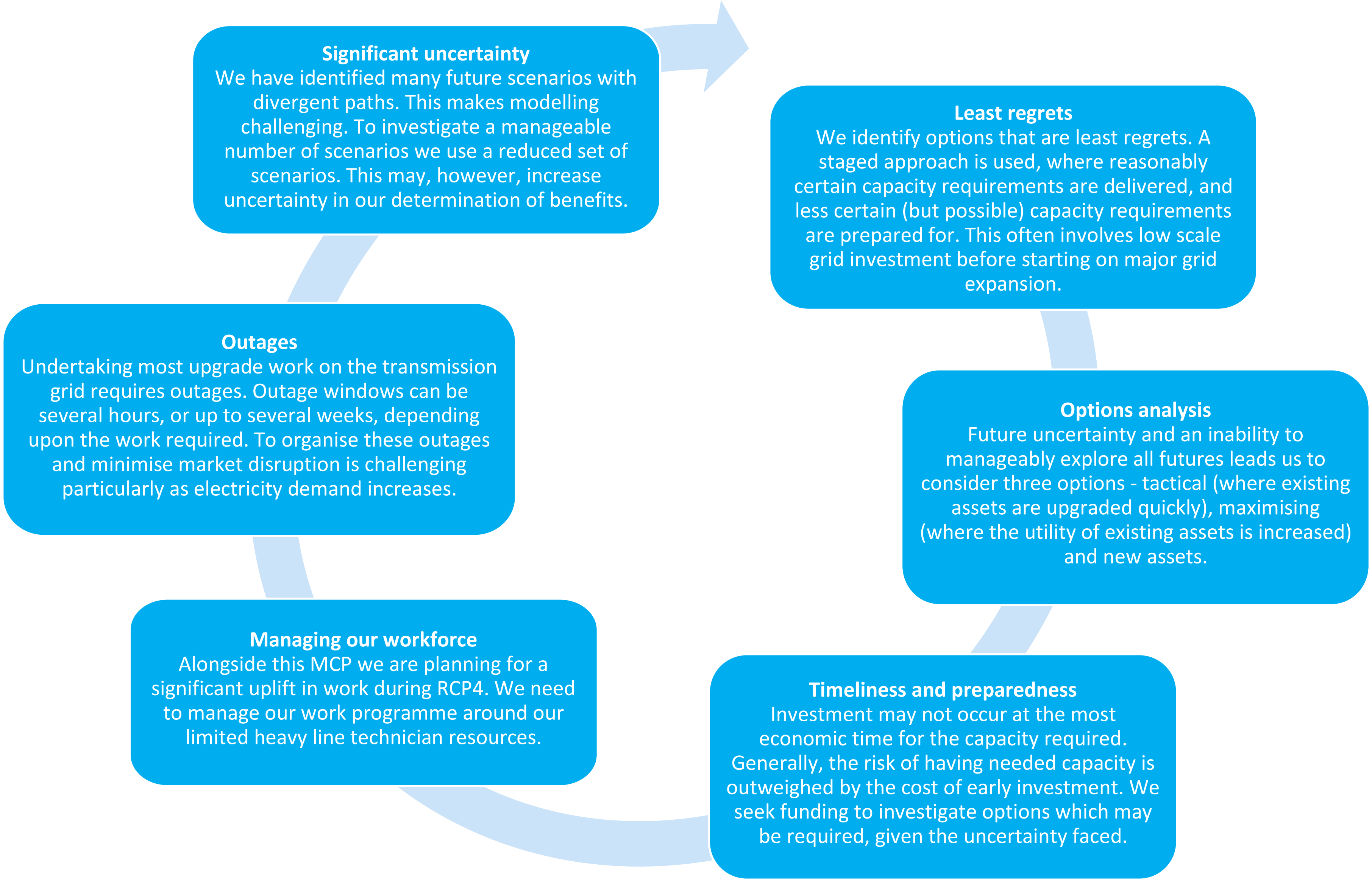
We have identified three stages to NZGP Phase 1. Staging allows us to start investing, while continuing to refine the scope and costing of projects that will not commence until the late 2020's. We refer to this application as NZGP1.1 as it will be followed by at least one other stage within the first phase of NZGP that are also aimed at enhancing the grid backbone prior to 2035. We expect to begin our detailed investigations into NZGP1.2 in 2023.

This document is an application to the Commission to recover the costs of investing in the grid to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid.

1.4.2 How we decide to invest

Our NZGP investigations have identified several key factors that inform the strategy involved in the choice and timing of investments. These are reflected in this Major Capex Proposal (MCP).

Figure 3: Strategic considerations informing Transpower's NZGP Stage 1 investment choices



1.5 Scenarios

In developing scenarios for NZGP, we used the Ministry of Business, Innovation and Employment (MBIE)'s current Electricity Demand and Generation Scenarios (EDGS) as a base. However, these were last updated in 2019 and are due for updating in 2023. These updates will be based on an integrated energy view for achieving net zero carbon by 2050.

With input from the wider industry we have updated key elements of the 2019 EDGS, including updating for the latest demand forecasts and information about potential new generation projects.

A summary document describing our variations was published in December 2021.[3] Considerations involved in our variations are briefly described below.

1.5.1 Tiwai Point Aluminium Smelter Closure

The genesis of this investigation came from an internal study in 2020[4], which considered the effect of Rio Tinto's announcement that they intended to wind-down and eventually close the Tiwai Point aluminium smelter. Tiwai consumes a considerable percentage of South Island hydro generation.

The study identified potential transmission constraints on the High Voltage Direct Current (HVDC) link and the North Island 220 kV Alternating Current (AC) network between Bunnythorpe and Whakamaru (otherwise called the 'Central North Island' or CNI) that would result from Tiwai's closure. The study found that relieving these constraints was likely to lead to consumers benefiting in the long run from lower electricity prices and more reliable supply.

We understand that New Zealand Aluminium Smelters have an electricity supply contract until December 2024. After this time the Tiwai smelter's continued operation will depend upon commercial negotiations with electricity suppliers. December 2024 is therefore the earliest time Tiwai might credibly close. Consistent with a prudent approach this MCP reflects a December 2024 Tiwai closure. We have run sensitivity analysis to estimate the impact on our proposal of Tiwai continuing to operate past 2024. We used a Tiwai closure year of 2034, which we consider to be a credible alternative closure date if Tiwai continues to operate past 2024.

1.5.2 Increase in demand

Our customers are forecasting a 60 – 80% increase in demand by 2050.

[3] Link to NZGP1 Scenarios Update

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

1.5.3 Significant increase in generation connection enquiries

We have seen a considerable increase in enquiries for new generation connections from five in 2019 to 74 in 2022. This is a leading indicator of generation connection growth that we expect to continue.

We are also aware of significant increases in the number of embedded generators being connected or enquiring about connection. A high proportion of these enquiries are potential connections feeding into our Wairakei Ring 220 kV network.

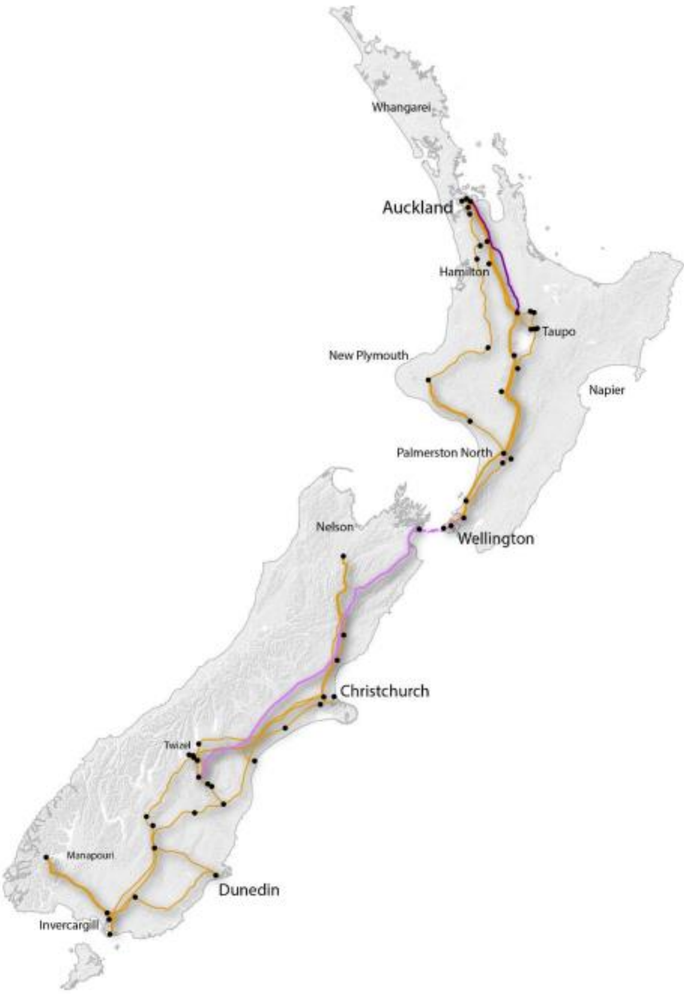
1.6 Our proposal – NZGP Phase 1

This MCP is the result of an investigation into:

- Inter-island HVDC capacity
- CNI 220 kV capacity between Bunnythorpe and Whakamaru
- Wairakei Ring capacity

We believe these areas of the grid backbone are the most likely to constrain prior to 2035.

Figure 4: Aotearoa New Zealand transmission grid backbone - the focus of NZGP Phase 1



1.6.1 Investment need

The investment need of NZGP1.1 is to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid.

To meet this investment need this proposal seeks funding approval for

(1) shorter term initiatives; and

(2) funding to investigate further longer-term planning issues and larger investments.

The process is staged. Overall, this is consistent with our least-regrets approach, deferring higher levels of capital to allow uncertainties to clarify or play out. Approval for the larger and longer-term grid investments (NZGP1.2 and possibly NZGP1.3) will be sought when the need, scope, and cost is more certain.

The total cost of NZGP1.1 is expected to be $327 million. The major capex allowance we are applying for (including estimates for scope uncertainties, inflation, and interest during construction costs) is $393 million. As this transmission enhancement is expected to cost more than $20 million, Transpower must submit this MCP to the Commerce Commission (the Commission) in order to recover the costs through the Transmission Pricing Methodology (TPM).

The proposed investment is a major capex project (staged) consisting of two stages - NZGP1.1 and NZGP1.2. A possible third stage (NZGP1.3) is contemplated but is not part of the proposed investment at this time.

The grid outputs for NZGP1.1 are as follows:

Table 1 NZGP1.1 at a glance

<table>
<tr><th colspan="2">NZGP1.1 at a glance</th></tr>
<tr><td>What:</td><td>Enable efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid through investing in:

HVDC investment

Purpose: To increase HVDC transfer capacity north from 1070 MW to 1200 MW

• Implement new +/-60 MVAr continuous/120 MVAr overload STATCOM, +49MVAr filter bank, bus extension and associated equipment.

Central North Island (CNI) investments

Purpose: To increase transfer capacity north from Bunnythorpe by between 60% and 90%[5]:

• Implement Variable Line Rating and tactical thermal upgrade (TTU) of both 220 kV circuits on the Tokaanu-Whakamaru A and B lines to 95°C

• Duplex the 220 kV Tokaanu-Whakamaru A and B circuits with Goat conductor to operate at a maximum temperature of 120°C

• Implement VLR and TTU of the 220 kV Bunnythorpe-Tokaanu A and B circuits to 95°C</td></tr>
</table>

	• Split the 110 kV Bunnythorpe-Ongarue A circuit at Ongarue • Upgrade protection on the 220 kV Huntly – Stratford 1 circuit on the Huntly-Taumaranui A line and Stratford-Taumaranui A line, between Huntly and Stratford • Replace the special protection scheme at Tokaanu *Purpose: Preparatory work for NZGP1.2 CNI investment:* • Investigate options for reconductoring either 220 kV Brunswick-Stratford line *Purpose: Preparatory work for possible later stage CNI investment:* • Prepare designs to duplex the 220kV Bunnythorpe-Tokaanu A and B circuits • Prepare designs to TTU the 220kV Bunnythorpe-Wairakei A circuits • Investigate options, routes and progress design for a new 220 kV line north of Bunnythorpe • Develop a methodology for quantifying resilience benefits ***HVDC/CNI investments*** *Purpose: Preparatory work for possible later stage CNI investment:* • Investigate lower North Island (**LNI**) voltage stability • Investigate LNI system stability • Investigate diversifying the Bunnythorpe substation ***Wairakei investments*** *Purpose: To increase Wairakei Ring transmission capacity by 25% (300 MW) under typical operating conditions:* • TTU the 220 kV Wairakei-Whakamaru C circuits to 100°C • TTU of the 220 kV Edgecumbe-Kawerau 3 circuit on the OHK-EDG A and KAW-DEV A lines between Edgecumbe and Kawerau to 90°C *Purpose: Preparatory work for NZGP1.2 Wairakei Ring investment:* • Investigate options, routes and progress designs for a new or enhanced Wairakei-Whakamaru line
When:	Commence work as soon as funding is approved. Commissioning date assumption: 30 June 2028.
How much:	Major capex allowance: $393.0 million.
Incentive elements	Major capex incentive rate: 15% Exempt major capex: none
Approval expiry date:	31 December 2030[6]

[6] For NZGP1.1, we propose the approval expiry date to be 31 December 2030 - being two years after the latest expected commissioning date of the NZGP1.1 components.

We will seek Commerce Commission approval for NZGP1.2 (the second stage of the proposed investment) later in a separate major capex proposal. The anticipated grid outputs for NZGP1.2 are as follows:

Table 2 Anticipated investments in NZGP1.2

Anticipated for NZGP1.2	
What (Stage 2, NZGP1.2):	Enable efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid through investing in: ***HVDC investment*** *Purpose: Preparatory work for NZGP1.2 Wairakei investment:* • Fourth HVDC Cook Strait cable ***CNI investment*** *Purpose: Preparatory work for NZGP1.2 Wairakei investment:* • Reconductor the 220 kV Brunswick-Stratford A line ***Wairakei investment*** *Purpose: Preparatory work for NZGP1.2 Wairakei investment:* • New or enhanced Wairakei-Whakamaru line

1.6.2 Project outcomes

This MCP covers investment in projects with specific physical outputs in NZGP1.1 (‘projects’). We are seeking approval for measures that will release more capacity from existing grid assets. These improvements can be typically deployed within three years of approval and provide prompt market benefits and certainty for new electricity consumers and generation developers.

1.6.2.1 HVDC availability and capacity

The role of the HVDC in Aotearoa New Zealand’s electricity system is changing. Originally installed to transfer South Island hydro to the North Island it is becoming a critical component in security of supply for both the North and South Islands. As thermal generation in the North Island closes, South Island hydro becomes more important for the North Island in terms of both energy supply and balancing intermittent generation. Additionally, as South Island process heat applications transition away from coal fuel, South Island demand will increase significantly, becoming more vulnerable to dry hydrological years.

In this MCP we are asking for funding to increase the average maximum northwards transfer capacity available from the existing HVDC. Currently, average maximum capacity is reduced due to regular outages of some equipment that enables higher levels of northward transfer. Our proposal is to install reactive support equipment which will provide improved link capacity availability. Our proposal targets a lift in the historic average capacity availability from 1071 MW to close to 1200 MW.

As demonstrated in our application of the Investment Test, it is also economic to install a fourth Cook Strait cable, increasing the northwards transfer capacity to 1400 MW. The funding request for that investment is anticipated be included in our NZGP 1.2.

1.6.2.2 Lower North Island voltage and system stability

A general finding of our investigations is that over time, South Island generation will play a more significant part in firming upper North Island intermittent generation. Along with likely interaction between the two regions in dry years, the lower North Island could be seen as through transmission, connecting these two regions. Resilience of the lower North Island transmission grid will be increasingly important and as electricity flows increase it is more likely that voltage issues will arise. Further investigation of voltage stability in the lower North Island is required. As thermal generation becomes unavailable or decommissioned in the North Island the amount of inertia provided by this generation decreases. At some point, system stability issues may also arise. We therefore intend to further investigate system stability in the lower North Island. Our proposal is seeking funding to investigate these issues. Any projects resulting from these investigations are likely to proceed in NZGP 1.3.

1.6.2.2 Central North Island capacity

Although futures exist where high Central North Island (CNI) transmission capacity options are required, these are somewhat uncertain. Therefore, we propose to enhance existing CNI transmission assets in NZGP1.1. At the same time we are also seeking funding to prepare for further enhancements to existing assets, including investigating a new line option that may be required in NZGP1.3.

As electricity flows increase through our Bunnythorpe substation near Palmerston North, it becomes an increasing single point of failure risk in our electricity network. Funding in NZGP1.1 will allow us to study this issue further and consider at what point we should diversify electricity flows through Bunnythorpe and potentially establish a new substation in the region.

Resilience will be key in the choice of route for any new line north of Bunnythorpe to connect at or beyond Whakamaru. Resilience consists of the system's ability to lessen the impact of very severe events on electricity supply and to accelerate the recovery of normal operating conditions. While any route which differs to our existing Bunnythorpe to Whakamaru lines will provide geographical diversity, we also need to consider resilience to climate change effects and natural disasters such as volcanic eruptions. Although we have approaches to identifying resilience risks in our investigation into new line routes north of Bunnythorpe, we do not have an adequate methodology for valuing resilience differences. Funding in NZGP1.1 will allow us to develop an appropriate methodology.

1.6.2.4 Wairakei Ring line capacity

Some existing Wairakei Ring lines are near capacity, and our ability to connect new generation without constraints is limited. We are well underway with a device at Atiamuri that will more evenly use these lines. In addition, we propose to thermally uprate one of these lines as a part of NZGP1.1. This will increase the electricity flow by a further 20% or 200 MW northwards through the Wairakei Ring.

However, after this work we anticipate a significant uprating to an existing line, or a new line altogether, may be required in the region. We have included funding to identify a suitable new line option in this MCP. The uprating or new line would be included in NZGP1.2.

1.6.2.5 Preparedness funding

NZGP1.1 includes funding for the investigations described above (preparing for projects in later stages) as ‘preparedness’.

This preparedness allows early planning of additional major grid upgrades, which may be included in an MCP for NZGP1.2 or NZGP1.3. These investigations will enable Transpower to advance its response to large binary step-changes in generation and demand, should they occur.

Table 3: List of future likely NZGP1.2 and possible NZGP1.3 projects including high level P50 cost estimates

	Likely Stage 2 MCP (NZGP1.2)		**Possible Stage 3 MCP** (NZGP1.3)	
	Project	**$m**	**Project**	**$m**
HVDC	New Cook Strait cable	120	Lower NI system stability support	30-120
CNI	Reconductor BRK-SFD A line	75	Upgrade remaining CNI lines/new line from Bunnythorpe Lower NI voltage support	200-600 30-80
Wairakei Ring	New WRK-WKM line	100		

1.6.3 Project grid outputs and timing

We have determined our project timings on the basis of:

- Tiwai closing at the end of 2024 when its current electricity supply contract expires (a prudent assumption)
- the foreseen difficulties of obtaining outages for delivery of these projects
- the lack of flexibility our workforce will have to change workplans at short notice, particularly once the expected ramp-up in electricity is underway

Providing notice of our intention to deliver these projects at these timings will also offer confidence to potential users wanting to switch from fossil-fuelled to electricity-based energy and generation investors.

We have tested the sensitivity of Tiwai negotiating a long-term electricity supply contract and staying until 2034. Two variations are reported – one where we proceed with the proposal and one where the fourth Cook strait cable is deferred until 2034, at which time the existing cables are also replaced. This lowers the cost of the fourth cable because a cable laying ship is only required once. The proposal has a negative net benefit if Tiwai closure is deferred until 2034, unless the fourth cable is also deferred. The latter option would be sensible in such a situation.

We would not look to defer work on the Central North Island lines, or Wairakei Ring lines if Tiwai does not close in 2024, because, as our strategic considerations describe, this is unlikely to be plausible (see Section 2.4).

1.6.4 NZGP1.1 P50 costs and Maximum Capex Allowance

The P50 costs for this MCP and the Major Capex Allowance (MCA) we are seeking approval to recover are shown in Table 4. Our costing approach is discussed further in section 5.1.1. The MCA is higher than the P50 because it is calculated by adding Interest During Construction costs and inflation to the P50 cost estimate.

Table 4: Estimated P50 and MCA costs ($m) of NZGP1.1 projects

Staged project	Purpose	Abbreviated grid outputs[7]	P50	MCA	Estimated commissioning
HVDC	Stage 1	Implement reactive plant, filter banks and associated equipment to uprate HVDC	84.4	103.1	2027
			84.4	**103.1**	
CNI	Stage 1	Implement VLR and TTU 220 kV Tokaanu-Whakamaru A&B circuits	45.5	50.8	2024
CNI	Stage 1	Implement duplex conductors on 220 kV Tokaanu-Whakamaru A&B circuits	94.4	119.4	2028
CNI	Stage 1	Implement VLR and TTU 220 kV Bunnythorpe-Tokaanu A&B circuits	68.1	83.2	2027
CNI	Supports Stage 1	Implement split on 110 kV Bunnythorpe-Ongarue A line at Ongarue	0.5	0.5	2026
CNI	Supports Stage 1	Implement upgraded on 220 kV Huntly-Stratford 1 circuit	2.0	2.0	2026
CNI	Supports Stage 1	Replace Special Protection Scheme at Tokaanu	1.0	1.0	2026
			211.5	**256.9**	
CNI	Prepare for Stage 2	Investigate options for reconductoring either 220kV Brunswick-Stratford line	2.0	2.0	2025
			2.0	**2.0**	
CNI	Possible Stage 3	Prepare detailed design to duplex 220kV Bunnythorpe-Tokaanu A&B circuits	1.5	1.5	2025
CNI	Possible Stage 3	Prepare detailed design to TTU 220kV Bunnythorpe-Wairakei A circuits	0.5	0.5	2025
CNI	Possible Stage 3	Investigate options, routes, progress design new 220 kV line north of Bunnythorpe	3.0	3.0	2026
CNI	Possible Stage 3	Develop a methodology for quantifying resilience benefits	0.3	0.3	2026
			5.3	**5.3**	
			218.8	**264.2**	
Wairakei	Stage 1	Implement TTU on 220 kV Wairakei-Whakamaru C circuits	10.6	11.8	2024
Wairakei	Supports Stage 1	Implement TTU on 220 kV Edgecumbe-Kawerau 3 circuit	10.1	11.0	2024
			20.7	**22.8**	
Wairakei	Prepare for Stage 2	Investigate options, routes, design new/replaced Wairakei- Whakamaru line	2.0	2.0	2026
			2.0	**2.0**	
			22.7	**24.8**	
HVDC/CNI	Possible Stage 3	Undertake investigation into lower North Island voltage stability	0.3	0.3	2026
HVDC/CNI	Possible Stage 3	Undertake investigation into lower North Island system stability	0.3	0.3	2026
HVDC/CNI	Possible Stage 3	Investigate potential benefits and cost of diversifying Bunnythorpe substation	0.3	0.3	2026
			0.9	**0.9**	
Total			**326.8**	**393.0**	

[7] These are abbreviated versions of the grid outputs more fully described in Table 1 – abbreviated for readability.

1.6.5 Previous consultation

1.6.5.1 Long-list options

We consulted on a long-list of options in August 2021.[8] That document was:

- 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.

Our description of assumptions included detail on the demand and generation scenarios we were intending to use (see Attachment D).

1.6.5.2 Non-transmission solutions

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

As previously noted, electricity flows over the backbone grid differ considerably to those elsewhere in the grid. We have formed a view that, due to these issues, it is unlikely NTS would be a viable substitute to the projects covered in this MCP. However, NTS may be able to help manage operational risk due to unavailability of grid assets during delivery of the investments included in this proposal and we will explore opportunities for this once they are known.

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

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

1.6.5.3 Feedback on long-list consultation

We received 11 submissions in response to our long-list consultation, from a mixture of lines companies, gentailers and generators. These were generally supportive of our aim to enable electrification and renewables. A number of submissions noted the value of considering NTS and incremental investments.

A more complete description of the feedback and our views is included in Attachment H.

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[8] NZGP1 long-list consultation document

1.6.5.4 Short-list consultation

Having completed a preliminary application of the Investment Test, and having identified a preferred option, we undertook a short-list consultation in July 2022.[9] That consultation described:

- our variations on MBIE's current (2019) EDGS
- how we reduced the long-list of options to an intermediate list and then a short-list
- how we used a variation on the "similar" parameter to identify a preferred short-list option
- how our NZGP considerations defined the timing constraints
- our preferred scenario weightings
- our preliminary application of the Investment Test
- our preferred option
- sensitivity analysis
- proposed treatment of NTS in this project

1.6.5.5 Feedback on short-list consultation

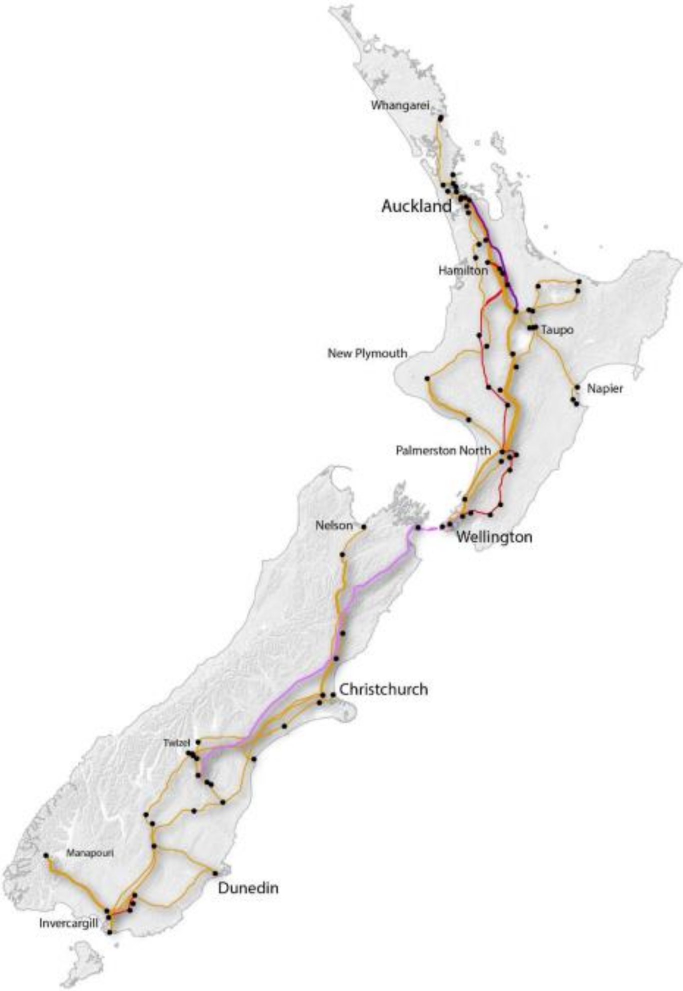
We received 17 short listing consultation responses from both generation developers, distribution companies and the Major Electricity Users Group. Generally, these submissions supported our approach to NZGP1, however, some noted that the modelling of our assumptions was complex. We met with the Major Electricity Users Group following the consultation on specific questions they had responded on. Other comments were received on the proposed treatment of NTS, noting our position that any feasible options were best signalled and explored closer to the required date, when more specifics were known regarding both timing and capacity. A more complete description of the feedback and our views is included in Attachment H.

[9] Link to SLC document.

1.7 NZGP Phase 2

As already discussed, we will also commence industry engagement on NZGP Phase 2 in 2023. This work will look out to 2050 to identify how the grid backbone and regional interconnections need to develop to provide the required reliability and resilience.

Figure 5: Aotearoa New Zealand transmission grid backbone - the focus of NZGP Phase 2



Overall, the output from the NZGP project will be a long-term transmission plan, or series of plans, showing how we envisage the transmission system could be developed between now and 2050. This plan will provide important information for electricity demand and generation investors giving guidance on future transmission capacity.

2.0 Need for investment

2.1 Existing system

Net Zero Grid Pathways (NZGP) Phase 1[10] 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.

In December 2020, we undertook work to consider the effect on the transmission system of Rio Tinto's announcement to wind-down, and eventually close, the Tiwai Point aluminium smelter (Tiwai).[11] That study identified the most restrictive transmission constraints as occurring on the High Voltage Direct Current (HVDC) link and the North Island 220 kV Alternating Current (AC) network between Bunnythorpe and Whakamaru (referred to as the Central North Island or CNI). Relieving these constraints would provide the highest benefit to consumers. Although the Tiwai closure has now been deferred until at least December 2024, it will still have a significant effect when it does occur, and we need to be as prepared as possible.

In addition, the high number of new generation connections we are receiving in the vicinity of the Wairakei ring led us to include this part of the transmission grid into our investigation.

We therefore advised the Commission of this investigation, for a Major Capex Project (staged) covering the first stage in Phase 1 of NZGP (NZGP1.1). Staging the investment will best allow us to take a least-regrets approach and commit to significant expenditure with the maximum amount of certainty. Our investigation covered:

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

Our focus has been on investigating thermal constraints on the grid backbone because the lead-time to relieve such constraints is the longest. However, as parts of the grid become more highly loaded and thermal generation closes, voltage and other stability constraints can also emerge. We have started voltage and stability constraint studies separately. This MCP includes a request for funding to assist with external studies in order to understand whether alleviating any such constraints will need to be included in a subsequent stage of NZGP1.

A general finding of our investigations is that, over time, South Island generation will play a more significant part in firming upper North Island intermittent generation. Along with likely interaction between the two regions in dry years, the lower North Island could be seen as through transmission, connecting these two regions. Resilience of the lower North Island transmission grid will be increasingly important. This proposal starts to address that requirement, but we expect Stage 2 and possibly Stage 3 investment will be required longer term.

Our investigation did consider both a single solution, bypassing this part of the grid and a solution that involved upgrading individual parts of the existing grid. We found that upgrading individual parts of the existing grid is more beneficial.

The rest of this section comprises a description of the HVDC link, the 220 kV transmission between Bunnythorpe and Whakamaru and the Wairakei Ring. These descriptions are abbreviated, and more information is available in our Transmission Planning Report.[12]

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[10] As identified in our recent Integrated Transmission Plan 2022

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

[12] https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/uncontrolled_docs/2022 Transmission Planning Report.pdf?VersionId=v6h_P0Vwhmys9BEpp3OGicM1aj4Fr_OZ

Figure 6: The existing transmission network covered in this MCP

2.1.1 Inter-island High Voltage Direct Current (HVDC) link

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

- Two ± 350 kV thyristor bipole converters, Pole 2 and 3, both rated at 700 MW, with converter stations and protection and control systems at our Benmore substation in the South Island and Haywards substation in the North Island.
- Two 350 kV bipolar transmission lines. These comprise a 535 km length from Benmore to Ōraumoa/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.

Figure 7: Geographic view of the HVDC Cook Strait link

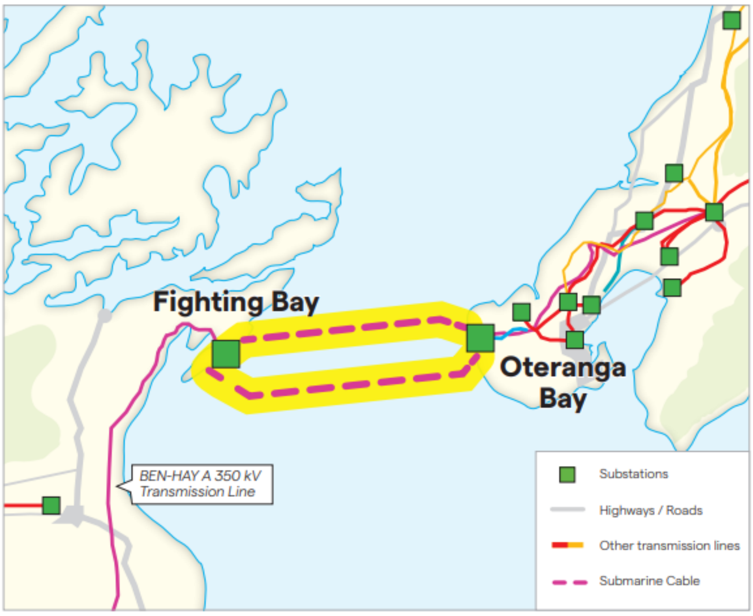
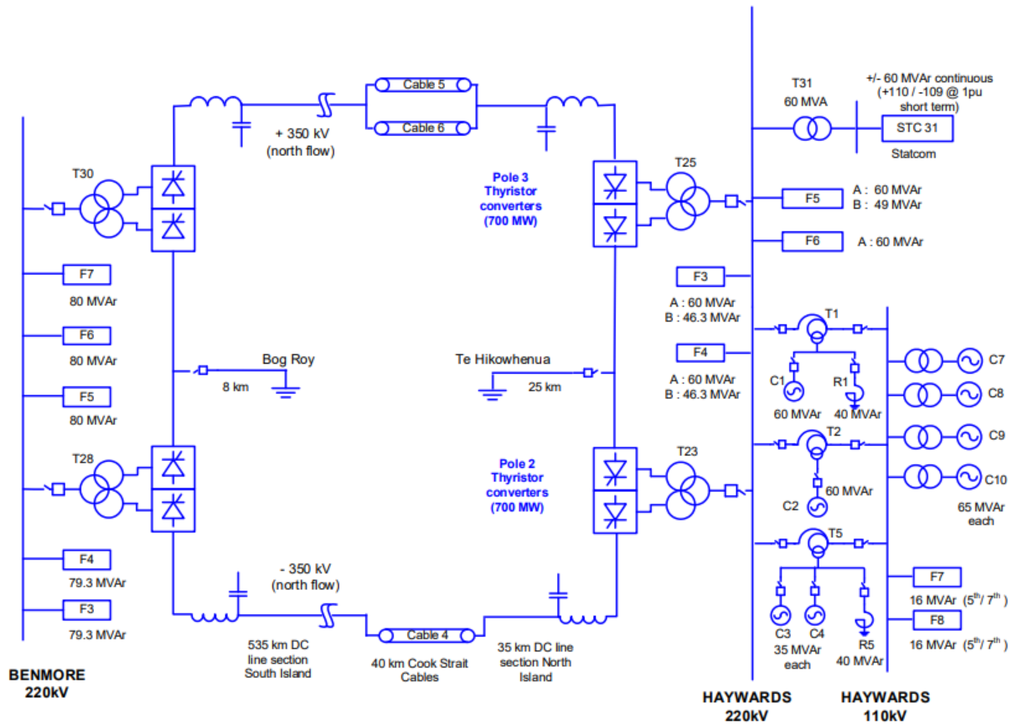


Figure 8: Simplified schematic of the existing HVDC link



2.1.2 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.

These 220 kV circuits form part of the grid backbone. The lower North Island also has a 110 kV network, which is mainly supplied through the 220/110 kV interconnecting transformers at our Bunnythorpe substation. The direction of power flow through the region is determined by generation, direction of HVDC flow, and demand outside of the region. 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;
- Taranaki region to the west;
- Waikato region to the north; and
- Hawke's Bay region to the east.

A geographic view of the CNI is shown in Figure 9 and a single line diagram of the CNI and Wairakei Ring regions is shown in Figure 10.

Figure 9: Geographic view of the Central North Island region transmission network

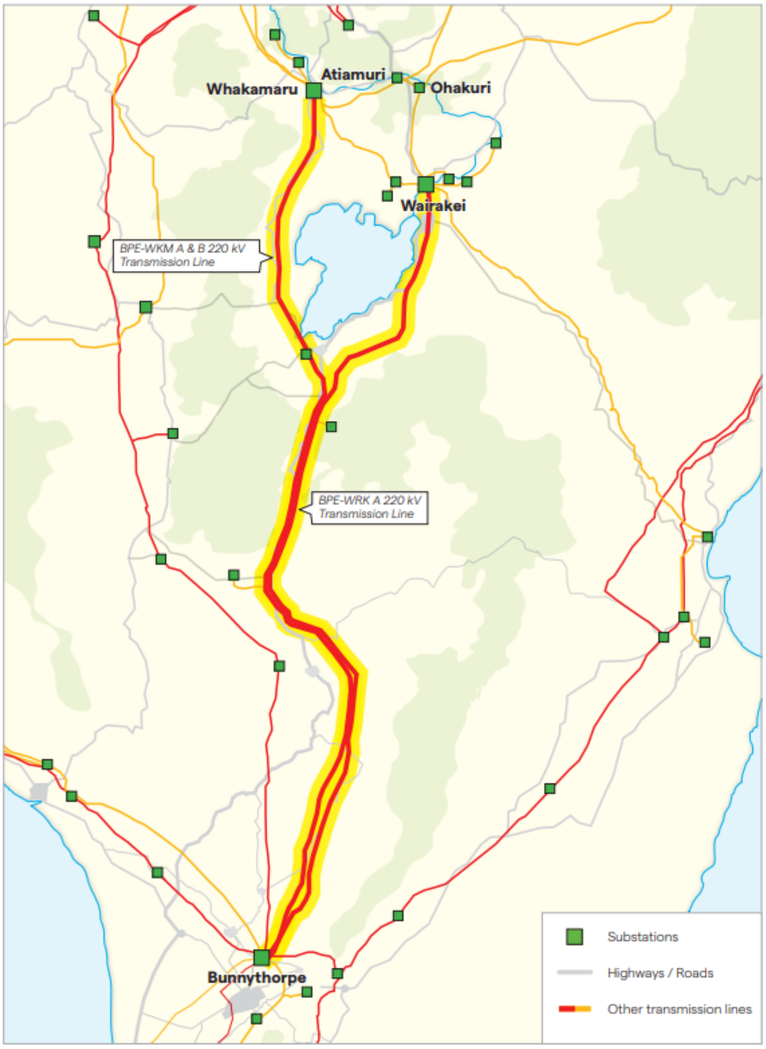
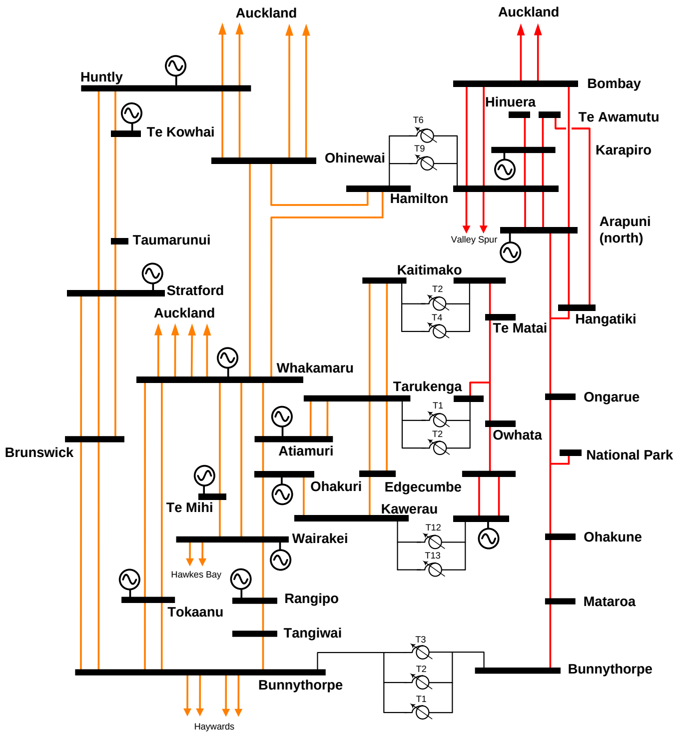


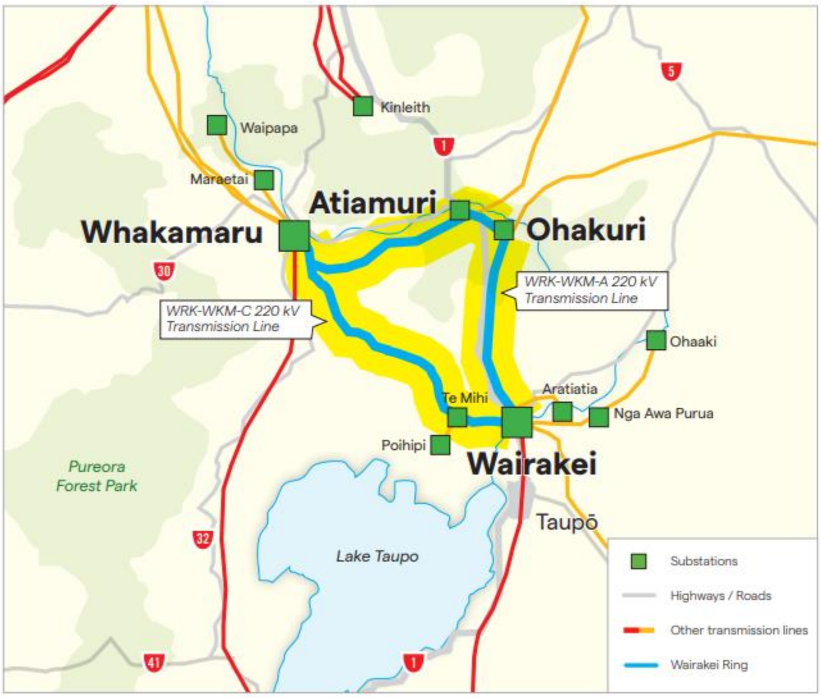
Figure 10: Single Line Diagram of the Central North Island (including Wairakei Ring) transmission network



2.1.3 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. The Wairakei Ring consists of two 220 kV transmission lines: the Wairakei – Ohakuri – Atiamuri - Whakamaru A line, which is a single circuit; and the Wairakei – Whakamaru C double circuit line. The geographic layout of these lines is shown in Figure 11 and a single line diagram is included in Figure 10.

Figure 11: Geographic view of the Wairakei Ring



2.1.4 Other North Island constraints

There are other North Island transmission constraints which can limit north flow from Bunnythorpe on the backbone grid, or in the Wairakei Ring region. These constraints are described below. Our analysis includes the work required to relieve these constraints.

2.1.4.1 110 kV constraints

In the 1950s and 1960s, before the North Island 220 kV grid was built, the national grid consisted of a 110 kV network. When the 220 kV grid was built it was integrated with the existing 110 kV grid. Some parts of this older 110 kV grid now constrain flows on the 220 kV grid.

An example is the Bunnythorpe – Mataroa 110 kV circuit, which is expected to overload in the future. As thermal generation in the upper North Island is decommissioned it is likely that generation from the South Island or lower North Island will increase and the Bunnythorpe – Mataroa 110 kV circuit will constrain.

Our investigations indicate this constraint needs to be resolved to allow more generation from Wellington, the Taranaki region, and other areas of the south of the North Island to be exported to the upper North Island. To avoid the CNI proposal being constrained, we are proposing a 110 kV split be implemented concurrently with the CNI proposal.

2.1.4.2 Huntly-Stratford protection limit

As well as the CNI 220 kV lines heading north from Bunnythorpe to Whakamaru, there is also a 220 kV line from Bunnythorpe to Brunswick, which then heads to Stratford and then all the way to Huntly. The Huntly – Stratford portion of this 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 2024 will reduce the frequency of this constraint, but we expect it to still experience constraints at times. Options such as re-building the line and enhancing capacity are possible, although expensive. Our investigations indicate that the thermal rating of the Huntly – Stratford 220 kV circuit is currently limited by a protection relay. If a low-cost project to replace the protection relay is completed, the full thermal capacity of the line becomes available.

2.1.4.3 Tokaanu Special Protect Scheme (SPS)

The existing Tokaanu SPS monitors the two Tokaanu – Whakamaru circuits and splits the Tokaanu 220 kV bus when it detects the outage of one of the circuits. The scheme results in power flow from Bunnythorpe towards the upper North Island being redistributed to other transmission paths to relieve the loading on the constraining Tokaanu – Whakamaru circuit.

Our investigations indicate that once the Tokaanu – Whakamaru circuits are upgraded, the constraint will be on the Bunnythorpe – Tokaanu circuits. Upgrading the Tokaanu SPS to also split the Tokaanu 220 kV bus following a Bunnythorpe – Tokaanu circuit outage will have a similar effect to relieve the loading on the remaining Bunnythorpe – Tokaanu circuit. (see Attachment C: 3.5.3 Use of Area Wide and Special Protection and Runback Schemes).

2.1.4.4 Edgecumbe – Kawerau 220kV line

The Edgecumbe – Kawerau 220 kV circuit is part of a 220 kV corridor that runs from Ohakuri to Atiamuri via Kawerau, Edgecumbe, and Tarukenga. Because this corridor runs in parallel with the Atiamuri – Ohakuri direct circuit, increased north flow through the Wairakei Ring implies increased flow from Kawerau to Edgecumbe.

There are already high power transfers from Kawerau to Edgecumbe, driven by a generation excess in the Eastern Bay of Plenty and high load in the Western Bay of Plenty. Without a capacity increase on the Edgecumbe – Kawerau 220 kV circuit, higher power transfer through the Wairakei Ring could not be achieved without pre-contingency generation constraints at Kawerau and/or Ohakuri.

A thermal upgrade of the Edgecumbe – Kawerau 220 kV circuit would also enable further generation development in the Eastern Bay of Plenty and increase the ability of the grid to supply the growing Western Bay of Plenty loads from Eastern Bay of Plenty generation.

This thermal uprating is required to make full use of the proposed Wairakei Ring upgrades.

2.1.4.5 Brunswick – Stratford 220 kV

The Brunswick – Stratford section of the Bunnythorpe to Huntly 220 kV route can also constrain flows north from Bunnythorpe.

This part of the route consists of two lines, with one line nearing end-of-life. A plan has yet to be formulated for the two Brunswick – Stratford lines, with options ranging from replacing the old line to dismantling the old line and upgrading the newer line.

In our analysis we assume the Brunswick – Stratford constraint is relieved by 2030.

2.2 Overview of the need for investigation and investment

We have investigated how best to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid.

Irrespective of the timing of the Tiwai closure, as Aotearoa New Zealand pursues its goal of being net zero carbon by 2050, electricity demand will grow as electrification occurs and new renewable generation will be built. As this occurs a number of constraints will emerge on the transmission grid between the top of the South Island and Whakamaru (including the Wairakei Ring).

Relieving these constraints would provide confidence to generation investors that new generation could be economically dispatched and ensure the generation investment market remains competitive.

We could build a new connection between these parts of the network or enhance parts of the existing network – the HVDC, our CNI 220 kV network and the Wairakei Ring.

Figure 12: Initiatives being investigated in NZGP1

2.2.1 HVDC capacity

The nominal rating of the Pole 2 and Pole 3 HVDC converters is 700 MW each. However, we only have three 500 MW cables across Cook Strait. Two are connected to Pole 3 and one is connected to Pole 2. This means the nominal end-to-end capacity of Pole 2 is limited to 500 MW and the combined HVDC capacity is limited to 1200 MW.

Historically, the HVDC was installed to transfer electricity produced from South Island hydro generation to the North Island. The North Island had adequate thermal generation to be self-sufficient in terms of electricity supply, so North Island demand was not reliant on when electricity from the south was dispatched north. This is changing as South Island supply is more critical in meeting North Island peaks with the retirement of thermal generation and inability to rely on wind and solar to cover peaks.

In total, the HVDC link between the North and South Islands has a capacity of up to 1000 MW in balanced 500/500 MW bipole operation and up to 1200 MW[13] in unbalanced 500/700 MW bipole operation. The ability to run in unbalanced mode depends upon the availability of instantaneous reserves from the electricity market, as this mode requires more reserves to be procured. These are north flow capacities, with south flow limited to 850 MW.

Other factors also affect the north flow capacity, in particular the availability of ancillary equipment at Haywards and surrounding AC transmission. There are eight synchronous condensers at Haywards which provide voltage support to the HVDC. These large mechanical rotating machines require frequent maintenance. If any machine is out of service for maintenance, the HVDC north flow limit is reduced. Similarly, the AC lines between Haywards and Bunnythorpe are all required. These lines are taken out of service from time-to-time for maintenance, which also reduces the north flow limit. A recent historical analysis found that, over the last five years, average north flow capability has been 1071 MW when taking account of available ancillary equipment and AC line outages.

Our studies indicate that the role of the HVDC link in the Aotearoa New Zealand power system is likely to change. Wind and solar generation is intermittent. Electricity from wind generation is only available if the wind is blowing and electricity from solar generation is only available if the sun is shining. Other forms of generation are required to “firm” such intermittent generation. Currently, as wind and solar generation grows in the North Island, it can be firmed by hydro generation in the North Island and peaking gas fired generation. However, as gas fired generation is closed and more North Island wind and solar generation is built, it will start to be firmed using South Island hydro generation. Eventually South Island hydro will be critical to real-time operation of North Island load and availability of the HVDC will play a critical role.

Our investigation considered not only options for increasing HVDC Cook Strait capacity, but also options to lift the availability of that capacity.

[13] 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.

2.2.2 CNI 220 kV

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

Previous analysis indicates that the two Tokaanu – Whakamaru 220 kV circuits 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 become the limiting constraint.

Our investigation considered options to increase flows through the CNI, including thermal upgrades of existing lines through to building a new line altogether.

2.2.3 HVDC and CNI timing

The HVDC and CNI constraints will bind frequently following a Tiwai exit, which could happen as early as 2024. The constraints should therefore be alleviated as soon as reasonably practicable to ensure lower South Island renewable generation can be released in the event there is a 2024 Tiwai exit. Taking into account investment approval and project execution timelines, we consider the earliest this work could be completed is 2027 (for the first stage of the HVDC investment) and 2028 (for the first stage of the CNI investment). Another timing consideration for the CNI investment is that the longer the work is delayed, the more difficult it will be to secure the necessary grid outages without compromising reliability (owing to load growth). If the CNI investment is delayed for too long, some outages may become infeasible.

2.2.4 Wairakei Ring

The capacity of the Wairakei – Whakamaru line and Wairakei – Ohakuri – Atiamuri – Whakamaru line 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. High through transmission on the CNI lines north to Whakamaru can also exacerbate the Wairakei Ring constraint, but to a lesser extent.

Thermal uprating is possible on the Wairakei – Whakamaru line, but not on the Wairakei – Ohakuri – Atiamuri – Whakamaru line. A series reactor is currently being installed on the Wairakei – Ohakuri – Atiamuri – Whakamaru line (to balance flows on the Wairakei Ring circuits). Our investigations have assumed the reactor is installed and commissioned.

Our investigation focussed on thermal uprating of the Wairakei – Whakamaru line, duplexing the single circuit Wairakei – Ohakuri – Atiamuri – Whakamaru line and new line options.

2.2.5 Wairakei timing

The Wairakei constraints will bind frequently if the large volume of current enquiries for the connection of new renewable generation in the Wairakei region materialise into new generation projects (or even if only some of them do). The constraints should therefore be alleviated as soon as reasonably practicable to enable new renewable generation projects in the region. Taking into account investment approval and project execution timelines, we consider the earliest the first stage of this work could be completed is 2024.

2.3 Relevant asset condition issues

2.3.1 Condition of Pole 2 Equipment and HVDC Cables

The Cook Strait environment is one of the world's 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.

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 the half-life point in their lifecycle, which is now. Preparations are now in progress for these refurbishments during the remainder of Regulatory Control Period 3 (RCP3) and RCP4.

Pole 2 control systems which had a shorter 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 Pole 3 project was replaced in 2020 along with all snubber capacitor assemblies within the valves. With these refurbishments, we expect Pole 2 will last well beyond 2040 and for the purposes of this analysis, we have assumed an expected life to 2050.

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 2032.

A study is underway into the replacement of existing cables. This investigation has demonstrated that installation of a fourth cable, to lift HVDC transfer north capacity to 1400 MW, is economic. We have evaluated the cost on the basis of separate installation of a fourth cable. However, this could also be undertaken at the same time as replacing the others. We are therefore examining whether to bring replacement of the other cables forward or defer installation of a fourth cable until the others are replaced at their expected end-of-life. In all circumstances, how the replacement of the existing cables will be funded will be agreed separately with the Commission.

2.3.2 Condition of CNI and Wairakei Ring lines

The most relevant condition issue for both the CNI and Wairakei Ring sections of the backbone grid are the condition of the conductors and when they would otherwise be replaced.

In some options future maintenance (conductor replacement) may be avoided. The following table summarises the assumptions used in our NZGP1 analysis.

Table 5: NZGP1 CNI and Wairakei Ring 220kV line end-of-life assumptions

Line	End of life range	NZGP1 end of life assumption
Bunnythorpe – Whakamaru A	2034 – 2049	2042
Bunnythorpe – Whakamaru B	2034 – 2050	2042
Bunnythorpe – Wairakei A	2050 -2076	>2050
Wairakei – Whakamaru A	2037 – 2070	>2050
Wairakei – Whakamaru C	2109 - 2137	>2050

2.3.3 Good electricity industry practice

The Capex IM requires Transpower to comply with Good Electricity Industry Practice (GEIP) and as such we have ensured that the planning and performance standards used to determine the investment options reflect GEIP. The requirement is specified in the Code as:

> *"the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."*

2.4 Key factors affecting our application

2.4.1 Significant uncertainty

In order to model possible economic benefits from our investments, we require plausible scenarios of Aotearoa New Zealand's future electricity supply and demand. These scenarios must be consistent with Aotearoa New Zealand achieving net zero carbon by 2050. While we started from MBIE's 2019 Electricity Demand and Generation Scenarios (EDGS), we identified an unusually large number of possible futures.

For instance:

- Rio Tinto has announced that they intended to wind-down and eventually close the Tiwai Point aluminium smelter. Tiwai uses a considerable percentage of South Island hydro generation. When will the timing of this eventuate?
- Electrifying Transport. How quickly will Aotearoa New Zealand adopt electric vehicles (EVs) and replace our fossil fuel fleet? Will heavy vehicles also become electric or use an alternative fuel? How will consumers and business charge these vehicles?
- Process heat electrification. Electricity is the likely fuel for low temperature process heat applications, but will electricity, biomass or some other fuel dominate high-temperature applications?
- Grid-scale wind and solar generation costs are forecast to drop over time. Currently there is cost parity between wind and solar generation installation. Will this persist?
- Widespread battery storage could significantly change the services required from both electricity transmission and distribution. Will storage costs fall to the point where batteries are widespread?
- Aotearoa New Zealand has world class offshore wind resources, and some locations are ideally suited for offshore wind development. Will that occur?
- The Huntly coal-powered Rankine units currently provide the majority of Aotearoa New Zealand's back-up electricity supply in the event of a dry hydrological year. Assuming they are closed, what will replace them for dry year reserve?

Each of these uncertainties are significant for transmission grid planning, so we developed a range of future scenarios and combined them into a matrix. For this investigation we developed 30 scenarios. Because it is infeasible to analyse so many scenarios and it would be difficult to justify these scenarios from a regulatory point of view, we reverted to developing variations of the five Electricity Demand and Generation Scenarios (EDGS).

2.4.2 A least regrets approach

A high level of uncertainty increases the risk of under or over-building transmission capacity. Scenario analysis helps to identify investments that produce the highest net benefits across the range of scenarios. However, for NZGP we have also applied a least regrets approach. This is where we undertake investment for a more certain level of need but prepare for adding more capacity.

Pursuing least regret options allows us to provide the capacity as it is needed, reducing the risk of late investment while protecting consumers from investing too early in significantly more expensive projects such as building new transmission lines. This approach is commonly used on overseas networks, maintaining flexibility of when to proceed with further transmission grid capacity enhancements as the future unfolds.

2.4.3 Timeliness and preparedness

Alongside a least regrets approach, it is important that we prepare for adding more capacity. There are significant lead times to a large build. For example, some detailed design investigations can take up to two years. Undertaking this design work early allows us to accelerate the build when we have better certainty around the timing of the investment.

Preparing for uncertain futures does incur a cost and there is a risk that some plans may not be used, but the expected costs are relatively small compared to the benefits. The costs will vary from project to project but are expected to be in the range of <1 per cent up to 10 per cent of the delivered benefit. We consider that undertaking early design work is a prudent and efficient approach.

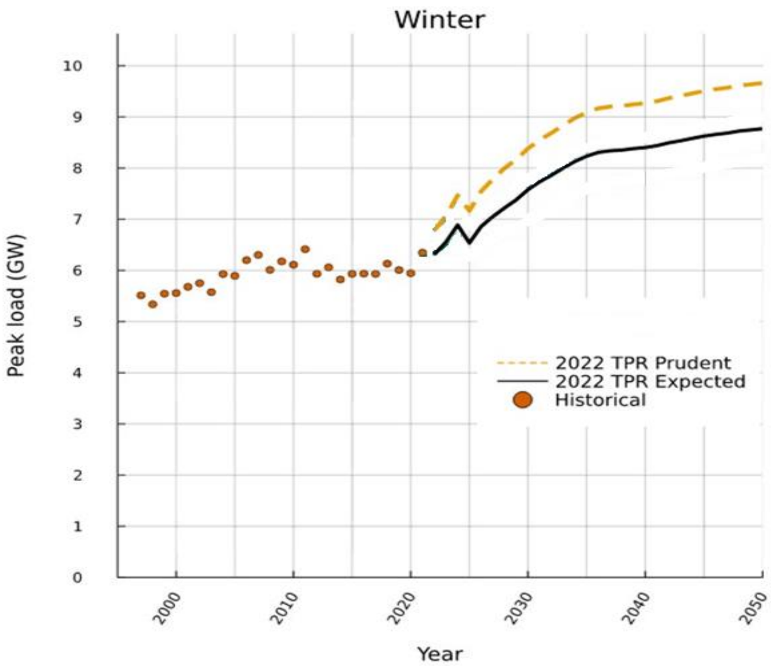
2.4.4 Managing our workforce

Part of following good electricity industry practice, and being a prudent and efficient operator, is managing our resources. If we do this, we are able to deliver major capex projects alongside our ongoing grid replacement and refurbishment and customer work.

Our workforce consists of specialised teams of highly trained people. It often takes many years to develop the necessary skills to safely undertake work on transmission assets.

The national peak demand forecast compiled for our 2022 Transmission Planning Report, as shown in Figure 13, clearly shows a ramp-up in demand in the next 15 years. This will be matched by a similar or even greater ramp-up from new generation connections. This is an expected feature of Aotearoa New Zealand's electrification endeavours and creates workforce challenges.

Figure 13: Transmission Planning Report 2022 peak demand forecast



Our workforce will be stretched during the expected ramp-up. Planning will be important, and we expect workforce plans to cover longer time periods than usual. Our flexibility to change plans will be limited and changing plans at short notice may result in other work not being undertaken, as rescheduling may be implausible.

To ensure that capacity is available when it is required, the most economical approach may be undertaking work slightly ahead of its specific need date.

2.4.5 Transmission outages

Most upgrade work on the transmission grid requires transmission outages. If a transmission line is thermally upgraded, for instance, the line needs to be de-energised (turned off) while the necessary work is undertaken. The time while a line is de-energised is called an outage. Such outages are usually scheduled in periods of time (windows) to minimise disruption to the electricity market. Windows can be as short as several hours, or up to several weeks, depending upon the work required.

As demand on the transmission grid increases, it becomes more difficult to find outage windows which do not significantly impact on the electricity market. Longer outage windows become infeasible and as a result, some major transmission upgrades would need to be delivered using short outage windows over several years.

Finding suitable outage windows for transmission upgrades is particularly difficult on the backbone of the grid, as electricity flows tend to be more constant than in some regional parts of the grid where flows are more highly correlated with electricity demand.

The need for transmission outages to undertake upgrade work can ultimately determine when upgrades need to occur. In some instances, if an upgrade is required, it may need to be undertaken several years ahead of the upgrade need, because the outages required otherwise would create an unacceptable impact on market participants, or would be infeasible due to insufficient generation in the constrained region during the outage.

2.4.6 Approval expiry date

The Capex IM requires a MCP application to include an approval expiry date. This is the date beyond which the Commission's approval becomes null and void. Our interpretation of the Capex IM is that the approval expiry date should be set at a point in time beyond which the approval may not be relevant anymore and the proposed investments may not be appropriate.

For NZGP1.1, we propose the approval expiry date to be 31 December 2030 - being two years after the latest expected commissioning date of the NZGP1.1 components.

3.0 Regulatory process for the approval of investments expected to cost more than $20 million

3.1 Regulatory process

This investigation has determined that enhancing the service provision of the existing grid is economic. The cost will exceed $20 million. Approval of this MCP by the Commission will allow Transpower to recover the costs of the project from transmission customers. This would occur either as operating expenditure (should the investment be a recoverable cost), or as investment on our regulated asset base. The costs (opex, and the return of and on the capex) will be recovered through the Transmission Pricing Methodology (TPM).

On 12 April 2022, the Electricity Authority announced its decision to adopt a new TPM. Transpower is working to implement the new TPM into prices that will take effect from 1 April 2023.

A key component of the new TPM is a benefit-based charge (BBC). This is designed to recover the costs of seven historical grid investments and grid investments made post-2019. The BBC aims to allocate the cost of those grid investments to transmission customers. This will occur broadly in proportion to customers' positive net private benefits from those investments (as expected at the time of setting the charge). For any investment over the base capex threshold in the Transpower Capex IM with a capital cost of more than $20 million (a 'high-value investment') one of the TPM's standard methods would be used to calculate customer allocations.

To support this NZGP1.1 MCP, we will publish a supporting document presenting indicative covered costs and indicative benefit-based regional allocations calculated under the new TPM for the proposal. Transpower will consult on proposed starting customer allocations and will aim to carry out this consultation before the Commission consults on its own draft determination (to approve the MCP, or otherwise).

Following the Commission's final determination, if approved Transpower will then make its own final investment decision and publish the starting customer allocations.

3.2 Transpower process

We began this investigation in 2020, notifying the Commission of our intent, in a letter dated 23 July 2021.

The process we have used for this investigation is consistent with the requirements of the Commission's Capex IM. We have, however, consulted more widely than required.

The Capex IM requires that we use the most recent Electricity Demand and Generation Scenarios (EDGS) in our investigation, or reasonable variations of those scenarios. We identified several important changes since the last EDGS were published and conducted a review with a view to developing more up-to-date variations. The review involved forming a panel of external (to Transpower) experts to advise us on potential variations and two online panel sessions.[14] This enabled us to develop a set of variations (published in December 2020) for consultation.[15] Further explanation of the EDGS is available in Appendix A.

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[14] Link to panel discussions

[15] Link to scenarios document.

After feedback on that consultation we undertook further consultation to help us develop our generation scenario variations. We then published a long-list consultation document in August 2021 and a final version of the scenarios in December 2021.

Our analysis reduced the long-list of options to address the need to a short-list. We then applied the Investment Test to that short-list of options. This document describes our application of the Investment Test and the resulting stage of Phase 1 of NZGP.

In response to our previous consultations, this document departs to some extent from our previous MCP applications in relation to relevant demand and generation scenarios. We summarise our scenario variations only, with a reference to our December 2021 document for complete detail. Although different, this approach is still consistent with the requirements of section I3 of Schedule I of the Capex IM.

3.3 Treatment of non-transmission solutions

We have also departed from our traditional approach to the consideration of non-transmission solutions (NTS).

Previously, we issued an RFI for NTS with our long-list consultation and followed up on any interest during our analysis, reporting on the outcome as a part of our Investment Test application.

We issued a high level RFI with our long-list consultation and received some responses. However, interest from proponents was mostly limited to supporting the overall concept of NTS, rather than offering specific projects or technologies to replace or defer transmission options. We therefore consider that NTS are unlikely to be a viable substitute for transmission on the backbone grid, due to the nature of the backbone grid.

Electricity flows over the backbone grid are determined by electricity market operations rather than local demand peaks and troughs. As a result, determining the peaks, which drive our investment, are difficult to predict. In the future, when North Island thermal generation is retired, peak usage may become more aligned with the strength of the wind and cloud cover, which is even less predictable.

Despite this, NTS may be able to help manage operational risk caused by the unavailability of grid assets during delivery of the investments included in this proposal. We will explore opportunities for this once the risks are clear.

Our experience to date with contracting NTS for major projects has been hindered by process. We have evaluated NTS as long-list or short-list options. This has, however, often occurred several years ahead of the need for such NTS. Our understanding is that, unsurprisingly, NTS proponents are reluctant to commit to services that far ahead. The process we follow is a regulatory requirement, but it was developed when neither ourselves nor the regulator had experience with NTS.

4.0 Long and Short-list of options

4.1 Options

Our long-list of options comprises options that:

- bypass the existing grid altogether;
- increase transfer capacity across the inter-island HVDC link;
- increase capacity on the backbone grid north of Bunnythorpe; and
- increase capacity in the Wairakei Ring region.

These options are detailed in Attachment C and are not described in detail here. They comprise options as varied as a new HVDC link between Haywards and Whakamaru, undersea cables from near Nelson to Taranaki and undergrounding our transmission lines between Bunnythorpe and Whakamaru.

The long-list gathers all potential options to meet the need, irrespective of perceived cost or practicality. This means long-lists tend to be lengthy. We use a set of short-listing criteria to reduce the long-list to a short-list for Investment Test analysis. These high-level short-listing criteria are used to sieve out options which are infeasible and/or uneconomic.

4.1.1 Shortlisting criteria

We evaluated our long list of options using the following high-level screening criteria. The screening criteria were used to eliminate options inappropriate for consideration in development plans. The criteria are:

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.

4.1.2 Intermediate development plan options

In general, development plan options include combinations of options, commissioned at different times. For instance, where a component option has a long lead-time e.g., building a new transmission line, we may also include a short-term, or “tactical” option to enhance capacity until such time as a new line can be commissioned.

The long-lists of options were developed differently in the three different staging project investigations – HVDC, CNI and Wairakei Ring. The HVDC and Wairakei Ring options were created as combinations of individual component options and development plan options. For the CNI, only component options were developed.

The Investment Test evaluates development plan options. For the CNI this involved a combination of more than one short-listed component option: an HVDC development plan option was combined with a CNI development plan option and a Wairakei Ring development plan option.

A summary of the short-listed development plan options which emerged from applying the short-listing criteria, is shown in Table . We labelled these ‘intermediate development plan options’.

We had 2 x HVDC, 11 x CNI and 7 x Wairakei ring development plan options, giving 154 development plan options in total. Typically, we evaluate three to six options using the Investment Test. To undertake the Investment Test for 154 options over the five varied EDGS would require more than 700 individual analyses. The benefits for each option are identified using SDDP, a proprietary load-flow modelling tool, which takes up to 24 hours to evaluate an individual analysis. This level of analysis was infeasible.

To reduce the intermediate development plan options to a more practicable number, we undertook limited economic analysis to identify a preferred option for upgrading the existing grid. We then used our NZGP considerations to compile a short list to which we could apply the Investment Test. This ensured the options we were considering used the existing grid as much as possible along with a new asset option.

Table 6: List of Intermediate development plan options matrix

List of intermediate development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to meet the overall need and bypass the existing grid									
	New North Island HVDC	New inter-island HVDC							
Option B1	✓								
Option B2		✓							
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2	✓	✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C1	✓	✓	✓	✓					
Option C2	✓	✓	✓	✓	✓				
Option C3	✓	✓	✓	✓		✓			
Option C4	✓	✓	✓	✓	✓	✓			
Option C5	✓	✓	✓	✓			✓		
Option C6	✓	✓	✓	✓	✓		✓		
Option C7	✓	✓	✓	✓	✓		✓	✓	
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Option C10	✓	✓	✓	✓	✓	✓			✓
Option C11	✓	✓	✓	✓	✓		✓	✓	✓
Options to enhance WRK capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A Option D5A	Replace WRK-WKM A Option D7	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓		✓					
Option W2	✓	✓	✓						
Option W3	✓	✓	✓	✓					
Option W4	✓	✓		✓	✓				
Option W5	✓			✓		✓		✓	
Option W6	✓	✓		✓		✓			
Option W7	✓			✓			✓	✓	

4.1.3 Evaluating the intermediate list of HVDC and CNI options

We note our intermediate list analysis, which was undertaken using an Investment Test-like approach, resulted in us implementing the "similar" definition defined in the Capex IM to differentiate between options.

Our approach and results are described in detail in Attachment C, with the outcome being the short-list of options in Table . In summary, we varied the similar parameter from 10 per cent, as outlined in the Capex IM, to 15 per cent. Varying the similar parameter is allowed for in the Capex IM, provided Transpower convinces the Commission such a variation is reasonable. The similar parameter recognises that uncertainty can lead (under prescribed circumstances) to more than one option passing the Investment Test. In this analysis, we limited our choice of scenarios to five. However, we originally identified more than five scenarios would be required to fully describe future uncertainty, particularly around generation expansion. This leads us to consider that the uncertainty in benefits is higher than normal. We therefore consider 15 per cent to be a reasonable setting for the similar parameter.

Having established that options are similar, unquantified benefits can then be used to distinguish between options. Transpower concluded that, for the CNI, the similar option C6 would add significantly higher capacity than option C1 and the unquantified competition benefit of option C6 made it preferred over option C1. Option C6 therefore progressed to the short-list.

4.1.4 Evaluating the intermediate list of Wairakei Ring options

Our approach to evaluating the intermediate list of Wairakei Ring options and results are described in detail in Attachment C, with the outcome being the short-list of options in Table . The intermediate list from Table comprised seven options to enhance the Wairakei capacity, ranging from tactical investments, such as splitting the Edgcumbe-Kawerau bus, through to a new Wairakei to Whakamaru D Line.

We then undertook a simplified analysis to reduce the intermediate list to a short-list for Investment Test analysis. These three options comprised a combination of both tactical and new line options.

4.2 Short-listed development plan options

Following the above evaluations, we were left with the following list of short-listed development plan options, including two which bypass the existing grid altogether.

Table 7: Short list development plan options matrix

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

4.2.1 Bypassing the existing grid

We undertook a high-level economic analysis to consider whether Options B1 and/or B2 should be carried forward for Investment Test analysis. Both these options include building new HVDC links between different parts of the grid.

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

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

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

Our similarly high-level cost estimate to upgrade the existing AC grid (including a new line north of Bunnythorpe) is $1.3 billion, which includes our proposed works for the Wairakei Ring.

Table 8: Options to bypass the existing grid

Option	High level cost, $b	Comments
Upgrade existing grid - preferred	$1.3	Includes all Stage 1 and 2 costs
New North Island HVDC Option	$2.0	Requires new HVDC line from HAY to WKM plus new HVDC converters at WKM
New inter-island HVDC Option	$4.0	Requires new HVDC lines in North and South Island plus new HVDC converters in South Island and HLY, plus new inter-island cables

Although we have not attempted to quantify the resiliency benefits of options B1 and B2, in our view they are unlikely to outweigh the extra cost and this analysis is sufficient to demonstrate that upgrading the existing grid is more economic. Neither option B1 or B2 is therefore carried forward for Investment Test analysis.

The other options passed the initial high-level economic analysis, leaving a short-list comprising:

- two HVDC options;
- three CNI options; and
- three Wairakei Ring options.

4.2.2 Final short-list of options for Investment Test analysis

We evaluated 18 short-list options in the Investment Test.

Table 9: Shortlist development options

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

5.0 Options analysis

5.1 Investment Test approach

Having received mostly supportive feedback for our preferred option, we have finalised our short-list options. This included delivery timing, which considers the availability of third parties to undertake the construction works while continuing to fulfil obligations to other Transpower work.

We engaged further with our Engineering Consultant partners and further refined the scope of work based on our development plans and more refined pricing for our construction options.

We then assessed the short-list of development plans using the Investment Test, as prescribed in Schedule D of the Capex Input Methodology.[16]

Sensitivity analysis was undertaken to test the robustness of the Investment Test result and this MCP application has been prepared for the Commission to consider. Allocations to recover the costs of this investment will be made under the new TPM.

More information on how the TPM, EDGS, and investment test parameters affect the Investment Test is contained in Appendix A.

5.1.1 Project costs

Project costs are costs reasonably incurred by Transpower 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; and
- Compliance costs relating to applicable legislation and administrative requirements.

Since the short-list consultation, all projects have been costed. This excludes some potential future developments and new line options on the central North Island, HVDC and Wairakei ring. Costing has occurred via the engagement of concept design and/or solution study reports as appropriate. Any options not costed in this way have been approached using our internal knowledge of past projects. We feel this is an acceptable level of accuracy for the Investment Test and note that any final application for construction costs of such options would form part of a later stage MCP application.

5.1.1.1 Preparedness funding

The cost of other options, including new lines, sits across a continuum considering the variability we would face in regard to route, line length, property cost, etc. We have included funding to further investigate the cost of these other options in this application. This funding will be used to either develop detailed designs to enhance existing assets, or start on a process to identify areas, corridors, and potential routes for new lines. This will ensure indicative costs for new lines have sound basis in subsequent Investment Test analyses. It will also shorten the delivery timeframe if these options are required.

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

5.1.1.2 HVDC cable upgrade

For the HVDC cable upgrade, a Request for Pricing (RFP) process was undertaken with international vendors. This sought pricing for the manufacture, transport, and installation of appropriate undersea cables. We received a good response to this process and are comfortable with the price accuracy for the purposes of Investment Test analysis.

We are also considering coordination of a new HVDC cable with the end-of-life replacement of our current HVDC cables. It is possible that any final investment decision into the installation of additional HVDC cable capacity would be made in parallel with an investment decision to replace the three existing cables. This would allow us to achieve economies of scale and reduce the costs faced if we proceeded with the two projects independently.

As this is ongoing, we have analysed the HVDC 1400 MW option as an independent project for now. The cost of this project segment may reduce prior to its submission as Stage 2 of this MCP.

International demand for undersea cables is high at the moment and the lead time for the delivery of a cable or cables to Aotearoa New Zealand is expected to be four to five years. Given this long lead time, we further tested the viability of booking manufacturing capacity to await a trigger point with suppliers. One such trigger would be the confirmed closure of NZAS Tiwai point. We did this to establish a reduced lead time to installation. This process was unsuccessful with little engagement from the RFS respondents.

5.1.1.3 Outage costs

In some options where existing transmission lines would be upgraded, the outages required to implement parts of the option would have a market cost. Where we assessed the outages as significant, we have undertaken SDDP analysis to determine an approximate likely cost. For the purposes of our Investment Test analysis, we have included that estimated cost.

5.1.2 Expected net electricity market benefit

We have determined the net electricity market benefit for each short-listed option, for each demand and generation scenario. This includes its aggregated quantum of each electricity market benefit or cost element, less the 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. The weighting is that determined for each demand and generation scenario, as discussed in Appendix A.

5.1.3 Passing the Investment Test

An investment option satisfies the Investment Test if:

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

- it is sufficiently robust under sensitivity analysis.

Some electricity market benefits are unquantified. This occurs when:

- the cost of calculating its quantum is likely to be disproportionately large relative to the quantum, or
- when its expected value cannot be calculated with an appropriate level of certainty due to the extent of uncertainties in underlying assumptions or calculation approaches.

Competition effects may fall into this category because subjective assessments of market behaviour are required to determine their magnitude. Resilience benefits also fall into this category. Currently we do not have a suitable methodology for determining these effects to an appropriate level of certainty. However, the effects may be large, especially where an option includes building a new, geographically diverse transmission line. For that reason, we have included funding in NZGP1.1 to develop a suitable methodology which can be used to evaluate our possible Stage 3 of NZGP Phase 1 (NZGP1.3) for the CNI.

5.1.4 Sensitivity analysis

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

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

5.2 Our application of the Investment Test

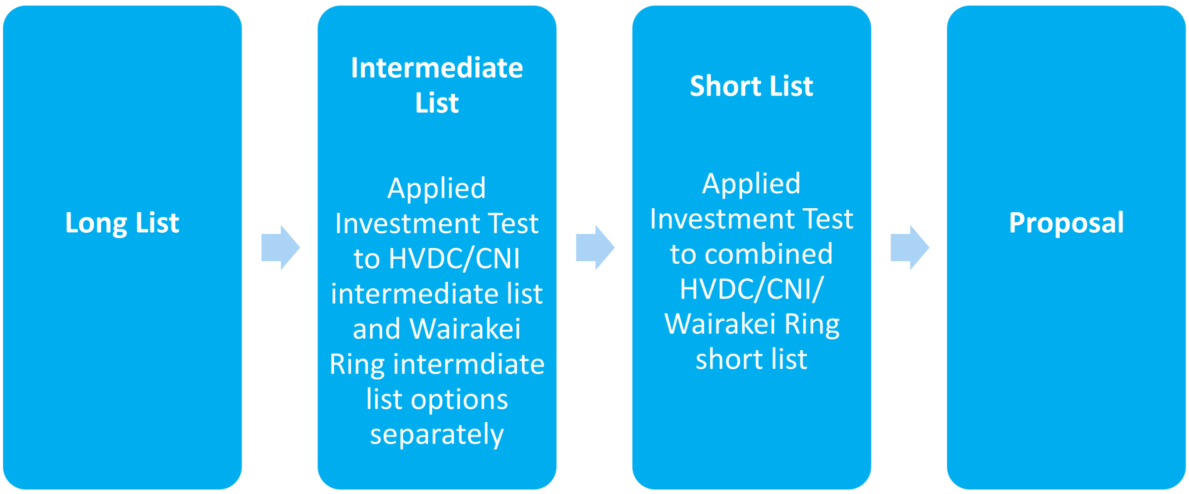
As discussed above, our application of the Investment Test used two stages to make the necessary analysis tractable. After working through the intermediate development plan options, we were able to reduce the options to a short list of:

- two HVDC options;
- three CNI options; and
- three Wairakei Ring options.

The three CNI and Wairakei Ring options consist of a tactical option, which squeezes the most out of existing assets and a new asset option. This resulted in 90 SDDP runs plus a Base Case for each scenario.

Diagrammatically, this process is summarised as:

Figure 14: Long list to Proposal Investment Test process



5.2.1 Determining net electricity market benefit

The Investment Test requires that we determine the net benefit for each option studied.

In this case the net benefit is:

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

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

Formulaically, this could be represented as:

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

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

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

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

where:

- A = respective capital costs
- B= respective operating and maintenance cost
- C = dispatch costs
- D = unserved energy costs
- existgen = existing generation
- existgridnm = existing grid not modified
- existgridmb = existing grid modified, before modification costs
- existgridma = existing grid modified, after modification costs
- newgen = new generation
- newgrid = new grid
- existnewgen = existing and new generation
- before = before modification
- after = after modification

5.2.2 Investment Test results

For the purposes of applying the Investment Test, we defined short-list option names for each of the HVDC, CNI and Wairakei Ring combinations as described in Table 10 Table 10.

Table 10: Summary of our shortlisted options

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

Table 11 shows the expected net benefit of each short-listed option.

Table 11: Net benefit of shortlist of HVDC and CNI and Wairakei Ring options

Shortlisted option	Expected net benefit, PV, $m
Option 1	-$112
Option 2	-$132
Option 3	-$101
Option 4	-$150
Option 5	-$171
Option 6	-$141
Option 7	-$363
Option 8	-$385
Option 9	-$356
Option 10	$57
Option 11	$32
Option 12	$64
Option 13	$17
Option 14	-$10
Option 15	$20
Option 16	-$186
Option 17	-$215
Option 18	-$187

Option 12 is the option which maximises net market benefit. This option comprises a 1400 MW HVDC link, TTU'ing plus duplexing the TKU-WKM A and lines, TTU'ing the BPE-TKU A&B lines, TTU'ing the WRK-WKM C line and building a new WRK-WKM D line. The total cost of Option 12 on a present value basis is $564 million.

The difference in expected net market benefit between Option 12 and Options 10, 11, 13, 14 and 15 all fall within 10% of the cost of Option 12 and meet the criteria to be considered similar. We therefore consider unquantified benefits in order to distinguish the proposal.

Table 12: Recap of various options

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 10	1400 MW	TTU and duplex TKU-WKM A&B lines, TTU BPE-TKU A and B lines	TTU WRK-WKM C line
Option 11	1400 MW	TTU and duplex TKU-WKM A and B lines, TTU BPE-TKU A and B lines	TTU WRK-WKM C line and replace WRK-WKM A line
Option 12	1400 MW	TTU and duplex TKU-WKM A and B lines, TTU BPE-TKU A and B lines	TTU WRK-WKM C line and build a new WRK-WKM D line
Option 13	1400 MW	TTU/duplex TKU-WKM A and B lines, TTU/duplex BPE-TKU A and B, TTU BPE-WRK A line	TTU WRK-WKM C line
Option 14	1400 MW	TTU/duplex TKU-WKM A and B lines, TTU/duplex BPE-TKU A and B, TTU BPE-WRK A line	TTU WRK-WKM C line and replace WRK-WKM A line
Option 15	1400 MW	TTU/duplex TKU-WKM A and B lines, TTU/duplex BPE-TKU A and B, TTU BPE-WRK A line	TTU WRK-WKM C line and build a new WRK-WKM D line

We are not far enough advanced on developing options for either replacing the existing WRK-WKM A line (Option 11 and 14) or building a new WRK-WKM D line (Option 12 and 15), to rely on the cost estimates included in our economic analysis as far as submitting a build application to the Commerce Commission. The cost estimates used in our analysis suffice for the purposes of analysis, but do not meet the rigour required to become a proposal. We note that the costs used in our analysis suggest these options are economic.

Option 13 squeezes the most capacity out of our existing assets, but would require considerable and currently uncosted outages in order to deliver the upgrades. Identifying the likely cost of outages is fraught and time-consuming. The analysis required uses many assumptions in regard to market behaviour and these are prone to judgement. The cost of outages (the cost of bypass lines aside) falls into the category of unquantified benefits and we have assumed as such in this analysis.

Option 10 is well costed, has lesser outage requirements than Option 13 and can be delivered in the soonest possible time of all of these options. For those reasons Option 10 is preferred and becomes our proposal.

This option includes:

Table 13: Composition of Option 10

	Stage 1 MCP (NZGP1.1)		Likely Stage 2 MCP (NZGP1.2)	
	Project	**$m**	**Project**	**$m**
HVDC	Haywards reactive support	84.4	New Cook Strait cable	120
CNI	TTU/Duplex TKU-WKM A and B TTU BPE_TKU A and B Split BPE-ONG 110 kV line Replace protection HLY SFD 220 kV line Replace TKU SPS	208.0 0.5 2.0 1.0	Reconductor BRK-SFD A line	75
Wairakei Ring	TTU WRK-WKM C TTU EDG-KAW 220 kV line	20.7	New/replaced WRK-WKM line	100
Stage 2 Preparatory	Investigate reconductoring BRK-SFD A line Investigate options for new/replaced WRK-WKM line	2.0 2.0		

Consistent with the least regrets approach discussed above, we propose to stage all three elements of the proposed investment. The first stage contains projects that enhance the capabilities of the existing grid to provide relief for the relevant constraints as soon as reasonably practicable. The second stage contains projects that involve significant changes to grid configuration to relieve the constraints further. We consider it prudent to stage the proposed investment in this way to hedge against the risk of over-investment, given the significant uncertainties about future electricity supply and demand in New Zealand, including when (and if) Tiwai exits and when (and how many) proposed renewable generation projects in the Wairakei region go ahead. Staging the proposed investment in this way also allows us more time to scope the anticipated projects for NZGP1.2 and projects for a possible later stage of NZGP1.

5.3 Investment Test Sensitivities

In order to test the economic robustness of our proposal, the Capex IM requires that we undertake sensitivity analysis to potentially significant parameters.

For this application of the Investment Test, we have considered the following sensitivities relevant:

Table 14: Investment test sensitivities to be reported

Parameter sensitised	Comment
Capital cost of preferred option	The capital costs are varied +/-30 per cent relative to other options
Ongoing cost of preferred option	The ongoing costs are varied +/-30 per cent compared to other options
Discount rate	Sensitivities of 4 per cent and 10 per cent are compared
Electricity demand growth	Tiwai closes in 2034 demand forecast
Tiwai closure date	A closure date of 2034 is compared

Table 15 shows how expected net market benefit varies for the short-listed options, for all except the Tiwai closure date sensitivity which is considered separately.

Table 15: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options

Sensitivity of expected net benefit to various sensitivities, PV, $m								
	Sensitivity							
	Investment Test	-30% capital cost	+30% capital cost	-30% ongoing costs	+30% ongoing costs	4% discount rate	10% discount rate	High demand
Option 1	-$112	-$26	-$198	-$70	-$153	$44	-$173	
Option 2	-$132	-$27	-$237	-$92	-$172	$43	-$199	
Option 3	-$101	$1	-$203	-$59	-$143	$92	-$179	
Option 4	-$150	-$30	-$270	-$114	-$186	$40	-$221	
Option 5	-$171	-$32	-$311	-$136	-$206	$36	-$248	
Option 6	-$141	-$5	-$278	-$105	-$178	$84	-$228	
Option 7	-$363	-$184	-$542	-$307	-$419	-$223	-$396	
Option 8	-$385	-$187	-$584	-$330	-$441	-$228	-$424	
Option 9	-$356	-$160	-$551	-$299	-$412	-$181	-$404	
Option 10	$57	$169	-$55	$101	$13	$378	-$87	$36
Option 11	$32	$164	-$100	$75	-$11	$368	-$116	
Option 12	$64	$193	-$65	$108	$19	$418	-$95	
Option 13	$17	$163	-$130	$55	-$22	$368	-$136	
Option 14	-$10	$156	-$176	$27	-$48	$354	-$167	
Option 15	$20	$183	-$143	$59	-$19	$401	-$146	
Option 16	-$186	$20	-$391	-$127	-$244	$124	-$305	
Option 17	-$215	$10	-$440	-$158	-$273	$106	-$337	
Option 18	-$187	$35	-$409	-$128	-$246	$151	-$318	

Option 10 meets the criteria to be considered similar in all sensitivities where there are positive net benefits. In those sensitivities where no option has a positive net benefit, Option 10 is the least negative.

We note the sensitivity to discount rate, where the expected net market benefits are significantly higher for a 4% discount rate and lower for a 10% discount rate. We did receive feedback during consultation that a 7% discount rate seems high and that a lower rate, say 4%, may be more reasonable.

The expected net market benefit appears to be particularly sensitive to capital cost and discount rates. This reinforces concerns about the readiness of our plans in regard to Options 11, 12, 14 and 15 and supports our choice of Option 10.

We are reporting the result of our Tiwai leaving in 2034 sensitivity as a high demand sensitivity. In this sensitivity, demand remains high until 2034 and then reduces. We have undertaken analysis for the proposal only, but this demonstrates a positive net benefit.

Overall, we believe Option 10 is the most robust option to sensitivity analysis. We note that the net benefits of these investments are not large, however in our opinion this is a result of the conservative nature of our analysis. In particular:

a) We have studied 1-hour load block resolutions in our analysis. It is questionable whether this approach appropriately captures the benefits of the HVDC and CNI in ensuring South Island hydro can be used to firm North Island intermittent generation. In our NZGP Phase 2 analysis we hope to improve that aspect of our analysis, but in the meantime are of the opinion that our dispatch benefits are undervalued.
b) We have assumed a North Island mixed dry year reserve solution. In our modelling dry year reserve is provided from a combination of generation over-build, replacement of the Huntly Rankine units with a bio-peaker and some deficit. This approach reflects the uncertainty over how such dry year reserve will be provided and is designed to be as neutral as possible to future grid configurations. If dry reserve is provided from north of Whakamaru, our analysis is reasonable. If it is provided from south of Whakamaru, then our analysis is conservative, as flows over the CNI lines and/or HVDC would likely be higher.

We adopted this conservative approach in order to not exaggerate the benefits of enhancing capacity in the lower North Island region. Our economic analysis demonstrates that our proposal is economic even under such conservative assumptions and it is likely the benefits are much higher.

5.3.1 Tiwai closure date

Our analysis assumes Tiwai aluminium smelter closes at the end of 2024. We have undertaken two sensitivities to consider alternative Tiwai closures:

- Tiwai closes at the end of 2034 (negotiates a longer-term electricity supply contract) and we install a fourth Cook Strait cable as per our proposal – in 2027
- Tiwai closes at the end of 2034 (negotiates a longer-term electricity supply contract) and we defer installation of a fourth cable until 2034

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

The sensitivity results are:

Table 16: Sensitivity of expected net benefit of proposal to Tiwai closure assumption

Tiwai closure option	Short-list option	Expected net market benefit, $m
Tiwai closes in 2024, fourth cable in 2027	Option 10	57
Tiwai closes in 2034, fourth cable in 2027	Option 10	-17
Tiwai closes in 2034, fourth cable in 2034	Option 10	36

As shown, the expected net market benefit is marginally negative in the Tiwai closes in 2034 and a fourth cable is installed in 2027 sensitivity and positive for the Tiwai closes in 2034 and a fourth cable is installed in 2034 sensitivity.

These sensitivities demonstrate that our proposal has a positive net expected market benefit if Tiwai closure is deferred until 2034, provided we also defer installation of the fourth Cook Strait cable. This would mean combining the installation of a fourth Cook Strait cable with replacement of the existing cables, which would be sensible in such a situation.

We conclude that our choice of proposal, Option 10, is reasonably robust to sensitivity analysis.

5.4 Preparedness projects

Our proposal increases CNI and Wairakei Ring capacity incrementally. There are possible futures where these incremental upgrades do not provide sufficient capacity and further upgrades will be required. These likely to be NZGP1.2 and NZGP1.3 MCPs. Preparedness costs are for projects to prepare for those possibilities by preparing the detailed designs for upgrades to existing assets or exploring potential approaches for new assets.

Preparing for NZGP1.2 and NZGP1.3 MCPs now balances risks for consumers. On one hand, it requires spending money to develop plans which may then just sit on the shelf and never be used. On the other hand, they are options which can be rolled out at shorter notice if they appear appropriate.

For NZGP1.1 that approach translates to:

- Developing detailed designs for the duplexing of the existing BPE-TKU A and B lines
- Developing detailed designs for the thermal upgrading of the BPE-WRK A line
- Taking forward plans to build a new line north of Bunnythorpe
- Taking forward plans to either replace the WRK-WKM A line, or build a new WRK-WKM D line
- Developing a methodology to quantify resilience benefits. This will support forward planning for a new line north of Bunnythorpe
- Completing a study to consider when and where we may need to consider diversifying our Bunnythorpe substation. This will also support forward planning for a new line north of Bunnythorpe
- Developing a methodology to quantify resilience benefits. This will also support forward planning for a new line north of Bunnythorpe

The other two projects included in Table 17 are further studies required to investigate possible Stage 3 investments.

Table 17: List of NZGP1.1 preparedness projects and P50 cost estimates

Preparedness projects (included in Stage 1 MCP)	Supports project	Approx. cost $m
Investigate options for reconductoring the BRK-SFD A line	CNI (likely Stage 2 MCP)	2.0
Routes/high level design new WRK-WKM line, or replacement of existing WRK-WKM A line	Wairakei Ring (likely Stage 2 MCP)	2.0
Detailed design to duplex BPE-TKU A and B lines	CNI (possible Stage 3 MCP)	1.5
Detailed design for TTU of BPE-WRK A line	CNI (possible Stage 3 MCP)	0.5
Routes/high level design new BPE north 220 kV line	CNI (possible Stage 3 MCP)	3.0
Quantifying resilience methodology	CNI (possible Stage 3 MCP)	0.3
Diversification of BPE substation study	CNI (possible Stage 3 MCP)	0.3
Lower NI voltage stability study	CNI (possible Stage 3 MCP)	0.3
Lower NI system stability study	CNI (possible Stage 3 MCP)	0.3

5.5 MCA calculation

Our proposal comprises the projects listed in Tables 17 and 18.

We have determined the P50 and MCA for each line item individually. Collectively they add up to our NZGP1.1 with the following MCA:

Table 18: List of NZGP1.1 projects, including P50 cost and MCP allowance

Stage 1 Capital Projects	P50 (in $m)	Major Capex Allowance
Central North Island	211.5	256.9
HVDC	84.4	103.1
Wairakei Ring	20.7	22.8
Preparedness Projects	10.2	10.2
Total	**326.8**	**393.0**

The MCA is larger than the P50 cost because it includes some scope risk allowances, inflation and interest during construction costs. The MCA of $393.0 million represents the maximum cost that Transpower can include in our Regulatory Asset Base for these projects collectively.

Appendix A: Relationship of the new TPM to this proposal

A.1 Relationship of the new TPM with the Investment Test

Some of the component investments are 'high-value' benefit-based investments (BBI), which are over the base capex threshold in the Transpower Capex IM, with a capital cost of $20 million. Therefore, the TPM's standard methods will be used to calculate customer allocations for the proposed investments, if they are approved by the Commission. The simple method will be used for components with a capital cost of less than $20m. Where we are using the standard method, the assumptions and other inputs (including the factual, counterfactual, modelled constraints and scenarios) Transpower uses in applying a standard method to a BBI must be:

"as consistent as reasonably practicable with the assumptions and other inputs used in applying the Investment Test, except … to the extent Transpower determines such alignment would not produce BBI customer allocations that are broadly proportionate to positive NPB from the post-2019 BBI, in which case Transpower may use different assumptions and other inputs provided they do not contradict what Transpower determines were its key drivers…"[17].

A.2 The role of the TPM

The 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.

If this MCP is approved by the Commission, that expenditure (and an allowable return on investment) may be recovered through the TPM.

The 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."[18]

[17] https://www.ea.govt.nz/assets/dms-assets/30/Certified-Instrument-TPM-Transmission-Pricing-Methodology-2022.PDF clause 43(5)

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

Appendix B: List of Figures and Tables

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