Issue Date	9 October 2023	**RFI No.**	RFI 10
Attention	[redacted]	**Date required**	**18 October 2023**
Originator	[redacted]		
Subject	Proposed investment and unquantified benefits, short list of options, Sensitivity Analysis		

Clarification	✓	require clarification of information that is unclear or contradictory
Confirmation	☐	seeking confirmation of information previously considered preliminary
Incomplete	☐	current information is incomplete
New data	☐	require additional information
Other	☐	

Detailed description of request

1. Clearly specify the Investment need and all credible investment options that meet the investment need

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

Notwithstanding the inherent difficulties when forecasting in an uncertain environment and using the demand and generation scenario (NZGP1 Variation of EDGS) forecasts you have used to develop for the NZGP1 proposal, please quantify the investment need considering;

- the forecast capacity increases required for CNI and Wairakei Ring investments under NZGP1 through to 2035 and through to the calculation period (2050); and
- the targeted capacity increases under NZGP1 stage one for CNI and Wairakei Ring investments for the duration of the calculation period.

Based on the above investment need;

- establish credible investment options that will meet the investment need until the end of the period; and
- update Table 15 with only the short-list credible investment options, ensuring that each of these options include all the workstream components.

The Stage 1 investments included in NZGP1.1 have been derived as economic investments which have both a positive net benefit and which maximise expected electricity net market benefit in enabling the efficient dispatch of existing and new generation through the analysis period to 2050. The question asks for *"…the forecast capacity increases required for CNI and Wairakei Ring…"* and then "*…credible investment options that will meet the investment need…*". Our analysis has been undertaken by determining generation expansion plans, then testing various transmission investment options with those plans.

Our investment need is consistent with the Capex IM as, through our analysis, we identified that constraints could arise that would limit the dispatch of lower cost generation to meet demand. In order to identify the grid investments that would deliver the highest expected electricity net market benefits, we tested a variety of investments that would lead to more efficient dispatch (i.e., dispatch of lower cost generation which should lead to lower end use electricity prices).

This economic investment analysis differs from an application of the investment test for a reliability investment:

a. rather than define a quantified "need" we test which transmission option will maximise expected electricity net market benefit. The difficulties associated with defining scenarios is relevant because it has led us to keeping an open mind about future electricity demand and generation and ensuring the options we choose have flexibility to cope with that future uncertainty.
b. there is considerable uncertainty in future demand and generation that isn't fully covered by the EDGS variations. Future uncertainty influenced our choice of options. Our short-list attempts to allow for this uncertainty and other practical considerations. Each option included in Table 15 is credible, depending on future scenarios. Detailed workstream components of each short-listed option is presented in Appendix C.

We have determined the economic cost (effectively the delivered cost of electricity) of our base case i.e., not enhancing the grid.

We then determine the economic cost with transmission enhancements. One example of our approach is the consideration of generation fuel costs. If we do not enhance the grid then generation constraints will occur and lead to increased dispatch of higher-cost generation sources and likely higher associated fuel costs. Conversely, upgrading the grid can mitigate or eliminate these constraints, resulting in a reduction in generation fuel expenses. We have calculated the benefit associated with each transmission upgrade option in terms of how much these fuel costs decrease. We then calculate a net benefit by subtracting the transmission option cost from this benefit. This ensures the cost of transmission investment is factored into our analysis. In effect the net benefit we have calculated represents the economic gain we expect from the investment, in this case through the reduction in generation fuel costs, which we expect (and the investment test assumes) to translate into lower electricity prices for consumers. Determining the economic impact of transmission "enable[s] the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid".

As such there are not *targeted capacity increases under NZGP1 Stage one* investment for CNI and Wairakei Ring for the duration of the calculation period. The NZGP1 Stage one investments in our preferred option add approximately an additional 760 MW to the CNI and Figure 9 shows how the capacity increases for the Wairakei ring (which depends upon Bay of Plenty demand).

c. our MCP is staged to account for future uncertainty, but in this MCP we are only seeking funding for Stage 1 (and some preparatory costs for investigating Stage 2). There will be a detailed investigation into the efficacy of any Stage 2 investment before approval is sought for those investments. We believe this approach is justified because the EDGS variations represent a relatively narrow subset of potential futures, and the actual future may evolve differently than expected by the time we undertake our investigation for Stage 2.

With the uncertainty we face and given the widespread concerns surrounding climate change and the upside of large-scale electrification, it is essential we are able to include options that accommodate large-scale electrification. In this context, we have selected Option 14 over Option 12 (the option with the highest net benefit); as while the Stage 1 investments are similar under both Options 12 and 14, Option 14 enables us to investigate a broader range of future possible upgrades.

As explained in our response to Question 4, Option 14 could also provide benefits through increasing the security to the Bay of Plenty.

Overall, this approach ensures the existing Capex IM is workable in a highly uncertain world and we believe all options on the short-list are credible options to meet this need while managing future uncertainty. As a result of this, we consider it appropriate that the short-list contains the investment options we have proposed.

We add for further explanation, that our decision criteria when comparing options is that the option with the highest net benefit passes the Investment Test. This is irrespective of option cost (as required by the Capex IM) in clause D1 (1) (c):

> "The **investment test** is satisfied in respect of a **proposed investment** if the **proposed investment** is an **investment option** that-…. has… the highest **expected net electricity market benefit**…"

Further, the Capex IM recognises the inherent uncertainty in determining costs and benefits and all options which are similar can be considered as satisfying the quantified investment test. Similar is a defined term per clause D1 (2) (a):

> "…a similar **expected net electricity market benefit** is one where the difference in quantum…is 10% or less of the aggregate **projects costs** of the **investment option** to which the **proposed investment** is compared…"

If a qualitative assessment of associated unquantified costs and benefits favour a similar option, that option can be preferred and considered to satisfy the requirements of the investment test.

2. Proposed investment and requirement of WKM-WRK stage 2

Refer to Updated Proposal, pages 61 to 63.

Please ensure that your proposed investment complies with the Capex IM.

Transpower considers that the MCP and the proposed investment of Option 14 does comply with the Capex IM.

Update Table 16 with all the workstream components of the proposed investment for which you are seeking funding.

An updated Table 16 is provided below:

Table 16: Composition of Option 14 (UPDATED)

	Stage 1 MCP (NZGP1.1)		Possible Stage 2 MCP (NZGP1.2)	
	Project	Expected $m	Project	Expected $m
HVDC	• Install reactive plant, filter banks, and associated equipment	84.4	• New Cook Strait cable	120
CNI	• Install Variable Line Rating (**VLR**) and tactical thermal upgrade (**TTU**) of both 220 kV Tokaanu-Whakamaru A and B circuits • Duplex the 220 kV Tokaanu-Whakamaru A and B circuits • Install VLR and TTU on the 220 kV Bunnythorpe-Tokaanu A and B circuits	208.0	• Reconductor BRK-SFD A line • Duplex BPE-TKU A&B • TTU BPE-WRK A	75 189 55
Wairakei Ring	• Install TTU of the 220 kV Wairakei-Whakamaru C circuits • Install TTU of the 220 kV Edgecumbe-Kawerau-3 circuit	20.7	• New WRK-WKM line or replacement WRK-WKM A line	92
CNI Supporting projects	• Split the 110 kV Bunnythorpe-Ongarue A circuit at Ongarue • Upgrade protection on the 220 kV Huntly-Stratford-1 circuit • Replace the special protection scheme (SPS) at Tokaanu	3.5		
Stage 2 Preparatory	• Detailed design to duplex BPE-TKU A and B lines • Detailed design for TTU of BPE-WRK A line • Investigate routes/high level design for new BPE north 220 kV line • Investigate options for reconductoring a Brunswick-Stratford line • Investigate Routes/high level design new WRK-WKM line, or replacement of existing WRK-WKM A line • Develop quantifying resilience methodology • Diversification of BPE substation study • Lower NI voltage stability study • Lower NI system stability study *A further breakdown of these expected costs is included in table 19 of our MCP proposal.*	10.2		

An example of potential non-compliance is on page 62 of the Updated Proposal. You state that "*Option 11 is similar to Option 10 but includes a replacement of the existing Wairakei–Whakamaru A line as a Stage 2 for the Wairakei Ring. The logic applied to the CNI options in section 4.1.2, also applies to the Wairakei Ring and the works in Option 10 may not provide sufficient transmission capacity in some possible futures not evaluated in this analysis. There is merit in including a potential Stage 2 for the Wairakei Ring.*"

The above comment indicates that the need for the proposed stage 2 for the Wairakei ring is based on ‘merit’. If this is the case, then it’s problematic given that a project’s needs should be analytically demonstrated.

Please demonstrate whether the subsequent stage of Wairakei ring is required.

At this point the subsequent stage of Wairakei Ring is economic and is included in our preferred option, but we are only seeking approval for Stage 1 investments and preparatory costs for Stage 2. As part of the investment approval for Stage 2 Transpower would need to demonstrate conclusively whether the subsequent stage of Wairakei ring is required, based on the information known at that time.

The Investment Test has found that Option 12 has the highest net electricity market benefit, but 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 (in terms of subclause D1(1)(c)(ii) of the Capex IM). Subclause D1(1)(c)(ii) allows Transpower to consider unquantified electricity market benefits of these options in order to identify the preferred option. After considering unquantified benefits and sensitivity analysis, Option 14 which contains potential investments at Stage 2 is our preferred option.

The Investment Test analysis revealed that, across the various future EDGS scenarios, both Option 12 (the highest net benefit) and Option 14 (the preferred option) are similar. We have confined our analysis to just five EDGS scenarios which are reasonable EDGS variations, however, a wider range would be required to fully capture future uncertainty faced in the electricity industry.

To illustrate this point, we have produced a figure showing the potential new generation that could be built in our generation stack and compared against what was built by region in the EDGS variation Growth scenario. The figure shows that through our modelling there are significantly more potential generation projects listed in the generation stack than are built (i.e. required) in our generation expansion plan. For various reasons some of these alternative generation plants may be built and as such impact on the results of our analysis.

Because of this future uncertainty, and the additional capacity Option 14 would provide to cope with higher than expected investment in generation in Region 2, not completely covered by the current EDGS scenarios and other unquantified benefits, Option 14 is our preferred option. Please note that Option 12 and Option 14 deliver similar Wairakei Ring capacity by the end of Stage 2, but in Option 14 we deliver a portion earlier than in Option 12. When applying the Investment Test to NZGP1.2, Transpower will thoroughly assess the costs and benefits of any actual Stage 2 Investment during the NZGP1.2 investigation to determine whether what (if any) investment case for funding approval can be made in a Stage 2 MCP. It is important to note that for Stage 1, the funding sought for the Wairakei components is very similar to the other options deemed similar in the Investment Test.

Given the extra flexibility of Option 14 to deal with future uncertainty, we prefer this option over other options.

3. Short list of options

Your short list of options replicates at least some of the issues we mentioned while assessing the original proposal. As advised previously, all investment options should be credible options that meet the investment need. For example, if a replacement or new line is required to meet the investment need, then options 10 and 13 are not credible investment options. Similarly, if analysis shows that they are not needed, then they should not be in the short list of options.

The above also applies to “enhancement (TTU) of BPE-WRK circuit’. Some of the short-listed investment options include these enhancement and others do not.

Please note that the short list of options should include all investment projects that meet the investment need and they should not include any additional projects. Additional projects represent an over-investment.

Please revised the short list investment options and amend Tables 15 and 16 accordingly.

Our analysis considers reasonable variations of the five 2019 EDGS. In our view, uncertainty around future electricity demand and generation has increased significantly since these were developed and even reasonable variations can no longer reflect the full extent of this uncertainty. Ultimately, it may be that a broader range of scenarios is appropriate, but in light of this uncertainty and along with practical considerations, we have used three distinct approaches to developing our short list of credible options:

1. 'Tactical' options, where existing assets are rapidly upgraded.
2. Options that maximise the utilisation of 'existing assets.'
3. Options involving 'new assets.'

We believe that all short-listed investment options are credible and can adequately address the investment need, depending upon the uncertain future. The short list of investment options were considered using the Investment Test to assess the net benefits of these potential options. We did not receive any feedback through our consultation that the options were not credible. The preferred option demonstrates a high net benefit and is similar to the option with the highest net benefit (for the purposes of subclause D1(1)(c)(ii) of the Capex IM).

The preferred option (Option 14) includes potential future Stage 2 investments for each of HVDC, CNI and Wairakei Ring, but aside from some funding for investigation, we are not seeking Stage 2 project funding. This future investment will be thoroughly evaluated at Stage 2. Therefore, the preferred option does not signify an over-investment.

Given the future uncertainty and range of scenarios that may occur, we consider that the shortlist of options remains appropriate. We have therefore not revised our shortlist of investment options in Table 15. A revised version of Table 16 is included above.

Appendix C lists the detailed workstream components of each short-listed option.

The table below shows the differences between Options 12 and Options 14. Workstream components in red are potential Stage 2 components.

Components			Option 12	Option 14
HVDC	New HAY reactive support 1200MW		✓	✓
	4th Cook Strait cable 1400MW		✓	✓
CNI	TTU TKU-WKM		✓	✓
	TTU BPE-TKU		✓	✓
	Duplex TKU-WKM		✓	✓
	Duplex BPE-TKU			✓
	TTU BPE-WRK			✓
	BRK-SFD enhance		✓	✓
CNI Supporting	BPE-ONG split		✓	✓
	HLY-SFD protect upgrade		✓	✓
	Replace SPS at TKU		✓	✓
WRK	110 kV EDG-KAW split		✓	✓
	TTU 220 kV EDG-KAW		✓	✓
	TTU WRK-WKM C line			✓
	Replace WRK-WKM A line			✓
	New WRK-WKM D line		✓	
	WRK sub equip		✓	
Total benefit			632	659
Total cost			451	514
Net benefit			181	145
Unquantified benefits				
	Capacity to deal with uncertainty		✓✓	✓✓✓
	Security to BoP			✓✓✓

The unquantified benefits of Option 14 compared to Option 12, comprise two elements:

a) Both Option 12 and Option 14 result in similar Wairakei Ring capacity increases by the end of Stage 2. However, Option 14 allows us to deliver some of the capacity increase earlier than Option 12. By staging the capacity increase we will have the ability to defer or accelerate/decelerate Stage 2, depending on how future electricity demand and generation emerges.
b) Security of supply for BoP electricity consumers is enhanced in Option 14. Atiamuri and Ohakuri are connected to the rest of the grid with 3 circuits, ensuring that during a planned maintenance outage on any single circuit along the WRK-WKM-A line, n-1 security will be retained.

As future electricity demand and generation develops, we expect that, at Stage 2, the Option 14 benefits (both quantified and unquantified) will result in a higher expected net market benefit compared with Option 12.

Please note that a further unquantified benefit of Option 14 arises because of the potential to increase CNI capacity in Stage 2. This would increase the ability of the grid to accommodate higher load and growth than is reflected in the EDGS scenarios.

4. Unquantifiable benefits

Based on the discussions on pages 62 and 63 of the Updated Proposal, your proposed investment is one of the options that includes replacing/upgrading WKM-WRK A line based on unquantified benefits. On page 62 of the Updated Proposal, you state that:

"Replacing the existing A line includes an unquantified benefit in that it ensures Bay of Plenty consumers will have n-1 security of supply at all times. Currently, the Bay of Plenty only has n security when maintenance is undertaken on existing lines".

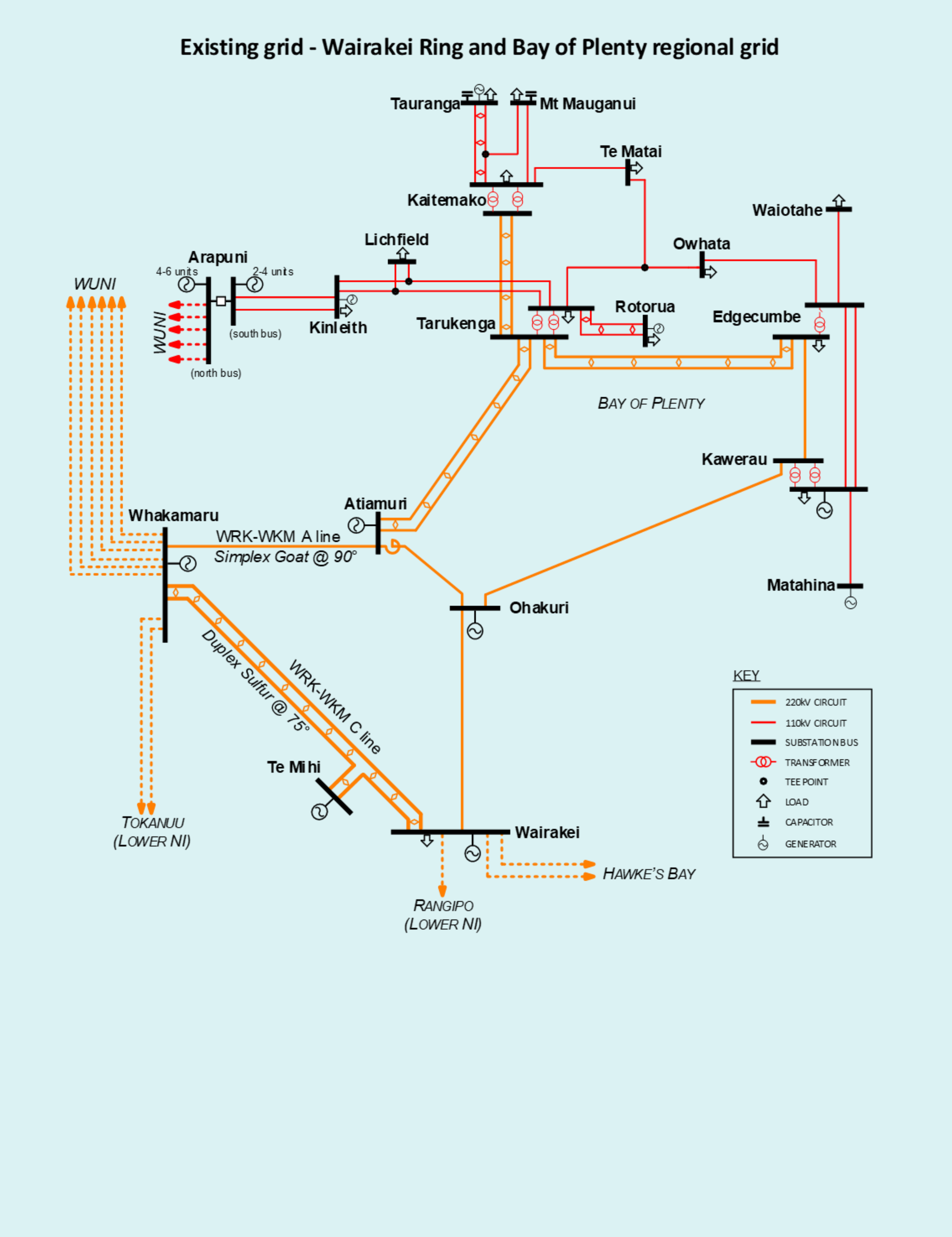
For Wairakei ring upgrade, the Updated Proposal mention "*replace WRK-WKM A line*". In Attachment C, this workstream component is described as "*New 220kV line from Wairakei to Ohakuri and upgrade existing Ohakuri-Whakamaru section of the Wairakei-Whakamaru A line to a 220kV duplex line.*"

Please clarify how replacing the WKM-WRK A line will provide n-1 security to the BOP under maintenance.

Our current view is that BOP will be on N security when two of the existing lines (eg, either the OHK-WRK line or the ATI-WKM line) are out for maintenance.

The current grid configuration is shown below. An outage of either the Atiamuri–Whakamaru-1 circuit or the Ohakuri–Wairakei-1 circuit would leave the whole Bay of Plenty region on N security. Planned outages on either of these two circuits are currently managed by closing the Arapuni 110 kV bus split and dispatching enough generation in the region to ensure that its net total load can be supplied from Arapuni by the two low-capacity Arapuni–Kinleith–Tarukenga 110 kV circuits (should the remaining 220 kV connection between the Bay of Plenty and the grid backbone trip).

As the region continues to develop and regional load increases, it is likely that this approach will not be possible in the future, meaning that the risk of a regional loss of supply will become greater.


Existing grid - Wairakei Ring and Bay of Plenty regional grid
Tauranga
Mt Maunganui
Te Matai
Kaitemako
Waiotahe
Owhata
Lichfield
Arapuni
4-6 units
2-4 units
WUNI
(south bus)
(north bus)
Kinleith
Tarukenga
Rotorua
Edgecumbe
BAY OF PLENTY
Kawerau
Atiamuri
Whakamaru
WRK-WKM A line
Simplex Goat @ 90°
Ohakuri
Matahina
Duplex Sulfur @ 75°
WRK-WKM C line
Te Mihi
TOKANUU
(LOWER NI)
Wairakei
HAWKE'S BAY
RANGIPO
(LOWER NI)
KEY
220kV CIRCUIT
110kV CIRCUIT
SUBSTATION BUS
TRANSFORMER
TEE POINT
LOAD
CAPACITOR
GENERATOR

The differences between Option 12 and Option 14 are presented below.

Option 12

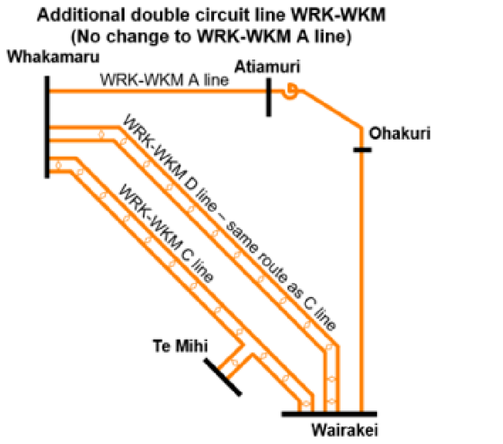


Figure 15: additional double circuit line in the Wairakei Ring – simplified schematics

Option 14

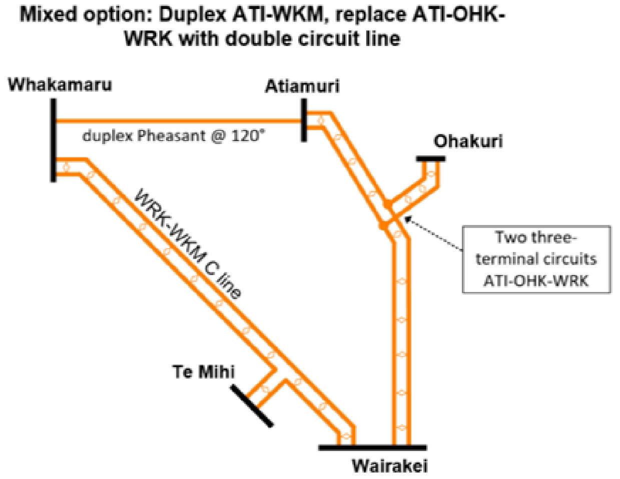


Figure 17: mixed replacement / reconductoring of the WRK–WKM A line– simplified schematics

With respect to the Bay of Plenty, the WRK–WKM A line partial/hybrid replacement (Option 14) would turn Atiamuri and Ohakuri into more robust interface points between the grid backbone and the Bay of Plenty regional 220 kV grid. Atiamuri and Ohakuri are connected to the rest of the grid with 3 circuits, ensuring that during planned maintenance on any single circuit along the new WRK-WKM-A line, N-1 security will be retained.

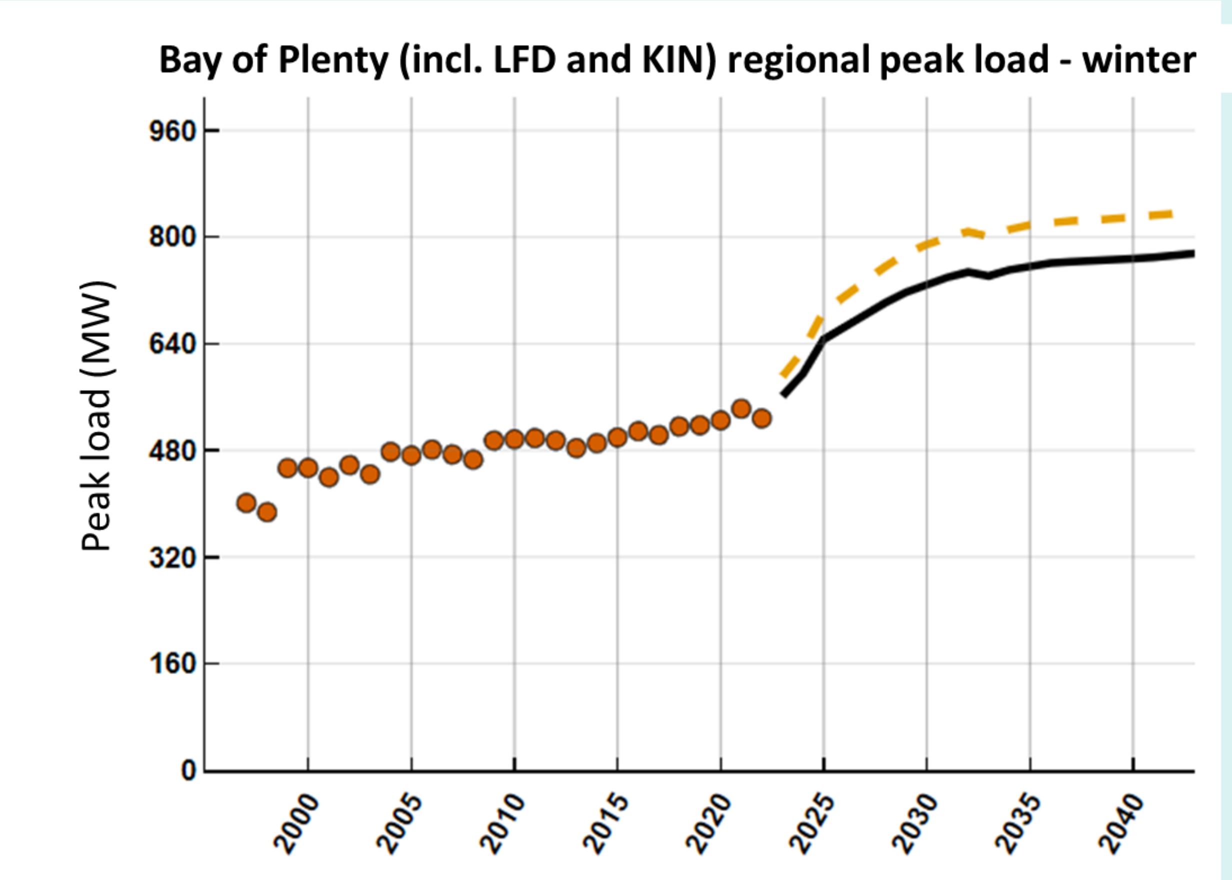
We also question the merits of providing n-1 transmission security to BOP if there is a cost premium. This is because the Bay of Plenty has reasonable spread of generation using the three main renewable generation technologies – hydro (at least 147 MW), geothermal (approx. 167 MW) and solar.

Since generation is an acceptable alternative to transmission, what is the advantage of further investment in transmission to provide n-1 under all operating conditions?

The Bay of Plenty region has a growing amount of installed generation capacity from different technologies. However, it is important to remember that solar without BESS does not help to cover the morning and evening peaks. Hydro generation in the Bay of Plenty does help to some extent in reducing the regional net load, but this help cannot always be relied on due to the limited storage capacity of most of the hydro schemes in the region.

We must also keep in mind that we are expecting a major load increase in the region, mostly in the western region (see the forecast below from our latest Transmission Planning Report). Because periods of high generation do not necessarily coincide with periods of high load (especially for solar and hydro generation with limited or no storage capability), we expect that in the next 25 years the Bay of Plenty region will at times experience significantly higher net loads, and at other times significantly higher net generation excess than what we experience now.

During periods of higher net load (winter peak load in low hydrology conditions), maintaining n-1 security with the existing grid will become increasingly challenging. During periods of higher net generation excess (summer midday on a sunny day with high hydrology), the existing WRK-WKM A line will limit the amount of generation that can be exported from the Bay of Plenty. Replacing the A line (where the Atiamuri–Ohakuri - Wairakei section is replaced and the Atiamuri – Whakamaru section is duplexed, as proposed in Option 14). Note that it is possible the 220 kV regional lines within the Bay of Plenty might also require an upgrade at some point in the future for the reasons highlighted above. This upgrade would only make sense if we have a robust connection point at Atiamuri and Ohakuri, which would be provided by Option 14 through the A line replacement.



We therefore raise for consideration whether the WRK ring solution should be based on the option with the highest net benefits to provide best value to consumers given the unqualified benefit you have identified. Your cost estimate shows that the cost of WRK-WKM D line (capital cost $92m) is comparable to the modified cost of upgrading the WKM-WKM A line which includes replacing OHK-ATI line and duplexing ATI-WKM A line (capital cost $92.5m) but the investment test shows the D line options as providing much higher net benefits.

Further, in terms of unquantified benefits, the WRK-WKM D line option will provide three circuits between the WKM and WKM. Our current view is that three lines will provide better reliability for through transmission from WRK to WKM and potentially higher resilience.

We understand that you mean that the WRK-WKM D line option (Option 12) will provide three lines between WRK and WKM. From a grid backbone resilience perspective, it is true that having three different line routes would be better. However, a potential D line would likely follow a route very close to the existing WRK-WKM-C line (= the shortest route). If the D line is geographically close to the C line, they would both be exposed mostly to similar risks in terms of storm damage or volcanic ash. Conversely, should we replace the A line (complete or “hybrid” replacement) we would have another high-capacity corridor following a different route (except for a few spans at WKM and WRK).

If WRK ring stage 2 is justified and required, to meet the investment need, please clarify why replacing WRK-WKM A line is proposed ahead off a new WRK-WKM D line. The clarification needs to clearly state the quantified and unquantified benefits.

Although the preferred option has potential future investments at Stage 2, we still need to undertake further analysis under NZGP1.2 to help inform a decision on the best way forward for Stage 2 (if any). We are not seeking approval or funding for any investment in Stage 2 (other than preparatory costs).

The NZGP1.2 investigation will provide a better class of cost estimate for the new/ replacement line options. Current costs included in the investment test are based on a high-level estimation: line routes have not been chosen so actual property and geotechnical costs are not yet known. Furthermore, at the time of submission of any Stage 2 option we will have updated the load and generation scenarios, and included any relevant information gathered through the current Western Bay of Plenty MCP to inform the investigation and inputs.

Our results are based on SDDP simulations which have identified that, all else being equal, options comparing an additional WRK-WKM D line have greater benefits than the options involving a partial/hybrid or complete replacement of the A line by a double circuit line. In other words, options 12 compared with 11; 15 compared with 14; and 18 compared with 17 exhibit greater benefits.

From a load flow perspective, the figure below (from our proposal, Attachment B) illustrates how the short-term (Stage 1) upgrade proposed in Option 14 impact the grid transfer capacity from Wairakei to Whakamaru. Option 12 is represented by the black line, while Option 14 is indicated by the green line. The data illustrates that Option 14 can provide up to an additional 250MW of capacity compared to Option 12, specifically during periods of low to medium Bay of Plenty load. It is worth noting that neither Option 12 or 14 will provide a transfer capacity increase during times of generation excess in the Bay of Plenty region. Given that the peak load in the Bay of Plenty typically aligns with the national peak load, it is anticipated that the additional capacity provided by Option 14 will be useful during peak periods.

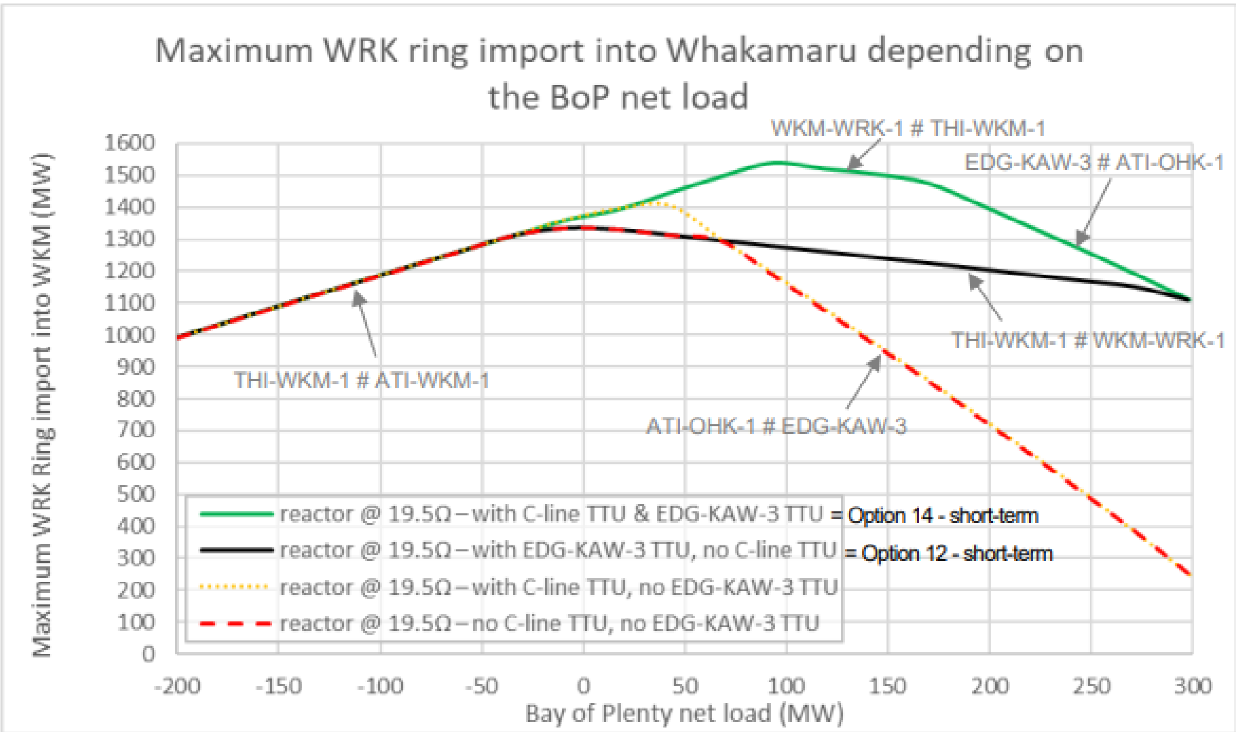
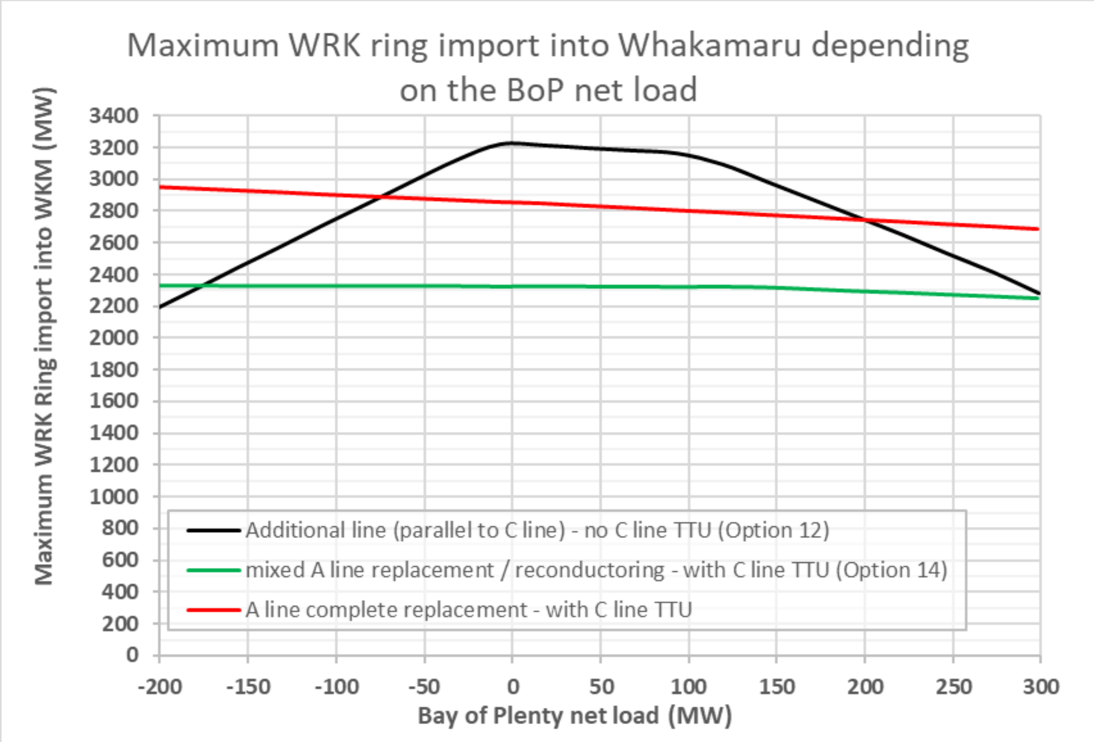


Figure 9: Wairakei Ring maximum transfer capacity with and without WRK–WKM C line TTU

Wairakei Ring maximum transfer capacity – Option 12 and Option 14 (Stage 1 Upgrades)

Impacts from the potential longer-term (Stage 2) upgrades are illustrated in the figure below and need to be further investigated as part of Stage 2. Option 12 is represented by the black line, while Option 14 is indicated by the green line. We have found that Option 12 (the new D line option) offers the highest long-term Wairakei ring transfer capacity under optimal Bay of Plenty conditions. However, it experiences a sharp drop in transfer capacity during periods of higher Bay of Plenty generation and excess load.

By contrast, Option 14 (and the complete A line replacement Option shown in red) offers a relatively stable transfer capacity, regardless of fluctuations in the region's load and generation profile. These options offer a more robust and resilient supply for the Bay of Plenty compared with Option 12 and the existing situation.



Wairakei Ring maximum transfer capacity – Option 12 and Option 14 (Stage 2 Upgrades)

Our choice of preferred option is based on:

- an ability to provide an increase in connection capacity quickly in Option 14 compared to Option 12
- Option 14 having an unquantified benefit of improving security of supply for Bay of Plenty electricity consumers and providing more robust connection points for future potential Bay of Plenty regional grid capacity upgrades
- Option 14 offers more geographic diversity in the Wairakei Ring transmission lines, which may have an unquantified resilience benefit
- Option 14 stages the investment and better caters for future uncertainty than that of Option 12.

The flexibility to implement a larger transfer capacity increase as soon as possible and having the flexibility to tailor the longer term solution to potential futures as they unfold, is preferable.

Please refer to our Power System Planning Attachment (MCP-Attachment B, page 108-110) for further explanation of these benefits.

Please refer to Appendix A which provides a summary of our approach to modelling costs and benefits.

5. Sensitivity studies - Table 18 in the Updated Proposal

In Table 18, the NPV for some of the options (eg, options 10, 11 and 12) with higher on-going costs is higher than that for lower on-going costs. **Please advise the reason for this.**

Table 18 shows the net benefit of each investment option compared with the counterfactual/base case and how total net benefit changes when there are changes to input assumptions.

It appears that the +30% and -30% columns in Table 18 have been labelled around the wrong way. A corrected Table 18 is in Appendix B of this RFI response.

The ongoing costs component of the Investment Test represents the difference (delta) between the ongoing cost of the investment option compared with the base (counterfactual) case. Table 18 shows how the overall option net benefit NPV changes when the ongoing cost component is adjusted by either increasing or decreasing it by 30%.

For some options, the overall ongoing cost delta is a negative number (meaning that ongoing costs differential represents a financial benefit against the base case), i.e., the upgrade results in reduced ongoing expenses compared to the base case. This occurs when future conductor replacements are avoided because they are undertaken now as a part of an investment. The ongoing cost changes are shown in the table below.

The mislabelling explains the sensitivity results for Options 10, 11 and 12, whilst the negative ongoing cost differences explain the sensitivity results for Options 4, 5, 6, 13, 14 and 15.

Total ongoing cost (compared with base case), $PV

Option	Ongoing cost change from Base Case ($millions)
1	5
2	1
3	6
4	-67
5	-71
6	-66
7	25
8	21
9	27
10	13
11	9
12	15
13	-59
14	-63
15	-58
16	33
17	29
18	35

6. Correct mapping of allocated investment to workstreams

In the spreadsheet "NZGP1.1 MCA – Final Version_20 September 2023, in sheet "MCA – annual costs" it shows that CNI Supporting projects investment as $10.2m and Preparedness projects as $3.5m, yet in the proposal, CNI Supporting projects is stated as $3.5m and Preparedness projects as $10.2m.

Please provide the correct investment amounts for the two workstreams.

The costs for CNI Supporting Projects is $3.5m and the Preparedness projects is $10.2m. The numbers in the Proposal are correct and it appears we have labelled these incorrectly in the spreadsheet tab referenced above.

A corrected (changes highlighted) excerpt of the relevant cells from the spreadsheet "NZGP1.1 MCA – Final Version_20 September 2023, in sheet "MCA – annual costs" is attached in Appendix B.

Impact on evaluation

Transpower's response

Appendix A: Modelling Costs and Benefits for NZGP1

This appendix summarises the modelling approach we adopted to evaluate the need for this project. It builds on information provided in our proposal (e.g., in Section 3 of Attachment D: Scenario & Modelling Report).

Modelling Costs and Benefits

The Investment Test objective is to identify transmission options that lead to higher (net beneficial) outcomes for consumers, this can be through lower wholesale prices in the energy market (e.g. as more lower cost generation can be dispatched), reducing losses, or increasing competition.

In our proposal we have focused on quantified costs and benefits (see section D4 of Division 2 of Schedule D of the Capex IM) associated with the following:

a) fuel costs incurred by generators in relation to existing assets, committed projects and modelled projects.

b) capital costs of modelled projects

c) the cost of losses

d) the cost of deficit i.e. electricity not supplied

e) the costs from operations and maintenance expenditure on committed projects, existing assets and modelled projects.

To assess the impact of these factors on generation costs we have modelled how various transmission options will impact generation expansion and generation dispatch. For instance, each transmission option has different transmission constraints that in turn influence what generation projects are developed (e.g. generation may not invest if it is constrained) and how the generation is dispatched. The Investment Test does not require that all transmission constraints are removed or reduced, as this may lead to a negative (non-net beneficial) outcome for consumers.

The process we have adopted is illustrated below:

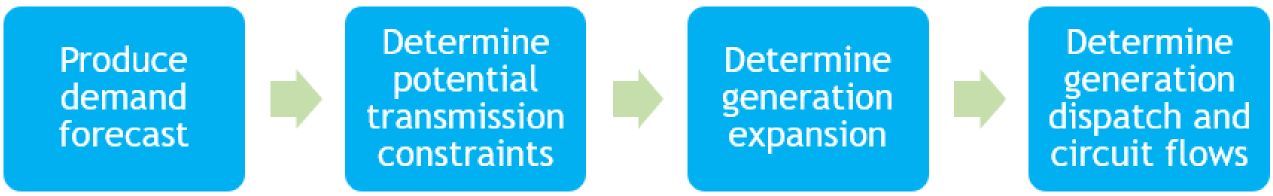


Figure A1: Modelling Approach

Briefly we outline each step below:

1) *Produce demand forecast.* We have based our analysis on reasonable variations to MBIE's EDGS scenarios. Our forecasts are hourly forecasts over the calculation period for the analysis. This allows us to model how load changes over a day and from week to week.

2) *Determine potential transmission constraints.* We have completed load flow studies using the prudent demand forecasts produced in step 1, and studied how the grid performs across a variety of system conditions (e.g. various assumptions around generation dispatch). These studies have identified what transmission constraints could arise and be mitigated by various transmission options. They also have informed what contingency monitor pairs we should model, and the constraint equations associated with each transmission options. Contingency monitor pairs are combinations of circuits that if the first was to

have an outage, the second may become overloaded. Constraint equations represent this relationship as an equation. They state that a combination of the flow on the circuits should not exceed a limit pre-contingency, so that if one of the circuits was to have a contingency it would not overload the remaining circuit e.g. flow on TKU-WKM-1 + 0.386* RPO-WRK-1 =< 321.6.

3) *Determine generation expansion.* For each scenario we have produced a generation expansion plan that is a plan of future generation that is built to meet the demand forecast we produced in step 1. We have used a model called OptGen2 to create generation expansion plans. This model takes into account various inputs including information about existing committed generation and retirements, and the list of potential new generation projects (i.e. the generation stack) that can be built. Its primary objective is to discern the most cost-effective generation projects to be built to expand generation capacity, factoring in key elements such as generation capital expenditures and fuel costs. The model considers the constraint equations found in step 2, as would apply to key central North Island and Wairakei Ring circuits. In this way the model considers if transmission constraints will impact on what future generation is built. OptGen2 considers hydro uncertainty using 3 weighted hydro inflow sequences and evaluates 13 "typical days" per year. As noted above, there are significantly more generation projects in the stack than needed to supply demand, hence while OptGen2 produces a generation expansion plan it is still possible that in the future other plants are built and some plants OptGen2 chooses to build may not be built.

4) *Determine generation dispatch and circuit flows*. We model generation dispatch using a model called SDDP. SDDP is a stochastic dispatch model. It considers the opportunity cost of using water for generation given the uncertainty associated with hydro inflows. It then simulates the lowest cost dispatch of generation for each hydro inflow sequence, given the opportunity costs associated with water, and given the availability of other generation. In this optimisation the model is allowed to not supply load, but the cost associated with non-supply of load is high. The cost of non-supplied load is called the deficit cost. SDDP simulates transmission flows and in doing so, considers the contingency monitor pairs found in step 2 to ensure the generation dispatch would not overload a monitored circuit post a contingency (e.g., in this way it models n-1 constraints on the system). SDDP consider 50 hydro inflow sequences, and we have run it using weekly time steps with 21 load blocks and at an hourly level for 5-year snapshots to better capture the impact of intermittent generation.

With this modelling approach a) to e) of the costs and benefits outlined above can be calculated:

a) fuel costs incurred by generators – are derived from the fuel costs modelled using SDDP in step 4.

b) capital costs of modelled projects (e.g. new generation) – are derived from the generation expansion plan costs calculated in step 3.

c) cost of losses – are derived from the flows on lines calculated in step 4

d) cost of deficit – are derived from our SDDP modelled dispatch. Our generation expansion and dispatch models acknowledge that there will be a limited occasions where generation must be supplemented by some form of demand response to ensure system security e.g. in extreme hydrological conditions.

e) the costs from operations and maintenance expenditure – fixed costs are calculated in step 3 in deriving a generation expansion plan, and variable costs are calculated in step 4 when calculating dispatch costs.

Application to NZGP1

As the need for this project relates to enabling "the efficient dispatch of new generation and a reliable supply of future demand growth over the interconnected grid" and the Investment Test is a net benefit test, our analysis has focused on determining the economic costs associated with the base case, no investment, and comparing them to the costs of a transmission upgrade option.

If no investment in new transmission occurred, then we would expect that transmission constraints would occur meaning that generation could not be built and/or operated efficiently and could cause amongst other things:

a) higher fuel costs incurred by generators

b) higher capital costs associated with new generation

c) higher costs associated with higher levels of losses.

d) higher costs associated with greater amounts of demand response.

If we invest in transmission investment the transmission constraints will change and this will affect these costs. However, it is not trivial to determine how these costs will change without applying the modelling approach above. An option may constrain generation, but the economic cost of the constraint may be small if the next best generator available is of similar cost. For this reason, we have considered a broad range of credible options to consider how these costs change.

On the following page we illustrate our results for the Growth scenario.

Table A1 shows the results for the Growth scenario for Options 10, 12 and 14, assuming a 7% discount rate. The table shows that Option 10,12, and 14 reduce costs, relative to our base case of not enhancing the grid, by $476m, $544m, and $570m. For a complete set of results refer to Tables 14 and 15 in Attachment C of our proposal.

Table A1: Net benefit results for the Growth Scenario, $m+

Option		Generation capital cost benefits*	Fuel cost benefits**	Loss cost benefits***	Total benefits	Transmission costs****	Net Benefit*****
Option 10		-8	395	89	476	393	83
Option 12		-8	392	160	544	451	93
Option 14		-8	410	169	570	514	56

* includes generation fixed operation and maintenance costs

** includes thermal operating costs, carbon charges, and deficit costs

*** relates to losses in the Central North Island and Wairakei Ring AC region

**** includes all transmission related expenditure, including ongoing costs

*****overall net benefits, across all scenarios, using the default weightings are $176m, $181m and $145m for Options 10, 12 and 14 respectively (Table 16, Attachment C)

Option 14 has the highest total benefit, but Option 12 has the highest net benefit. Option 14 has a higher cost than Option 12 that results in a slightly lower net benefit. However, as we outline in our proposal, while this is the case in this analysis, there is potential for these results to change in the future due to the uncertainty associated with demand and generation. Further, we consider there are unquantified benefits from Option 14, particularly in terms of providing additional security to the Bay of Plenty consumers, as outlined in response to Question 4 above.

To illustrate the benefits of investment we illustrate what our modelling shows in terms of impacts on transmission constraints and flows. We modelled N-1 security constraints for key central North Island and Wairakei Ring circuits. Figure A1 shows the percentage of time the three security constraints most likely to constrain bind for 2035, for the Table A1 options. We show results for the Growth Scenario and for the average over all hydrological sequences and the p90 hydrological sequence (a wet year). Security constraints are described using the following terminology, by way of example, “cont TKU-WKM-1:mont TKU-WKM-2” refers to constraints on the TKU-WKM-2 circuit due to a contingency on the TKU-WKM-1 circuit.

Figure A1 shows that Option 10 and Option 12, substantially relieve the constraints on both TKU-WKM lines, at the expense of constraining the BPE-TNG line. Option 12 relives the Wairakei Ring constraint on MTR-OKN. Option 14 substantially relieves constraints on both the central North Island and Wairakei Ring.

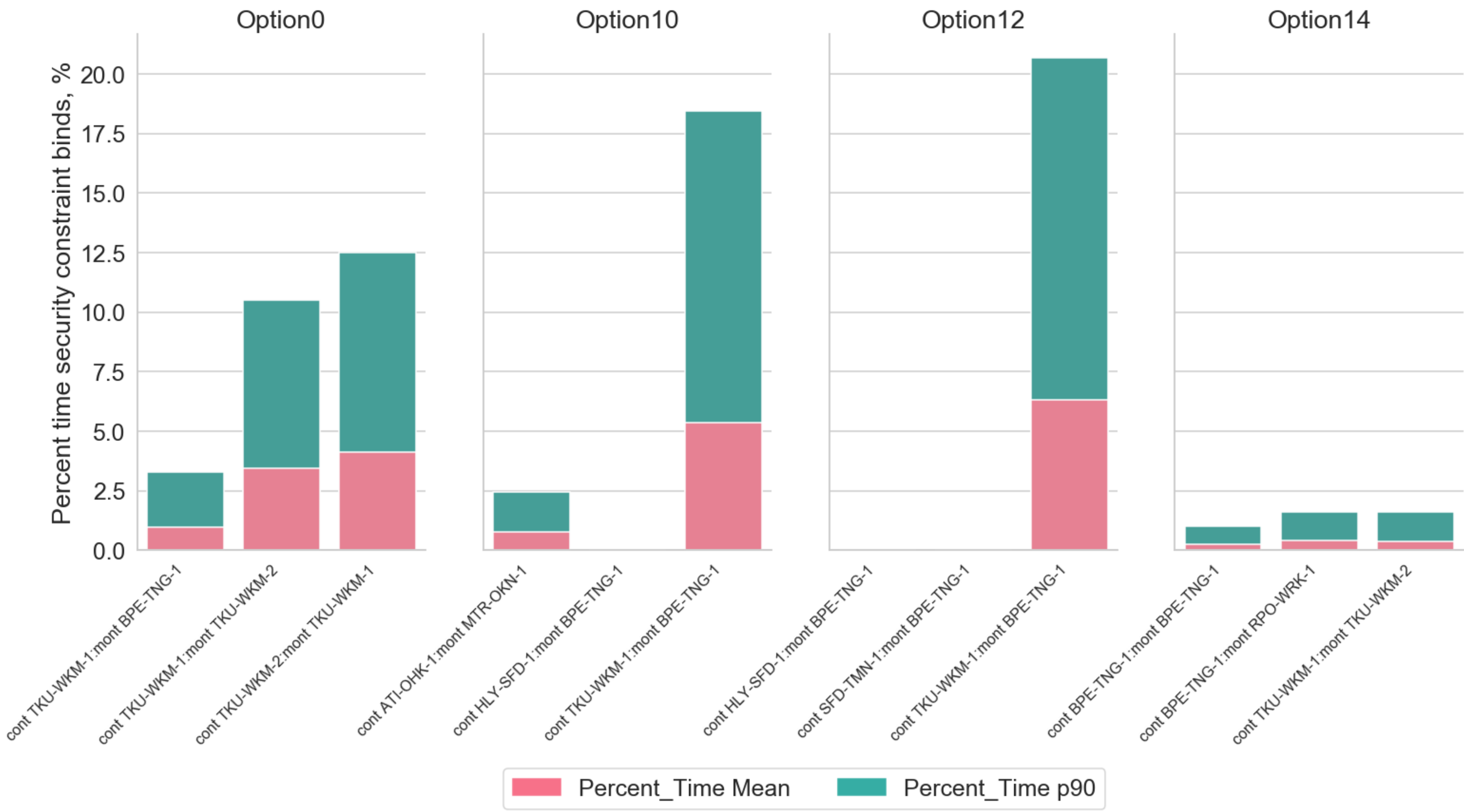


Figure A1: Percentage of time constraint is binding, for 2035 using the Growth Scenario

Figure A2 shows CNI corridor flows, in MW, if Tiwai leaves in 2024, and with the HVDC fourth cable installed in 2027. These charts show circuit flows summed across the main 220 kV circuits forming the CNI corridor (including BPE-TKU, BPE-TNG, BPE-BRK), with positive flows designated as "northwards”. We show results for the Growth Scenario and for p50 and the p90 hydrological sequence (a wet year). This Figure shows that as transmission constraints are relieved, northwards transmission flows through the CNI corridor increase. In turn this will lead to reduced thermal generation dispatch and associated costs. The extent to which each option increases northwards CNI corridor transmission flows depend on hydrology. Option 14 provides substantially greater northwards CNI corridor transmission flows during the p90 wet year, while Options 10, 12 and 14 provide similar CNI corridor transmission flows for a median hydrology year.

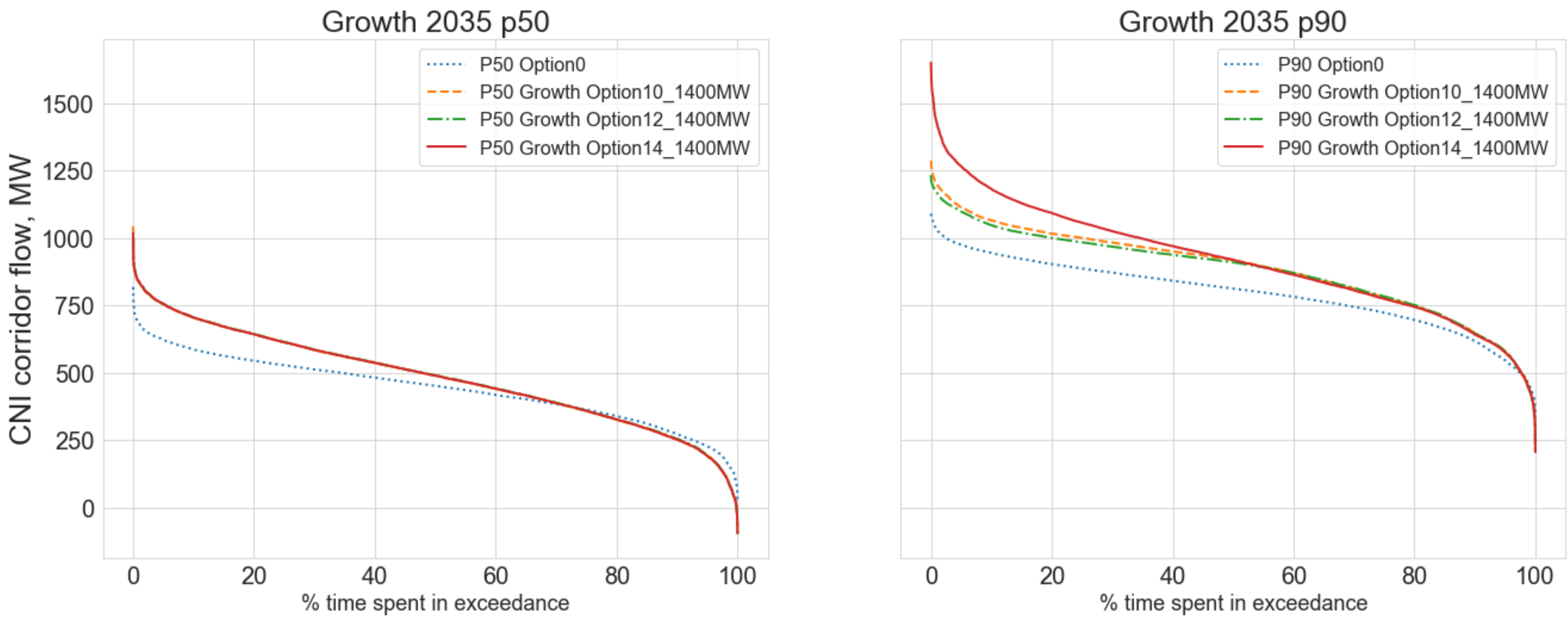


Figure A2: Flows on the CNI corridor lines, for 2035 using the Growth Scenario

Appendix B

Updated except from “NZGP1.1 MCA – Final Version_20 September 2023, in sheet “MCA – annual costs” Changes highlighted.

Project	Major Capex Allowance, $000, P50	2022	2023	2024	2025	2026	2027	2028	2029	Total
Stage 2 Preparatory Projects	Capex- total risk adjusted (real 2022)		3,400,000	3,400,000	3,400,000	-	-	-	-	10,200,000
Stage 2 Preparatory Projects	Inflation		-	-	-	-	-	-	-	-
Stage 2 Preparatory Projects	Capex- total risk adjusted (nominal)		3,400,000	3,400,000	3,400,000	-	-	-	-	10,200,000
Stage 2 Preparatory Projects	Interest during construction (IDC)		-	-	-	-	-	-	-	-
Stage 2 Preparatory Projects	Major Capex Allowance		3,400,000	3,400,000	3,400,000	-	-	-	-	10,200,000
CNI Supporting Projects	Capex- total risk adjusted (real 2022)		1,166,667	1,166,667	1,166,667	-	-	-	-	3,500,000
CNI Supporting Projects	Inflation		-	-	-	-	-	-	-	-
CNI Supporting Projects	Capex- total risk adjusted (nominal)		1,166,667	1,166,667	1,166,667	-	-	-	-	3,500,000
CNI Supporting Projects	Interest during construction (IDC)		-	-	-	-	-	-	-	-
CNI Supporting Projects	Major Capex Allowance		1,166,667	1,166,667	1,166,667	-	-	-	-	3,500,000

Table 18 UPDATED – Sensitivity of expected net benefit to various sensitivities. PV, $m

Sensitivity of expected net benefit to various sensitivities, PV, $m											
	Sensitivity										
	Investment Test	-30% capital cost	+30% capital cost	-30% ongoing costs[1]	+30% ongoing costs	4% discount rate	5% discount rate	10% discount rate	Scenario weighting 5/10/25/30/30	Scenario weighting 0/10/30/30/30	Scenario weighting 0/0/33/33/33
Option 1	7	94	-80	9	6	212	125	-84	-3	-11	-13
Option 2	-14	93	-121	-14	-14	210	114	-112	-20	-27	-27
Option 3	17	121	-88	18	15	258	156	-92	13	6	7
Option 4	7	134	-120	-13	27	283	165	-114	2	-5	-4
Option 5	-16	130	-162	-37	5	277	152	-143	-18	-25	-22
Option 6	14	157	-130	-6	34	325	193	-123	15	9	12
Option 7	-217	-35	-398	-209	-224	-4	-98	-293	-223	-230	-227
Option 8	-241	-40	-442	-234	-247	-11	-112	-322	-244	-250	-246
Option 9	-211	-13	-409	-203	-219	37	-72	-303	-211	-217	-212
Option 10	176	290	62	180	172	545	390	1	154	141	145
Option 11	150	283	16	153	147	533	372	-29	133	121	126
Option 12	181	312	51	186	177	583	415	-8	167	155	161
Option 13	173	327	20	156	191	609	425	-30	155	142	146
Option 14	145	318	-28	126	164	594	404	-62	129	117	123
Option 15	175	345	5	158	192	641	445	-41	162	150	156
Option 16	-39	169	-247	-29	-49	342	179	-202	-59	-71	-65
Option 17	-70	157	-298	-62	-79	322	153	-236	-87	-99	-91
Option 18	-42	183	-267	-32	-53	366	191	-217	-56	-67	-59

[1] Please note that net benefit = benefit – cost. For options 10-12, ongoing costs are positive and as they decrease, net benefit increases. For options 13-15, ongoing costs are negative, because compared to the Base Case, future reconductoring costs are avoided. When ongoing costs are negative, a decrease in costs result in them being less negative (ie they increase) and net benefit decreases.

Appendix C

Short-list of options: Detailed component list

[Stage 2 components in red]

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 1	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW
Option 2	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 3	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 4	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW
Option 5	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 6	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 7	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW
Option 8	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 9	New HAY reactive support	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip
Option 10	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 11	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 12	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip
Option 13	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 14	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 15	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu TTU BPE-WRK Duplex BPE-TKU	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip
Option 16	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 17	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 18	New HAY reactive support 4th Cook Strait cable	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Replace SPS at Tokaanu New line north BPE	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip

*Our proposal reflects the inclusion of preparatory costs for Stage 2 which are not included in this table.