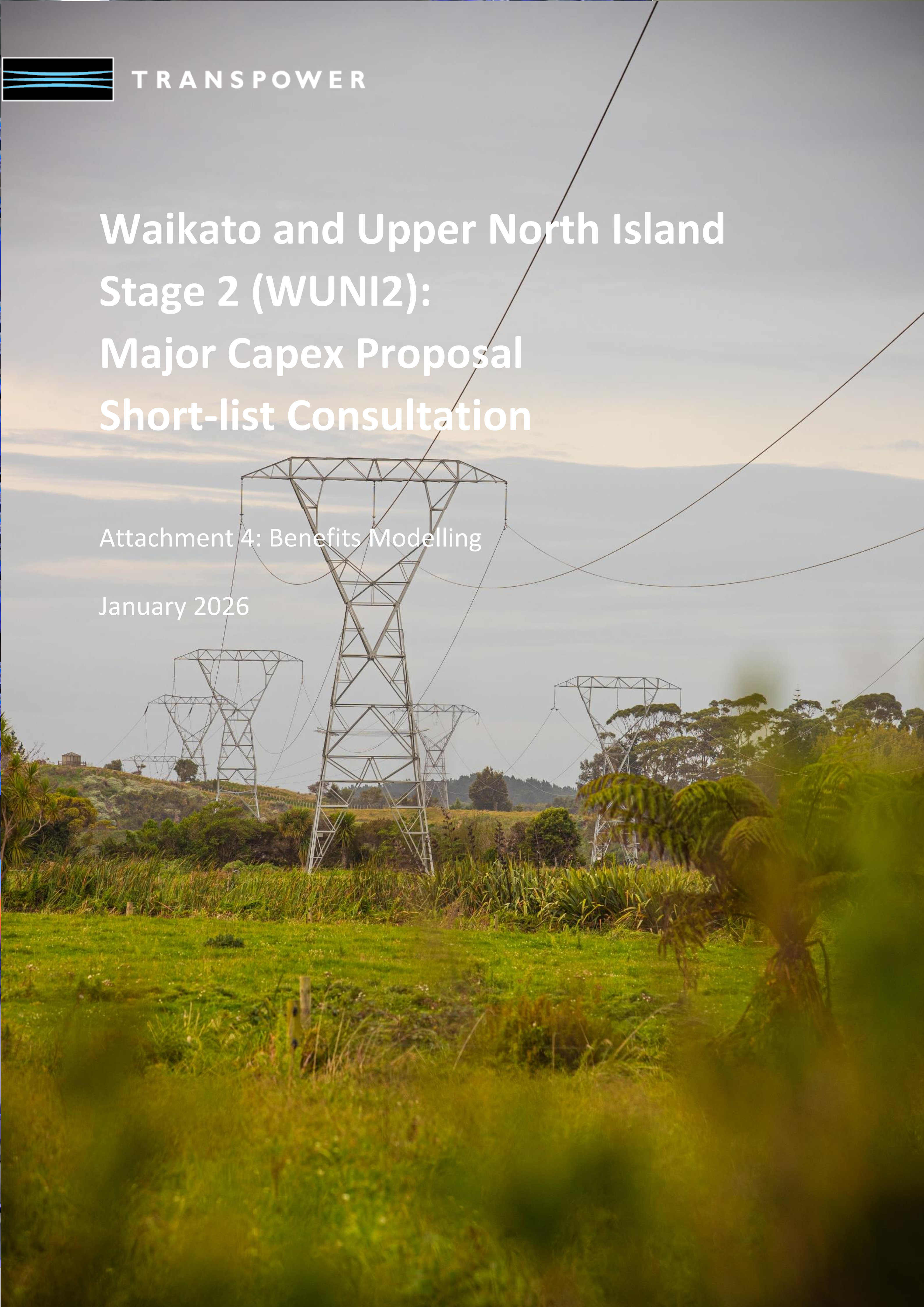
TRANSPOWER

Waikato and Upper North Island Stage 2 (WUNI2): Major Capex Proposal Short-list Consultation

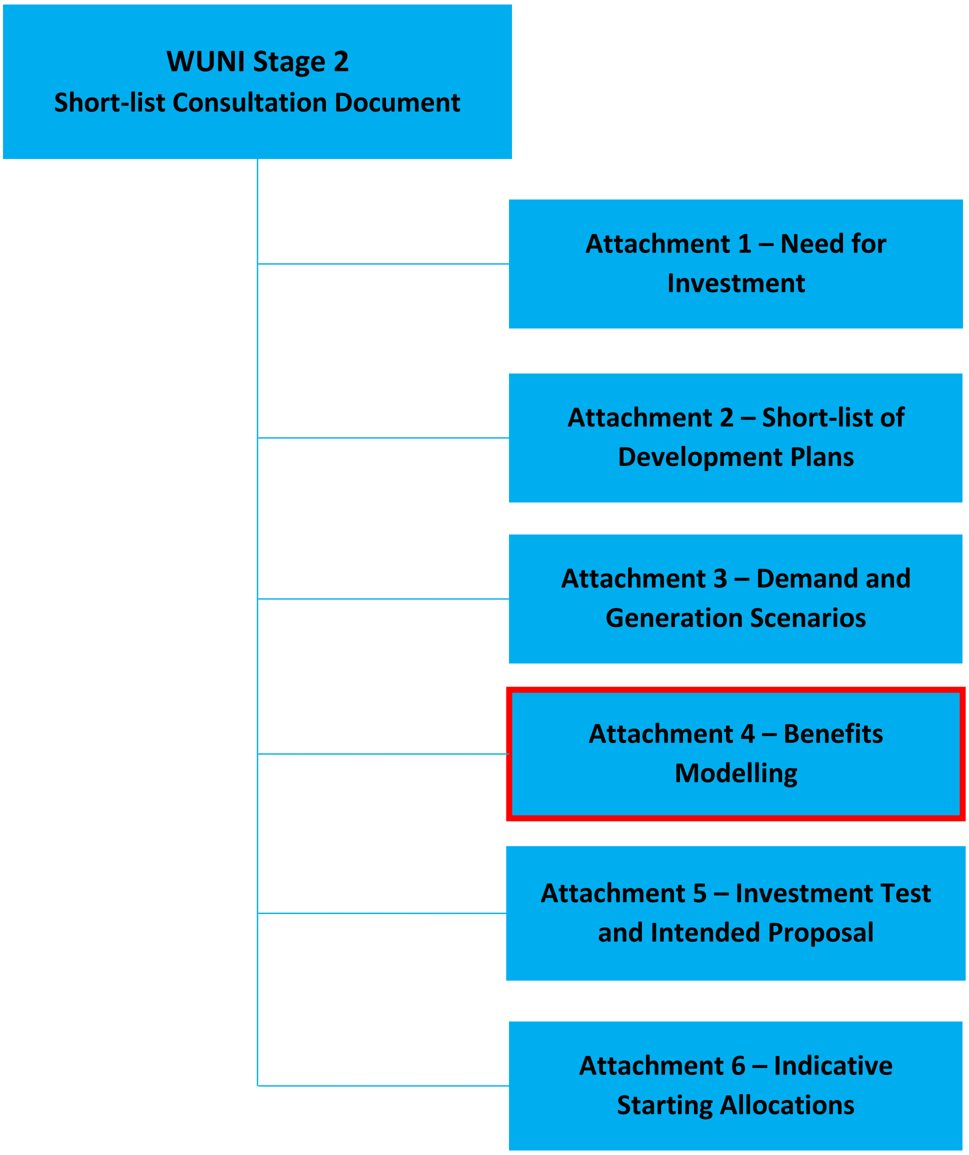
Attachment 4: Benefits Modelling

January 2026



Purpose

This Attachment forms part of our Waikato and Upper North Island (**WUNI**) Stage 2 Short-list consultation. This Attachment describes how we have calculated the benefits of the short-listed investment options for the WUNI Stage 2 project. We used models of the New Zealand electricity system to calculate the benefits of the investment options to meet the investment needs of the WUNI region, and to inform our decision-making for this potential major capex proposal.



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1 Benefits Modelling Approach

This section describes the approach used in our analysis to model and calculate the benefits of the investment options.

1.1 Overview

We use models of the New Zealand electricity system to calculate the benefits of investment options to provide transmission into the WUNI region.

The main components of our analysis are:

- **Power system analysis:** Conducted by our system planning team, this analysis helps determine the investment need, investment options and the timing of each investment option. It also provides inputs into our generation dispatch simulation modelling, such as upgraded circuit capacities for each investment option.
- **Generation expansion planning:** We find the lowest cost combination of new generation projects required to meet our forecast demand. For this analysis we use PSR Inc's OptGen software. Like the demand scenarios, the generation expansion plans are developed for the Growth, Reference and Environmental scenarios of MBIE's 2019 Electricity Demand and Generation Scenarios (**EDGS**), with variations.[1] We selected three of the five 2019 EDGS scenarios (which we refer to as the "selected scenarios") as this simplified the modelling while covering a wide range of demand and generation inputs. We did not use the Global scenario due to its unreasonably low level of growth. The Disruptive scenario is within the range of the selected scenarios and therefore does not provide additional insights. The original OptGen expansion plans for each selected scenario are modified to improve revenue adequacy and limit Auckland and Northland (upper North Island, or **UNI**) generation.
- **Generation dispatch simulations:** These simulations estimate electricity system operating costs for the 'base case' and the investment options. For this we use PSR Inc's SDDP software with generation dispatch simulations developed for the selected scenarios.

Our 'base case' is the scenario in which no transmission investment is made, resulting in a high risk of unserved energy. While this base case does not meet the N-1 standard of the GRS and we do not consider the option to be good electricity industry practice, we include it to demonstrate the economic benefits of the alternative investment options

Our modelling provides estimates of electricity system costs for the base case and the investment options. The benefits of a transmission option are calculated as the difference between the system costs of the investment option and the system costs of the base case.

[1] See Attachment 3 for further information about the selected scenarios.

1.2 Power System Analysis

Power system analysis, using DigSILENT's Power Factory software, provides key inputs to the transmission network models used for our generation dispatch simulations. An overview of these inputs follows.

1.2.1 Timing of Transmission Network Changes

Power system analysis is used to determine the timing of each investment option's transmission upgrades. The load on existing transmission assets is calculated assuming Environmental scenario prudent peak demand. Investment is timed so that loads on existing transmission assets do not exceed their current capabilities prior to being replaced or upgraded.

1.2.2 Specifications of Transmission Network Changes

Power system analysis is also used to help determine new and upgraded circuit capacities and electricity characteristics for each investment option's transmission upgrades.

Transmission development plans are modelled in Power Factory to resolve the identified Investment Need by combinations of:

- upgrading existing assets
- reconfiguring existing assets
- adding new assets, and/or
- adding an operational procedure, such as a Special Protection Scheme (**SPS**), to address part or all of the system need.

1.2.3 Transmission Network Constraints

Transmission network constraints are also derived from power system analysis and defined for all our investment options. These constraints ensure flows in and through the WUNI region reflect actual market conditions. Constraints are applied to limit circuit flows to ensure that circuit thermal ratings are respected in the event of a contingency (failure of a line or transformer) or to avoid voltage stability issues. These constraints may limit flows substantially below the thermal rating of a circuit.

Only network constraints that cannot be modelled in our generation dispatch simulation software need to be produced through power systems analysis. Our generation dispatch simulations use a simplified, linear, DC load flow model. Thermal N, and N-1, limits can be captured within the simulation model dynamically, resulting in security constrained dispatch outcomes. However, some constraints, such as voltage stability, cannot be modelled explicitly in the generation dispatch simulation. These limits must be produced by power systems analysis in the form of linear constraints where sums of circuit flows and/or grid injections are forced to satisfy specified limits.

To better capture the interaction between Huntly generation and the voltage stability constraint for the WUNI region, we included "generic constraints". These constraints limit the sum of WUNI boundary transfer and Huntly generation. The impact of these generic constraints is to force SDDP to increase WUNI generation, particularly at Huntly (HLY) to optimise power transfer within the WUNI region to avoid voltage stability issues.

In addition, we also applied a "circuit sum constraint", which simply represents the limits of the sum of flows in a defined combination of circuits (e.g., to represent three-terminal circuit contingencies).

1.3 Generation Expansion Planning

Generation expansion planning is the process of forecasting future grid connected generation for a given demand forecast. Generation expansion plans are an input to our generation dispatch simulations.

1.3.1 Least Cost Generation Plans

Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (out to 2055 in this case), building new generation as required to meet forecast demand. It chooses new generation from the generation stack with the overall objective of minimising the cost of electricity over the period being considered. We recognise that there are other factors that play a role in generation investment decisions such as the availability of capital, future views on wholesale electricity prices, the ability of the project to gain consents, power purchase agreements, and retail positions relative to generation. However, our view is that it is reasonable to focus on generation costs on the basis that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, electricity cost will be the major deciding factor.

1.3.2 Using OptGen

PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use PSR's 'Optgen1' algorithm.

Optgen1 finds the lowest cost combination of capital costs (due to investments in new generation) and operating costs (due to operating existing and new generation plant) over the modelling horizon. This is done in two separate stages:

- Operating costs are estimated using the same SDDP algorithm as used for our generation dispatch simulations Although we make some simplifications to ensure that the model run time is practical, we do account for hydro inflow uncertainty and renewable energy variability.
- Operating costs are assessed by a separate algorithm to determine the least cost combination of capital and operating costs.

Optgen1 can be configured with several possible generation energy or capacity constraints. To align the expansion plans with our expectations of what the market will deliver in the short term, we initially constrain the build to generation projects which developers have committed to, and to those projects which are in the advanced stages of Transpower's connection pipeline. We achieved this by applying a maximum wind and solar installed capacity constraint that varies over time. Specifically, the annual wind and solar build limit is set to 600 MW in 2026 and then grows by 100 MW each year until it reaches 1,000 MW in 2030. From 2030 onwards, the annual wind and solar build cap remains constant at 1,000 MW through to the end of the modelling horizon.

1.3.3 How Many Generation Expansion Plans?

We produced generation expansion plans for the selected scenarios (Growth, Reference and Environmental). We assumed that:

- future generation would be unaffected by WUNI regional constraints. Initial testing of this assumption produced generation expansion plans that were not materially different with different transmission development plans, and
- that the AC grid is unconstrained.

For these reasons, we applied the same generation expansion plan for a given EDGS scenario across the base case and all short-listed investment options.

1.4 Generation Dispatch Simulation

SDDP minimises the electricity system operating costs, accounting for:

- future changes in generation and grid scale batteries - as provided by our generation expansion plans
- future changes to the transmission network for each investment option
- changes in demand - arising from daily and weekly demand variations through to long term forecast demand growth
- hydro inflow variability and uncertainty
- renewable energy variability
- grid scale battery operation
- plant operational constraints - including thermal plant unit commitment and hydro plant minimum flow constraints.

SDDP is a well-established model that is widely used in many jurisdictions around the world.

1.4.1 SDDP Policies and Water Values

SDDP generation dispatch simulations are produced in two steps:

- **Policy evaluation:** In this step SDDP derives a policy, effectively a set of water values for each of New Zealand's major hydro reservoirs. Water values provide the opportunity cost of using or storing water in each hydro reservoir, accounting for risks of both dry year energy shortages and wet year hydro spillage.

- **Simulation:** Using the water values from the policy evaluation, the operation of the electricity system is simulated for a given set of hydro inflow sequences.

SDDP policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water storage values. For the WUNI Stage 2 analysis, consistent with our generation expansion plan approach, we ran policies for each selected EDGS variant. For a given scenario we applied the same policy to the base case and each investment option, on the basis that WUNI Stage 2 investment options are unlikely to affect water values for our major hydro generation schemes.

1.4.2 Resolution

The process of choosing the best resolution for a model is a compromise between model accuracy and computational tractability. For SDDP, resolution relates to the size of the time step considered by the model. Resolution is improved by reducing the size of the time step. A model with a high resolution will better capture real world variations in demand and renewable generation. However, this will be at the expense of increasing model solve time and model result data storage requirements.

For this analysis, we use an hourly resolution over the full modelling horizon to 2055 for generation dispatch simulations.

1.4.3 Hydro Inflow Sequences

SDDP simulates the dispatch of generation and battery resources across the electricity system for a defined set of yearly hydro inflow sequences that represent conditions for all modelled hydro generators. In New Zealand, electricity system costs vary significantly with hydro inflows and capturing this behaviour is a critical part of our generation dispatch simulations.

We use 'synthetic' hydro inflow sequences that are derived from historical hydro inflow records. Synthetic inflows reduce the level of fluctuations, help the model converge, and reduce model solve time. SDDP creates these sequences by considering the relationships between historical hydro plant inflows and the time of year, and the relationships between different hydro plant inflows.

For this analysis, we used:

- **For the policy evaluation step:** 15 and 50 synthetic inflow sequences, respectively, for the 'backward' and 'forward' phase of the SDDP algorithm
- **For the simulation step:** 50 synthetic inflow sequences.

1.4.4 Modelling the Transmission Network with SDDP

SDDP uses a simplified, linear, DC load flow model. For this analysis, we also make the following further simplifications:

- AC circuit flows are constrained to respect both thermal ratings and other circuit constraints only for the interface between the rest of the North Island (RNI) and the WUNI region. Where appropriate different thermal ratings and constraints are applied for the base case and each investment option. For the rest of the AC Grid circuit flows are unconstrained.

- Only circuits 66 kV and above are included in our grid model.
- AC network losses are not treated explicitly in the SDDP generation dispatch simulation. To account for the extra generation required to counteract average losses, all loads are escalated by an island loss factor (2.85% in the North Island and 3.85% in the South Island[2]). To estimate benefits, losses are estimated as a post processing step (after the model has been run), based on dispatch circuit flows and North Island short run marginal costs.
- Losses on the HVDC are modelled within SDDP using a linearised approximation of observed HVDC losses.

2 Modelling Assumptions

Demand and generation assumptions for each selected scenario are described in Attachment 3. These assumptions form the core of our modelling inputs. Assumptions specific to the either the base case or each investment option are discussed in this section.

2.1 Transmission Network

Transmission network assumptions for the base case and each investment option are detailed in Appendix A.

2.2 AC Losses

As outlined in Section 1.4.4, Transpower typically runs SDDP with a lossless AC network to reduce computational complexity. To account for AC system losses, escalation factors are applied to North Island and South Island loads to reflect the expected losses in the AC network in each island. These loss factors are included in the Assumptions Book and are based on analysis of historical system losses.

This simplifying assumption is generally fit for purpose for investment testing as losses typically do not change the merit order of dispatch, and explicitly modelling losses in the market model does not materially influence the results.

[2] See the Assumptions Book paragraph 63 and Section 2.2 of this Attachment for additional information about AC network loss modelling for this analysis.

However, for this analysis, our comparison of SDDP network flows with network flows from an AC power-flow model that explicitly modelled losses found that assuming a constant loss factor across the North Island leads to an underestimation of AC losses in the WUNI region and a corresponding overestimation in the rest of the North Island (**RNI**) region.

To align losses in SDDP with AC losses, we calibrated the distribution of the North Island losses between the WUNI and RNI regions to reflect the loss patterns observed in the power systems modelling.

To achieve this, we increased the load in the WUNI region by a percentage of its gross load to account for the underestimated losses under the standard approach. This was done via a negative power injection at OTA220. Similarly, we decreased the RNI region's load by the same amount as we increased the WUNI region load using an equal and opposite power injection. The values of these factors are based on the scenarios with the highest boundary transfers, which have the most significant impact on network constraint. The equal and opposite adjustments mean that total North Island losses remain unchanged, while a greater share of losses is attributed to the WUNI region. Based on the power system analysis, the applicable percentage adjustments for each option are as follows:

- Base case: 6.06%
- Option 1: 4.49%
- Option 2: 4.02%
- Option 3: 4.53%
- Option 4: 4.11%

The calibration results in system states – the combination of circuit flows, bus demand, losses, and generation – that align more closely with power systems modelling and therefore provide a more accurate estimation of benefits.

2.3 Deficit Cost

The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plan and generation dispatch simulation modelling. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network. To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing tranches as described in Table 1. Each tranche is for a given amount of deficit, expressed as a percentage of hourly[3] island demand. The first three tranches are intended to represent voluntary demand response measures, such as retailers controlling hot water cylinder demand. The last high value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency.

[3] For Optgen1, deficit tranches are specified for the quantity of deficit expressed as a percentage of 'load block' Island demand. Load blocks are groups of similar periods of demand within a given week.

Table 1: Generation Expansion Plan Modelling Deficit Cost Tranches

Deficit as a proportion of Island hourly demand	Cost ($, real 2021)
First 5% of demand	$600 per MWh
Between 5% and 10% of demand	$800 per MWh
Between 10% and 15% of demand	$2,000 per MWh
Greater than 15% of demand	$10,000 per MWh

3 Generation Expansion Plans

This section describes the generation expansion plans derived for this analysis. These plans use the selected scenarios described in Attachment 3 and are an input to the generation dispatch simulations. For a given scenario, generation expansion plans are the same for all options.

Figure 1 shows cumulative new generation capacity additions and deletions, out to 2055, for the selected scenarios (Growth, Environmental, and Reference) based on the final generation expansion plan. New generation build is dominated by wind and solar for all selected scenarios. Fossil fuel retirements are covered by grid scale batteries, geothermal or biofuels. In addition, a new hybrid gas-bio OCGT plant was built by the model few years after the retirement of the Huntly plants.

Our assumptions, intended to provide diversity across our generation expansion plans, drive the relatively strong growth in geothermal generation in the Growth scenario, while the other scenarios have greater growth in solar or biogas thermal.

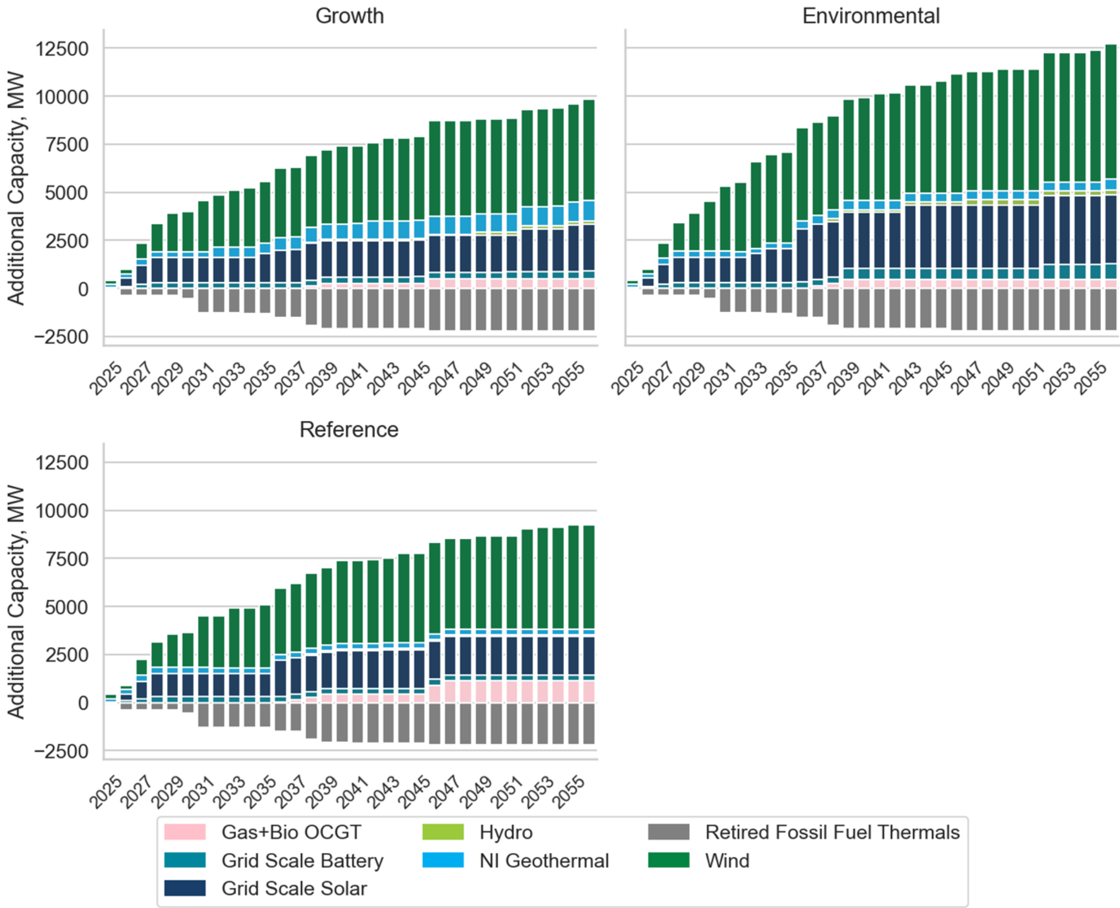

Figure 1: Generation expansion plans, capacity additions and deletions

3.1 OptGen Adjustments for Revenue Adequacy

We adjusted the OptGen generation expansion plans for the selected scenarios to improve revenue adequacy, as described in Section 1.1. Only wind and solar generating plants were adjusted in the policy iterations. Other power plant technologies were unchanged.

3.2 Adjustments to Limit UNI Generation

Given that the OptGen runs assume an unconstrained grid, we have adjusted the total capacity of new plants in the UNI region according to the grid capability informed by our Northland REZ study.[4] The study showed that without significant transmission investment, generation north of Huapai 220 kV (HPI220) should be limited to around 440 MW, with an additional 200 MW potentially accommodated at HPI220. The 220 kV circuits connected to the Bream Bay 220 kV (BRB220) and

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HPI220 bus would require significant upgrades if the existing generation expansion plan (after revenue adequacy adjustments) were implemented without further adjustments.

To respect these Northland generation limits while maintaining the same generation mix as the OptGen build (with revenue adequacy adjustments), excess Northland generation was replaced with similar plants from our generation stack. These replacement plants share the same technology and commissioning date and have as close as possible mean capacity[5] and total costs as the original Northland plants. For example, in the Growth scenario, the list of original plants built by OptGen and the corresponding replacement plants are listed in Table 2.

Table 2: List of replaced Northland plants for the Growth scenario

Technology	Original Plant	Original Capacity, MW	New Plant	New Capacity, MW
Geothermal	Ngawha6	25	Mokai4	25
Solar	S_WEL110A	80	S_MST110	82
Solar	S_HPI220	200	Solar_KAW_1	200
Wind	FarNorth_2	75	Eastland_2	75
Wind	FarNorth_1	75	BOPTaupo_5	75
Wind	Northland_3	100	SouthernWa_1	100
Wind	Northland_6	100	Manawatu_4	100
Wind	W_MDN110	120	Auckland_3	125
Wind	Northland_2	150	Manawatu_1	150
Wind	Northland_5	150	CentralPla_2	150
Wind	FarNorth_3	200	Eastland_3	200
Wind	Northland_1	300	Manawatu_5	300

Figure 2 and Figure 3 compare nationwide projections of installed wind and solar capacities in 2035 and 2055 for the original OptGen results and the adjusted expansion plans after considering revenue adequacy, the Northland limitations and SRMC balance, for each selected scenario.

[5] When replacing renewable plants, we considered both the capacity of the original plant and the annual mean capacity factor. The replacement plant was chosen from available plants in the stack that was closest to the original plant in terms of (installed capacity × mean capacity factor) and total costs.

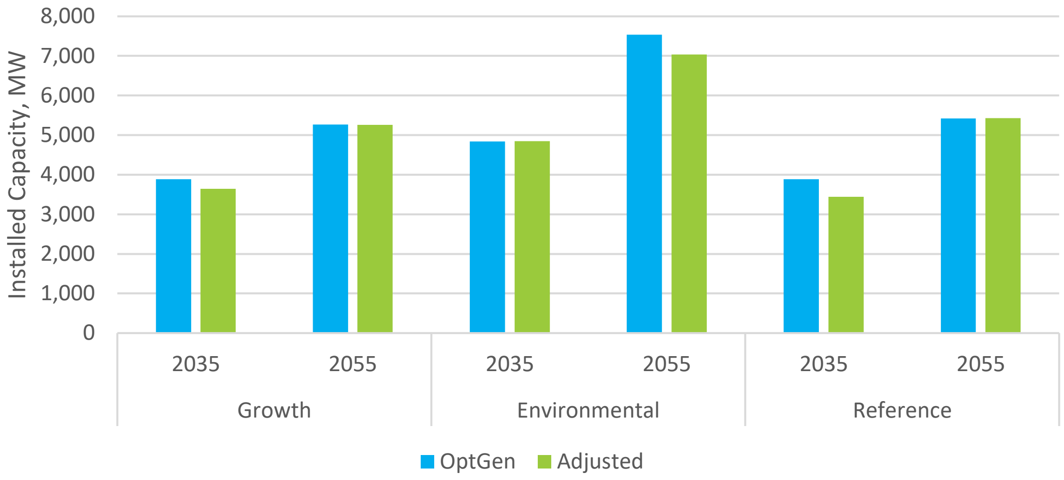

Figure 2: Nationwide wind installed capacity in the final expansion plan

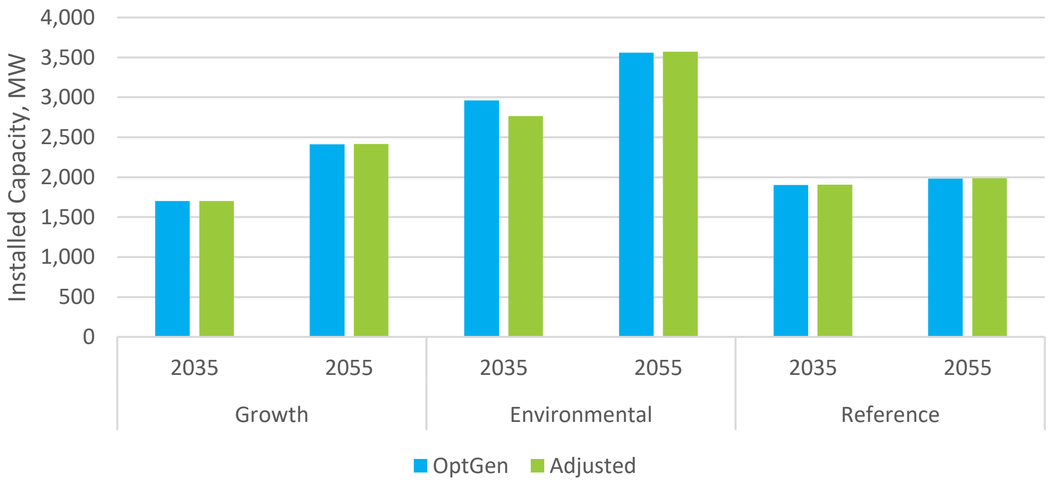

Figure 3: Nationwide solar installed capacity in the final expansion plan

4 Generation Dispatch Simulation Results

This section provides an overview of our generation dispatch simulation results. Benefits derived from our generation dispatch simulations are combined with all other investment option benefits and costs in Attachment 5.

4.1 Generation Dispatch Simulation Benefits

Generation dispatch simulation benefits ('dispatch benefits') are calculated for each investment option by finding the difference between simulated electricity system costs for that investment and the base case of no investment. These benefits are gross in that they exclude the cost of the transmission investment upgrade. Dispatch benefits are calculated for these cost categories:

- **Thermal operating costs:** Including fuel costs, variable operating costs and emission costs.
- **Deficit costs:** Unserved energy costs, using the tranches set out in Section 2.3.
- **AC loss costs:** The treatment of AC grid energy losses, as explained in Section 2.2. Loss costs are estimated using Island short run marginal costs.

There are no generation investment benefits as we are using the same set of generation expansion plans for the base case and each investment option.

All costs are sourced from dispatch simulation modelling and are averaged over 50 simulated synthetic hydro inflow sequences.

Dispatch benefits, broken down by costs category, are shown in the tables below for the selected scenarios. Dispatch benefits are net present values (in 2025 dollars) over the 2034 to 2055 period, with a 5% real discount rate.

Dispatch benefits for all investment options and all market scenarios are mainly due to reductions in AC loss costs relative to the base case. There are also benefits due to the reduction of deficit. The investments also lead to small increases in thermal generation costs (a disbenefit).

Dispatch benefits vary substantially by demand scenario. These variations are primarily due to the differences in the rate of demand growth and the respective generation expansion plans.

Table 3: Environmental scenario, gross benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1	-6	248	41	283
Option 2	-6	306	39	338
Option 3	-7	263	40	296
Option 4	-6	358	40	391

Table 4: Growth scenario, gross benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1	15	277	80	373
Option 2	15	318	82	417
Option 3	15	295	81	393
Option 4	15	382	82	481

Table 5: Reference scenario, gross benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1	4	179	6	190
Option 2	4	223	7	235
Option 3	4	190	6	200
Option 4	4	262	6	274

As discussed in the Overview document, Option 4 is our preferred stage 2 option. We focus on the base case and Option 4 in our discussion of the dispatch simulation results below.

4.1.1 Benefits Over Time

Figure 4 shows the discounted dispatch benefits of option 4 over time for the Growth scenario. AC loss benefits become significant from 2030 and remain the dominant source of benefit for the remainder of the study period. Deficit benefits become apparent from 2037, when the voltage stability constraint starts to bind more frequently due to demand growth.

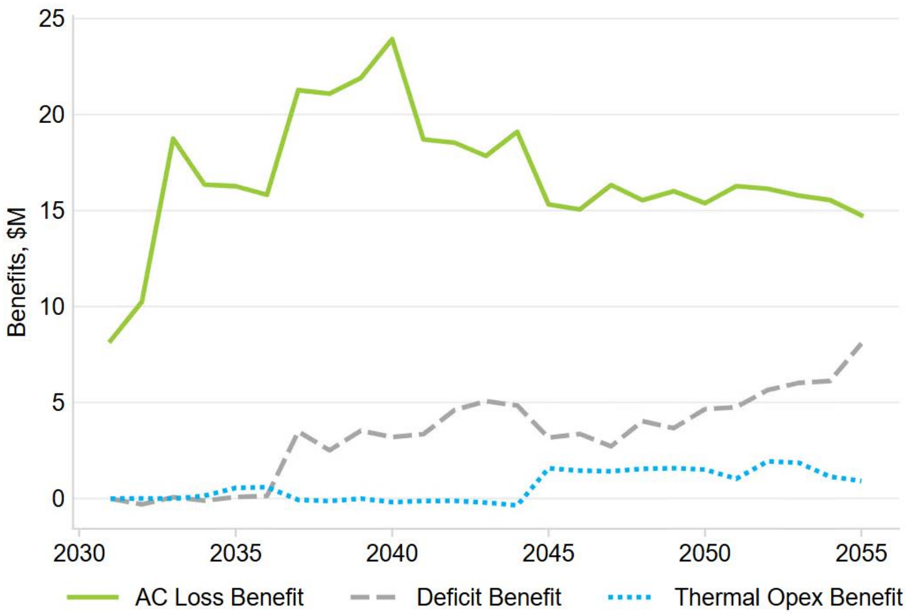

Figure 4: Dispatch benefits over time for option 4. Benefits are gross and discounted at a 5% real discount rate

4.2 Sensitivity to Huntly Retirement Assumptions

The Assumptions Book, which the inputs to the SDDP modelling are based on, have the Huntly Rankine units 1, 2, and 4 retiring in 2030. Recent developments point to these plants retiring in 2035. To test the impact of the 2035 retirement assumption and to verify that the preferred option is sufficiently robust, we simulated a 2035 retirement for the Huntly Rankine's for the Growth scenario only. Comparing Table 6 below with Table 4 shows that the impact is relatively small and has no impact on the preferred option.

Table 6: Growth scenario, Huntly Rankines retiring in 2035, gross benefits by cost category. Benefits are NPV, 5% real discount rate

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 1	14	276	81	373
Option 2	15	317	81	414
Option 3	15	295	81	391
Option 4	15	383	87	486

4.3 Circuit Flow

4.3.1 Circuit flow duration and constraints

We have applied "generic constraint" equations to represent voltage stability constraints for all options. A "circuit sum constraint" has been included to address thermal constraints in the event of contingencies involving three-terminal circuits. These constraints were applied to restrict the sum of circuit flows and prevent voltage issues. These constraints bind infrequently for the base case[6] and the investment options.

To illustrate, Figure 5 ("zoomed in" in Figure 6) shows the flow duration curves across the WUNI boundary for the Growth scenario for the base case and the investment options. The flow duration curves shown are for each hour in 2045 for all hydro scenarios. The base case is more constrained than the investment options, leading to the dispatch benefits for each investment.

[6] All base case results are labeled as Option 0 in the charts in this report.

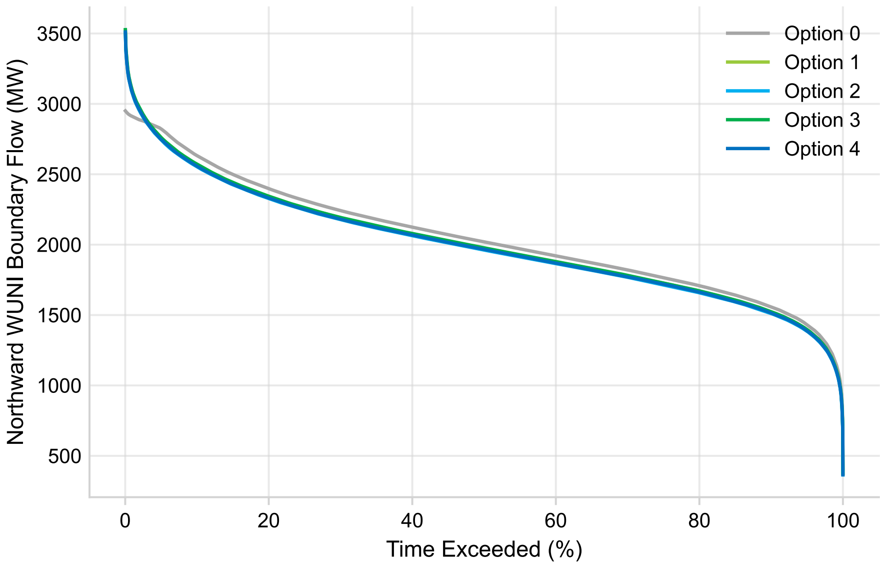

Figure 5: Flow duration curves (2045) for flow across the WUNI boundary

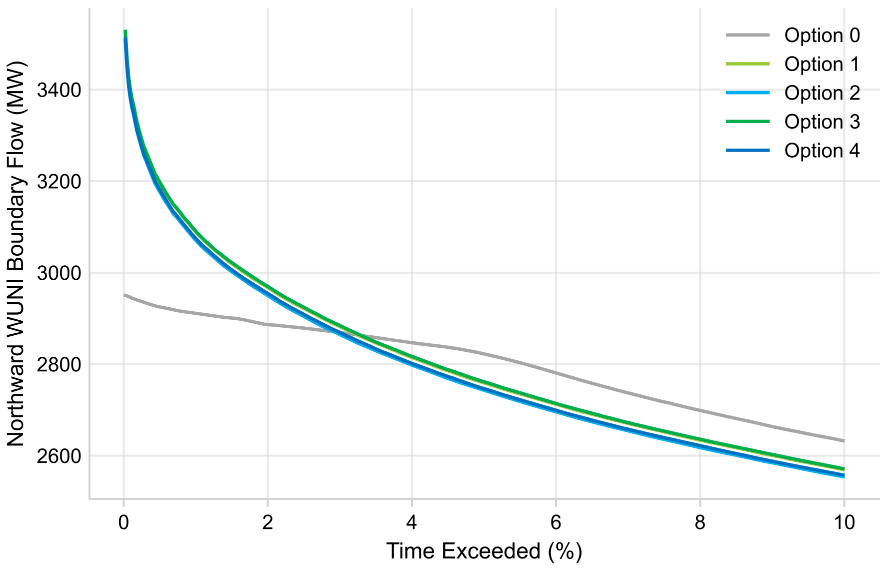

Figure 6: Flow duration curves (2045, top 10% of sum of flows) for flow across the WUNI boundary

4.4 AC Loss Benefits

We analysed the AC losses for the circuits within the WUNI region. For the Growth scenario, Figure 7 shows the WUNI circuits sorted from the highest AC loss costs in the base case.

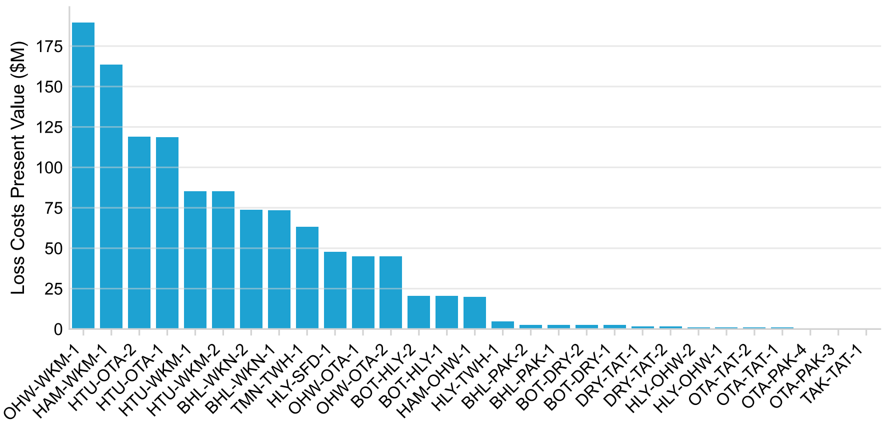

Figure 7: Present value of base case loss costs (5% discount rate to 2025, in $m) for each circuit considered in the Growth market scenario.

The AC loss benefits are illustrated in Figure 8 after comparing the AC loss costs in each investment option versus the base case. There are some circuits which shows disbenefits resulting from less or no circuit flows in the investment option compared to the base case. For example, in Option 1, there is a disbenefit from OHT-WKN 1 and 2, because these lines are not present in the base case. However, there is a general loss benefit because the total flows from the other circuits are reduced, offsetting these disbenefits. Therefore, there is an overall net positive benefit for AC losses for all investment options.

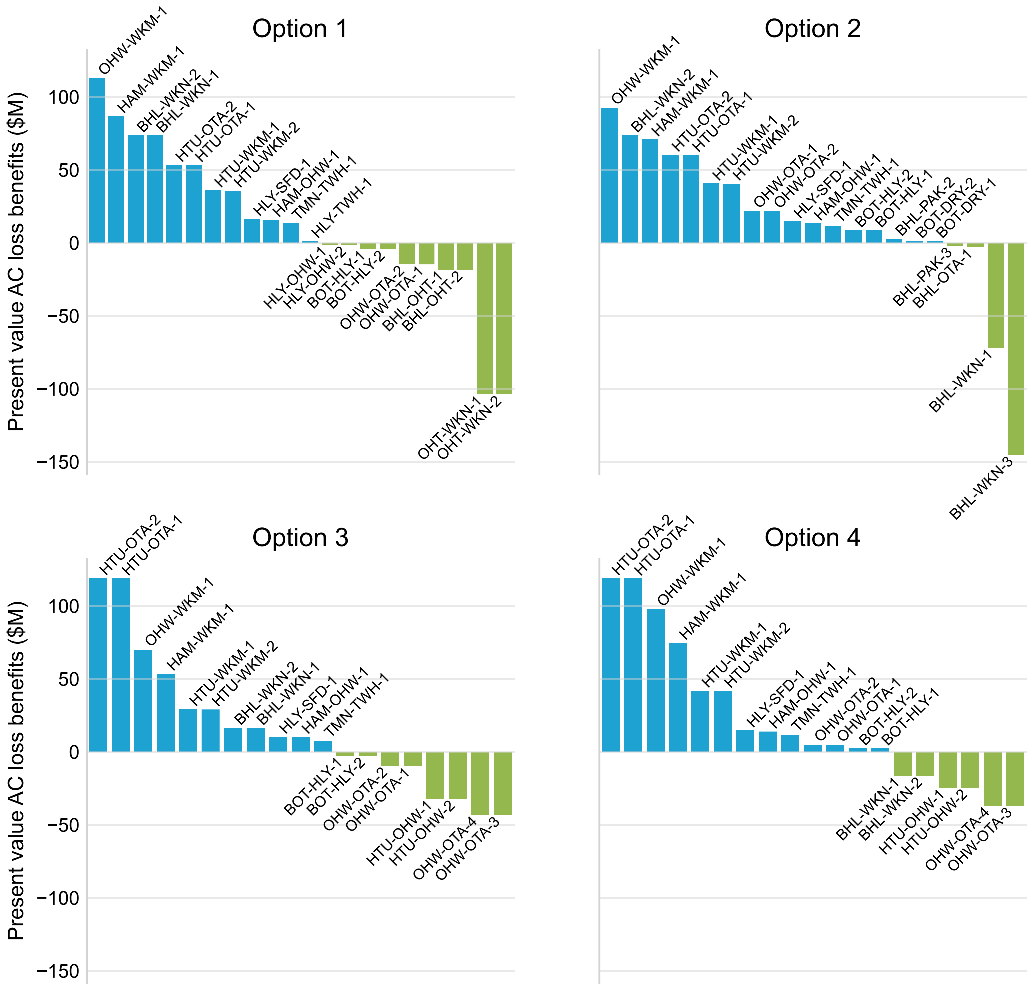

Figure 8: Present value of Base case (do nothing) loss benefits (5% discount rate to 2025, in 2025 NZ $m) for each circuit considered in the Growth market scenario.[7]

4.5 Deficit

Figure 9 and Figure 10 show the deficit for the Growth Scenario in the WUNI region for all investment options. Deficit is averaged over all hydro scenarios.

On average, the investment options reduce deficit beginning around mid-2030s, growing to 9% by 2040 and 34% by 2055. For all our investment options there will always be some residual deficit across the country associated with either dry years or generation capacity shortages. For these types of events SDDP spreads deficit across the Island in proportion to demand.

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[7] For Option 2, BHL-WKN-3 is the model representation of BHL-WKN-2 after being bussed at Brownhill. Therefore, the actual loss benefit/disbenefit for BHL-WKN-2 is the sum of BHL-WKN-2 and BHL-WKN-3 in the chart.

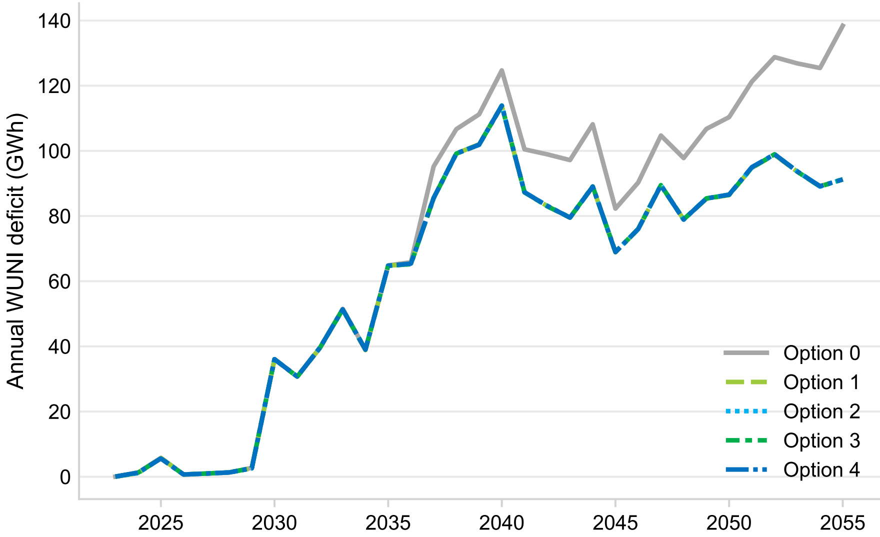

Figure 9: Deficit in the WUNI region for the Growth scenario, averaged over all hydro scenarios

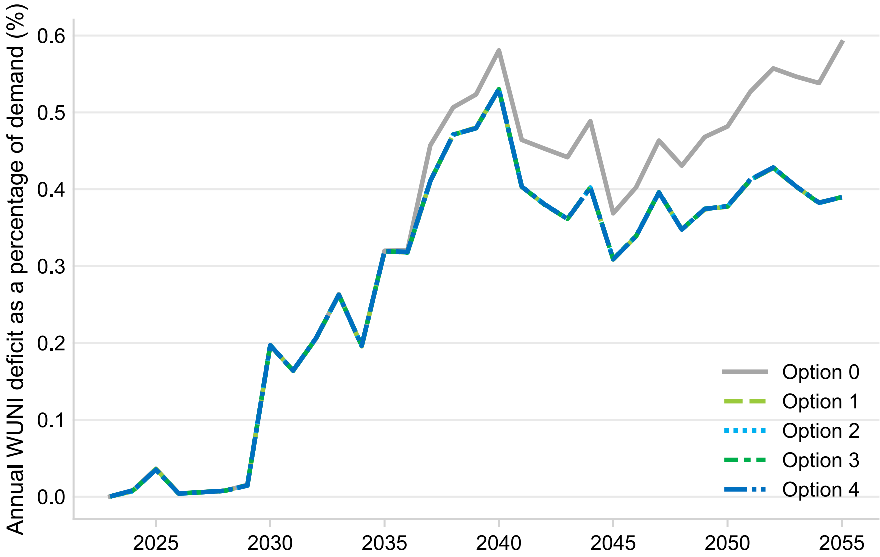

Figure 10: Deficit in the WUNI as a percentage of total WUNI load, averaged over all hydro scenarios

Appendix A – Transmission Network Assumptions

A1 Short-listed options

- **Option 0:** Do nothing (Otahuhu STATCOM in service)
- **Option 1:** 16.93 Ohm series compensation, Ohinewai Tee
  - +/- 150 Mvar STATCOM in North Auckland
  - 2x16.93 Ohm series capacitors at Hangawera Road
  - A tee connection between each BHL-WKN 1&2 circuit and Ohinewai
  - Shunt Capacitors and Dynamic Reactive Plant as required
- **Option 2:** 26.15 Ohm series compensation, BHL-OTA cable
  - +/- 150 Mvar STATCOM in North Auckland
  - 2x 26.15 Ohm series capacitors at Hangawera Road / Install additional 2x9.22 Ohm series capacitors at a site north of Ohinewai
  - 220 kV Brownhill bus
  - 220 kV Brownhill–Otahuhu cable
  - Shunt Capacitors as required
- **Option 3:** Otahuhu–Whakamaru duplexing
  - +/- 150 Mvar STATCOM in North Auckland
  - Reconductoring of Otahuhu–Whakamaru A&B line south of Ohinewai
  - Connect Otahuhu–Whakamaru A&B line into Ohinewai
  - Shunt Capacitors and Dynamic Reactive Plant as required
- **Option 4:** 16.93 Ohm series compensation, Otahuhu–Whakamaru duplexing
  - +/- 150 Mvar STATCOM in North Auckland
  - 2x16.93 Ohm series capacitors at Hangawera Road
  - Reconductoring of Otahuhu–Whakamaru A&B line south of Ohinewai
  - Shunt Capacitors

Table 7: Transmission options summary

Upgrade	Transmission options					Modelled Commissioning Date
	0	1	2	3	4	
Automatic over-voltage switching scheme (AOVCS)	✓	✓	✓	✓	✓	2024
Otahuhu STATCOM in service	✓	✓	✓	✓	✓	2025
OTA-WKM VLR	✓	✓	✓	✓	✓	2025
Hautapu GXP+VLR	✓	✓	✓	✓	✓	2025
Hobson St second 220/110 kV transformer, Split Liverpool St – Hobson Street 110 kV	✓	✓	✓	✓	✓	2027
Bombay 110 kV changes	✓	✓	✓	✓	✓	2027
1x100 Mvar PAK capacitor (220 kV)		✓	✓	✓	✓	2028
+/- 150 Mvar STATCOM at Henderson		✓	✓	✓	✓	2029
2x16.93 Ohm series capacitors at Hangawera Road		✓			✓	2030
220 kV Brownhill bus			✓			2030
220 kV Brownhill–Otahuhu cable			✓			2030
2x26.15 Ohm series capacitors at Hangawera Road			✓			2030
Connect Otahuhu–Whakamaru A&B line into Ohinewai				✓	2033 ✓	2030
Reconductoring of Otahuhu–Whakamaru A&B line south of Ohinewai				✓	2033 ✓	2030
1x100 Mvar ALB capacitor (220 kV)		✓		✓	✓	2031
1x100 Mvar PEN capacitor		✓		✓	✓	2031
1x100 Mvar HEN capacitor (220 kV)		✓		✓	✓	2032
2x75 Mvar OHW capacitor (220 kV)		✓				2032
1x100 Mvar ALB capacitor (220 kV)			✓			2032
1x100 Mvar PEN capacitor (220 kV)			✓			2032
1x100 Mvar HEN capacitor (220 kV)			✓			2033
2x75 Mvar OHW capacitor (220 kV)				✓	✓	2032
1x100 Mvar DRY capacitor (220 kV)				✓		2033
1x100 Mvar WKM capacitor (220 kV)				✓		2033
Tee connection PAK-BHL-WKN at OHW		✓				2033

Note: Investments planned beyond 2033 are not included in this table.

A2 Common modelled projects

These modelled projects are applied to all transmission options.

A2.1 Hobson St – Penrose Series Reactor

The Penrose series reactor is presently bypassed. From 2027 the bypass switch is modelled as open. This change is a modelled project common to all development plans, not a committed project. When this occurs, additional developments will be required to alter the power flows in the parallel 110 kV Vector network. This network is presently modelled as a HOB220 and PEN110 load. The sharing between these loads may alter as the parallel path is assumed to be split with a second 220/110 kV transformer installed at Hobson St to provide security to the load there. However, the impact of this change is likely to have a lesser impact on the power flows into the WUNI region, so no change to the model is required.

Table 8: Penrose reactor line upgrade or new line

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HOB-PEN-1	0.10	0.97	899	915	899	2024	220
HOB-PEN-1	0.10	18.97	572	572	572	2027	220

A2.2 Hautapu GXP+VLR

The OTA-WKM 1 and 2 circuits will be bussed at the new GXP, Hautapu. The new configuration forms a three-terminal circuit, and in the event of an outage on either the northern or southern circuits at Hautapu, the corresponding southern or northern circuit will also trip.

Table 9: Decommissioned Lines

Line Name	Date
OTA-WKM-1	2025
OTA-WKM-2	2025

Table 10: Line upgrade or new lines for Hautapu GXP

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.62	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220

A2.3 Bombay 110 kV circuits

Currently, both BOB–HAM–1 and ARI–BOB–1 circuits are out of service. It is intended to dismantle BOB–HAM–1 and bus ARI–BOB–1 at Hamilton and dismantle the section between BOB and HAM.

Table 11: Decommissioned Lines

Line Name	Date
BOB-HAM-1	2027
ARI-BOB-1	2027

Table 12: Line upgrade or new line for Bombay

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
ARI-HAM-3	10.31	19.69	50.6	61.9	56.5	2027	110

A3 Network modification

A3.1 Option 0 (base case): existing grid

SDDP grid data was updated early 2024. This update also included future committed projects.

There is no grid modification in Option 0. The assumption of all options as presented in Table 7.

A3.2 Option 1: 16.93 Ohm series compensation, Ohinewai Tee

In this option, 2×16.93 series capacitors will be added into BHL-PAK-WKN at Hangawera Road and both BHL-WKN circuits will be connected into OHW as Tee connection using duplex Zebra 75^{0}C. The new configuration has been shown in Figure 11.

Table 13: Option 1 – line upgrade or new line

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	35.36	1354.3	1490.3	1424.4	2030	220
OHT-WKN-1 and 2 (Ohinewai Tee Connection)	1.76	16.63	1354.3	1490.3	1424.4	2033	220
BHL-OHT-1 and 2 (Ohinewai Tee Connection)	0.98	18.73	1354.3	1490.3	1424.4	2033	220

OHT-OHW- 1 and 2 (duplex Zebra 75°C)	0.03	0.31	709.5	780.8	746.1	2033	220
HTU-WKM 1 (series reactor)	6.35	37.51	363.5	390.2	372.3	2044	220
HTU-WKM-2 (series reactor)	6.38	37.63	363.5	390.2	372.3	2044	220

Table 14: Decommissioned Lines

Line Name	Date
BHL-WKN-1	2033
BHL-WKN-2	2033

The static and dynamic reactive plants will be added to WUNI based on Table 7.

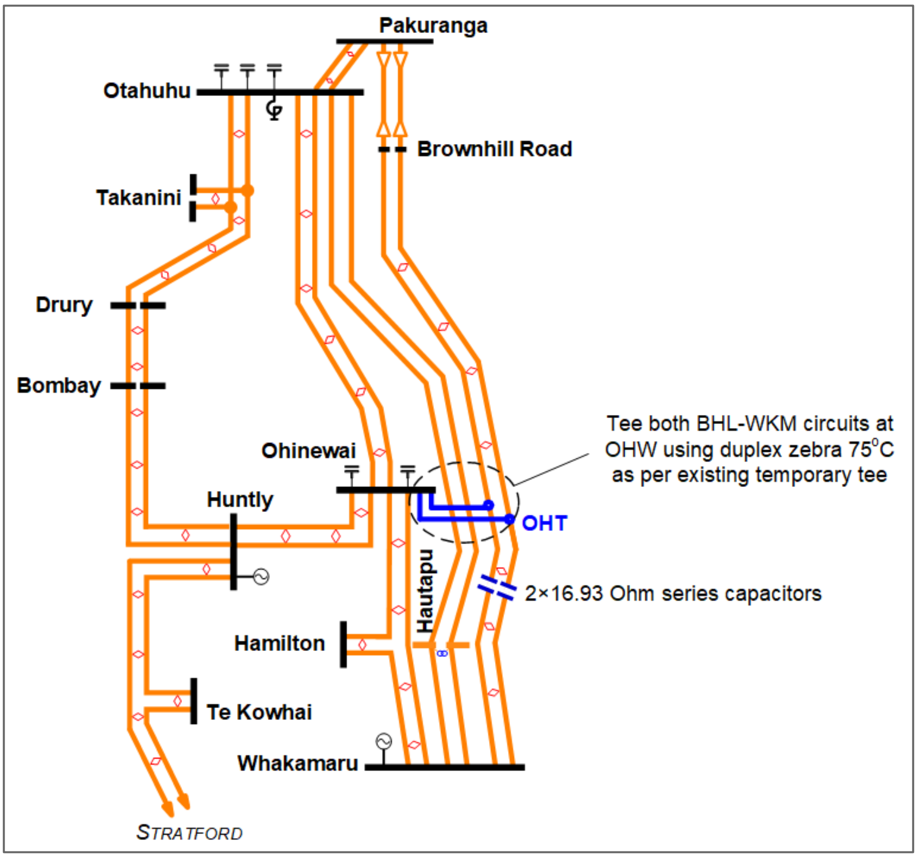

Figure 11: The grid configuration of Option 1 to 2033

A3.3 Option 2: 26.15 Ohm series compensation, BHL-OTA cable

In this option, 2×26.15 series capacitors will be added into BHL-PAK-WKN at Hangawera Road on both BHL-WKN circuits in 2030.

Also, to prevent overloading of BHL-PAK cables while increasing the compensation level, 220 kV Brownhill bus and 220 kV Brownhill-Otahuhu cable shall be built in 2030. The new configuration has been shown in Figure 12.

Table 15: Option 2 – Line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	26.14	1354.3	1490.3	1424.4	2030	220
BHL-OTA cable	0.10	1.79	768.2	808.2	768.2	2030	220
HTU-WKM 1 (series reactor)	6.35	33.51	363.5	390.2	372.3	2051	220
HTU-WKM-2 (series reactor)	6.38	33.63	363.5	390.2	372.3	2051	220
BHL-PAK-1 (series reactor)	0.10	4.9	768.2	808.2	768.2	2053	220
BHL-PAK-2 (series reactor)	0.10	4.92	768.2	808.2	768.2	2053	220
BHL-OTA-1 (series reactor)	0.10	4.79	768.2	808.2	768.2	2053	220

The static and dynamic reactive plants will be added to WUNI based on Table 7.

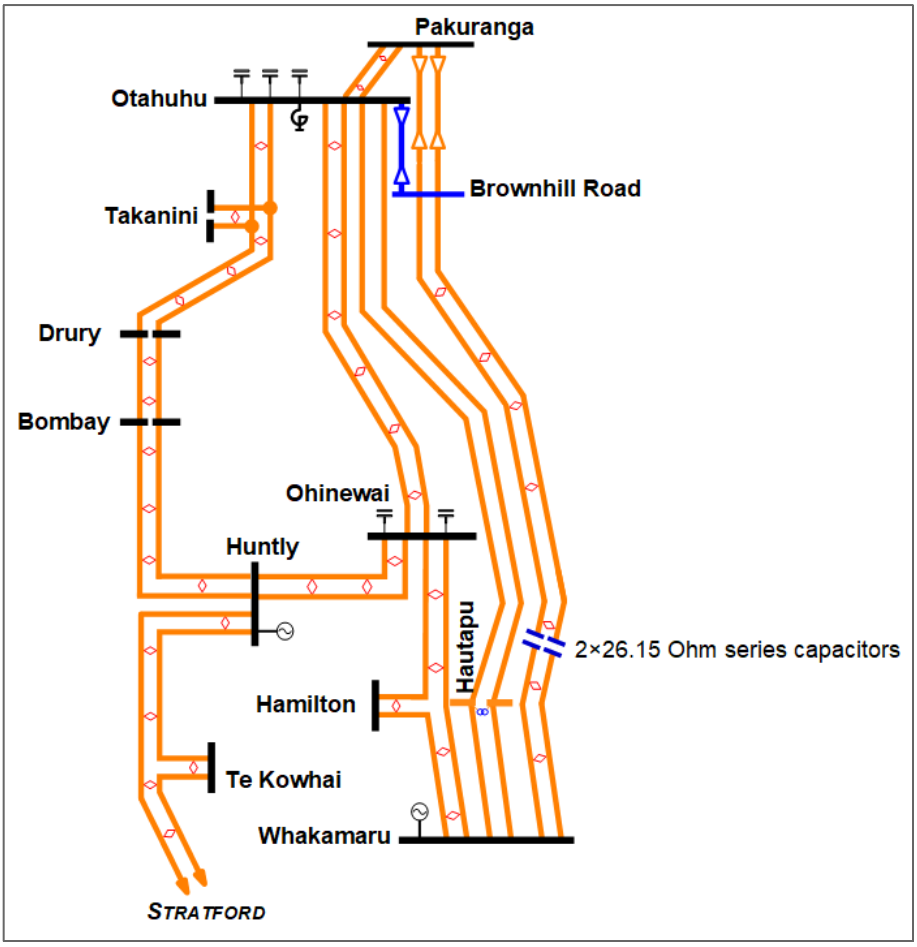

Figure 12: The grid configuration of Option 2 to 2033

A3.4 Option 3: Otahuhu–Whakamaru duplexing

This option includes the following investments in 2030:

- Duplexing the Otahuhu–Whakamaru A&B lines south of Ohinewai
- Connecting the Otahuhu–Whakamaru A&B lines to Ohinewai.

The new 220 kV configuration has been shown in Figure 13.

Table 16: Option 3 – 220 kV line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2030	220
HTU-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2030	220

OHW-OTA-3	6.29	30.51	368.1	362.4	366.4	2030	220
OHW-OTA-4	6.29	30.57	368.1	362.4	366.4	2030	220
OHW-OTA-3 (series reactor)	6.29	33.51	362.4	370.4	368.1	2038	220
OHW-OTA-4 (series reactor)	6.29	33.57	362.4	370.4	368.1	2038	220

Table 17: Decommissioned Lines

Line Name	Date
HTU-OTA-1	2030
HTU-OTA-2	2030

The static and dynamic reactive plants will be added to WUNI based on Table 7.

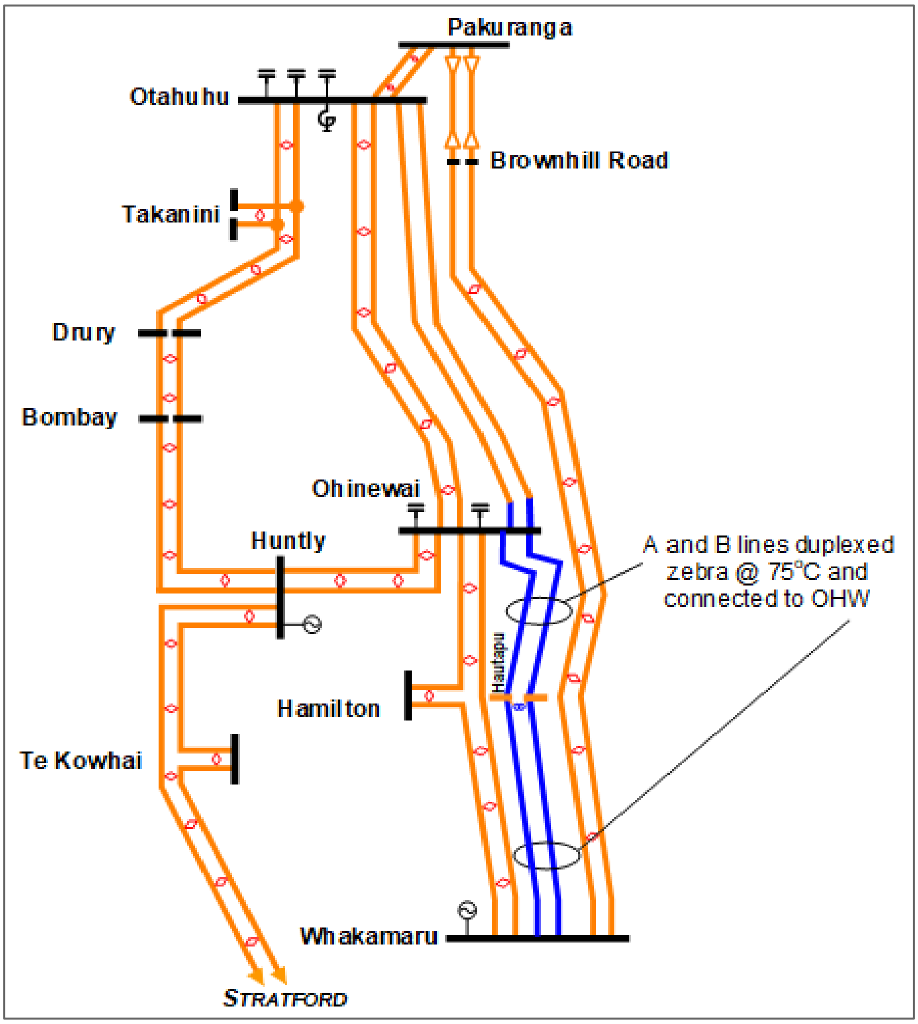

Figure 13: The Grid configuration of Option 3 to 2033

A3.5 Option 4: 16.93 Ohm series compensation, Otahuhu–Whakamaru duplexing

This option includes the following investments in 2030:

- Adding 2×16.93 series capacitors into BHL-PAK-WKN at Hangawera Road in 2030
- Duplexing the Otahuhu–Whakamaru A&B lines south of Ohinewai in 2033
- Connecting the Otahuhu–Whakamaru A&B lines to Ohinewai in 2033

The new 220 kV configuration has been shown in Figure 14.

Table 18: Option 4 – 220 kV line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	35.36	1354.3	1490.3	1424.4	2030	220
HTU-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2033	220
HTU-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2033	220
OHW-OTA-3	6.29	30.51	362.4	370.4	368.1	2033	220
OHW-OTA-4	6.29	30.57	362.4	370.4	368.1	2033	220

Table 19: Decommissioned Lines

Line Name	Date
HTU-OTA-1	2033
HTU-OTA-2	2033

The static and dynamic reactive plants will be added to WUNI based on Table 7.

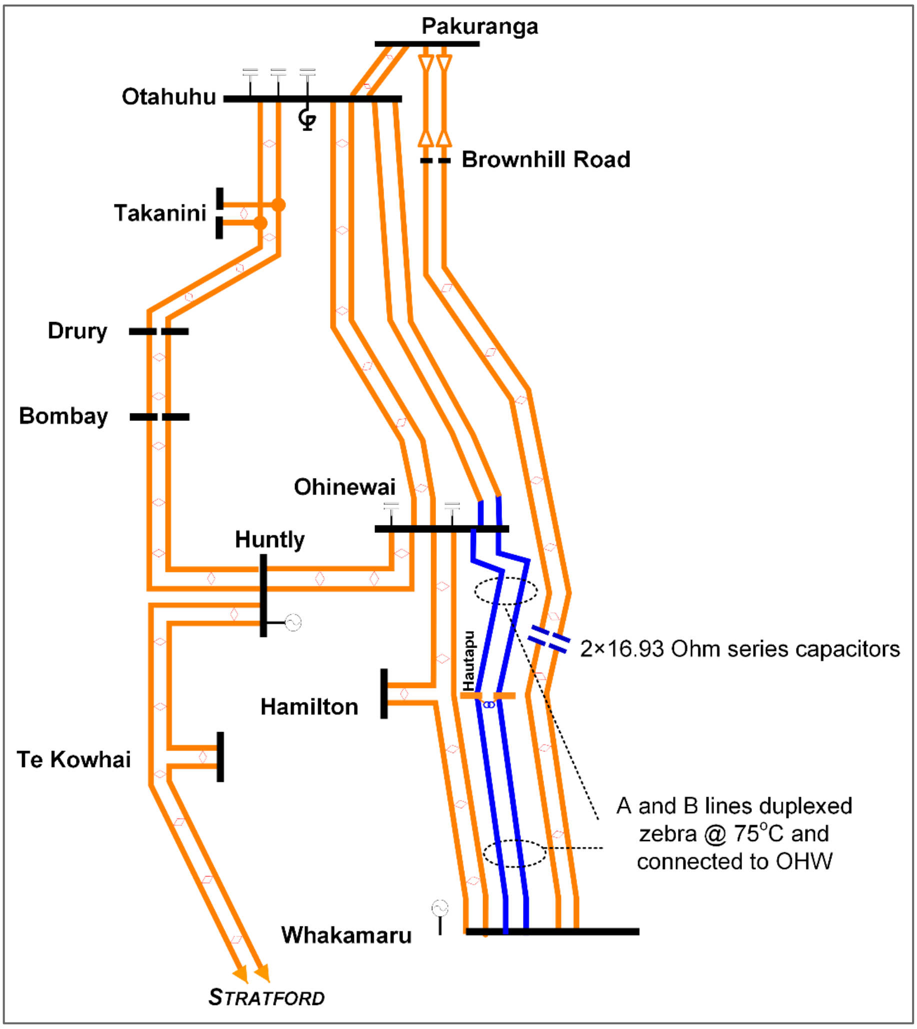

Figure 14: The Grid configuration of Option 4 to 2033

A4 Transmission constraints

The economic calculations for WUNI2 project use two scenarios:

1. Existing Grid (for counterfactual study) – Option 0 (Base case)
2. Short-listed transmission options- Options 1, 2, 3 and 4

A4.1 Option 0 (counterfactual) – Base case

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A group constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered. The coefficients for the new generation at Huntly could also be applied to the Rankine units for the period before 2030. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) should be included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-PAK-WKN-1 contingency equation: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.21*E3p + 0.34 * HLY_{Gen}^{new} ≤ 2951 MW
HLY-UN5 contingency equation: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.14*E3p +0.25 * HLY_{Gen}^{new}≤ 3233 MW

Table 20: Thermal contingency for Option 0

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	TMN-TWH-1	HTU-WKM-1, HTU-OTA-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1	
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1	

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton-Whakamaru 1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai-Whakamaru 1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu-Otahuhu 1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu-Whakamaru 1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

A4.2 Option 1

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A group constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered for 2030 and 2033. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) should be included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-OHT-WKN-1 contingency equation-2030: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.18*E3p +0.28 * HLY_{Gen}^{new}≤ 3159 MW
BHL-OHT-WKN-1 contingency equation-2033: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*OHT-WKN-1 + -1* OHT-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.21*E3p +0.28 * HLY_{Gen}^{new}≤ 3440 MW

Table 21: Thermal contingency for Option 1-2030

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4
BHL-WKN-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1

Table 22: Thermal contingency for Option 1-2033

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	OHT-OHW-1, OHT-OHW-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	OHT-OHW 1, OHT-OHW-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1

Since SDDP is not capable of modelling three-terminal circuit contingencies, the following constraint equations can be used as an alternative to represent the thermal contingency in table above:

Contingency: BHL-OHT-WKM-1 or 2 and Constraint: HTU-WKM-1 or 2

- Winter:

  -1* HTU-WKM-1 - 0.11*OHT-WKN-1 ≤ 371 MW

- Shoulder:

  -1* HTU-WKM-1 - 0.11*OHT-WKN-1 ≤ 357 MW

- Summer:

  -1* HTU-WKM-1 - 0.11*OHT-WKN-1 ≤ 353 MW

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton-Whakamaru 1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai-Whakamaru 1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu-Otahuhu 1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu-Whakamaru 1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

The above constraint equations apply for the investment period (until 2033). There are incremental developments particularly to manage voltage stability limits over the years beyond 2033 to increase the transfer limit into the region. These changes cannot be represented in a DC load flow without using constraint equations. To prevent the perception of precision in these later developments higher level constraints are calculated. The format of the equations is the same as above with only the generating unit coefficients and RHS values presented in the table below.

Table 23: Option 1 Constraint equations beyond 2033

Year	Contingency	E3p coefficient	HLY_{Gen}^{new} coefficient	RHS
2034	PAK-OHW-WKN	0.2	0.3	3545
2035	PAK-OHW-WKN	0.2	0.3	3637
2038	PAK-OHW-WKN	0.2	0.3	3730
2044	PAK-OHW-WKN	0.2	0.3	3797
2051	PAK-OHW-WKN	0.2	0.3	3836
2053	PAK-OHW-WKN	0.2	0.3	3866

In addition, the introduction of series reactors on the Hautapu-Whakamaru circuits will reduce the proportion of power that will be transferred from the OHT-WKN circuit to the HTU-WKM circuits for a contingency. The coefficient for the Hautapu-Whakamaru circuit will change as a result. From 2053 the following thermal constraint equation should be applied:

Contingency: PAK-OHT-WKM-1 or 2 and Constraint: HTU-WKM-1 or 2

- Winter:

  -1* HTU-WKM-1 - 0.1*OHT-WKN-1 ≤ 371 MW

- Shoulder:

  -1* HTU-WKM-1 - 0.1*OHT-WKN-1 ≤ 357 MW

- Summer:

  -1* HTU-WKM-1 - 0.1*OHT-WKN-1 ≤ 353 MW

A4.3 Option 2

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A group constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered for 2030 and 2033. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) should be included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-WKN-1 contingency equation-2030: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.17*E3p +0.29 * HLY_{Gen}^{new} ≤ 3285 MW
BHL-WKN-1 contingency equation-2033: -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.15*E3p +0.25 * HLY_{Gen}^{new} ≤ 3438 MW

Table 24: Thermal contingency for Option 2

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1	
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	BHL-OTA-1	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	BHL-OTA-1	TMN-TWH-1
BHL-PAK-1	BHL-PAK-2	BHL-OTA-1	HTU-WKM-1, HTU-OTA-1		
BHL-OTA-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1			

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton-Whakamaru 1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai-Whakamaru 1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu-Otahuhu 1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu-Whakamaru 1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

The above constraint equations apply for the investment period (until 2033). There are incremental developments, particularly to manage voltage stability limits, over the years beyond 2033 to increase the transfer limit into the region. These changes cannot be represented in a DC load flow without using constraint equations. To prevent the perception of precision in these later developments higher level constraints are calculated. The format of the equations is the same as above with only the generating unit coefficients and RHS values presented in the table below.

Table 25: Option 2 Constraint equations beyond 2033

Year	Contingency	E3p coefficient	HLY_{Gen}^{new} coefficient	RHS
2034	BHL-WKN	0.2	0.3	3524
2035	BHL-WKN	0.2	0.3	3607
2038	BHL -WKN	0.2	0.3	3677
2045	BHL -WKN	0.2	0.3	3764
2051	BHL -WKN	0.2	0.3	3810
2053	BHL -WKN	0.2	0.3	3865

A4.4 Option 3

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A group constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered for 2030 and 2033. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) should be included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-WKN-1 contingency equation-2030:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.23*E3p + 0.31 * HLY_{Gen}^{new} ≤ 3228 MW

HLY-UN5 contingency equation-2030:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.11*E3p +0.26 * HLY_{Gen}^{new}≤ 3496 MW

BHL-WKN-1 contingency equation-2033:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.19*E3p +0.25 * HLY_{Gen}^{new} ≤ 3510 MW

HLY-UN5 contingency equation-2033:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.13*E3p +0.22 * HLY_{Gen}^{new} ≤ 3809 MW

Table 26: Thermal contingency for Option 3 - (2030 and 2033)

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	OHW-OTA-3	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	OHW-OTA-3	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	OHW-OTA-3	TMN-TWH-1
OHW-OTA-1	OHW-OTA-3	OHW-OTA-4	OHW-OTA-2		

Since SDDP is not capable of modelling three-terminal circuit contingencies, the following constraint equations can be used as an alternative to represent the thermal contingency. Regarding thermal limits, there is no significant difference between 2030 and 2033.

Contingency: HTU-OHW-WKM-1 or 2 and Constraint: HAM-WKM-1

- Winter:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 750 MW

- Shoulder:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 744 MW

- Summer:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 729 MW

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton-Whakamaru 1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai-Whakamaru 1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Ohinewai - Otahuhu 3 & 4 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)

The above constraint equations apply for the investment period (until 2033). There are incremental developments, particularly to manage voltage stability limits, over the years beyond 2033 to increase the transfer limit into the region. These changes cannot be represented in a DC load flow without using constraint equations. To prevent the perception of precision in these later developments higher level constraints are calculated. The format of the equations is the same as above with only the generating unit coefficients and RHS values presented in the table below.

Table 27: Option 3 Constraint equations beyond 2033

Year	Contingency	E3p coefficient	HLY_{Gen}^{new} coefficient	RHS
2034	PAK-BHL-WKN	0.2	0.3	3563
2034	HLY UN 5	1.1	0.25	3876
2035	PAK-BHL-WKN	0.2	0.3	3672
2035	HLY UN 5	1.1	0.25	3991
2040	PAK-BHL-WKN	0.2	0.3	3727
2040	HLY UN 5	1.1	0.25	4055
2044	PAK-BHL-WKN	0.2	0.3	3793
2044	HLY UN 5	1.1	0.25	4133
2049	PAK-BHL-WKN	0.2	0.3	3854
2049	HLY UN 5	1.1	0.25	4208
2052	PAK-BHL-WKN	0.2	0.3	3893
2052	HLY UN 5	1.1	0.25	4237
2054	PAK-BHL-WKN	0.2	0.3	3928
2054	HLY UN 5	1.1	0.25	4279

A4.5 Option 4

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A group constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered for 2030 and 2033. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) should be included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-WKN-1 contingency equation-2030:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.23*E3p + 0.31 * HLY_{Gen}^{new} ≤ 3228 MW

BHL-WKN-1 contingency equation-2033:

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.22*E3p +0.29 * HLY_{Gen}^{new} ≤ 3537 MW

Table 28: Thermal contingency for Option 4 - (2030 and 2033)

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	OHW-OTA-3	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	TMN-TWH-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	OHW-OTA-3	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	OHW-OTA-3	TMN-TWH-1
OHW-OTA-1	OHW-OTA-3	OHW-OTA-4	OHW-OTA-2		

Since SDDP is not capable of modelling three-terminal circuit contingencies, the following constraint equations can be used as an alternative to represent the thermal contingency. Regarding thermal limits, there is no significant difference between 2030 and 2033.

Contingency: HTU-OHW-WKM-1 or 2 and Constraint: HAM-WKM-1

- Winter:

  -1* HAM-WKM-1 - 0.21*HTU-WKM-1 ≤ 786 MW

- Shoulder:

  -1* HAM-WKM-1 - 0.21*HTU-WKM-1 ≤ 779 MW

- Summer:

  -1* HAM-WKM-1 - 0.21*HTU-WKM-1 ≤ 760 MW

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton-Whakamaru 1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai-Whakamaru 1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Ohinewai - Otahuhu 3 & 4 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)

The above constraint equations apply for the investment period (until 2033). There are incremental developments, particularly to manage voltage stability limits, over the years beyond 2033 to increase the transfer limit into the region. These changes cannot be represented in a DC load flow without using constraint equations. To prevent the perception of precision in these later developments higher level constraints are calculated. The format of the equations is the same as above with only the generating unit coefficients and RHS values presented in the table below.

Table 29: Option 4 Constraint equations beyond 2033

Year	Contingency	E3p coefficient	HLY_{Gen}^{new} coefficient	RHS
2035	PAK-BHL-WKN	0.2	0.3	3622
2038	PAK-BHL-WKN	0.2	0.3	3717
2047	PAK-BHL-WKN	0.2	0.3	3794
2052	PAK-BHL-WKN	0.2	0.3	3879

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