TPM consultation:

Brownhill – Pakuranga B Cable Joint Refurbishment final starting BBI customer allocations

Final record of application of the price quantity method

Date: 10 September 2026

Contents

1 Introduction

1. This final record of application of the price-quantity method (**record**) presents our application of the transmission pricing methodology's (**TPM's**)[1] price-quantity method to calculate the Brownhill-Pakuranga B Cable Joint Refurbishment Benefit-based Investment's (**Brownhill Cable Joint Refurbishment BBI's**) final starting BBI customer allocations. From here on we refer to the starting BBI customer allocations as the starting allocations.

2. We have generally used the input assumptions in chapter 2 of the BBC assumptions book[2] (**assumptions book**) and followed the processes in section 3.2 and 3.3 of chapter 3 to calculate the Brownhill Cable Joint Refurbishment BBI's final starting allocations. Where we have used different input assumptions from the assumptions book, we have stated them in this record.

3. Except as otherwise stated in this record, the assumptions and other inputs we used for modelling the benefits of the Brownhill Cable Joint Refurbishment BBI are either consistent with the investment test for the Brownhill Cable Joint Refurbishment or had no equivalent in that investment test.[3]

4. We have defined some terms in this record for convenience. Please also reference the glossary in the assumptions book. Other terms used in this record have the meanings given to them in the TPM. All clause references are to clauses in the TPM, unless stated otherwise.

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1 The TPM is in Schedule 12.4 of Part 12 of the Electricity Industry Participation Code 2010 (Code) - [Part 12—Transport | Electricity Authority]().

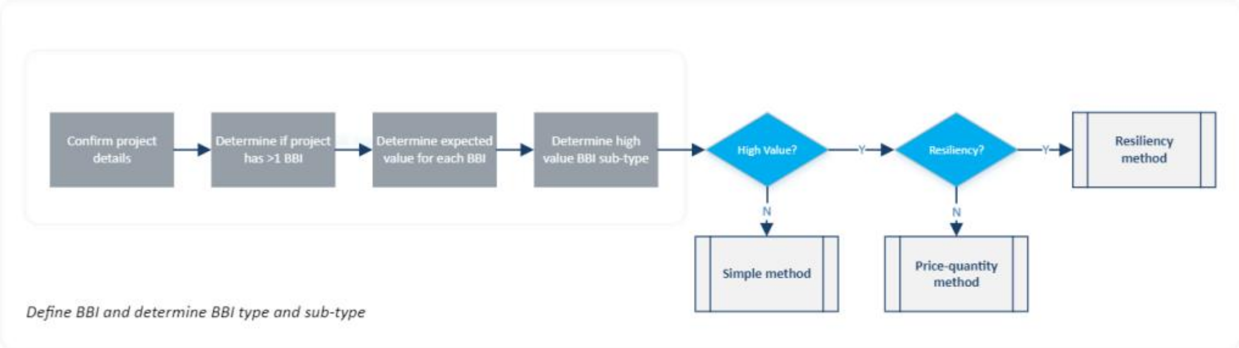
2 [TPM Determination: BBC Assumptions Book v3.0](), 30 June 2026.

3 The Brownhill Cable Joint Refurbishment investment was a high-value base capex project, so the investment test was under clause 3.2.1 of the Capex IM (footnote 4).

2 Define BBI and determine BBI type and sub-type

5. This section describes our application of the stages set out in section 3.2 of the assumptions book (and as shown in Figure 1).

Figure 1: Define BBI and determine BBI type and sub-type



2.1 Confirm project details

6. The Pakuranga to Whakamaru transmission line is part of the transmission network supplying electricity to the Auckland region. This line comprises two circuits – PAK-WKM-1 and PAK-WKM-2 - which together form a key component of the eastern Auckland supply corridor. Each circuit includes underground high-voltage cables (denoted A and B) connecting the Brownhill and Pakuranga substations.

7. The PAK-WKM 1 and 2 circuits were commissioned in 2012 as part of the North Island Grid Upgrade (**NIGU**) project to strengthen supply into Auckland and improve security of supply to the region. Together, the two circuits provide redundancy and support N-1 security for load supplied in the area.

8. The Brownhill-Pakuranga B cable has 45 cable joints. The condition of these cable joints required investment to reduce failure risk and provide at least another 20 years of service. The Brownhill Cable Joint Refurbishment involved replacing all existing joints on the Brownhill-Pakuranga B cable with new joints.

9. The cable joints on the Brownhill-Pakuranga A cable do not exhibit the same condition issues, do not present the same failure risk, and therefore do not require replacement.

10. The Brownhill Cable Joint Refurbishment BBI is expected to have market benefits because it maintains N-1 security of transmission between the Central North Island and the Waikato and Upper North Island, which affects prices and dispatch quantities in the wholesale electricity market. We do not expect the Brownhill Cable Joint Refurbishment BBI to have material reliability benefits (see section 5.1) or ancillary service benefits (see section 6.1). We have not identified any other benefits that meet the requirements of clause 55(2) (see section 7.1).

11. The fully commissioned asset value of the Brownhill Cable Joint Refurbishment BBI is expected to be $53.85m. There will be no transmission alternative opex associated with the Brownhill Cable Joint Refurbishment.

12. The Brownhill Cable Joint Refurbishment BBI was commissioned during financial year (**FY**) 2025/26. The Brownhill Cable Joint Refurbishment BBI is therefore a post-2019 BBI.

13. All of the principal benefits of the Brownhill Cable Joint Refurbishment BBI are expected to be released by the assets commissioned before the end of FY 2025/26. We have determined the Brownhill Cable Joint Refurbishment BBI's expected effective full commissioning date to be 30 June 2026.

2.2 Determine if project has >1 BBI

14. We consider the Brownhill Cable Joint Refurbishment to be one BBI because:

   a. the investment was undertaken as a single project committed at the same time

   a. the investment is in the same electrical region of the grid (i.e. the transmission corridor between Brownhill and Pakuranga substations within the Auckland region), and

   b. the investment addresses a single investment need, being to refurbish cable joints on the Brownhill-Pakuranga B cable section of the PAK-WHM 2 circuit to minimise the risk of unplanned outages of the PAK-WKM 2 circuit due to an unplanned failure of those cable joints.

2.3 Determine expected value of each BBI

15. The fully commissioned asset value of the Brownhill Cable Joint Refurbishment BBI is expected to be $53.85m. There will be no transmission alternative opex associated with the Brownhill Cable Joint Refurbishment BBI.

16. As the sum of the Brownhill Cable Joint Refurbishment BBI's fully commissioned asset value and transmission alternative opex is greater than the base capex threshold specified in the Transpower Capital Expenditure Input Methodology (**Capex IM**)[4], the Brownhill Cable Joint Refurbishment BBI is a high-value post-2019 BBI. Therefore, Transpower is required to use one of the standard methods in the TPM (price-quantity or resiliency) to calculate the BBI's starting allocations.

2.4 Determine high-value BBI sub-type

17. The Brownhill Cable Joint Refurbishment BBI – the Brownhill Cable Joint Refurbishment's investment need was not primarily attributable to mitigating a risk of cascade failure or a high impact low probability (**HILP**) event.

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[4] At the time of the investment test for the Brownhill Cable Joint Refurbishment, the base capex threshold was $20m. This has since increased to $30m. The fully commissioned asset value of the Brownhill Cable Joint Refurbishment BBI is above both thresholds. The latest version of the Capex IM is here: https://www.comcom.govt.nz/assets/Uploads/Transpower-Capital-Expenditure-Input-Methodology-consolidated-as-at-1-April-2025-4-June-2026.pdf.

18. Therefore, the Brownhill Cable Joint Refurbishment BBI is not a resiliency BBI under the TPM and we are required to apply the price-quantity method to calculate its starting allocations (clause 43(2)).

2.5 Expenditure on existing BBIs

19. Under clause 37(2), we are required to treat the Brownhill Cable Joint Refurbishment as a separate post-2019 BBI because it:

    a. is a refurbishment investment

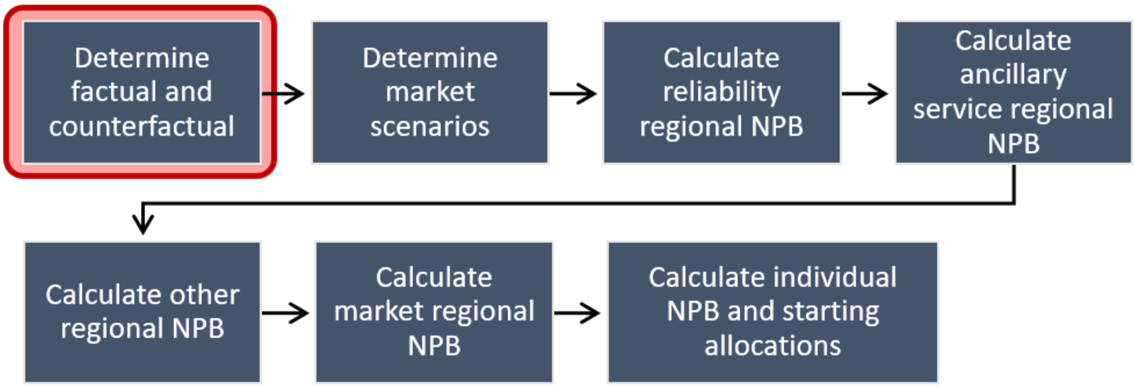
    b. is in respect of an Appendix A BBI (the NIGU Appendix A BBI), and

    c. is not an exempt post-2019 investment (it was commissioned after 30 June 2021) (clause 37(5)).

3 Determine factual and counterfactual

20. This section describes our application of the stages set out in section 3.3.1 of the assumptions book (and as shown in Figure 2).

Figure 2: Determine factual and counterfactual



3.1 Determine factual

21. The factual is the grid state after the Brownhill Cable Joint Refurbishment BBI has been fully commissioned.

3.2 Determine investment type and counterfactual

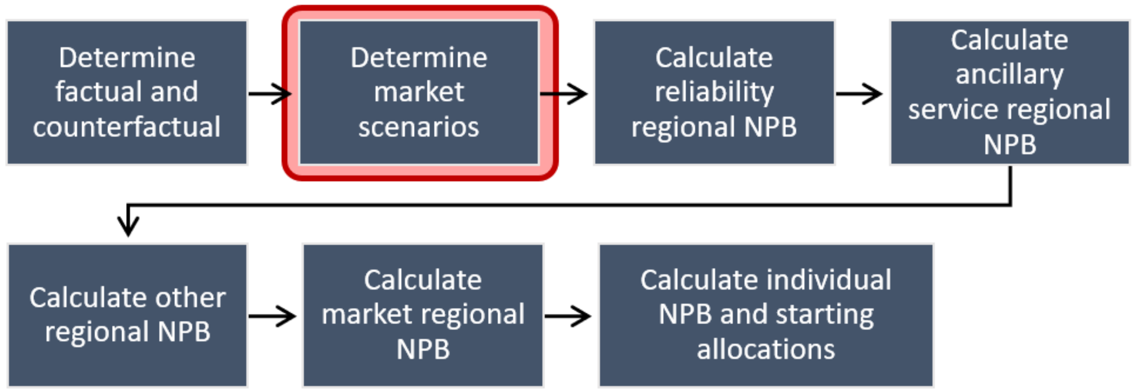
22. The Brownhill Cable Joint Refurbishment is a refurbishment investment.

23. We have used the default counterfactual that applies to refurbishment investments under clause 45(2)(c). Under this counterfactual, the existing grid asset would remain in service without refurbishment until it reaches its replacement state, after which they would be immediately decommissioned and not replaced. In this case, this corresponds to decommissioning the Brownhill-Pakuranga B cable section, and therefore the PAK-WKM 2 circuit, following a cable joint failure, from January 2026.[5]

4 Determine market scenarios

24. This section describes our application of the stages set out in section 3.3.2 of the assumptions book (and as shown in Figure 3).

Figure 3: Determine market scenarios



4.1 Obtain market scenarios used in consultation

25. The investment test for the Brownhill Cable Joint Refurbishment did not use market scenarios because the investment need was condition-based. Had market scenarios been used in the investment test, we would have used MBIE's 2019 electricity demand and generation scenarios (**EDGS**), which were the most recent EDGS at the time. The 2019 EDGS have since been superseded by the 2024 EDGS.

26. We used the 2024 EDGS assumptions to calculate the starting allocations for the Brownhill Cable Joint Refurbishment BBI because we consider they will produce starting allocations that are broadly proportionate to expected positive net private benefit (**EPNPB**).

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5 The cable joints reached replacement criteria before 1 January 2026, which itself is before the start of the standard method calculation period for the Brownhill Cable Joint Refurbishment BBI (1 January 2027).

4.2 Obtain market scenarios from the assumptions book

27. We used the market scenarios in chapter 2 of the assumptions book to calculate the final starting allocations for the Brownhill Cable Joint Refurbishment BBI. The assumptions book includes five scenarios based on MBIE's 2024 EDGS:

    a. Reference

    b. Growth

    c. Constraint

    d. Environmental

    e. Innovation.

28. Chapter 2 of the assumptions book contains most of the modelling inputs that make up these market scenarios. Additional modelling inputs are described in section 8.3 below.

4.3 Determine if different market scenarios are required

29. We did not depart from the market scenarios in chapter 2 of the assumptions book. We consider those market scenarios will produce starting allocations for the Brownhill Cable Joint Refurbishment BBI that are broadly proportionate to EPNPB.

4.4 Determine if sensitivities should be modelled

30. A sensitivity is a market scenario included in the modelling to specifically test (and include) the influence of one discrete change to our input assumptions occurring independently of other input assumptions.

31. We assessed a number of possible sensitivities against the criteria in section 3.3.2.6 of the assumptions book.

32. Based on this assessment, we have not modelled any sensitivities for the Brownhill Cable Joint Refurbishment BBI.

33. Each market scenario is applied to the factual and counterfactual. Because the permanent decommissioning of the Brownhill-Pakuranga B cable following a cable joint failure is unlikely to change or influence generation investment decisions, we chose not to model different generation expansion market scenarios in the factual and counterfactual (clause 46(2)).

34. We note that clause 46(3) does not apply to the Brownhill Cable Joint Refurbishment BBI because there are no market scenarios in which a customer ceases to exist.

4.5 Determine the weightings to be applied

35. The assumptions book does not contain weightings for the market scenarios and so we chose weightings we consider will produce starting allocations that are broadly proportionate to EPNPB.

36. As we have no reliable information to suggest one market scenario is more likely than another, we have given each scenario an equal weighting.

4.6 Hydro, load, and generation expansion variations

37. The market scenarios are consistent with clause 46(1) because they include the following variations:

    a. load growth across the market scenarios (see section 8.3.3)

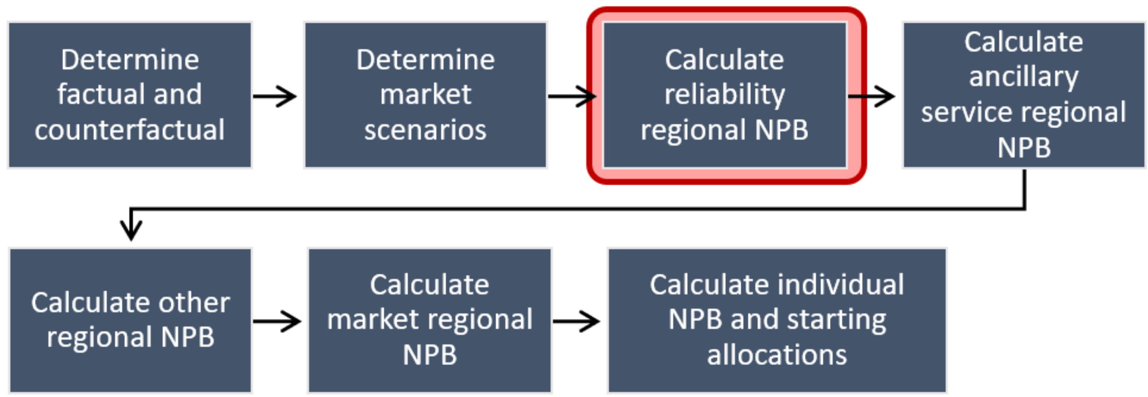
i. generation expansion, by using a range of different generation expansion forecasts resulting from different demand forecasts and the generation cost declines specified in the assumptions book (see section 8.3.4), and

    b. hydrology, by using the 50 synthetically generated inflow sequences based on the historical hydro inflow sequences (across 90 inflow years from 1932 – 2021) (section 2.3.4.4 of the assumptions book).

5 Calculate reliability regional NPB

38. This section describes our application of the stages set out in section 3.3.3 of the assumptions book (and as shown in Figure 4).

Figure 4: Calculate reliability regional NPB



5.1 Determine if there are reliability benefits

39. While the Brownhill Cable Joint Refurbishment BBI is expected to improve asset condition and reduce the likelihood or duration of potential interruptions to supply, we consider that the reliability benefits relative to the counterfactual are small. Under N-1 security conditions, pre-contingency constraints are applied by the system operator to maintain security such that loss of load is unlikely under credible single-contingency events.

40. Under these conditions, the primary impact of the counterfactual is expected to occur through changes in dispatch, prices and quantities in the wholesale electricity market, as constraints bind pre-contingency to maintain N-1 security. These effects are captured through market benefit modelling.

41. Any reliability benefits would therefore arise primarily from low-probability events (for example, multiple simultaneous outages or N-security conditions such as when circuits are out of service for planned maintenance).

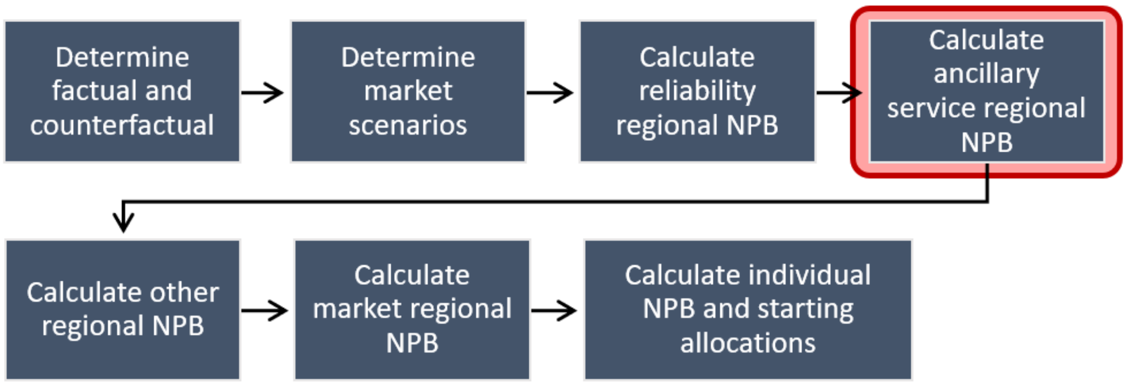
42. Given the low likelihood of such events, the expected value of post-contingency reliability benefits (i.e. the value of post contingency lost load) is small.

43. Accordingly, we do not consider the Brownhill Cable Joint Refurbishment BBI to be a reliability BBI and we have not calculated reliability regional NPB for the BBI under clause 54.

6 Calculate ancillary service regional NPB

44. This section describes our application of the stages set out in section 3.3.4 of the assumptions book (and as shown in Figure 5).

Figure 5: Calculate ancillary service regional NPB



6.1 Determine if there are ancillary service benefits

45. We do not expect the Brownhill Cable Joint Refurbishment BBI to materially reduce the cost allocated to our customers of any specified ancillary service (through changes in price or quantity) relative to the counterfactual. In general, we only expect a BBI to reduce the cost of ancillary services if it provides or enables ancillary services in the market (e.g. HVDC frequency

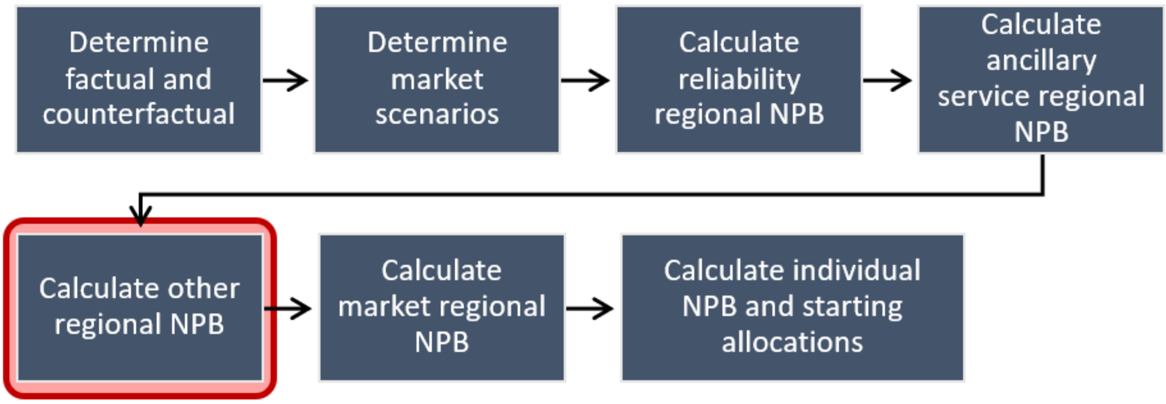
keeping control),[6] or if it enables another ancillary service provider to be dispatched (e.g. a transmission project that enabled a grid-scale battery to connect to the grid and provide instantaneous reserve). The Brownhill Cable Joint Refurbishment BBI does not provide or enable ancillary services as is related to asset condition on the AC network.

46. Accordingly, we do not consider the Brownhill Cable Joint Refurbishment BBI to be an ancillary service BBI and we have not calculated ancillary service regional NPB under clause 53.

7 Calculate other regional NPB

47. This section describes our application of the stages set out in section 3.3.5 of the assumptions book (and as shown in Figure 6).

Figure 6: Calculate other regional NPB



7.1 Determine if there are other benefits

48. We do not expect the Brownhill Cable Joint Refurbishment BBI to have any material or measurable benefits other than market benefits.

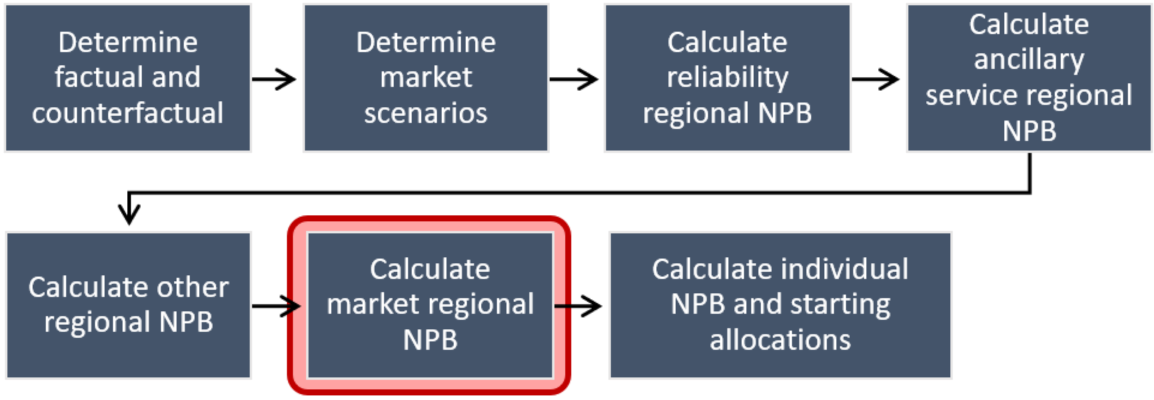
49. Accordingly, we have not calculated other regional NPB for the Brownhill Cable Joint Refurbishment BBI under clause 55.

6 Frequency keeping control and roundpower information | Transpower

8 Calculate market regional NPB

50. This section describes our application of the stages set out in section 3.3.6 of the assumptions book (and as shown in Figure 7).

Figure 7: Calculate market regional NPB



8.1 Determine if there are market benefits

51. We expect the Brownhill Cable Joint Refurbishment BBI to have a material impact on prices and/or dispatch quantities in the wholesale electricity market because it significantly alleviates constraints that would apply in the wholesale electricity market in the counterfactual.

52. Accordingly, we consider the Brownhill Cable Joint Refurbishment BBI to be a market BBI and we have calculated market regional NPB as set out below.

8.2 Determine modelled constraints and investment grids

53. We applied section 3.3.6.4 of the assumptions book to determine the modelled constraints for the Brownhill Cable Joint Refurbishment BBI. This is part of determining the investment grids for the BBI under clause 49(2).

54. There are two methods for modelling security constraints in the market model:

    a. by simulating selected circuit contingencies (outages) and ensuring that the lines remaining in service do not exceed their thermal ratings, and

    b. by including a constraint in the model that forces a sum of flows on selected circuits and generation from selected generators to satisfy some limit reflecting a security constraint developed through AC powerflow modelling.

55. Typically, the first approach is used to capture the impact of thermal constraints and the second approach is used to capture the impact of voltage stability constraints which cannot be captured in SDDP's DC load-flow model.

56. Table 1 shows the list of circuit contingencies that were simulated in the market model and the list of circuits monitored to ensure that they do not overload following a circuit contingency or when all circuits are in service.

Table 1. Security constraints used for the Brownhill Cable Joint Refurbishment BBI

Contingent circuits	Monitored circuits
BHL-WKN-1 HAM-WKM-1 OHW-WKM-1 OTA-WKM-1	BHL-WKN-1 BHL-WKN-2 HAM-WKM-1 OHW-WKM-1 OHW-OTA-1 OHW-OTA-2 OHW-OTA-3 OHW-OTA-4 BHL-PAK-1 BHL-PAK-2 HTT-WKM-1 HTT-WKM-2 HTT-OHW-1 HTT-OHW-2 TMN-TWH-1 HTT-OTA-1 HTT-OTA-2 HLY-SFD-1

57. In addition to the contingencies, the constraints shown in Table 2 and Table 3 were included in the model to capture voltage stability constraints and three-terminal circuits[7] in the counterfactual and factual cases, respectively.

Table 2: Constraints used for the counterfactual for the Brownhill Cable Joint Refurbishment BBI

Counterfactual
*BHL-WKN-1 contingency equation-**pre-2035**:* -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.17*E3p + 0.28 * $Rankine_{Gen} \leq$ 2658 MW
*HLY-UN5 contingency equation-**pre-2035**:*

[7] A three-terminal circuit is typically formed by three circuit sections connected at a common tee connection rather than a bus. A contingency on any one section disconnects all three sections simultaneously. This behaviour is not represented by the contingency modelling in the version of SDDP used for this analysis and is therefore modelled using circuit sum constraints.

Counterfactual
-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.17*E3p +0.24 * $Rankine_{Gen} \leq$ 3030 MW
*BHL-WKN-1 contingency equation-**2035 onwards**:* -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.2*E3p +0.28 * $Rankine_{Gen} \leq$ 3066 MW
*HLY-UN5 contingency equation-**2035 onwards**:* -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.15*E3p +0.24 * $Rankine_{Gen} \leq$ 3419 MW
HTU-OTA-WKM-1 contingency -1* HTU-WKM-2 - 0.19*HTU-WKM-1 ≤ 385/370/360 MW (Winter/Shoulder/Summer)

Table 3: Constraints used for the factual for the Brownhill Cable Joint Refurbishment BBI

Factual
*BHL-WKN-1 contingency equation-**pre-2035**:* -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 + 0.24 * $Rankine_{Gen}$ + 0.2 * NLD^{new}_{Gen} + 0.41 * WKT^{new}_{Gen} ≤ 2976 MW
*HLY-UN5 contingency equation-**pre-2035**:* -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 * $Rankine_{Gen}$ + 0.21* NLD^{new}_{Gen} + 0.42 * WKT^{new}_{Gen} ≤ 3255 MW
*BHL-WKN-1 contingency equation-**2035 onwards**:* -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 +0.25 * $Rankine_{Gen}$ + 0.17* NLD^{new}_{Gen} + 0.39 * WKT^{new}_{Gen} ≤ 3368 MW
*HLY-UN5 contingency equation-**2035 onwards**:* -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+ 1.12*E3p +0.26 * $Rankine_{Gen}$ + 0.19* NLD^{new}_{Gen} + 0.4 * WKT^{new}_{Gen} ≤ 3641 MW

Factual
HTU-OTA-WKM-1 contingency -1* HTU-WKM-2 - 0.16*HTU-WKM-1 ≤ 381/367/359 MW (Winter/Shoulder/Summer)

58. Therefore, the investment grids for the Brownhill Cable Joint Refurbishment BBI comprise:
    a. all existing branches and market nodes,
    b. the HVDC constraints and losses from sections 2.3.2.2 and 2.3.2.3 of the assumptions book,
    c. the above modelled contingencies and constraints in the counterfactual and in the factual, and
    d. future changes to the AC network detailed in section 8.3.4.

8.3 Include other market model inputs

59. As noted above, chapter 2 of the assumptions book contains most of the modelling inputs for the market scenarios we used for the Brownhill Cable Joint Refurbishment BBI (the assumptions book market scenarios).

60. We also used the following additional modelling inputs, applying section 3.3.6.5 of the assumptions book. These are either required by the TPM (in the case of the standard method calculation period) or chosen because we consider they will produce starting allocations that are broadly proportionate to EPNPB.

8.3.1 Standard method discount rate

61. We used a rate of 5% to discount expected market benefits and disbenefits (the standard method discount rate).

8.3.2 Standard method calculation period

62. The replacement cable joints are expected to have useful lives of greater than 20 years. Therefore, we used a 20-year standard method calculation period for the Brownhill Cable Joint Refurbishment BBI (the maximum possible standard method calculation period), beginning on 1 January 2027 – the first 1 January after the BBI's expected effective full commissioning date (30 June 2026).

63. We discounted all values to 2026. For the Brownhill Cable Joint Refurbishment BBI, 2026 is "year 0" in the present value calculation in clause 48(1) because the standard method calculation period starts in 2027.

8.3.3 Demand forecast

64. Our demand forecast is not specified in the assumptions book because it changes annually as we get new information from customers and consumers.

65. For the Brownhill Cable Joint Refurbishment BBI, we applied clause 43(5)(b) to use our most up to date demand forecast used in SDDP (our market model) and OptGen (our generation expansion tool). We consider using the most up to date demand reasonably available is most likely to produce starting allocations that are broadly proportionate to EPNPB.

8.3.4 AC Network modifications

66. The only difference between the counterfactual and factual network models is that one Whakamaru-Pakuranga circuit is decommissioned in the counterfactual to represent the decommissioning of the Brownhill-Pakuranga B cable. The following future AC network changes are common to both the factual and the counterfactual cases:

67. Penrose series reactor followed by new line

    - the Penrose series reactor is presently bypassed. From 2027 the bypass switch is modelled as open. This change is a modelled network change common to all development plans. The corresponding network model modifications are shown in Table 4.

Table 4: HOB-PEN-1 AC network modification

Line Name	R (%)	X (%)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HOB-PEN-1	0.02	0.2	899	915	899	2024	220
HOB-PEN-1	0.02	3.92	572	572	572	2027	220

68. Decommissioning Bombay-Hamilton-Arapuni circuits

    - BOB–HAM–1 and ARI–BOB–1 are currently not in service. It is intended that, from 2027, BOB–HAM–1 will be permanently decommissioned, ARI–BOB–1 with be bused at Hamilton, and the section between BOB and HAM will be dismantled. The corresponding network model modifications are shown in Table 5.

Table 5: BOB-HAM-1 and ARI-BOB-1 AC network modification

Decommissioned Line Name	Date
BOB-HAM-1	2025
ARI-BOB-1	2025

69. Upgrade Arapuni-Hamilton-3 circuit

- The upgrade of ARI–HAM–3 is assumed to be commissioned in 2027. The corresponding network model modifications are shown in Table 6.

Table 6: ARI-HAM-3 AC network modification

Line Name	R (%)	X (%)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
ARI-HAM-3	8.52	16.28	50.6	61.9	56.5	2027	110

70. Duplex the southern section of Otahuhu to Whakamaru lines (from Ohinewai to Whakamaru) and decommission northern section

- It is assumed that the southern sections of the Otahuhu to Whakamaru A and B lines between Whakamaru and Hautapu are duplexed, consistent with the current preferred investment option for the WUNI Stage 2 Project.
- This work is assumed to coincide with connecting the northern end of the duplexed section at Hautapu to Ohinewai and decommissioning the northern section of the Otahuhu to Whakamaru lines, between Hautapu and Otahuhu.
- The corresponding network model modifications are shown in Table 7 and Table 8.

Table 7: HTT-WKM, HTT-OHW, HLY-SFD and OHW-OTA AC modifications

Line Name	R (%)	X (%)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTT-WKM-1	0.48	4.26	709.5	780.6	746.1	2035	220

Line Name	R (%)	X (%)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTT-WKM-2	0.48	4.26	709.5	780.6	746.1	2035	220
HTT-OHW-1	0.31	2.73	709.5	780.6	746.1	2035	220
HTT-OHW-2	0.31	2.73	709.5	780.6	746.1	2035	220
OHW-OTA-3	1.30	6.30	362.4	368.1	366.4	2035	220
OHW-OTA-4	1.30	6.32	362.4	368.1	366.4	2035	220
HLY-SFD-1	3.91	23.49	469	492.3	480.8	2026	220

Table 8: HTT-OTA AC modification

Decommissioned Line Name	Date
HTT-OTA-1	2035
HTT-OTA-2	2035

71. Variable line ratings

- Select circuits across Transpower's network are operated to take advantage of variable line rating (**VLR**), which increases circuit capacity when the System Operator expects environmental conditions to permit it. As peak network load in New Zealand often coincides with periods of cooler weather, VLR can provide higher transfer capacity during periods of high network loading. The VLR adjusted circuit ratings relevant to the Brownhill Cable Joint Refurbishment BBI are presented in Table **9**.

Table 9: VLR circuit ratings relevant to this BBI

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

8.3.5 Wind and solar assumptions

72. Wind and solar generation profiles for existing, committed and new generation were derived using historical wind flow and solar irradiance data from 1980 to 2024, rather than the 1980–2017 period specified in section 2.3.4.6 of the assumptions book. This departure from the assumptions book incorporates the most recent available historical wind and solar data and provides a longer historical record on which to develop the generation profiles.

8.3.6 Committed generation and decommissionings

73. Except as described in the next paragraph, we used the committed generation assumptions in section 2.3.8.2 of the assumptions book.

74. Tauhei BESS was removed from the committed project stack because we consider the BESS project status should not be treated as equivalent to the associated Tauhei solar project. Consistent with the treatment of other non-committed BESS projects, Tauhei BESS was represented through generic grid-zone BESS assumptions, rather than as a committed project. This is a departure from the assumptions book.

75. In addition to the committed generation assumptions in the assumptions book (with Tauhei BESS removed), we used the following committed generation assumptions in all market scenarios:

- 200MW BESS at Glenbrook by Contact (HLY_GLN_s2),[8]
- 100 MW BESS at Huntly by Genesis (HLY_BESS_s2),[9] and
- 115 MW Solar Farm at Edgecumbe by Genesis (S_Tihori).[10]

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8 Glenbrook Ohurua Battery 2 | Contact Energy

9 Genesis reaches Final Investment Decision on second-stage Huntly BESS | Genesis NZ

10 Tihori Solar Farm | Genesis NZ

76. Modelling these projects as committed assumes they are proceeding irrespective of other modelling assumptions such as demand.

77. We used the thermal decommissioning assumptions in section 2.3.4.9 of the assumptions book.

8.3.7 New generation

78. We used the new generation shown in Appendix B. This new generation was developed by running our generation expansion tool, OptGen,[11] with the same inputs as in the factual SDDP case, but with the following exceptions:

    a. We started our generation expansion forecast in 2025 to account for any generation built between now and the beginning of the standard method calculation period (1 January 2027).

    b. OptGen requires the capital cost and location of each potential new generating station to determine which stations to build over the standard method calculation period. We used the assumptions in section 2.3.8 of the assumptions book.

    c. We applied a maximum build constraint of 750 MW per year for solar, 500 MW per year for wind, and 200 MW per year for geothermal because we found that without these constraints an unrealistic quantity of generation was being built in the early years of the standard method calculation period.

    d. We applied a maximum capacity build constraint of 440 MW in Northland and 640 MW across Northland and Huapai to reflect export constraints from the Northland region. The generation stack includes a large amount of generic capacity in this region, but a significant amount of transmission investment would be required to allow it to be exported south.

79. Clause 46(2) allows us to use different generation expansion scenarios in the factual and counterfactual if a BBI is expected to influence materially investment in new generation. We decided to use the generation expansion scenarios from the factual in both the factual and counterfactual as the counterfactual outages associated with unplanned failures of the cable joints are unlikely to significantly influence generation investment decisions.

8.4 Run market model

80. We ran SDDP (our market model) using the input assumptions and market scenarios described in sections 4, 8.2 and 8.3 to produce market model outputs and calculated outputs, as described in section 3.3.6.6 of the assumptions book.

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11 For our generation expansion planning we applied paragraph 222 of the assumptions book by only modelling primary fuels to reduce complexity and materially reduce computational effort.

8.5 Determine if clause 51 or 52 applies

81. We applied section 3.3.6.7 of the assumptions book to choose between the methods in clauses 51 and 52 to calculate market regional NPB for the Brownhill cable Joint Refurbishment BBI.

82. We are required to use clause 51 (the default method) to calculate market regional NPB unless certain conditions are met, as specified in clauses 51 and 52. The TPM broadly requires:

    a. the use of clause 51 if we determine that most of the market benefits of the BBI relate to new large generating plant (clause 51(1)(a))

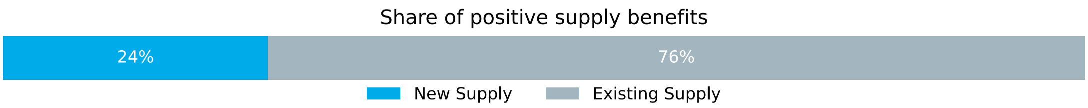
    b. the use of clause 52 if clause 51(1)(a) does not apply and we determine that most of market benefits of the BBI are due to consumers avoiding high prices due to a lack of transmission and generation capacity during peak periods (clause 52(1)(b)(i)).

83. We have applied clause 51 for the Brownhill Cable Joint Refurbishment BBI.

84. We assessed whether clause 51(1)(a) applies to the Brownhill Cable Joint Refurbishment BBI by applying the test in paragraph 370 of the assumptions book (checking if most of the positive market regional NPB for the Brownhill Cable Joint Refurbishment BBI's regional supply groups relates to new large generating plant.)

85. We determined it does not because the majority of positive market regional NPB for the Brownhill Cable Joint Refurbishment BBI's regional supply groups accrues to existing generating plant rather than new large generating plant (as shown in Figure 8).

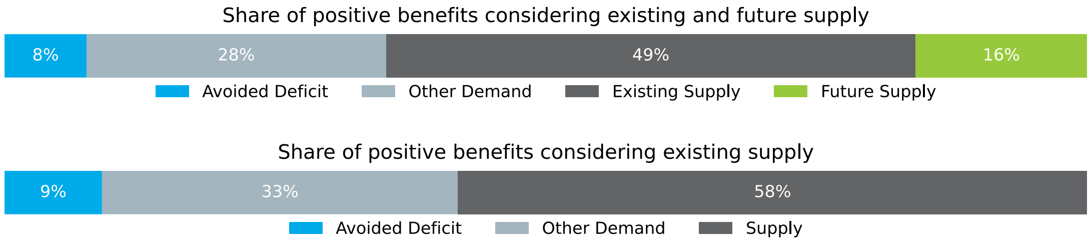
Figure 8: Share of positive supply benefits



86. As clause 51(1)(a) does not apply, we are required to use clause 52 for the Brownhill Cable Joint Refurbishment BBI if either clause 52(1)(b)(i) or 52(1)(b)(ii) applies.

87. We assessed whether clause 52(1)(b)(i) applies to the Brownhill Cable Joint Refurbishment BBI by applying the test in paragraph 371 of the assumptions book (checking if most of the positive market regional NPB for the Brownhill Cable Joint Refurbishment BBI is derived from consumers avoiding having to pay their estimated cost of self-supply for electricity during peak demand periods). Since the total positive NPB from consumers avoiding having to pay their estimated cost of self-supply is less than 50% of total consumer positive NPB (~9%, as shown in Figure 9) we are not required to use clause 52 by clause 52(1)(b)(i).

Figure 9: Share of positive consumer benefit



88. We assessed whether clause 52(1)(b)(ii) applies by considering whether using clause 51 will produce starting allocations that are broadly proportionate to EPNPB.

89. We estimated allocations using clause 52, and they were broadly similar to those calculated for clause 51, so we have determined clause 51 does produce starting allocations that are broadly proportionate to EPNPB from the Brownhill Cable Joint Refurbishment BBI. Further, as per paragraphs 373 to 375 of the assumptions book, we would expect clause 51 to produce broadly proportionate allocations because of the lack of WUNI deficit in the counterfactual and that the Brownhill-Pakuranga cables are part of the grid backbone (i.e. not on the extremity of the grid).

8.6 Determine if clause 49(6) should be applied

90. For the Brownhill Cable Joint Refurbishment BBI, we do not consider it necessary to adjust the prices from SDDP under clause 49(6) to moderate sensitivity. We used clause 51 to calculate market regional NPB, which is much less sensitive to modelled prices than clause 52, as the modelled prices are not used to calculate market regional NPB values (only to determine the potential modelled regions).

8.7 Determine modelled regions

91. We applied section 3.3.6.9 of the assumptions book to determine final modelled regions for the Brownhill Cable Joint Refurbishment BBI.

92. Based on the results of the price correlation algorithm (paragraph 383 of the assumptions book) we determined three final modelled regions:

- Waikato and Upper North Island (WUNI), which comprises locations: ALB, ARI[12], BOB, BRB, CBG, GLN, HAM, HEN, HEP, HIN, HLY, HOB, HTI, HTU, KOE, KPU, MNG, MPE, MTO, OTA, PAK, PAO, PEN, ROS, SVL, SWN, TAK, TMU, TWH, WEL, WHU, WIR, WKO, WRD, BHL, BOT, DRY, HPI, HTT, KPO, MDN, MVE, OHW, RTO, TAT
- the Rest of the North Island (RNI)

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12 Arapuni is a split bus, where the split divides WUNI from the Bay of Plenty grid regions. For this analysis because all ARI load is modelled to be at ARI110A, and also more generation is connected to ARI110A (Aripuni1-5) than to ARI110B(Aripuni6-8), we consider the ARI location to be in the WUNI region.

- the South Island (SI).

93. The distinction between the WUNI and RNI regions is consistent with the voltage stability constraints shown in Table 2 and Table 3, which limit northward flows over the eight 220kV circuits that supply the WUNI region.

94. We consider these final modelled regions meet the requirements of clause 50(1) for the Brownhill Cable Joint Refurbishment BBI, including being likely to produce starting allocations that are broadly proportionate to EPNPB.

8.8 Calculate PVEMBD for each customer at each connection location

95. We applied clause 51 and section 3.3.6.10 of the assumptions book to calculate PVEMBD for each customer at each connection location.

8.8.1 Calculate EMBD for each market scenario – clause 51

96. We determined the Brownhill Cable Joint Refurbishment BBI's periods of benefit as described in paragraphs 385 to 394 of the assumptions book. Specifically:

    - If the price at OTA220 is higher[13] than the price at WKM220 in the counterfactual, then the AC constraint is considered binding northwards; if the price at OTA220 is lower than the price at WKM220, then the AC constraint is considered binding southwards.
    - If the HVDC is modelled to be fully utilised in the northward direction in the counterfactual, the DC constraint is considered to be binding northwards; if the HVDC is modelled to be fully utilised in the southward direction, the DC constraint is considered to be binding southwards.
    - With the exception of times where both the AC and HVDC constraints are binding in the same direction in the counterfactual (see paragraphs 387 and 388 of the assumptions book), north binding periods are periods of benefit for load customers north of the constraint and generators south of the constraint, and periods of disbenefit for generators north of the constraint and load customers south of the constraint.

97. The periods of benefit and disbenefit for load customer groups for different constraint conditions are shown in Figure 10.

13 We use a threshold of 0.00005 $/MWh to determine whether prices are considered different. In unconstrained regions of the grid, SDDP produces prices that are equal to within floating point precision.

Figure 10: Periods of (dis)benefit for load customer groups

Region	AC • DC ↑	AC • DC ↓	AC ↑ DC •	AC ↑ DC ↑	AC ↑ DC ↓	AC ↓ DC •	AC ↓ DC ↑	AC ↓ DC ↓
WUNI	•	•	+	+	+	-	-	-
RNI	•	•	-	-	-	+	+	+
SI	•	•	-	•	-	+	+	•

Up/down arrows in the column headers represent North/South binding respectively; dots mean no binding. Green "+" cells mean load customers benefit, red "-" cells mean they disbenefit, grey dots mean they neither benefit nor disbenefit. The signs are reversed for supply customer groups.

98. We then calculated EMBD (and PVEMBD) by customer and connection location using the equations shown in paragraphs 391 and 392 of the assumptions book. For example, for load customers at a location, paragraph 392 of the assumptions book gives:

$$EMBD_{Load_{cust,loc}} = Load_{cust,loc,CF,a} - Load_{cust,loc,CF,e} + LoadDelta_{cust,loc}$$

$Load_{cust,loc,CF,a}$ refers to load supplied in the counterfactual during periods where the price would be alleviated by the BBI. Referring to Figure 10, these are the periods with green "+" cells. For example, for WUNI load customers, the $Load_{cust,loc,CF,a}$ term includes load supplied whenever the AC constraint is binding north; for South Island load customers, the $Load_{cust,loc,CF,a}$ term includes load supplied whenever the AC constraint is binding south except when the HVDC link is also south binding.

$Load_{cust,loc,CF,e}$ refers to load supplied during periods where the price would be exacerbated by the BBI. These are the red "-" cells in Figure 10. For example, for WUNI load customers, the $Load_{cust,loc,CF,e}$ term includes load supplied whenever the AC constraint is binding south; for South Island load customers, the $Load_{cust,loc,CF,e}$ term includes load supplied whenever the AC constraint is binding north except when the HVDC link is also north binding.

The $LoadDelta_{cust,loc}$ term is the difference between loads supplied in the factual and counterfactual (former minus latter).

99. Intuitively, WUNI load customers benefit from the investment during periods when the AC constraint would be binding northwards in the counterfactual, because alleviating that constraint gives these customers access to cheaper generation from the central and lower North Island and the South Island.

100. Similarly, RNI load customers benefit from the investment during periods when the AC constraint would be binding southwards in the counterfactual, because alleviating that constraint gives these customers access to WUNI generation. South Island load customers also benefit from alleviating the AC constraint when it southward binding except when a southward binding HVDC constraint prevents access to the WUNI generation.

101. The EMBD equation for supply customers (paragraph 391 of the assumptions book) is similar to the load equation, except that the signs of the a and e terms are reversed:

$$EMBD_{Load_{cust,loc}} = Gen_{cust,loc,CF,e} - Gen_{cust,loc,CF,a} + LoadGen_{cust,loc}$$

As for load, the *a* terms correspond to generation during the green "+" periods in Figure 10, and the *e* terms correspond to the red "-" periods. The change in signs of the *a* and *e* terms mean that, for example, periods where the AC constraint is binding north contribute positively to WUNI load customers, but negatively to WUNI supply customers.

8.8.2 Calculate present value EMBD (PVEMBD)

102. We calculated market scenario-weighted EMBD, according to paragraph 404 of the assumptions book by multiplying EMBD by the weighting for each market scenario, and calculated EMBD as a present value in this step.

8.8.3 Remove PVEMBD for customers or large plant that do not currently exist

103. As described in paragraph 405 of the assumptions book, we removed PVEMBD for customers or large plant that do not currently exist.

104. For load, this was achieved through the step load adjustment detailed in the "Step load adjustments for consumer PVEMBD" section of the **allocations report**.

105. For generation, we removed PVEMBD for all new large generating plant that did not exist at the end of capacity measurement period (CMP) B for the Brownhill Cable Joint Refurbishment BBI (31 August 2023)[14].

106. We treated modelled future repowering of existing wind farms as new large generating plant. Accordingly, future PVEMBD of these plants is scaled back to reflect their current capacity. This is detailed in the "Wind repowering adjustments for generator PVEMBD" section of the **allocations report.**

8.8.4 Split loads with more than one customer at a connection location

107. Where there are multiple load customers at a connection location, the modelled load PVEMBD for that connection location is distributed according to paragraph 406 of the assumptions book. We used intra-regional allocator (**IRA**) values calculated on the basis of mean annual offtake over CMP B for the Brownhill Cable Joint Refurbishment BBI to do this. This is detailed in the "Reallocation of load growth to EDBs at multi-customer nodes" section of the **allocations report.**

108. The Whareroa cogeneration plant at Hawera was modelled as being decommissioned from 1 January 2026. Since the standard method calculation period for the Brownhill Cable Joint Refurbishment BBI starts after this date, no generation benefits were modelled for the relevant customer, Whareroa Cogeneration Limited (customer code KIWI) at Hawera. However, KIWI at Hawera has a small offtake IRA value, and the load-splitting approach described in paragraph 406 of the assumptions book results in a modelled demand side disbenefit even though the plant is no longer modelled as operating. To ensure this customer

14 BBI customer allocations for customers or large plant that connected after 31 August 2023 are determined by applying the pre-start adjustment event provisions of the TPM.

and plant was included in the correct potential regional customer group (RNI cogen), and that the customer's load disbenefit was not attributed to that group, the offtake IRA value for KIWI at Hawera was set to zero. This is a departure from the assumptions book.

8.9 Determine potential regional customer groups

109. We applied section 3.3.6.11 of the assumptions book to determine potential regional customer groups for the Brownhill Cable Joint Refurbishment BBI.

110. As described in paragraph 412 of the assumptions book, we set off generation disbenefits from load benefits (and vice versa) where a customer has injection and offtake at the same connection location, including where a distributor has embedded generation hosted in their network but we modelled it as a grid-connected generator under clause 49(5). We did this using the following formulae:

$$PVEMBD\_NetGen_{cust,loc} = PVEMBD\_Gen_{cust,loc} + PVEMBD\_Load_{cust,loc} - (PVLoadDelta_{cust,loc} * 2)$$

$$PVEMBD\_NetLoad_{cust,loc} = PVEMBD\_Gen_{cust,loc} + PVEMBD\_Load_{cust,loc} - (PVGenDelta_{cust,loc} * 2)$$ [15]

where:

- $PVEMBD\_NetGen_{cust,loc}$ is the present value of EMBD for a customer ($cust$) at a connection location (loc) calculated based on net generation
- $PVEMBD\_NetLoad_{cust,loc}$ is the present value of EMBD for a customer ($cust$) at a connection location (loc) calculated based on net load

111. The potential regional supply groups for each modelled region are listed in paragraph 415 of the assumptions book. A list of existing customers included in each potential regional supply group containing at least one customer is in Appendix C (Table C.1).

112. We grouped Alpine at Albury, Westpower at Kumara, and Aurora at Clyde into the South Island controlled hydro potential regional supply group. We did this because these customers at these connection locations have injection greater than their offtake during CMP B for the Brownhill Cable Joint Refurbishment BBI. They have significant embedded generation, which

15 The term $-(PVGenDelta_{cust,loc} * 2)$ is used to make $PVGenDelta_{cust,loc} + PVLoadDelta_{cust,loc}$ mathematically equivalent to $PVLoadDelta_{cust,loc} - PVGenDelta_{cust,loc}$, which represents the change in net load between the factual and counterfactual.

we do not model in SDDP.[16] If we did model this embedded generation, we expect these customers and connection locations would be in South Island regional supply groups, and we consider grouping them as such will result in starting allocations that better reflect EPNPB.

113. The Whareroa cogeneration plant at Hawera was modelled to be decommissioned on 1 Jan 2026, so had no modelled supply PVEMBD. Because the Whareroa plant was generating in the CMP B period, and Whareroa Cogeneration Ltd (KIWI) is still a customer at KIWI, we grouped Whareroa Cogeneration Ltd at Hawera into the "RNI cogen" potential regional supply group.

114. Potential regional demand groups for each modelled region are listed in paragraph 414 of the assumptions book. A list of existing customers included in each potential regional demand group containing at least one customer is in Appendix C (Table C.2).

115. We did not separate new and existing customers into separate regional customer groups because the benefits of the Brownhill Cable Joint Refurbishment BBI do not primarily accrue to new customers (paragraph 4.16 of the assumptions book).

116. However, we created potential future regional supply groups for each of the following generation technologies that do not already exist in the relevant modelled region. Without these potential future regional supply groups, customers with these types of new large plant would not have a regional customer group to join, and the BBI customer allocations after the new plant arrives would not be broadly proportionate to EPNPB.[17]

- RNI battery generation
- RNI solar generation
- SI wind generation[18]
- SI solar generation
- SI battery generation
- SI thermal generation.

117. To estimate PVEMBD and notional IRA values for the SI battery generation and SI thermal generation potential future regional supply groups, we modelled placeholder generators as described in paragraphs 266 to 270 of the assumptions book. To estimate PVEMBD for the RNI solar generation, SI wind generation, and SI solar generation potential future regional supply groups, we modelled the Te Herenga solar plant, the Kaiwera Downs wind farm, and the Lauriston solar plant respectively. These plants exist from the start of the standard method calculation period but did not exist during CMP B for the Brownhill Cable Joint Refurbishment BBI.

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16 Because we did not model the embedded generation in SDDP, these customers are not listed in table C.1.

17 Unless they are later amalgamated with another group – see section 8.11.

18 While there are existing wind generating stations in the South Island (Mahinerangi and White Hill), both are embedded, so the generators are not treated as existing customers in respect of these stations.

8.10 Calculate PVMRNPB for potential regional customer groups

118. We applied section 3.3.6.12 of the assumptions book to calculate PVMRNPB for the potential regional customer groups for the Brownhill Cable Joint Refurbishment BBI.

119. We calculated PVMRNPB for each potential regional customer group by summing customer PVEMBD at each location as described in paragraph 419 of the assumptions book. The calculated PVMRNPB for each potential regional customer group are provided in the "Regional Customer Groups" section of the **allocations report**.

120. We removed potential regional customer groups with a PVMRNPB that was not positive (all WUNI regional supply groups and RNI and South Island regional demand groups), which left the following potential regional customer groups:

- RNI controlled hydro generation
- RNI run-of-river hydro generation
- RNI wind
- RNI geothermal
- RNI cogeneration
- RNI thermal
- RNI solar (future)
- RNI battery (future)
- SI controlled hydro generation
- SI run-of-river hydro generation
- SI wind (future)
- SI solar (future)
- SI battery (future)
- SI thermal (future)
- WUNI industrial load
- WUNI non-industrial load
- WUNI load with generation

121. We did not need to convert the quantity values of PVMRNPB to dollar values, as described in paragraphs 421 and 422 of the assumptions book, because we have not calculated regional NPB other than market regional NPB.

8.11 Finalise regional customer groups

122. We applied section 3.3.6.13 of the assumptions book to finalise the final regional customer groups for the Brownhill Cable Joint Refurbishment BBI.

123. We have amalgamated some potential regional supply groups. Table 10 shows the potential regional supply groups, the final regional supply groups (following amalgamation), and the PVMRNPB and IRA values that determined the amalgamations.

124. The final SI hydro/wind regional supply group is the result of two amalgamations. First, the two SI hydro potential regional supply groups were amalgamated (because their PVMRNPB/IRA ratios were closest) and then the SI wind potential regional supply group was amalgamated with the combined SI hydro potential regional supply group.

Table 10: Potential and final regional supply groups

Potential regional supply group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Final regional supply group
RNI run-of-river hydro	1107.95	1849.59	0.5990	RNI hydro (0.5870)
RNI controlled hydro	1503.70	2599.24	0.5785	
RNI wind	989.36	2110.87	0.4687	RNI wind
RNI battery (future)	0.0324	0.0958	0.3382	RNI battery (future)
RNI geothermal	2013.75	7509.14	0.2682	RNI geothermal
RNI solar (future)	8.348	67.88	0.1229	RNI solar (future)
RNI cogeneration	21.58	250.29	0.0862	RNI cogeneration
RNI peaker	99.39	1489.21	0.0667	RNI peaker
SI battery (future)	0.0173	0.0355	0.4873	SI battery (future)
SI run-of-river hydro	16.10	41.12	0.3912	SI hydro/wind (0.3659)
SI controlled hydro	6489.42	17712.18	0.3664	
SI wind (future)	47.43	157.68	0.3008	
SI peaker (future)	0.0043	0.0221	0.1963	SI peaker (future)
SI solar (future)	13.66	95.79	0.1427	SI solar (future)

125. We have amalgamated two potential regional demand groups (the WUNI load with generation and WUNI non-industrial load potential regional demand groups). Table 11 shows the

potential regional demand groups, the final regional demand groups (following amalgamation), and the PVMRNPB and IRA values that determined the amalgamation.

Table 11: Potential and final regional demand groups

Potential regional demand group	PVMRNPB (GWh)	IRA (MW)	PVRMNPB/IRA (GWh/MW)	Final regional demand group
WUNI industrial load	34.21	4.208	8.129	WUNI industrial load
WUNI load with generation	118.9	19.28	6.168	WUNI non-industrial load and load with gen. (5.920)
WUNI non-Industrial load	7030.54	1181.45	5.916	

126. PVRMNPB and the percentage of total PVRMNPB for each final regional customer group (other than the five final future regional supply groups that we did not amalgamate) are shown in Table 12.

Table 12: PVRMNPB for final regional customer groups as a proportion of total PVRMNPB (excluding final future regional supply groups)

Final regional customer group	PVRMNPB (GWh)	Percentage of PVRMNPB
WUNI non-industrial load and load with gen	7149.48	36.81%
SI hydro/wind	6552.96	33.49%
RNI hydro	2611.65	13.44%
RNI geo	2013.75	10.37%
RNI wind	989.36	5.09%
RNI peaker	99.39	0.51%
WUNI industrial load	34.21	0.18%
RNI cogeneration	21.58	0.11%

127. The final regional customer groups include five final future regional supply groups that had no customers at the end of CMP B for the Brownhill Cable Joint Refurbishment BBI. When customers that belong to these future regional customer groups connect to the grid, an

adjustment event will be triggered, and the following PVRMNPB/capacity ratios can be used to calculate the customers' BBI customer allocations for the BBI.

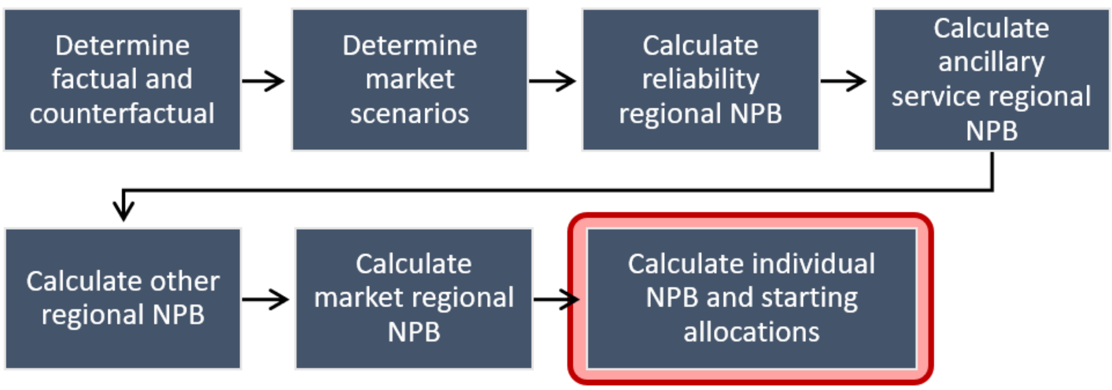
Table 13: PVRMNPB / capacity ratios for final future regional supply groups

Final regional supply group	PVMRNPB (GWh)	Modelled capacity (MW)	PVMRNPB/capacity (GWh/MW)
RNI battery (future)	0.0324	0.4	0.810
RNI solar (future)	8.348	33 (Te Herenga)	0.253
SI battery (future)	0.0173	0.2	0.0865
SI peaker (future)	0.0043	0.2	0.0215
SI solar (future)	13.66	47 (Lauriston)	0.291

9 Calculate individual NPB and starting BBI customer allocations

128. This section describes our application of the stages set out in section 3.3.7 of the assumptions book (and as shown in Figure 11).

Figure 11: Calculate individual NPB and starting allocations



9.1 Calculate IRA per customer per regional customer group

129. Final IRA values for the Brownhill Cable Joint Refurbishment are calculated from historical data between 1 September 2018 and 31 August 2023 which spans the five complete capacity years immediately preceding The Brownhill Cable Joint Refurbishment's final investment decision date (September 2023).[19] This is CMP B for the Brownhill Cable Joint Refurbishment BBI.

130. The Brownhill Cable Joint Refurbishment BBI is a peak BBI because its investment need is primarily attributable to meeting peak demand. The modelled constraints for the BBI are expected to bind in the counterfactual simulations less than 4% of the time, as shown in Figure A.8, and these are times of peak load in the WUNI region.

131. As a peak BBI, the IRAs for the Brownhill Cable Joint Refurbishment BBI are (clause 65(1)):

- for regional demand groups, the mean of the 100 demand peaks[20] in each capacity year in CMP B; and
- for regional supply groups, mean historical annual injection over CMP B.

132. We calculated the IRA values in accordance with clauses 65(7) and 65(6), respectively, for most beneficiaries.

133. New customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRAs estimated, but, for recent customers, taking into account any available information about their offtake and injection (clauses 66 and 83(3)(a)).

134. We applied clauses 65(13) and 66 to estimate the IRA values for the following pre-start adjustment events that occurred during CMP B.[21]

Table 14: Pre-start adjustment events during CMP B

Customer	Location	Adjustment
TOPE	KOE	IRA values adjusted up to December 2020 due to Ngawha generation expansion using Te Mihi Geothermal as a comparator.
NPOW	BRB	IRA values adjusted up to April 2022 due to refinery load disconnection and import terminal load connection using the refinery and import terminal data provided by Northpower.
CHHE	KAW	IRA values adjusted up to May 2023 due to Oji Fibre Solutions (CHHE) connection as new customer using the most recent metering data available for CHHE (capacity years 2023-2025).
WELE	TWH	IRA values adjusted up to June 2023 due to Te Rapa generation disconnection using Te Rapa embedded generation metered data.

19 Transpower to replace joints on underground Auckland cable | Transpower.
20 Paragraph 432 of the assumptions book requires us to use 100 peaks.
21 Norske Skog Tasman (SKOG) was a customer in the WUNI region during CMP B, but ceased to be a customer in May 2023. Accordingly, we have not calculated an IRA value or starting allocation for SKOG.

Customer	Location	Adjustment
VECT	SVL	IRA values adjusted up to November 2022 due to CDC Data Centre load connection, based on offtake data provided by Vector.
VECT	HEN	IRA values adjusted up to November 2022 due to CDC Hobsonville Data Centre load connection and up to January 2023 due to Microsoft Data Centre load connection, based on offtake data provided by Vector.
MERI	HRP	Harapaki wind farm connected June 2023. IRA values calculated based on an estimated injection of 542 GWh per annum provided by Meridian.
MSVP	LTN	Turitea wind farm connected in August 2020. IRA values estimated based on Tararua wind farm's IRA value, using relative plant capacity as a scaling factor.
WAV1	WVY	Waipipi wind farm connected in November 2020. IRA values estimated based on available metered data.

135. We are aware there are pre-start adjustment events that have occurred after the end of CMP B. We expect to process those as pre-start adjustments events under clause 75(4)(b).[22]

9.2 Calculate individual NPB

136. We calculated each customer's individual NPB for the Brownhill Cable Joint Refurbishment BBI as the sum of the present value of PVRNPB for each regional customer group with positive PVRNPB of which the customer is a member, multiplied by the customer's IRA value for the group as a proportion of the total of all customers' IRA values for the group.

22 IRAs can be found in the "Benefiting customers and locations" section of the allocations report.

9.3 Calculate starting allocations

137. We calculated each customer's final starting allocation for the Brownhill Cable Joint Refurbishment as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the allocations (to two decimal places)[23] set out in Table 15.

Table 15: Final starting allocations for the Brownhill Cable Joint Refurbishment BBI

Customer Name	Final starting allocation (%)
Vector Ltd	25.09%
Meridian Energy Ltd	24.49%
Contact Energy Ltd	11.90%
Mercury NZ Ltd	8.16%
Genesis Energy Ltd	7.22%
WEL Networks Ltd	3.53%
Powerco Ltd	2.58%
Manawa Energy Ltd	2.26%
Northpower Ltd	1.98%
Counties Energy Ltd	1.64%
Nga Awa Purua Joint Venture	1.61%
MEL (West Wind) Ltd	1.21%
Kawerau Geothermal Ltd	1.16%
Waipa Networks Ltd	1.08%
Ngatamariki Geothermal Ltd	1.01%
Tararua Wind Power	0.98%

23 This is extended to 3 decimal places for Southpark Utilities Ltd, whose final starting allocation is less than 0.005%.

Customer Name	Final starting allocation (%)
MEL (Te Apiti) Ltd	0.61%
Waverly Wind Farm Ltd	0.57%
Mercury SPV Ltd	0.42%
New Zealand Steel Ltd	0.40%
The Lines Company Ltd	0.32%
Oji Fibre Solutions (NZ) Ltd	0.29%
Southern Generation Ltd	0.29%
Unison Networks Ltd	0.26%
Nova Energy Ltd	0.21%
Top Energy Ltd	0.19%
KiwiRail Holdings Ltd	0.17%
Horizon Energy Distribution Ltd	0.11%
Aurora Energy Ltd	0.09%
Whareroa Cogeneration Ltd	0.07%
Westpower Ltd	0.07%
Alpine Energy Ltd	0.03%
Southpark Utilities Ltd	0.001%

138. To calculate benefit-based charges (**BBCs**) for the Brownhill Cable Joint Refurbishment BBI, the starting allocations will be multiplied by the Brownhill Cable Joint Refurbishment's covered cost. We have not included this step in this record as this step takes place after the calculation of starting allocations – which is the focus of this record.

139. A BBI's covered cost changes annually due to parameters including WACC and the attributed opex ratio and will not be certain until the final project costs are confirmed.

Appendix A: Modelling detail

Modelling Approach

A.1 This section describes the approach used in our analysis to model and calculate the benefits of the Brownhill Cable Joint Refurbishment BBI.

A.2 We use models of the New Zealand electricity system to calculate the benefits of the Brownhill Cable Joint Refurbishment BBI, by comparing the factual and counterfactual cases. We refer to the Brownhill Cable Joint Refurbishment BBI being fully commissioned as the factual. The counterfactual is the “do nothing” option where the existing grid asset remains in service without refurbishment until it reaches its replacement state, after which they would be immediately decommissioned and not replaced. In this case, this corresponds to decommissioning the Brownhill-Pakuranga B cable section following a cable joint failure, resulting in the permanent decommissioning of the Brownhill-Pakuranga B cable from January 2026.

A.3 The key components of our analysis are:

- **Demand forecasting**. We have used variations of the market development scenarios produced by the Ministry of Business, Innovation and Employment (**MBIE**) in 2024. MBIE’s scenarios are called the Electricity Demand and Generation Scenarios (**EDGS**). We used all five of the 2024 EDGS scenarios in order to cover the widest range of possible future demand growth. These scenarios are the Reference, Growth, Constraint, Innovation, and Environmental scenarios.
- **Generation expansion planning**. We find a combination of new generation projects that would meet forecast demand while minimising system cost and considering firming requirements and hydrological uncertainty. For this analysis we use PSR Inc’s OptGen software. Aligning with the demand scenarios, unique generation expansion plans are developed for each 2024 EDGS scenario. The OptGen expansion plans for each 2024 EDGS scenario are modified to improve revenue adequacy of the generating plants, to better align with a realistic electricity market.
- **Generation dispatch simulations**. These simulations estimate electricity system operating costs for the counterfactual and factual cases. For this, we use PSR Inc’s SDDP software (v17.3.13) with generation dispatch simulations developed for each 2024 EDGS scenario.

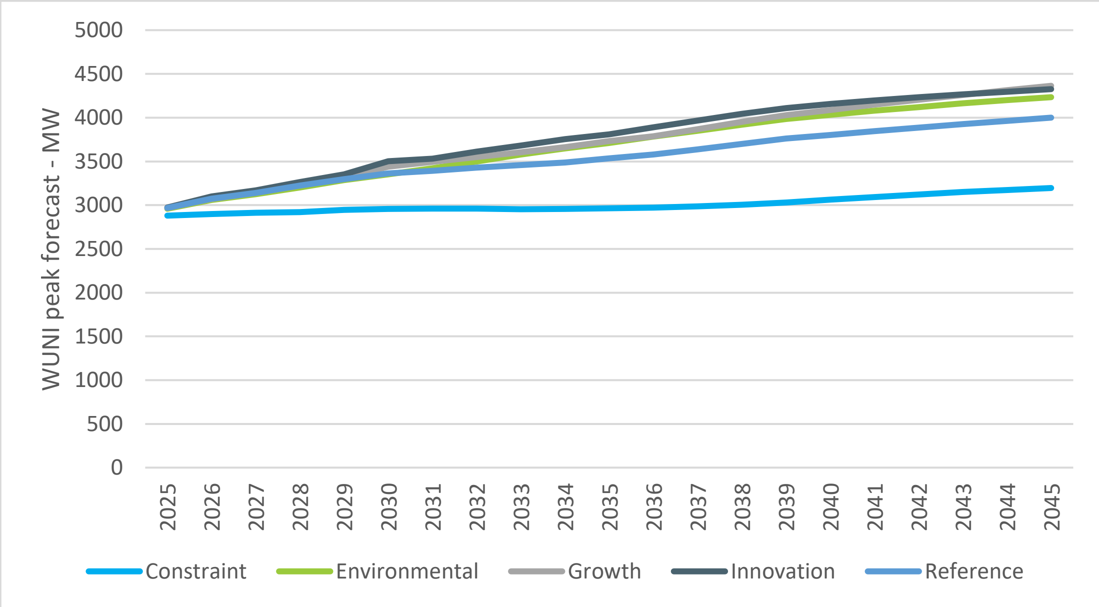
A.4 Our modelling provides estimates of electricity system costs for the counterfactual and factual cases. The benefits of the factual are then calculated as the difference between the system costs of the factual and counterfactual cases.

A.5 For this analysis, we have generally aligned with the modelling assumptions and approach used in our previous benefits modelling. The primary difference is that this analysis adopts version 3 of the assumptions book, which incorporates a number of updated assumptions based on the latest available information. Consistent with our previous analysis, we have assumed that the Tiwai smelter will remain in operation throughout the standard method calculation period.[24] We have not modelled any sensitivities related to the smelter's closure.

Demand Forecasting

A.6 The demand forecast used was based on the EDGS 2024 scenarios. Figure A.1 shows a comparison between the North and South Island demand forecasts used for the current modelling (Tiwai remains open) across the scenarios.

Figure A.1 Demand forecast comparison between EDGS 2024 scenarios



Generation Expansion Planning

A.7 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.

24 Although the current electricity supply contract expires in December 2044, for simplicity we have assumed it will be renewed, or replaced with a new contract, for the remainder of the standard method calculation period (i.e. until at least the end of December 2047). We note that benefits accruing at the end of the standard method calculation period have a relatively small impact on EPNPB due to discounting.

A.8 Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (to the end of 2045), adding new generation as required to meet forecast demand while minimising system cost. 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, cost will be the major deciding factor.

A.9 PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use PSR's 'Optgen1' algorithm. Optgen1 finds a least-cost plan by de-composing the build decision from the operation decision and running them in an iterative loop until the results converge. This approach ensures that build decisions see the full range of hydrological uncertainty considered in the operational model.

A.10 We constrain the model in the first two to three years (market scenario dependent) to build generation projects to which developers have committed, or that are in the advanced stages of Transpower's connection pipeline. For the remainder of the standard method calculation period, the model is allowed to build from a wider generation stack of specific known projects at earlier stages of development and generic projects where the resource is known to exist, but a project has not been publicly announced.

A.11 As an additional step, the generation expansion plans from OptGen are adjusted to improve the modelled revenue adequacy of future generation projects. Revenue adequacy is the ratio of expected revenues over expected capital costs. While it can be difficult to model revenue adequacy, particularly in a future dominated by intermittent renewable generation, future generation plants should in general be revenue adequate.

A.12 These adjustments are made as a 'post-processing' step, after the OptGen modelling process. The existing and committed generation is left untouched, but future generation is shifted in time through an iterative process with the goal of achieving plant revenue adequacy over a 10-year period. Adjustments are done in such a way as to introduce no significant difference between North Island and South Island average short run marginal costs (**SRMCs**), while still ensuring revenue adequacy remains within reasonable modelling tolerances.

A.13 We produced generation expansion plans for each of the five 2024 EDGS scenarios. We applied the same generation expansion plan to the counterfactual and factual cases for each 2024 EDGS scenario. We assumed that the AC grid is unconstrained (i.e., that future generation development would be unaffected by circuit constraints on the refurbishment of the Brownhill cable).

A.14 All changes to generation capacity from 2022 to 2045 are summarised in Appendix B:.

Generation Dispatch Simulation

A.15 SDDP is a well-established dispatch model that is widely used internationally. 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 and the counterfactual,
- 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, and
- plant operational constraints - including thermal plant unit commitment and hydro plant minimum flow constraints.

A.16 SDDP generation dispatch simulations are produced in two steps:

- **Policy evaluation**: In this step SDDP derives a policy, effectively a set of water value functions considering all of New Zealand's major hydro reservoirs. Water value functions provide the weekly opportunity cost of using or storing water in each hydro reservoir as a function of lake levels, accounting for risks of both dry year energy shortages and wet year hydro spillage.
- **Simulation**: Using water value function from the policy evaluation, the operation of the electricity system is simulated for a set of 50 unique hydro inflow sequences.

A.17 SDDP policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water values. For this analysis, consistent with our generation expansion plan approach, we ran policies for each of the five 2024 EDGS scenarios. For a given 2024 EDGS scenario, we applied the same policy to the counterfactual and factual cases, on the basis that refurbishment of the Brownhill cable is unlikely to substantively alter water values for major hydro generation schemes.

A.18 For this analysis, we use an hourly resolution over the standard method calculation period to 2045 for generation dispatch simulations. The hourly resolution allows us to capture real world variations in demand and renewable generation, at the cost of increased model solve time and storage requirements.

A.19 SDDP models the optimal dispatch of generation and battery resources across the electricity system using a 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, so capturing this behaviour is a critical part of our generation dispatch simulations.

A.20 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. They are produced by SDDP by analysing the relationship between an inflow sequence and time of year, as well as the interdependence among inflows to different hydro catchments.

A.21 For this analysis, we used:

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

A.22 SDDP uses a simplified, linear, DC load flow model. For this analysis, we introduced the following additional simplifications to our modelling approach:

- Circuit upgrades/changes in the factual case are given in Section 8.3.4. In addition to these modifications, we include modifications to existing AC circuits that have been committed but not yet commissioned or are otherwise likely to occur soon. These "existing" circuit modifications appear in the investment grids for both the factual and counterfactual cases; however, they do not affect the results of the modelling because they relate to circuits that are unaffected by the modelled constraints for this BBI.

- Circuit flows are constrained to respect both thermal ratings and other system constraints only for the key circuits listed below. The rest of the AC grid is modelled as unconstrained.
- AC network losses are not included in the SDDP generation dispatch simulation.
- The following circuit contingencies are modelled in the factual and counterfactual cases: BHL-WKN-1, HAM-WKM-1, OHW-OTA-1, OHW-WKM-1
- The following circuits are monitored for loading pre-contingency and post-contingency: BHL-PAK-1 & 2, BHL-WKN-1 & 2, HAM-WKM-1,HLY-SFD-1, HTT-OTA-1 & 2, HTT-WKM-1 & 2, OHW-OTA-1 & 2, OHW-WKM-1, TMN-TWH-1, HTT-OHW-1&2, OHW-OTA-3&4.
- In addition to modelled contingencies, generic constraints are applied to reflect voltage stability limits derived by AC power-systems modelling. These constraints are a weighted sum of selected circuit flows and generation being forced to be less than some voltage stability limit.
- Losses on the HVDC link are modelled within SDDP using a linearised approximation of observed HVDC losses.

A.23 The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plans and generation dispatch simulations. The deficit cost tranches used in this modelling are described in section 2.3.7 of the assumptions book.

A.24 Many other model inputs are not explicitly listed here and are consistent with those in chapter 2 of the assumptions book.[25]

Generation Dispatch Simulation Results

A.25 This Section provides an overview generation dispatch simulation results that directly relate to the calculation of the Brownhill Cable refurbishment BBI's starting allocations. The benefits and disbenefits differ per 2024 EDGS scenario as customers' exposure to the security constraints across the network differ per 2024 EDGS scenario. We defined the periods of benefit to be periods when there is price separation between nodes OTA220 and WKM220.

Benefits are primarily to generation upstream and load downstream of constraints

A.26 The Brownhill Cable Joint Refurbishment keeps both Brownhill to Pakuranga connections in service, increasing the transfer capacity from the Central North Island to the Waikato and Upper North Island

A.27 With only one Brownhill to Pakuranga cable in service, contingencies on the remaining Whakamaru-Brownhill-Pakuranga circuit or at Huntly Unit 5 could result in voltage collapse under some load and generation conditions.

A.28 This risk must be managed by the System Operator pre-contingency by constrained circuit flows and generation to ensure that – should an unplanned outage occur – the system remains stable.

A.29 Similarly, with only one Brownhill to Pakuranga cable in service, unplanned circuit outages on the 220 kV can overload the remaining parallel circuits. This risk is also managed pre-

25 TPM Determination: BBC Assumptions Book v3.0, 30 June 2026.

contingency by the system operator by imposing constraints on network flows to ensure that the system remains stable following an unplanned outage.

A.30 As illustrated in the diagrams below, when a transmission constraint binds in the wholesale electricity market, prices upstream of the constraint fall, and prices downstream rise. The price represents the cost of supplying the next MW of load at the location. When there are no constraints binding, ignoring the effect of losses, prices across the country are equal as the next MW of load at any location can be supplied by the generator with the cheapest uncleared offer. When a constraint binds, upstream generation with lower offer prices is constrained down/off, meaning the next MW of load at any upstream node can be supplied by this lower cost generation, resulting in lower prices upstream of the constraint. Conversely, downstream generation with higher offer prices is constrained up/on, and the next MW of load for downstream nodes must come from this higher-cost downstream generation, resulting in higher prices.

Figure A.2 Prices with circuit at less than capacity

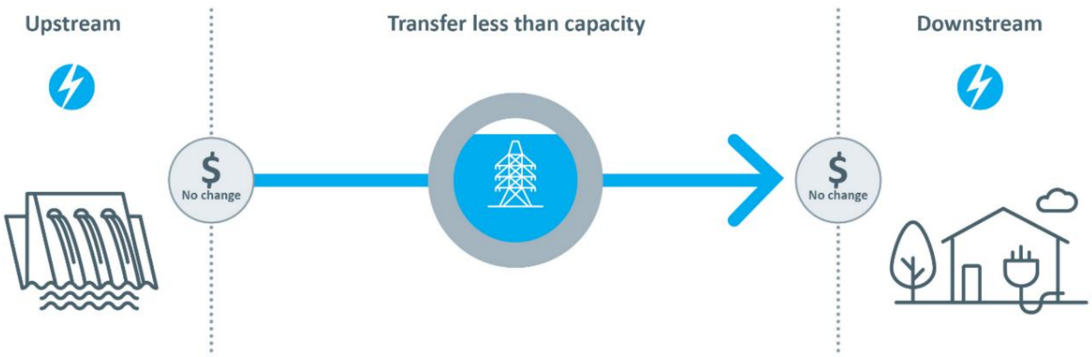
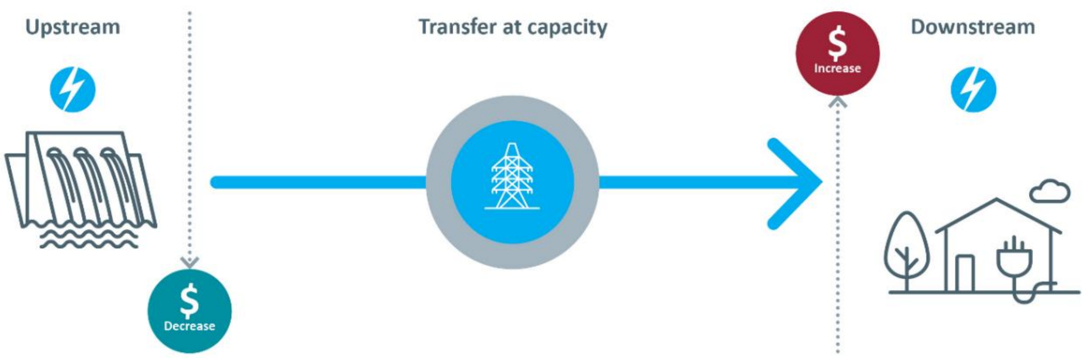


Figure A.3 Prices with circuit at capacity



A.31 By reducing the likelihood of a binding constraints between the Central North Island and the Waikato and Upper North Island, the Brownhill Cable Joint Refurbishment is expected to deliver private benefits to load in the Waikato and Upper North Island, and generation in rest of the network. This is primarily because Waikato and Upper North Island load does not have to pay elevated energy prices due to the binding transmission constraints and upstream generation in the rest of the network is not paid suppressed energy prices due to those constraints. Similarly, load will disbenefit in the region where generation benefits, and vice versa.

Beneficiaries are consistent with the direction of flow between the Central North Island and WUNI

A.32 We have modelled five market scenarios, based on the five market scenarios in chapter 2 of the assumptions book. Each scenario is modelled from 2026 to 2045 and across 90 historical hydrological sequences, with the results shown as the mean of these hydro sequences.

A.33 The benefits and disbenefits differ per market scenario as the beneficiaries' exposure to export and import constraints differ per market scenario.

A.34 We have defined the periods of benefit to be periods when price separation of greater than a tolerance of $\$5\text{x}10^{-5}$/MWh occurs between the OTA220 node and the WKM220 node, noting that losses are not modelled so all price separation is due to the modelled constraints.

A.35 We refer to the case where OTA220 price are greater than WKM220 prices as "Northward" and the case where WKM220 prices are greater than OTA220 price as "Southward". We refer to cases when OTA220 and WKM220 price are closer than the tolerance as "None".

A.36 Figure A.4 shows the frequency of binding constraints for the five scenarios in 2026. Figure A.5 is a flow duration curve for HVDC flows during a three-month winter outage at various points in the modelling horizon.

Figure A.4 Frequency of binding constraints in each scenario in 2026

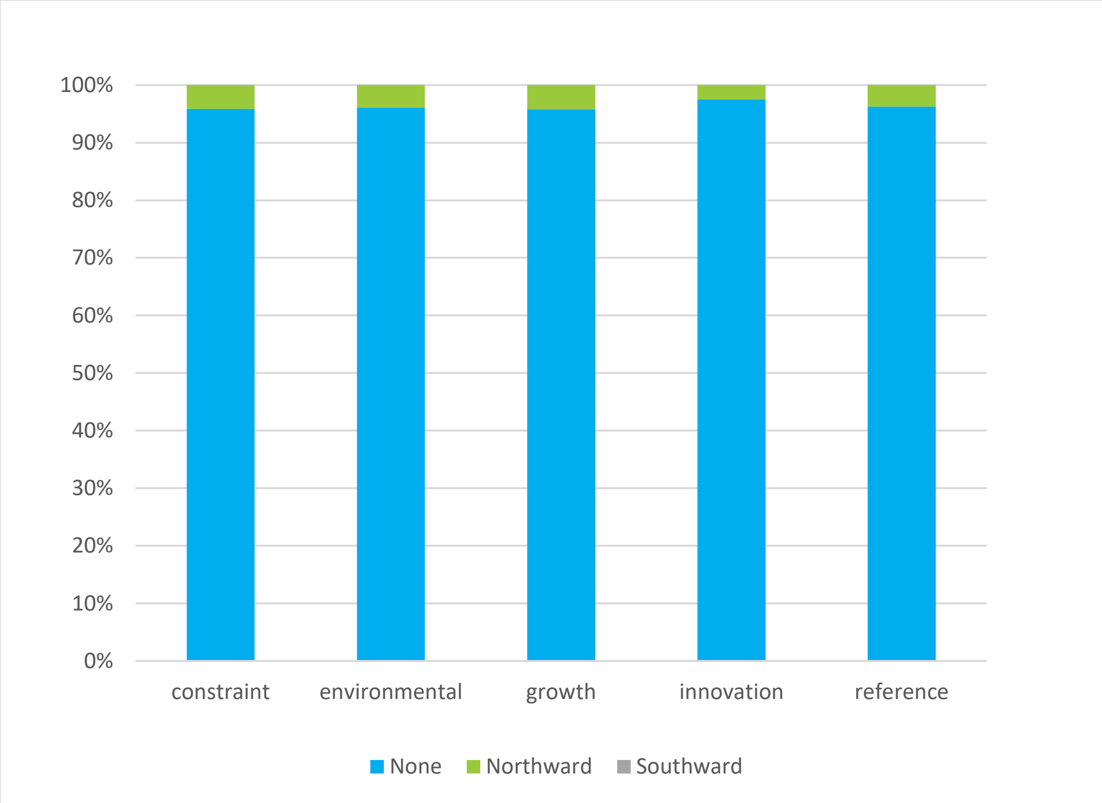
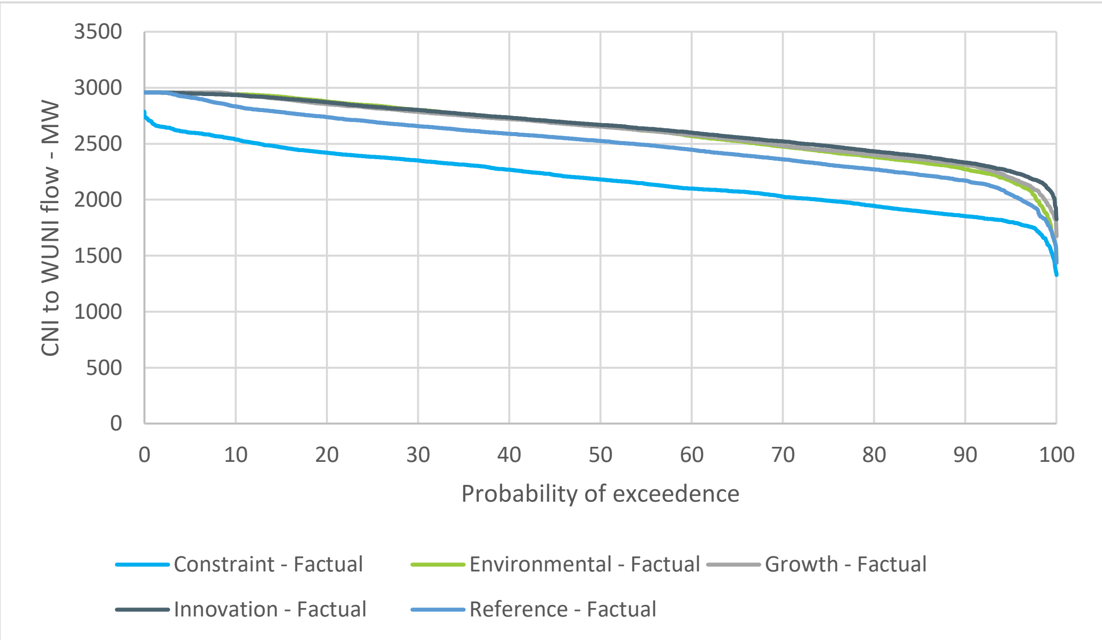


Figure A.5 CNI to WUNI flow duration curve for 2034



A.37 Load customers in the WUNI region and generators in the rest of the network are beneficiaries because the export constraint binds more often than the import constraint across the five scenarios in the counterfactual.

A.38 Conversely, load customers in the rest of the network and generators in the WUNI region are dis-beneficiaries.

A.39 This is illustrated by the following modelling results, which show time-weight average price (TWAP) impacts downstream (in the WUNI region) and upstream (in the rest of the network) of the constraint. Positive values indicate higher prices in the counterfactual than in the factual.

Figure A.6 Impact of BHL-PAK cable on OTA220 prices

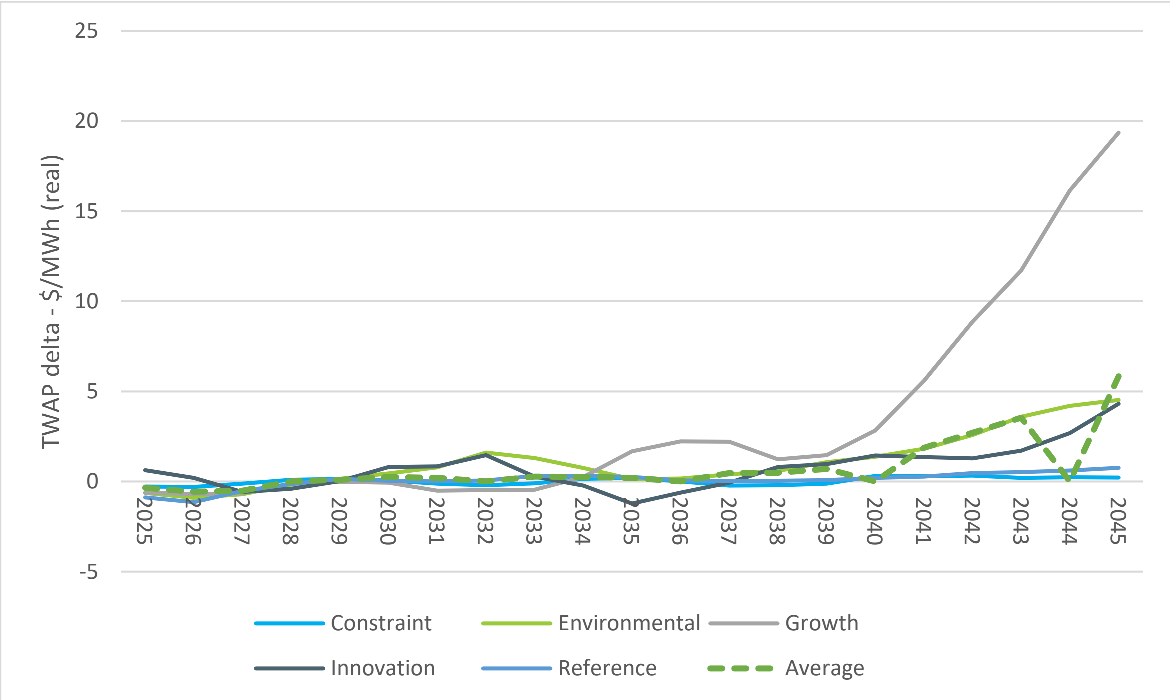
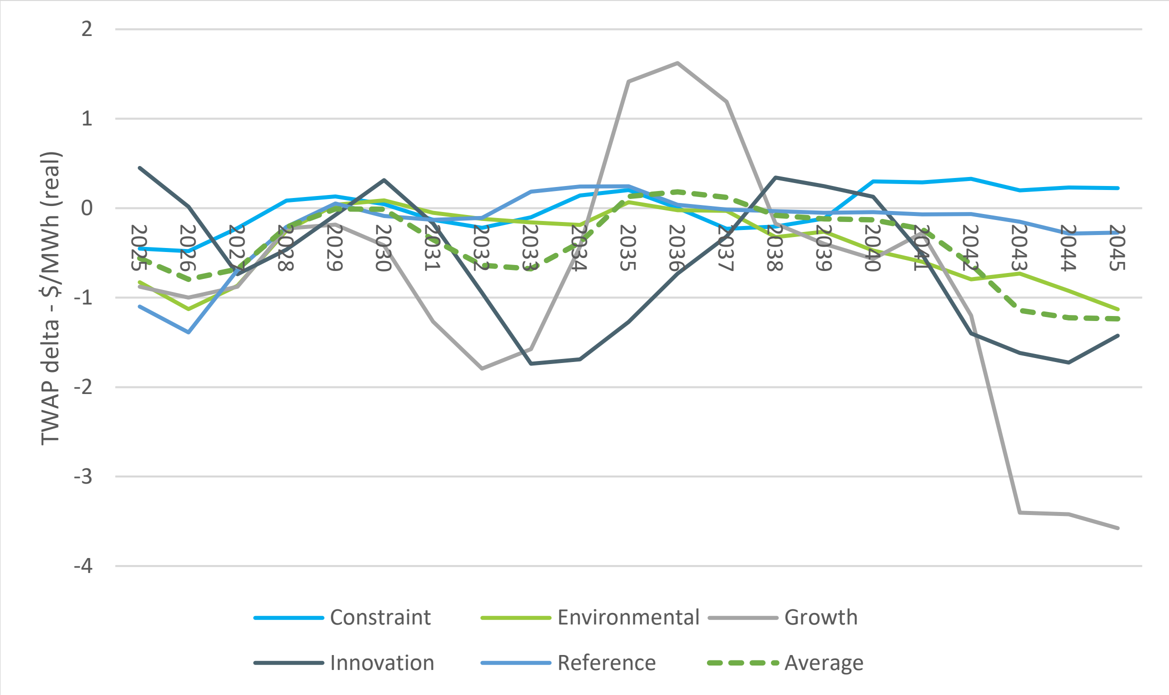


Figure A.7 Impact of BHL-PAK cable on HAY220 prices



Northward constraint frequency reduced by modelled projects until 2035 but then begins to grow again.

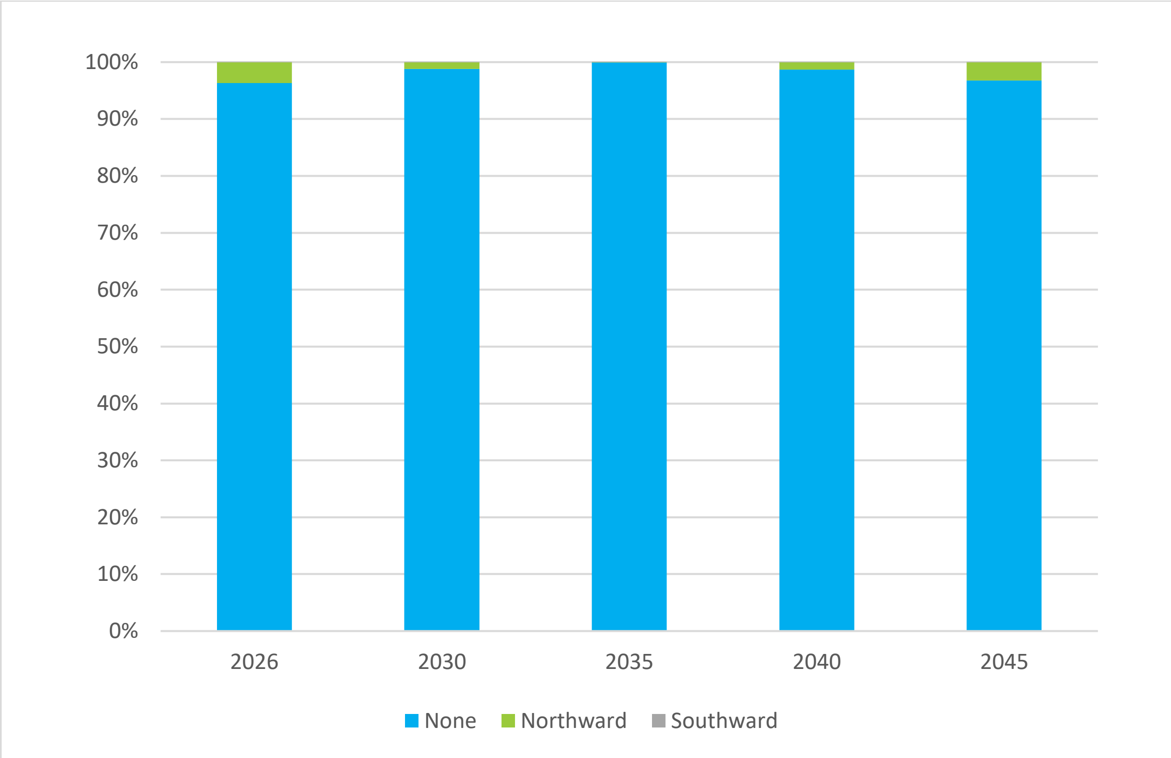
A.40 The periods during which the northward constraint bind decrease in the first few years of the modelling horizon due to modelled grid projects and some generation WUNI capacity expansion.

A.41 This effect is not sufficient to change the beneficiaries we have identified or the return to increasing periods of northward constraint in the counterfactual over the remainder of the modelling horizon.

A.42 The frequency of southward constraint remains very close to zero throughout the modelling horizon.

A.43 Figure A.8 shows how the frequency of constraints binding in each direction changes over the modelling horizon in the counterfactual.

Figure A.8 Frequency of binding constraints by year



Appendix B: New generation assumptions

B.1 We used the assumptions set out in the following tables for new generation (including decommissionings and increases to the capacity of existing generators) across the market scenarios.

Table B.1 Environmental new generation assumptions (MW)

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2026	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152
2027	757	-	-	130	115	-	-	-	-	-	31	-	-	-	-	-	-
2028	25	30	-	410	160	-	-	-	-	-	-	-	-	-	-	265	-
2029	7	20	26	-	-	-	-	-	-	-	-	290	-	-	467	275	189
2030	27	10	13	-	-	-	-	-	-	-	-	-	-	-	68	204	468
2031	-	30	4	-	-	-	-	-	-	-	64	-	-	-	-	216	319
2032	7	50	4	-	-	-	-	-	-	-	70	-103	-	-	-	312	43
2033	5	27	34	-	-	-	-	-	-	-	-	17	-	-	-	35	469
2034	18	55	62	53	134	89	-	-	-	-	51	-	-44	-	88	350	147

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2035	-	-	-	-	-	52	-	-	-	-	-	7	-200	-	-	-	1,049
2036	-	-	-	-	179	317	-	-	-	-	-	-440	64	-	-	-	-
2037	4	6	10	-	79	-	-	-	-	-	202	-	-	-	-	11	117
2038	-	-	-	-	62	-	-	-	-	-	78	-	-100	-	-	-	-
2039	17	57	-	129	17	-	-	-	-	-	141	-	-155	-	-	65	-
2040	-	-	38	12	3	-	-	-	3	-	25	-140	296	-	90	-	778
2041	14	34	8	19	183	-	-	-	-	-	25	-	-	-	63	560	56
2042	-	-	-	-	-	16	-	-	-	-	-	209	-	-	145	-	171
2043	-	-	75	-	-	254	-	-	-	-	20	21	-	-	-	-	-
2044	30	46	39	-	-	385	-	-	-	-	5	378	-	-	33	28	110
2045	-	-	-	-	-	94	-	-	-	-	-	-	-100	-	3	-	-
2046	-	-	-	-	-	-	-	-	68	-	-	-	-	-	123	-	-

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2047	-	50	-	-	475	194	-	-	16	-	25	-	-	-	127	131	-
2049	-	-	-	-	-	35	-	-	-	-	-	-	-	-	3	-	-
2050	-	-	-	-	-	46	-	-	-	-	-	-	-	-	-	1,039	-
2051	6	21	5	-	-	-	-	-	-	-	-	-	-	-	27	59	-
2052	16	40	2	-	-	-	-	-	-	-	-	-	-	-	73	-	-
2053	9	15	28	-	-	-	-	-	-	-	-	-	-	-	219	171	46
2054	-	20	-	-	-	-	-	-	-	-	-	241	58	-	-	-	-
2055	2	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table B.2 Constraint new generation assumptions (MW)

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2026	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152
2027	700	-	-	130	115	-	-	-	-	-	31	-	-	-	-	-	-
2028	2	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	6	17	10	-	-	-	-	-	-	-	-	-	34	-	-	71	-
2030	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	344	42
2031	-	-	-	-	-	-	-	-	-	-	-67	-	-	-	-	189	-
2032	15	-	10	-	-	-	-	-	-	-	-	-385	-	-	-	54	199
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-
2034	15	-	-	-	-	-	-	-	-	-	-	-	-44	-	-	134	453
2035	-	-	10	-	-	-	-	-	-	-	20	-478	-	-	-	54	199
2036	6	-	6	-	-	-	-	-	20	-	-	-	-	-	-	78	117
2037	-	-	-	-	-	-	-	-	-	-	-	-	-100	-	-	26	48

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2038	12	-	-	-	-	-	-	-	-	-	-	-	-155	-	-	65	38
2039	-	17	6	-	-	66	-	-	55	-	36	-162	-	-	-	259	103
2040	7	24	2	-	-	-	-	-	12	-	-	-	-	-	27	-	12
2041	-	-	-	-	-	-	-	-	-	-	64	211	-	-	-	27	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	-
2043	2	5	-	-	-	-	-	-	-	-	71	328	-	-	-	28	-
2044	-	-	8	-	-	-	-	-	-	-	-	-	-100	-	-	-	-
2045	8	25	27	-	-	-	-	8	-	-	61	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	361	100
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	202	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	-
2050	-	-	-	-	117	-	-	-	-	-	-	-	-	-	-	60	-

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2051	3	5	-	-	43	-	-	-	-	-	-	-	-	-	-	3	-
2052	-	-	-	-	-	-	-	-	-	-	-	-	326	-	-	-	-
2053	23	-	3	-	29	-	-	-	-	-	-	-	-200	-	136	1	-
2054	1	12	-	-	11	-	-	-	-	-	-	-	-	-	-	132	-
2055	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152

Table B.3 Growth new generation assumptions (MW)

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2026	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152
2027	700	-	12	130	115	570	-	-	-	-	31	-	-	-	-	-	-
2028	15	-	-	-	110	50	-	-	-	-	-	-	-	-	322	350	-
2029	18	-	7	83	67	-	-	-	-	-	-	-	-	-	166	71	456
2030	1	3	-	327	135	68	-	-	-	-	-	-	-	-	-	124	242
2031	1	4	1	-	105	32	-	-	-	-	30	-	-	-	-	264	42
2032	-	-	-	-	-	-	-	-	-	-	118	-	-	-	-	-	88
2033	5	-	5	-	-	-	-	-	-	-	181	-	-	-	-	-	198
2034	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	313	121
2035	-	-	6	25	-	89	-	-	-	-	50	-	32	-	-	63	180
2036	1	-	6	-	66	269	-	-	-	-	-	-720	303	-	-	-	316

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2037	5	-	2	28	-	32	-	-	-	-	137	-278	25	-	136	350	117
2038	-	10	-	-	-	-	-	-	-	-	23	112	-100	-	-	-	-
2039	4	-	6	-	-	-	-	-	-	-	115	361	-155	-	-	65	80
2040	-	-	-	-	174	-	-	-	-	-	25	-	-44	-	213	133	1,412
2041	-	20	1	34	255	-	-	-	70	-	-	-	-	-	86	-	12
2042	4	8	11	74	-	-	-	-	17	-	25	125	-	-	-	560	606
2043	-	-	16	92	365	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	3	-	-	73	576	-	-	-	-	-	295	-	-	-	28	64
2045	-	-	-	-	-	193	-	-	-	-	-	-	-100	-	-	-	-
2046	5	5	-	-	-	180	-	-	-	-	-	-	-	-	123	1,400	-
2047	-	6	5	-	-	-	-	-	-	-	-	-	115	-	412	-	-
2049	-	-	2	-	-	-	-	-	-	-	-	-	348	-	-	-	194

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2050	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	389
2051	-	13	-	-	-	-	-	-	-	-	-	-	-	-	55	144	436
2052	-	4	-	-	-	-	-	-	-	-	-	-	-	-	127	3	-
2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102	-	-
2054	8	4	4	268	-	-	-	-	-	-	-	397	-80	-	29	148	-
2055	2	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table B.4 Innovation new generation assumptions (MW)

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2026	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152
2027	702	7	60	130	115	516	-	-	-	-	31	-	-	-	-	159	122
2028	39	118	-	484	312	29	-	-	-	-	-	-	-	-	356	226	365
2029	38	114	4	78	121	68	-	-	-	-	-	-	-	-	356	278	225
2030	5	16	44	111	40	-	-	-	-	-	73	-	-	-	-	221	123
2031	12	29	20	115	361	117	-	-	-	-	-40	-	-	-	-	154	191
2032	34	34	6	53	43	-	-	-	-	-	140	-385	-	-	97	10	286
2033	-	-	55	-	-	-	-	-	-	-	-	-	-	-	-	116	-
2034	-	36	110	-	-	618	-	-	-	-	131	-	-	-	39	215	488
2035	-	-	-	-	-	-	-	-	-	-	-	496	-163	-	-	-	-
2036	14	22	-	-	420	92	-	-	-	-	49	-376	51	-	-	-	1,664
2037	6	58	11	77	9	-	-	-	10	-	-	-	-	-	199	11	158

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2038	2	22	-	123	49	40	-	-	-	-	76	-	-100	-	43	130	14
2039	28	72	7	-	115	-	-	-	-	-	78	30	117	-	30	180	85
2040	-	-	9	-	169	-	-	-	-	-	50	-185	-44	-	-	-	-
2041	12	26	16	-	31	45	-	-	-	-	72	18	-	-	27	205	39
2042	-	26	118	-	-	20	-	-	-	-	50	197	-	-	-	-	571
2043	-	-	83	-	-	400	-	-	-	-	-	30	-	-	137	-	190
2044	26	79	-	-	1	452	-	-	-	-	25	-	-	-	63	639	276
2045	-	-	-	-	-	-	-	-	63	-	-	-	-100	-	-	-	-
2046	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-
2047	6	18	-	-	200	510	-	78	-	-	25	-	-	-	-	377	145
2049	-	-	-	-	-	-	-	-	-	-	-	170	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	98	-	-	-	-	-

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2051	4	13	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-
2052	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2053	33	119	5	-	-	-	-	-	-	-	-	-	-	-	-	1	-
2054	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152

Table B.5 Reference new generation assumptions (MW)

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2026	402	-	-	171	229	1,105	-	-	-	-	-	-	-600	-	231	-	152
2027	700	-	25	130	115	288	-	-	-	-	31	-	-	-	-	-	-
2028	6	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	3	10	6	-	43	332	-	-	-	-	-	-	-	-	488	568	324
2030	13	-	7	-	-	-	-	-	-	-	-	-	-	-	-	351	220
2031	10	-	2	-	-	-	-	-	-	-	-67	-	-	-	-	-	-
2032	10	-	1	50	-	-	-	-	-	-	-	-	-	-	-	223	105
2033	18	-	-	68	101	-	-	-	-	-	-	-	-	-	-	34	-
2034	41	-	9	-	34	215	-	-	-	-	20	-	-44	-	-	302	-
2035	-	-	-	-	145	-	-	-	-	-	-	-	-	-	-	-	94
2036	-	-	-	-	45	-	-	-	-	-	100	-617	360	-	-	-	39
2037	1	3	4	246	236	-	-	-	-	-	65	-346	-	-	-	190	117

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2038	-	-	-	-	-	-	-	-	-	-	-	296	-100	-	-	-	-
2039	2	7	-	-	-	-	-	-	-	-	8	-	-155	-	-	65	227
2040	-	-	12	-	-	-	-	-	8	-	190	70	-	-	1	-	258
2041	9	-	2	-	-	-	-	-	-	-	-	-	-	-	73	-	12
2042	-	2	10	57	-	73	-	-	-	-	113	159	-	-	88	-	-
2043	-	-	-	-	64	170	-	-	-	-	-	-	-	-	-	-	-
2044	43	-	-	-	230	-	-	-	-	-	100	-	-	-	70	28	-
2045	-	-	-	3	-	-	-	-	-	-	-	-	-100	-	202	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	63	-	-	-	-	-
2047	-	-	14	304	343	-	-	-	-	-	-	106	-	-	-	-	991
2049	-	-	-	-	-	-	-	-	-	-	2	45	113	-	-	-	102
2050	-	-	-	-	-	-	-	-	-	-	46	-	-	-	-	-	17

	Battery			Grid Scale Solar			Hydro			Geothermal		Thermal			Wind		
	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	WUNI	NI ex. WUNI	SI	WUNI	NI ex. WUNI	SI
2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	502
2052	-	10	15	-	-	-	-	-	-	-	52	-	-	-	-	3	274
2053	-	17	3	-	-	-	-	-	-	-	-	-	-	-	-	-	28
2054	-	12	2	-	-	-	-	-	-	-	19	-	-161	-	-	1	512
2055	-	7	-	-	-	-	-	-	-	-	-	119	-	-	-	-	-

Appendix C: Potential regional customer group mapping

C.1 The table below shows a list of generators included in each potential regional supply group.

C.2 The potential modelled regions are:

- Waikato and Upper North Island (WUNI)
- Rest of North Island (RNI)
- South Island (SI).

Table C.1 Map of SDDP generators to potential regional supply group

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
Aniwhenua	SOU2	MAT	RNI	run of river
Arapuni1-5	MRPL	ARI	WUNI	storage
Arapuni6-8	MRPL	ARI	WUNI	storage
Aratiatia	MRPL	ARA	RNI	storage
Atiamuri	MRPL	ATI	RNI	storage
Aviemore	MERI	AVI	SI	storage
Benmore	MERI	BEN	SI	storage
BranchRiver	TRUG	ARG	SI	run of river
Clyde	CTCT	CYD	SI	storage
Cobb	TASM	STK	SI	storage
Coleridge	TRUG	COL	SI	storage
E3p	GENE	HLY	SI	commit
Edgcumbe	HRZE	EDG	WUNI	cogen
Glenbrook	NZST	GLN	RNI	cogen

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
Harapaki	MERI	HRP	WUNI	wind
Harapaki_Rpr	MERI	HRP	RNI	wind
Hawera	KIWI	HWA	RNI	cogen
Highbank	EASH	ASB	RNI	run of river
HuntC1	GENE	HLY	SI	commit
HuntC2	GENE	HLY	WUNI	commit
HuntC4	GENE	HLY	WUNI	commit
JunctionRd	TBOP	JRD	WUNI	peaker
Kaimai	POCO	TGA	RNI	run of river
Kaitawa	GENE	TUI	RNI	storage
Kapuni	TBOP	KPA	RNI	cogen
Karapiro	MRPL	KPO	RNI	storage
Kawerau_KAG	KWGL	KAW	WUNI	geo
Kawerau_TAM	HRZE	KAW	RNI	geo
Mahiner__Rpr	DUNE	HWB	RNI	wind
Mahiner_s1	DUNE	HWB	SI	wind
Manapouri	MERI	MAN	SI	storage
Mangahao	HORO	MHO	SI	run of river
Maraetai	MRPL	MTI	SI	storage
Matahina	TRUG	MAT	RNI	run of river
McKee	TBOP	MKE	RNI	peaker

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
MillCree_Rpr	UNET	WIL	RNI	wind
MillCreek	UNET	WIL	RNI	wind
Mokai12	MRPL	WKM	RNI	geo
NGA_OEC1	TOPE	KOE	RNI	geo
NgaAwaPurua	NAPA	NAP	RNI	geo
Ngatamariki	NTRG	NAP	WUNI	geo
NGB_OEC4	TOPE	KOE	WUNI	geo
Ohaaki	CTCT	OKI	RNI	geo
Ohakuri	MRPL	OHK	RNI	storage
OhauA	MERI	OHA	RNI	storage
OhauB	MERI	OHB	RNI	storage
OhauC	MERI	OHC	SI	storage
Onepu_KA24	CHHE	KAW	SI	geo
Onepu_TA2	CHHE	KAW	SI	geo
Onepu_TA3	CHHE	KAW	RNI	geo
Onepu_TOPP1	CHHE	KAW	RNI	geo
P40	GENE	HLY	RNI	peaker
Patea	TRUG	HWA	RNI	run of river
Piripaua	GENE	TUI	SI	storage
plant	cust_code	location	WUNI	type
Poihipi	CTCT	PPI	RNI	geo

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
Rangipo	GENE	RPO	RNI	run of river
Rotokawa	UNIS	WRK	RNI	geo
Roxburgh1_5	CTCT	ROX	RNI	storage
Roxburgh6_8	CTCT	ROX	RNI	storage
SFDOCGT	CTCT	SFD	SI	peaker
TaraW1	POCO	BPE	SI	wind
TaraW1_Rpr	POCO	BPE	RNI	wind
TaraW2	POCO	LTN	RNI	wind
TaraW2_Rpr	POCO	LTN	RNI	wind
TaraW3	TARW	TWC	RNI	wind
TaraW3_Rpr	TARW	TWC	RNI	wind
TCC	CTCT	SFD	RNI	commit
TeApiti	MELT	WDV	RNI	wind
TeApiti_Rpr	MELT	WDV	RNI	wind
TeHuka	UNIS	WRK	RNI	geo
TekapoA	GENE	TKA	RNI	storage
TekapoB	GENE	TKB	RNI	storage
TeMihi1	CTCT	THI	RNI	geo
TeReHau	TARW	TWC	RNI	wind
TeReHau_Rpr	TARW	TWC	RNI	wind
TeUku	WELE	TWH	WUNI	wind

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
TeUku_Rpr	WELE	TWH	WUNI	wind
Tokaanu1-2	GENE	TKU	SI	run of river
Tokaanu3-4	GENE	TKU	SI	run of river
Tuai	GENE	TUI	RNI	storage
Turitea	MSVP	LTN	RNI	wind
Turitea_Rpr	MSVP	LTN	RNI	wind
Waipapa	MRPL	WPA	RNI	storage
Waipipi	WAV1	WVY	RNI	wind
Waipipi_Rpr	WAV1	WVY	RNI	wind
Waipori1A	DUNE	HWB	RNI	storage
Waipori2A1	DUNE	HWB	RNI	storage
Waipori2A2	TRUG	BWK	SI	storage
Waipori2A3	TRUG	BWK	SI	storage
Waipori3	TRUG	BWK	SI	storage
Waipori4	TRUG	BWK	SI	storage
WairakiNet	CTCT	WRK	SI	geo
Waitaki	MERI	WTK	SI	storage
WestWind	MELW	WWD	RNI	wind
WestWind_Rpr	MELW	WWD	SI	wind
Whakamaru	MRPL	WKM	RNI	storage
Wheao	TRUG	ROT	RNI	run of river

SDDP generator	Customer	Connection location	Potential modelled region	Potential regional supply group
Whirinaki	CTCT	WHI	RNI	peaker
WhiteHil_Rpr	POWN	NMA	RNI	wind
WhiteHill	POWN	NMA	RNI	wind

C.3 The table below shows a list of load customers included in each potential regional demand group.

Table C.2 Map of load customers to a potential regional demand group

Customer	Connection location	Potential modelled region	Potential regional demand group
Counties Energy Ltd	BOB	non-industrial load and load with gen	Counties Power Ltd
Counties Energy Ltd	GLN	non-industrial load and load with gen	Counties Power Ltd
KiwiRail Holdings Ltd	HAM	industrial load	KiwiRail Holdings Ltd
KiwiRail Holdings Ltd	PEN	industrial load	KiwiRail Holdings Ltd
KiwiRail Holdings Ltd	SWN	industrial load	KiwiRail Holdings Ltd
New Zealand Steel Ltd	GLN	non-industrial load and load with gen	New Zealand Steel Ltd
Northpower Ltd	BRB	non-industrial load and load with gen	Northpower Ltd
Northpower Ltd	MPE	non-industrial load and load with gen	Northpower Ltd
Northpower Ltd	MTO	non-industrial load and load with gen	Northpower Ltd
Powerco Ltd	ARI	non-industrial load and load with gen	Powerco Ltd
Powerco Ltd	HIN	non-industrial load and load with gen	Powerco Ltd
Powerco Ltd	KPU	non-industrial load and load with gen	Powerco Ltd
Powerco Ltd	PAO	non-industrial load and load with gen	Powerco Ltd
Powerco Ltd	WHU	non-industrial load and load with gen	Powerco Ltd

Customer	Connection location	Potential modelled region	Potential regional demand group
Powerco Ltd	WKO	non-industrial load and load with gen	Powerco Ltd
Southpark Utilities Ltd	PEN	industrial load	Southpark Utilities Ltd
The Lines Company Ltd	HTI	non-industrial load and load with gen	The Lines Company Ltd
Top Energy Ltd	KOE	non-industrial load and load with gen	Top Energy Ltd
Vector Ltd	ALB	non-industrial load and load with gen	Vector Ltd
Vector Ltd	HEN	non-industrial load and load with gen	Vector Ltd
Vector Ltd	HEP	non-industrial load and load with gen	Vector Ltd
Vector Ltd	HOB	non-industrial load and load with gen	Vector Ltd
Vector Ltd	MNG	non-industrial load and load with gen	Vector Ltd
Vector Ltd	OTA	non-industrial load and load with gen	Vector Ltd
Vector Ltd	PAK	non-industrial load and load with gen	Vector Ltd
Vector Ltd	PEN	non-industrial load and load with gen	Vector Ltd
Vector Ltd	ROS	non-industrial load and load with gen	Vector Ltd
Vector Ltd	SVL	non-industrial load and load with gen	Vector Ltd
Vector Ltd	TAK	non-industrial load and load with gen	Vector Ltd
Vector Ltd	WEL	non-industrial load and load with gen	Vector Ltd
Vector Ltd	WIR	non-industrial load and load with gen	Vector Ltd
Vector Ltd	WRD	non-industrial load and load with gen	Vector Ltd
Waipa Networks Ltd	CBG	non-industrial load and load with gen	Waipa Networks Ltd
Waipa Networks Ltd	TMU	non-industrial load and load with gen	Waipa Networks Ltd
WEL Networks Ltd	HAM	non-industrial load and load with gen	WEL Networks Ltd

Customer	Connection location	Potential modelled region	Potential regional demand group
WEL Networks Ltd	HLY	non-industrial load and load with gen	WEL Networks Ltd
WEL Networks Ltd	TWH	non-industrial load and load with gen	WEL Networks Ltd

Appendix D: Demand forecasts

D.1 This section outlines our approach to developing GXP level forecasts that are consistent with the 2024 Electricity Demand and Generation Scenarios (EDGS) produced by the Ministry of Business, Innovation and Employment (MBIE). It also documents reasonable variations that Transpower has made to the EDGS.

Summary

D.2 We have attempted to closely align with the EDGS forecasts produced by MBIE, but we have chosen to vary some assumptions based on other information available.

D.3 The main areas of variation include:

- Increasing MBIE's energy figures to include distribution losses. MBIE's figures relate to household consumption so do not include distribution losses. We have added 3.5% to MBIE's figures consistent with the approach we took in developing scenario for our Net Zero Grid Pathways Major Capex Project.
- 'Rebasing' the forecasts to account for new actuals. MBIE's figures were produced in 2024 with 2025 as the first forecast year. As data for 2025 is now available we have adjusted the forecast figures we align with to reflect the 2025 values. In effect we have moved the forecast figures up or down so that the align with 2025 actual figures.
- Adjusted process heat electrification uptake. The rate of uptake of electrification, informed by s-curves in the EDGS, appears to be very fast in the 2030 to 2035 period. We have reduced the assumed speed of uptake. Our 2055 values are like the 2050 values final by MBIE, but our uptake is significantly slower.
- Modest attempt to algin with MBIE's peak forecasts. As we model profiles in detail, we have not imposed a restriction that national level peak demand should align with the figures in EDGS. For "base" peak demand (e.g. underlying demand from normal GDP and population growth) we have assumed it will grow at a GXP level based on a combination of historical trends and historical peak to energy ratios. For components like new EVs we have modelled charging profiles and "smartness" in the way EVs charge to determine their contribution to peak demand.

Table D.1 Summary table of EDGS 2024 and EDGS 2024 variations for 2050

		EDGS 2024					Transpower				
Scenarios	Year	Base Energy (TWh)	Solar Capacity (GW)	Data Centre (TWh)	EV (TWh)	Fuel Switching (TWh)	Base Energy (TWh)	Solar Capacity (GW)	Data Centre (TWh)	EV (TWh)	Fuel Switching (TWh)
Innovation	2030	41.5	3.8	1.4	5.7	0.8	43	2.4	1	3.3	0.8
	2040	43	4.6	5.5	13.3	1.5	44.5	3.6	5.2	9.4	1.5
	2050	43.6	4.6	10.1	13.7	2.8	45.2	3.6	9.8	12.1	2.8
Environmental	2030	41.6	1.8	1.3	5.6	0.8	43.1	0.5	1	2.3	0.8
	2040	43.8	1.8	5.3	12.4	1.5	45.4	0.7	4.9	7.4	1.5
	2050	44.6	1.8	9.6	12.6	2.8	46.2	0.7	9.2	10.5	2.8
Growth	2030	42.1	3	1.4	1.7	0.8	43.5	1	1.1	2.6	0.7
	2040	45.8	3	5.9	7.5	1.2	47.4	2	5.6	5.6	1.2
	2050	48.3	3	11.3	9	1.9	50	2	11	8.1	1.9

Scenarios	Year	EDGS 2024 Base Energy (TWh)	Solar Capacity (GW)	Data Centre (TWh)	EV (TWh)	Fuel Switching (TWh)	Transpower Base Energy (TWh)	Solar Capacity (GW)	Data Centre (TWh)	EV (TWh)	Fuel Switching (TWh)
Reference	2030	41.7	1.8	1	1.6	0.7	43.2	0.5	0.8	2.2	0.7
	2040	42.8	1.8	4.4	6.8	1.1	44.3	0.7	4.1	4.1	1
	2050	43.5	1.8	8.9	7.8	1.5	45	0.7	8.6	6.4	1.5
Constraint	2030	40.9	0.9	0.8	1.6	0.7	42.3	0.5	0.5	1.1	0.7
	2040	40.3	0.9	3	6.3	0.8	41.7	0.5	2.7	2.4	0.8
	2050	39.4	0.9	6.6	6.7	1	40.8	0.5	6.3	4.4	1

Our modelling process

D.4 We have a two-stage modelling process. Stage 1 considers how underlying, business-as-usual growth will evolve. We consider specific information from distribution companies (referred to as customers) and major electricity users about their expectations of future demand. The process produces our national level base peak and energy forecasts. Stage 2 considers how the uptake of electric vehicles, solar photovoltaic panels, battery storage and industrial electrification will impact demand.

D.5 In developing our forecasts, we bring 2024 EDGS projections at a national level of different components into our models. We supplement these assumptions with GXP level information obtain from our annual survey of distribution companies and other more detailed information. The detailed treatments of each component and our adjustments will be discussed further below. Generally, we weighted our forecast more towards customer forecast in the near-term and EDGS 2024 projection more by 2040.

Input from annual customer survey

D.6 Each year, we send out survey to major Electricity Distribution Business (EDBs), who are well-placed, to advise on local growth at their connected GXPs and additional information like solar and battery installation numbers and new step loads etc. Considering the uncertainty of the project realisation, we ask for a confidence rating for each new load reported. It is illustrated in the table below.

Table D.2: Demand confidence rating

Likelihood	Notes to inform confidence
90-100%	Committed projects, projects with finance, consents, construction contracts etc.
75-90%	Projects where some aspects of the project have been completed (e.g. consents and finance) but some still have to be completed (e.g. construction contract).
50-75%	Projects that are likely to take place, but aspects of the project are still to be finalised.
0-25%	More speculative projects that are still highly uncertain

D.7 The size of the steps in MW was requested both for summer and winter seasons. The steps were designated as either ‘Nameplate’ or ‘Expected GXP Increase’. Steps designated as ‘Nameplate’ were given an appropriate half-hourly profile with the given step’s size. Steps designated as ‘Expected GXP increase’ were given a profile that increased the GXP peak by the amount given.

D.8 In developing our EDGS scenarios, we include steps for different scenarios based on the likelihood and MBIE's descriptions of each scenario. For example, Constraint only contains steps from committed projects, while Innovation contains highly uncertain projects. The likelihood threshold for each scenario is:

Scenario	Growth	Environmental	Innovation	Constraint	Reference
Likelihood (inclusive)	60%	60%	10%	90%	70%

D.2.10 Rebase

D.6 In the two years since the end of the data gathered for the EDGS 2024 release, our understanding of many demand components has changed materially. We think it is more plausible to shift projection year forward to reflect the passage of time. The term rebase refers to rebase the first forecast year, where the component projection starts, to be 2026 instead of 2024. As a result, there will be no component in the current year. All components forecast start from the first forecast year. We are comfortable that previous forecast components like EV and fuel switching are reflected in historical data. Therefore, forecast earlier than the forecast year subtracted from the forecast

D.7 We have applied rebase in treating all MBIE's component projections, with the exception of rooftop solar.

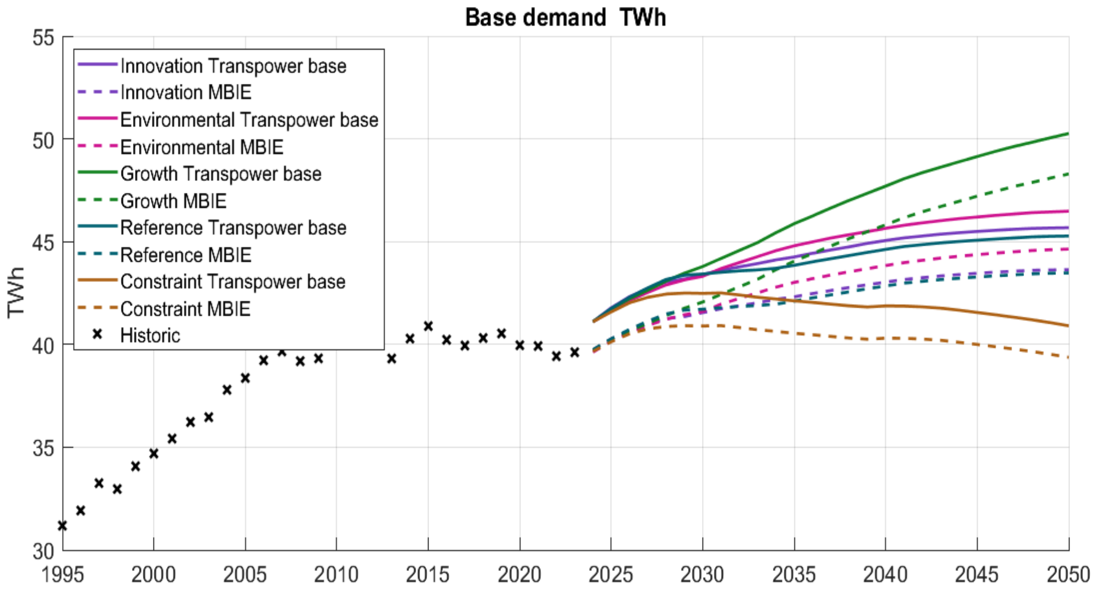
D.2.11 Base Energy

D.6 Base demand equals traditional electricity consumption by domestic, commercial and industrial consumers, but it excludes industrial process heat and transport consumption, which are considered separately.

D.7 Base energy used in our forecast is informed by extra data provided by MBIE. We used historical regional to national ratio to derive regional and island energy forecast.

D.8 We are interested in the electricity demand at our substations before the distribution process. Therefore, we change the EDGS electricity demand forecasts into substation-level forecasts by subtracting embedded generation and adding distribution line losses. This is consistent with NZGP1. The resulting difference is illustrated by Figure D.1. We have made 2026 as our first forecast year, and rebase our final data year to 2025, 2 years forward of 2023 when EDGS was firstly published. We have subtracted the forecast value of these two years from the total forecast as we believe they are reflected in historical data. The final national energy forecast is very close to EDGS 2024 for all scenarios plus the distribution loss.

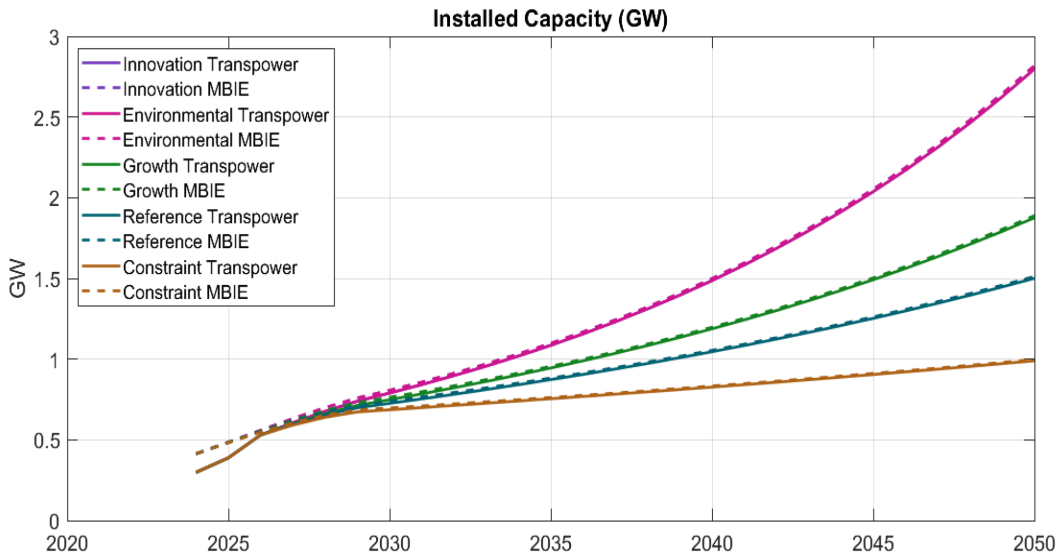
Figure D.1 Stage 1 base energy demand and MBIE EDGS 2024 base energy demand



D.2.12 Solar installed capacity

D.13 Solar uptake generally matches well. Noted that compared to other demand components, we do not treat solar installations as incremental.

Figure D.2 Installed solar capacity

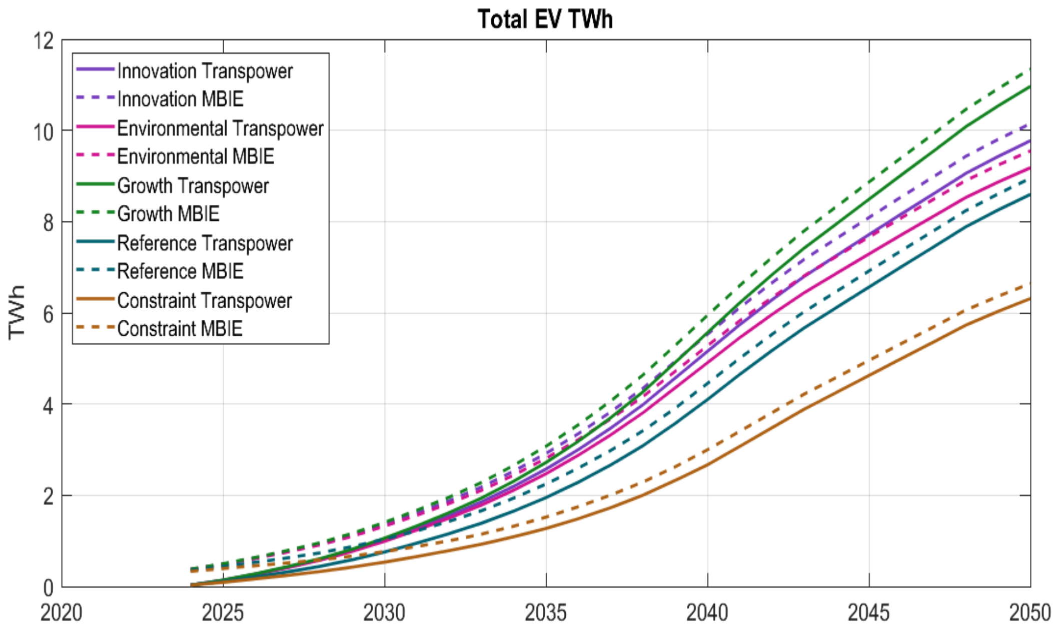


D.2.13 EV

D.14 Smart and fixed EV are forecasted separately in our model. To bring MBIE's projection into our assumption, we use our ratio of light and heavy EV loads to disaggregate the MBIE transport loads into Light and Heavy EV loads. Furthermore, we have applied the rebase discussed above to EV forecast.

D.15 The final combined EV load matches well. There are some slight differences at the start of the forecast as our process aligns with customers' EV forecast.

Figure D.3 Forecast EV uptake



D.2.14 Fuel switching

D.16 Our current forecast does not differentiate process heat and fuel switching. MBIE projection of fuel switching is therefore, brought in as process heat. We input process heat as low, medium and high. We have the following classification of MBIE's sectorial breakdown of fuel switching:

EDGS 2024 Category	Corresponding Transpower Category
Residential Fuel Switching	Low Temperature Process Heat
Commercial Fuel Switching	Medium Temperature Process Heat
Industrial Fuel Switching	High Temperature Process Heat

D.17 EDGS 2024 uses a 2023 data horizon and S-curve assumptions that create a wide scenario spread by 2026 (0.2–2 TWh). Given new information available through 2025, such uncertainty is no longer realistic. We think rebasing the first forecast year to 2024 is necessary.

D.18 Furthermore, we have made following adjustments to MBIE's projection:

2026-2030	2030-2040	2040 onwards
Match customer-supplied forecasts based on known projects	Apply a smooth S-curve transition to converge to MBIE EDGS 2024 trajectories	Aligned fully with MBIE EDGS 2024 taking account of long-term uncertainty.

D.19 Transpower's customer forecasts show approximately ~2 TWh realistic fuel switching by 2030. By comparison, the high EDGS 2024 high scenarios reach approximately 6 TWh by 2030, which is no longer appears plausible, while the low EDGS scenarios appear too low given the scale of projects already underway.

D.20 The customer forecasts reflect real projects, network constraints, and credible timelines.

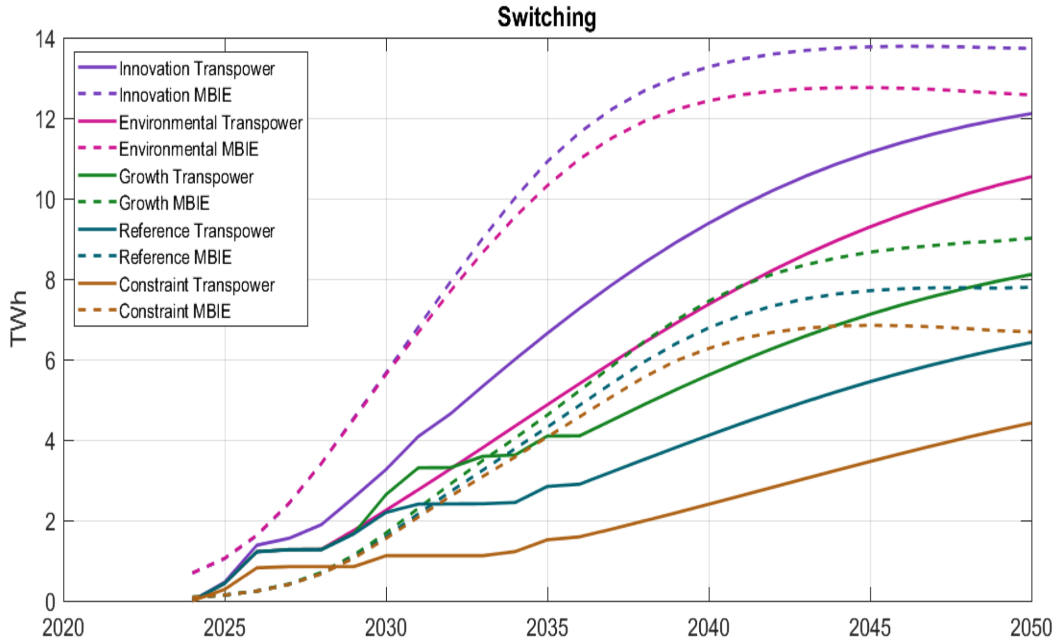
D.21 Analysis of the Electricity Authority's generation pipeline shows that approximately 6.8 TWh of likely new generation is likely by 2030 (solar, geothermal, wind). After subtracting expected new data-centre load and transport electrification, the remaining headroom is approximately only ~2 TWh under the Innovation scenario, and ~4 TWh under the Environmental scenario. This effectively caps feasible fuel-switching electricity demand by 2030.

D.22 EECA's RETA analysis also indicates further support for lower near-term fuel switching. The RETA MAC-optimised pathway reaches ~2 TWh by 2030. Although fuel switching is materially higher over the longer term, the analysis remains consistent with lower electrification over the near term and provides further evidence that the high EDGS 2024 scenarios are too aggressive for the 2026–2030 period.

D.23 As a result, the uncertainty – high and low – shown in the EDGS 2024 fuel switching assumptions in the near term does not appear to be fit for purpose for Transpower's 2026 forecasts to be used in Investment Tests. The low scenarios appear too low relative to the demand expected from projects that are already well advanced and the high scenarios appear out of line with all current information available to distribution networks as well as the expected new generation in the pipeline.

D.24 The resulting Transpower forecast is lower in the near term but accelerates beyond 2040 and catches up with MBIE's forecast.

Figure D.4 Switching

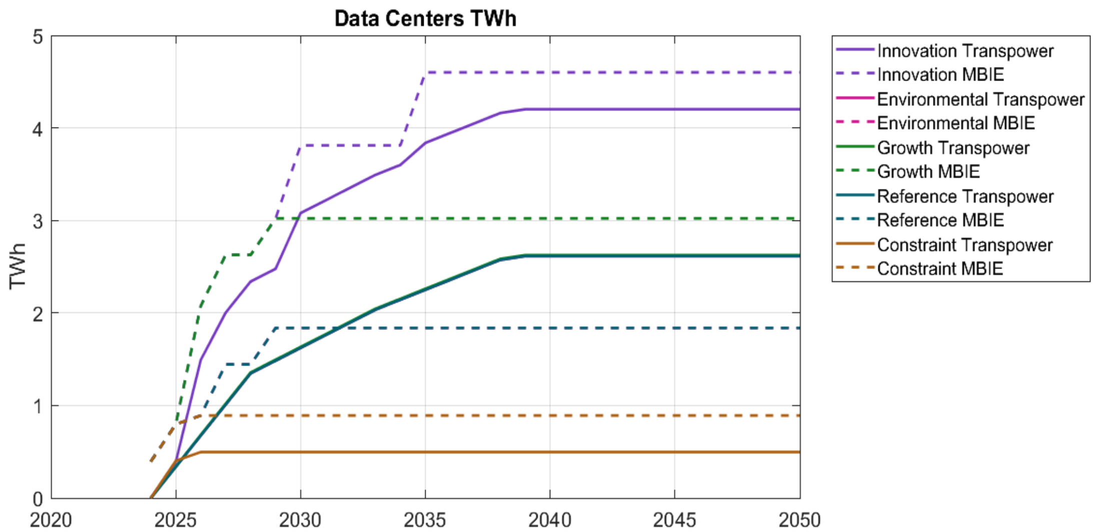


D.2.15 Data centres

D.25 We applied rebase to data centre assumptions as well for the similar reason.

D.26 Our data centre forecast input include customer reported data centre projects. They are included in different scenarios based on threshold discussed above. As a result, we have lower end-year results compared to MBIE.

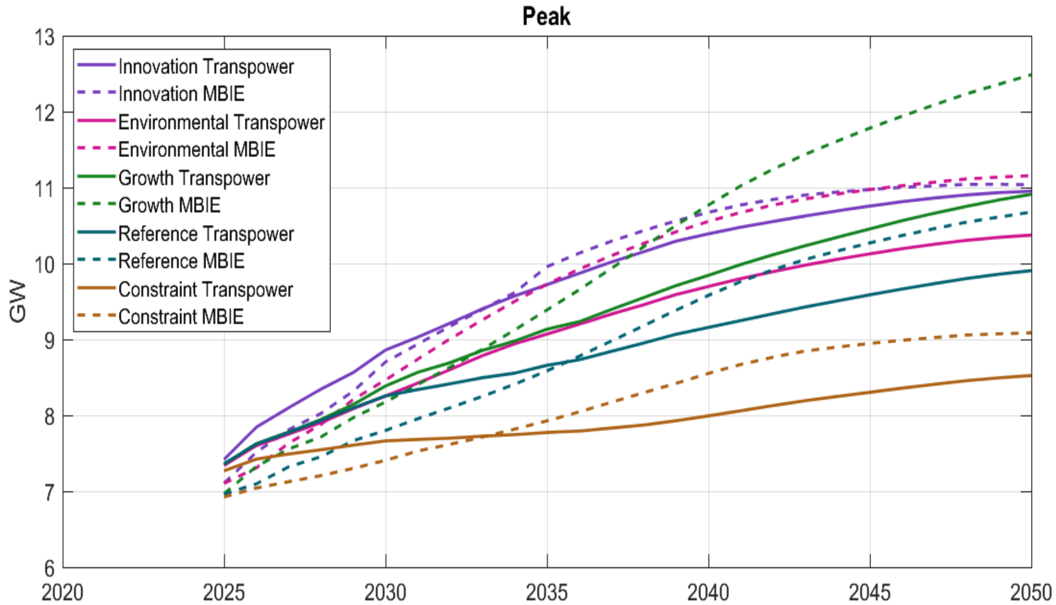
Figure D.5 Data centre forecast



D.2.16 Base peak growth

D.27 Although energy demand forecasting is a critical part of developing scenarios for transmission planning, the grid is largely planned around peak electricity demand. In developing EDGS 2024 scenario, we calculate the historical energy and peak correlation and use MBIE's national energy forecasting to produce base peak demand forecast for different levels (national, island and regional). We then create complete half hourly profiles for all levels use the base forecast, in combination with historical half-hourly profiles and assumptions of the uptake of different technologies that shave the peak. Consistent with NZGP1, our base peak forecast is lower.

Figure D.6 Base peak growth



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