

TPM consultation: CNI proposed starting BBI customer allocations

Draft Record of application of the price-quantity method

Date: 27 April 2023



Contents

1	Introduction	3
2	Define BBI and determine BBI type and sub-type	4
3	Determine factual and counterfactual.....	7
4	Determine market scenarios	8
5	Calculate reliability regional NPB	12
6	Calculate ancillary service regional NPB	13
7	Calculate other regional NPB	14
8	Calculate market regional NPB.....	15
9	Calculate individual NPB and starting BBI customer allocations	33
	Appendix A: Modelling results	37
	Appendix B: Glossary	43

1 Introduction

1. This **draft record** presents our application of the price-quantity method to calculate the Central North Island (**CNI**) benefit-based investment's (**BBI's**) proposed starting BBI customer allocations under the transmission pricing methodology (**TPM**).¹ The CNI BBI is one component of the NZGP1.1 major capex proposal.² We refer to the starting BBI customer allocations as the **starting allocations**.
2. We modelled the CNI BBI using the input assumptions from our application of the investment test for the NZGP1.1 major capex proposal. These are generally consistent with the input assumptions in chapter 2 of the BBC assumptions book (**assumptions book**).³ We have generally followed the processes in section 3.2 and 3.3 of chapter 3 of the assumptions book to calculate the CNI BBI's proposed starting allocations. Where we have used different input assumptions or processes than those in the assumptions book, we have stated them in this draft record.
3. We have defined some terms in this draft record for convenience. Please also reference the glossary in Appendix B.⁴ Other terms used in this draft record have the meanings given to them in the TPM. All clause references are to clauses in the TPM, unless stated otherwise.
4. This draft record is structured as follows:
 - Sections 2-9 of this document step through the processes in sections 3.2 and 3.3 of the assumptions book as applied to this BBI.
 - Appendix A describes some of the modelling results from our wholesale market model (SDDP) to help stakeholders understand the proposed starting allocations.
 - Appendix B contains a glossary of terms used in this document.

¹ The TPM, as published by the Electricity Authority (Authority) on 20 December 2022, is in [Part 12, Schedule 12.4 of the Electricity Industry Participation Code](#).

² [Net Zero Grid Pathways 1 – Major Capex Proposal \(Staged\)](#).

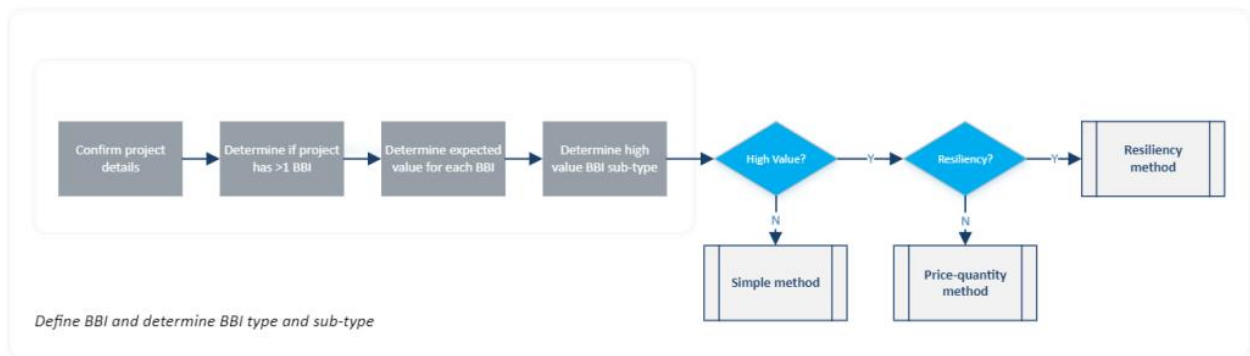
³ [TPM Determination: BBC Assumptions Book v1.1, 16 March 2023](#).

⁴ The definitions in Appendix B are consistent with the assumptions book definitions.

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 to the CNI BBI (and as shown in Figure 1).

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



2.1 Confirm project details

6. The CNI 220 kV transmission system consists of the 220 kV Bunnythorpe–Whakamaru A and B lines and the 220 kV Bunnythorpe–Wairakei A line. These 220 kV circuits form part of the grid backbone. The lower North Island also has a 110 kV network, which is mainly supplied through the 220/110 kV interconnecting transformers at our Bunnythorpe substation. The direction of power flow through the region is determined by generation, direction of HVDC flow, and demand outside of the region. The CNI region is a main corridor for 220 kV transmission circuits through the North Island.
7. The NZGP1.1 proposal seeks to increase transfer capacity north from Bunnythorpe by 60-90% by:
- implementing Variable Line Rating and tactical thermal upgrade (TTU) of both 220 kV circuits on the Tokaanu-Whakamaru A and B lines to 95°C,
 - duplexing the 220 kV Tokaanu-Whakamaru A and B circuits with Goat conductor to operate at a maximum temperature of 120°C,
 - implementing VLR and TTU of the 220 kV Bunnythorpe-Tokaanu A and B circuits to 95°C,
 - splitting the 110 kV Bunnythorpe-Ongarue A circuit at Ongarue,
 - upgrading protection on the 220 kV Huntly – Stratford 1 circuit on the Huntly-Taumaranui A line and Stratford-Taumaranui A line, between Huntly and Stratford, and
 - replacing the special protection scheme at Tokaanu.
8. The application of the investment test to NZGP1.1 quantified changes in the cost of transmission losses, deficit (i.e. unsupplied demand), thermal operating costs, capital and fixed costs of generation, and emissions costs – all of which we consider to be market benefits as defined in the TPM. The application of the investment test to NZGP1.1 did not quantify any

reliability, ancillary service, resiliency, or other benefits relating to the NZGP1.1 preferred options, including the CNI BBI (see sections 2.4, 5.1, 6.1 for more detail).

9. The fully commissioned asset value of the CNI BBI is expected to be \$257m. There will be no transmission alternative opex associated with the CNI BBI.
10. We expect the CNI BBI to be fully commissioned by the end of 2027,⁵ if the NZGP1.1 proposal is approved by the Commerce Commission. The CNI BBI is therefore a post-2019 BBI.
11. All of the principal benefits of the CNI BBI are expected to be released by the assets commissioned before the end of 2027. The CNI BBI's expected effective full commissioning date is 2027 (during FY 27/28).

2.2 Determine if project has >1 BBI

12. We applied the principles in paragraph 219 of the assumptions book to consider whether the CNI BBI should be combined with other investments in NZGP1.1 (e.g. the HVDC Reactive Support and the Wairakei Ring projects). We decided the CNI BBI should be a separate BBI from both the HVDC Reactive Support and Wairakei Ring projects because the BBIs:
 - are in different electrical regions of the grid i.e. the link between the North and South Islands (HVDC Reactive Support project) vs. the central North Island (CNI project) and the region north of Taupo (Wairakei project), and therefore are likely to have different beneficiaries;⁶
 - have different periods in which the benefits accrue to beneficiaries – in addition to the CNI BBI's benefits resulting from relieving constraints, an important aspect of the CNI BBI's benefits results from it reducing transmission losses which occur whenever power is flowing through the CNI. The HVDC Reactive Support BBI only provides benefits when flow is approaching the existing capacity of the HVDC; and
 - have different expected commissioning dates.⁷
13. We have not included NZGP1's proposed reconductoring of the Brunswick-Stratford A line as part of the CNI BBI as that is a second stage of NZGP1 for which we are not currently seeking approval from the Commerce Commission.

2.3 Determine expected value of each BBI

14. The fully commissioned asset value of the CNI BBI is expected to be \$257m. There will be no transmission alternative opex associated with the CNI BBI.

⁵ See section 3.3.5 of [NZGP1 Attachment D – Scenario and Modelling Report](#).

⁶ For example, we expect generators in the Wairakei region will benefit from the Wairakei Ring but not the HVDC Reactive Support or CNI projects.

⁷ The majority of the assets that make up the HVDC Reactive Support, CNI, and Wairakei investments are expected to be commissioned by 2026, 2027, and 2024 respectively – see section 3.3.5 of [NZGP1 Attachment D – Scenario and Modelling Report](#).

15. As the sum of the BBI's fully commissioned asset value and transmission alternative opex is greater than the base capex threshold specified in the Capex IM,⁸ the CNI 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 its starting allocations.

2.4 Determine high-value BBI sub-type

16. There are no material resiliency risks being mitigated by the CNI BBI – its need is not primarily attributable to mitigating a risk of cascade failure or a high impact low probability (**HILP**) event. This is consistent with the application of the investment test, which did not quantify any resiliency benefits associated with the CNI investment.
17. Therefore, the CNI 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

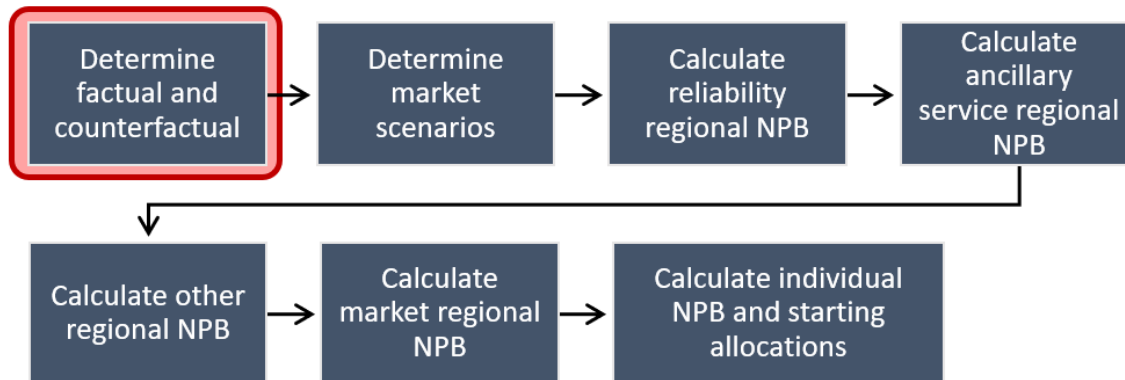
18. We are required to treat the CNI BBI as a separate post-2019 BBI because it:
- is an enhancement investment commissioned after 23 July 2019 (clause 37(3)), and
 - is not an exempt post-2019 investment (it will be commissioned after 1 July 2021) (clause 37(5)).

⁸ [Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf \(comcom.govt.nz\)](https://www.comcom.govt.nz/Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf)

3 Determine factual and counterfactual

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

Figure 2: Determine factual and counterfactual



3.1 Determine factual

20. The factual is the grid state after the CNI BBI has been fully commissioned.

3.2 Determine investment type and counterfactual

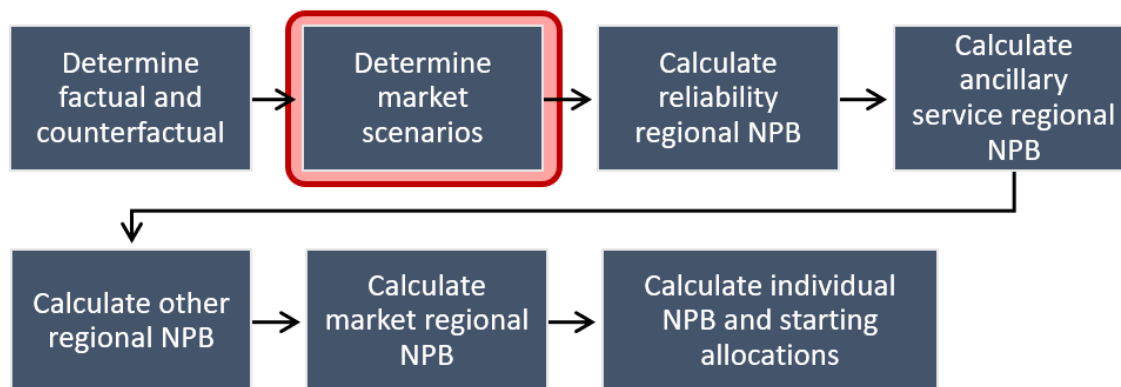
21. The CNI BBI does not constitute a refurbishment or replacement investment as defined in the TPM (which refers to the corresponding definitions in the Transpower Capex IM⁹). It is therefore an enhancement investment.
22. Consistent with clause 45(2)(a), the counterfactual is the current state of the grid in the CNI without the CNI BBI.

⁹ [Transpower Capital Expenditure Input Methodology Determination](#), definitions of “asset refurbishment” and “asset replacement”.

4 Determine market scenarios

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

Figure 3: Determine market scenarios



4.1 Obtain market scenarios used in consultation

24. We have used the market scenarios from the NZGP1.1 proposal, as described in Attachment D.¹⁰ Unless otherwise stated in section 4.2 of Attachment D, these are consistent with the assumptions in v1.1 of the assumptions book.¹¹ Section 8.3 presents the additional assumptions used that are not shown in either Attachment D or the assumptions book.

4.2 Obtain market scenarios from the assumptions book

25. We have not departed from the market scenarios or modelling inputs used in the application of the investment test, as we consider these will produce starting allocations that are broadly proportionate to EPNPB.

4.3 Determine if different market scenarios are required

26. We have not departed from the market scenarios or modelling inputs used in the application of the investment test, as we consider these will produce starting allocations that are broadly proportionate to EPNPB.

¹⁰ [NZGP1 Attachment D – Scenario and Modelling Report](#), December 2022.

¹¹ In addition to the assumptions described in section 4.2 of Attachment D, we also assume the Te Rapa generation plant closes in 2023 both here and in NZGP1.1's application of the investment test. This assumption is based on Contact's [June 2022 announcement](#).

4.4 Determine if sensitivities should be modelled

27. 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.
28. In the application of the investment test to NZGP1.1, the Tiwai Point aluminium smelter (**Tiwai**) is assumed to close in December 2024, with a sensitivity of Tiwai closing in 2034 (as noted in section 1.5.1 of the NZGP1.1 proposal). Therefore, we have included this sensitivity in our application of the standard method.
29. The NZGP1.1 proposal did not assess any other sensitivities relating to the market scenarios. On the basis that we do not consider any other sensitivities meet the assumptions book criteria at section 3.3.2.6 and for consistency with the assumptions used in the application of the investment test, we have not used any other sensitivities (consistent with clause 43(5)).
30. Therefore, there are 10 scenarios used in total – the five Electricity Demand and Generation Scenarios (**EDGS**) scenarios, each with Tiwai leaving in 2024 and 2034.¹²
31. We note that applying clause 46(3) (excluding scenarios for New Zealand’s Aluminium Smelter (**NZAS**)) does not make any difference to the starting BBI customer allocations because NZAS does not receive any positive individual Net Private Benefit (**NPB**) under either of the 2024 or 2034 scenarios.¹³

4.5 Determine the weightings to be applied

32. As described in section 4.1.1 of the proposal, the application of the investment test gave equal weighting to the five EDGS scenarios.
33. The proposal did not explicitly state a weighting for the Tiwai sensitivities (2024 and 2034). As discussed in section 1.5.1 of the proposal:

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

34. Therefore, we consider an equal weighting for the Tiwai 2024 and 2034 scenarios best reflects the assumptions used in the application of the investment test, and will produce allocations that are broadly proportionate to EPNPB.

¹² [Electricity demand and generation scenarios \(EDGS\) | Ministry of Business, Innovation & Employment \(mbie.govt.nz\)](https://www.mbie.govt.nz/electricity-demand-and-generation-scenarios-edgs).

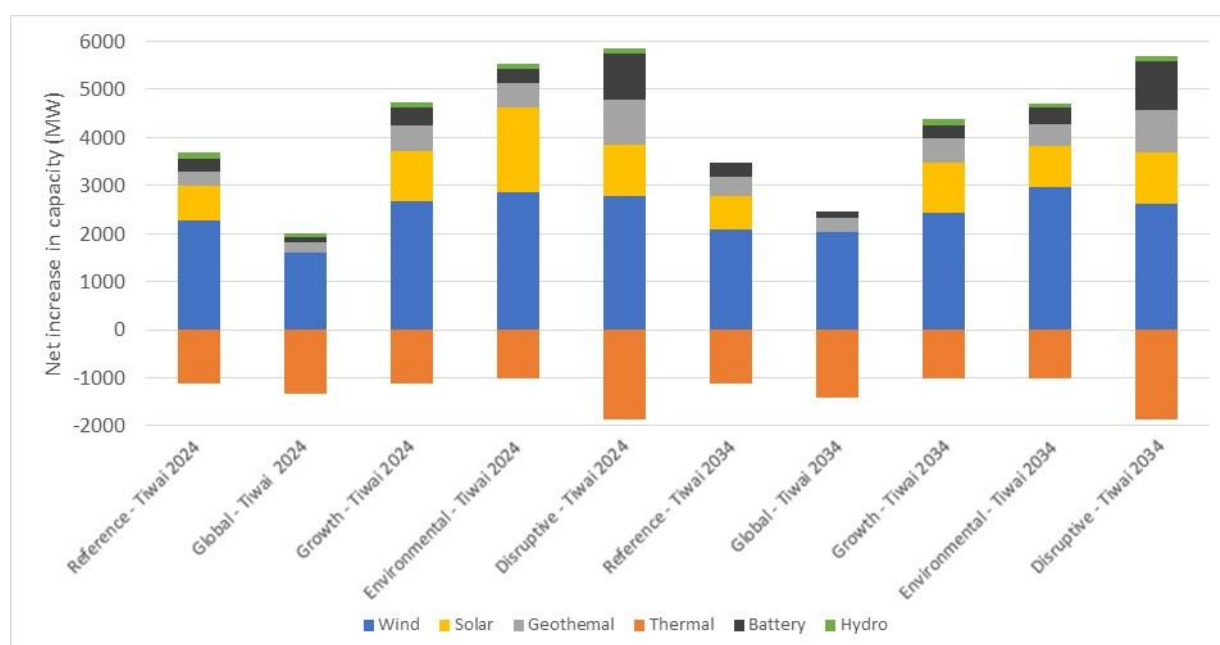
¹³ Clause 46(3) is relevant to situations where a customer exists in some scenarios and not in others (i.e. receives a benefit in some scenarios and not others). Because NZAS does not receive a positive individual NPB in either the 2024 or 2034 scenarios, it does not matter which of these scenarios we use to calculate its individual NPB as it will always be zero.

4.6 Hydro, load, and generation expansion variations

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

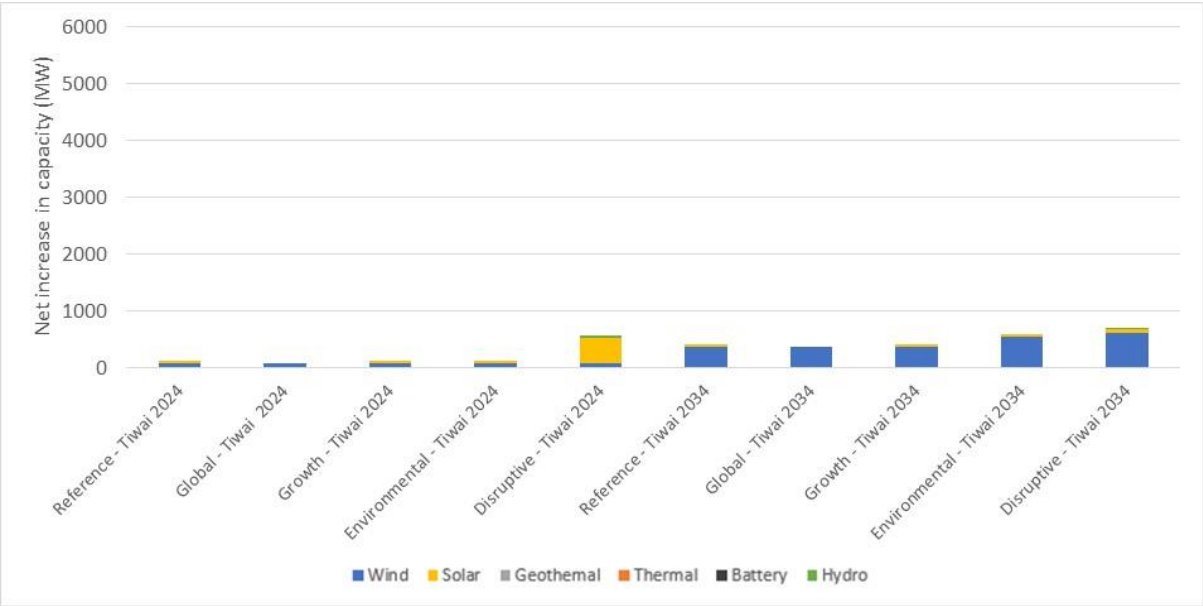
- Load growth across the scenarios (see section 2.3 of the NZGP1 Attachment D – Scenario and Modelling Report)
- Hydrology, by using 50 synthetic hydro inflow sequences for each market scenario, representing the historical hydro inflow distribution (see section 4.2 of NZGP1 Attachment D – Scenario and Modelling Report)
- Generation expansion, by using different generation expansion forecasts resulting from different demand forecasts and the generation cost declines specified in the assumptions book. The graphs below show the generation expansion scenarios we have used. These scenarios are the same as used in the counterfactual (do nothing) option in the application of the investment test (see NZGP1 Attachment D – Scenario and Modelling Report). We used the same generation expansion scenarios in both the factual and counterfactual. We expect the CNI BBI to materially influence generating plant investment decisions but we have exercised our discretion not to apply different generation expansion market scenarios in the factual and counterfactual as we do not think using the same generation expansion scenarios in the factual and counterfactual will materially impact the allocations for the CNI BBI:¹⁴
 - The standard method aims to identify each beneficiaries' benefit relative to other beneficiaries, rather than absolute benefits.
 - The CNI BBI uses the clause 51 method (see section 8.5), for which allocations are largely determined by the counterfactual modelling.

Figure 4: North Island generation expansion assumptions



¹⁴ Further, there was not an equivalent factual scenario available from the investment test, because the investment test modelled all projects together in a single analysis, whereas here we are assessing EPNPB of each BBI separately.

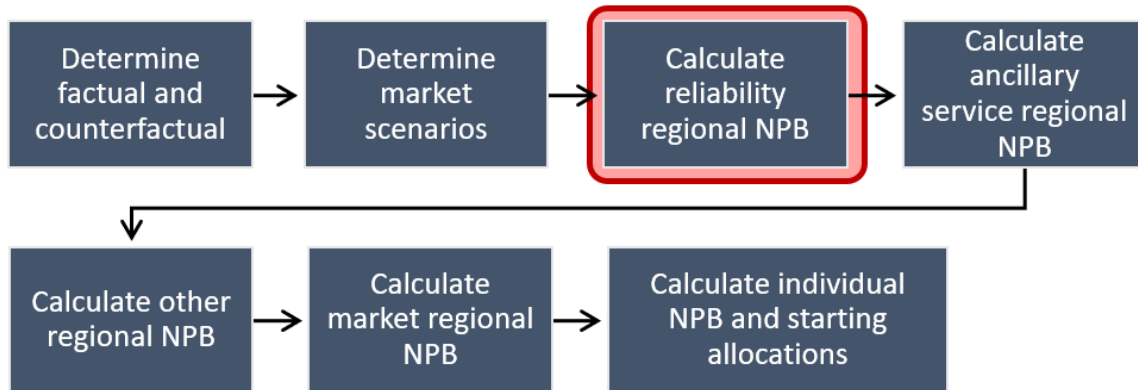
Figure 5: South Island generation expansion assumptions



5 Calculate reliability regional NPB

36. This section describes our application of the stages set out in section 3.3.3 of the assumptions book to the CNI BBI (and as shown in Figure 6).

Figure 6: Calculate reliability regional NPB



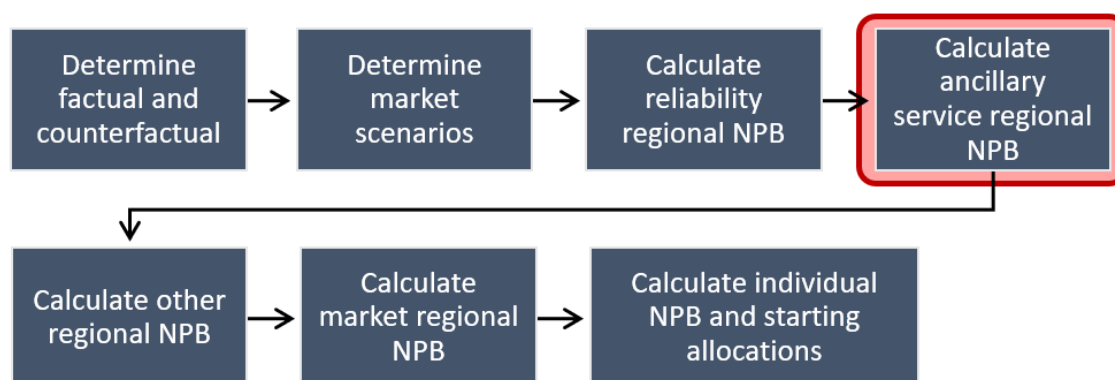
5.1 Determine if there are reliability benefits

37. We do not expect the CNI BBI to have reliability benefits relative to the counterfactual because the investment does not increase the redundancy of supply to any grid points of connection (it adds no new lines or circuits).
38. Therefore, we do not consider the CNI BBI to be a reliability BBI and did not calculate reliability regional NPB under clause 54.

6 Calculate ancillary service regional NPB

39. This section describes our application of the stages set out in section 3.3.4 of the assumptions book to the CNI BBI (and as shown in Figure 7).

Figure 7: Calculate ancillary service regional NPB



6.1 Determine if there are ancillary service benefits

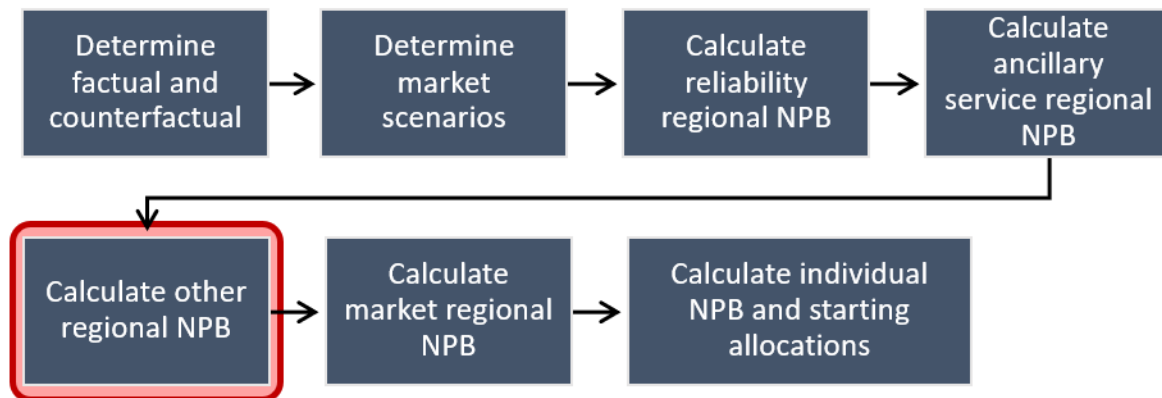
40. We do not expect the CNI BBI to materially reduce the cost allocated to our customers of any specified ancillary service (through changes in price or quantity) relative to the counterfactual. In general, we only expect a BBI to reduce the cost of ancillary services if it provides or enables ancillary services in the market (e.g. the HVDC's Frequency Keeping Control),¹⁵ 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 reserves. The CNI BBI does not provide ancillary services as it is an enhancement to the AC network, and we have no reason to think it materially enables ancillary service providers to be dispatched.
41. Therefore, we did not calculate ancillary service regional NPB under clause 53.

¹⁵ [Frequency keeping control and round power information](#)

7 Calculate other regional NPB

42. This section describes our application of the stages set out in section 3.3.5 of the assumptions book to the CNI BBI (and as shown in Figure 8).

Figure 8: Calculate other regional NPB

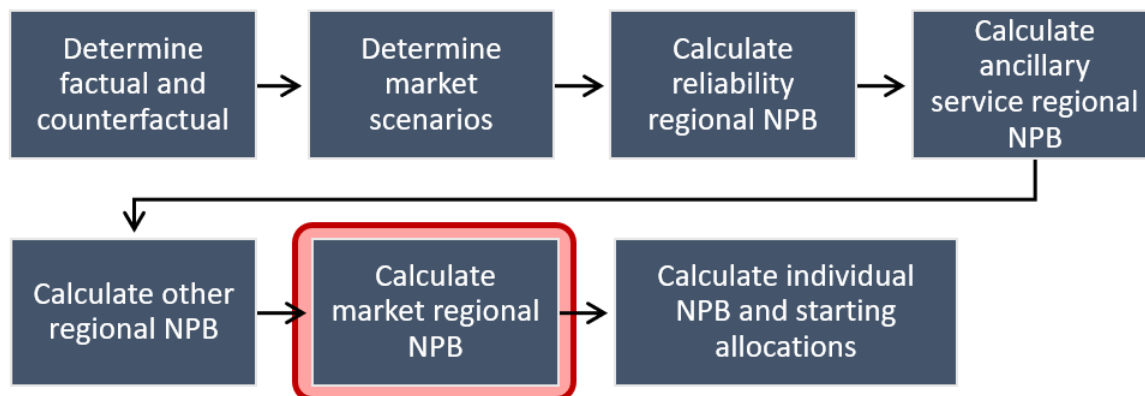


43. We do not expect the CNI BBI to have any material or measurable other benefits. Specifically, we do not expect any customer or embedded plant owner to receive benefits other than wholesale electricity market benefits from the CNI BBI.
44. Therefore, we did not calculate other regional NPB for the CNI BBI under clause 55.

8 Calculate market regional NPB

45. This section describes our application of the stages set out in section 3.3.6 of the assumptions book to the CNI BBI (and as shown in Figure 9).

Figure 9: Calculate market regional NPB



8.1 Determine if there are market benefits

46. We expect the CNI 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. Therefore, in accordance with section 3.3.6.3 of the assumption book, we calculate market regional NPB as set out below.

8.2 Determine modelled constraints and investment grids

47. We followed the process in chapter 3, section 3.3.6.4 of the assumptions book to determine the modelled constraints for the CNI BBI.¹⁶
48. The modelled constraints comprise the following security constraints in the factual and counterfactual.

¹⁶ We departed from the typical 20% threshold used to determine if contingencies should be included in the investment grid and instead used a 15% threshold. We did this to improve the accuracy of the process and therefore produce allocations that are broadly proportionate to EPNPB.

Table 1: Security constraints used for the CNI BBI

Contingency	Protected Circuit 1	Protected Circuit 2	Protected Circuit 3	Protected Circuit 4	Protected Circuit 5
BPE-BRK	TKU-WKM-2				
BPE-TKU-1	BPE-TKU-2	HLY-SFD-1			
BPE-TNG-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		
BRK-SFD-1	TKU-WKM-2				
HLY-SFD-1	TKU-WKM-2	BPE-TKU-1			
HLY-TWH-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		
RPO-TNG-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		
RPO-WRK-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		
SFD-TMN-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		
TKU-WKM-2	TKU-WKM-1	HLY-SFD-1	RPO-TNG-1	RPO-WRK-1	BPE-TNG-1
TMN-TWH-1	TKU-WKM-2	BPE-TKU-1	HLY-SFD-1		

49. Typically, we do not model AC transmission losses within SDDP. For the CNI BBI, we modelled transmission losses on the following branches:¹⁷

- BPE-MTR
- HLY-SFD
- SFD-TMN
- BPE-TNG
- TKU-WKM-1 and 2

50. Modelling AC losses internal to SDDP is a departure from the approach described in section 2.3.2.4 of the assumptions book. It is also a departure from the approach described in section 3.1.4 of NZGP1 Attachment D – Scenario and Modelling Report, which describes how the

¹⁷ We consider losses to be modelled constraints for the purpose of the TPM, because they are a soft limit on transfer across the CNI circuits, which result in price separation either side of the circuit in a similar manner to a hard constraint.

investment test calculated losses in post-processing, rather than modelling them internally to SDDP.

51. We consider these departures are necessary in order for us to calculate allocations that are broadly proportionate to EPNPB because:
- AC losses are a significant benefit of the CNI, as shown in Figure 16 of NZGP1 Attachment D – Scenario and Modelling Report, and
 - by modelling AC losses internally to SDDP, we can determine modelled regions based on the price separation caused by the losses.
52. While there are other branches that have a reduction in losses as a result of the CNI BBI, these branches have the greatest reduction. Furthermore, because we are only modelling some AC branches with losses, we want to model a discrete set of parallel branches between the LNI and UNI included, but no more. If we included more branches, we would risk transmission flows becoming unbalanced through this interface in an unrealistic manner.
53. Therefore, the investment grids for the CNI BBI comprise:
- all existing branches and market nodes,
 - a limit on HVDC transfer of 1200 MW in the factual and counterfactual respectively – i.e. assuming the HVDC Reactive Support BBI is commissioned independently of the CNI,
 - the above modelled constraints in the counterfactual and alleviated in the factual, and
 - some future AC circuit modifications (see section 8.3.3 below).

8.3 Include other market model inputs

54. As noted above, chapter 2 of the assumptions book and the application of the investment test contain most of the modelling inputs for the market scenarios we used for the CNI BBI. We used those modelling inputs.
55. We also used the following additional modelling inputs. These are either required by the TPM (in the case of the standard method calculation period and discounting of values to 2027) or chosen because we consider they will produce starting allocations that are broadly proportionate to EPNPB.

8.3.1 Standard method calculation period

56. The majority of the assets that make up the CNI BBI are expected to have useful lives of greater than 20 years. Therefore, we used a 20-year standard method calculation period (the maximum possible standard method calculation period), beginning on 1 January 2028 – the first 1 January after the CNI BBIs expected effective full commissioning date of 2027.¹⁸
57. We discounted all values to 2027. For the CNI BBI, 2027 is “year 0” in the present value calculation in clause 48(1) because the standard method calculation period starts in 2028.

¹⁸ See section 3.3.4 of NZGP1 Attachment D – Scenario and Modelling Report.

8.3.2 Model resolution

58. Unlike the HVDC Reactive Support BBI, we used SDDP with a load block resolution (21 load blocks per week). This is because the current version of SDDP cannot model both security constraints and losses at an hourly resolution.

8.3.3 AC circuit modifications

59. The below table shows modifications as a result of the CNI BBI, which only apply in the investment grid for the factual. In addition to these modifications, we included modifications to existing AC circuits that have been committed but not yet commissioned or are otherwise likely to occur in the near future. These modifications appear in the investment grids for both the factual and counterfactual; however, they do not affect the results of the modelling because they relate to circuits that are unaffected by the modelled constraints for the CNI BBI.

Table 2: AC circuit modifications used in CNI BBI

Name	From Bus	To Bus	Resistance (%)	Reactance (%)	Winter/ Summer/ Shoulder rating (MW)	Start Date
TKU-WKM-1	TKU220A	WKM220	0.58	4.44	823/864/844	1/6/2027
TKU-WKM-2	TKU220B	WKM220	0.58	4.41	823/864/844	1/6/2027
BPE-TKU-1	BPE220	TKU220A	3.00	14.45	399/429/418	1/12/2025
BPE-TKU-2	BPE220	TKU220B	2.99	14.36	399/429/418	1/12/2025
HLY-SFD-1	HLY220	SFD220	3.91	23.49	469/492/481	1/1/2024
ONG-RTO-1	ONG110	RTO110	NA	NA	open	1/1/2024

8.4 Run market model

60. We ran SDDP¹⁹ using the input assumptions and market scenarios described in sections 4, 8.2 and 8.3. Because the network being modelled is different to that used for the application of the investment test to NZGP1.1, we re-ran SDDP to apply the TPM to the CNI BBI.
61. That is, by proposing to treat the CNI BBI as a separate BBI (see section 2.2 above), we are required to run SDDP using inputs for the CNI BBI specifically, whereas the investment test

¹⁹ The market model used by Transpower. See [Software | PSR – Energy Consulting and Analytics \(psr-inc.com\)](#)

involved running SDDP using inputs for NZGP1.1 as a whole.²⁰ The differences in the SDDP modelling for the CNI BBI (i.e. running SDDP using inputs that relate to the CNI BBI specifically) are required to isolate those private benefits attributable to the CNI BBI rather than other BBIs that make up NZGP1.1.

8.5 Determine if clause 51 or 52 applies

62. The criteria for choosing between clauses 51 and 52, and the way in which we apply those criteria, are set out in section 3.3.6.7 of the assumptions book. Broadly, 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.
63. The TPM broadly requires:
 - 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)), or
 - 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)).
64. We have applied clause 51 for the CNI BBI.
65. We assessed whether clause 51(1)(a) applies to the CNI BBI by applying the test in paragraph 298 of the assumptions book (checking if most of the positive market regional NPB for the CNI BBI's regional supply groups relates to new large generating plant).
66. We determined it does not because the majority of positive market regional NPB for the CNI BBI's regional supply groups accrues to existing generating plant and customers rather than new large generating plant. South Island generators are expected to be beneficiaries of the CNI BBI, and our generation expansion model shows that generation capacity additions in the South Island will not exceed existing South Island generation capacity of ~3500 MW (as shown in Figure 5 above).
67. As clause 51(1)(a) does not apply, we are required to use clause 52 for the CNI BBI if either clause 52(1)(b)(i) or 52(1)(b)(ii) applies.
68. We assessed whether clause 52(1)(b)(i) applies to the CNI BBI by applying the test in paragraph 299 of the assumptions book (checking if most of the positive market regional NPB for the CNI BBI is derived from consumers avoiding having to pay their estimated cost of self-supply for electricity during peak demand periods). We did this using the following steps:²¹
 - For each market scenario, factual/counterfactual, and each load block of the calculation period, we calculated the cost to serve the load (demand × price). We combined these into periods with and without system deficit. We estimated the change in the cost to

²⁰ NZGP1.1 includes the HVDC Reactive Support, Central North Island and Wairakei investments.

²¹ This calculation is different from the one used in the application of the standard method for the Pole 2 Converter Transformer Refurbishment consultation and Clutha-Upper Waitaki Lines Project (**CUWLP**) decision. This is because the NZGP1.1 investment test (and therefore the application of the TPM), uses multiple deficit tranches. The methodology used for Pole 2 and CUWLP is not accurate with multiple deficit tranches because the calculation was based on all deficit being incurred at a single deficit cost. Both versions are consistent with the process described in paragraph 299 of the assumptions book.

serve the load during periods of deficit as a result of the BBI by subtracting the costs in the factual from those in the counterfactual for each market scenario.

- Similarly, we calculated the total change in the cost to serve load during all periods for each market scenario.
69. 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 NPB²² (~5%) we are not required to use clause 52 by clause 52(1)(b)(i).
70. 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.
71. Having considered the matters in paragraphs 301 to 303 of the assumptions book, we have determined clause 51 does produce starting allocations that are broadly proportionate to EPNPB from the CNI BBI. This is because:
- the CNI circuits are part of the grid backbone i.e. not on the extremity of the grid, and
 - our modelling clearly shows a reduction in price downstream of the modelled constraints between the factual and counterfactual, but – on average – shows a small reduction in price upstream, implying upstream generators would not benefit from the BBI. However, this BBI is likely to be particularly sensitive to input assumptions and the modelling framework used:
 - There are spring washer prices at Mataroa, Ohakune, National Park, and Ongerue in the counterfactual. Spring washer prices are notoriously sensitive to market conditions – or in a model – to its input assumptions.
 - Transmission losses can either result in prices being depressed upstream or rising downstream of the transmission circuit depending on if the marginal generator is upstream or downstream of the circuit in question. This means identifying the beneficiary of a reduction in losses relative to the counterfactual can be very sensitive to the precise location of the marginal generator. We do not consider it possible to forecast the marginal generator over 20 years with any precision. Therefore, the use of clause 52 could result in an arbitrary allocation between generation and load beneficiaries.
 - There is greater demand for generation in the counterfactual scenarios than the factual due to the higher losses. This increase in effective demand is not offset by an increase in generation build, because we used the generation scenarios from the application of the investment test which did not model losses internally (see section 8.2). As a result of using these generation scenarios with an SDDP run that has losses modelled internally, prices are artificially higher in the counterfactual scenarios everywhere in the grid, which is likely obscuring the price movements between the factual and counterfactual.
72. More generally, a reduction in transmission losses results in lower price separation between upstream generators and downstream loads. This results in a benefit to upstream generators

²² We have not included producer benefit in this analysis as the consumer benefit by itself is conclusive. Furthermore, the calculation does not differentiate between periods of deficit that occur during peak periods vs. those that occur during other periods e.g. during a dry year. Therefore, it overestimates the proportion of the benefits that accrue due to consumers avoiding having to pay their estimated cost of self-supply during peak periods. This strengthens our conclusion clause 52(1)(b)(i) does not apply.

irrespective of whether a reduction in losses results in prices falling downstream of the transmission circuit or rising upstream, as without this reduction in losses:

- Generation closer to the downstream consumer would be dispatched before generation upstream as it does not face the additional cost of transmitting its output to consumers.
- Similarly, in the long-run, transmission losses create a competitive disadvantage to upstream generation as new generation enters the market downstream to avoid the additional costs of transmitting via lossy circuits.

73. Therefore, we think the clause 51 method better reflects EPNPB for upstream generators than the clause 52 method.

8.6 Determine if clause 49(6) should be applied

74. For the CNI, we do not consider it necessary to adjust the prices from SDDP 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 potential modelled regions

75. As per paragraph 307 of the assumptions book, modelled regions are determined using the points of modelled constraint and the HVDC link constraints. We determined modelled regions by analysing prices in the counterfactual at each modelled node in the network. This resulted in the following modelled regions:

- South Island (**SI**)
- Lower North Island (**LNI**), all nodes in the North Island electrically south of and including TKU220, SFD220, BPE110 – including grid zone 6, grid zone 8, and grid zone 7 excluding MTR, OKN, NPK
- Upper North Island (**UNI**), all other nodes in the North Island

76. We consider these modelled regions meet the requirements of clause 50(1) for the CNI 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

8.8.1 Calculate EMBD for each market scenario – clause 51

77. We determined the CNI BBI's periods of benefit as the periods in which the price at Otahuhu is different to the price at Haywards in the counterfactual, which can only be because one or more of the CNI modelled constraints is binding, including due to the modelling of losses on certain circuits or because security constraints are binding (see section 8.2 above). As a result,

most periods are periods of benefit because there is almost always price separation between Haywards and Otahuhu due to transmission losses.²³ This includes periods in which the price at Otahuhu is higher and lower than the price at Haywards, depending on the direction CNI constraints bind.

78. For South Island customers, the periods of benefit exclude periods in which the HVDC constraint is binding at the same time the CNI modelled constraints are binding, and power is flowing across the HVDC in the same direction as across the circuits affected by the CNI modelled constraints.
79. We then calculated expected market benefits or disbenefits (**EMBD**) and the present value of expected market benefits or disbenefits (**PVEMBD**) by customer and connection location before assigning the values to potential regional customer groups (section 8.10 below). We calculated EMBD by customer and connection location first because this is how SDDP produces the generation and load outputs used to calculate EMBD. This also allows for multiple regional supply or demand groups to be created in the same modelled region and for regional NPB attributable to future generation or load to be removed, as appropriate. This does not materially impact results and it facilitates, rather than detracts from, producing allocations proportionate to benefits.
80. The generation portion of EMBD for a customer at a connection location for each counterfactual outage was calculated using the following formulae from paragraph 319 of the assumptions book:

$$EMBD_Gen_nonUNI_{cust,loc} = (Gen_{cust,loc,CF,Nth} - Gen_{cust,loc,CF,Sth} + GenDelta_{cust,loc})$$

$$EMBD_Gen_UNI_{cust,loc} = (Gen_{cust,loc,CF,Sth} - Gen_{cust,loc,CF,Nth} + GenDelta_{cust,loc})$$

where

- $EMBD_Gen_nonUNI_{cust,loc}$ is the generation portion of EMBD for a non-UNI customer (*cust*) at a connection location (*loc*)
 - $EMBD_Gen_UNI_{cust,loc}$ is the generation portion of EMBD for a UNI customer (*cust*) at a connection location (*loc*)
 - $Gen_{cust,loc,CF,Sth}$ is the generation for the customer (*cust*) at the connection location (*loc*) in the counterfactual (*CF*), during the periods of benefit when electricity is flowing south through the CNI (where prices are alleviated for non-UNI regional supply groups and are exacerbated for UNI regional supply groups) (*Sth*)
 - $Gen_{cust,loc,CF,Nth}$ is the generation for the customer (*cust*) at the connection location (*loc*) in the counterfactual (*CF*), during the periods of benefit when electricity is flowing north through the CNI (where prices are exacerbated for non-UNI regional supply groups and are alleviated for UNI regional supply groups) (*Nth*)
 - $GenDelta_{cust,loc}$ is, for the customer (*cust*) at the connection location (*loc*), factual generation minus counterfactual generation.
81. The load portion of EMBD for a customer at a connection location was calculated using the following formulae from paragraph 320 of the assumptions book:

²³ We have excluded periods in which price separation is very small ($< 5 \times 10^{-5}$).

$$EMBD_Load_nonUNI_{cust,loc} = (Load_{cust,loc,CF,Sth} - Load_{cust,loc,CF,Nth} + LoadDelta_{cust,loc})$$

$$EMBD_Load_UNI_{cust,loc} = (Load_{cust,loc,CF,Nth} - Load_{cust,loc,CF,Sth} + LoadDelta_{cust,loc})$$

where

- $EMBD_Load_nonUNI_{cust,loc}$ is the load portion of EMBD for a non-UNI customer (*cust*) at a connection location (*loc*)
- $EMBD_Load_UNI_{cust,loc}$ is the load portion of EMBD for a UNI customer (*cust*) at a connection location (*loc*)
- $Load_{cust,loc,CF,Sth}$ is the load supplied to the customer (*cust*) at the connection location (*loc*) in the counterfactual (*CF*), during the periods of benefit when electricity is flowing south through the CNI (where prices are alleviated for non-UNI regional demand groups and are exacerbated for UNI regional demand groups) (*Sth*)
- $Load_{cust,loc,CF,Nth}$ is the load supplied to the customer (*cust*) at the connection location (*loc*) in the counterfactual (*CF*), during the periods of benefit when electricity is flowing north through the CNI (where prices are exacerbated for non-UNI regional demand groups and are alleviated for UNI regional demand groups) (*Nth*)
- $LoadDelta_{cust,loc}$ is, for the customer (*cust*) at the connection location (*loc*), factual load minus counterfactual load.

8.8.2 Calculate present value EMBD

82. We calculated a market scenario-weighted EMBD by multiplying EMBD by the weighting for each market scenario, and also calculated EMBD as a present value in this step:²⁴

$$PVEMBD = \frac{1}{\sum W_s} \sum_{s,t} \frac{EMBD_{t,s}}{(1 + \text{discount rate})^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

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

83. We did not remove PVEMBD for large consuming plants that do not currently exist or any new load customers because we did not model any.
84. We removed PVEMBD for all new large generating plant that does not currently exist.

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

85. When there are multiple load customers at a connection location, load outputs from the market model were split into individual customers based on each customer's offtake at that connection location. For example, Bunnythorpe has two customers, Powerco and Kiwirail. Since the market model returns a combined load output for these two customers at Bunnythorpe, we split Bunnythorpe's load based on the two customers' intra-regional allocator (**IRA**) ratio. This step is necessary because a connection location may have two customers that are part of different regional customer groups e.g. a distribution customer and a non-distribution customer.
86. When splitting load outputs where there are both distributor and non-distributor customers at a connection location, we assumed the load growth at the connection location is wholly assigned to the distributor customers. This is consistent with our demand forecasts for non-distributor customers, which generally assume no growth. The steps taken to do this are listed below using the Glenbrook (**GLN**) connection location as an example, which has two customers, Counties Energy (**COUP**) as a distributor customer and NZ Steel (**NZST**) as a non-distributor customer:
- Split load output for the first year (i.e. 2027 for the CNI BBI) based on the customers' IRAs. This resulted in 75% of GLN's first year load output assigned to NZST (~844 GWh) and 25% assigned to COUP (~301 GWh)
 - Assume NZST's load at GLN remains the same at 844 GWh per annum throughout the standard method calculation period
 - Calculate COUP's annual load at GLN by subtracting from GLN's total annual load 844 GWh (NZST's annual load for the first year). This resulted in an increasing load forecast for COUP, from 301 GWh in 2027 to 354 GWh in 2046

²⁴ As contemplated in clause 48(2). This effectively combines the calculations in clauses 48(1) and 51(6), and produces a mathematically equivalent result to doing those calculations separately.

- Calculate a present value for the two customers' load forecasts using a 7% discount rate.²⁵ This resulted in 3,422 GWh for COUP and 8,937 GWh for NZST
- Calculate a present value load allocation based on the two load present values. This resulted in 28% for COUP and 72% for NZST

8.9 Determine potential regional customer groups

87. 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:

$$\begin{aligned} PVEMBD_NetGen_nonUNI_{cust,loc} \\ &= PVEMBD_Gen_nonUNI_{cust,loc} + PVEMBD_Load_nonUNI_{cust,loc} \\ &\quad - (PVLoadDelta_{cust,loc} * 2)^{26} \end{aligned}$$

$$\begin{aligned} PVEMBD_NetGen_UNI_{cust,loc} \\ &= PVEMBD_Gen_UNI_{cust,loc} + PVEMBD_Load_UNI_{cust,loc} \\ &\quad - (PVLoadDelta_{cust,loc} * 2) \end{aligned}$$

$$\begin{aligned} PVEMBD_NetLoad_nonUNI_{cust,loc} \\ &= PVEMBD_Gen_nonUNI_{cust,loc} + PVEMBD_Load_nonUNI_{cust,loc} \\ &\quad - (PVGenDelta_{cust,loc} * 2)^{27} \end{aligned}$$

$$\begin{aligned} PVEMBD_NetLoad_UNI_{cust,loc} \\ &= PVEMBD_Gen_UNI_{cust,loc} + PVEMBD_Load_UNI_{cust,loc} \\ &\quad - (PVGenDelta_{cust,loc} * 2) \end{aligned}$$

Where:

- $PVEMBD_NetGen_nonUNI_{cust,loc}$ is the present value of EMBD for a non-UNI customer (*cust*) at a connection location (*loc*) calculated based on net generation
- $PVEMBD_NetGen_UNI_{cust,loc}$ is the present value of EMBD for a UNI customer (*cust*) at a connection location (*loc*) calculated based on net generation

²⁵ We discounted the load forecast so that the allocation used to split the PVEMBD between the two customers is calculated on the same basis as the benefits to which it is applied.

²⁶ The term $-(PVLoadDelta_{cust,loc} * 2)$ is used to make $PVGenDelta_{cust,loc} + PVLoadDelta_{cust,loc}$ mathematically equivalent to $PVGenDelta_{cust,loc} - PVLoadDelta_{cust,loc}$, which represents the change in net generation between the factual and counterfactual.

²⁷ 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.

- $PVEMBD_NetLoad_nonUNI_{cust,loc}$ is the present value of EMBD for a non-UNI customer (*cust*) at a connection location (*loc*) calculated based on net load
 - $PVEMBD_NetLoad_UNI_{cust,loc}$ is the present value of EMBD for a UNI customer (*cust*) at a connection location (*loc*) calculated based on net load.
88. We used the following potential regional supply groups (in each modelled region) to group customers at connection locations into potential regional supply groups for the CNI BBI.²⁸ A list of existing customers included in each regional supply group is in the Input Tables worksheet, Table 7 of the post-processing model. Where there are multiple generation technologies owned by a customer at a connection location, we group based on the largest generation type.
- Wind generation (Wnd)
 - Controlled hydro generation (Chyd)
 - Geothermal generation (Geo)
 - Run-of-river hydro generation (RoR)
 - Thermal commitment generation (ThermalCommit)
 - Thermal peaking generation (Peaker)
 - Battery storage (Batteries)
 - Cogeneration (Cogen)²⁹
 - Generation with embedded load (GenerationWithLoad) – connection locations with generation and significant load³⁰ owned by the same customer (or hosted by the same customer in the case of embedded load), excluding customers at a connection location with negative PVEMBD. The customer at the connection location is in this group if the customer's PVEMBD from the generation is greater than its PVEMBD from the load.
89. We grouped Alpine at Albury, Westpower at Kumara, and Aurora at Clyde into the South Island controlled hydro regional supply group despite these customer connection locations having negative PVEMBD. We did this because these customer connection locations have injection greater than their offtake during the capacity measurement period (CMP B) for the CNI BBI, which indicates they have significant embedded generation, which we do not model in SDDP. If we did model this embedded generation, we expect these customer connection locations would be in South Island regional supply groups, and we consider grouping them as such would result in starting allocations that better reflect EPNPB. This is a departure from paragraph 335 of the assumptions book because we are taking into account information other than the SDDP outputs to group a customer at a connection location into a regional customer group.

²⁸ We did not create the Biofuel or Solar potential regional supply group for existing customers discussed in section 3.3.6.11 of the assumptions book because there is currently no grid-connected generating plant with these technologies. However, we created a solar and diesel (representing all thermal plant including biofuel) potential future regional customer group, as discussed in paragraph 93 below.

²⁹ The cogeneration group is a departure from paragraph 337 of the assumptions book. We consider this departure is necessary to produce allocations that are broadly proportionate to EPNPB as cogeneration is modelled as having a fixed production schedule rather than responding to market conditions like other thermal plant.

³⁰ Specifically, where supply benefits are no less than 50% of demand benefits, or vice versa.

90. We used the following potential regional demand groups (in each modelled region) to group customers at connection locations into potential regional demand groups for the HVDC Reactive Support BBI. A list of existing customers included in each regional demand group is in the Input Tables worksheet, Table 3 of the post-processing model.
- Industrial load (Industrial) – load associated with industrial customers
 - Non-industrial load (EDB) – load associated with non-industrial customers (primarily EDBs)
 - Load with embedded generation (LoadWithGeneration) – connection locations with load and significant generation³¹ owned by the same customer (or hosted by the same customer in the case of embedded generation), excluding customers at a connection location with negative PVEMBD. The customer at the connection location is in this group if the customer's PVEMBD from the load is greater than its PVEMBD from the generation.
91. Due to the different magnitudes of market benefit that may accrue to these customer types from the CNI BBI, we considered it necessary to create these potential regional customer groups in each modelled region to produce starting allocations that are broadly proportionate to EPNPB.
92. We did not separate new and existing customers into separate regional customer groups because the benefits of the CNI BBI do not primarily accrue to new customers.
93. However, we created potential future regional customer groups for each of the following generation technologies that do not already exist in that modelled region. Without these potential future regional customer 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.³²
- UNI Solar Generation
 - UNI Battery Generation
 - UNI Wind Generation
 - LNI Solar Generation
 - LNI Battery Generation
 - SI Wind³³ Generation
 - SI Solar Generation
 - SI Battery Generation
 - SI Thermal Generation

³¹ Specifically, where supply benefits are no less than 50% of demand benefits, or vice versa.

³² Unless they are later amalgamated with another group – see section 8.11.

³³ While there are existing wind generating stations in the South Island (Mahinerangi and White Hill), both are embedded so the owners are not beneficiaries of the CNI BBI in respect of those stations.

8.10 Calculate PVMRNPB for potential regional customer groups

94. We calculated the present value of market regional net private benefit (**PVMRNPB**) for each potential regional customer group as the sum of PVEMBD of all customers in that group. This was done using the following formulae:

$$PVMRNPB_S = \sum_{(cust,loc) \in S} PVEMBD_{NetGen}_{cust,loc}$$

$$PVMRNPB_D = \sum_{(cust,loc) \in D} PVEMBD_{NetLoad}_{cust,loc}$$

Where

- S is a set of all customers and connection locations belonging to potential regional supply group s
 - D is a set of all customers and connection locations belonging to potential regional demand group d
 - $PVMRNPB_S$ is PVMRNPB for potential regional supply group S
 - $PVMRNPB_D$ is PVMRNPB for potential regional demand group D
 - $PVEMBD_{NetGen}_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location (loc) calculated based on net generation
 - $PVEMBD_{NetLoad}_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location (loc) calculated based on net load.
95. We removed potential regional customer groups with a PVMRNPB that was not positive (all UNI regional supply groups except UNI Battery Generation, all LNI and SI regional demand groups, and SI Thermal and Battery Generation), which left the following potential regional customer groups:
- SI Controlled Hydro Generation
 - SI Run-of-River Hydro Generation
 - LNI Run-of-River Hydro Generation
 - LNI Thermal Peaking Generation
 - LNI Cogeneration
 - LNI Wind Generation
 - LNI Generation with Load
 - UNI Non-industrial Load
 - UNI Industrial Load
 - UNI Battery Generation (potential future regional customer group)
 - LNI Solar Generation (potential future regional customer group)

- SI Wind³⁴ Generation (potential future regional customer group)
 - SI Solar Generation (potential future regional customer group)
96. We did not need to convert the quantity values of PVMRNPB to dollar values as we have not calculated regional NPB other than market regional NPB.

8.11 Finalise regional customer groups

97. We applied the process described in section 3.3.6.13 of the assumptions book to determine the final regional customer groups.

8.11.1 Finalise regional supply groups

98. As per paragraph 348 of the assumptions book, this amalgamation process requires the PVMRNPB/IRA ratio of an amalgamated group to be within 80% of the largest group ratio. The largest ratio in this case belongs to the LNI Wind Generation regional supply group, with a value of 12.4. As the LNI Cogeneration ratio of 10.7 is greater than 80% of the LNI Wind Generation ratio, these regional supply groups can be combined.
99. Similarly:
- The LNI Run-of-River Hydro Generation sits within 80% of the LNI Solar Generation group, and so these groups are combined.
 - The SI Wind and Solar Generation groups sit within 80% of the SI Run-of-River Hydro Generation Group, and so these groups are combined.
100. In general, the other potential regional supply groups are not within 80% of the ratio of the group with the next highest group, so are not combined. The only exception to this is the LNI Solar and Run-of-River Hydro Generation group which is within 80% of the SI Run-of-River Hydro Generation group. However, in accordance with paragraph 346(c) of the assumptions book, we have not combined these groups as the difference in their benefits is due – at least in part – to constraints on the HVDC.
101. The PVMRNPB of each potential and proposed regional supply group is shown in Table 3.

Table 3: PVMRNPB of each potential and proposed regional supply group

Modelled region	Potential regional supply group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional supply group
Lower North Island	Wind Generation	25,624	2,074	12.4	9.9	Lower North Island Wind and Cogeneration

³⁴ While there are existing wind generating stations in the South Island (Mahinerangi and White Hill), both are embedded so the owners are not beneficiaries of the CNI BBI in respect of those stations.

Lower North Island	Cogeneration	1,670	156	10.7	-	Lower North Island Wind and Cogeneration
South Island	Run-of-River Hydro Generation	416	42	9.8	7.8	South Island Run-of-River Hydro, Wind, and Solar Generation
South Island	Wind Generation (future)	2.9	0.35	8.3	-	South Island Run-of-River Hydro, Wind, and Solar Generation
South Island	Solar Generation (future)	1.2	0.15	8.1	-	South Island Run-of-River Hydro, Wind, and Solar Generation
Lower North Island	Solar Generation (future)	1.4	0.15	9.5	7.6	Lower North Island Run-of-River Hydro and Solar Generation
Lower North Island	Run-of-River Hydro Generation	7,376	799	9.2	-	Lower North Island Run-of-River Hydro and Solar Generation
South Island	Controlled Hydro Generation	134,269	17,448	7.7	6.2	South Island Controlled Hydro Generation
Lower North Island	Generation with Embedded Load	295	113	2.6	2.1	Lower North Island Generation with Embedded Load
Lower North Island	Peaking Generation	525	1,765	0.3	0.2	Lower North Island

						Peaking Generation
Upper North Island	Battery Generation (future)	0.03	0.4 ³⁵	0.1	-	Upper North Island Battery Generation

8.11.2 Finalise regional demand groups

102. We have amalgamated the potential regional demand groups into a smaller number of proposed regional demand groups. As per paragraph 348 of the assumptions book, this amalgamation process requires the PVMRNPB/IRA ratio of an amalgamated group to be within 80% of the largest group ratio. The largest ratio in this case belongs to the UNI Non-industrial Load regional demand group. As the UNI Industrial Load has a ratio of greater than 80% of the Non-industrial Load group, those regional demand groups can be combined.

103. As a result, we finalised one regional demand group – UNI Load.

104. PVMRNPB for each proposed regional demand group is shown in Table 4, and the proportion of total PVMRNPB for each proposed regional customer group is in Table 5.

Table 4: PVMRNPB for each potential and proposed regional demand group

Modelled region	Potential regional demand group	PVMRNPB (GWh)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional demand group
Upper North Island	Non-industrial Load	204,313	15,998	12.8	10.2	Upper North Island Load
Upper North Island	Industrial Load	13,361	1,143	11.7	-	Upper North Island Load

³⁵ Based on an assumed 1MWh cycle per day per MW capacity.

Table 5: PVMRNPB for proposed regional customer groups as a proportion of total PVMRNPB

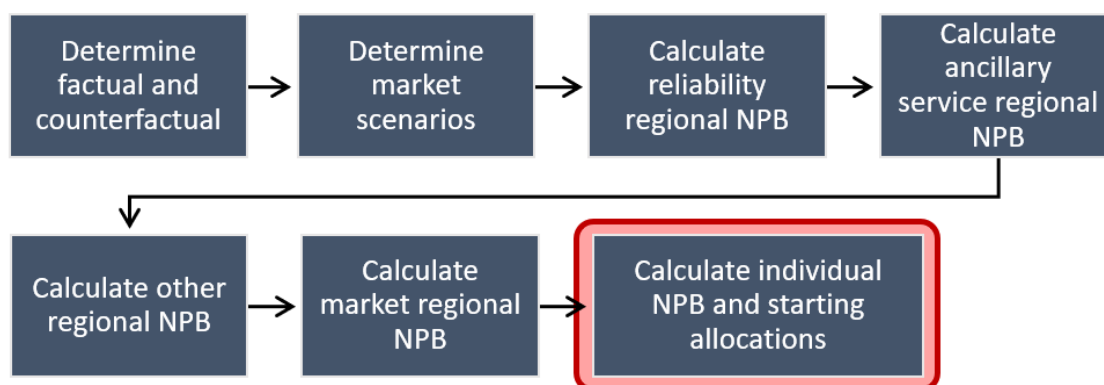
Proposed regional customer group	PVMRNPB (GWh)	Percentage of PVMRNPB
Upper North Island Load	217,674	56.1%
Upper North Island Battery Generation ³⁶	n/a	n/a
Lower North Island Wind and Cogeneration	27,294	7.0%
Lower North Island Run-of-River Hydro and Solar Generation	7,376	1.9%
Lower North Island Peaking Generation	525	0.1%
Lower North Island Generation with Embedded Load	295	0.1%
South Island Controlled Hydro Generation	134,268	34.6%
South Island Run-of-River Hydro, Wind, and Solar Generation	416	0.1%

³⁶ The Upper North Island Battery Generation regional supply group is a potential future regional customer group and so has no starting allocation.

9 Calculate individual NPB and starting BBI customer allocations

105. This section describes the stage highlighted in Figure 10 (and as set out in section 3.3.7 of the assumptions book).

Figure 10: Calculate individual NPB and starting allocations



9.1 Calculate IRA per customer per regional customer group

106. Proposed IRA values for the CNI BBI are calculated from historical data between 1 September 2017 and 31 August 2022 which we expect to be the five capacity years in capacity measure measurement period (CMP) B for the CNI BBI. The IRAs are in the Input Tables worksheet, Table 5 of the post-processing model. We expect to make a final investment decision after the Commerce Commission's final decision later in 2023. It is possible our final investment decision could occur after 31 August 2023, in which case the actual CMP B may be a different period of time than indicated here.
107. The CNI BBI is a non-peak BBI based on the amount of time the CNI BBI's modelled constraints are expected to bind during a counterfactual outage i.e. >90% as shown in Figures A8 and A9 below. If the benefits primarily accrued during peak periods, the modelled constraints would be binding much less frequently.
108. The IRAs for the CNI BBI are therefore mean historical annual offtake for regional demand groups and mean historical annual injection for regional supply groups. We calculated the IRA values in accordance with clauses 65(5) and 65(6), respectively, for most beneficiaries.
109. 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 (clauses 66 and 83(3)(a)).
110. We did not need to apply clause 66 to estimate the IRA value for any recent customers as there were none that were beneficiaries of the BBI.
111. We have applied clauses 65(13) and 66 to estimate the IRA value for Top Energy at Kaikohe, for whom a specified pre-start adjustment event occurred during CMP B. We have adjusted Top Energy's IRA value to account for the connection of new large plant (clause 85) associated with the 32 MW Ngawha geothermal expansion connected in 2020. This has reduced Top's

offtake IRA from 110,047,574 kWh to 14,096,240 kWh and increased its injection IRA from 34,251,852 kWh to 101,195,284 kWh. To estimate the injection from Ngawha, we used the annual injection from Te Mihi, and scaled this down by 81%, which is the ratio between the capacity of Ngawha and the highest injection from Te Mihi during CMP B (171.4 MW).

112. We have applied clause 75(4)(a) to estimate the IRA value for Northpower at Bream Bay, for whom a pre-start adjustment event has or will occur after the end of CMP B. We have adjusted Northpower's IRA value to account for the disconnection of large plant (clause 85) associated with the Marsden Point refinery's conversion to an import terminal, which is to be completed by the end of March 2023. This has reduced Northpower's offtake IRA at Bream Bay from 348,544,464 kWh to 81,566,717 kWh.
113. We are aware there may be other pre-start adjustment events that occur after the end of CMP B. We expect to process those as pre-start adjustment events under clause 75(4)(b).

9.2 Calculate individual NPB

114. We calculated each customer's individual NPB for the CNI BBI as the sum of the present value of MRNPB for each regional customer group with positive PVMRNPB 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.

9.3 Calculate starting allocations

115. We calculated each customer's proposed starting allocation for the CNI BBI as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the allocations (to two decimal places)³⁷ set out in Table 6. The unrounded allocations are available in the Allocation worksheet of the post-processing model.

Table 6: Each customer's proposed starting allocation for the CNI BBI

Customer Name	Proposed starting allocation (%; 2 d.p.)
Vector Ltd	28.08%
Meridian Energy Ltd	24.05%
Powerco Ltd	7.89%
Contact Energy Ltd	7.75%

³⁷ This was extended to 3 decimal places for customers with allocations lower than 0.005%, of which this only includes Southpark Utilities Ltd and Southdown Cogeneration Ltd.

Customer Name	Proposed starting allocation (% , 2 d.p.)
Unison Networks Ltd	4.37%
Genesis Energy Ltd	3.64%
WEL Networks Ltd	3.27%
Northpower Ltd	2.53%
Counties Power Ltd	1.98%
Mercury SPV Ltd	1.79%
MEL (West Wind) Ltd	1.62%
New Zealand Steel Ltd	1.51%
Waipa Networks Ltd	1.38%
Pan Pac Forest Product Ltd	1.36%
Tararua Wind Power	1.30%
Horizon Energy Distribution Ltd	1.19%
Manawa Energy Ltd	1.08%
Waverly Wind Farm Ltd	1.07%
Eastland Network Ltd	0.97%
MEL (Te Apiti) Ltd	0.76%
Winstone Pulp International	0.74%
The Lines Company Ltd	0.72%
Whareroa Cogeneration Ltd	0.49%
KiwiRail Holdings Ltd	0.13%
Nova Energy Ltd	0.12%
Aurora Energy Ltd	0.09%

Customer Name	Proposed starting allocation (% , 2 d.p.)
Westpower Ltd	0.07%
Alpine Energy Ltd	0.03%
Southdown Cogeneration Ltd	0.01%
Southpark Utilities Ltd	0.00% ³⁸

116. To calculate BBCs for the CNI BBI, the starting allocations will be multiplied by the CNI BBI's covered cost. We have not included this step in this draft record as this step takes place after the calculation of starting allocations – which is the focus of this draft record.
117. A BBI's covered cost changes annually due to parameters including WACC and the attributed opex ratio and will not be certain until the BBI is fully commissioned. To assist stakeholders responding to consultation on this draft record, we present an estimate of covered cost and indicative BBCs for the CNI BBI in the consultation paper accompanying this draft record.

³⁸ Southpark Utilities has a starting allocation of 0.001% when rounded to 3 d.p.

Appendix A: Modelling results

- A.1 This section presents and describes some of the modelling results from our wholesale market model (**SDDP**) to help stakeholders understand the proposed starting allocations for the CNI BBI contained in section 9.3.

A1.1 Benefits are primarily to generation upstream and load downstream of constraints

- A.2 The CNI BBI reduces losses on energy transported through the central North Island and reduces transmission security constraints in the same region.
- A.3 Losses are reduced by splitting the 110 kV network at Ongarue, meaning that energy that is presently transported on the 110 kV network will be redirected through the less lossy 220 kV network.
- A.4 Security constraints are relieved by capacity increases on TKU-WKM 1 and 2, BPE-TKU 1 and 2, and HLY-SFD-1. In addition to relieving security constraints, the TKU-WKM 1 and 2 duplexing enhancement also reduces losses on the circuit, further increasing the loss benefit of the split on the 110 kV network.
- A.5 As losses are a key aspect of the market benefits of the CNI BBI, we have modelled losses explicitly in our market modelling on an interface spanning the North Island grid (see section 8.2).
- A.6 As illustrated in the diagrams below, when a security 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.1 Prices with circuit at less than capacity

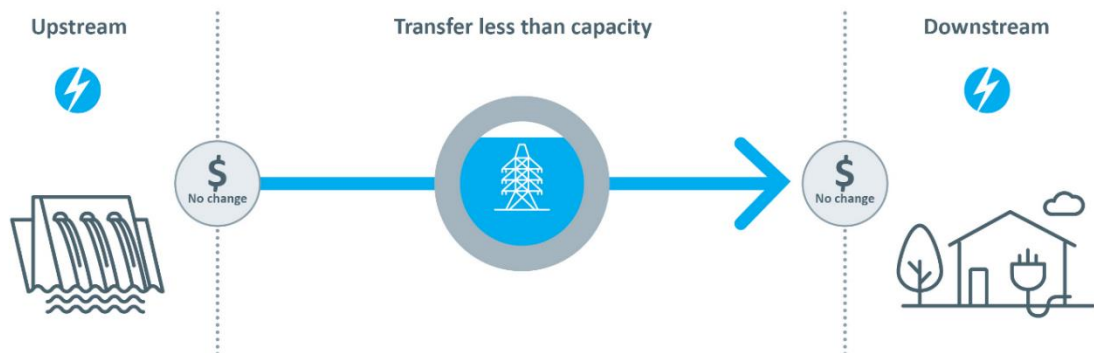
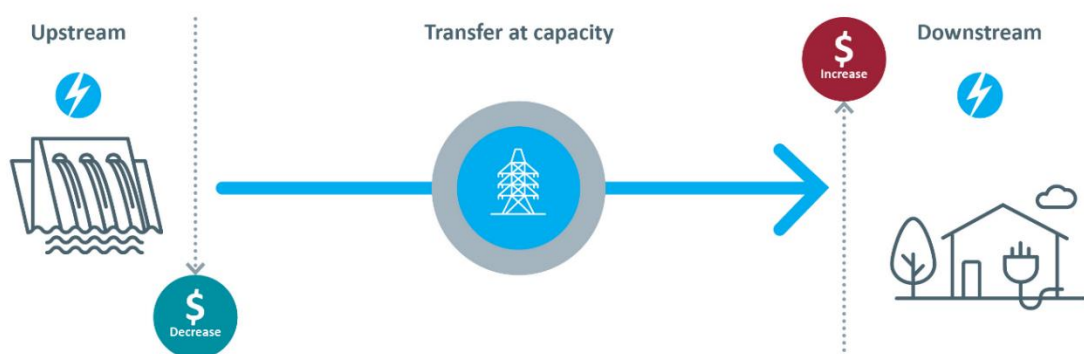


Figure A.2 Prices with circuit at capacity

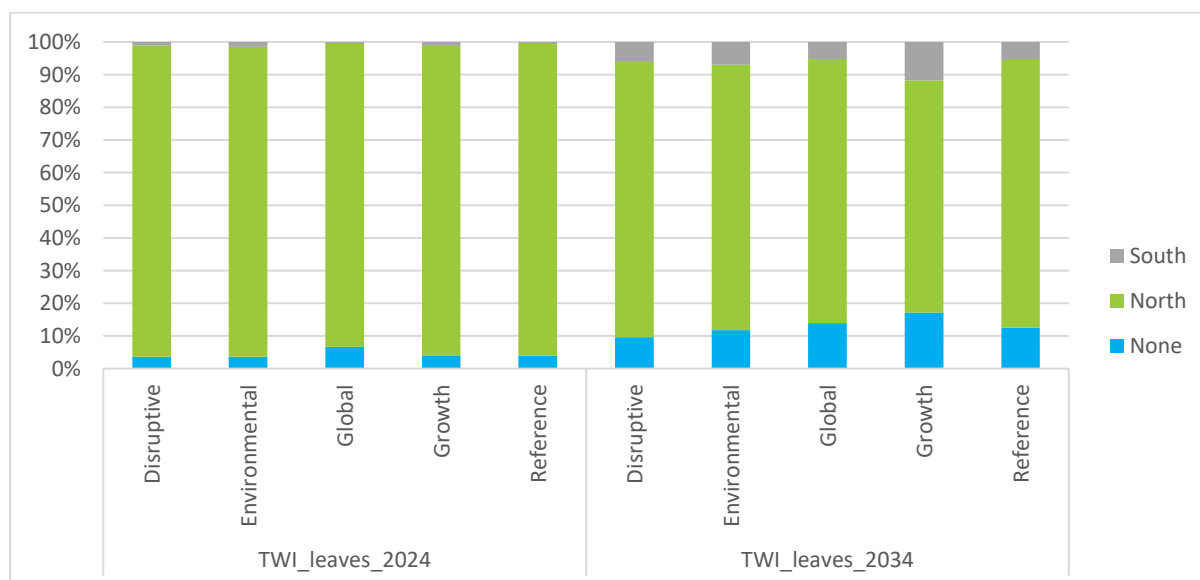


- A.7 In a similar manner to security constraints, by reducing losses on energy transport through the central North Island, the CNI BBI is expected to deliver private benefits to load north of the investment, and generation south of the investment. This is primarily because the prevailing flow of energy across the interface is south to north, meaning load downstream of the interface will experience lower energy prices due to reduced losses, and generation upstream of the interface will receive higher prices and be more competitive with generation downstream as price separation reduces. Similarly, load will disbenefit in the region where generation benefits, and vice versa.
- A.8 For the purposes of this appendix, we refer to price separation due to losses or security constraints a binding constraint.

A1.2 Beneficiaries are consistent with the direction of energy flows through the central North Island

- A.9 We have modelled ten market scenarios, based on the ten market scenarios used in NZGP1.1's application of the investment test. Each scenario is modelled from 2028 to 2047 and across 50 synthetic hydrological sequences, with the results shown as the mean of these hydro sequences.
- A.10 The benefits and disbenefits differ per market scenario as the beneficiaries' exposure to the loss reductions and security constraints across the central North Island interface differ per market scenario.
- A.11 We have defined the periods of benefit to be periods when there is price separation between nodes OTA220 and HAY220.
- A.12 In the graphs below, we refer to any period with a higher price at OTA220 than HAY220 as the "north constraint binding" and any period with a higher price at HAY220 than OTA220 as the "south constraint binding". Any period in which there is no price separation between HAY220 and OTA220 is considered "no constraint binding".
- A.13 There is price separation due to losses or security constraints on the interface approximately 85% to 100% of the time depending on the scenario.
- A.14 On average³⁹ across the ten market scenarios, the north constraint binds significantly more often than the south constraint in the counterfactual. Figures A.3 and A.4 show the frequency of binding constraints for the ten scenarios in 2030 and 2035, respectively. Figure A.5 shows flow duration curves across the modelled interface for various years in the modelling horizon.

Figure A.3 Frequency of binding constraints in each scenario in 2030



³⁹ All graphs in Appendix A show the results as averages of all hydro scenarios.

Figure A.4 Frequency of binding constraints in each scenario in 2035

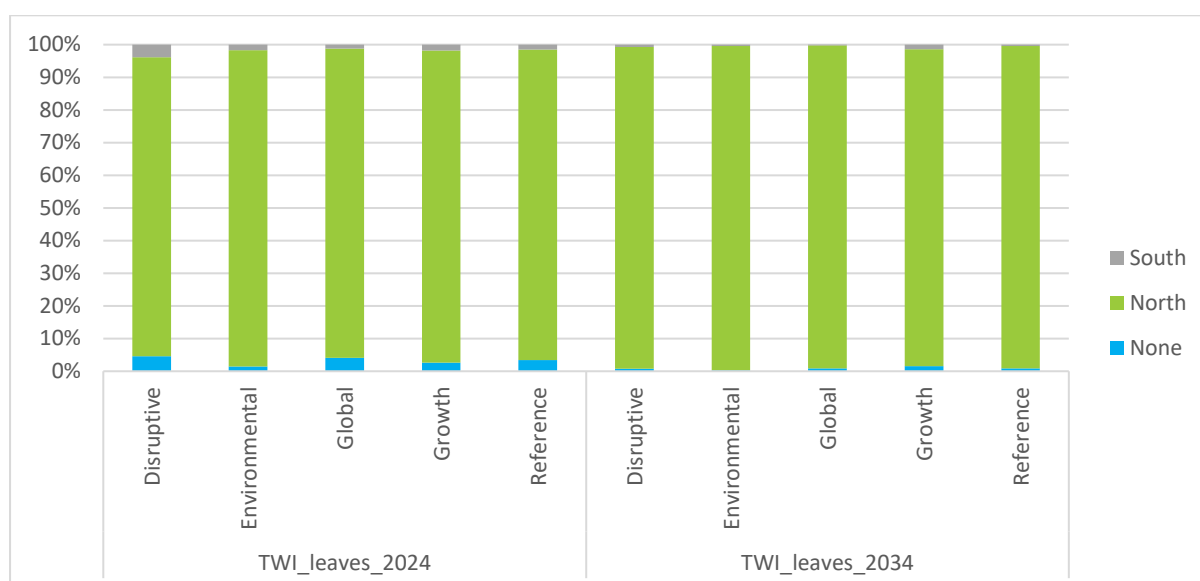
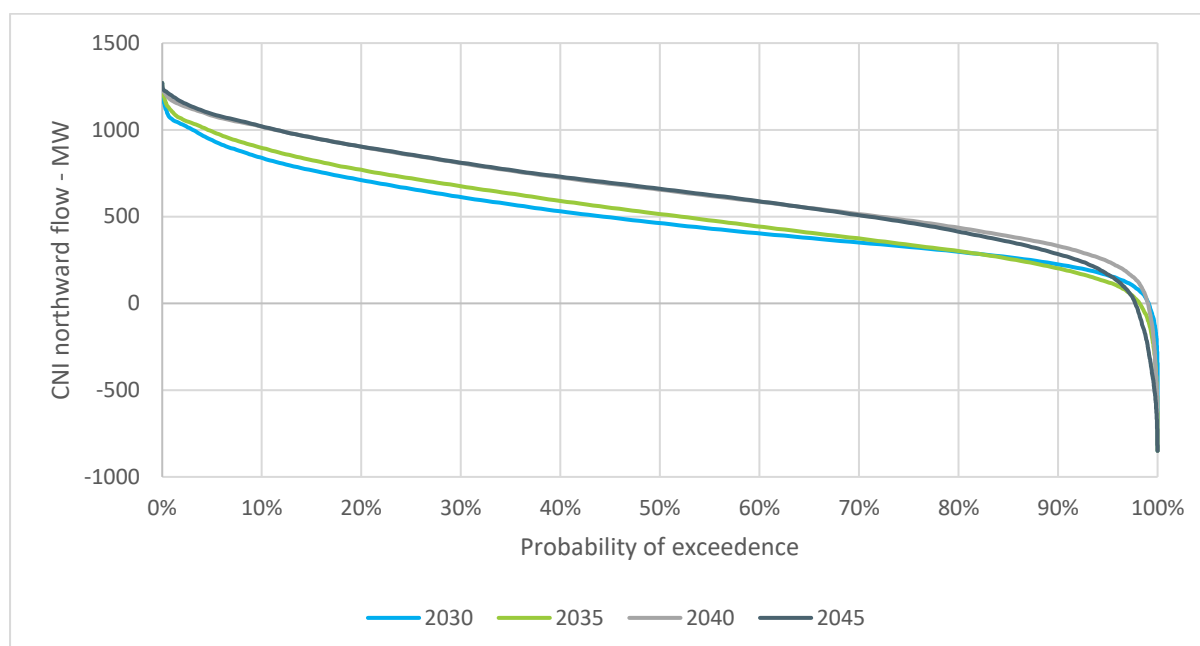


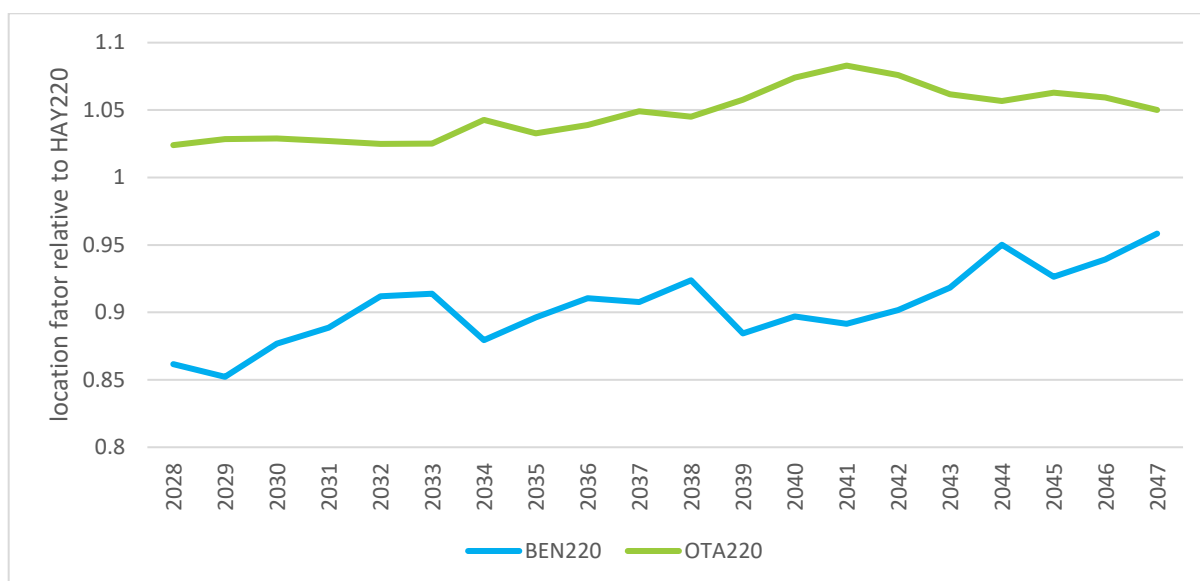
Figure A.5 CNI flow duration curve for selected years – Reference counterfactual



- A.15 Load customers in UNI and generators in the LNI and SI are beneficiaries because the north constraint binds more often than the south constraint across the five scenarios in the counterfactual.
- A.16 Conversely, load customers in south of the interface and generators in the north of the interface are disbeneficiaries.
- A.17 This is illustrated by the following modelling results, which show the price impacts throughout the grid. Figure A.6 shows the location factor at OTA220 and BEN220 relative to HAY220 in the counterfactual for each year of the modelling horizon, showing elevated prices at OTA220, and depressed prices at HAY220 and BEN220 relative to OTA220.⁴⁰

⁴⁰ Note, the BEN220 prices are lower than HAY220 in part due to losses on the HVDC, which is unrelated to the BBI.

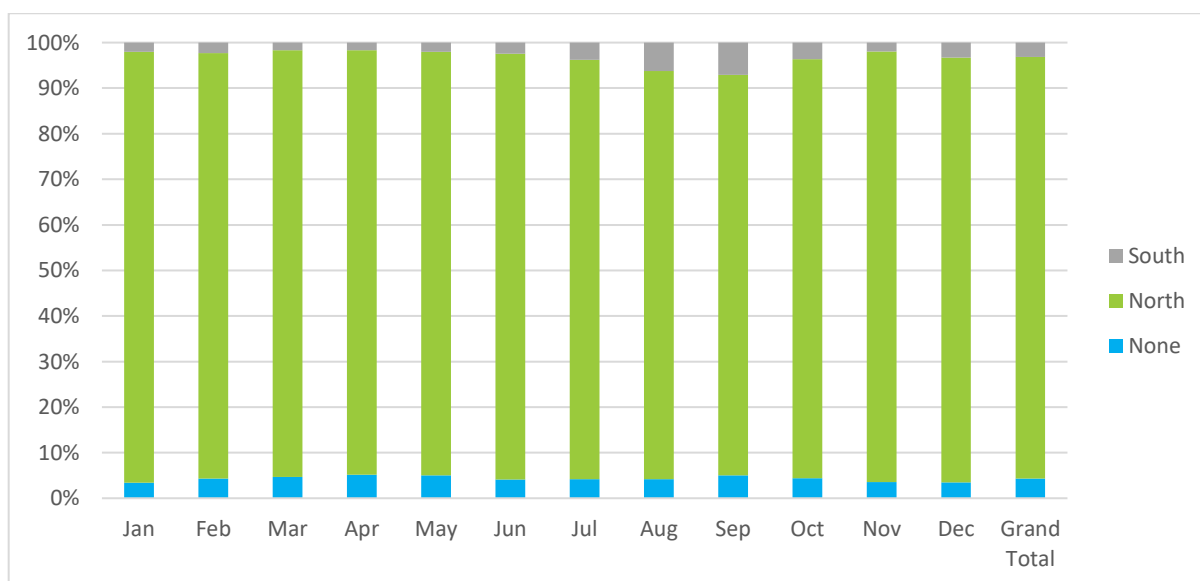
Figure A.6 Prices at BEN220 and OTA220 relative to HAY220



A1.3 The beneficiaries we have identified are not sensitive to time of year

A.18 Modelling results have shown the beneficiaries we have identified are not sensitive to the season. The proportion of time for the north and south constraints are binding during an outage is similar for across seasons, with a small seasonal relationship with greater south-flow during winter as hydro plant in the South Island conserves water during this low inflow period, with thermal generation in the upper North Island generating more to offset this lower output from hydro generation. Figure A.7 shows the time proportion of binding constraints for different season in the counterfactual.

Figure A.7 Frequency of binding constraints by month



A.19 In all cases, the north constraint is binding significantly more than the south constraint, so the beneficiaries we have identified are not affected by the time of year.

A1.4 The beneficiaries do not change over the modelling horizon

A.20 The frequency with which the north and south constraints bind is stable over the modelling horizon. Figure A.8 and Figure A.9 show the frequency of constraints binding in each direction over the modelling horizon in the counterfactual in scenarios in which Tiwai leaves in 2024 and 2034, respectively.

Figure A.8 Frequency of binding constraints by year – Tiwai leave 2024

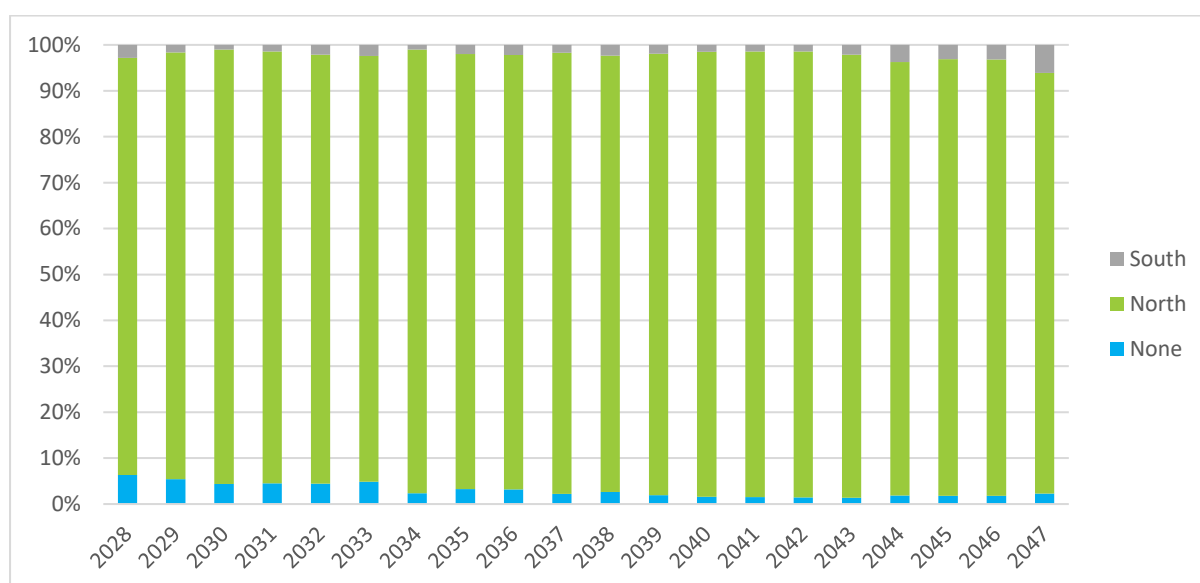
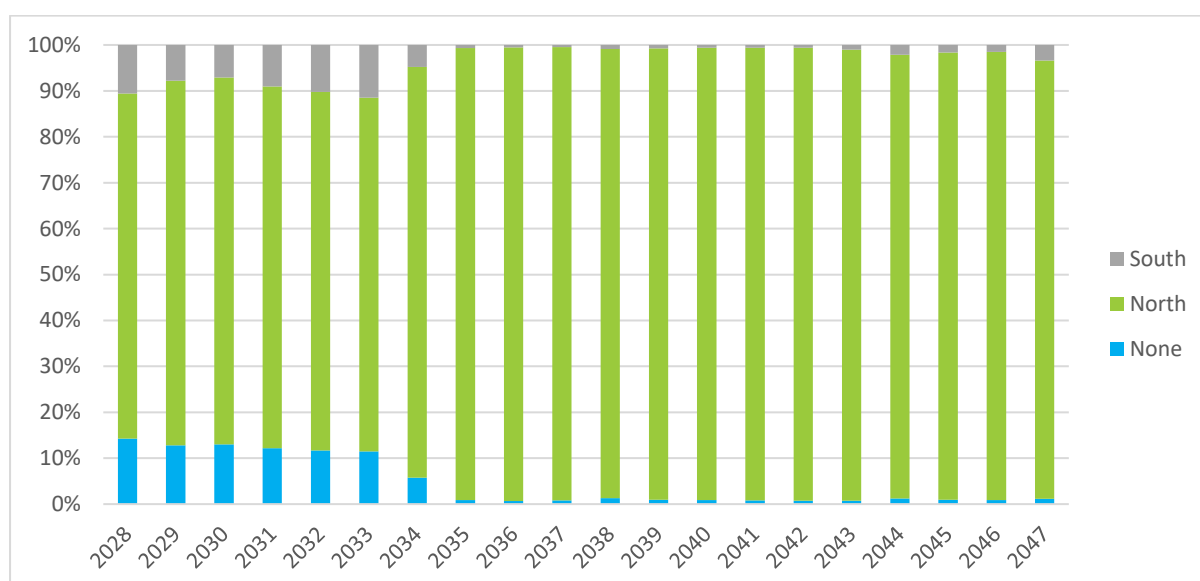


Figure A.9 Frequency of binding constraints by year – Tiwai leave 2034



A.21 In each year, the north constraint binds significant more often than the south constraint, so the beneficiaries identified do not change over time.

Appendix B: Glossary

Term	Meaning
AC	Alternating Current
Authority	Electricity Authority
BBI consultation documents	The documents produced to support the consultation on the proposed starting BBI allocations for each high-value post-2019 BBI
Capex	Capital expenditure
Cascade failure	The successive failure of transmission or generation components leading to widespread failure of the power system over a large area
CMP	Capacity measurement period
Code	Electricity Industry Participation Code 2010
Constraint	A local limitation in the transmission capacity of the grid required to maintain grid security or power quality
Contingency	An unplanned event in the power system, including loss of a transmission asset
CUWLP	Clutha-Upper Waitaki Lines Project
Deficit	Unsupplied electricity demand due to a lack of transmission and/or generation capacity
EDGS	Electricity Demand and Generation Scenarios – see Electricity demand and generation scenarios (EDGS) Ministry of Business, Innovation & Employment (mbie.govt.nz)
EMBD	Expected market benefit or disbenefit
EPNPB	Expected positive net private benefits

Term	Meaning
HVDC link	High voltage direct current inter-island link, the transmission link between the North and South Islands
IM	Input Methodology
IRA	Intra-regional allocator
Investment test	The investment approval test under section III of Part F of the Electricity Governance Rules 2003 (now revoked) or the Transpower Capex IM
kVAr	KiloVolt Ampere reactive (reactive power)
kWh	KiloWatt hour (energy)
MBIE	Ministry of Business, Innovation & Employment
MW	MegaWatt (power)
MWh	MegaWatt hour (energy)
NPB	Net private benefit
Opex	Operating expenditure
OptGen	The generation expansion tool used by Transpower. See PSR OptGen — Model for generation expansion planning and regional interconnections (psr-inc.com)
Pre-contingent load management	Load management that results from the application of a pre-contingent market constraint.
Pre-contingent market constraint	A security constraint applied by the system operator in the wholesale electricity market, usually limiting transmission flow over one or more circuits, affecting the dispatch and prices.
PVEMBD	Present value of expected market benefit or disbenefit
PVMRNPB	Present value of market regional net private benefit

Term	Meaning
SDDP	The market model used by Transpower. See Software PSR – Energy Consulting and Analytics (psr-inc.com)
SPD	The scheduling, pricing, and dispatch tool used by the system operator for dispatching generators, creating prices, and forecasting dispatch and prices
SPS	Special protection scheme
System condition	The load and generation patterns Transpower uses to highlight transmission issues we can reasonably expect to occur with currently available information and trends. See Transmission Planning Report 2021.pdf (transpower.co.nz)
TPM	Transmission pricing methodology
Transmission alternative	A service provided by a third party to Transpower to defer or avoid investment in the grid – e.g. demand response
TWAP	Time weighted average price
VoLG	Value of lost generation
VoLL	Value of lost load

