TRANSPOWER

# TPM CONSULTATION:

# NZGP1.1 - HVDC Reactive Support proposed starting BBI customer allocations

# Draft Record of application of the price-quantity method

**Date: 27 April 2023**

# Contents

# 1 Introduction

1. This **draft record** presents our application of the price-quantity method to calculate the High Voltage Direct Current (**HVDC**) Reactive Support benefit-based investment's (**BBI's**) proposed starting BBI customer allocations under the transmission pricing methodology (**TPM**).[1] The HVDC Reactive Support 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 HVDC Reactive Support 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 HVDC Reactive Support 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.

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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).

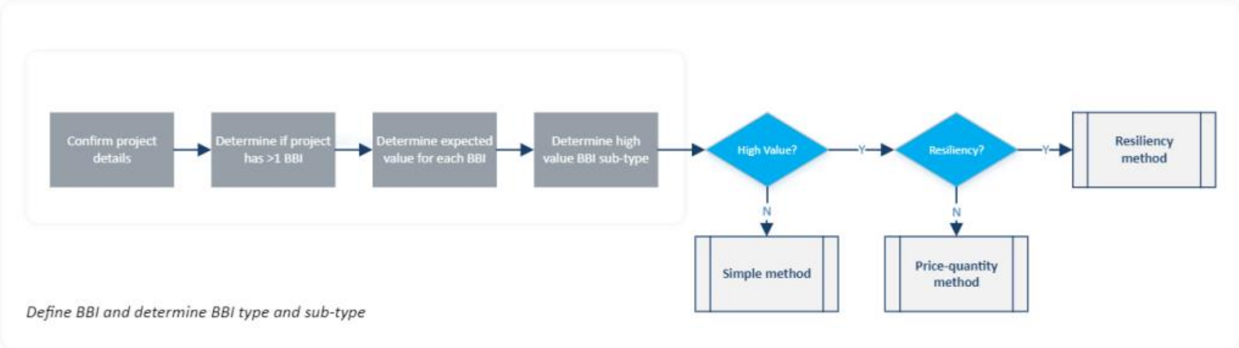
3 TPM Determination: BBC Assumptions Book v1.1, 16 March 2023.

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 HVDC Reactive Support 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 HVDC link connects the North and South Island electricity transmission systems at Benmore in the South Island (**SI**) and Haywards in the North Island (**NI**). It currently comprises two circuits, Pole 2 and Pole 3, which convert electricity between direct and alternating current. Pole 2 was built in the early 1990s and Pole 3 in 2013.

7. The HVDC grid output in the NZGP1.1 proposal seeks to increase the average maximum northwards transfer capacity[5] available from the existing HVDC link. Currently, average maximum capacity is reduced due to regular outages of some equipment that enables higher levels of northward transfer when in service. The NZGP1.1 proposal is to install reactive support equipment which will provide improved link capacity availability, targeting a lift in the average maximum capacity from 1071 MW to close to 1200 MW (from the South Island to the North Island). See the section 2.2.1 of the NZGP1.1 proposal for more information.

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 HVDC Reactive Support BBI (see sections 2.4, 5.1, and 6.1 for more detail).

9. The fully commissioned asset value of the HVDC Reactive Support BBI is expected to be $103m. There will be no transmission alternative opex associated with the HVDC Reactive Support BBI.

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5 By average maximum capacity, we mean the maximum capacity the HVDC is able to provide on average after accounting for plant outages. The BBI will not change the nominal maximum capacity of the HVDC.

10. We expect the HVDC Reactive Support BBI to be fully commissioned by the end of 2026,[6] if the NZGP1.1 proposal is approved by the Commerce Commission. The HVDC Reactive Support BBI is therefore a post-2019 BBI.

11. All of the principal benefits of the HVDC Reactive Support BBI are expected to be released by the assets commissioned before the end of 2026. Therefore, the HVDC Reactive Support BBI's expected effective full commissioning date is 2026 (during FY 26/27).

## 2.2 Determine if project has >1 BBI

12. We applied the principles in paragraph 219 of the assumptions book to consider whether the HVDC Reactive Support BBI should be combined with other investments in NZGP1.1 e.g. the Central North Island and the Wairakei Ring projects. We consider that the HVDC Reactive Support BBI should be a separate BBI from both the CNI 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;[7]
    - 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.[8]

13. We have not included NZGP1's proposed upgrade of the HVDC to 1400 MW as part of the HVDC Reactive Support 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 HVDC Reactive Support BBI is expected to be $103m. There will be no transmission alternative opex associated with the HVDC Reactive Support BBI.

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6 See section 3.3.5 of [NZGP1 Attachment D – Scenario and Modelling Report].

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

8 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,[9] the HVDC Reactive Support 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 HVDC Reactive Support BBI – the HVDC Reactive Support BBI's investment 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 HVDC Reactive Support BBI investment.

17. Therefore, the HVDC Reactive Support 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 HVDC Reactive Support BBI as a separate post-2019 BBI because it:

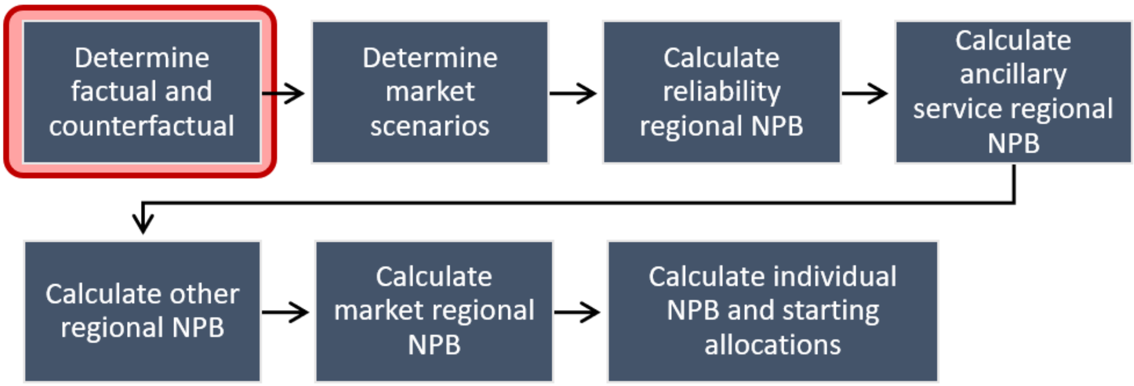
- is an enhancement investment commissioned after 23 July 2019 (clause 37(3)), and
- is not an exempt post-2019 investment (it will be commissioned after 1 July 2021) (clause 37(5)).

9 Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf (comcom.govt.nz).

# 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 HVDC Reactive Support BBI (and as shown in Figure 2).

**Figure 2: Determine factual and counterfactual**




## 3.1 Determine factual

20. The factual is the grid state with the HVDC at its full MW capacity after the HVDC Reactive Support BBI has been fully commissioned (1200 MW north transfer limit, and 850 MW south transfer limit).

## 3.2 Determine investment type and counterfactual

21. The HVDC Reactive Support BBI does not constitute a refurbishment or replacement investment as defined in the TPM (which refers to the corresponding definitions in the Transpower Capex IM).[10] It is therefore an enhancement investment.

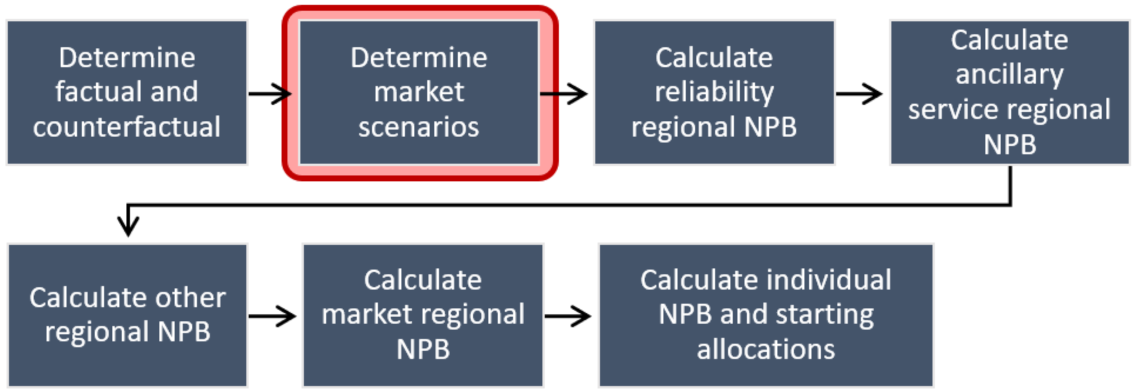
22. Consistent with clause 45(2)(a), the counterfactual is the HVDC link without the HVDC Reactive Support BBI investment. Specifically, the counterfactual is modelled as a maximum north transfer limit of 1071 MW and a maximum south transfer limit of 762 MW, which represents the HVDC's average maximum capacity.

10 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 HVDC Reactive Support 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 of the NZGP1.1 proposal.[11] Except where stated in section 4.2 of Attachment D, these are consistent with the assumptions in v1.1 of the assumptions book.[12]

25. Section 8.3 below 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

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 expected positive net-private benefit (**EPNPB**).

## 4.3 Determine if different market scenarios are required

27. 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.

11 NZGP1 Attachment D – Scenario and Modelling Report, December 2022.

12 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

28. 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.

29. 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.

30. 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)).

31. 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.[13]

32. 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.[14]

## 4.5 Determine the weightings to be applied

33. As described in section 4.1.1 of the NZGP1.1 proposal, the application of the investment test gave equal weighting to the five EDGS scenarios.

34. The NZGP1.1 proposal did not explicitly state a weighting for the Tiwai sensitivities (2024 and 2034). As discussed in section 1.5.1 of the NZGP1.1 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.*

35. 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.

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13 [Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz).]

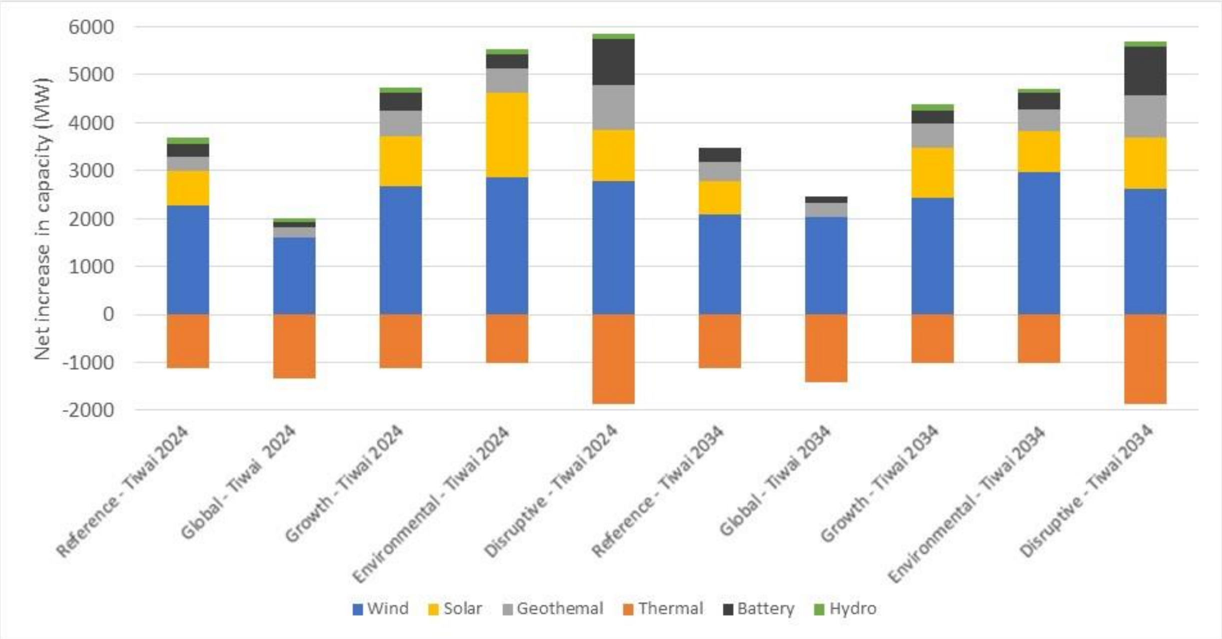
14 Clause 46(3) is relevant to situations where a customer exists in some scenarios and not in others (i.e. receives a benefit in some scenarios and not others). Because NZAS does not receive a positive individual NPB in either the 2024 or 2034 scenarios, it does not matter which of these scenarios we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

## 4.6 Hydro, load, and generation expansion variations

36. The market scenarios are consistent with clause 46(1) because they include variations in:

- 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, and the different generation expansion in the factual and counterfactual for each scenario. We used different generation expansion scenarios for the factual and counterfactual because we expect the HVDC Reactive Support BBI to materially influence generation investment decisions – particularly in relation to allowing more capacity to be built in the South Island.[15] The graphs below show the generation expansion scenarios we have used for the counterfactual.[16] The counterfactual scenarios are those used for the application of the investment test. The factual scenarios are those used in the transmission options that upgrade the HVDC to 1200 MW. See NZGP1 Attachment D – Scenario and Modelling Report.

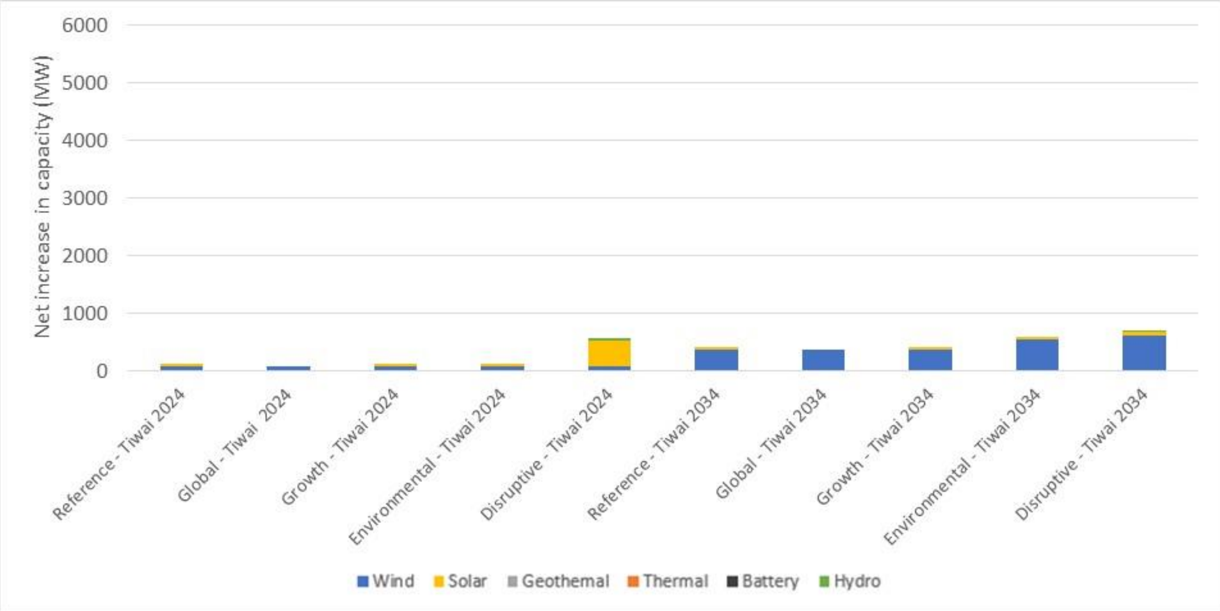
**Figure 4: North Island generation expansion assumptions used in the counterfactual**




15 The use of different generation expansion scenarios in the factual and counterfactual is also consistent with the investment test.

16 For brevity, we have not shown the factual scenarios because these are similar to the counterfactual relative to the total capacity built over the calculation period e.g. see section 3.2.4 of NZGP1 Attachment D – Scenario and Modelling Report.

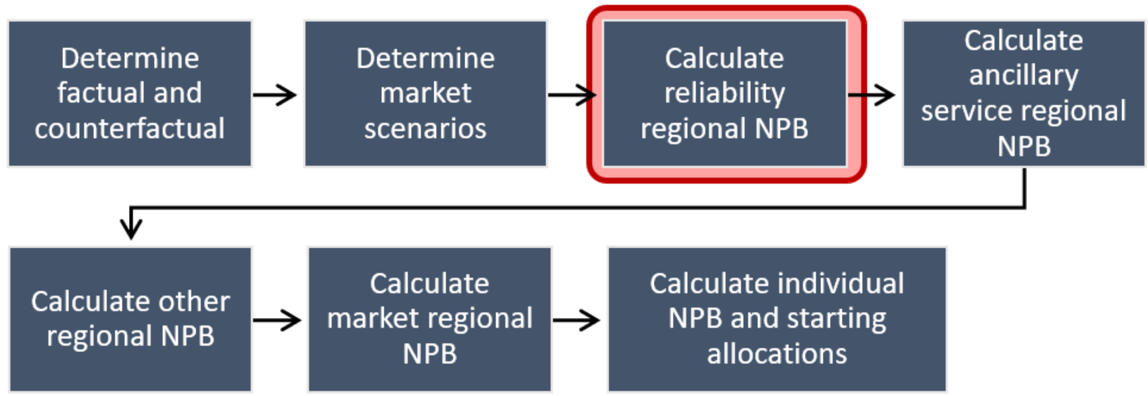
**Figure 5: South Island generation expansion assumptions in the counterfactual**



# 5 Calculate reliability regional NPB

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

**Figure 6: Calculate reliability regional NPB**




## 5.1 Determine if there are reliability benefits

38. We do not expect the HVDC Reactive Support 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 because it does not add new lines or circuits or change the configuration of the grid, and
- the only other reliability benefit associated with the HVDC would relate to avoiding an AUFLS[17] event. Increased transfer across the HVDC does not affect the likelihood of AUFLS being activated (assuming the HVDC would be the reserves risk setter at its maximum transfer level in both the factual and counterfactual) so the investment does not materially reduce the extent or duration of any potential interruption to supply. This assumption is consistent with our application of the investment test for the HVDC Reactive Support BBI.

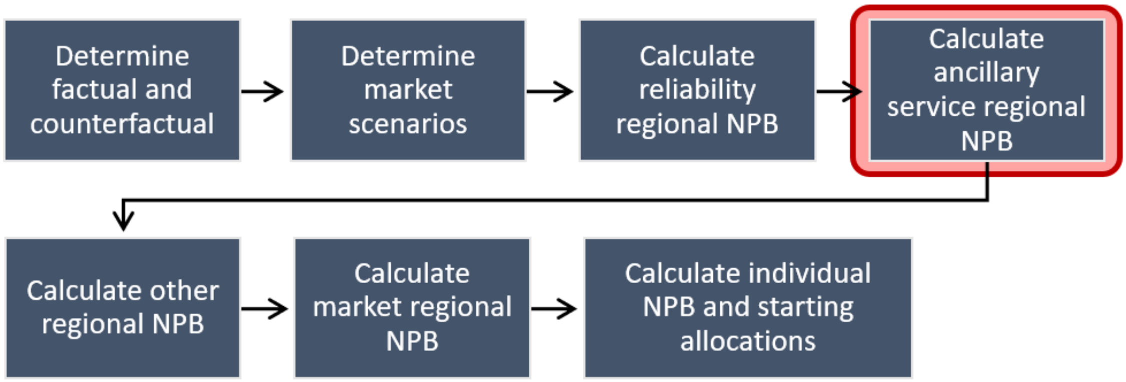
39. Therefore, we do not consider the HVDC Reactive Support BBI to be a reliability BBI and did not calculate reliability regional NPB under clause 54.

17 Automatic Under Frequency Load Shedding (**AUFLS**) is an under-frequency management tool used to manage power system stability and prevent total system blackouts. The scheme disconnects large blocks of demand in the event of a large loss in energy supply. The automatic disconnection of demand aims to restore the supply-demand balance necessary to maintain the stability of the power system and prevent blackouts.

# 6 Calculate ancillary service regional NPB

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

**Figure 7: Calculate ancillary service regional NPB**




## 6.1 Determine if there are ancillary service benefits

41. We do not expect the HVDC Reactive Support 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. This is because the primary function of the HVDC Reactive Support BBI is to increase the redundancy of reactive support at Haywards currently provided by synchronous condensers and a STATCOM. This supports transfer capability by avoiding transient and static voltage limits, which apply to the HVDC's maximum transfer rather than the affecting its risk subtractor (which would affect the quantity, and potentially the price, of reserves that are procured to support HVDC transfer).

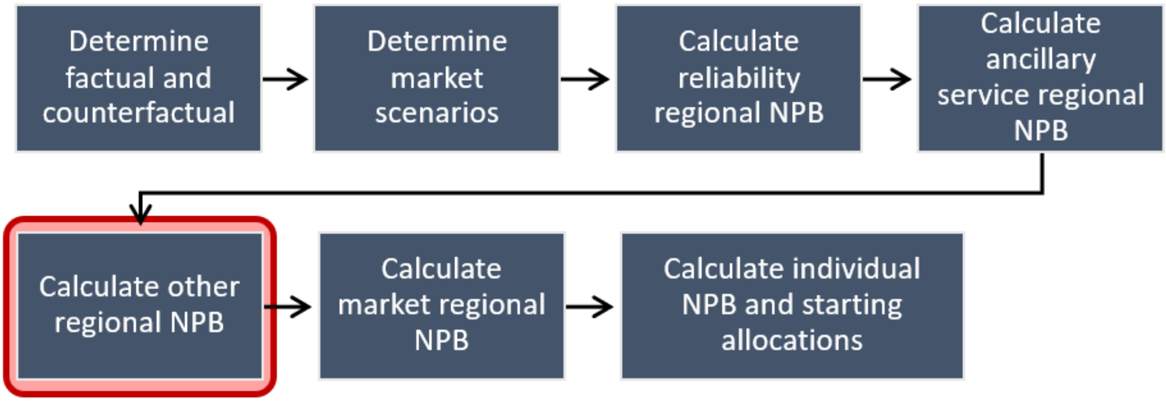
42. Furthermore, as noted in section 3.1.3 of the NZGP1.1. proposal Attachment D, the NZGP1.1 proposal did not assess any impacts on the reserves market as a result of the HVDC Reactive Support BBI.

43. Therefore, we did not calculate ancillary service regional NPB under clause 53.

# 7 Calculate other regional NPB

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

**Figure 8: Calculate other regional NPB**



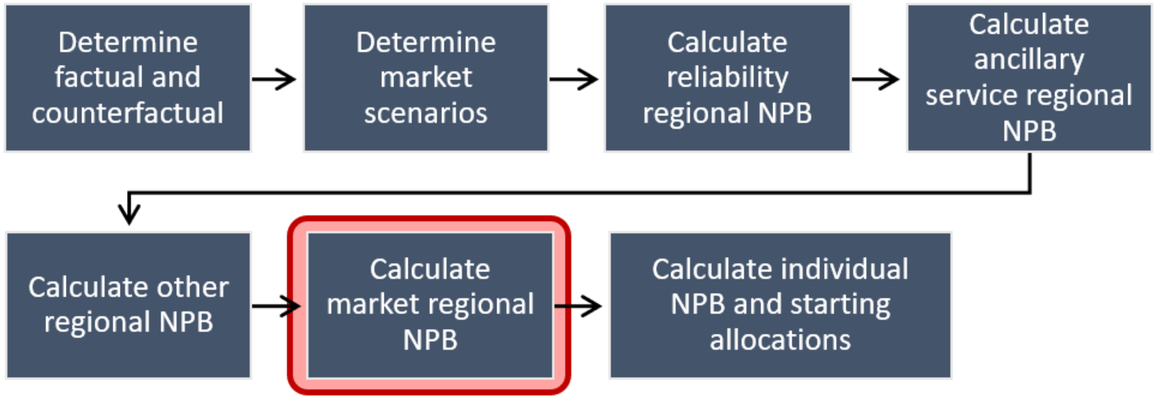

45. We do not expect the HVDC Reactive Support BBI to have any material or measurable other benefits. Specifically, we do not expect any customer or embedded plant owner to receive benefits other than wholesale electricity market benefits from the HVDC Reactive Support BBI.

46. Therefore, we did not calculate other regional NPB for the HVDC Reactive Support BBI under clause 55.

# 8 Calculate market regional NPB

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

**Figure 9: Calculate market regional NPB**




## 8.1 Determine if there are market benefits

48. We expect the HVDC Reactive Support 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

49. No AC transmission constraints have been included as modelled constraints as there are no AC constraints that affect a new grid asset that is part of the BBI, and there are no AC constraints that would be materially alleviated by the BBI.[18]

50. Therefore, the investment grids for the HVDC Reactive Support BBI comprise:

- all existing branches and market nodes, and
- a limit on HVDC north transfer of 1200 MW and 1071 MW in the factual and counterfactual respectively, and a limit on HVDC south transfer of 850 MW and 762 MW in the factual and counterfactual respectively.

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[18] 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 HVDC Reactive Support BBI.

## 8.3 Include other market model inputs

51. As noted above, chapter 2 of the assumptions book and the investment test contain most of the modelling inputs for the market scenarios we used for the HVDC Reactive Support BBI. We used those modelling inputs.

52. We also used the following additional modelling inputs:

- We used a standard method calculation period of 20 years from 1 January 2027 – the first 1 January after the HVDC Reactive Support BBI's expected effective full commissioning date of 2026.[19] We used the maximum possible standard method calculation period as the majority of the assets that make up the HVDC Reactive Support BBI are expected to have useful lives of greater than 20 years.
- We discounted all values to 2026. For the HVDC Reactive Support BBI, 2026 is "year 0" in the present value calculation in clause 48(1) because the standard method calculation period starts in 2027.
- We used SDDP with an hourly resolution rather than load blocks for consistency with the application of the investment test.[20]

53. These additional inputs are either required by the TPM (in the case of the standard method calculation period and discounting of values to 2026) or chosen because we consider they will produce starting BBI customer allocations that are broadly proportionate to EPNPB.

## 8.4 Run market model

54. We ran SDDP[21] 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 HVDC Reactive Support BBI.

55. That is, by proposing to treat the HVDC Reactive Support BBI as a separate BBI (see section 2.2 above), we are required to run SDDP using inputs for the HVDC Reactive Support BBI specifically, whereas the investment test involved running SDDP using inputs for NZGP1.1 as a whole.[22] The differences in the SDDP modelling for the HVDC Reactive Support BBI (i.e. running SDDP using inputs that relate to the HVDC Reactive Support BBI specifically) are required to isolate those private benefits attributable to the HVDC Reactive Support BBI rather than other BBIs that make up NZGP1.1.

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

20 Note the investment test used hourly resolution at five-year snapshots, and scaled benefits calculated at a load block resolution in the intervening years (see section 3.1.3 of NZGP1 Attachment D – Scenario and Modelling Report). Because the TPM requires post-processing on SDDP outputs to calculate private benefits for each customer, we couldn't scale the modelling results in the same manner. We consider using an hourly resolution is most consistent with the application of the investment test.

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

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

## 8.5 Determine if clause 51 or 52 applies

56. 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.

57. 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)).

58. We have applied clause 51 for the HVDC Reactive Support BBI.

59. We assessed whether clause 51(1)(a) applies to the HVDC Reactive Support BBI by applying the test in paragraph 298 of the assumptions book (checking if most of the positive market regional NPB for the HVDC Reactive Support BBI's regional supply groups relates to new large generating plant).

60. We determined it does not because the majority of positive market regional NPB for the HVDC Reactive Support 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 HVDC Reactive Support 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).

61. As clause 51(1)(a) does not apply, we are required to use clause 52 for the HVDC Reactive Support BBI if either clause 52(1)(b)(i) or 52(1)(b)(ii) applies.

62. We assessed whether clause 52(1)(b)(i) applies to the HVDC Reactive Support BBI by applying the test in paragraph 299 of the assumptions book (checking if most of the positive market regional NPB for the HVDC Reactive Support 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:[23]

- For each market scenario, factual/counterfactual, and each hour 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 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.

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23 This calculation is different from the one used in the application of the standard method for the Pole 2 Convertor 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.

63. 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[24] (48%) we are not required to use clause 52 by clause 52(1)(b)(i).

64. 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.

65. 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 HVDC Reactive Support BBI. This is because:

- the HVDC is part of the grid backbone i.e. not on the extremity of the grid,
- our modelling clearly demonstrates a significant price impact on both upstream and downstream regions, and
- the corroborative modelling carried out for the CUWLP demonstrated that CUWLP's modelled prices were very sensitive to input assumptions. We consider this would likely also be the result of corroborative modelling for the HVDC Reactive Support BBI as the HVDC Reactive Support BBI and CUWLP are similar types of investment – both are investments in the grid backbone and both provide the primary benefit of relieving constraints that prevent South Island hydro generation from reaching load in the rest of the country.

## 8.6 Determine if clause 49(6) should be applied

66. For the HVDC Reactive Support BBI, 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). Consistent with that, for HVDC Reactive Support BBI specifically, we consider the directional price changes from SDDP result in potential modelled regions that will produce starting BBI customer allocations that are broadly proportionate to EPNPB, as discussed in section 8.7 below.

## 8.7 Determine potential modelled regions

67. As per paragraph 307 of the assumptions book, modelled regions are determined using the points of modelled constraint and the HVDC link constraints.

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24 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 (which strengthens our conclusion that clause 52(1)(b)(i) does not apply.

68. As the only modelled constraint is the HVDC link itself, we determined two modelled regions for the HVDC Reactive Support BBI, the North Island and South Island. We consider these modelled regions meet the requirements of clause 50(1) for the HVDC Reactive Support 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

69. We determined the HVDC Reactive Support BBI's periods of benefit as the periods in which one of the HVDC modelled constraints is binding.

70. This approach to determining periods of benefit is a departure from paragraph 314 of the assumptions book, because paragraph 314 is only applicable to a BBI that is in the AC network and the HVDC, which converts electricity from direct to alternating current, is not an AC network. We consider the departure necessary to produce starting allocations for the HVDC Reactive Support BBI that are broadly proportionate to EPNPB.

71. 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.

72. The generation portion of EMBD for a customer at a connection location was calculated using the following formulae from paragraph 319 of the assumptions book:

$$EMBD\_Gen\_SI_{cust,loc} = \left(Gen_{cust,loc,CF,Nth} - Gen_{cust,loc,CF,Sth} + GenDelta_{cust,loc}\right)$$

$$EMBD\_Gen\_NI_{cust,loc} = (Gen_{cust,loc,CF,Sth} - Gen_{cust,loc,CF,Nth} + GenDelta_{cust,loc})$$

Where:

- $EMBD\_Gen\_SI_{cust,loc}$ is the generation portion of EMBD for an SI customer ($cust$) at a connection location ($loc$)
- $EMBD\_Gen\_NI_{cust,loc}$ is the generation portion of EMBD for a NI 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 HVDC (where prices are alleviated for SI regional supply groups and are exacerbated for NI 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 HVDC (where prices are exacerbated for SI regional supply groups and are alleviated for NI regional supply groups) ($Nth$)

- $GenDelta_{cust,loc}$ is, for the customer ($cust$) at the connection location ($loc$), factual generation minus counterfactual generation.

73. 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:

$$EMBD\_Load\_SI_{cust,loc} = \ (Load_{cust,loc,CF,Sth} - Load_{cust,loc,CF,Nth} + LoadDelta_{cust,loc})$$

$$EMBD\_Load\_NI_{cust,loc} = (Load_{cust,loc,CF,Nth} - Load_{cust,loc,CF,Sth} + LoadDelta_{cust,loc})$$

Where:

- $EMBD\_Load\_SI_{cust,loc}$ is the load portion of EMBD for an SI customer ($cust$) at a connection location ($loc$)
- $EMBD\_Load\_NI_{cust,loc}$ is the load portion of EMBD for a NI 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 HVDC (where prices are alleviated for SI regional demand groups and are exacerbated for NI 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 HVDC (where prices are exacerbated for SI regional demand groups and are alleviated for NI 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

74. 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:[25]

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

where $W_s$ is the probability weighting for the market scenario.

[25] 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.

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

75. 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.

76. 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

77. 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.

78. 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. 2026 for the HVDC Reactive Support BBI) based on the customers' IRAs. This resulted in 74% of GLN's first year load output assigned to NZST (~844 GWh) and 26% 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 of 844 GWh (NZST's annual load for the first year). This resulted in an increasing load forecast for COUP, from 301 GWh in 2026 to 354 GWh in 2046
- Calculate a present value for the two customers' load forecasts using a 7% discount rate.[26] 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

79. 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

26 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.

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:

$$PVEMBD\_NetGen\_SI_{cust,loc} = PVEMBD\_Gen\_SI_{cust,loc} + PVEMBD\_Load\_SI_{cust,loc} - (PVLoadDelta_{cust,loc} * 2)^{27}$$

$$PVEMBD\_NetGen\_NI_{cust,loc} = PVEMBD\_Gen\_NI_{cust,loc} + PVEMBD\_Load\_NI_{cust,loc} - (PVLoadDelta_{cust,loc} * 2)$$

$$PVEMBD\_NetLoad\_SI_{cust,loc} = PVEMBD\_Gen\_SI_{cust,loc} + PVEMBD\_Load\_SI_{cust,loc} - (PVGenDelta_{cust,loc} * 2)^{28}$$

$$PVEMBD\_NetLoad\_\mathrm{NI}_{cust,loc} = PVEMBD\_Gen\_NI_{cust,loc} + PVEMBD\_Load\_NI_{cust,loc} - (PVGenDelta_{cust,loc} * 2)$$

Where:

- $PVEMBD\_NetGen\_SI_{cust,loc}$ is the present value of EMBD for an SI customer ($cust$) at a connection location ($loc$) calculated based on net generation
- $PVEMBD\_NetGen\_NI_{cust,loc}$ is the present value of EMBD for a NI customer ($cust$) at a connection location ($loc$) calculated based on net generation
- $PVEMBD\_NetLoad\_SI_{cust,loc}$ is the present value of EMBD for an SI customer ($cust$) at a connection location ($loc$) calculated based on net load
- $PVEMBD\_NetLoad\_NI_{cust,loc}$ is the present value of EMBD for a NI customer ($cust$) at a connection location ($loc$) calculated based on net load.

80. 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 HVDC Reactive Support BBI.[29] 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.

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27 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.

28 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.

29 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 85 below.

- Wind generation (Wnd)
- Controlled hydro generation (Chyd)
- Geothermal generation (Geo)
- Run-of-river hydro generation (RoR)
- Thermal commitment plant (ThermalCommit)
- Thermal peaker plant (Peaker)
- Battery storage (Batteries)
- Cogeneration (Cogen)[30]
- Generation with embedded load (GenerationWithLoad) – connection locations with significant generation and load[31] 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.

81. We grouped Alpine at Albury, Westpower at Kumara, and Aurora at Clyde into the SI 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 HVDC Reactive Support 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 SI regional supply groups, and we consider grouping them as such will 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.

82. 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, 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 generation[32] 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.

83. Due to the different magnitudes of market benefit that may accrue to these customer types from the HVDC Reactive Support BBI, we consider it necessary to create these potential

30 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.

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

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

regional customer groups in each modelled region to produce starting allocations that are broadly proportionate to EPNPB.

84. We did not separate new and existing customers into separate regional customer groups because the benefits of the HVDC Reactive Support BBI do not primarily accrue to new customers.

85. 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:[33]

- NI Solar Generation
- SI Wind Generation[34]
- SI Solar Generation
- SI Battery Generation
- SI Thermal Generation

## 8.10 Calculate PVMRNPB for potential regional customer groups

86. 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

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

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 HVDC Reactive Support BBI in respect of those stations.

- $PVEMBD\_NetLoad_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location ($loc$) calculated based on net load.

87. We removed potential regional customer groups with a PVMRNPB that was not positive (all North Island regional supply groups, South Island regional demand groups, and South Island Thermal generation), which left the following potential regional customer groups:
    - SI Controlled Hydro Generation
    - SI Run-of-River Hydro Generation
    - NI Non-industrial Load
    - NI Industrial Load
    - NI Load with Embedded Generation
    - SI Solar Generation (potential future regional customer group)
    - SI Wind Generation (potential future regional customer group)
    - SI Battery Generation (potential future regional customer group)

88. 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

89. 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

90. We have amalgamated the potential regional supply groups into a single proposed regional supply group. 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 SI Run-of-River Hydro Generation regional supply group. As the SI Controlled Hydro Generation ratio is >80% of the SI Run-of-River Generation ratio, the regional supply groups can be combined. The finalised customer group is named SI Hydro Generation.

91. The PVMRNPB of each potential and proposed regional supply group is shown in Table 1.

**Table 1: 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 |
|---|---|---|---|---|---|---|
| South Island | Run-of-River Hydro Generation | 126 | 42 | 3.0 | 2.4 | South Island Hydro Generation |
| South Island | Controlled Hydro Generation | 49,766 | 17,448 | 2.9 | - | South Island Hydro Generation |

92. We calculated PVMRNPB and notional IRAs for the potential future regional supply groups shown in Table 2. Based on their PVMRNPB/IRA ratios, we determined that these potential future regional supply groups do not have similar benefits to the SI Hydro Generation regional supply group because they all have a PVMRNPB ratio of less than 2.4. Similarly, each potential future regional supply group is not amalgamated because each group has a PVMRNPB/IRA ratio that is less than the grouping threshold of the preceding group. Therefore, these future members will be in their own groups if and when they connect to the grid.

**Table 2: PVMRNPB of each potential future regional supply group**

| Modelled region | Potential future regional supply group | PVMRNPB (GWh/MW)[35] | IRA (GWh/MW) | PVMRNPB/IRA | Grouping threshold | Proposed regional supply group |
|---|---|---|---|---|---|---|
| South Island | Solar Generation (future) | 3.3 | 1.5 | 2.2 | 1.7 | SI Solar Generation |
| South Island | Wind Generation (future) | 5.6 | 3.5 | 1.6 | 1.3 | SI Wind Generation |
| South Island | Battery Generation (future) | 0.4 | 0.4[36] | 1.2 | - | SI Battery Generation |

93. The SI Thermal Generation potential future regional supply group did not have positive PVMRNPB. Therefore, any thermal generators connecting in the South Island (or elsewhere) will not receive a BBI customer allocation for the HVDC Reactive Support BBI.

35 Note that the IRA values are presented per unit of MW capacity.
36 Based on an assumed 1MWh cycle per day per MW capacity.

### 8.11.2 Finalise regional demand groups

94. 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 NI Non-industrial Load potential group at 3.1. Other potential groups sitting at or above 80% of this ratio can be amalgamated into this group. As the NI Industrial Load with a ratio of 2.7 sits at greater than 80% of the NI Non-industrial Load group's ratio, they are amalgamated into a single final regional customer group. The final regional customer group for these potential groups is labelled as NI Load. The NI Load with Embedded Generation group has a PVMRNPB/IRA ratio of 1.8. This is less than 80% of the NI Non-industrial Load's ratio, so is below the amalgamation threshold and is not combined.

95. As a result, we finalised the following potential regional demand groups for the HVDC Reactive Support BBI:

- NI Load with Embedded Generation
- NI Load

96. PVMRNPB for each proposed regional demand group is shown in Table 3, and the proportion of total PVMRNPB for each proposed regional customer group is in Table 4.

**Table 3: 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 |
|---|---|---|---|---|---|---|
| North Island | Non-industrial Load | 63,772 | 20,762 | 3.1 | 2.5 | North Island Load |
| North Island | Industrial Load | 3467 | 1,306 | 2.7 | - | North Island Load |
| North Island | Load with Embedded Generation | 161 | 91 | 1.8 | - | North Island Load with Embedded Generation |

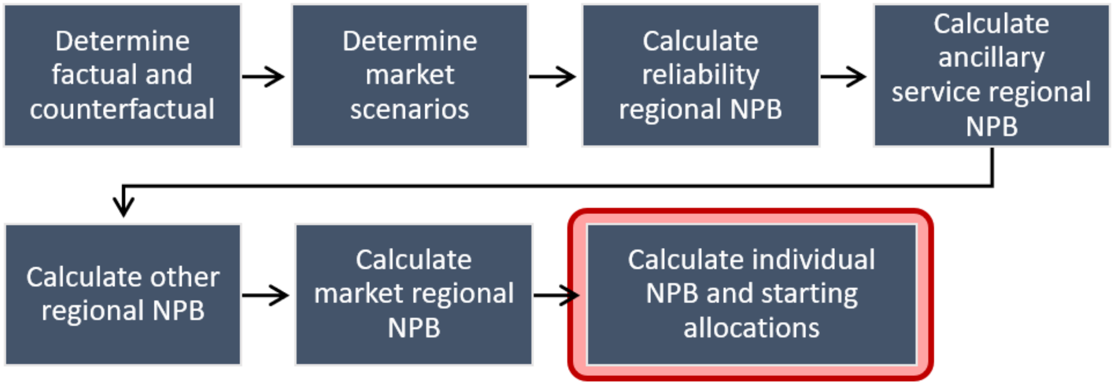
**Table 4: PVMRNPB for proposed regional customer groups as a proportion of total PVMRNPB**

| Proposed regional customer group | PVMRNPB (GWh) | Percentage of PVMRNPB |
|---|---|---|
| North Island Load | 67,239 | 57.33% |
| South Island Hydro Generation | 49,892 | 42.54% |
| North Island Load with Embedded Generation | 161 | 0.14% |

# 9 Calculate individual NPB and starting BBI customer allocations

97. 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

98. Proposed IRA values for the HVDC Reactive Support 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 HVDC Reactive Support 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.

99. The HVDC Reactive Support BBI is a non-peak BBI based on the amount of time the HVDC Reactive Support BBI BBI's modelled constraints (just the HVDC link) are expected to bind during a counterfactual outage i.e. ~10-40% 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.

100. The IRAs for the HVDC Reactive Support 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.

101. 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)).

102. 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.

103. 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).

104. 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.

105. 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

106. We calculated each customer's individual NPB for the HVDC Reactive Support 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

107. We calculated each customer's proposed starting allocation for the HVDC Reactive Support 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) set out in Table 5. The unrounded allocations are available in the Allocation worksheet of the post-processing model.

**Table 5: Each customer's proposed starting allocation for the HVDC Reactive Support BBI**

| Customer Name | Proposed starting allocation (%) |
|---|---|
| Meridian Energy Ltd | 29.48% |
| Vector Ltd | 22.28% |
| Powerco Ltd | 11.52% |
| Contact Energy Ltd | 9.39% |

| Customer Name | Proposed starting allocation (%) |
|---|---|
| Wellington Electricity Lines Ltd | 5.81% |
| Unison Networks Ltd | 3.47% |
| WEL Networks Ltd | 2.60% |
| Genesis Energy Ltd | 2.44% |
| Northpower Ltd | 2.01% |
| Counties Power Ltd | 1.57% |
| New Zealand Steel Ltd | 1.20% |
| Waipa Networks Ltd | 1.09% |
| Pan Pac Forest Product Ltd | 1.08% |
| Manawa Energy Ltd | 1.00% |
| Horizon Energy Distribution Ltd | 0.94% |
| Electra Ltd | 0.81% |
| Eastland Network Ltd | 0.77% |
| The Lines Company Ltd | 0.66% |
| Winstone Pulp International | 0.59% |
| Centralines Ltd | 0.31% |
| Scanpower Ltd | 0.22% |
| Beach Energy Resources NZ (Holdings) Ltd | 0.19% |
| Methanex New Zealand Ltd | 0.13% |
| Aurora Energy Ltd | 0.11% |
| KiwiRail Holdings Ltd | 0.11% |
| OMV NZ Production Ltd | 0.10% |

| Customer Name | Proposed starting allocation (%) |
|---|---|
| Westpower Ltd | 0.09% |
| Alpine Energy Ltd | 0.04% |
| Top Energy Ltd | 0.02% |
| Southdown Cogeneration Ltd | 0.01% |
| Southpark Utilities Ltd | 0.00%[37] |

108. To calculate BBCs for the HVDC Reactive Support BBI, the starting allocations will be multiplied by the HVDC Reactive Support 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.

109. 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 HVDC Reactive Support BBI in the consultation paper accompanying this draft record.

[37] Note Southpark Utilities has an 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 HVDC Reactive Support BBI contained in section 9.3.

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

A.2 The investment proposed in the HVDC Reactive Support BBI would relieve voltage stability constraints that currently limit northward flow on the HVDC to 1,071 MW and southward to 762 MW (on average).

A.3 After commissioning, the northward flow limit on the HVDC would increase to the 1,200 MW and the southward flow limit on the HVDC would increase to 850 MW.

A.4 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.1 Prices with circuit at less than capacity**

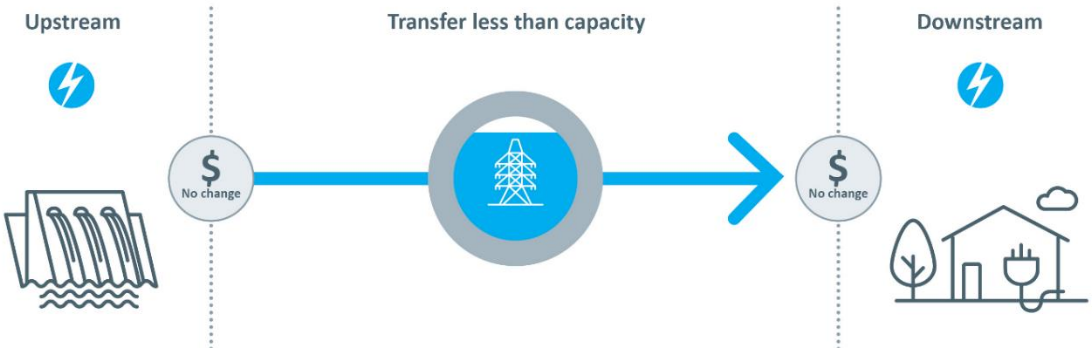
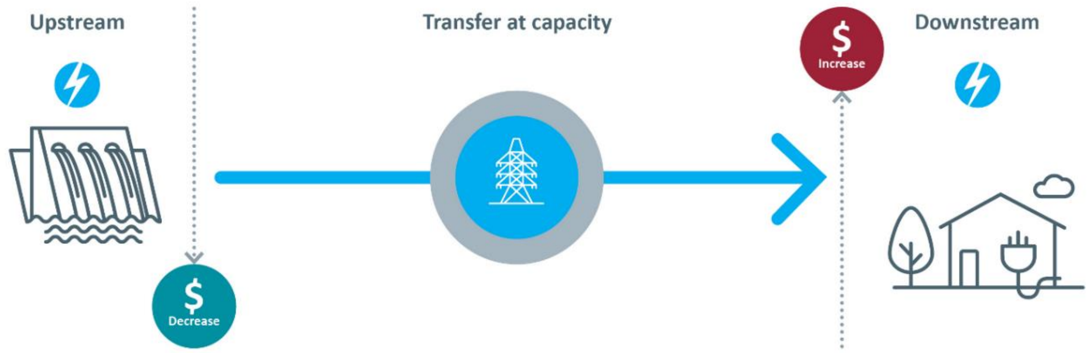


Figure A.2 Prices with circuit at capacity




A.5 By increasing the northward capacity of the HVDC, the HVDC Reactive Support BBI is expected to deliver private benefits to load in the North Island, and generation in the South Island. This is primarily because North Island load would have greater access to South Island generation, and upstream generation in the South Island would have greater access to North Island load. Similarly, load will disbenefit in the region where generation benefits, and vice versa.

## A1.2 Beneficiaries are consistent with the direction of HVDC flow

A.6 We have modelled ten market scenarios, based on the ten market scenarios used in the NZGP1.1 investment test. Each scenario is modelled from 2027 to 2046 and across 50 synthetic hydrological sequences, with the results shown as the mean of these hydro sequences.

A.7 The benefits and disbenefits differ per market scenario as the beneficiaries' exposure to north-flow and south-flow constraints.

A.8 We have defined the periods of benefit to be periods during which the HVDC flow is equal to the 1071 MW northward or 762 MW southward in the counterfactual.

A.9 Figure A.3 and Figure A.4 show the average frequency of binding constraints for the ten scenarios in 2030 and 2035, respectively. Figure A.5 is a flow duration curve for HVDC flows.

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

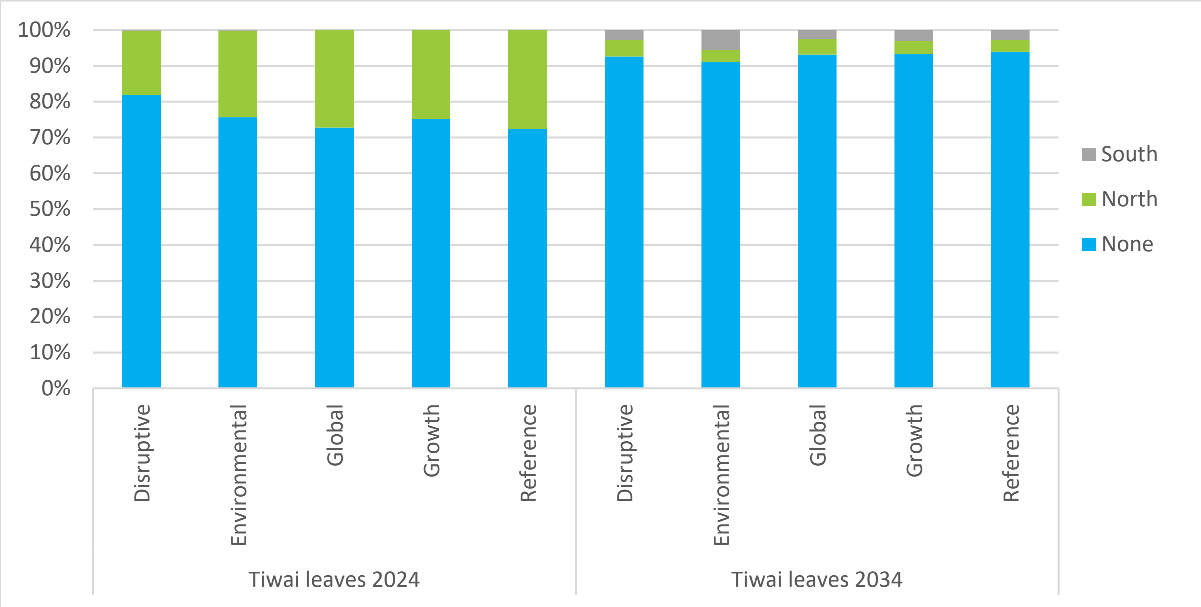



Figure A.4 Frequency of binding constraints in each scenario in 2035

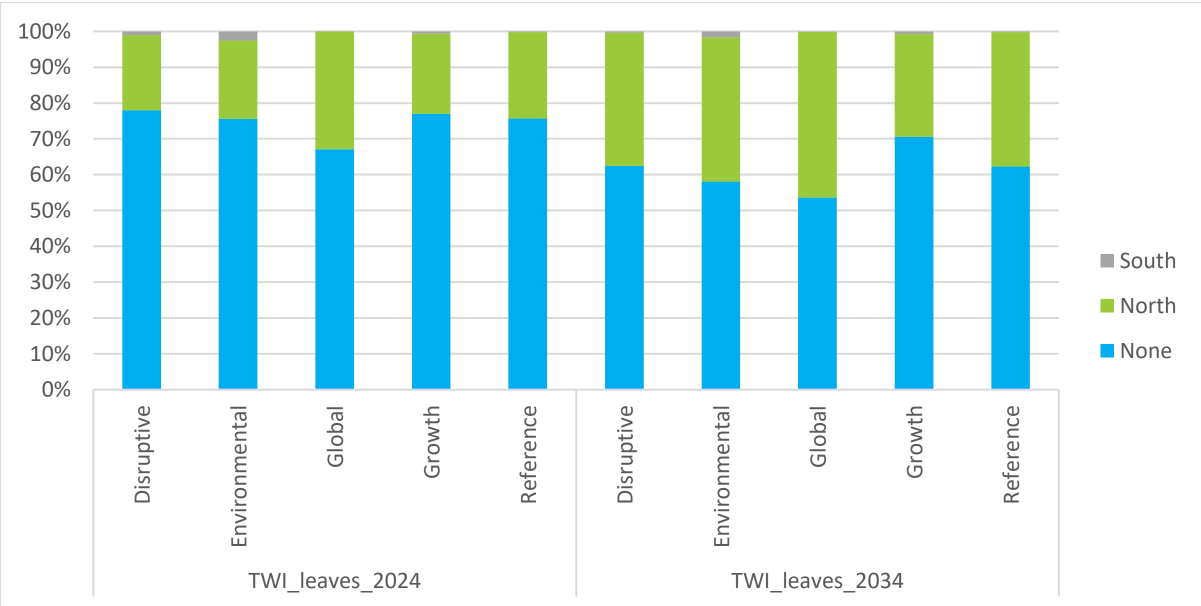
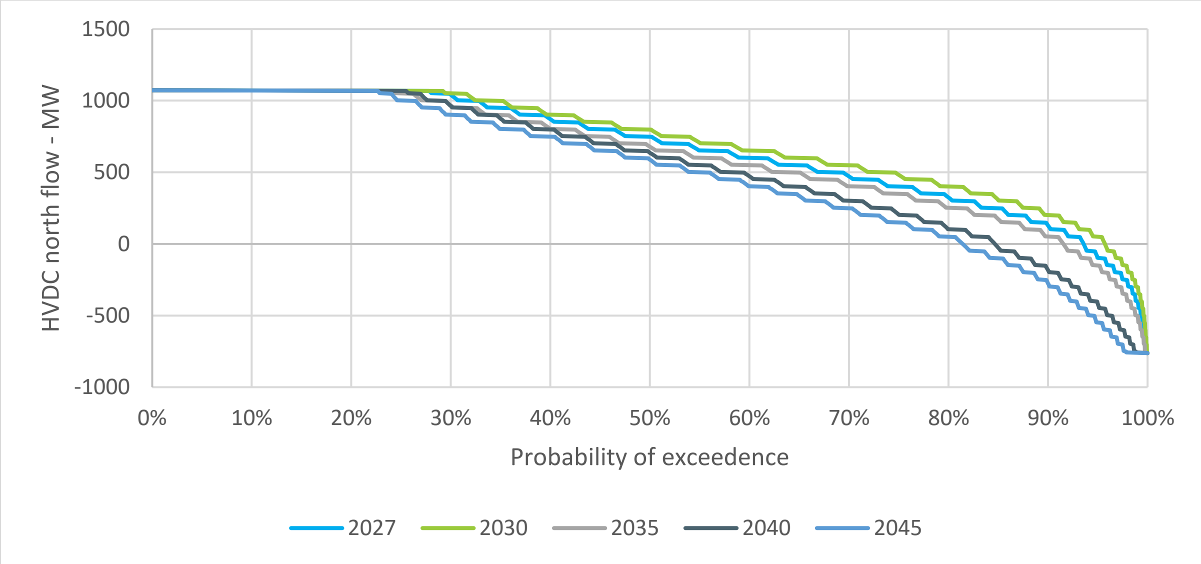


**Figure A.5 HVDC flow duration curve for selected years – Disruptive Tiwai leave 2024**

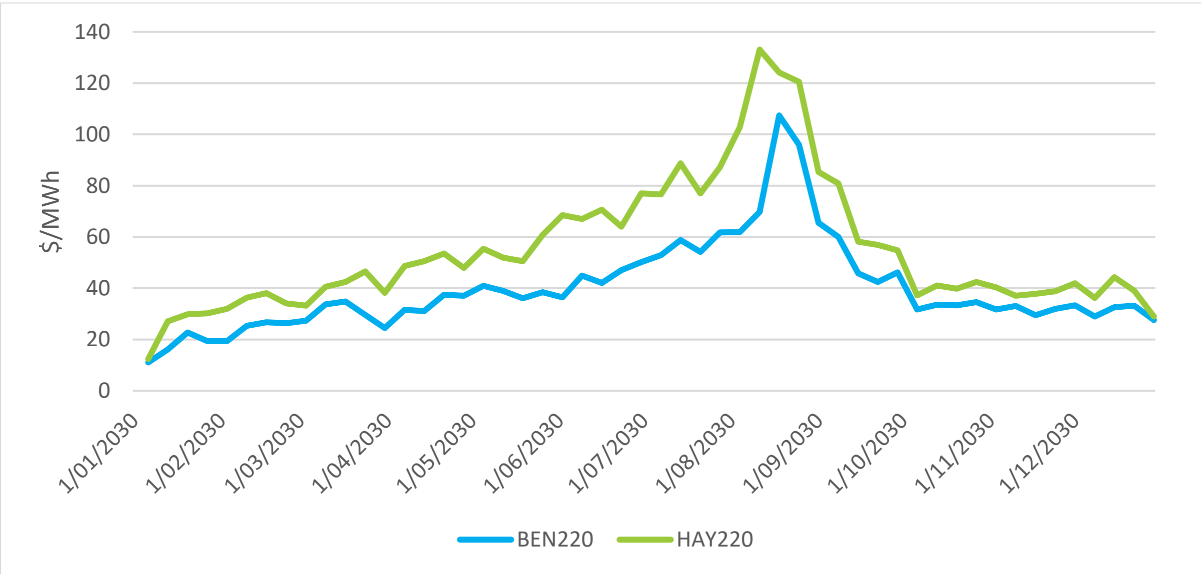



A.10 Load customers in the North Island and generators in the South Island are beneficiaries because the north-flow constraint binds more often than the south-flow constraint across the ten scenarios in the counterfactual.

A.11 Conversely, load customers in the South Island and generators in the North Island are disbeneficiaries.

A.12 This is illustrated by the following modelling results, which show price impacts downstream (in the North Island) and upstream (in the South Island) of the constraint. Figure A.6 shows an example of the price separation between the BEN220 and HAY220 in the Counterfactual.

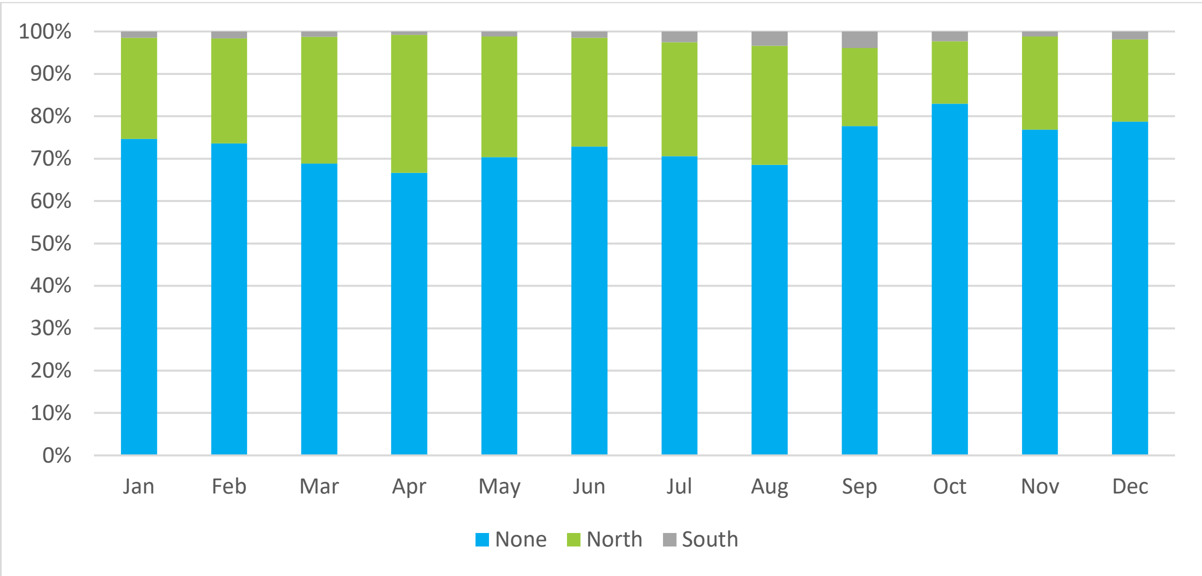
**Figure A.6 Price separation between BEN220 and HAY220 in 2030**



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

A.13 Modelling results have shown the beneficiaries we have identified are not sensitive to the time of year. The proportion of time during which the north and south constraints binds. Figure A.7 shows the time proportion of binding constraints for each month, in the counterfactual.

**Figure A.7 Frequency of binding constraints by month**




A.14 In all cases, the north-flow constraint is binding significantly more than the south-flow constraint, so the beneficiaries we have identified are not affected by the season or the duration of the outage.

## A1.4 South-flow constraint frequency increases over modelling horizon but not enough to change the beneficiaries we have identified

A.15 The periods during which the south-flow constraint binds increase over the modelling horizon due to the increasing role of the HVDC link in firming North Island variable renewable generation.

A.16 For example, during periods of high wind in the North Island, the HVDC link allows South Island load to act as a demand sink by reducing generation from South Island generation. During periods of lower wind in the North Island, the HVDC link allows South Island generation to provide firming support. Therefore, the benefits of the HVDC link become less dominated by northward flow. Furthermore, the majority of new generation built is in the North Island (see section 4.6), also increasing the likelihood if south-flow constraints.

A.17 This effect is not sufficient to change the beneficiaries we have identified. Figure A.8 shows how the frequency of constraints binding in each direction changes over the modelling horizon in the counterfactual average across all scenarios in which Tiwai leaves in 2024. Figure A.9 shows the same information for scenarios in which Tiwai leaves in 2034.

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

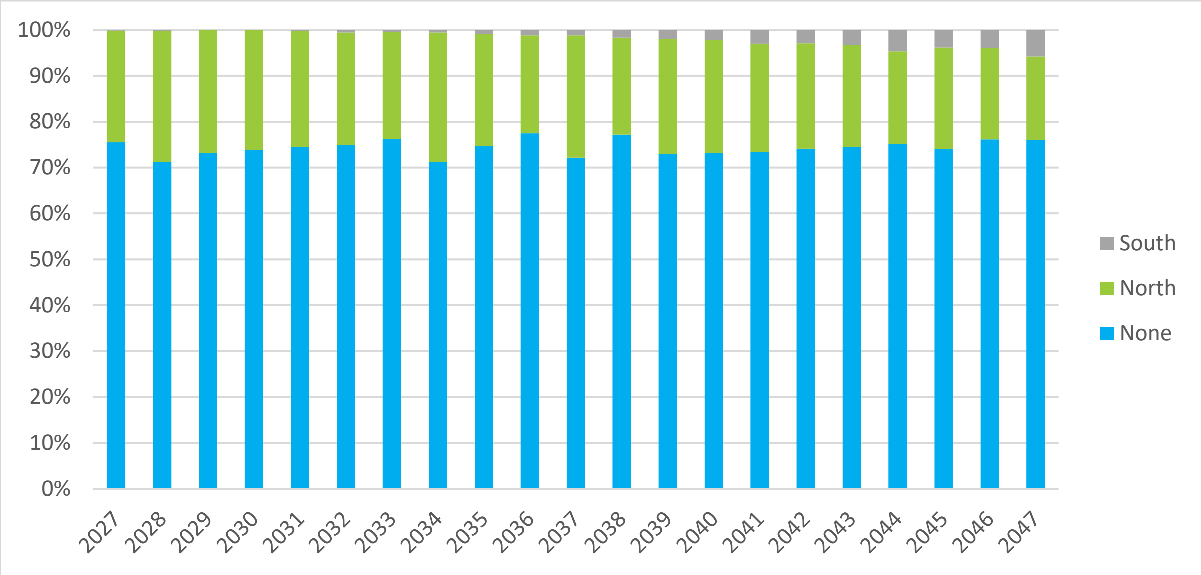
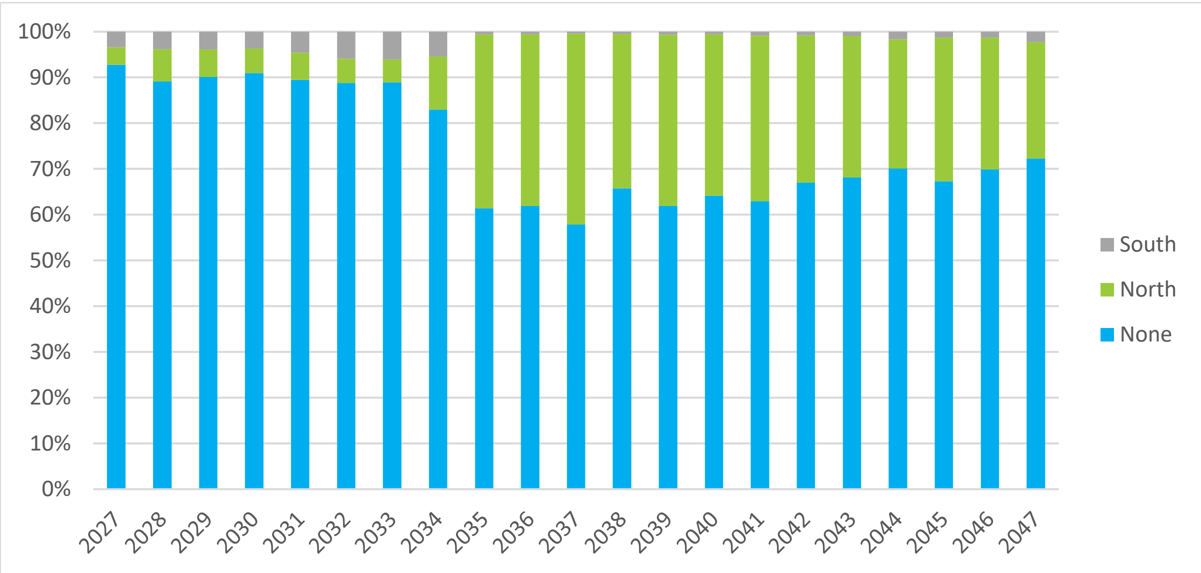



Figure A.9 Frequency of binding constraints by year – Tiwai leaves 2034




A.18 In most years, the north-flow constraint binds significantly more often than the import constraint, so the beneficiaries identified are not affected by this trend towards more south flow on the HVDC.

# Appendix B: Glossary

| Term | Meaning |
|---|---|
| AC | Alternating Current |
| Authority | Electricity Authority |
| AUFLS | Automatic Under Frequency Load Shedding |
| 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 |
| 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 |

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