TRANSPOWER

TPM CONSULTATION:

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

Draft Record of application of the price-quantity method

Date: February 2026

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 project.[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 to NZGP1.1, as set out in the NZGP1.1 major capex proposal (**NZGP1.1 proposal**),[3] except in relation to our assumption about the longevity of the Tiwai point aluminium smelter (**Tiwai**). These input assumptions are generally consistent with the input assumptions in chapter 2 of version 1.1 of the BBC assumptions book (**assumptions book**).[4] 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 applied version 1.1 of the assumptions book because that is the version that applied at the time of our original application of the price-quantity method to the HVDC Reactive Support BBI in 2023, which we refer to as our **previous benefits modelling**. As noted above, the input assumptions in chapter 2 of version 1.1 of the assumptions book reflect the input assumptions we used in the application of the investment test to NZGP1.1. The changes to the analytical steps in chapter 3 of the assumptions book between version 1.1 and version 2.0 (the current version) of the assumptions book do not affect materially the application of the price-quantity method to the HVDC Reactive Support BBI. All references in this draft record to paragraphs of the assumptions book are to paragraphs in version 1.1 of the assumptions book, unless stated otherwise.

4. We have defined some terms in this draft record for convenience. Please also reference the glossary in Appendix B.[5] 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.

5. 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 is in Part 12, Schedule 12.4 of the Electricity Industry Participation Code.

2 Net Zero Grid Pathways | Transpower.

3 NZGP1 submission | Transpower.

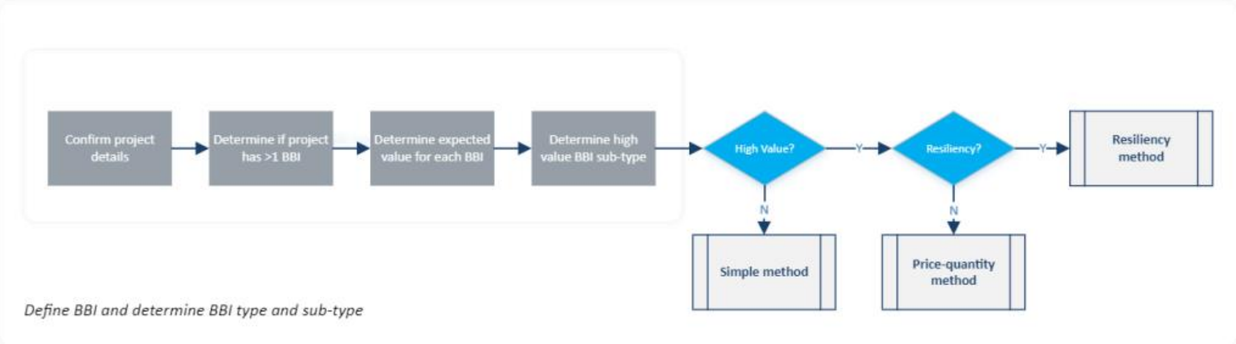
4 TPM Determination: BBC Assumptions Book v1.1, 16 March 2023.

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

2 Define BBI and determine BBI type and sub-type

6. 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

7. 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.

8. The HVDC Reactive Support BBI will increase the average maximum northwards transfer capacity[6] 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 HVDC Reactive Support BBI will 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.

9. 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 of the NZGP1.1 proposal for more detail).

10. 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] By average maximum capacity, we mean the maximum capacity the HVDC link is able to provide on average after accounting for plant outages.

11. We expect the HVDC Reactive Support BBI to be commissioned after 23 July 2019 and it is not an exempt post-2019 investment. The HVDC Reactive Support BBI is therefore a post-2019 BBI.

12. 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

13. We applied the principles in paragraph 219 of the assumptions book to consider whether the HVDC Reactive Support project should be combined with other investments in NZGP1.1 (the CNI and Wairakei projects). We consider that the HVDC Reactive Support project should be a separate BBI from both the CNI and Wairakei projects because the projects:

- 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 project's benefits resulting from relieving constraints, an important aspect of the CNI project's benefits results from it reducing transmission losses which occur whenever power is flowing through the CNI. The HVDC Reactive Support project only provides benefits when flow is approaching the existing capacity of the HVDC link; and
- have different expected commissioning dates.[8]

14. We have not included NZGP1's proposed upgrade of the HVDC link to 1400 MW as part of the HVDC Reactive Support BBI as that is a second stage of NZGP1 for which we have not yet sought approval from the Commerce Commission.

2.3 Determine expected value of each BBI

15. 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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[7] For example, we expect generators in the Wairakei region will benefit from the Wairakei Ring but not the HVDC Reactive Support or CNI project.

[8] The majority of the assets that make up the HVDC Reactive Support project and CNI project are expected to be commissioned by 2026 and 2027 respectively. The majority of the assets that make up the Wairakei project were commissioned in 2025.

16. 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

17. 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.

18. 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

19. 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)).

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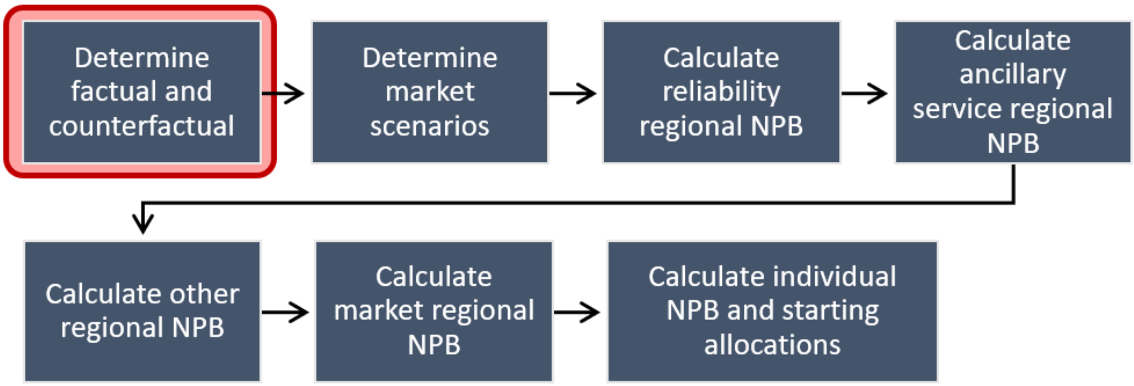
9 At the time of our previous benefits modelling, the base capex threshold was $20m. This has since increased to $30m. The fully commissioned asset value of the HVDC Reactive Support BBI is above both thresholds. The latest version of the Capex IM is here: [Transpower-Capital-Expenditure-Input-Methodology-IM-Review-2023-Amendment-Determination-13-December-2023.pdf.]

3 Determine factual and counterfactual

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

Figure 2: Determine factual and counterfactual



3.1 Determine factual

21. The factual is the grid state with the HVDC link 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

22. 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.

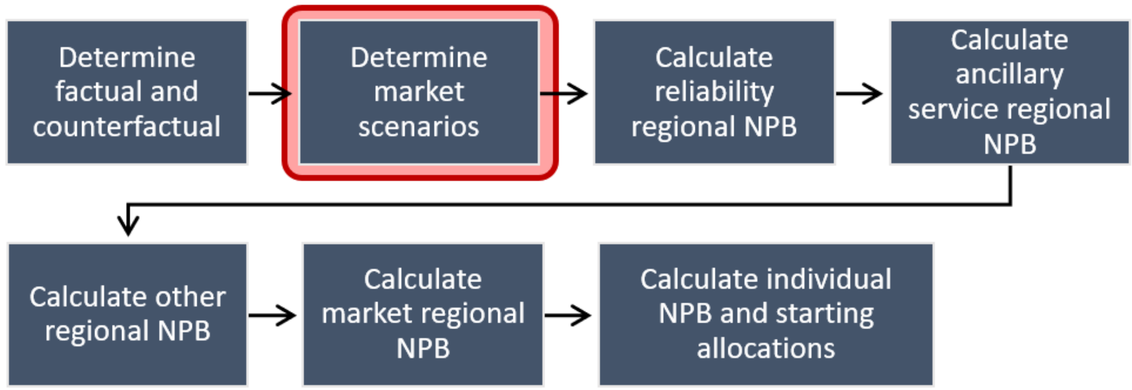
23. Consistent with clause 45(2)(a), the counterfactual is the HVDC link without the HVDC Reactive Support BBI. Specifically, the counterfactual is modelled as a maximum north transfer limit of 1071 MW and a maximum south transfer limit of 762 MW, which represents the HVDC link's average maximum capacity.

10 See Capex IM definitions of "asset refurbishment" and "asset replacement".

4 Determine market scenarios

24. 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

25. We have mostly used the market scenarios from the application of the investment test to NZGP1.1, as described in Attachment D of the NZGP1.1 proposal. Except where stated in section 4.2 of Attachment D of the NZGP1.1 proposal, these are consistent with the assumptions in version 1.1 of the assumptions book.[11] Section 8.3 presents the additional assumptions used that are not shown in either Attachment D of the NZGP1.1 proposal or the assumptions book.

26. A significant change from the application of the investment test to NZGP1.1 and our previous benefits modelling is our assumption around Tiwai, which was assumed to leave in either 2024 or 2034. We now assume that Tiwai remains throughout the standard method calculation period. We also developed new generation expansion plans to ensure there is enough generation in the system with the higher demand.

4.2 Obtain market scenarios from the assumptions book

27. Other than the assumption around Tiwai, we have not departed from the market scenarios or modelling inputs used in the application of the investment test to NZGP1.1 and our previous benefits modelling. We consider these will produce starting allocations that are broadly proportionate to expected positive net-private benefit (**EPNPB**).

[11] In addition to the assumptions described in section 4.2 of Attachment D of the NZGP1.1 proposal, we also assume the Te Rapa generation plant closes in 2023, consistent with the application of the investment test to NZGP1.1.. At the time of our previous benefits modelling, this assumption was based on Contact's June 2022 announcement. The Te Rapa generation plant closed in June 2023.

4.3 Determine if different market scenarios are required

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

4.4 Determine if sensitivities should be modelled

29. 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.

30. In the application of the investment test to NZGP1.1 and our previous benefits modelling, 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). We have not included this sensitivity in this application of the price-quantity method to the HVDC Reactive Support BBI.

31. 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)).

32. Therefore, there are five scenarios used in total – the five 2019 Electricity Demand and Generation Scenarios (**EDGS**) scenarios, each with Tiwai remaining throughout the standard method calculation period.[12]

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 2019 EDGS scenarios. We have used the same weightings for this application of the price-quantity method to the HVDC Reactive Support BBI.

4.6 Hydro, load, and generation expansion variations

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

- load growth across the scenarios (see section 2.3 of Attachment D of the NZGP1 proposal);
- hydrology, by using 50 synthetic hydro inflow sequences for each market scenario, representing the historical hydro inflow distribution (see section 4.2 of Attachment D of the NZGP1.1 proposal); and

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

- generation expansion, by using different generation expansion scenarios for the factual and counterfactual. Figure 4 and Figure 5 show the generation changes from 2022 to 2047 for each 2019 EDGS scenario.

35. Additional modelling detail is provided in Appendix A.

Figure 4: North Island generation changes from 2022 to 2047

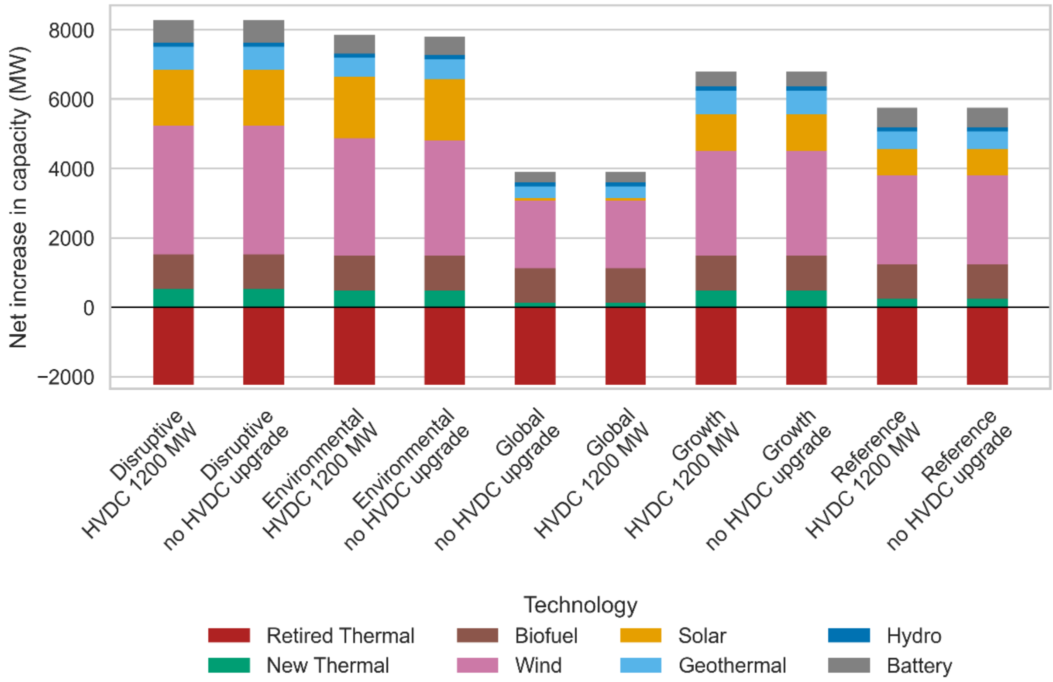
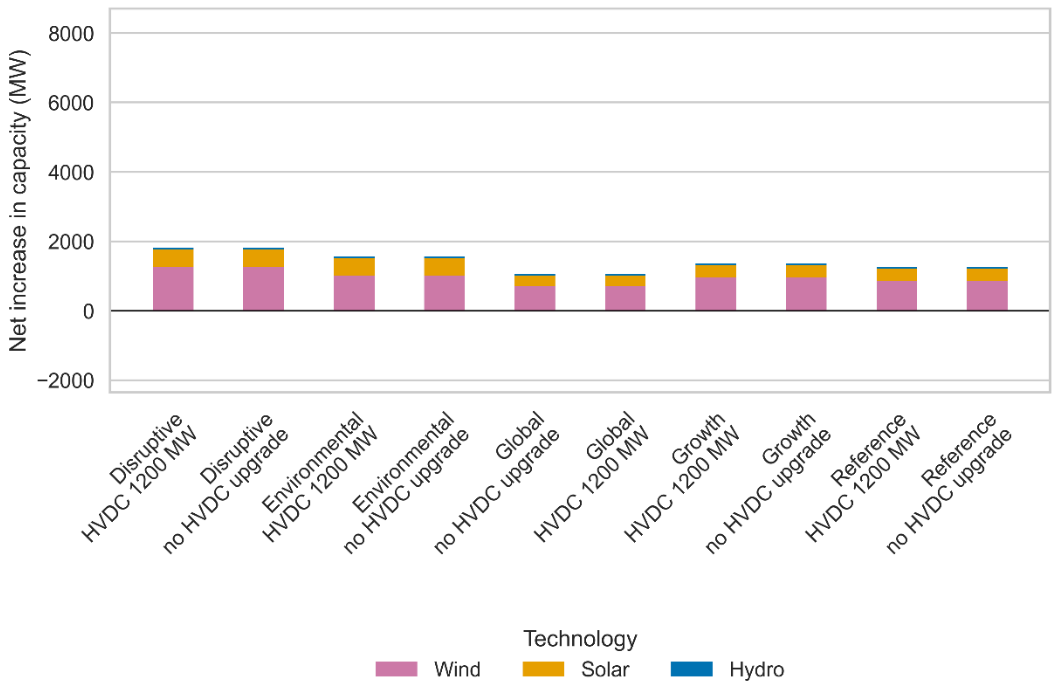


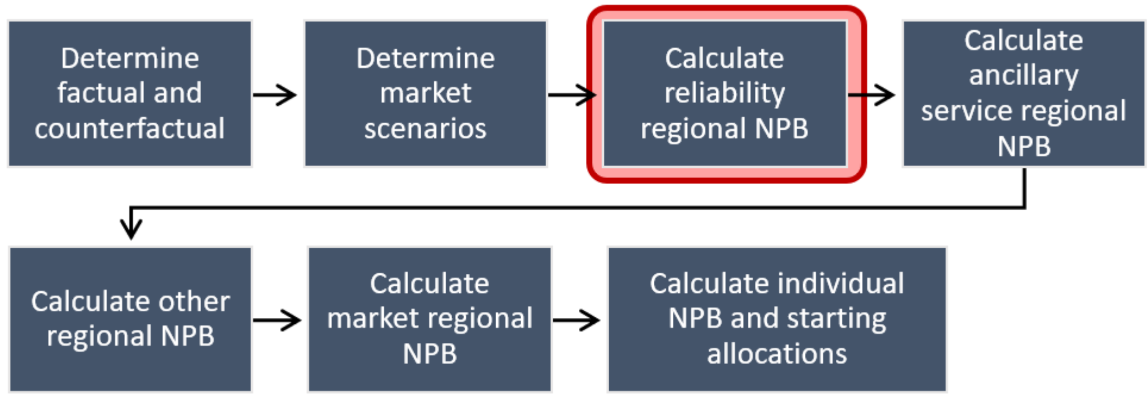
Figure 5: South Island generation changes from 2022 to 2047



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 HVDC Reactive Support 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 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 link would relate to avoiding an AUFLS[13] event. Increased transfer across the HVDC link does not affect the likelihood of AUFLS being activated (assuming the HVDC link 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.

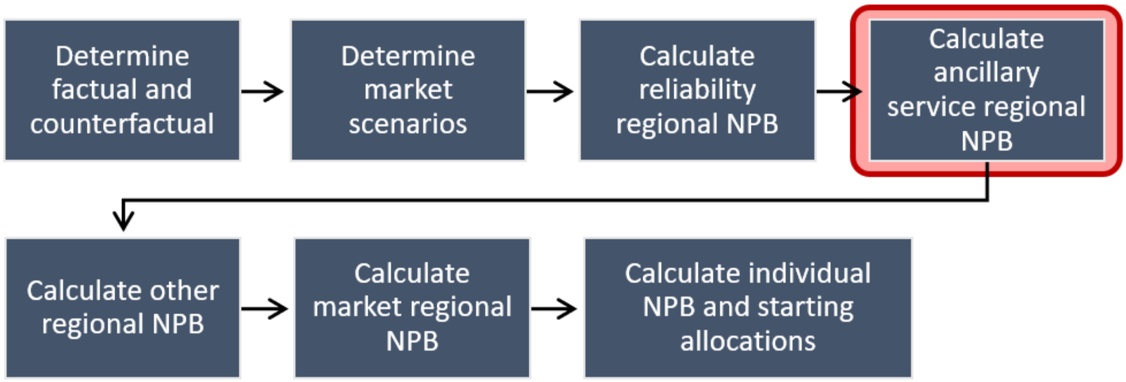
38. Therefore, we do not consider the HVDC Reactive Support BBI to be a reliability BBI and did not calculate reliability regional NPB under clause 54.

13 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

39. 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

40. 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 link'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).

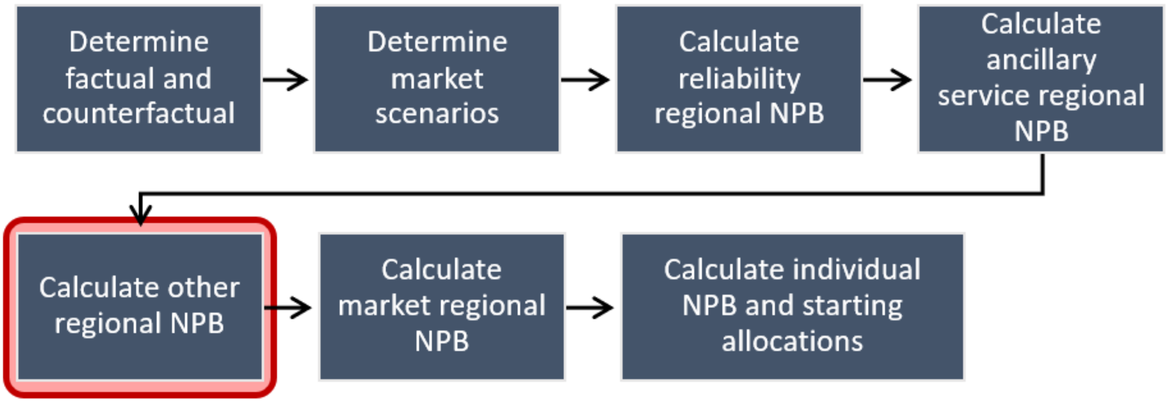
41. Furthermore, as noted in section 3.1.3 of Attachment D of the NZGP1.1 proposal, the NZGP1.1 proposal did not assess any impacts on the reserves market as a result of the HVDC Reactive Support BBI.

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

7 Calculate other regional NPB

43. 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



7.1 Determine if there are other benefits

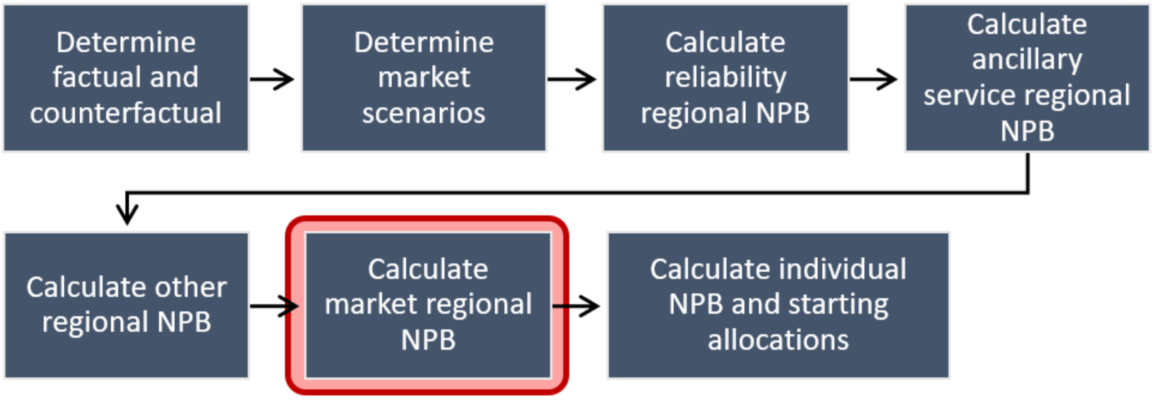
44. We do not expect the HVDC Reactive Support BBI to have any material or measurable other benefits. Specifically, we do not expect any customer or embedded plant owner to receive benefits other than wholesale electricity market benefits from the HVDC Reactive Support BBI.

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

8 Calculate market regional NPB

46. 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

47. 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

48. 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 HVDC Reactive Support BBI, and there are no AC constraints that would be materially alleviated by the BBI.[14]

49. 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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14 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

50. As noted above, chapter 2 of the assumptions book and the NZGP1.1 proposal contain most of the modelling inputs for the market scenarios we used for the HVDC Reactive Support BBI. We used those modelling inputs.

51. 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.[15] 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 to NZGP1.1.[16]

52. 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 allocations that are broadly proportionate to EPNPB.

8.4 Run market model

53. We ran SDDP[17] 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.

54. That is, by proposing to treat the HVDC Reactive Support BBI as a separate BBI (see section 2.2), 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.[18] 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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15 See section 3.3.4 of Attachment D of the NZGP1.1 proposal.

16 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 Attachment D of the NZGP1.1 proposal). Because the TPM requires post-processing on SDDP outputs to calculate private benefits for each customer, we could not scale the modelling results in the same manner. We consider using an hourly resolution is most consistent with the application of the investment test.

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

18 NZGP1.1 includes the HVDC Reactive Support, CNI and Wairakei investments.

8.5 Determine if clause 51 or 52 applies

55. 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.

56. 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)).

57. We have applied clause 52 for the HVDC Reactive Support BBI.

58. 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).

59. 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).

60. 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.

61. 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). To determine whether this applies we divide

- the present value of positive EMBD for regional customer demand groups during periods of deficit during the standard method calculation period; by
- the present value of positive EMBD for all regional customer groups over the standard method calculation period,

where EMBD is calculated according to clause 52. This method is a departure from paragraph 299 of the assumptions book in so far as periods of deficit may not exactly coincide with peak demand periods. However, we do not consider this lack of alignment affects the conclusion materially.

62. Since the total positive NPB from consumers avoiding having to pay their estimated cost of self-supply is less than 50% of total positive NPB (45%) we are not required to use clause 52 by clause 52(1)(b)(i).

63. 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.

64. Having considered the matters in paragraphs 301 to 303 of the assumptions book, we have determined clause 51 would not produce starting allocations that are broadly proportionate to EPNPB from the HVDC Reactive Support BBI. This is because:

- deficit and the cost of self-supply have a significant impact on prices downstream of the constrained HVDC link in the counterfactual; and
- we expect the change in price between the factual and counterfactual to be of a significantly greater magnitude for one group of beneficiaries compared to another.

65. When using clause 51, information about price movements are excluded from the calculation. The implicit assumption is that price changes on both sides of the constraint are symmetric. However, this does not appear to be the case for the counterfactual as in many situations when the HVDC constraint is binding, price increases are disproportionally higher in the constrained region. For example, in periods of low hydro inflows there is potential for prices to be significantly higher in the constrained region. For this reason, we have not applied clause 51 as it seems reasonable to account for asymmetric price changes in the calculation of benefits and starting allocations.

66. Periods of north binding and south binding are somewhat evenly matched. Applying clause 51 would base allocations entirely on the relatively small differences in load supplied and generation between the north-binding and south bind-binding periods. These differences are sensitive to modeling assumptions and can flip allocations between the North Island and South Island.

67. Under clause 52, load customers in both Islands benefit because the downstream price reductions due to HVDC constraint alleviation outweigh the upstream price increases. This outcome is relatively stable and represents the real-world effects of deficit and marginal generation costs.

8.6 Determine if clause 49(6) should be applied

68. For the HVDC Reactive Support BBI, because we have applied clause 52, we have used the inputs in paragraphs 142(a) and (b) of the assumptions book. This includes capping prices during periods of deficit to $600/MWh according to paragraph 142(a). $600/MWh is our estimated long-run marginal cost of self-supply. We departed from paragraph 142(c) of the assumptions book by not applying the $600/MWh and $10,000/MWh deficit tranches specified in that paragraph; the deficit tranches we used in dispatch modelling are described in Table 6 below, which include intermediate tranches at $800/MWh and $2,000/MWh.

8.7 Determine potential modelled regions

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

70. As the only modelled constraint is the HVDC link itself, we determined two modelled regions for the HVDC Reactive Support BBI - the North Island (**NI**) and South Island (**SI**). 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 52

71. We 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). 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 starting 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 323 of the assumptions book:

$$\begin{aligned} &market\ benefit\ for\ regional\ supply\ group\ (\$) \\ &\qquad = [price_F\ (\$/MWh) \times generation_F(MWh) -\ fuel\ cost_F(\$) \\ &\qquad - carbon\ emissions\ cost_F] \\ &\qquad -\ [price_{CF}\ (\$/MWh) \times generation_{CF}(MWh) -\ fuel\ cost_{CF}(\$) \\ &\qquad - carbon\ emissions\ cost_{CF}] \end{aligned}$$

where:

- $market\ benefit\ for\ regional\ supply\ group$ is EMBD for a customer in a regional supply group, which is the modelled change in producer benefit for its generation
- $price_F$ or $price_{CF}$ is hourly nodal price for the generator in the factual (F) or counterfactual (CF)
- $generation_F$ or $generation_{CF}$ is hourly generation for the generator in the factual (F) or counterfactual (CF)
- $fuel\ cost_F$ or $fuel\ cost_{CF}$ is hourly fuel cost of the generator in the factual (F) or counterfactual (CF)
- $carbon\ emissions\ cost_F$ or $carbon\ emissions\ cost_{CF}$ is hourly carbon emission cost for the generator in the factual (F) or counterfactual (CF).

73. The load portion of EMBD for a customer at a connection location was calculated using the following formulae from paragraph 323 of the assumptions book:

$$\begin{aligned} &market\ benefit\ for\ regional\ demand\ group\ (\$) \\ &\qquad = \left[\left(deficit\ cost\ (\$/MWh) - price_F\ (\$/MWh)\right) \times load\ supplied_F(MWh)\right] \\ &\qquad - \left[\left(deficit\ cost\ (\$/MWh) - price_{CF}\ (\$/MWh)\right) \right. \\ &\qquad \left. \times\ load\ supplied_{CF}(MWh)\right] \end{aligned}$$

where:

- $market\ benefit\ for\ regional\ demand\ group$ is EMBD for a customer in a regional demand group, which is the modelled change in consumer benefit for the customer at their connection location
- $deficit\ cost$ is \$600/MWh, as documented in section 2.3.7 of the Assumptions Book
- $price_F$ or $price_{CF}$ is hourly nodal price for the customer at their connection location in the factual (F) or counterfactual (CF)
- $load\ supplied_F$ or $load\ supplied_{CF}$ is load supplied to the customer at their connection location in the factual (F) or counterfactual (CF).

74. According to clauses 52(3) and 52(4), when calculating EMBD under clause 52 we must include the modelled change in loss and constraint excess (**LCE**) received by customers.

75. The LCE generated by the HVDC link is the amount paid by consumers for electricity exiting the HVDC link minus the amount generators are paid for electricity entering the HVDC link. This is given by:

$$LCE = P_{HAY220}(F_{\mathrm{HAY}Pole2} + F_{HAYPole3}) - P_{BEN220}(F_{BENPole2} + F_{BENPole3})$$

where P are prices at HAY220 and BEN220 and F are flows on poles 2 and 3 of the HVDC link at Haywards and Benmore[19].

76. According to the Settlement Residual Allocation Methodology[20] (**SRAM**), before LCE is distributed to customers, LCE is used to settle financial transmission rights and the costs of operating SRAM are recovered. We assume that these settlements are not changed by the HVDC Reactive Support BBI and therefore the change in the total amount distributed to customers is given by the change in LCE as calculated using the equation above.

77. The LCE payments are distributed to customers using current simple method allocators for the investment region containing the HVDC link.

8.8.2 Calculate present value EMBD

78. 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:[21]

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

where W_s is the probability weighting for the market scenario.

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

79. 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.

80. We removed PVEMBD for all new large generating plant that does not currently exist.

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19 The pole flows at Haywards and Benmore differ due to losses.

20 [Settlement Residue Allocation Methodology | Transpower]

21 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.

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

81. 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.

82. 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.[22] 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

83. 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 formula:

$$PVEMBD_{cust,loc} = PVEMBD\_Gen_{cust,loc} + PVEMBD\_Load_{cust,loc}$$

where:

- $PVEMBD_{cust,loc}$ is the present value of EMBD for a customer ($cust$) at a connection location (loc)

[22] 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.

- $PVEMBD\_Gen_{cust,loc}$ is the present value of EMBD for the customer ($cust$) at the connection location (loc) calculated based on generation
- $PVEMBD\_Load_{cust,loc}$ is the present value of EMBD for the customer ($cust$) at the connection location (loc) calculated based on load.

84. 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.[23] A list of existing customers included in each regional supply group is available on our website as part of this consultation package.[24] Where there are multiple generation technologies owned by a customer at a connection location, we group based on the largest generation type.

    - Wind Generation
    - Controlled Hydro Generation
    - Geothermal Generation
    - Run-of-River Hydro Generation
    - Thermal Commitment Plant
    - Thermal Peaker Plant
    - Battery Storage
    - Cogeneration[25]
    - Generation with Embedded Load (GenerationWithLoad) – connection locations with significant generation and load[26] 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.

23 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, at the time of our previous benefits modelling, there were no grid-connected generating plants 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.

24 [Starting BBI customer allocations | Transpower].

25 The Cogeneration group is a departure from paragraph 337 of the assumptions book. We consider this departure is necessary to produce starting 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.

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

85. 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**) 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.

86. 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 available on our website as part of this consultation package.[27]

- Industrial Load – load associated with industrial customers
- Non-industrial Load – load associated with non-industrial customers (primarily EDBs)
- Load with Embedded Generation – connection locations with load and significant generation[28] 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.

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

88. 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.

89. 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:[29]

- NI Solar Generation
- NI Battery Generation
- SI Wind Generation[30]
- SI Solar Generation

27 Starting BBI customer allocations | Transpower.

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

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

30 While there were existing wind generating stations in the South Island at the time of our previous benefits modelling (Mahinerangi and White Hill), both were embedded so the owners are not beneficiaries of the HVDC Reactive Support BBI in respect of those stations.

- SI Battery Generation
- SI Thermal Generation

8.10 Calculate PVMRNPB for potential regional customer groups

90. 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 formula:

$$PVMRNPB_g = \sum_{(cust,loc)\in G} PVEMBD_{cust,loc}$$

where:

- G is a set of all customers and connection locations belonging to potential regional customer group g
- $PVMRNPB_g$ is PVMRNPB for potential regional customer group g
- $PVEMBD_{cust,loc}$ is PVEMBD for a customer ($cust$) at a connection location (loc).

91. We removed potential regional customer groups with a PVMRNPB that was not positive (all South Island regional supply groups except SI Battery Generation and North Island Solar, Hydro, Geothermal and Battery Generation regional supply groups), which left the following potential regional customer groups:

- NI Wind Generation
- NI Cogeneration
- NI Peaking Generation
- NI Thermal Commitment Generation
- NI Non-industrial Load
- NI Industrial Load
- NI Load with Embedded Generation
- SI Non-industrial Load
- SI Industrial Load
- SI Load with Embedded Generation
- SI Battery Generation (potential future regional customer group)

8.11 Finalise regional customer groups

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

8.11.1 Finalise regional supply groups

93. We have amalgamated the NI Peaking Generation and NI Thermal Commitment Generation 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 (larger) ratio of the other amalgamated group.[31] The NI Thermal Commitment Generation ratio sits within 80% of the NI Peaking Generation ratio, and so these groups are combined into a proposed regional supply group named NI Thermal Generation.

94. As a result, we finalised the following proposed regional supply groups for the HVDC Reactive Support BBI:

- NI Wind Generation
- NI Cogeneration
- NI Thermal Generation
- SI Battery Generation (future)

95. 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 ($)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional supply group
South Island	Battery Generation (future)	3,547	0.1	47,935	38,348	South Island Battery Generation
North Island	Wind Generation	17,778,473	2,697	6,591	5,273	North Island Wind Generation
North Island	Cogeneration	583,257	151	3,862	3,090	North Island Cogeneration
North Island	Peaking Generation	2,206,010	1,552	1,421	1,137	North Island Thermal Generation
North Island	Thermal Commitment Generation	5,026,703	3,982	1,263	1,010	North Island Thermal Generation

[31] Amalgamation of potential regional customer groups is subject to the further conditions in paragraph 346 of the assumptions book.

8.11.2 Finalise regional demand groups

96. We have amalgamated some potential 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 (larger) ratio of the other amalgamated group.[32]

- The NI Load with Embedded Generation ratio sits within 80% of the NI Non-industrial Load ratio, and so these groups are combined into a proposed regional demand group named NI Non-industrial Load and Load with Embedded Generation.
- The SI Industrial Load ratio sits within 80% of the SI Non-industrial Load ratio, and so these groups are combined into a proposed regional demand group named SI Load.

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

- NI Non-industrial Load and Load with Embedded Generation
- NI Industrial Load
- SI Load with Embedded Generation
- SI Load

98. PVMRNPB for each potential and proposed regional demand group is shown in Table 2, and the proportion of total PVMRNPB for each proposed regional customer group is in Table 3.

Table 2: PVMRNPB for each potential and proposed regional demand group

Modelled region	Potential regional demand group	PVMRNPB ($)	IRA (GWh)	PVMRNPB/IRA	Grouping threshold	Proposed regional demand group
South Island	Non-industrial Load	65,770,830	9,095	7,231	5,785	South Island Load
South Island	Industrial Load	31,663,874	5,113	6,193	4,955	South Island Load
North Island	Non-industrial Load	82,346,032	20,622	3,993	3,194	North Island Non-industrial Load and Load with Embedded Generation
North Island	Load with Embedded Generation	3,094,420	954	3,243	2,595	North Island Non-industrial Load and Load with Embedded Generation

32 Amalgamation of potential regional customer groups is subject to the further conditions in paragraph 346 of the assumptions book.

Modelled region	Potential regional demand group	PVMRNPB ($)	IRA (GWh)	PVMRNP B/IRA	Grouping threshold	Proposed regional demand group
South Island	Load with Embedded Generation	133,706	140	954	763	South Island Load with Embedded Generation
North Island	Industrial Load	538,632	780	691	552	North Island Industrial Load

Table 3: PVMRNPB for proposed regional customer groups as a proportion of total PVMRNPB

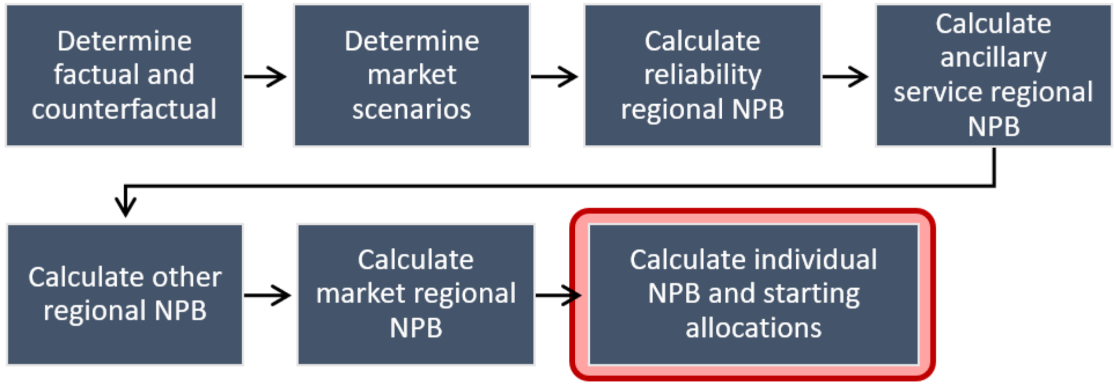
Proposed regional customer group	PVMRNPB ($)	Percentage of PVMRNPB (excluding potential future regional customer groups)
South Island Load	97,434,704	46.59%
North Island Non-industrial Load and Load with Embedded Generation	85,440,451	40.85%
North Island Wind Generation	17,778,473	8.50%
North Island Thermal Generation	7,232,713	3.46%
North Island Cogeneration	583,257	0.28%
North Island Industrial Load	538,632	0.26%
South Island Load with Embedded Generation	133,706	0.06%
South Island Battery Generation (future)[33]	n/a	n/a

33 The proposed South Island Battery Generation regional supply group is a proposed future regional customer group and so has no starting allocations.

9 Calculate individual NPB and starting BBI customer allocations

99. 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

100. Proposed IRA values for the HVDC Reactive Support BBI are calculated from historical data between 1 September 2018 and 31 August 2023 which are the five capacity years in CMP B for the HVDC Reactive Support BBI.[34] The IRA values are available on our website as part of this consultation package.[35]

101. The HVDC Reactive Support BBI is a non-peak BBI based on the amount of time the HVDC Reactive Support BBI's modelled constraints (just the HVDC link) are expected to bind during a counterfactual outage i.e. >20% by 2046 as shown in Figure 13. If the benefits primarily accrued during peak periods, the modelled constraints would be binding much less frequently.

102. 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.

103. 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)).

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

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34 We made a final investment decision for the HVDC Reactive Support BBI in August 2024.

35 Starting BBI customer allocations | Transpower.

Table 4: Pre-start adjustment events during CMP B

Customer	Location	Adjustment
TOPE	KOE	IRA values adjusted up to December 2020 due to Ngawha generation connection using Te Mihi Geothermal as comparator
NPOW	BRB	IRA values adjusted up to April 2022 due to refinery load disconnection and import terminal load connection using the refinery and import terminal data provided by Northpower
CHHE	KAW	IRA values adjusted up to May 2023 due to CHHE connection as new customer using KAW0112 transformed meter data and gross non-SKOG load provided by SKOG
WELE	TWH	IRA values adjusted up to June 2023 due to Te Rapa generation disconnection using Te Rapa embedded generation metered data
VECT	SVL	IRA values adjusted up to November 2022 due to CDC Data Centre load connection, based on offtake data provided by Vector
VECT	HEN	IRA values adjusted up to November 2022 due to Hobsonville Data Centre load connection and up to January 2023 due to Microsoft Data Centre load connection. These adjustments were calculated based on offtake data provided by Vector.
MERI	HRP	Harapaki wind farm connected June 2023. IRA value calculated based on an estimated injection of 542 GWh per annum provided by Meridian.
MSVP	LTN	Turitea wind farm connected in August 2020. IRA values estimated based on Tararua wind farm's IRA value, using relative plant capacity as a scaling factor.
WAV1	WVY	Waipipi wind farm connected in November 2020. IRA values estimated based on available metered data.

105. We are aware there are other pre-start adjustment events that have occurred 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 proposed starting allocations set out in Table 5. The unrounded proposed starting allocations are available upon request.

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

Customer Name	Proposed starting allocation (%)
NZ Aluminium Smelters Ltd	16.58%
Vector Ltd	16.55%
Orion New Zealand Ltd	11.21%
Powerco Ltd	8.60%
Wellington Electricity Lines Ltd	4.24%
Aurora Energy Ltd	3.67%
PowerNet Ltd	2.75%
Alpine Energy Ltd	2.64%
Unison Networks Ltd	2.53%
Genesis Energy Ltd	2.49%
WEL Networks Ltd	2.30%
Mainpower New Zealand Ltd	2.09%
Network Tasman Ltd	1.90%
Mercury SPV Ltd	1.76%
Meridian Energy Ltd	1.73%
MEL (West Wind) Ltd	1.57%
EA Networks	1.57%
Northpower Ltd	1.53%

Customer Name	Proposed starting allocation (%)
Waverly Wind Farm Ltd	1.38%
Marlborough Lines Ltd	1.30%
Tararua Wind Power	1.28%
Counties Power Ltd	1.17%
OtagoNet	1.15%
Network Waitaki Ltd	0.91%
New Zealand Steel Ltd	0.87%
Waipa Networks Ltd	0.81%
MEL (Te Apiti) Ltd	0.79%
Contact Energy Ltd	0.63%
Eastland Network Ltd	0.56%
Electra Ltd	0.50%
The Lines Company Ltd	0.47%
Westpower Ltd	0.41%
Nova Energy Ltd	0.35%
Horizon Energy Distribution Ltd	0.28%
Whareroa Cogeneration Ltd	0.28%
Centralines Ltd	0.22%
Daiken Southland Ltd	0.19%
Nelson Electricity Ltd	0.16%
Scanpower Ltd	0.16%
Buller Electricity Ltd	0.12%

Customer Name	Proposed starting allocation (%)
Pan Pac Forest Product Ltd	0.12%
Winstone Pulp International	0.07%
Top Energy Ltd	0.03%
Beach Energy Resources NZ (Holdings) Ltd	0.03%
Methanex New Zealand Ltd	0.02%
OMV NZ Production Ltd	0.01%
KiwiRail Holdings Ltd	0.01%
GTL Energy New Zealand Ltd	0.0003%
Southpark Utilities Ltd	0.0002%

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.

Appendix A: Modelling detail

A1.1 Modelling Approach

A.1 This Appendix describes the approach used in our analysis to model and calculate the benefits of the HVDC Reactive Support BBI.

A.2 We use models of the New Zealand electricity system to calculate the benefits of the HVDC Reactive Support BBI, comparing the factual and counterfactual cases. The factual is the grid state with the HVDC link 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). The counterfactual is the HVDC link without the HVDC Reactive Support BBI investment, leaving a maximum north transfer limit of 1071 MW and a maximum south transfer limit of 762 MW.

A.3 The key components of our analysis are:

- **Demand forecasting**. We have used variations of the market development scenarios produced by the Ministry of Business, Innovation and Employment (**MBIE**) in 2019. MBIE's scenarios are called the Electricity Demand and Generation Scenarios (**EDGS**).[1] We used all five of the 2019 EDGS scenarios (with variations) in order to cover the widest range of possible future demand growth. These scenarios are the Disruptive, Environmental, Global, Growth, and Reference scenarios.
- **Generation expansion planning.** We find a combination of new generation projects that would meet forecast demand while minimising system cost and considering firming requirements and hydrological uncertainty. For this analysis we use PSR Inc's OptGen software. Aligning with the demand scenarios, unique generation expansion plans are developed for each 2019 EDGS scenario. The OptGen expansion plans for each 2019 EDGS scenario are modified to improve revenue adequacy of the generating plants, to better align with a realistic electricity market.
- **Generation dispatch simulations**. These simulations estimate electricity system operating costs for the counterfactual and factual options. For this, we use PSR Inc's SDDP software (v17.3.13) with generation dispatch simulations developed for each 2019 EDGS scenario.

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

A.5 For this analysis, we generally align with the modelling assumptions we used for our previous benefits modelling, which reflected the modelling assumptions in version 1.1 of the assumptions book. The primary exception is that, in 2023, we assumed that NZAS' aluminium smelter at Tiwai Point would close in 2024 or 2034. In May 2024, NZAS and Meridian announced they had negotiated a new electricity supply contract to 31 December 2044. We have therefore assumed for this analysis that the Tiwai smelter will remain open throughout the standard method calculation period,[36] greatly increasing South Island demand compared to our previous benefits modelling. We have not modelled any sensitivities for the smelter's closure.

A1.2 Demand Forecasting

A.6 The demand forecast used here aligns exactly with the demand forecast used in our previous benefits modelling (Tiwai closes 2024/34), with the single variation that the South Island demand continuously grows instead of dropping precipitously in the year of NZAS closing. Figure 11 shows a comparison between the North and South Island demand forecasts used for the current modelling (Tiwai remains open) and the previously consulted on modelling that assumed Tiwai closed in 2024.

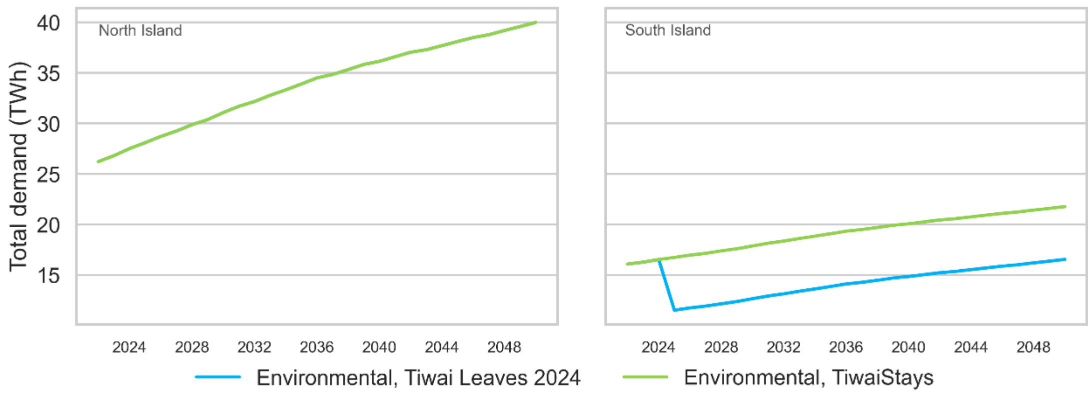

Figure 11: Demand forecast comparison between Tiwai leaves (2024) and Tiwai stays modelling (Environmental scenario)

A1.3 Generation Expansion Planning

A.7 Generation expansion planning is the process of forecasting future grid connected generation for a given demand forecast. Generation expansion plans are an input to our generation dispatch simulations.

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36 Although the current electricity supply contract expires in December 2044, for simplicity we have assumed it will be renewed, or replaced with a new contract, for the remainder of the standard method calculation period (i.e. until at least the end of December 2046). We note that benefits accruing at the end of the standard method calculation period have a relatively small impact on EPNPB due to discounting.

A.8 Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (to the end of 2047), adding new generation as required to meet forecast demand while minimising system cost. We recognise that there are other factors that play a role in generation investment decisions such as the availability of capital, future views on wholesale electricity prices, the ability of the project to gain consents, power purchase agreements, and retail positions relative to generation. However, our view is that it is reasonable to focus on generation costs on the basis that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, cost will be the major deciding factor.

A.9 PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use PSR's 'Optgen2' algorithm. Optgen2 finds a least-cost plan by co-optimising build decisions and hourly operation in one optimisation. It represents wind/solar ups and downs with typical days and seasons and uses firm capacity constraints.

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

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

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

A.13 We produced generation expansion plans for each of the five 2019 EDGS scenarios. We applied the same generation expansion plan to the counterfactual and factual options for each EDGS scenario. We assumed that the AC grid is unconstrained. 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.

A.14 All changes to generation capacity from 2022 to 2047 are summarised (cumulatively) in Figure 4 and Figure 5 for the North and South Island, respectively. The expansion plans are similar but not identical between the factual (HVDC 1200 MW) and counterfactual (no HVDC upgrade) cases.

A1.4 Generation Dispatch Simulation

A.15 SDDP is a well-established dispatch model that is widely used internationally. SDDP minimises the electricity system operating costs, accounting for:

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

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

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

A.17 SDDP policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water values. For this analysis, consistent with our generation expansion plan approach, we ran policies for each of the five 2019 EDGS scenarios and independently for the factual and the counterfactual. Changing the capacity of the HVDC link impacts future generation build schedules and therefore the water value functions that determine hydro dispatch from controlled storage reservoirs. Therefore, we have used different policies for the factual and counterfactual cases in each scenario.

A.18 For this analysis, we use an hourly resolution over the standard method calculation period to 2047 for generation dispatch simulations. The hourly resolution allows us to capture real world variations in demand and renewable generation, at the cost of increased model solve time and storage requirements. This is an enhancement on the modelling undertaken in 2023, which is now feasible due to improvements in SDDP.

A.19 SDDP models the optimal dispatch of generation and battery resources across the electricity system using a set of yearly hydro inflow sequences that represent conditions for all modelled hydro generators. In New Zealand, electricity system costs vary significantly with hydro inflows, so capturing this behaviour is a critical part of our generation dispatch simulations.

A.20 We use 'synthetic' hydro inflow sequences that are derived from historical hydro inflow records. Synthetic inflows reduce the level of fluctuations, help the model converge, and reduce model solve time. They are produced by SDDP by analysing the relationship between an inflow sequence and time of year, as well as the interdependence among inflows to different hydro catchments.

A.21 For this analysis, we used:

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

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

- Losses on the HVDC link are modelled within SDDP using a linearised approximation of observed HVDC losses.
- No AC transmission constraints are included as modelled constraints.
- AC losses are ignored for all AC circuits.

A.23 The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plans and generation dispatch simulations. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network. To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing tranches as described in Table 6. Each tranche is for a given amount of deficit, expressed as a percentage of hourly island demand. The first three tranches are intended to represent voluntary demand response measures, such as retailers controlling hot water cylinder demand. The last high value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency.

Table 6 Generation expansion plan modelling deficit cost tranches

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

A.24 Many other model inputs are not explicitly listed here here and are consistent with the modelling assumptions we used to calculate starting allocations for the HVDC Reactive Support BBI in 2023, which reflect those in chapter 2 of the assumptions book.[37]

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

A1.5 Generation Dispatch Simulation Results

A.25 This Section provides an overview generation dispatch simulation results that directly relate to the BBI calculation and allocation. 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.

A.26 After commissioning, the northward flow limit on the HVDC link would increase to the 1200 MW and the southward flow limit on the HVDC link would increase to 850 MW. In all EDGS cases, the south-flow constraint binds significantly more than the north-flow constraint. The flow duration curves for 2035 and 2045 are given in Figure 12. The yearly trends for north and south flow binding frequency are given in Figure 13. The “blocky” appearance of each curve arises from SDDP’s representation of HVDC losses.[38] Both figures show the results for the environmental scenario factual and counterfactual cases, all hydro scenarios are included. Clearly, both north and south flow constraints are alleviated by the HVDC Reactive Support BBI. Figure 14 gives the average yearly price ratio BEN220 to HAY220, demonstrating that the investment brings NI and SI price ratio closer to 1.

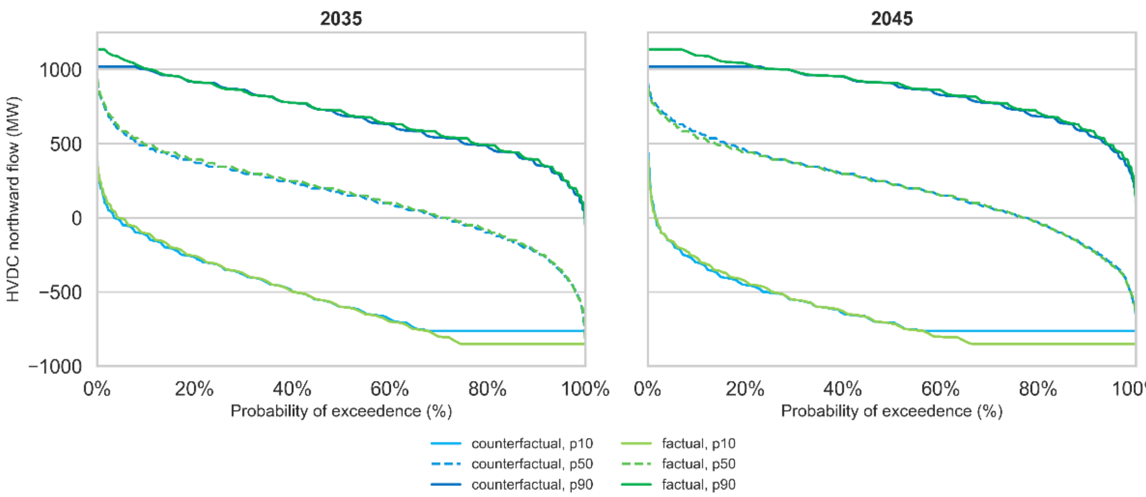

Figure 12: HVDC flow duration curve for 2035 and 2045 – Environmental scenario

38 The model applies a constant loss rate within a 50 MW HVDC flow tranche, and the loss rate increases when flow enters the next tranche. Because higher tranches carry higher loss rates, the optimisation tends to hold flows close to the upper limit of the current tranche, resulting in a partially stepped HVDC flow-duration curve.

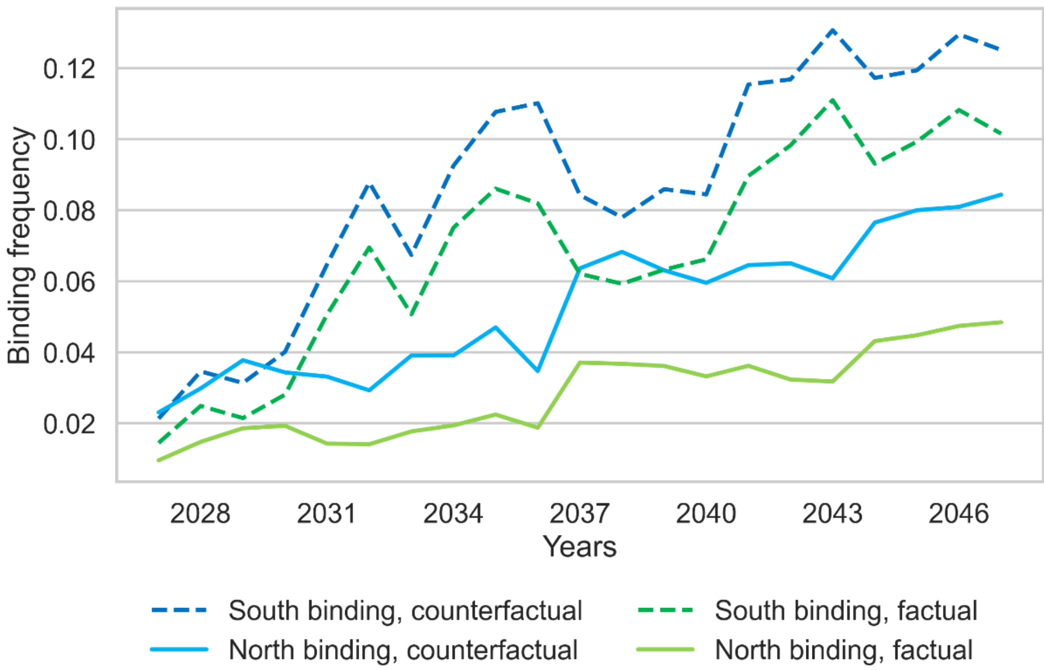

Figure 13: Frequency of binding constraints by year – Environmental scenario

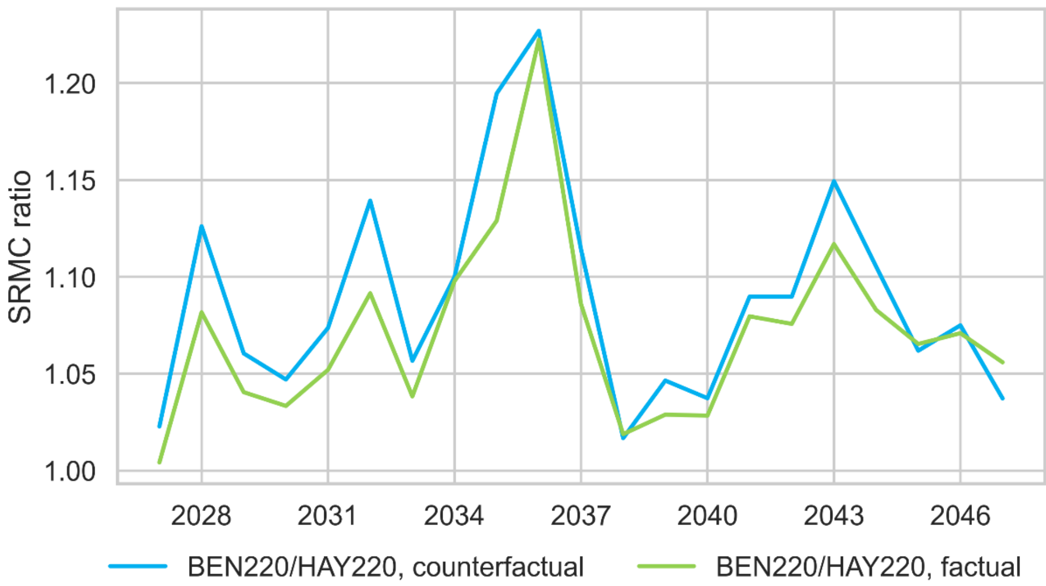

Figure 14: Price separation between BEN220 and HAY220 throughout modelling horizon (average over all hydro) - Environmental scenario

A.27 Figure 15 shows the total yearly deficit averaged over all hydro scenarios for the environmental scenario. The deficit costs are alleviated by the investment, making deficit avoidance a significant benefit of the HVDC Reactive Support BBI.

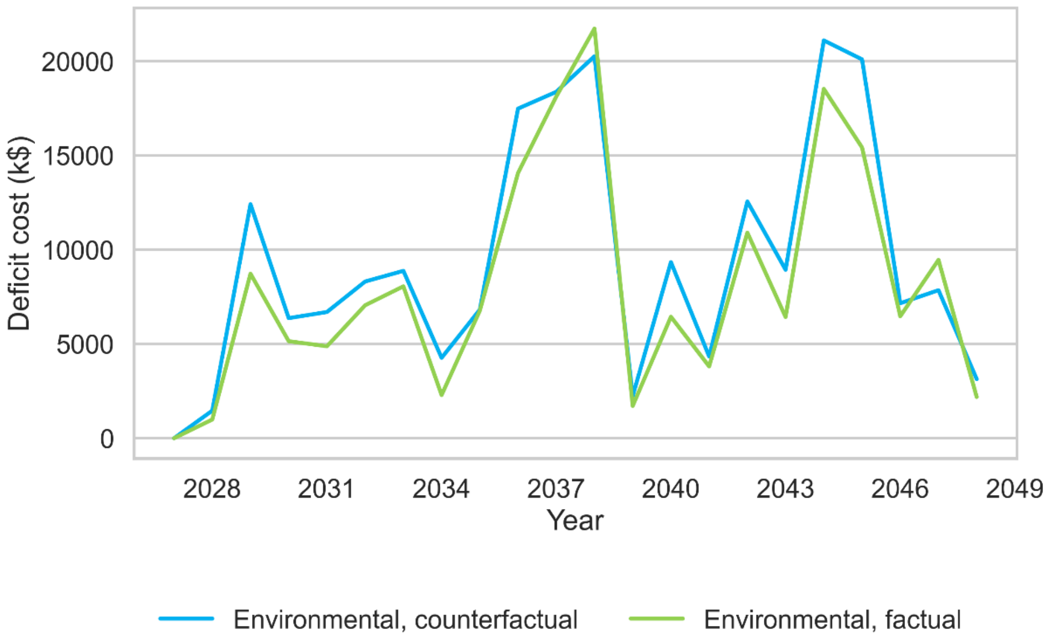

Figure 15: Deficit costs for the Environmental scenario (average over all hydro)

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 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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