TRANSPOWER

Net Zero Grid Pathways 1
Major Capex Project (Staged)

Attachment F

Indicative covered costs and starting BBI customer allocations

Date: 02 December 2022

Contents

1 Purpose

1. This document is attachment F of the Net Zero Grid Pathways (**NZGP1.1**) proposal to the Commerce Commission (**Commission**).[1] As detailed in the proposal and summarised in section 2.1, the preferred NZGP1.1 option includes the HVDC, Central North Island, and Wairakei Ring investments.

2. Under the new transmission pricing methodology (**TPM**),[2] the covered costs of post-2019 investments in interconnection assets and transmission alternatives (benefit-based investments or **BBIs**) are recovered from customers identified as beneficiaries, in proportion to their expected positive net private benefit (**EPNPB**) from those investments. The TPM contains the methods for calculating charges for BBIs (benefit-based charges or **BBCs**).

3. The purpose of this attachment is to provide information to the Commission and stakeholders about the estimated increase in transmission charges associated with the proposal. This document is an update to the version provided to stakeholders as part of the NZGP1 shortlist consultation,[3] and is the same other than:

   - An update to the covered costs in section 3 based on the latest cost estimates in the proposal, and
   - An additional section 6 that describes how we have satisfied the requirements of clause 7.5.1(1)(c) of the Capex IM for NZGP1.1.

4. This document covers:

   4.1 Section 2: background on the investments and indicative BBIs comprised in the preferred NZGP1.1 option and future steps under the Transpower Capital Expenditure Input Methodology Determination 2012 (**Capex IM**)[4] and TPM

   4.2 Section 3: indicative covered costs for the indicative BBIs comprised in the preferred NZGP1.1 option (HVDC/CNI and Wairakei Ring BBIs)

   4.3 Section 4: indicative starting BBI customer allocations for the high-value[5] BBI (HVDC/CNI BBI),[6] which is required to be calculated using a standard method under the TPM

   4.4 Section 5: indicative starting BBI customer allocations for the Wairakei Ring BBI

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1 Net Zero Grid Pathways 1: Major Capex Project (Staged) Investigation: Shortlist consultation, 30 June 2022.

2 The TPM approved by the Electricity Authority (**Authority**) on 11 April 2022, and effective from 1 April 2023, is published here: https://www.ea.govt.nz/assets/dms-assets/30/New-TPM.pdf.

3 NZGP1 shortlist consultation: indicative covered costs and starting BBI customer allocations, 14 July 2022

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

5 A high-value BBI is a BBI that is expected to involve capital expenditure and/or transmission alternative opex of more than the base capex threshold under the Capex IM, which is currently $20m. BBIs expected to cost $20m or less are low-value BBIs.

6 For the purpose of indicative allocations, we have grouped the HVDC and CNI investments into one BBI, as explained in section 2.1.

4.5 Section 6: describes the method we have used to produce the indicative transmission charges in attachment G.

5. Ahead of the Commission's draft determination, we will carry out formal consultation on proposed starting BBI customer allocations for the high-value BBI(s) comprised in the NZGP1.1 option, as required by the TPM.

6. We have applied the methodologies in the TPM and BBC assumptions book to produce the indicative allocations for the HVDC/CNI BBI in this document.[7] However, our calculations have not been at the level of detail we will apply when we calculate proposed starting BBI customer allocations for the NZGP1.1 high-value BBI(s) for consultation under the TPM (as noted above, this will be after our MCP to the Commission). Nevertheless, we consider the indicative allocations presented in this document provide a reasonable indication of the distribution of EPNPB from the HVDC/CNI BBI using the modelling inputs and assumptions set out in this document (which themselves are indicative only).

7. We stress that the indicative covered costs and allocations set out in this document are not the proposed or the final covered costs or allocations for the BBIs comprised in the preferred NZGP1.1 option or any other potential NZGP1 investment. Transpower cannot, and does not, accept any liability for the accuracy or completeness of the information in this document or the consequences of your or others' reliance on it. We recommend you review the TPM itself and seek independent expert advice before relying on anything in this document.

8. Unless otherwise stated, in this document:

8.1 references to NZGP1.1 mean stage 1 of NZGP1 (there is a stage 2 contemplated); and

8.2 clause references are to clauses of the TPM.

[7] The first edition of the BBC assumptions book is online here.

2 Background

2.1 Investments and BBIs comprised in the preferred NZGP1.1 option

9. The investments and indicative BBIs comprised in the preferred NZGP1.1 option are as follows:[8]

   9.1 HVDC/CNI BBI:

   i) New reactive plant at Haywards to enhance the availability of maximum transfer over the HVDC ($103m); and

   ii) Tactical thermal upgrades (**TTUs**) of the Tokaanu-Whakamaru and Bunnythorpe-Tokaanu lines and duplexing of the Tokaanu-Whakamaru lines to enhance the capacity of transfer through the central North Island (CNI) ($257m).[9]

   9.2 Wairakei Ring BBI: TTU of the Wairakei-Whakamaru C line to enhance the capacity of the Wairakei Ring and TTU of the Edgecumbe-Kawerau 220 kV circuit ($23m).

10. More detail on these investments is in the NZGP1.1 MCP.

2.1.1 The price-quantity method applies to the HVDC/CNI BBI

11. Because the HVDC/CNI BBI would be a high-value post-2019 BBI, Transpower must use a standard method under the TPM to determine its beneficiary customers and calculate their starting BBI customer allocations.

12. For the purpose of indicative allocations, we have grouped the HVDC and CNI investments together as a single BBI. Our initial view is these investments should be treated as a single BBI because the benefits of the CNI investment are linked to the HVDC investment occurring (and vice versa). This is because the CNI lines and HVDC sit in series configuration;[10] the HVDC moves power from the South Island to the lower North Island (and vice versa) and the CNI lines from the lower North Island to the upper North Island (and vice versa).

13. Before calculating the proposed starting BBI customer allocations for consultation under the TPM, we will consider again whether to treat the HVDC and CNI investments as a single BBI. A key factor we will consider is whether grouping them is likely to result in allocations that are broadly proportionate to EPNPB, particularly for generation in the lower North Island (see section 4.2.2).

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8 Both the HVDC/CNI and Wairakei ring investments include investigation and design outputs for later stages of the proposed investment. We have excluded those elements from the covered costs of the BBIs in this analysis, pending a decision on whether or how the costs of those elements will be capitalised.

9 The CNI investment also includes supporting projects including a system split of the Bunnythorpe-Ongarue line, new protection on the 220 kV Bunnythorpe-Stratford line, and the replacement of a special protection scheme at Tokaanu.

10 Series configuration means that the electrical current passes through each asset successively.

14. We have used the price-quantity method (one of two standard methods in the TPM) for the HVDC/CNI BBI because it is not a resiliency BBI - its primary investment need is to alleviate, or prevent, transmission constraints that would affect quantities and prices in the wholesale market for electricity, not to mitigate a risk of cascade failure or a high impact, low probability event.

15. Within the price-quantity method there are four types of regional NPB that may be calculated – market regional NPB, ancillary service regional NPB, reliability regional NPB and other regional NPB. For the HVDC/CNI BBI we have calculated market regional NPB only (regional NPB relating to changes in quantities and prices in the wholesale market for electricity). This is because we do not expect the HVDC/CNI BBI to have material reliability or other benefits, and we have not yet assessed the impact of the BBI on ancillary service costs.

16. Within the price-quantity method there are two options for calculating market regional NPB arising from changes in the wholesale market for electricity. The default option is to calculate market regional NPB based on quantities during periods of benefit (clause 51). The alternative option uses both quantities and prices to calculate market regional NPB (clause 52).

17. For the purpose of indicative allocations, we have used the quantity-based option (clause 51) because it is the default method for calculating market regional NPB and the one we expect to use most often. We will reassess this prior to calculating and consulting on the proposed starting BBI customer allocations for the NZGP1.1 high-value BBI(s).

18. Section 4 contains indicative starting BBI customer allocations for the HVDC/CNI BBI.

2.1.2 We have used the simple method for the Wairakei Ring BBI

19. We have treated the TTU of the Wairakei-Whakamaru C line and the TTU of the Edgecumbe-Kawerau 220 kV circuit as one BBI as they are in a similar area of the network, and the Edgecumbe-Kawerau upgrade is required to fully realise the benefits of the Wairakei-Whakamaru C upgrade.

20. Although the Wairakei ring BBI is expected to be high-value (based on its P50 project costs), we have not yet done the modelling necessary to determine indicative allocations for the Wairakei Ring BBI as a high-value BBI. Therefore, in this attachment, we treat it as low-value for the purpose of providing indicative allocations and charges. We will produce and consult on the proposed starting allocations using the standard method in due course.

21. Section 0 contains indicative starting BBI customer allocations for the Wairakei Ring BBI.

2.2 Interaction with the Capex IM

22. The combined investment value of the preferred NZGP1.1 option is currently estimated at $393 million and its constituent parts are enhancement investments. This means the option is a major capex project under the Capex IM, for which Transpower must submit an MCP to the Commission for approval.

23. Under clause 7.5.1(1) of the Capex IM, an MCP must include information about the expected increase in transmission charges due to the proposed expenditure. We have included this in attachment G and explained our methodology in section 6.

24. The NZGP1.1 MCP also includes the market scenarios and other modelling assumptions and parameters we use to apply the Capex IM investment test to the major capex project. Clause 43(5) of the TPM generally requires consistency in approach with the Capex IM's investment test when we calculate starting BBI customer allocations for a high-value BBI. We may depart from the investment test approach if we determine that approach would not produce allocations that are broadly proportionate to EPNPB from the BBI.

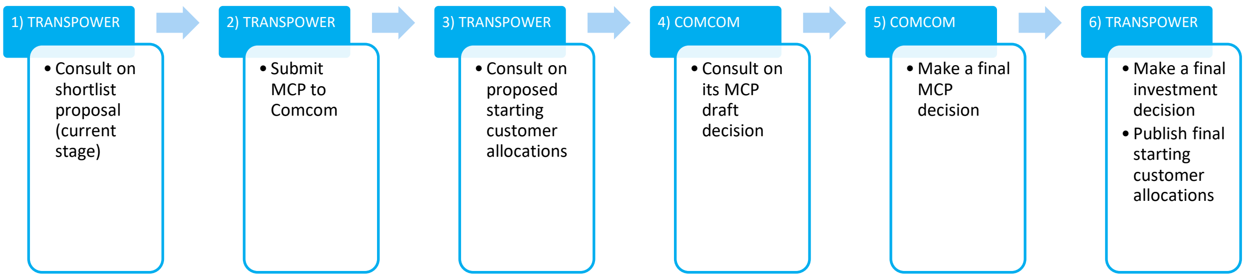
2.3 What happens next for the NZGP1.1 allocations?

25. Under clause 15 of the TPM, Transpower must consult on the proposed starting BBI customer allocations for each high-value post-2019 BBI. We will therefore consult on the proposed starting BBI customer allocations for the NZGP1.1 high-value BBIs before finalising its BBCs.

26. We plan to consult on the proposed starting BBI customer allocations after we have submitted the NZGP1.1 MCP and before the Commission consults on its draft decision on the MCP. Following the Commission's final decision, assuming the Commission approves the proposed NZGP1.1 option, Transpower will make its final investment decision, at which time we will publish the final starting BBI customer allocations for the NZGP1.1 high-value BBI(s).[11]

27. These planned stages are illustrated in Figure 1 below.

Figure 1: Planned stages to final starting BBI customer allocations



11 If we amend the proposed investment after consulting on the proposed starting BBI customer allocations we will re-consult on the allocations if the amendment is likely to affect them materially.

3 Indicative covered costs of the BBIs

28. This section summarises the assumptions and results of the indicative covered costs for the HVDC/CNI and Wairakei Ring BBIs.

3.1 TPM requirements for calculating covered cost

29. The cost recovered through the BBCs for a BBI is referred to in the TPM as the BBI's 'covered cost'.[12] A BBI's covered cost is calculated annually, using the same approach for every BBI.

30. Under clauses 39 and 40 of the TPM, a BBI's covered cost is calculated based on the values of certain capex and opex inputs for the relevant pricing year. A BBI's covered cost is made up of:

    30.1 costs that are directly attributable to the BBI or have a verifiable causal relationship with it. This captures capex costs (depreciation calculated in accordance with the Transpower IMs and a return on investment using our regulated WACC) and some types of opex

    30.2 a portion of our "overhead" opex, which does not have a direct or causal relationship with the BBI but is reasonably attributable to it. This type of opex is attributed to all BBIs in proportion to their depreciation (depreciation multiplied by an attributed opex ratio).

3.2 Latest estimate of covered costs

31. We have used the same cost estimates as in attachment E to estimate the covered costs (excluding investigation and design costs).

32. The initial annual covered cost of a BBI will be confirmed as part of calculating transmission charges for the pricing year for which BBCs are calculated for that BBI. At this stage, we can simply estimate the covered costs for the NZGP1.1 BBIs. Our current estimate of the NZGP1.1 BBIs' covered costs into the future relies on a number of estimates including final asset composition and asset values, which we will not know until after each investment is fully commissioned.

12 For more information see also Transpower's TPM Information sheet: Benefit-based charges: Covered Cost.

Figure 2: HVDC/CNI BBI indicative covered cost

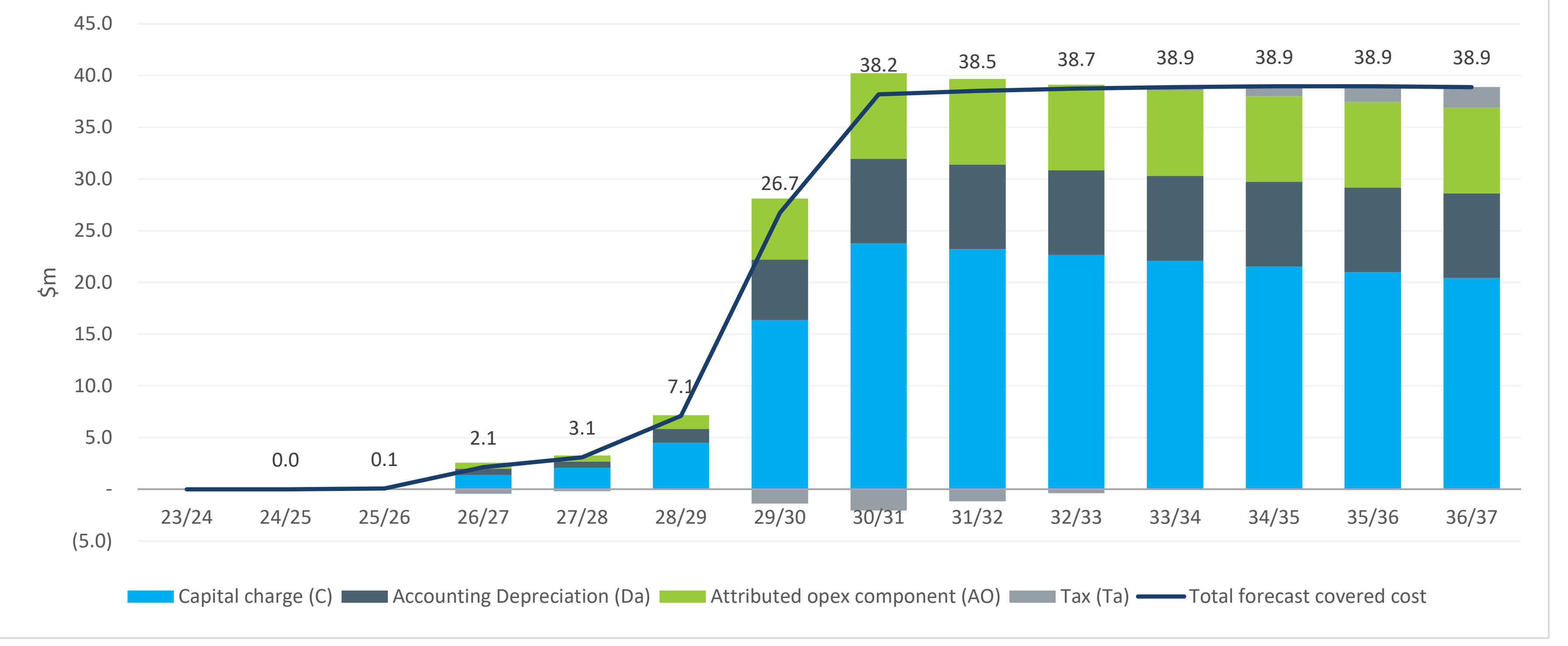


Table 1: HVDC/CNI BBI indicative covered cost

Pricing year, PY (ending 31 March)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Accounting Depreciation (Da)	-	-	-	0.6	0.6	1.3	5.8	8.2	8.2	8.2	8.2	8.2
Capital charge (C)	-	-	0.1	1.4	2.1	4.5	16.4	23.8	23.2	22.7	22.1	21.5
Attributed opex component (AO)	-	-	-	0.6	0.6	1.3	5.9	8.3	8.3	8.3	8.3	8.3
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	-	-	0.0	(0.4)	(0.2)	(0.1)	(1.4)	(2.0)	(1.2)	(0.4)	0.3	1.0
Total forecast covered cost	-	-	0.1	2.1	3.1	7.1	26.7	38.2	38.5	38.7	38.9	38.9

Figure 3: Wairakei Ring BBI indicative covered cost

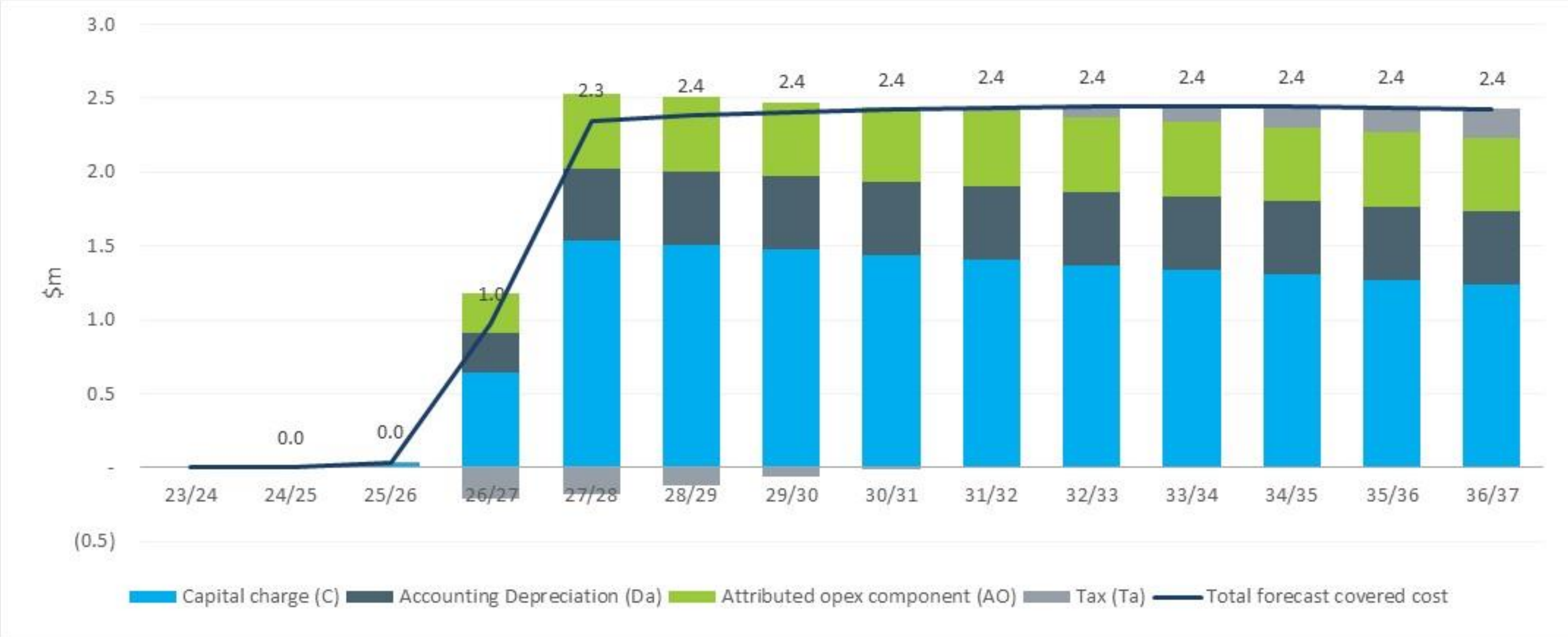


Table 2: Wairakei Ring BBI indicative covered cost

Pricing year, PY (ending 31 March)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Accounting Depreciation (Da)	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Capital charge (C)	-	-	0.0	0.6	1.5	1.5	1.5	1.4	1.4	1.4	1.3	1.3
Attributed opex component (AO)	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sum of Transpower's depreciation tax loss/gain and income tax on the capital charge (Ta)	-	-	0.0	(0.2)	(0.2)	(0.1)	(0.1)	(0.0)	0.0	0.1	0.1	0.1
Total forecast covered cost	-	-	0.0	1.0	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4

33. As shown in the figures and tables above, the annual covered costs initially increase reflecting progressive asset commissioning, before stabilising once the assets that make up the BBI are fully commissioned. Covered cost for PY 2027/28 to PY 2032/33 includes a forecast increase in Transpower's regulated WACC for the regulatory control period commencing on 1 April 2025 (**RCP4**), reflecting expected higher inflation.[13]

34. The key assumptions and inputs we have applied to estimate the BBIs' covered costs are as follows:

    34.1 Nominal WACC is forecast to increase from 4.57% in RCP3 to 6.83% in RCP4 reflecting forecast higher inflation. The RCP4 WACC first takes effect in pricing for PY 2027/28.

    34.2 The attributed opex ratios for RCP4 and RCP5 are calculated based on Transpower's opex allowances for RCP3.

    34.3 The covered cost for a BBI incorporating HVDC assets may include an allocation of the insurance and reserve costs associated with the HVDC link (called HVDC opex in the TPM). As there is only one such BBI currently (the HVDC Appendix A BBI), we have not yet developed a methodology for allocating HVDC opex between HVDC BBIs. Our estimate of covered cost for the HVDC/CNI BBI in this attachment does not include any HVDC opex. It is likely actual covered cost for the HVDC/CNI BBI will include some HVDC opex.

[13] The Commission's determination of Transpower's RCP4 WACC will have effect for revenue-setting purposes for the five pricing years commencing PY 2025/26.

4 Indicative allocations for the HVDC/CNI BBI

35. This section summarises our application of the price-quantity method[14] to the HVDC/CNI BBI and presents indicative starting BBI customer allocations (**starting allocations**).

4.1 Market scenarios and other key modelling assumptions

36. For the purpose of these indicative starting allocations, we have used the modelling assumptions and inputs from the NZGP1 shortlist consultation, which will be updated in our proposed starting allocations. The key modelling inputs we have used in our application of the price-quantity method to the HVDC/CNI BBI are as follows:

    36.1 Expected market benefits and disbenefits have been discounted at a rate of 7% per annum (the standard method discount rate in the TPM), which is the same rate as used in the application of the investment test in the NZGP1 shortlist consultation.

    36.2 For the purpose of indicative starting allocations, we have used a single market scenario – the Growth scenario used in the application of the investment test in the NZGP1 shortlist consultation. We chose this scenario because it is the middle of the five scenarios used in the NZGP1 shortlist consultation with respect to electricity demand.

    36.3 We have used the same assumptions to produce indicative starting allocations as used in the Growth scenario in the application of the investment test in the NZGP1 shortlist consultation, except that we have not modelled upgrades to the HVDC/CNI BBI associated with stage 2 of NZGP1, because these will be the subject of a future investment proposal if and when that occurs.

37. We note, in general, the modelling assumptions used in the NZGP1 shortlist consultation are consistent with chapter 2 of the draft assumptions book. However, there are several assumptions that are different which are discussed in the shortlist consultation document. For example:

    37.1 The inclusion of a number of additional generation units as possible new wind, solar, and battery generation projects associated with new connection enquiries.

    37.2 In the Environmental scenario carbon price projections are based on the IEA's 2021 World Energy Outlook. Specifically, the IEA's carbon prices for their "Net Zero" scenario and for "advanced economies".[15] All other market scenarios use the Climate Change Commission's projections for carbon prices.

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14 For more information see also Transpower's [TPM Information sheet: Benefit-based charges: Standard methods].

15 For further details see: https://www.iea.org/reports/world-energy-model/macro-drivers

37.3 The use of a conservative cost decline for wind generation in the Disruptive scenario to achieve a balance of new wind and solar that better reflects the large number of proposed solar projects.

37.4 A different timing for the HVDC upgrade, reflecting the proposed timing of the HVDC investment in the major capex project.

37.5 A reduced discount rate for solar projects to either 5% or 6% (depending on the market scenario) to reflect the wider pool of capital that is available given solar is simpler to consent, construct, and maintain than other generation technologies.

37.6 A 50% reduction in the capital cost of geothermal generation to reflect that exhaust steam can be used for industrial processes (thereby reducing the revenue required to be recovered from the electricity market).

38. Where the investment test in the NZGP1 shortlist consultation uses a different assumption than in the assumptions book, we have used the assumption from the investment test (if relevant) to produce indicative starting allocations for the HVDC/CNI BBI. This is so that the indicative starting allocations are consistent with the application of the investment test, which, as noted above, is a general requirement of the TPM.

4.2 Modelled regions and market regional NPB

4.2.1 Modelled regions

39. To determine the modelled regions for the HVDC/CNI BBI we analysed prices in the counterfactual at each modelled node in the network. We calculated the correlation coefficient between all pairs of nodes, and grouped nodes into a region if they had a high correlation. This resulted in the following modelled regions:

39.1 Upper North Island (UNI) including Bay of Plenty and Hawke's Bay

39.2 Lower North Island (LNI) including Taranaki and Manawatu-Whanganui

39.3 South Island (SI).

4.2.2 Market regional NPB

40. Under clause 51 of the TPM, market regional NPB is calculated based on:

40.1 The volume of load or generation exposed to a transmission constraint alleviated by the BBI, which effectively produces allocations that are consistent with an equal change in market price to each beneficiary either side of the constraint; plus

40.2 any additional volume of generation or load enabled by the BBI.

41. As illustrated in the diagrams below, load customers downstream of a transmission constraint alleviated by a BBI benefit because prices downstream of the constraint are

elevated in the counterfactual. Prices are elevated downstream of a transmission constraint because downstream loads cannot access lower cost resources upstream of the constraint.

42. Generation customers upstream of a transmission constraint alleviated by a BBI benefit because prices are depressed upstream of the constraint in the counterfactual. Prices are depressed upstream of a transmission constraint because there is a surplus of generation which would otherwise be transmitted to other regions via the transmission network.

43. Conversely, load customers upstream and generation downstream of a transmission constraint alleviated by a BBI disbenefit.

Figure 4: Prices with circuit at less than capacity

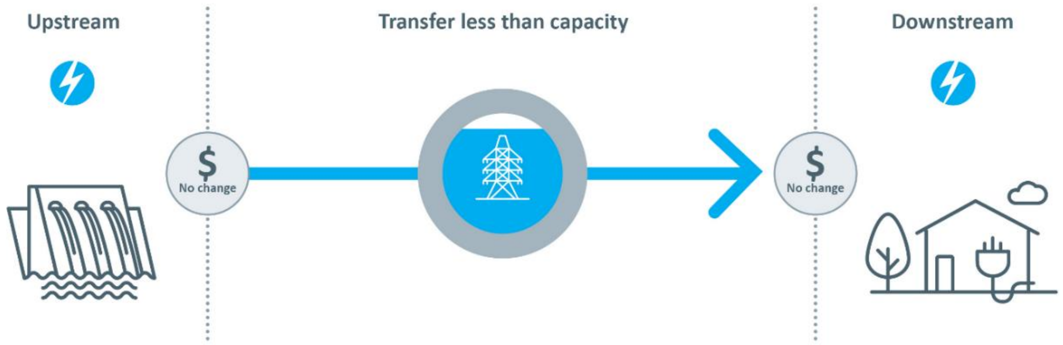
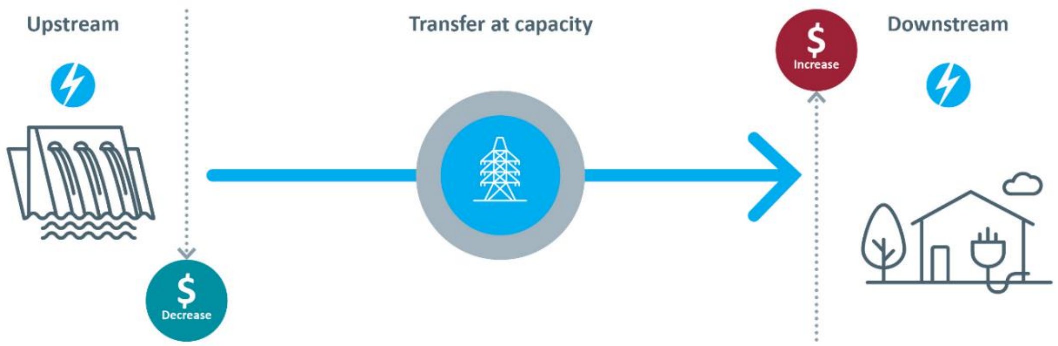


Figure 5: Prices with circuit at capacity



44. As applied to the HVDC/CNI BBI, UNI load and SI generation benefit if either or both of the HVDC and CNI constraints are binding north (and disbenefit if they are binding south).

45. Because the LNI sits between the HVDC and CNI constraints, load benefits if the HVDC constraint is binding north, and disbenefits if the CNI constraint is binding north (and vice versa for generation in the LNI).

46. The following table shows the indicative allocations of positive regional NPB to regional customer groups for the HVDC/CNI BBI. For the purpose of indicative allocations, we have

not split regional customer groups in the same region into more discrete groups (e.g. distributors and industrial load), as is permissible under the TPM.

Table 3: Indicative allocations of positive regional NPB to regional customer groups

Indicative modelled region	Indicative regional customer group	Indicative regional NPB share
UNI	Load	50.6%
LNI	Load	4.2%
SI	All generation	44.2%
LNI	Wind Generation	1.0%

47. A high-level summary of the results of our application of the price-quantity method to the HVDC/CNI BBI is as follows:

47.1 SI generation and UNI load receive the majority of the allocation of positive regional NPB because the CNI and HVDC constraints primarily bind north, rather than south. Because the HVDC and CNI constraints are – collectively – approximately half-way up the grid backbone, this results in an allocation that is fairly even between these groups.

47.2 LNI load receives an allocation of positive regional NPB because the HVDC constraints bind north (during which this group benefits) more frequently than the CNI constraints bind north (during which this group disbenefits). This results in an allocation that is smaller on a volume-weighted basis than UNI load.

47.3 LNI wind generation receives only a small allocation of positive regional NPB, in part because this region has a relatively low volume of generation, but also because we have treated the HVDC and CNI projects as a single BBI. If we were to treat them as separate BBIs, we expect LNI wind generation would receive a larger allocation for the CNI BBI and no allocation for the HVDC BBI – which may result in a larger allocation overall.[16] Unlike other generation in the LNI, wind generation receives an allocation because it tends to have a higher capacity factor when the CNI constraints are binding north (during which this group benefits) than when the HVDC constraints are binding north (during which this group disbenefits).

47.4 All other groups disbenefit from the HVDC/CNI BBI more than they benefit and therefore receive no allocation of positive regional NPB.

16 Splitting the HVDC/CNI into two BBIs may also result in other generation in the LNI receiving an allocation of positive regional NPB for the CNI BBI (e.g. thermal generation in Taranaki).

4.3 Indicative starting BBI customer allocations

48. As required under the TPM, we calculated each customer's indicative starting BBI customer allocation for the HVDC/CNI BBI as the customer's individual NPB divided by the sum of all customers' individual NPBs. This results in the following starting allocations (to two decimal places).

49. To calculate individual NPB for the purpose of indicative starting allocations we used the same intra-regional allocators as we used for the proposed starting allocations for the CUWLP BBI[17] (i.e. mean offtake or injection from 1 September 2014 to 31 August 2019). This will be updated prior to calculating and consulting on the proposed starting BBI customer allocations for the NZGP1.1 high-value BBI(s).

Table 4: Indicative starting allocations for the HVDC/CNI BBI

Customer Name	Indicative starting allocation (%)[18]
Meridian Energy Limited	30.58%
Vector Limited	25.24%
Contact Energy Limited	9.78%
Powerco Limited	8.35%
Unison Networks Limited	3.84%
Northpower Limited	3.18%
WEL Networks Limited	2.85%
Genesis Energy Ltd	2.55%
Wellington Electricity Lines Limited	1.80%
Counties Power Ltd	1.64%
Pan Pac Forest Product Limited	1.47%
New Zealand Steel Limited	1.45%
Waipa Networks Limited	1.19%

17 https://www.transpower.co.nz/our-work/industry/transmission-pricing-methodology/tpm-consultations-2022.

18 In this table, a "-" indicates a zero allocation, and "0.00%" indicates a very small non-zero allocation.

Manawa Energy Limited	1.18%
Horizon Energy Distribution Ltd	1.10%
Eastland Network Limited	0.86%
The Lines Company Ltd	0.57%
Top Energy Ltd	0.48%
Electra Limited	0.26%
Winstone Pulp International	0.19%
Mercury SVP Ltd	0.27%
KiwiRail Holdings Limited	0.12%
MEL (West Wind) Limited	0.23%
Tararua Wind Power	0.20%
Aurora Energy Limited	0.10%
Centralines Limited	0.09%
Waverly Wind Farm Ltd	0.16%
Scanpower Limited	0.07%
MEL (Te Apiti) Limited	0.10%
Beach Energy Resources NZ (Holdings) Ltd	0.05%
Methanex New Zealand Ltd	0.04%
OMV NZ Production Ltd	0.04%
Southpark Utilities Limited	0.001%
Mercury NZ Limited	-
Nga Awa Purua Joint Venture	-
Southern Generation Ltd	-
Orion New Zealand Limited	-

Alpine Energy Ltd	-
Mainpower New Zealand Limited	-
Network Tasman Limited	-
EA Networks	-
Marlborough Lines Limited	-
Network Waitaki Limited	-
OtagoNet	-
Westpower Limited	-
Nelson Electricity Ltd	-
Buller Electricity Ltd	-
PowerNet Limited	-
Norske Skog Tasman Limited	-
Todd Generation Taranaki Limited	-
Whareroa Cogeneration Limited	-
Nova Energy Limited	-
Kawerau Geothermal Ltd	-
NZ Aluminium Smelters Limited	-
Powernet Ltd	-
Daiken Southland Limited	-
GTL Energy New Zealand Ltd	-

5 Indicative starting allocations for the Wairakei Ring BBI

50. As noted above, we have calculated indicative starting allocations for the Wairakei Ring BBI using the simple method modelled regions and allocators for the first simple method period in chapter 4 and Part E of the assumptions book.

51. We note:

51.1 We have applied the modelled regions and simple method allocators for the first simple method period because the Wairakei Ring BBI is expected to be commissioned during the first simple method period.

51.2 The Wairakei-Whakamaru C line and the Edgecumbe-Kawerau 220 kV circuit is in the Lower North Island High Voltage (LNI_HV) simple method modelled region. Accordingly, we have used the simple method regional NPB allocations that relate to the LNI_HV investment region.

Table 5: Indicative starting allocations for the Wairakei Ring BBI

Customer Name	Indicative starting BBI customer allocation (%)[19]
Vector Limited	28.8%
Genesis Energy Ltd	11.4%
Contact Energy Limited	9.1%
Powerco Limited	6.7%
Wellington Electricity Lines Limited	5.9%
Mercury NZ Limited	5.4%
Meridian Energy Limited	4.2%
Northpower Limited	3.7%
WEL Networks Limited	3.3%
Unison Networks Limited	3.0%
Nga Awa Purua Joint Venture	2.3%

19 In this table, a "-" indicates a zero allocation, and "0.00%" indicates a very small non-zero allocation.

Pan Pac Forest Product Limited	1.5%
Ngatamariki Geothermal Ltd	1.4%
New Zealand Steel Limited	1.4%
Counties Power Ltd	1.3%
Norske Skog Tasman Limited	1.2%
Mercury SPV Limited	1.1%
Horizon Energy Distribution Ltd	1.0%
Electra Limited	1.0%
Tararua Wind Power	0.8%
Waipa Networks Limited	0.8%
Winstone Pulp International	0.8%
Waverley Wind Farm	0.7%
Eastland Network Limited	0.5%
The Lines Company Ltd	0.5%
Top Energy Ltd	0.5%
Orion New Zealand Limited	0.4%
NZ Aluminium Smelters Limited	0.2%
Centralines Limited	0.2%
KiwiRail Holdings Limited	0.1%
Scanpower Limited	0.1%
Alpine Energy Ltd	0.1%
Beach Energy Resources NZ (Holdings) Ltd	0.1%
Aurora Energy Limited	0.1%

Kawerau Geothermal Limited	0.1%
Mainpower New Zealand Limited	0.1%
Network Tasman Limited	0.1%
OMV New Zealand Production Ltd	0.1%
Methanex New Zealand Ltd	0.1%
EA Networks	0.1%
Powernet Ltd	0.1%
Marlborough Lines Limited	0.0%
Todd Generation Taranaki Limited	0.0%
Network Waitaki Limited	0.0%
Manawa Energy Limited	0.0%
Westpower Limited	0.0%
MEL (Te Apiti) Limited	0.0%
Southern Generation GP Limited	0.0%
Whareroa Cogeneration Limited	0.0%
Nova Energy Limited	0.0%
Nelson Electricity Ltd	0.0%
Southdown Cogeneration Ltd	0.0%
Buller Electricity Ltd	0.0%
MEL (West Wind) Limited	0.0%
Southpark Utilities Limited	0.0%
Daiken Southland Limited	0.0%
GTL Energy New Zealand Ltd	0.0%

6 Estimated increase in transmission charges

52. This section describes the methodology used to calculate the increase in transmission charges from the HVDC/CNI and Wairakei Ring BBIs in accordance with clause 7.5.1(1)(c) of the Capex IM. The indicative charges are in attachment G.

53. We have shown the total indicative charge attributable to each affected GXP/GIP by multiplying the covered cost for each BBI by its indicative starting allocations from section 4 (clause 7.5.1(1)(c)(iii) of the Capex IM).

54. We have used the gross AMD used to calculate residual charges to calculate the indicative charge for each affected GXP (or GIP with offtake) on a $/kW basis (clause 7.5.1(1)(c)(i) of the Capex IM).[20]

55. We have used the offtake intra-regional allocators (IRAs) during the capacity measurement period from 1 Sep 2014-31 Aug 2019 (the same IRAs used to calculate the starting allocations in section 4 of this document) to calculate the indicative charge for each affected GXP (or GIP with offtake) on a $/MWh basis (clause 7.5.1(1)(c)(ii) of the Capex IM).

56. The covered cost used in these calculations is from the 2033/34 pricing year, when covered cost is expected to peak for these BBIs – as shown in section 3.

57. Note, these charges illustrate the indicative benefit-based charges associated with the BBIs, but not the decrease in the residual charge as a result of commissioning the BBIs. This decrease will result as the covered cost calculation will attribute some of Transpower's operating costs to the BBIs (in proportion to the BBIs' depreciation), which will shift revenue from the residual to the benefit-based charge. In other words, the increase in Transpower's revenue as a result of these BBIs is smaller than the covered cost attributable to the BBIs.

20 Sourced from: Indicative pricing model, May 2022

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