Transmission Pricing Methodology Consultation

Submission by Transpower New Zealand Limited

Date: 2 December 2021

Contents

1. Executive summary

1. Transpower welcomes the Electricity Authority's (**Authority's**) consultation on the proposed Transmission Pricing Methodology (**TPM**).

2. We remain of the view that our 30 June proposal, including the amendments and additions made as part of the Authority's refer-back process, (**Proposal**)[1] is consistent with the Authority's 2020 TPM Guidelines (**Guidelines**), the Authority's statutory objective and our regulation under Part 4 of the Commerce Act 1986. We note most of the version of the proposed TPM included in the Authority's consultation paper is unaltered from the version we submitted to the Authority with our Part 2 Refer-Back Response.

3. A particular focus of this submission is on the practical workability of the new TPM. In our view, some of the alternative options included in the Authority's consultation paper, or that may be considered during the consultation process, could adversely impact the workability and durability of the new TPM, as well as add costs associated with developing, administering and complying with the TPM and, potentially, extend the lead time required to implement it.

4. We have provided some targeted recommendations to help improve the drafting of the proposed TPM. As well as minor tidy-ups (corrections of errors etc), our recommendations reflect the development of our thinking on discrete matters since we submitted our Proposal and changes to help achieve a more workable TPM.

5. There are some specific matters where the Authority and Transpower have differing views, or where the Authority is still developing its views, about the best way to apply the Guidelines (noting that for some topics more than one interpretation or option may be available under the Guidelines):

   5.1 **We remain of the view the cost allocation methodology for determining covered costs for benefit-based investments should include a reasonable attribution of overhead opex**. Among other factors, this is necessary to avoid cross-subsidies from load to generation, which would arise under the Authority's alternative option of greater overhead recovery through residual charges/only including directly attributable overheads in covered costs (particularly in the absence of an injection overhead component in connection charges).[2]

   5.2 **We are cautious about the Authority's alternative options for "enhancement" that determine generation/load weighting factors as part of the periodic review of the split in benefit-based charge allocations between generation and load under the simple method.** Some of the enhancements under consideration would blur the separate responsibilities of Transpower in administering the TPM and the Authority in approving it. In our view, our proposed framework and timing for reassessing the weighting factors is appropriate[3] and would not be improved by any of the Authority's alternative options.

   5.3 **We do not support the Authority's proposal to use the simple method allocation factors to recover the costs of anticipatory capacity in connection investments (relating to Type 2 first mover disadvantage).** We remain of the view the "pool and share" approach discussed in the Authority's consultation paper would be a better way to recover the

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[1] TPM Proposal Reasons Paper, 30 June 2021 (**Reasons Paper**); TPM Proposal 30 June 2021: Decision Part 1 refer back: Transpower's response, 25 August 2021 (**Part 1 Refer-Back Response**); TPM Proposal 30 June 2021: Decision Part 2 refer back: Transpower's response, 15 September 2021 (**Part 2 Refer-Back Response**).

[2] Reasons Paper, chapter 6, section 5; Part 1 Refer-Back Response, pages 3-7.

[3] Reasons Paper, chapter 7, section 16.4.

costs of anticipatory capacity in connection investments.[4] In our view, applying the simple method allocation factors to anticipatory capacity in connection investments could not be relied on to produce allocations that are broadly in proportion to expected positive net private benefits (**EPNPB**), and would carry a higher risk of cost-concentration (making anticipatory capacity investments more difficult). Added mechanisms to address the cost-concentration risk would add complexity and cost to the administration of the new TPM.

5.4 **We remain of the view adjustments to residual charges for a new entrant or new large consuming plant should be applied on a step change basis, rather than adopting a lagged approach.** In our view, this is the best way to eliminate, or at least minimise, the competitive disadvantage problem the Authority discusses in its consultation paper.

5.5 **We remain of the view the application of the residual charge to battery storage is a policy matter to be decided by the Authority.** If the Authority decides to deviate from the Guidelines, we agree the final consumption approach would pose the fewest workability issues as it would minimise the information Transpower needs to know about the charging and discharging activity of battery storage.

5.6 **We remain of the view the prudent discount practice manual should be optional and non-binding:** In our view, the framework for developing and implementing a prudent discount manual set out in our Proposal is appropriate. In particular, we consider it would be disproportionate and premature to require the development of a prudent discount practice manual between now and 1 April 2023. The practice manual is intended as an optional tool to be developed as Transpower gains experience with prudent discount applications under the new TPM. All key rules and criteria for prudent discounts are incorporated in the proposed TPM, and applicants will not be disadvantaged by the lack of a manual (but may be disadvantaged by a manual produced too early if it narrows options available to applicants).

6. Transpower's views may develop and change when we consider stakeholder submissions to the Authority's consultation. We appreciated the insights provided by stakeholders during development of our Proposal.

7. We recommend the Authority includes a **technical drafting consultation** step in its process before the new TPM is finalised. This is standard practice for the Commerce Commission in the context of setting Transpower's individual price-quality path. This step could be undertaken towards the end of the Authority's process, between cross-submissions and the Authority's decision on the proposed TPM, and is unlikely to impact the timing of implementation of the new TPM. A final technical drafting consultation would help ensure any remaining TPM drafting issues or anomalies are rectified prior to formal incorporation into the Code.

[4] TPM Development: Checkpoint 2 submission: First Mover Disadvantage, March 2021, section 6; TPM Development: Checkpoint 2 resubmission: First Mover Disadvantage, May 2021, section 2; Reasons Paper, chapter 5, section 10.2; Part 1 Refer-Back Response, section 3.

2. Introduction

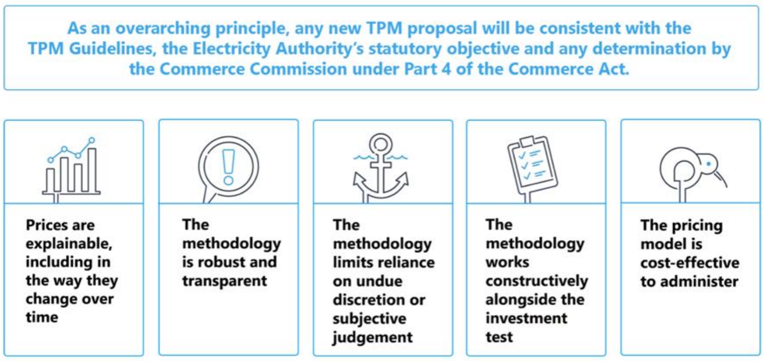
8. Transpower welcomes the Authority's consultation on the proposed TPM.

9. Transpower's views on a number of topics are set out in more detail in our Proposal. Our Proposal should be treated as part of this submission.

10. A particular focus of this submission is the practical workability of the new TPM. In our view, some of the alternative options included in the Authority's consultation paper could adversely impact the workability and therefore durability of the new TPM, as well as add costs associated with developing, administering and complying with the TPM and, potentially, extend the lead time required to implement it (the same may arise for new options considered during consultation). An example is the option presented in the Authority's consultation paper of requiring Transpower to develop a prudent discount practice manual between now and 1 April 2023.

11. We continue to be guided by the principles in the Guidelines and the TPM Design Principles we developed and consulted on at the initial stages of developing our Proposal. These principles have informed our assessment of options.

TPM Design Principles



12. There are some areas where we consider the proposed TPM drafting could be improved, or specific matters clarified. This includes some elements of the proposed TPM where our thinking has developed with the benefit of more time since we submitted our Proposal, and having regard to the matters set out in the Authority's consultation paper and feedback provided in stakeholder workshops.

13. Unless otherwise stated, all TPM clause references in this submission are to the clauses of the revised proposed TPM drafting accompanying this submission.

14. In the time available for cross-submissions, we look forward to considering stakeholder submissions, which may also impact our views on aspects of the proposed TPM.

2.1 Scope of our submission

15. Given that a number of our views are detailed in our Proposal, we have largely limited our submission to areas where the Authority proposal differs from our own or the Authority is consulting on alternative options. Our submission also includes some points of clarification (section 3), and the revised proposed TPM drafting mentioned above.

16. We have not commented on the underlying policy merits of the Guidelines or proposed TPM, or the Authority's cost benefit analysis.

2.2 Next steps - technical drafting

17. Our expectation is further changes will be needed to the consultation version of the proposed TPM to reflect submissions on the proposed TPM drafting (including our own).

18. We recommend the Authority include a technical drafting consultation step in its process before the new TPM is finalised. This is standard practice for the Commerce Commission in the context of setting Transpower's individual price-quality path, and would provide an opportunity for any drafting issues or anomalies to be resolved prior to final approval and implementation of the new TPM.

3. Points of clarification

19. Below we respond briefly to some elements of the Authority's consultation paper by way of clarification.

3.1 Beneficiary-pays versus causer-pays

20. Over the course of the Authority's consultation workshops it became apparent there is some confusion over the distinction between beneficiary-pays and causer-pays (or user-pays). The two concepts are very different, and benefit-based charges (**BBCs**) in the proposed TPM reflect a beneficiary-pays model.

21. A causer-pays transmission charge – such as a congestion or capacity charge – is set on the basis of the cost caused by customers' use of the grid, e.g. the cost of future expected investment in capacity, and does not require the grid owner to identify the benefits customers will receive.[5]

22. A beneficiary-pays transmission charge, on the other hand, is based on the value or benefit customers may receive or be expected to receive from the grid.

23. It may be the case that the beneficiary and causer overlap, though not necessarily, and there may be no particular relationship between a causer-pays charge and a beneficiary-pays charge. By way of example, the need for the HVDC link was largely caused by decisions to invest in more generation capacity in the South Island than needed to meet South Island demand. However, in Schedule 1 of the Guidelines, the Authority has determined the principal beneficiaries of the HVDC link are both South Island generators (the causers) and North Island load.

3.2 Discretion in quantifying market benefits (BBC standard method)

24. In paragraphs 5.14-5.16 of its consultation paper, the Authority summarises its assessment of whether the proposed TPM provides Transpower too much discretion in determining which method to use to quantify market benefits for high-value benefit-based investments (**BBIs**), i.e. a quantities-based or price and quantities-based approach.

25. The Authority notes Transpower's revised approach developed during the refer-back process appropriately limits discretion and provides greater assurance that allocations will be broadly in proportion to expected positive net private benefits (**EPNPB**), but has invited comment on whether any other criteria should be included to limit discretion.

26. In our view, it is not possible to produce an ex-ante pricing methodology aligned with a principles-based investment decision-making framework (Transpower's capital expenditure input methodology) without using some discretion in its application. For this reason, we have carefully developed the framework for evaluating market benefits in the proposed TPM, and remain of the view this approach best implements the intent of the Guidelines whilst ensuring there is flexibility to select the method that will best ensure allocations are broadly in proportion to EPNPB for the given investment.

27. As we said in chapter 7, paragraphs 33 and 34 of our Reasons Paper:

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5 Under causer-pays charges, if the benefits the consumer will receive are less than the cost their consumption will impose, they will not consume or will reduce their consumption.

> We are very mindful of the level of discretion Transpower will have to have to apply under a new TPM that complies with the requirements of the Guidelines and that this could result in the application of the BBC being highly contentious amongst our customers given the commercial outcomes and impact on individual customers and, ultimately, on end-consumers. While a more formulaic methodology would reduce discretion, it would also risk resulting in anomalous allocations that are not broadly proportional to EPNPB (e.g. PJM's Artificial Island example) …In order to attempt to mitigate against discretion we are aiming to make the application of the BBC as transparent as practicable, and to enable customers and other stakeholders to engage with us in the pricing determination process.

28. Transpower would prefer to have less discretion when applying the proposed TPM (consistent with our design principles above). However, for some topics we do not consider it possible or appropriate to remove all discretion. Further discussion on this topic, and the criteria we will apply to determine market benefits, is in our Part 2 Refer-Back Response.[6]

3.3 References to "excess capacity"

29. In our view, "anticipatory capacity" is the most appropriate label for additional capacity built into the grid to meet expected future capacity needs. Transpower and the Authority have moved on from the somewhat more pejorative term "excess capacity", although there are still some uses of it in the Authority's consultation paper and we heard it used at times during the Authority's consultation workshops.

30. "Excess capacity" fails to distinguish between investment that is inefficient, unnecessary or excessive, and prudent and efficient investment required in reasonable anticipation of future capacity needs. Type 2 first mover disadvantage (**FMD**) is about the latter - investment in capacity that is expected to be needed at the time it is made - and how the cost of that investment should be recovered.

3.4 Residual charge: large party exit and large plant disconnection

31. The discussion in paragraphs 8.47 to 8.52 of the Authority's consultation paper appears to assume the proposed TPM does not treat a large de-rating the same as large plant disconnection for the purposes of adjusting residual charges. In fact it does, in clause 96(3).[7]

32. We consider this to be the appropriate approach in order to eliminate arbitrarily different treatments under the new TPM of essentially the same event. This also applies to treating a large upgrade the same as large plant connection.

3.5 50/50 split under simple method

33. Paragraph 5.32 of the Authority's consultation paper states *"Transpower has proposed a weighting factor that is broadly 50:50 between load and generation"* under the simple method.

34. To clarify, it is more accurate to say our Proposal does not apply any weighting; the approximate 50:50 split is simply an outcome of the simple method we have proposed. A different outcome would need to be "forced" by applying a weighting factor other than 1 (referred to as a "demand adjustment factor" in the proposed TPM), which is proposed to be reassessed every five years.

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[6] Part 2 Refer-Back Response, section 2.

[7] And similarly in clause 84(3)(b) for BBC adjustments.

3.6 Exceptional Operating Circumstances

35. Paragraph 13.21 of the Authority's consultation paper states *"The proposed TPM does not define what would be classed as an exceptional operating circumstance"* (**EOC**).

36. For context, our view is it would be inappropriate to define, and therefore limit, the scenarios that may engage the EOC mechanism. However, the proposed TPM does include some criteria for when an EOC will be considered to have occurred,[8] which are consistent with how we apply the EOC mechanism under the current TPM. The EOC provisions in the proposed TPM provide greater clarity as to the circumstances in which the EOC mechanism may apply than those in the current TPM.

3.7 Applying the price cap to intermingled customers

37. Paragraph 12.36 of the Authority's consultation paper may be suggesting clause 5(3) of the proposed TPM (Transpower discretion as to the treatment of customers with intermingled load and generation) is a departure from the requirements of the transitional cap-related clauses of the Guidelines.

38. If that is the Authority's view then we disagree. Clause 5(3) is about classifying an intermingled customer as being either a direct consumer or a grid-connected generator. If we have classified the customer as a direct consumer, the Guidelines (and the proposed TPM) require us to apply the transitional cap.

[8] Namely, if Transpower determines there are exceptional operating circumstances in the power system caused by a Grid Owner requirement or outage (clause 14). Our submission is that this should extend to exceptional operating circumstances caused by System Operator requirements, as well.

4. Drafting of the proposed TPM

Consultation question (Chapter 13)
Do you have any feedback that would improve the drafting of the proposed TPM?

39. We have provided a tracked changes version of the proposed TPM as part of our submission. The changes are shown against the proposed TPM the Authority released with its consultation paper.

40. We have included embedded comments explaining our recommended amendments to the proposed TPM, which are categorised as follows:

    40.1 **Typo:** Typographical corrections.

    40.2 **Style:** Stylistic changes, including for consistency.

    40.3 **Clarification:** Recommended changes to clarify points that might not otherwise be obvious to the reader.

    40.4 **Change:** Our recommendations for an alternative approach to the drafting without making a substantive change, or where, on further consideration since our Proposal, we consider the drafting should change in a substantive way.

41. The revised proposed TPM accompanying this submission contains alternative drafting for some clauses (highlighted in grey).[9] This drafting illustrates the alternative approaches we support for recovering the capital cost of anticipatory capacity in connection investments (Type 2 FMD) and adjusting residual charges when new customers enter or large consuming plant is connected. These alternative approaches are discussed in sections 5 and 9.2 below.

42. We have also recommended some amendments to the drafting that our alternative drafting would replace. To be clear, we prefer our alternative drafting over the drafting it would replace for the reasons discussed below and in our Proposal, but have provided some suggested amendments to the Authority's drafting for completeness in the event the Authority decides not to adopt Transpower's recommended approach.

43. We consider the revised proposed TPM, including the alternative drafting, is consistent with the Guidelines (except for the departures from the requirements of the Guidelines discussed in sections 4.2 and 4.3 below and in our Proposal), the Authority's statutory objective and our regulation under Part 4 of the Commerce Act 1986.

4.1 Summary of recommended amendments

44. The main amendments Transpower recommends (in addition to the alternative approaches noted above) are as follows:

    44.1 The costs of certain post-2019 investments in respect of pre-2019 interconnection investments would be rolled into the covered cost for the relevant Appendix A BBI or, if the pre-2019 interconnection investment is not comprised in an Appendix A BBI, recovered through residual charges. This would only apply to such post-2019

[9] The alternative drafting shaded grey is identical or very similar to TPM drafting we have previously submitted to the Authority. There may need to be some other consequential changes to the TPM drafting if the alternative approaches are accepted.

investments commissioned before 1 July 2021. This proposal arises from a legacy issue with our asset register functionality, and is discussed further in section 4.2 below.

44.2 Depreciation due to connection asset write-downs would be removed from the connection asset pool and recovered through residual charges instead of connection charges. This is consistent with the proposed approach to calculating covered cost for BBIs. This proposal is discussed further in section 4.3 below.

44.3 Permissible data sources for calculating gross energy, maximum gross demand and total gross energy (referred to in this submission collectively as "gross load") would be listed, and there would be a statement we are not obliged to factor in other data sources. This would help insulate Transpower from potentially recurring disputes about the data sources used to calculate gross load, and would dovetail with any changes the Authority makes to the Code to ensure sufficient embedded generation information is provided to Transpower.

44.4 The partial sale of business adjustment events for connection charges, BBCs and residual charges would be extended to also cover a sale of the entire business. This is so we would not have to go through the steps for the new customer adjustment event when all that needs to happen is to port the vendor's relevant charges to the purchaser. There would also be a consequential apportionment of cap and prudent discount recovery charges when there is a full or partial sale of business affecting BBCs or residual charges.

44.5 Capacity measurement period (CMP) C, which is relevant to calculating simple method allocations, would be pushed back by one capacity year to allow sufficient time for Transpower to obtain the input data and calculate the allocations for the subsequent simple method period.

44.6 To avoid double-counting, the residual charge step adjustment for the disconnection of large plant would phase out as the effect of the disconnection manifests in changes to the customer's lagged residual charge adjustment factor.

44.7 The definition of "embedded" would be amended to accommodate plant that is simultaneously embedded and grid-connected. This would ensure gross load is attributed to the appropriate load customer in this scenario.

44.8 The definition of "investment agreement" would be extended to cover investments in transmission alternatives. To avoid double-recovery, contributions to transmission alternatives made under investment agreements would be carved out of the connection operating costs pool and the covered costs of the BBIs in which the transmission alternatives are comprised.

44.9 Anytime maximum demand (residual) (AMDR) baseline estimates for new or recent load customers would factor in losses for embedded batteries as well as grid-connected batteries. Ignoring losses for embedded batteries may create an inefficient incentive for new batteries to embed (or at least claim to be embedded) or lead to residual charges that are always zero.

44.10 The reverse flow and exceptional operating circumstances (**EOC**) mechanisms would not apply to calculating regional NPB under the simple method (but would still apply to calculating individual NPB, if required). Applying the reverse flow and EOC mechanisms to regional NPB under the simple method would be a difficult task and would not result in significant changes.

44.11 The EOC mechanism would be extended to cover exceptional operating circumstances caused by System Operator requirements as well as Grid Owner requirements and outages. This is consistent with how we apply the EOC mechanism under the current TPM.

44.12 The standard method assumptions and inputs for "tested investments" would not be updated after the final investment date. This is to remove incentives for beneficiaries to change their behavior after a BBI is committed to try to get lower allocations, and is most likely to be relevant to high-value intervening BBIs.

44.13 The method for calculating the asset return rate (**ARR**) for connection charges would stay as in our Proposal, rather than changing to factor in Type 2 FMD adjustments as proposed by the Authority. This avoids the complication of having to estimate notional regulated asset base and depreciation values.

44.14 The wording for the Type 2 FMD adjustment (reduction of replacement cost) would change to avoid any suggestion the replacement cost reduction has to be exactly proportional to the anticipatory capacity and to align with the wording used for reassignment. Economies of scale mean the replacement cost reduction is likely to proportionately less than the anticipatory capacity.

45. Each of these changes is shown as tracked changes in the revised proposed TPM drafting accompanying this submission.

4.2 Post-2019 investment in respect of pre-2019 interconnection assets

46. In the course of preparing to implement the new TPM, we encountered an issue with the ability of our asset register to track some post-2019 investments in respect of pre-2019 interconnection investments.

47. The issue arose because such post-2019 investments commissioned before 1 July 2021 (which we have called "exempt post-2019 investments" in the revised proposed TPM drafting) were not preserved as stand-alone investments in our asset register.[10] As a result, after the financial year during which an exempt post-2019 investment was commissioned, it became indistinguishable from the underlying pre-2019 interconnection investment to which it relates. It is therefore not possible to track depreciation and capital return separately for the exempt post-2019 investment without a complex manual work-around to our FMIS.[11] We have since modified our FMIS so that this issue does not affect interconnection investments commissioned from 1 July 2021, including the post-2019 CUWLP investment.[12]

48. As a consequence:

48.1 We have revised our original proposal to treat all post-2019 investments in respect of the Appendix A BBIs as separate post-2019 BBIs. Instead, we propose to treat an exempt post-2019 investment in respect of an Appendix A BBI as part of the underlying Appendix A BBI. As a result, the covered cost of the Appendix A BBI would increase and the relevant Appendix A allocations would apply (subject to any future adjustments). This may be a departure from clause 26(b)(ii) of the Guidelines, to the extent the post-2019 investment is "upgrading expenditure", because we do not propose to calculate separately EPNPB for the post-2019 investment.

10 This issue arose because our asset register was designed principally for revenue-setting rather than transmission pricing.

11 FMIS stands for financial management information systems and refers to the systems that collectively constitute our asset register and other financial and regulatory records and registers.

12 Some parts of the post-2019 CUWLP investment were commissioned before 1 July 2021. These assets will be tagged to the post-2019 CUWLP investment when it is fully commissioned, which is expected to be this financial year.

48.2 We also propose the new TPM departs from the requirements of clause 14(a) of the Guidelines by not treating exempt post-2019 investments in respect of other (non-Appendix A) pre-2019 interconnection investments as BBIs. This proposal means the costs of such exempt post-2019 investments would be recovered through residual charges.

49. In the revised proposed TPM drafting accompanying this submission, these proposals are captured in the new definition of "exempt post-2019 investment", the change to the definition of "post-2019 BBI", and the changes to clause 39. We note the post-2019 CUWLP investment is not an exempt post-2019 investment, meaning that investment will be treated as a post-2019 BBI.

50. We consider the departure and potential departure from the requirements of clauses 14(a) and 26(b)(ii) of the Guidelines are justified under clause 2 of the Guidelines:

50.1 We consider the departures are not inconsistent with the intent of the Guidelines. All post-2019 investments in the interconnected grid will be treated as BBIs apart from a small selection commissioned during a window of less than two years after 23 July 2019. We estimate the total commissioned value of the exempt post-2019 investments to be in the vicinity of $11-$12m.[13] This is very small in the context of our current interconnection asset base of approximately $3b.

50.2 We consider the departure promotes the efficiency limb of the Authority's statutory objective. In our view, the cost of implementing and maintaining a complex manual FMIS work-around for the life of the exempt post-2019 investments (potentially 50+ years) to avoid a very small recovery of costs through residual charges instead of BBCs and a very slightly different overall allocation for some Appendix A BBIs would be disproportionate and would not provide any material efficiency benefit, especially as the investments are already committed and commissioned. The principle in clause 1(b) of the Guidelines requires the new TPM to balance the economic benefits of precision with practical considerations, including the costs of administering the TPM.

4.3 Allocation of depreciation due to connection asset and BBI write-downs

51. Our Proposal excluded accelerated depreciation of an asset comprised in a BBI from the BBI's covered cost (clause 40(1) of the proposed TPM, variable D_a). This proposal was motivated by clause 32 of the Guidelines, which requires BBCs to be adjusted if there is material damage to the relevant BBI, the adjustment in this case being the removal of the part of the covered cost of the BBI attributable to the accelerated depreciation arising from the damage.[14]

52. In the revised proposed TPM accompanying this submission we have extended this concept as follows:

52.1 For added clarity, "write-down" is now a defined term, meaning a reduction in an asset's value due to damage to, or destruction, stranding or decommissioning of, the asset before the end of its economic life. The phrase "depreciation due to write-down" is now used instead of "accelerated depreciation".

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13 The contribution of these investments to our annual recoverable revenue will be much smaller.

14 Clause 85 also allows for RAB values used in the calculation of covered cost to be adjusted as necessary to reflect any material damage.

52.2 Depreciation due to write-down is now also removed from the calculation of the depreciation tax loss or gain component of covered cost (clause 40(3)).

52.3 For consistency with the treatment for covered cost and BBCs, depreciation due to write-down is now also removed from the connection pool for the purposes of calculating the ARR for connection charges (clause 27(2), variable D_{total}).

53. These changes mean that depreciation due to write down of both BBIs and connection assets would be allocated to residual charges rather than BBCs and connection charges. This is consistent with Transpower's current practice whereby depreciation due to write-downs is allocated to interconnection charges under the current TPM (which was another motivating factor for the treatment of accelerated depreciation in covered cost in our Proposal).

54. We now consider the exclusion of depreciation due to write downs from both covered cost and the connection pool to be departures from the requirements of the Guidelines. Specifically:

54.1 clause 15 requires the covered cost of a BBI to include the capital cost of the BBI based on its commissioned value or (in the case of the historic BBIs) its depreciated value at the start of the first pricing year, and clause 16 requires the "full present value" of the covered cost to be recovered through BBCs (subject to some exceptions that do not include excluding depreciation due to write-downs); and

54.2 clause 11 requires the costs of connection investments, including capital costs, to be recovered from the connected customers.

55. We consider these departures are justified under clause 2 of the Guidelines:

55.1 We consider the departures are not inconsistent with the intent of the Guidelines. In our view, the intent of the Guidelines is that transmission charges targeted to specific groups of customers based on the benefits they receive from a connection or interconnection investment (including by reason of being connected to it) should only apply if, and to the extent, those specific customers are receiving those benefits. This intent is express throughout the Guidelines for BBIs and, in our view, implied for connection investments, including in clause 7. For BBIs, excluding depreciation due to all forms of write-down is also consistent with the intent behind clause 32.

55.2 We consider the departures promote the efficiency limb of the Authority's statutory objective (although only marginally) by avoiding the need for Transpower to make changes to its current practice for allocating depreciation due to write-downs. We do not consider there would be any countervailing downside in respect of either the efficiency, reliability or competition limb of the Authority's statutory objective.

56. An option for connection investments is to pool and share depreciation due to write-downs through the asset component of connection charges, which was the approach in our Proposal. However, on further consideration, we do not prefer that option because:

56.1 pooling and sharing through the asset component of connection charges would not result in allocations in respect of connection assets provided under investment agreements, which are deemed to have a replacement cost of zero. This would result in a relative concentration of the write-down costs, which may get worse over time as we expect an increasing proportion of connection assets to be provided under investment agreements; and

56.2 we consider it generally desirable to have a consistent treatment of depreciation due to write-downs across both connection and interconnection investments.

5. Type 2 FMD

> Consultation question (Chapter 4)
> **Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on:**
>
> - **the proposed FAC mechanism for Type 1 FMD**
> - **the alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD**
> - **the approach to applying 'above-limit costs' under this alternative option?**

57. We agree with the Authority that *"Having to carry the full cost of anticipatory capacity would create uncertainty and cost for the first mover that may discourage it from agreeing to anticipatory capacity, even if building this now would be efficient over the longer term (because building one bigger asset now is usually cheaper than building two smaller assets that add up to the same capacity - one now, one later)."*[15]

58. We also agree with the Authority that *"This FMD could lead to inefficiently undersized connection investments or deter connection by first movers. These effects would lead to higher transmission costs overall and could lead to businesses slowing down their electrification, or to generation investment being delayed".*[16]

5.1 Transpower continues to support a "pool and share" approach to Type 2 FMD

59. We remain of the view that the Authority should address the Type 2 FMD problem by accepting the solution in our Proposal, which is labelled as *"Alternative: pool and share the costs relating to anticipatory investments"* in the Authority's consultation paper. Our detailed reasons are set out in our Proposal.[17]

60. In summary, we consider Type 2 FMD should be dealt with by pooling (spreading the risk) of investment in prudent and efficient capacity investment over a large group of customers. There are several ways the pooling could be done including, for example, through the connection charges to other customers (our Proposal), the residual charge, or a pro-rata increase in transmission charges.

61. Under our proposed Type 2 FMD solution:

    61.1 The connection charge for the first mover customer would be based on the replacement cost of the capacity they need (C), rather than the "anticipatory capacity" (C+X) that is additionally provisioned to prudently and efficiently meet future demand.

    61.2 The part of the asset component of the connection charge for the discounted connection asset that is attributable to the incremental capital cost of the additional anticipatory capacity (X) would be allocated to other connection assets (including

[15] Authority's consultation paper, paragraph E.2.
[16] Authority's consultation paper, paragraph E.3.
[17] See footnote 4.

investment contract assets) in proportion to their replacement costs, and recovered from all connected customers accordingly.

62. We agree with the Authority's analysis that our preferred approach *"would address the Type 2 FMD issue and has the advantage of simplicity of implementation (it does not require benefit-based allocation or tracking)"* and *"address[es] many of the issues that the Authority is concerned about, i.e., it removes disincentives to connect, and incentives to undersize the connection asset"*.[18]

63. The objection raised in the Authority's consultation paper is that the Authority considers this approach *"risks leading to inefficient investment … due to a lack of any real incentives for scrutiny of proposed investments in anticipatory capacity"* and this could result in *"Inefficient investment"* and *"relatively higher electricity prices"*.[19]

64. We do not consider our Proposal generates a risk of inefficient investment. In particular, any connection investments provisioned with anticipatory capacity will be subject to scrutiny, and incentives, in accordance with Transpower's usual capital expenditure decision-making framework and overseen by the Commerce Commission (whether they constitute "base capex" or "major capex" proposals).

65. We do not consider the Authority's proposal to charge a smaller subset of customers a larger amount should be assumed to be more efficient or result in more efficient investment outcomes than a "pool and share" approach. Based on the reasoning for beneficiaries-pay, the Authority proposal could result in the small subset of customers opposing efficient investment in transmission capacity because the amount they pay would be disproportionate to, or in excess of, the benefits they would receive. We consider this to be a bigger risk than hypothetical "over-investment" risk. The cost of under versus over-investment is also shaped by the future transmission network requirements for decarbonisation/electrification.

5.2 We do not support the Authority's benefit-based approach

66. We do not support the Authority's benefit-based approach to allocating the cost of anticipatory connection investments using Additional Component C.

67. Having carefully considered this alternative approach, we consider the Authority's proposed approach to be problematic on several counts.

68. As part of the refer-back process, the Authority asked us to consider an approach conceptually the same as the approach proposed for this consultation. In our view, the following considerations noted at that time remain relevant: [20]

> 41. We have considered the suggestion that the balance can be struck by applying a benefits-based approach to allocating the cost of the anticipatory connection capacity. Our practical challenge with that approach is that, at the time of the investment, *we* will not know who the future beneficiaries are. The future beneficiaries may not even exist at the time of investment. We will only have a prediction as to the type of future beneficiary, which may not transpire.
>
> 42. In places, the choice comes down to socialising the cost across a subset of customers that have been selected on the basis of necessarily poor information, or socialising the cost across all customers. In our view the latter is more efficient. It avoids concentrating the socialisation on certain customers in an arbitrary and unfair way, when they are unlikely to represent all future beneficiaries, or possibly be future beneficiaries at all.

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[18] Authority's consultation paper, paragraph, 4.50.

[19] Authority's consultation paper, paragraph, 4.52.

[20] Part 1 Refer-Back Response, section 3.1.

In these circumstances, the additional investment scrutiny hoped for when concentrating the socialisation is less likely.

43. Another way of looking at this issue is to ask which customers should bear the risk that the anticipatory connection capacity is not needed or not fully needed? We consider pooling the risk over all customers rather than exposing a single customer or subset of customers to the risk is the most efficient approach, and avoids Transpower being put in a position of picking winners and losers based on poor information.

69. The Authority has indicated its view that the question of whether proposed benefit-based charges are consistent with the statutory objective requires that *"they can be expected to result in cost allocations that are broadly in proportion to benefits"*.[21] In our view, there would be an inherent difficulty in adopting Additional Component C *"to use a method substantially the same as for benefit-based charges"* for recovering the cost of anticipatory capacity, given the fundamental tenet of benefit-based charges that they *"must result in an allocation between designated transmission customers that is broadly in proportion to their expected positive net private benefits"*.[22]

70. Under the Authority's proposal the subset of customers that would be charged for the anticipatory capacity:

    70.1 may not necessarily be the expected majority or principal beneficiaries of the anticipatory capacity (X); and/or

    70.2 may not necessarily be expected to benefit from the anticipatory capacity (they could incur net disbenefits).

71. The subset of customers would simply be charged because they are there first. Any or all of the above outcomes would mean that the cost allocations under the Authority's benefit-based proposal cannot reasonably be expected to be broadly in proportion to benefits (which would be inconsistent with the benefits-based principle inherent throughout the Guidelines, for example in clause 8).

72. It is worth stressing it does not follow that because the simple method is suitable for allocating the cost of certain (low-value) BBIs – and can be relied on to result in allocations broadly in proportion to EPNPB – that the same allocation factors should be applied to connection investments, as the Authority is proposing. The Authority proposal is a modified version of the simple method which uses the allocation factors for only generation or only load.

73. The simple method was developed to allocate the cost of low value BBIs in the interconnected grid. It was not intended to allocate costs associated with connection assets. The simple method is designed to produce allocators that reflect the benefits from the interconnected grid, including the lower-voltage sections of the interconnected grid, based on historical patterns of load, generation, and interconnection branch flows. These are to be reviewed every five years to capture changing power flow patterns over time.

74. This issue is demonstrated by one of illustrative examples in Appendix E of the Authority's consultation paper: "*Figure 27 illustrates how costs relating to [anticipatory capacity] X would be allocated for an anticipatory capacity BBI in the Hawkes Bay low voltage region made in*

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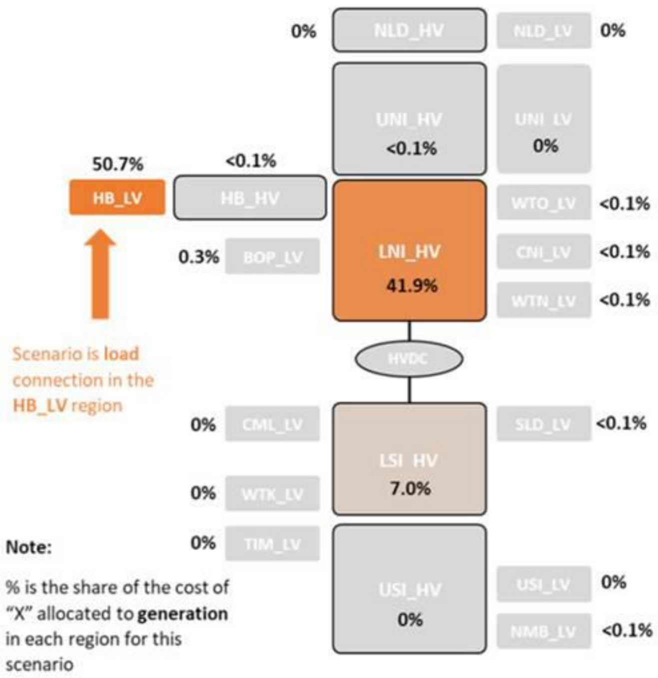
21 Authority's consultation paper, paragraph 5.5

22 This is compounded by clause (iv) of the Guidelines which states *"The purpose of the benefit-based charge is to ensure that the costs … are … recovered in accordance with the positive net private benefits that each designated transmission customer is expected … to receive from the investment"*. Clause viii(c) of the Authority's Intent links back to clause iv specifying *"Charges for connection investments to use a method substantially the same as for benefit-based charges. The purpose of this component is to allocate the charges for each connection investment in substantially the same way as the charges for each benefit-based investment"*.

anticipation of a new load connection, with costs allocated to local and upstream generation". The Authority considers "*This situation illustrates an investment for which the benefit-based approach would identify beneficiaries as widely spread. Beneficiaries are generators that would supply the new load. Benefiting generation is mostly spread across the lower North Island high voltage and Hawkes Bay low voltage regions, with some allocation also to the South Island.*"

Figure 27 The BB approach for anticipated capacity for load in the Hawkes Bay low voltage region.



75. This example shows that applying the simple method to connection assets would yield allocations that are demonstrably not in proportion to expected EPNPB because it concentrates 50.7% of the incremental cost of the anticipatory capacity on generation within the HB_LV simple method region (currently only Genesis' generation at Waikaremoana).

76. Waikaremoana is a small generator in a fairly large zone. It is not plausible to suggest Genesis receive 50.7% of the benefit of enabling new load to connect more easily in Hawkes Bay.

77. Using the simple method allocations for connection assets and anticipatory capacity for new load assumes the proportion of within region and outside region generation used to supply the existing HB_LV region load is also used to supply the new load connecting in the HB_LV region. However, in this example, it is likely most of the generation to supply the new load will come from generation outside the HB_LV simple method region. Using the existing simple method factors would thus allocate a greater proportion of the connection costs to the within region generation (currently Waikaremoana generation).

78. Over time (in this example), the increased proportion of the HB_LV region network load (including the additional connected load) would be supplied with an increased proportion of generation from outside the HB_LV region. In subsequent simple method periods this would be reflected by updated simple method allocation factors to broadly reflect the increased benefits outside region generators get from the interconnected grid in the HB_LV region.

79. We expect this type of pricing outcome, where a subset of customers would pay for a disproportionate share of the anticipatory capacity, will arise in many situations under the

Authority's proposed approach. In practice, it is unlikely to be tenable for Transpower to make efficient anticipatory investment when this does arise.

80. Charging a select sub-group of customers more than their share of benefits from an investment could result in poor incentives on participants to make sure grid investments are the best solution to improve the capacity of that part of the electricity system. The sub-group of customers that would pay would be over-incentivised to object even if it is an efficient investment.

81. Our view is the harm from inefficient investment is asymmetric, and the detriment from "under-investment" can be greater than any detriment from "over-investment", particularly given projected trends of increased electrification and grid use in future. This is consistent with the New Zealand's climate change goals, and the Authority's observation that *"decarbonisation objectives rely on significant new investment in process heat and transport electrification and new renewable generation, much of which may require additional connection assets or capacity"*.[23]

82. It also reflects that the risks of under-investment are much greater/costlier for consumers than the risks of over investment e.g. a constrained grid and/or delayed investment in generation leads rapidly to high prices.

83. This is consistent with the emphasis of dynamic efficiency over static efficiency in the Authority's interpretation of its statutory objective,[24] and the reasoning the Commerce Commission relied on to set WACC for regulated electricity and gas network businesses above mid-point.

84. The Commerce Commission's view of the relative importance of dynamic efficiency, which it equates with incentives to invest, is reflected in its commentary on its decisions to set WACC above the mid-point. The Commission's preference has been to err towards incentivising efficient investment:[25]

> That is, the Commission is acknowledging that where there is potentially a trade-off between dynamic efficiency (i.e. incentives to invest) and static allocative efficiency (i.e. higher short-term pricing), the Commission will always favour outcomes that promote dynamic efficiency. The reason is that dynamic efficiency promotes investment over time and ensures the longer term supply of the service, which thereby promotes the long-term benefit of consumers (consistent with outcomes in workably competitive markets).

5.3 We do not support the other alternatives the Authority has raised

85. The Authority has raised other alternatives, including charging the first mover for anticipatory capacity above a certain cap, "Temporary socialisation" and "Brownfield-only". Having carefully considered each alternative (including for some of them as part of the development of our Proposal), we consider each of these options would not be appropriate, including because they do not resolve, or only partly resolve, the Type 2 FMD problem, and could result in the TPM producing outcomes inconsistent with the outcomes in workably competitive markets.

23 Authority's consultation paper, paragraph 4.31.

24 The Authority states: *"In regard to long-term benefit, the Authority considers that its primary focus is to promote dynamic efficiency in the electricity industry"*.

25 Commerce Commission, Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, paragraph H1.31. A more fulsome discussion of this can be found in Commerce Commission, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services: Reasons paper, 30 October 2014.

86. The problems with the Authority's alternatives are highlighted by the Appendix E Northland scenario.

87. Appendix E provides a plausible scenario where Northland switches from an importing region to an exporting region, and this is due to large transmission investment which enables substantial new generation.

88. In this scenario the principal beneficiaries of transmission investment in Northland would switch from load customers in the region to future generators (who are unknown and not current customers) and customers in other regions who can access the additional generation supply.

89. The Authority's proposed application of a benefit-based approach would result in load customers in Northland being treated as the principal (majority) beneficiaries until the anticipated future generators arrive. This would result in load customers paying transmission charges for the new capacity disproportionate to the benefits they may receive, both initially and over time. While the possible option of a cap may mitigate the extent of this, it could result in a large first mover disadvantage acting as a substantial barrier or delay to the generation investment going ahead and (efficiently) utilising the new capacity.

90. In figure 29, the existing load customers pay "too much" relative to their share of benefits until such time as the second mover enters the market (if at all), and so bear the risk of whether (and when) the second mover enters the market. This is both inconsistent with the intent of benefit-based charges and efficient risk management.

91. If Transpower's "pool and share" option is adopted the risk that the second mover does not arrive (either at all or later than anticipated) is spread over a wider group of customers (figure 30).

92. Figure 31 shows the FMD allocations under temporary socialisation and illustrates that the first mover will pay too much – the efficient stand-alone cost of the connection asset is $17,915 but the first mover will pay $25,168 if the second mover does not arrive.

93. Using the Authority's bus analogy, under the Authority's preferred options, Northland load customers end up paying for a bus trip they will not use, and generation customers could be discouraged by the upfront initial ticket cost from getting on the (near empty) bus and may instead wait to see if a bus with more occupants arrives later so they can pay less.

A complementary alternative: Limit how much benefit-based charges can increase

94. The problems with this approach are highlighted by the need to identify a limit on how much benefit-based charges should increase with respect to anticipatory capacity. Adding this "complementary alternative" to the Authority's primary proposal would involve an arbitrary and difficult decision as to at what level to impose the cap. Under the Authority's proposal, "above cap" costs would either be borne by the first mover (perpetuating the same FMD problem) or broadly socialised (as per Transpower's proposal).

95. In principle, if charges are allocated in a way that is broadly in proportion to EPNPB then the quantum of the charges should not need to be capped. This is reflected in the Guidelines framework for the BBC allocation methodologies, which do not involve the use of a cap. A cap "fix" would only be attractive in the event the Authority's proposal was adopted and resulted in a subset of customers incurring charges for anticipatory capacity which are not broadly in

proportion to EPNPB.[26] In our view, this illustrates why the Authority's approach is not an adequate response to the FMD problem, particularly if it requires the need for complex "bolt-ons".

96. It is unclear why the Authority considers it might be efficient for "above cap" costs to revert to "*falling on the first mover*"[27]. This would perpetuate the type of situation a Type 2 FMD solution is intended to resolve.

Alternative: Temporary socialisation

97. In our view, the "Temporary socialisation" option would reduce the size of the FMD problem in the short term but would not remove it. The Authority recognises this problem in its statement *"A challenge for this option is that it does not eliminate second-mover risk for the first mover, so may leave the FMD issue unresolved"*.[28]

98. We also do not consider it would be efficient for the first mover to face the risk of ultimately bearing the full cost of the anticipatory investment.

99. As we said in our Part 1 Refer-Back Response:[29]

> Our concern is that an option that does not eliminate that risk will not be an effective solution to the Type 2 FMD problem. If the second and subsequent customers do not come on board within 10 years, the first mover will bear the cost of the anticipatory capacity, albeit in 10 years' time and not immediately. There remains a significant risk that, faced with the risk of ultimately bearing the full cost of "C+X", a customer would agree to pay for "C" (noting again the customer always has the option to build its own assets).

Alternative: Brownfield-only

100. Under "Brownfield-only", FMD would not be resolved for greenfield investments e.g. investment in capacity to meet future generation needs in a region where the renewable energy options have not been developed. We commented on this in our Part 1 Refer-Back Response:[30]

> 44. As we have said previously, Type 2 FMD is a potential problem that extends beyond brownfields connection investments. Unfortunately, the fact that greenfields (and brownfields) connection investments are funded under investment agreements, with capital costs recovered outside the TPM, does not make Type 2 FMD a non-issue. The fact remains that it may be prudent and efficient to build more connection capacity than the funding customer wants or needs. Making a distinction between greenfields and brownfields connection investments risks creating a boundary issue for the application of any mechanism to address Type 2 FMD.
>
> 45. We have considered whether competition from non-Transpower providers for greenfields connection investments addresses this dynamic. [It] is not clear that private connection investments would always be in the long term interests of consumers if they result in connection capacity being built without an eye to future capacity needs, the creation of private property rights in connection capacity or inefficient duplication of connection assets.

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26 Similarly, the variation where the Authority *"would propose 'above limit' costs could revert to falling on the first mover"* would mean (i) the FMD problem would not be resolved; and (ii) the first mover would incur charges that are out of proportion to their EPNPB.

27 Authority's consultation paper, paragraph 4.46.

28 Authority's consultation paper, paragraph 4.56.

29 Part 1 Refer-Back Response, paragraph 52.

30 Part 1 Refer-Back Response, section 3.2.

> 46. Transpower operates an open access grid and recovers the costs of new connections required by customers outside the TPM. A customer has the option to build its own new connection assets, or seek an alternative supplier to build them, if it does not consider Transpower's price to do so is competitive (or perhaps because it considers it is better able to mitigate timeline or financing risks). It is not unusual for our customers to do so. That competitive tension is healthy and our proposal would not change it.

101. The Authority considers this alternative *"would mean excluding investments in new connection capacity ('greenfields' investments), the building of which is potentially subject to competition"*.[31]

102. This statement is incorrect. The "Brownfield-only" option would not exclude anticipatory capacity in relation to greenfield investments from having their costs recovered through the TPM. Under this approach, the costs would still need to be recovered in some way.

103. It is not the role of the TPM to determine whether an investment is permitted or goes ahead.

104. The role of the TPM is to determine how the costs of transmission investment are recovered. Arguably the price signals under the TPM may *influence* what investment goes ahead. But the TPM (and the Code more broadly) does not have jurisdiction to *determine* what investment, including greenfields investment, may go ahead.

105. On the basis of the assumption this option would exclude Transpower from making greenfields investments, the Authority suggests *"alternative commercial providers are able to make appropriate risk-return trade-offs in agreements with connecting customers, so there are incentives to invest efficiently. That is, such a provider would have a commercial incentive to build the additional capacity if additional customers were likely to connect in future but would not have such an incentive where future connections were unlikely. This is efficient"*.[32]

106. The basis for these statements is unclear. We note, for example, that operating as a generation business (which requires a capacity of C, not C+X) is a very different business model, with different investment costs and risks, to operating as a transmission grid operator. We also note the Authority's observation it *"is also aware of the risk that potential commercial providers, if closely aligned to the connecting party, might have incentives not to build capacity that competitors of the connecting party might use (particularly competing generation)"*.[33]

107. Where the "alternative commercial provider" is a generator, it would need to consider the impact of providing access to its competitors and would have incentives to consider the benefits of foreclosing supply options for its competitors. Analogous issues have arisen in supermarkets and in retail fuel supply.

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31 Authority's consultation paper, paragraph 4.58.

32 Authority's consultation paper, paragraph 4.59.

33 Authority's consultation paper, paragraph 4.61.

6. Overhead opex and covered cost

<u>Consultation question (Chapter 6)</u>
Do you have any comment on the proposed approach to covered costs, including on:

- **whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view?**
- **the recovery of opex on fully depreciated assets through the residual charge?**

6.1 Transpower supports the proposed approach for allocating overhead opex to covered cost

108. The Authority has accepted (for consultation purposes) Transpower's proposed approach of recovering a share of overhead opex through BBCs. We support this approach, for the reasons set out in our Proposal.[34] We elaborate on some of those reasons below.

6.2 The requirements of the Guidelines

109. The Guidelines require that BBCs recover the covered cost of BBIs, with prescriptive rules about how covered costs are to be determined.

110. Clause 15 of the Guidelines specifies a BBI's covered cost must include:

110.1 the capital cost of the BBI;

110.2 a return on capital for the BBI, based on its capital cost and WACC;

110.3 an amount of opex "reasonably attributable" to the BBI based on an allocation of the opex allowance for the pricing year as set in the IPP; and

110.4 any other costs attributable to the BBI.

111. The cost allocation methodology used to determine the covered cost of BBIs will impact, amongst other things, the distribution of transmission costs (in aggregate) between generation and load, because it determines whether transmission costs will be recovered through BBCs or residual charges.

112. The less cost attributed to the covered cost of a BBI the lower the proportion of Transpower's allowable revenue that will be recovered through BBCs, which are payable by both generation and load. Accordingly, more cost would be recovered through residual charges and paid by load only. This would result in a higher contribution to transmission costs from load relative to generators. In this respect, it should be noted the injection overhead component of connection charges in the current TPM was designed to ensure generators pay a contribution towards overhead opex.

113. As set out in our Proposal, we consider there is a potential range of "reasonably attributable" cost allocation approaches available to meet the criteria for covered cost imposed by the Guidelines, in-between incremental or avoidable cost and stand-alone cost. In our view, the closer the allocation is to 0% (incremental cost) or 100% (stand-alone cost) the less likely the allocation will be reasonable. This range is narrower than that suggested in the Authority's

[34] See footnote 2.

consultation paper, which starts the potential range below incremental cost and instead at directly attributable costs.

114. The approach of attributing costs to both BBIs and non-BBIs, rather than solely to non-BBIs, is consistent with regulatory precedent for how "reasonably attributable" is applied under Part 4 of the Commerce Act 1986 and Part 6 of the Telecommunications Act 2001. We also note, by way of precedent, that under the Telecommunications Act, Total Service Long Run Incremental Cost (**TSLRIC**) is defined as including "*a reasonable allocation of forward-looking common costs*",[35] i.e. the TSLRIC pricing principles in the Telecommunications Act treat incremental costs and a contribution to common costs as a "reasonable allocation".

115. There is nothing we have gleaned from the different purposes of the legislation that would mean costs that are reasonably attributable for pricing under the Commerce Act or Telecommunications Act are not, or should not be considered, reasonably attributable for pricing under the Electricity Industry Act or in relation to the TPM.

6.3 Transpower does not support the Authority's alternative option

116. Under the Authority's alternative option, covered costs would only include costs (including overhead opex) that are directly attributable to the BBI. This issue was considered extensively as part of the development of the TPM, including through the Checkpoint and Refer-Back processes. Having carefully considered the matters set out in the Authority's consultation paper, our view remains that this alternative approach is not appropriate, and does not advance the Authority's statutory objective.

117. We consider this approach is not reasonably available on a plain reading of the Guidelines which require allocation of "reasonably attributable" opex and other costs that are "attributable". In our view, when read in the context of economic regulation, a direct attribution approach would fall outside the range of alternatives available, and would therefore require a departure from the requirements of the Guidelines.

118. We are concerned, on efficiency grounds, that the Authority's alternative option would result in outcomes that are inconsistent with outcomes in workably competitive markets and would result in cross-subsidies from load to generation. We also consider a cost allocation approach to opex that results in cross-subsidies would not satisfy the requirement to allocate "reasonably attributable" opex, and therefore is not within the spectrum of options that are consistent with the Guidelines.

119. We note the Authority's comments on the benefits of generators facing higher transmission costs and how this would result in greater scrutiny of transmission investment. The investment scrutiny argument is a key basis for the Guidelines:[36]

> It is likely that generators would seek to pass the charge on to consumers by raising their wholesale offers. To the extent that some generators face higher transmission costs than others (which is likely under the proposed approach) there will be a constraint on how much these generators can pass on in their charges. In other words, the situation is likely to be analogous to the ability of a potato farmer from Oamaru seeking to pass on the costs of transport of their potatoes to Auckland when they face competition from potatoes produced in Pukekohe. If generators face the charge they would have greater incentives to scrutinise the costs of transmission investment recovered through the charge, which would help promote more efficient transmission investment.

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35 Telecommunications Act 2001, Schedule 1, clause 1.

36 Authority, Transmission Pricing Methodology: issues and proposal: Consultation Paper, 10 October 2012, paragraph 5.6.74.

6.4 Consistency with outcomes in workably competitive markets

120. We consider the proposal that overheads be treated as attributable to both BBIs and non-BBIs, including investments in non-grid assets, historic investments whose costs are recovered through residual charges and fully depreciated assets, is consistent with workably competitive market outcomes.

121. In its 2019 issues paper, the Authority stated "*Our view is that the recovery of overheads should reflect how* they *would be recovered in a workably competitive market*".[37] The Commerce Commission considered this matter when it reviewed the previous avoidable cost allocation methodology (**ACAM**) rules which allowed allocation of all shared and common costs to the regulated business under Part 4 of the Commerce Act regulation, and when considering cost allocation under Part 6 the Telecommunications Act.

122. In both decisions, the Commerce Commission concluded a workably competitive market would result in common costs (including overheads) being shared and not allocated to one particular service or group of customers, e.g.:[38]

> … in the longer-term, all services are expected to recover some proportion of shared costs.
>
> Experts advising EDBs and GPBs (as well as Airports) unanimously agreed that in workably competitive markets firms would expect to recover some proportion of shared costs from all services in the longer-term.
>
> … The Commission does not consider that an approach which allocates all shared costs to the regulated businesses will produce outcomes which are consistent with those occurring in workably competitive markets.

and:[39]

> We consider that in most cases, ACAM would not lead to outcomes consistent with those produced in workably competitive markets. Under ACAM, shared costs would be allocated to regulated FFLAS to the extent that they would be non-avoidable if services that are not regulated FFLAS were no longer supplied. Axiom has previously recommended that ACAM should not be an allowable option in the cost allocation IM, as the ACAM approach would allocate a disproportionate share of shared costs to regulated FFLAS. We agree with the view expressed by Axiom, that "firms in workably competitive markets would expect to recover some portion of their common costs from all services in the long-term.

6.5 Requirements for subsidy-free pricing

123. From an economic stand-point, prices need to be equal to or above incremental/avoidable cost, and equal to or below stand-alone cost to be subsidy free and avoid economic rents. This is reflected in the Guidelines' provisions relating to stand-alone cost prudent discounts.

124. An allocation of directly attributable costs only would fall below these bounds and requires that BBIs are subsidised through residual charges, i.e. load customers would subsidise generators.

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37 Authority, 2019 issues paper: Transmission pricing review: Consultation paper, 23 July 2019, paragraph B.222

38 Commerce Commission, Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper, December 2010, paragraphs 3.5.52 to 3.5.56.

39 Commerce Commission, Fibre input methodologies: Draft decision - reasons paper, 19 November 2019, paragraph 3.392.

125. It is important to note directly attributable costs and overheads are accounting concepts and do not directly translate to incremental/avoidable costs or what the Commerce Commission refers to as "economic common costs".

126. The incremental/avoidable costs of providing a service or, in the TPM context, a particular BBI will include directly attributable costs and also a share of overheads where the size of the overhead depends in part on the provision of that service or asset.

127. This is illustrated in the following Commerce Commission example:[40]

Electricity lines and fibre (broadband)

Services provided separately

Service	*Total asset base*	*Poles*	*Other assets*
Electricity lines	100	25	75
Fibre	100	25	75

Services provided together

<table>
<tr><th>Service</th><th>Total asset base</th><th>Poles</th><th>Other assets</th></tr>
<tr><td>Electricity lines</td><td rowspan="2">180</td><td rowspan="2">30</td><td>75</td></tr>
<tr><td>Fibre</td><td>75</td></tr>
</table>

128. The electricity lines and fibre services the Commerce Commission uses in this example are not important and could be interchanged with BBIs and non-BBIs and have the same implications for subsidy-free pricing.

129. In the example, the directly attributable cost of each service is $75. Shared costs when the services are provided together (poles) are $30.

130. The incremental/avoidable cost of each service is $80 and more than the directly attributable cost of $75. This is because if the fibre service, for example, was not provided the electricity lines business would avoid $5 of the $30 in shared pole costs:

Incremental cost = directly attributable cost + the avoidable/incremental component of the shared costs (the poles) = $75 + $5 = $80.

131. What this means is that a BBI's covered cost needs to include directly attributable costs and an allocation of overheads to satisfy the economic efficiency requirement to be subsidy-free.

40 Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289, from paragraph [1807].

7. Allocation between generators and load under the simple method

<u>Consultation question (Chapter 5):</u> **Do you have any comment or additional evidence on the proposed weighting of benefits between load and generation customers under the simple method, or with respect to the proposed review of the allocation?**

132. The proposed simple method, as described in chapter 7, section 16 of our Reasons Paper, results in (but does not assume) a broadly equal split between injection and offtake groups, which is subject to review (for future BBIs) every 5 years.

133. The proposed simple method allows for an adjustment of the allocation between injection and offtake customer groups based on a "demand adjustment factor" which *"means a factor by which individual NPB under the simple method for offtake customers is scaled relative to individual NPB under the simple method for injection customers"*.

134. The determination of the proportion of EPNPB derived by load and generators could result in substantial wealth transfers. The higher the proportion of benefits that are deemed to be derived by load (and therefore the lower the proportion for generators) the higher (lower) the share of BBCs they will incur.

135. The way that wealth transfers could change over time is illustrated in paragraphs 5.42 to 5.45 of the Authority's consultation paper.

136. As part of TPM development, Transpower considered a number of different approaches to determining the allocation of BBCs between load and generation, including benchmarking against allocations of interconnection charges in different jurisdictions (initially proposed by Meridian) and basing the allocations on the Schedule 1 allocations in the Guidelines. These options are considered in chapter 7, section 16.4 of our Reasons Paper.

137. Our assessment of these different approaches was that they supported a range of different potential allocations and our proposal was comfortably within these ranges. We agree with the Authority there is not strong evidence for moving away from Transpower's proposed weighting factor, which has an initial value of 1 and results in a roughly 50:50 split between load and generation.

7.1 Weighting factor review mechanism in the proposed TPM

138. The Authority is proposing to adopt Transpower's proposed review mechanism. Under this mechanism, we will review the weighting factor at least every 5 years and update its value based on the average aggregate generation/load splits as determined from post-2019 standard method BBCs provided there are at least 10 of them.

139. The Authority has additionally raised for consideration some options that would apply to the future reviews of the weighting factor.

140. We do not support the options the Authority has raised, for the reasons set out below.

140.1 *"Requiring Transpower to consult early on a review methodology, (e.g., to be included in the assumptions book in year three of the proposed TPM) which is then applied in year four of a simple method period"*: We are uncertain what the Authority has in mind when it refers to a "review methodology" or what the potential benefits of consulting separately on it would be. The proposed TPM already contains an empirical basis for the review (the outcome of at least 10 standard method allocations) and already requires us to consult on any material update of the assumptions book (the demand adjustment factor is published in the assumptions book).

140.2 *"Transpower could be required to formally consult with the Authority on the weighting factors"*: This is unnecessary because Transpower would consult all stakeholders and interested parties (including the Authority) on the assumptions book update anyway.

140.3 *"Transpower could commission (by itself or jointly with the Authority) an independent reviewer of weighting factors (with a duty of care to both Transpower and the Authority) to review and provide recommendations"*: This proposal, which we understand to be based on the Commerce Commission price path application requirements, is in our view disproportionate for this discrete aspect of the proposed TPM, especially in view of the empirical basis for the review in the proposed TPM itself. Transpower has no vested interest in the weighting factor so the involvement of an independent third party seems unnecessary and an avoidable cost of administration.

140.4 *"The weighting factor could be for the Authority to determine (based on a proposal by Transpower)"*: In our view, this re-allocation of responsibilities would be out of step with the framework for implementation of the TPM which leaves operational aspects to Transpower, including all determinations and calculations. This option would blur the separate responsibilities of Transpower in administering the TPM and the Authority in approving it. We also note the Authority has previously said, in relation to prudent discounts, *"The Authority does not agree that it should take an active role in deciding on prudent discount applications and considers that Transpower is better suited to making such a decision, given its operational role and expertise"*.[41]

[41] Authority, Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM: Decision, 10 June 2020, paragraph 12.40.

8. Residual charge and battery storage

Consultation question (Chapter 7):
Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?

141. We remain of the view – having closely considered the Authority's consultation paper – that gross load would be a problematic allocator for batteries.

142. The submissions we received on this topic are relevant to the Authority's consultation. Stakeholder views were fairly binary. Legitimate arguments were raised both in favour of and against departing from the Guidelines to address potential problems associated with applying the gross load allocator to battery storage .[42]

143. Both Transpower's stakeholder engagement during TPM development and the Authority's consultation paper demonstrate a full exemption for battery storage would overshoot the problem, shifting the residual charge from a potential barrier to investment in battery storage to creating an artificial advantage for it. It would not be competitively neutral or efficient to charge other generators for electricity they consume but not batteries.

144. The Authority's proposed partial exemption for battery storage has a practical advantage over the other options as it would mean Transpower would not need ongoing information about what the battery storage is actually doing, including if the battery is part of hybrid plant or co-located with a generator. On an ongoing basis, all we would need to know is grid offtake and non-battery embedded generation (albeit the latter presents a non-trivial information challenge).

[42] Some submitters commented that the impact of the residual charge on batteries can be seen as an example of a wider competition/distortion problem not limited or specific to batteries.

9. Adjustments

9.1 “Whole-of-life” approach to BBC adjustments

> <u>Consultation question (Chapter 8):</u>
> **Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:…**
>
> - **the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines…**

145. We support the Authority’s proposal not to implement a “whole-of-life” approach to BBC adjustments that is backward-looking, for the reasons set out in chapter 10, paragraphs 63 to 69 of our Reasons Paper.

146. We differ from the Authority in that we do not consider this is a departure from the requirements of clause 33(b) of the Guidelines, which contains the important qualifier *“to the extent possible”*. As we said in chapter 10, paragraph 69 of our Reasons Paper:

> We consider a backward-looking adjustment will not increase our levels of confidence that BBCs reflect the share of net private benefits each customer is expected to receive from a BBI across the whole of its life. For this reason, the proposed TPM reflects a forward–looking approach to reallocating BBCs when a new customer enters (clause 80 of the proposed TPM). We have concluded the proposed TPM complies with clause 33(b) of the Guidelines, to the extent it is possible to do so, without including a backward-looking adjustment.

9.2 Residual charge adjustment for new entrant and expanding customer

> <u>Consultation question (Chapter 8):</u>
> **Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:…**
>
> - **the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed…**

147. The Authority has proposed to ramp up the residual charge for a new customer to mimic the outcome under the lagged residual charge adjustment mechanism for an existing customer connecting new plant. We do not support this proposal.

148. While we agree the Guidelines create a competitive neutrality problem, in terms of how the residual charge applies to new versus existing customers, we do not consider the Authority’s

proposal adequately addresses this problem. As we said in our Part 1 Refer-Back Response,[43] and illustrated in the accompanying worked example, the Authority's proposal leaves existing customers with existing plant at a competitive disadvantage compared to existing customers with new plant and new customers.

149. We remain of the view the proposed new TPM should provide for a step adjustment to an existing customer's residual charge if the customer connects new large consuming plant. In our view, this is the best way to eliminate, or at least minimise, the competitive disadvantage problem. We have suggested revised proposed TPM drafting to achieve this, which is substantively the same as the TPM drafting we proposed in our Checkpoint 2B submission.[44]

150. We do not consider our Proposal would defeat the purpose of the lagged adjustment mechanism (paragraph 8.46 of the Authority's consultation paper). The lagged adjustment would still apply to increases in gross load not arising from new plant or upgrades and would still operate to avoid inefficient actions to avoid the charge (noting that any avoidance behaviour would involve the customer reducing, not increasing, its gross load). The lagged adjustment would also capture increases in gross load attributable to new plant or upgrades that are not large, i.e. not grid-connected and not at least 10 MW embedded.

151. Another problem we see with the Authority's proposal is that extending the lagged residual charge adjustment mechanism to new customers and applying it to new large consuming plant would make it less likely a customer or embedded party would bear the full transmission charges cost of their decision to enter or expand. That cost will be borne eventually by whoever owns the relevant consuming plant four to eight years later, which may not be the original customer or embedded party. For embedded consuming plant that no longer exists at that time, the cost may be borne exclusively by parties who never had an interest in the plant.

9.3 Residual charge adjustment for customer exit and large plant disconnection

Consultation question (Chapter 8):
Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter…

152. The TPM drafting the Authority has proposed to make the step adjustment for large plant disconnection (clause 97) would result in double-counting of the reduction when the lagged adjustment mechanism "catches up". This would mean the disconnecting customer would ultimately under-pay residual charges. We have suggested a fix for this in the revised proposed TPM drafting accompanying this submission.

153. We note the adjustment provisions in the proposed TPM treat embedded plant changes, including large consuming plant disconnection or de-rating, as analogous to the same change

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[43] Part 1 Refer-Back Response, section 5.

[44] Checkpoint 2B proposed TPM drafting. We removed step adjustments from our 30 June proposal because the Authority indicated in response to our Checkpoint 2B submission that it did not intend the Guidelines to be departed from in that way.

happening at the grid interface. In all cases, the adjustment falls on the transmission customer, not the embedded plant owner (who will typically not be a transmission customer or pay transmission charges directly). We therefore do not understand the issue/problem the Authority discusses in paragraph 8.51 of its consultation paper relating to the proposed TPM's treatment of embedded party downsizing.

10. Prudent discounts

10.1 Prudent discount practice manual

<u>Consultation question (Chapter 9):</u>

Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:

- **Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower**

154. We consider the prudent discount practice manual should be an optional tool to be developed as we gain experience with prudent discount applications under the new TPM.

155. We do not support making the prudent discount practice manual mandatory, for the following reasons:

155.1 The prudent discount practice manual is not a pre-requisite for prudent discount applications. The key information required to enable prudent discount applications (in addition to the fundamental prudent discount conditions in the proposed TPM itself) are the application fees and application requirements. Under the proposed TPM these are required to be published on our website, whether there is a prudent discount practice manual or not (definitions of “application fee” and “application requirements”). We intend to publish the application fees and application requirements for prudent discounts before the first pricing year under the new TPM so that prudent discount applications can start straight away.[45]

155.2 Developing, consulting on and finalising a useful prudent discount practice manual containing all of the information contemplated in paragraph 9.12 of the Authority’s consultation paper would take time and require the application of considerable Transpower and stakeholder resource. In our view, this is not warranted at this time. We are mindful of the need to prioritise critical tasks while we are preparing to implement, or are in the early stages of implementing, the new TPM. We expect most of our customers would be of the same view. We are also mindful there is a reasonable chance we will never receive a prudent discount application, or at least not during the first pricing year, in which case the effort to produce the manual before the first pricing year (or at all) would be wasted.

155.3 We do not consider it axiomatic applicants would benefit from a prudent discount practice manual if prepared prematurely. Applicants may find it beneficial not to be constrained by our views about alternative project options, for example. Absent prescriptive prudent discount rules, applicants will have the benefit of more flexibility in how they construct their business and technical cases for a discount.

155.4 We consider it would be optimal to develop the manual in the context of real applications. Setting (even on a non-binding basis) particular prudent discount

[45] Noting, however, our ability to process early applications in a timely way, especially if there are several of them, may be affected by the need to prioritise matters essential to bedding in the new TPM.

assumptions or methodologies in the absence of at least one application is potentially inefficient, especially for SACPDs which are a new concept introduced by the Guidelines. We consider attempting to do so is likely to result in re-work, both for Transpower and applicants. In the early stages of the new TPM, applicants are as likely as Transpower to make valuable contributions to prudent discount "jurisprudence".

156. We do not consider the prudent discount practice manual should be binding, for the reasons set out in paragraph 9.20 of the Authority's consultation paper.

157. The above points apply equally to the development of the reassignment practice manual.

10.2 Duration of prudent discount agreements

> <u>Consultation question (Chapter 9):</u>
> **Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:…**
>
> - **15 years should be the default maximum period with a longer term possible on proof…**

158. In our view, it would be appropriate for the default duration for a prudent discount agreement to be 15 years in cases where the parties are unable to agree on a different duration.

159. While we consider there are potential inefficiencies with this approach because it introduces an unnecessary negotiating dimension, our principal concern is (and always has been) to ensure the default duration for a prudent discount agreement is not unreasonably long. A maximum duration of 15 years is consistent with the current prudent discount policy, and we do not see a strong justification for changing that.

160. We do not agree limiting the duration of a prudent discount agreement to 15 years could risk inefficient outcomes due to uncertainty about whether the agreement will be renewed. If the conditions for renewal are satisfied, then the agreement must be renewed; it is not discretionary. If the conditions are not satisfied, then it would be inefficient to renew the agreement and so it should not be. In any event, a customer would normally much rather have a prudent discount agreement than build the alternative project[46] because the prudent discount agreement avoids all project execution risk.

161. Whatever the duration of a prudent discount agreement, we consider there has to be a sensible limit on the prudent discount calculation period so that we are not required to assess discounted costs many decades into the future. We do not consider the prudent discount calculation period should be any longer than 20 years (matching the proposed maximum duration of the standard method calculation period).

10.3 Customer termination of prudent discount agreements

> <u>Consultation question (Chapter 9):</u>
> **Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:…**

[46] Assuming the alternative project can be built, which is not necessarily the case for a SACPD.

- **customers should be able to terminate a prudent discount agreement before the end date of the agreement?**

162. We consider the customer should be able to terminate a SACPD agreement, as we have proposed.

163. If a SACPD agreement no longer provides a discount, and therefore the customer's transmission charges no longer exceed the efficient stand-alone cost of the interconnection services the customer receives, why should the customer be forced to continue with the agreement? In that situation the SACPD agreement, if it continued, would have the effect of artificially raising the customer's transmission charges, the opposite of what it is intended to do.

164. The Authority's comment on page 84 of its consultation paper that *"the commercial discipline on a customer applying for an SACPD should reflect reality as closely as possible"* appears not to acknowledge the hypothetical nature of the alternative project underlying a SACPD (clause 47(a) of the Guidelines and clause 136(2) of the proposed TPM).

165. A SACPD should act as a ceiling for transmission charges and should not act as a floor as well. If a SACPD acts as a floor for transmission charges, that may act as a disincentive for customers to apply for one. A customer would not only have to assess that its current transmission charges exceed efficient stand-alone cost but would also have to make a judgement about whether that will continue to be the case for the duration of the SACPD agreement.

11. Commencement date

<u>Consultation question (Chapter 15):</u>
Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM?

166. We are committed to delivering the new TPM by the implementation date set by the Authority.

167. The proposed 1 April 2023 date will be challenging to achieve, especially as there are only a few months between the Authority's planned approval date for the new TPM (31 March 2022) and our effective deadlines for consulting on transmission charges for pricing year 2023 (1 September 2022) and producing audit-ready transmission prices (1 October 2022).

168. By various dates between now and 1 April 2023 we would need to carry out the following tasks, at a minimum:

168.1 Produce transmission prices for pricing year 2023 and have them audited, approved by our Board and notified to customers.[47] This includes:

- developing, consulting on and finalising the initial assumptions book, which will specify key inputs to the calculation of BBI customer allocations and factors for the standard and simple methods;
- calculating, consulting on and finalising standard method allocations, and then BBCs, for the two high-value post-2019 BBIs expected to be commissioned during financial year 2021;[48]
- calculating, consulting on and finalising the simple method allocations (regional and individual) for the first simple method period, and then BBCs for the low-value post-2019 BBIs commissioned before the end of financial year 2021;
- calculating, consulting on and finalising the residual charge allocations and residual charges for the first pricing year;
- obtaining all the inputs for the above calculations, using new Code information-gathering powers if necessary and available, consulting on those inputs[49] and finalising them; and
- working with our audit and assurance service providers to assist them to understand and prepare our Board for certifying transmission charges for pricing year 2023.

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[47] Transmission agreements allow transmission charges for a pricing year to be notified to customers as late as 1 January, but we routinely notify earlier than that due to the Christmas/New Year break and to provide sufficient time for our customers and retailers to factor transmission charges into their price-setting processes.

[48] The two investments are post-2019 CUWLP and the reconductoring of the Otara-Flat Bush section of OTA-WKM A&B. We have suggested a change to the proposed TPM that would allow us to delay the commencement of standard method BBCs for these investments by a year if necessary, but our intent is to try to have the standard method BBCs ready to start from the first pricing year

[49] We are planning to start consultation on the inputs to residual charge allocations, intra-regional BBC allocations and the transitional cap in February 2022.

168.2 Develop and publish application requirements and application fees for prudent discount and reassignment applications, and the list of BBIs eligible for reassignment.

168.3 Complete development and testing of our tools, systems and processes for the first pricing round under the new TPM, including our core transmission pricing system and FMIS.

168.4 Continue to engage with the Authority on the development of the new TPM, including responding to questions and participating in the Authority's consultation and any post-consultation interactions.

168.5 Engage with the Authority on TPM-related Code changes, including participating in the Authority's consultations.

168.6 Potentially develop, consult on and publish a new loss and constraint excess (**LCE**) allocation methodology.

168.7 Continue to engage with our customers and other stakeholders on their transmission pricing enquiries, a backlog of which is beginning to build up.

168.8 Develop collateral to support our customers to understand the new TPM and their transmission charges under it, including to assist customers to develop and communicate their methodologies for passing through their new transmission charges.

168.9 Support our New Zealand Grid Pathways consultation processes and investment proposals with indicative pricing under the new TPM.

168.10 Support our RCP4 consultation processes and base capex and opex proposals with indicative pricing under the new TPM.

169. This represents a considerable body of work to complete within the limited timeframe that is proposed. Further, any unforeseen or material delay to the transmission charge calculation or systems development work stream could put the proposed 1 April 2023 implementation date at risk.

170. We urge the Authority to closely consider the potential implications from a timing perspective of including in the new TPM any additional complication (such as "bolt-ons" to the proposed method for addressing Type 2 FMD) or additional, or intensified, pre-implementation work streams for Transpower (such as a mandatory prudent discount or reassignment practice manual).

171. In our view, the Authority should only include additional complication or additional pre-implementation work streams in the new TPM if the Authority is confident the new requirements will produce benefits to consumers that outweigh the administrative cost and risk of delay those new requirements may represent.

12. Potential supporting Code amendments

> Consultation question (Other):
> **Is there anything else in relation to the proposed Code amendment that you wish to comment on?**

172. Our views on the potential supporting Code amendments outlined in paragraphs 2.18(a), (b) and (d) of the Authority's consultation paper are set out in chapter 16 of our Reasons Paper. In short, we support those potential Code amendments in principle.

173. In relation to the potential Code amendment relating to the availability of behind-the-GXP[50] data, we note any new Code obligations should require customers to not only provide that data to Transpower but also to record and retain it so it can be used by Transpower for transmission pricing purposes.

174. In the absence of these additional obligations, a rational approach for some customers may be to simply not capture behind-the-GXP data or, if they do, to get rid of it as soon as possible. In our view, this potential incentive supports incorporating this amendment into the Code sooner rather than later. In any event, the amendment is required in good time before the start of the first pricing year to which the new TPM applies so we have access to the data necessary to calculate the initial residual charge allocation.

175. Related to this, we would support a further Code amendment to provide a "safe harbour" for our calculation of the baseline residual charge allocation metrics for existing customers. We consider this important because historic embedded electricity data going back to 2014 is likely to be relatively patchy and in some cases may need to be extrapolated from SCADA data. Any Code amendment requiring customers to record, retain and provide embedded electricity data would not resolve data gaps that already exist. Provided we consult on our calculation of those baseline metrics (as we are required to under clause 17(1) of the proposed TPM) and act reasonably in calculating them, we consider this calculations will be robust.[51]

176. We do not have a view on the potential supporting Code amendment outlined in paragraph 2.18(c) of the consultation paper (ACOT changes). We note however that removing a regulatory right to be paid ACOT (as is currently the case for all new embedded generation) is not the same as stopping ACOT payments where they have been agreed in a contract (either before or after the Code amendment).[52]

177. There is another Code amendment we think the Authority should consider. It would be useful if the System Operator were expressly able to disclose to the Grid Owner information about matters that may be relevant to the calculation or adjustment of transmission charges. For example:

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[50] The consultation paper refers to behind-the-GXP data, but behind-the-GIP data is also relevant to the calculation of gross load and residual charges. The issue really relates to data about activity behind points of connection to the grid.

[51] Related to this, the revised proposed TPM drafting accompanying this submission includes a recommended new subclause to specify the data Transpower may use to calculate gross load (subclause 5(7)).

[52] Even without a peak charge, distributed generation can help offtake customers avoid transmission charges because the individual allocations of future BBCs will be based on grid offtake.

177.1 We may need to use SCADA data to calculate gross load for some customers in some situations. SCADA data is provided by participants to the System Operator under Part 8 of the Code and therefore resides with the System Operator.

177.2 It is possible the System Operator will know about proposals to connect large embedded generating plant, or even that large embedded generating plant has already been connected, before the Grid Owner does.

178. Currently, clause 3(2) of Technical Code A of Schedule 8.3 of the Code prohibits the System Operator disclosing "*information about an asset, supply or demand of…asset owners*" except in limited situations which do not include assisting the Grid Owner to calculate or adjust transmission charges.

179. The Authority should also consider what changes may be required to the benchmark transmission agreement to align with the new TPM. Our initial view is the following clauses will or may need to be amended:

179.1 Clause 4.3 (benchmark agreement reviews) – This clause still refers to the Authority making recommendations to the Minister for amendments to the benchmark agreement.

179.2 Clauses 9.2, 9.3 and 12.1 (information from customers) – There may need to be consequential changes to these clauses arising from the new Code provisions about the availability of behind-the-GXP data.

179.3 Clause 10.3(e) (charges by connection location) – Not all of the new transmission charges are amenable to being assigned to particular connection locations as required by this clause. This is certainly the case for prudent discount and cap recovery charges.

179.4 Clauses 10.1 and 11.2 (date for invoicing and payment of invoices) – These clauses do not reflect the actual invoicing date (typically during and towards the end of the month being billed) or the actual due date for payment (20th of the month after the month of invoice).

179.5 Part D (LCE) – This Part may need to be amended depending on what LCE-related Code amendments the Authority decides to make.

179.6 Clause 4.4 of the Connection Code (minimum power factor) – The customer's obligations in this clause are linked to regional peak demand periods, which will not need to be determined under the new TPM.[53]

180. Generally, we consider the benchmark agreement is overdue for review[54] and the advent of the new TPM would be a good opportunity to bring it up to date.

181. If there are changes to the benchmark agreement, there should be a corresponding Code amendment to make those changes effective in existing transmission agreements. Changing the benchmark agreement will not automatically have that effect in all cases.[55]

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53 To amend the connection code the Authority would need to initiate a review of it under clause 12.18 of the Code.

54 As far as we are aware, the benchmark agreement has not been reviewed since it was amended in October 2007 by the Electricity Commission, shortly after it was added to the former Electricity Governance Rules.

55 Clause 4.3 of the benchmark agreement only carries through benchmark agreement changes for default transmission agreements deemed to apply under clause 12.10 or 12.13 of the Code. Most transmission agreements on benchmark terms are entered into by agreement and are therefore not covered by clause 4.3. Clause 4.3 does not cover legacy forms of transmission agreement either. There is also the arguable point that clause 4.3 can never now apply because the condition in subclause (a) (recommendation to the Minister) cannot be satisfied.

TRANSPOWER

TRANSPOWER.CO.NZ

Memorandum

Date:	2 December 2021
To:	Transpower

by email

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Confidential and Privileged

ELECTRICITY AUTHORITY CONSULTATION ON THE PROPOSED TPM: ASSURANCE OF TRANSPOWER'S SUBMISSION

Introduction

1 Transpower intends to make a submission to the Electricity Authority (**Authority**) in response to its consultation on the proposed transmission pricing methodology proposal (**TPM**).

2 The Authority is required to consult on the proposed TPM under clause 12.92 of the Electricity Industry Participation Code (**Code**) and has indicated that it will accept initial submissions by **2 December 2021**, and cross-submissions by **23 December 2021**.

3 Transpower intends to include in its submission:

3.1 comments in response to select questions raised by the Authority in relation to key TPM topics;

3.2 comments on the material changes made by the Authority to the drafting of the proposed TPM; and

3.3 revised TPM drafting, which builds on the changes made by the Authority and which are primarily intended to ensure workability of the proposed TPM, and/ or address additional issues identified by Transpower.

4 In making its submission, Transpower is guided by the matters set out in clause 12.89(1) of the Code, which require that the proposed TPM be consistent with:

4.1 the Guidelines published under clause 12.83(b);

4.2 the Authority's statutory objective in section 15 of the Act; and

4.3 any determination made under Part 4 of the Commerce Act 1986.

5 You have asked Chapman Tripp to provide assurance in relation to Transpower's submission, including its proposed TPM drafting, with a particular focus on compliance with the Guidelines and the Code, as applicable.

Assurance

6 In our opinion, and subject to any assumptions, qualifications and limitations noted below:

6.1 Transpower's revised TPM to be included as part of the submission is consistent with the requirements of the TPM Guidelines in all material respects, in that the revised TPM:

(a) addresses the scope and boundaries set in the TPM Guidelines;

(b) addresses any tests or criteria in the TPM Guidelines;

(c) is consistent with the content requirements of the TPM Guidelines (except where clause 2 departures have been clearly identified and documented); and

(d) addresses any process requirements in the TPM Guidelines;

6.2 Transpower has addressed the requirements of clause 12.89(1) of the Code, as applicable.

Assumptions, qualifications and limitations

7 Our assurance in paragraph 6 above is subject to the following:

7.1 our assurance is based on the information made available to us;

7.2 our assurance role addresses legal requirements and legal form, and does not address economic or engineering effects; and

7.3 Transpower has satisfied itself that the revised TPM contains the structural and fundamental aspects of the proposed methodologies.

Reliance

8 This opinion may be relied on by Transpower and its Directors. Except to the extent (if any) required by law, no other person may, without our written consent, use this letter, either directly or indirectly, or enable this letter to be relied upon by any other person, or allow this letter to be quoted or referred to in any document, whether public or private, or filed with any regulatory authority.

9 We are aware that Transpower may intend to disclose this letter when providing its submission to the Authority. We understand the disclosure of this letter is not intended to waive privilege in any advice we have given to Transpower, in this or any other process.

Lucy Cooper / Penelope Ward
Partner / Senior Associate

Schedule 12.4 cl 12.84
Transmission Pricing Methodology

Commented [A1]: The following recommended amendments fall into four categories:

Typo: Typographical corrections.

Style: Stylistic changes, including for consistency.

Clarification: Recommended changes to clarify points that might not otherwise be obvious to the reader.

Change: Our recommendations for an alternative approach to the drafting without a substantive change, or where, on further consideration since our Proposal, we consider the drafting should change in a substantive way.

Part A Preliminary

Introduction

1 Purpose

The **transmission pricing methodology** is used to recover the cost of **transmission services** provided by **Transpower**, other than **transmission services** provided under **investment agreements**, but not more than **recoverable revenue** for each **pricing year**. This **transmission pricing methodology** allocates that cost to **customers** through **transmission charges**.

2 Overview of Transmission Charges

The **transmission charges** are—

(a) **connection charges**, which recover part of **recoverable revenue** by reference to the cost of **connection investments**. Part C specifies how **connection charges** are calculated; and

(b) **benefit-based charges**, which recover part of **recoverable revenue** by reference to the **covered cost** of **benefit-based investments**. Part D specifies how **benefit-based charges** are calculated; and

(c) **cap recovery charges**, which are a redistribution of **transmission charges** that would otherwise be payable by **capped customers** who are receiving **cap reductions**; and

(d) **prudent discount recovery charges**, which are a redistribution of **transmission charges** that would otherwise be payable by **prudent discount recipients**; and

(e) **residual charges**, which recover the remainder of **recoverable revenue**. Part E specifies how **residual charges** are calculated.

Interpretation

3 General Definitions

In this **transmission pricing methodology**, unless the context otherwise requires—

2020 guidelines means the guidelines the **Authority** published under paragraph 12.83(b) of this Code on 10 June 2020

AC assets means **grid assets** other than **HVDC assets**

AC switch means a switch that is an **AC asset**

adjustment event means a **connection charge adjustment event**, **benefit-based charge adjustment event** or **residual charge adjustment event**

allocation data means any data, including **metering information**, about a **customer's supply**, **demand**, **injection**, **offtake** or **gross energy** that affects the **customer's** allocation of **transmission charges**

allowance means, for a cost or charge over a period, the building block in forecast MAR under the **Transpower IPP** over the period for the cost or charge

alternative project means—

(a) for an **inefficient bypass prudent discount**, an investment by the **customer** in a **transmission alternative** that, if implemented, would bypass existing **grid assets**; or

(b) for a **stand-alone cost prudent discount**, an investment in the **grid** or a **transmission alternative** by an efficient **transmission services** provider that, if implemented, would provide **transmission services** in substitution for all of the **transmission services** the **customer** currently receives from **interconnection assets**

alternative project costs has the meaning in clause 121

ancillary service BBI means a **post-2019 BBI** that is expected to have a material impact on prices or quantities in the **wholesale market** for a **specified ancillary service** relative to the **post-2019 BBI's counterfactual**. An **ancillary service BBI** may also be a **market BBI** or **reliability BBI**, but cannot be a **resiliency BBI**

ancillary service regional customer group means a **regional customer group** defined in subclause 56(3)

ancillary service regional NPB means **regional NPB** arising from changes in prices or quantities in the **wholesale market** for a **specified ancillary service**. **Ancillary service regional NPB** may be calculated for **ancillary service BBIs**

annual benefit-based charge has the meaning in subclause 36(2)

annual cap recovery charge has the meaning in subclause 116(1)

annual charges means the following **transmission charges** for a **customer** and **pricing year**:
(a) **annual connection charges**:
(b) **annual benefit-based charges**:
(c) **annual cap recovery charge**:
(d) **annual prudent discount recovery charge**:
(e) **annual residual charge**

annual connection charge has the meaning in subclause 25(2) or 25(3)

annual prudent discount recovery charge has the meaning in subclause 141(4)

annual residual charge has the meaning in subclause 71(2)

anticipatory capacity BBI has the meaning in subclause 28(4)~~27A(6)~~

anytime maximum demand (connection) or **AMDC** means, for a **customer**, **connection location** and **pricing year**, the average of the 12 highest **offtake** quantities for the **customer** at the **connection location** during **CMP A** for the **pricing year**, multiplied by 2 to convert to average **demand**

anytime maximum demand (residual) or **AMDR** means the amount calculated under clause 72 for a **load customer** and **pricing year**

anytime maximum injection (connection) or **AMIC** means, for a **customer**~~;~~, **connection location** and **pricing year**, the average of the 12 highest **injection** quantities for the **customer** at the **connection location** during **CMP A** for the **pricing year**, multiplied by 2 to convert to average **supply**

Commented [A2]: Typo

Appendix A BBI means the following **interconnection investments**:

Bunnythorpe Haywards	the **interconnection investment** approved by the **Commission** on 9 May 2014 as the Bunnythorpe-Haywards A and B Lines Conductor Replacement Project, including all amendments to that approved project subsequently approved by the **Commission**
HVDC	all **interconnection investments** in the **HVDC link commissioned** on or before 23 July 2019

LSI Reliability	the **interconnection investment** approved by the Electricity Commission on 9 August 2010 as the Lower South Island Reliability Transmission Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**
LSI Renewables	the **interconnection investment** approved by the Electricity Commission on 6 September 2010 as the Lower South Island Renewables Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**, but excluding the **post-2019 CUWLP investment**
NIGU	the **interconnection investment** approved by the Electricity Commission on 5 July 2007 as the North Island Grid Upgrade, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**
UNIDRS	the **interconnection investment** approved by the Electricity Commission on 5 July 2010 as the Upper North Island Dynamic Reactive Support Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**.
Wairakei Ring	the **interconnection investment** approved by the Electricity Commission on 20 February 2009 as the Wairakei Ring Investment, including all amendments to that approved project subsequently approved by the Electricity Commission or **Commission**

application means an application to **Transpower** under this **transmission pricing methodology**, including an application for a **prudent discount** or **reassignment**

application fee means a fee for a type of **application published** by **Transpower**

application requirements means, for an **application**, the content requirements for the **application published** by **Transpower**

assumptions book means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower**—
(a) intends to apply for allocating and adjusting **benefit-based charges**; and
(b) does not expect to vary between **BBIs** except according to the method (**standard method**, **simple method** or Appendix A) used to calculate their **BBI customer allocations**

avoided transmission charges means—
(a) for an **inefficient bypass prudent discount**, the **transmission charges** the relevant **customer** would avoid paying if the relevant **alternative project** were implemented—
  (i) assessed relative to the **transmission charges** the **customer** would pay if the **alternative project** were not implemented; and
  (ii) assuming none of the **alternative project costs** for the **alternative project** would be recovered through **transmission charges**; and
(b) for a **stand-alone cost prudent discount**, the relevant **customer's**—

(i) **benefit-based charges** for all **BBIs** of which the **customer** is a **beneficiary**; and
(ii) **residual charge**

battery storage means equipment functioning together as a single entity that is able to both—
(a) take **electricity** and store the energy in another form; and
(b) inject that energy as **electricity** into the **grid**, a **local network**, a **non-grid network** or **consuming plant**

BBI customer allocation means a **customer's** allocation of the **benefit-based charge** for a **BBI**—
(a) specified in **Appendix A** and as adjusted under clauses 84, 86 to 93 and 95, if the **BBI** is an **Appendix A BBI**; or
(b) calculated under subclause 45(1), if the **BBI** is a **post-2019 BBI**

BBI prudent discount recovery charge means a charge calculated under subclause 141(1) for a **prudent discount**, **customer** and **pricing year**

BBI reassignment factor has the meaning in subclause 107(4)

beneficiary means, for a **BBI**, a **customer** who has a positive **BBI customer allocation** for the **BBI**

benefit factor has the meaning in clause 4

benefit-based charge means a charge described in subclause 2(b) and calculated under clause 36 for a **BBI**, **beneficiary** and **pricing year**

benefit-based charge adjustment event has the meaning in subclause 84(1)

benefit-based investment or **BBI** means—
(a) an **Appendix A BBI**; or
(b) a **post-2019 BBI**

benefitting customer means, for an **application** for an **inefficient bypass prudent discount**, any **customer** named in the **application** whose **transmission charges** would be reduced if the **alternative project** for the **application** were implemented

cap condition means the condition specified in subclause 114(2)

cap recovery charge means a charge described in subclause 2(c) and calculated under clause 116 for a **customer** and **pricing year**

cap recovery-relevant charges means, for a **customer** and **pricing year**, the **customer's**—
(a) **annual benefit-based charges** for the **Appendix A BBIs** and **pricing year**; and
(b) **annual residual charge** for the **pricing year**

cap reduction means the total reduction in a **capped customer's transmission charges** for a **pricing year** under subclause 114(1)

capacity means the rated capacity of an asset to (as the case may be)—
(a) consume or generate **electricity**; or
(b) take **electricity** from or inject **electricity** into a **network**; or
(c) transmit or **distribute electricity**,
in each case measured in units appropriate for the context

capacity measurement period or **CMP** means a period over which a calculation under this **transmission pricing methodology** is made, being either:

CMP A for **pricing year** n, **capacity year** n-2. **CMP A** is relevant to calculating **connection charges**

CMP B for a **BBI**, the period ending on the last **trading period** of the most recent complete **capacity year** before the **final investment decision date** for the **BBI** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4. **CMP B** is relevant to calculating **benefit-based charges** for **BBIs** under a **standard method**

CMP C for ~~the first~~a **simple method period**, the period ending on the last **trading period** of the second most recent complete **capacity year** before the ~~start of the~~ first **pricing year** of the **simple method period** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4. **CMP C** is relevant to calculating **benefit-based charges** for **BBIs** under the **simple method**

~~for a subsequent **simple method period**, the period ending on the last **trading period** of the most recent complete **capacity year** before the first **pricing year** of the **simple method period** (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4~~

~~**CMP C** is relevant to calculating **benefit-based charges** for **BBIs** under the **simple method**~~

CMP D the period from the first **trading period** of **financial year** 2014 to the last **trading period** of **financial year** 2017. **CMP D** is relevant to calculating **benefit factors** and **residual charges**

CMP E for **pricing year** n, the period from the first **trading period** of **financial year** n-8 to the last **trading period** of **financial year** n-5. **CMP E** is relevant to calculating **residual charges**

CMP F for a **SSCGU**, the period ending on the last **trading period** of the most recent complete **capacity year** before the **SSCGU** occurred (**capacity year** n) and starting on the first **trading period** of **capacity year** n-4. **CMP F** is relevant to adjusting **benefit based charges** for **high-value BBIs**

CMP G the period from the first **trading period** of **pricing year** 2015 to the last **trading period** of **pricing year** 2019. **CMP G** is relevant to calculating **difference caps**

capacity year means a period of 12 months starting on 1 September and ending on 31 August. **Capacity year** n means the **capacity year** starting in year n

capital charge means **Transpower's** return on its investment in a **grid asset**

capped charges means, for a **capped customer** and **pricing year**, the **capped customer's**:
(a) **annual benefit-based charges** for the **Appendix A BBIs** and **pricing year**; and
(b) **annual residual charge** for the **pricing year**; and
(c) **annual cap recovery charge** for the **pricing year**

capped customer means—

Commented [A3]: Change: We consider all CMP Cs should end with the second most recent capacity year to ensure we have enough time to complete the calculations, consultation and audit for the next simple method period.

Commented [A4]: Clarification

(a) for the **first pricing year**, a **customer**, other than in its capacity as a **generator**, who was a **customer** during **pricing year** 2019 and at least 2 **pricing years** preceding **pricing year** 2019; and
(b) for each subsequent **pricing year**, any such **customer** who had a **cap reduction** for the previous **pricing year**

Commented [A5]: Typo

closing RAB value has the meaning in the **Transpower IMs**

coincident peak offtake has the meaning in subclause 68(8)

Commission means the Commerce Commission established by section 8 of the Commerce Act 1986

commissioned has the meaning in clause 6

commissioning date means the date a **grid asset**, **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned**

compliance investment means an investment by **Transpower** in a **grid asset** or **transmission alternative** to ensure the **grid asset** or **transmission alternative** is maintained, and can be operated, in accordance with **good electricity industry practice**. A **compliance investment** may also be an **enhancement investment**, **refurbishment investment** or **replacement investment**

connection asset has the meaning in subclause 22(1), and includes "deep" **connection assets** as described in paragraph 23(5)(b)

connection charge means a charge described in subclause 2(a) and calculated under clause 25 for a **customer** and **pricing year** and—
(a) a **connection asset** and **connection location**; or
(b) a **connection transmission investment**

connection charge adjustment event has the meaning in clause 79

connection customer allocation means a **customer's** allocation of the **connection charge** for a **connection asset** and **connection location** calculated under clause 33

connection investment means a **grid investment** or group of related **grid investments** exclusively in, or in relation to, 1 or more **connection assets**

connection link has the meaning in paragraph 21(1)(e)

connection node has the meaning in paragraph 21(1)(d)

connection region means a region determined by **Transpower** under subclause 65(4)

connection transmission alternative means a **transmission alternative** to the extent it is an alternative to an investment in a **connection asset**, as determined by **Transpower**

consuming plant means—
(a) equipment that consumes **electricity**, regardless of size, including electrical appliances as defined in the Electricity Act 1992; and
(b) **battery storage** when charging

continuing BBI has the meaning in subclause 87(5) or 88(4)

contributing customer means, for a **funded asset**—
(a) a **customer** who funded, or is funding, all or part of the capital cost of the **funded asset** under an **investment agreement**; or
(b) a **customer** who funded, or is funding, all or part of the capital cost of the **funded asset** through **connection charges**

counterfactual means, for a **BBI**, the expected future **grid** state assuming the **BBI** is not **commissioned**

covered cost means the amount of **recoverable revenue** allocated to a **BBI** for a **pricing year** calculated under subclause 40(1)

CPI means the consumers price index (all groups) published by Stats NZ

curtailed energy means **unserved energy** or **unsupplied energy**

customer means a **designated transmission customer**

demand adjustment factor means a factor by which **individual NPB** under the **simple method** for **offtake customers** is scaled relative to **individual NPB** under the **simple method** for **injection customers**, having an initial value of 1 and as may be adjusted under subclause 67(3)

depreciation means depreciation of a **grid asset** calculated in accordance with the **Transpower IMs**

de-rate means, for an asset or **plant**, to alter the asset or **plant** physically so that the asset's or **plant's capacity** is permanently reduced

difference cap has the meaning in clause 115(1)

direct supplied load customer means, for a **connection location** and **trading period**, a **connected asset owner** who—
(a) owns or controls a **local network** or **consuming plant** connected to the **grid** at the **connection location**; and
(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 5(1)(b) during the **trading period**

discounted BBI means—
(a) for an **inefficient bypass prudent discount**, a **BBI** that would be bypassed by the relevant **alternative project**; or
(b) for a **stand-alone cost prudent discount**, a **BBI** of which the **prudent discount recipient** is a **beneficiary**

economic life means, for an asset ~~**grid asset**~~, the asset's ~~**grid asset's**~~ physical asset life as defined in the **Transpower IMs**

Commented [A6]: Clarification: Consequential on the addition of the definition of "write-down" and also consistent with the definition of "physical asset life" in the Transpower IMs, which is not limited to grid assets.

EDB ID determination means the *Electricity Distribution Information Disclosure Determination 2012* [2012] NZCC 22

EDB IMs means the *Electricity Distribution Services Input Methodologies Determination 2012* [2012] NZCC 26

efficient stand-alone investment has the meaning in clause 138

eligible BBI means a **BBI**, including a **BBI** that is currently **reassigned** or was previously **reassigned**, for which both of the following conditions are satisfied (as applicable):
(a) the total **closing RAB value** of all **grid assets** comprised in the **BBI** for the most recent complete **financial year**, adjusted by the **reassignment factor** for any current **reassignment** the **BBI** is subject to, is at least the **reassignment threshold**:
(b) if the **BBI** is a **post-2019 BBI**, either—
  (i) at least 10 years have passed since the **BBI's commissioning date**; or
  (ii) since the **BBI's commissioning date**—
    (A) a **customer** permanently disconnected from the **grid** at a **connection location** at which the **customer** was a **beneficiary** of the **BBI** when it disconnected; and

(B) that disconnection, by itself and without taking into account other events, caused the **BBI's BBI reassignment factor** to decrease by at least 0.2; or

(iii) since the **BBI's commissioning date**—

(A) a **customer** who is a **beneficiary** of the **BBI** permanently disconnected **plant** from the **grid**; and

(B) that disconnection, by itself and without taking into account other events, caused the **BBI's BBI reassignment factor** to decrease by at least 0.2

eligible person means, for an **application** for r**eassignment** or a proposal to reverse a **reassignment**—

(a) a **beneficiary** of the **BBI** to which the **application** or proposal relates; or

(b) a person who owns or controls **embedded plant** connected to the **local network** or **grid**-connected **plant** of a **beneficiary** of the **BBI**

embedded means, for **plant**, that the **plant** is~~—~~ connected to a **local network** or to **grid**-connected **plant**. If the **plant** is also connected to the **grid**, **Transpower** may treat the **plant** as part **embedded** and part **grid**-connected

~~(a) connected to a **local network** or to **grid**-connected **plant**; and~~

~~(b) not connected to the **grid**~~

embedded electricity has the meaning in paragraph 5(1)(b), 5(1)(c) or 5(1)(d) for a **customer** and **trading period**

enhancement investment means an investment by **Transpower** in an existing **grid asset** or **transmission alternative** that is not a **refurbishment investment** or **replacement investment**. An **enhancement investment** may also be a **compliance investment**

event pricing year means the **pricing year** during which an **adjustment event** occurs

exempt post-2019 investment means an **interconnection investment**, other than the **post-2019 CUWLP investment**, that is—

(a) **commissioned** after 23 July 2019 and before the start of **financial year** 2021; and

(b) a **refurbishment investment**, **replacement investment** or **enhancement investment** in respect of an **Appendix A BBI** or another **interconnection investment commissioned** on or before 23 July 2019,

exempt pricing year means, for an **adjustment event** and **customer**—

(a) the **event pricing year**; and

(b) the **pricing year** after the **event pricing year** if the **adjustment event** occurred less~~more recently~~ than one month before the deadline for **Transpower** notifying the **customer** of its **transmission charges** for the **pricing year** under the relevant **transmission agreement**

factual means, for a **BBI**, the expected future **grid** state assuming the **BBI** is **fully commissioned**

final investment decision date means, for a **BBI**, the date **Transpower** makes its final decision to proceed with its investment in the **BBI**

financial year means a period of 12 months starting on 1 July and ending on 30 June. **Financial year** n means the **financial year** starting in year n

first pricing year means the first **pricing year** to which this **transmission pricing methodology** applies

forecast loading period has the meaning in subclause 107(1)

forecast peak loading has the meaning in subclause 107(2)

Commented [A7]: Change: There are, and may in future be, some plant configurations that involve connection to the grid on one side and connection to a local network or other grid-connected plant on the other. In this case we will need to treat the plant as partly grid-connected and partly embedded to produce accurate residual charge allocations.

Commented [A8]: Change: See section 4.2 of our submission.

Commented [A9]: Style

fully commissioned has the meaning in clause 6

funded asset means a **connection asset**—
(a) **commissioned** after the start of the **first pricing year**; and
(b) all or part of the capital cost of which was funded, or is being funded, by a **customer** under an **investment agreement**

future regional customer group means a **regional customer group**—
(a) that is expected to have no members when the relevant **post-2019 BBI** is **commissioned**; and
(b) the future members of which (if any) will be new **customers** and **customers** who connect new **plant** to the **grid**

GAAP means generally accepted accounting practice in New Zealand

GEIP (standing for good electricity industry practice) means, for an **alternative project**, the exercise of that degree of skill, diligence, prudence, foresight and economic management that would reasonably be expected from a skilled and experienced asset owner engaged in the management of the **alternative project**, under conditions comparable to those applicable to the **alternative project**, consistent with applicable law, safety and environmental protection

generating plant has the meaning in Part 1 of this Code and includes **battery storage** when discharging

grid assets has the meaning in subclause 18(1), subject to clause 42

grid investment means an investment by **Transpower** in the **grid** or a **transmission alternative**, including such an investment for which another person contributes to the capital, maintenance, operating or other cost under an **investment agreement**

grid point of connection means a **point of connection** to the **grid**

gross energy has the meaning in subclause 5(4)

GXP tie means a situation in which a **connected asset owner's assets** are simultaneously connected to the **grid** at more than 1 **point of connection**

high-value means, for a **BBI**, that the depreciated value of the **BBI** at the relevant time is more than the base capex threshold as defined in the **Transpower Capex IM**

high-value intervening BBI means a **post-2019 BBI**—
(c) with a **final investment decision date** before the start of the **first pricing year**; and
(d) **commissioned** on or before the last day of the **financial year** that precedes the **pricing year** after the **first pricing year**; and
(e) expected to be **high-value** when **fully commissioned**

high-voltage grid means the part of the **grid** with a nominal voltage of 220 kV or more

HILP event means a low probability event or group of events that, if it or they occurred, would have a high impact on **unserved energy** other than by way of cascade failure, as determined by **Transpower**

host customer means, for **embedded plant**, the **customer** who owns or controls the **local network** or **grid**-connected **plant** the **embedded plant** is connected to

HVDC asset means a **grid asset** that is part of the **HVDC link**

HVDC opex means—
(a) **availability costs** allocated to the **HVDC owner**; and
(b) insurance premiums for the **HVDC link**

Commented [A10]: Change: See comment on clause 42.

Commented [A11]: Clarification

ID WACC means, for **Transpower** or a **distributor**, the pre-tax weighted average cost of capital determined by the **Commission** under the **Transpower IMs** or **EDB IMs** for the purposes of **Transpower's** or the **distributor's** information disclosure regulation under Part 4 of the Commerce Act 1986

independent expert means an independent person who is a recognised technical expert in the matter that has been referred to him or her. In appointing an **independent expert**, the party referring the matter to the **independent expert** must nominate 3 persons and the other party may agree that any 1 of them be appointed. Failing agreement between the parties, the **independent expert** will be appointed by the **Authority**

independent verification means, for an **application**, a written report on the accuracy and sufficiency of the information and analysis contained in the **application** prepared by 1 or more persons who are—
(a) recognised technical experts on the subject matter of the **application**; and
(b) approved by **Transpower**

indirect supplied load customer means, for a **connection location** and **trading period**, an **asset owner** who—
(a) owns or controls a **local network**, **consuming plant** or **generating plant** connected to the **grid** at the **connection location**; and
(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 5(1)(c) during the **trading period**

individual NPB means **NPB** for a **customer** calculated under clause 50 or 60 or subclause 64(1)

inefficient bypass prudent discount means a discount of a **customer's transmission charges** provided under this **transmission pricing methodology** for the purpose in clause 130

injection means—
(a) for a **customer's grid point of connection**, the positive net quantity of **electricity** flow into the **grid** at the **grid point of injection** from the **customer's assets** during a **trading period** (if any); and
(b) for a **connection location**, the sum of the quantities calculated under paragraph (a) for all of the **customer's points of connection** to the **grid** at the **connection location** during a **trading period**

injection customer means, for a **connection location** and **trading period**, a **customer** who owns or controls **assets**—
(a) connected at the **connection location**; and
(b) from which **electricity** flowed into the **grid** during the **trading period**

interconnection asset has the meaning in subclause 22(2)

interconnection investment means a **grid investment** or group of related **grid investments** exclusively in, or in relation to, 1 or more **interconnection assets**

interconnection link has the meaning in paragraph 21(1)(f)

interconnection node has the meaning in paragraph 21(1)(a)

interconnection transmission alternative means a **transmission alternative** to the extent it is not a **connection transmission alternative**

intra-regional allocator has the meaning in subclause 68(1), 68(2), 68(3) or 68(4) for the relevant **regional customer group**

investment agreement means—

(a) a contract entered into at any time between **Transpower** and another person (who may or may not be a **customer**) under which—
  - (i) **Transpower** agrees to provide any new, **upgraded** or modified **grid** ~~**assets**~~**investment**; or
  - (ii) the other person agrees to make a contribution to the capital, maintenance, operating or other cost of a **grid** ~~**asset**~~**investment**,

including—
  - (iii) a **new investment agreement contract**; and
  - (iv) a contract to move or remove **grid assets**; or

(b) an agreement deemed to be an **investment agreement** under paragraph 29(5)(b)

Commented [A12]: Change: An investment agreement may involve a contribution to the costs of a transmission alternative, not just a grid asset.

investment agreement asset means a **grid asset** provided under an **investment agreement**

investment grid means a simplified model of the **grid** for a **market BBI's factual** or **counterfactual** that models—
(a) all existing **branches** and **market nodes**, as those **branches** and **market nodes** may be added to or removed in the **market BBI's factual** or **counterfactual** (as the case may be); and
(b) the **constraints** of the **HVDC link**, as those **constraints** would be in the **market BBI's factual** or **counterfactual** (as the case may be); and
(c) the **market BBI's modelled constraints**, as those **constraints** would be in the **market BBI's factual** or **counterfactual** (as the case may be)

investment reassignment factor has the meaning in subclause 107(3)

investment region means a **modelled region** under the **simple method** where a **BBI** or part of a **BBI** is located

investment test means the investment test applied to a **tested investment** under section III of Part F of the **rules** or the **Transpower Capex IM**

Commented [A13]: Change: See comment on definition of "tested investment".

land and buildings has the meaning in subclause 18(3)

large means, subject to clause 8—
(a) for **plant**, that the **plant**—
  - (i) is connected to the **grid**; or
  - (ii) has **capacity** of at least 10 **MW**; and

(b) for an **upgrade** of **plant**, that the **plant's capacity** has increased by at least 10 **MW** compared to the **plant's capacity** before the **upgrade**; and
(c) for a **de-rating** of **plant**, that the **plant's capacity** has reduced by at least 10 **MW** compared to the **plant's capacity** before the **de-rating**

link has the meaning in subclause 20(3)

load customer means a **customer** who, at a **connection location** during a **trading period**, is or was (as the context requires) 1 or more of the following:
(a) an **offtake customer**:
(b) a **direct supplied load customer**:
(c) an **indirect supplied load customer**:
(d) a **supplying load customer**

loop has the meaning in paragraph 21(1)(b)

low-value means, for a **BBI**, that the depreciated value of the **BBI** at the relevant time is not more than the base capex threshold as defined in the **Transpower Capex IM**

low-voltage grid means the part of the **grid** with a nominal voltage of less than 220 kV

market BBI means a **post-2019 BBI** that is expected to have a material impact on prices or quantities in the **wholesale market** for **electricity** relative to the **post-2019 BBI's**

counterfactual. A **market BBI** may also be an **ancillary service BBI** or a **reliability BBI**, but cannot be a **resiliency BBI**

market node means a **GXP** or **GIP**

market regional NPB means **regional NPB** arising from changes in prices or quantities in the **wholesale market** for **electricity**. **Market regional NPB** is calculated for **market BBIs**

market scenario means, for a **BBI**, a future state for factors that influence **NPB** for the **BBI**

material damage means destruction of, or substantial damage to, a **BBI**, as determined by **Transpower**

maximum gross demand has the meaning in subclause 5(5)

maximum revenue means, for a **pricing year**, the maximum revenue **Transpower** is permitted to recover for the **pricing year**, as determined by the **Commission** under Part 4 of the Commerce Act 1986. At the date of this **transmission pricing methodology**, this is the most recently updated forecast SMAR for the **pricing year** under the **Transpower IPP**

MCP opex means operating costs of the type described in clause 3.1.3(1)(d) of the **Transpower IMs**, being operating costs relating to major capex projects

mixed connection asset means a **connection asset** that, as well as connecting a **customer**, is used for **grid** operation generally

modelled constraint means, for a **market BBI**—
(a) a **constraint** affecting a new **grid asset** comprised in the **market BBI**; or
(b) a **constraint** that would be alleviated materially if the **market BBI** were **fully commissioned**, as determined by **Transpower**

modelled region means a region defined in, or determined by **Transpower** under—
(a) for a **BBI** under the **price-quantity method**, subclause 53(1), 54(3), 55(4) or 56(3) depending on the type of **regional NPB** being calculated; and
(b) for a **BBI** under the **resiliency method**, clause 61; and
(c) for a **BBI** under the **simple method**, subclause 65(1)

monthly benefit-based charge has the meaning in subclause 36(3)

monthly cap recovery charge has the meaning in subclause 116(2)

monthly charges means the following **transmission charges** for a **customer** and **pricing year**:
(a) **monthly connection charges**:
(b) **monthly benefit-based charges**:
(c) **monthly cap recovery charge**:
(d) **monthly prudent discount recovery charge**:
(e) **monthly residual charge**

monthly connection charge has the meaning in subclause 25(4)

monthly prudent discount recovery charge has the meaning in subclause 141(5)

monthly residual charge has the meaning in subclause 71(3)

net private benefit or **NPB** (which may be negative, zero or positive)**—**
(a) means, for a **regional customer group** or **customer**, the sum of the quantified benefits (positive values) and disbenefits (negative values) the **regional customer group** or **customer** is expected to receive from the relevant **BBI**; and
(b) for a **host customer**, includes the sum of the quantified benefits (positive values) and disbenefits (negative values) the **embedded plant** owners connected to the

host customer's local network or **grid**-connected **plant** are expected to receive from the relevant **BBI**

node has the meaning in subclause 20(1)

nominated peak kVar means, for a **connected asset owner**, **zone** and **pricing year**, the quantity $\sum_j Q_{xjz}$ in subclause 8.67(2) of this Code calculated using the **connected asset owner's** nomination for the **zone** applying from the most recent 1 March before the start of the **pricing year**

non-contributing customer means, for a **funded asset**, a **customer** who—
(a) is connected by the **funded asset** at a **connection location**; and
(b) was not a **contributing customer** for the **funded asset** before connecting to it

non-grid network means a system of **lines**, substations and other **works**, used primarily for the conveyance of **electricity**, that is not part of the **grid** or connected to the **grid**, including an **embedded network**

notional IRA value has the meaning in clause 70

offtake means—
(a) for a **customer's grid point of connection**, the positive net quantity of **electricity** flow out of the **grid** at the **grid point of connection** into the **customer's assets** during a **trading period** (if any); and
(b) for a **connection location**, the sum of the quantities calculated under paragraph (a) for all of the **customer's points of connection** to the **grid** at the **connection location** during a **trading period**

offtake customer means, for a **connection location** and **trading period**, a **customer** who owns or controls **assets**—
(a) connected at the **connection location**; and
(b) into which **electricity** flowed from the **grid** during the **trading period**

opening RAB value has the meaning in the **Transpower IMs**

optimised replacement cost means, for any **grid asset** or group of **grid assets**, the optimised replacement cost of the **grid asset** or group of **grid assets** as at 1 July 2006, as determined by **Transpower**

other regional NPB means **regional NPB** that is not **market regional NPB**, **ancillary service regional NPB** or **reliability regional NPB**. **Other regional NPB** may be calculated for **market BBIs**, **ancillary service BBIs** or **reliability BBIs**

outage scenario means, for a **reliability BBI**, an **outage** or other event or group of events affecting access to **transmission services** in respect of which the **reliability BBI** is expected to have a material impact on **curtailed energy**

peak BBI means a **post-2019 BBI** for which the investment need is primarily attributable to meeting peak **demand**

peak offtake period has the meaning in paragraph 68(8)(b)

peak offtake trading period has the meaning in paragraph 68(8)(a)

plant means **consuming plant** or **generating plant**

post-2019 BBI means an **interconnection investment commissioned** after 23 July 2019 other than an **exempt post-2019 investment**, including the **post-2019 CUWLP investment**. To avoid doubt—
(a) an **interconnection investment** that is an **Appendix A BBI** is not a **post-2019 BBI**; and

Commented [A14]: Change: See section 4.2 of our submission.

(b) an **interconnection investment** carried out or approved as a single project may comprise more than 1 **post-2019 BBI**; and
(c) a **post-2019 BBI** may comprise more than 1 **interconnection investment**, each of which is carried out or approved as a single project

post-2019 CUWLP investment means the **interconnection investment** comprising the following **grid investments** approved by the Electricity Commission on 6 September 2010 as part of the Lower South Island Renewables Investment:
(a) thermal upgrade of the circuits between Cromwell and Twizel:
(b) re-conductoring of the circuits between Roxburgh and Livingstone

PQ WACC means, for **Transpower** or a price-quality regulated **distributor**, the vanilla or pre-tax (as the context requires) weighted average cost of capital determined by the **Commission** under the **Transpower IMs** or **EDB IMs** for the purposes of **Transpower's** or the **distributor's** price-quality regulation under Part 4 of the Commerce Act 1986

pre-existing customer means a **customer** who has been a member of a **regional customer group** for (as the case may be)—
(a) at least 2 full **pricing years** during **CMP B** for the relevant **BBI**; or
(b) at least 2 full **financial years** during **CMP C** for the relevant **simple method period**

pre-existing load customer means a **load customer** who was a **customer** for the whole of **CMP D**

previous transmission pricing methodology means, as applicable, the transmission pricing methodology comprised in this Code when it came into force, as subsequently amended up to the date this **transmission pricing methodology** came into force

price-quantity method means the method for calculating **NPB** for a **post-2019 BBI** specified in clauses 46 to 58

pricing year has the meaning given to that term in the **Transpower IMs**. At the date of this **transmission pricing methodology**, a **pricing year** is a period of 12 months starting on 1 April and ending on 31 March. **Pricing year** n means the **pricing year** starting in year n

prior contributing customer means, for a **funded asset** and in respect of a **non-contributing customer** for the **funded asset**, a **contributing customer** who was connected to the **funded asset** before the **non-contributing customer** became connected to the **funded asset**

prudent discount means an **inefficient bypass prudent discount** or **stand-alone cost prudent discount**

prudent discount calculation period means, for a **prudent discount**, the period—
(a) starting at the start of the **prudent discount's start pricing year**, or estimated **start pricing year** assuming the **prudent discount** is approved; and
(b) ending—
  (i) for an **inefficient bypass prudent discount**, at the end of the remaining **economic life** of the **grid assets** the relevant **alternative project** would bypass, up to a maximum of 15 years after the start of the **prudent discount calculation period**; or
  (ii) for a **stand-alone cost prudent discount**, 15 years after the start of the **prudent discount calculation period**

prudent discount confirmation date means, for a **prudent discount** decision, the date the following conditions are satisfied:
(a) either—

(i) the relevant **customer** has confirmed to **Transpower** in writing that it does not intend to refer any aspect of **Transpower's** decision to an **independent expert**; or

(ii) the **customer** did not refer any aspect of **Transpower's** decision to an **independent expert** before time to do so expired under subclause 124(3); or

(iii) an **independent expert** has made final binding decisions on all aspects of **Transpower's** decision referred to the **independent expert**:

(b) for an approved **prudent discount**, **Transpower** and the **customer** have entered into a **prudent discount** agreement for the **prudent discount**

prudent discount practice manual means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower**—

(a) intends to apply for assessing **applications** for **prudent discounts**; and

(b) does not expect to vary between **prudent discount applications** except according to whether the **application** is for an **inefficient bypass prudent discount** or **stand-alone cost prudent discount**

prudent discount rate means—

(a) subject to paragraph 131(c), for an **inefficient bypass prudent discount**—

(i) if the applicant **customer** is a **distributor**, the **distributor's ID WACC** at the time of the **application** for the **prudent discount**; or

(ii) if the applicant **customer** is not a **distributor** but is subject to another regulated pre-tax weighted average cost of capital, that pre-tax weighted average cost of capital; or

(iii) otherwise, a pre-tax weighted average cost of capital for the applicant **customer** determined by **Transpower** by applying the methodology for estimating **ID WACC** for **distributors** in the **EDB IMs**; or

(b) for a **stand-alone cost prudent discount**, **Transpower's ID WACC** at the time of the **application** for the **prudent discount**

prudent discount recipient means a **customer** receiving a **prudent discount**

prudent discount recovery charge means a charge described in subclause 2(d), being a **BBI prudent discount recovery charge** or **residual prudent discount recovery charge**

reassignment means a reassignment of all or part of the **covered cost** of a **BBI** to **residual revenue**, and **reassigned** has a corresponding meaning

reassignment amount has the meaning in clause 102

reassignment confirmation date means, for a **reassignment** decision, the date 1 of the following conditions is satisfied:

(a) the relevant **eligible person** has confirmed to **Transpower** in writing that it does not intend to refer any aspect of **Transpower's** decision to an **independent expert**:

(b) the **eligible person** did not refer any aspect of **Transpower's** decision to an **independent expert** before time to do so expired under subclause 109(3) or paragraph 112(2)(c):

(c) an **independent expert** has made final binding decisions on all aspects of **Transpower's** decision referred to the **independent expert**

reassignment practice manual means a document **published** by **Transpower** containing assumptions and detailed methodologies that **Transpower**—

(a) intends to apply for assessing **applications** for **reassignment**; and

(b) does not expect to vary between **reassignment applications**

reassignment threshold has the meaning in subclause 103(2)

recent customer means a **customer** who has been a member of a **regional customer group** for (as the case may be)—
(a) less than 2 full **pricing years** during **CMP B** for the relevant **BBI**; or
(b) less than 2 full **financial years** during **CMP C** for the relevant **simple method period**

recent load customer means a **load customer** who is not a **pre-existing load customer**

recoverable revenue means, for a **pricing year**—
(a) **maximum revenue** for the **pricing year**; less
(b) any part of **maximum revenue** for the **pricing year Transpower** is able or required to recover other than through **transmission charges**, including by way of annuities paid by **prudent discount recipients**

reduction event means, for a **pre-existing load customer**, a ~~sustained~~ reduction in the **pre-existing load customer's** expected **maximum gross demand** compared to the **pre-existing load customer's AMDR** baseline calculated under clause 73(1)—
(a) of at least 10 **MW**; and
(b) due to an event or series of directly related events that—
(i) occurred, or **Transpower** determines will occur, after the start of **CMP D** and before the start of the **first pricing year**; and
(ii) **Transpower** determines was, were or will be beyond the **pre-existing load customer's** reasonable control, not being—
(A) a change in the basis for calculating future transmission charges; or
(B) a change in the market for the **pre-existing load customer's** products or services, other than the services the **pre-existing load customer** supplies to an **embedded plant** owner connected to the **pre-existing load customer's local network** or **grid**-connected **plant** who is not a **related entity** of the **pre-existing load customer**; or
(C) any of the events specified in paragraph (d) of the definition of **force majeure event** in clause 1.1(1) of this Code occurring in respect of the **pre-existing load customer** or a **related entity** of the **pre-existing load customer**; or
(D) 1 or more events that could have been prevented by the **customer** by the exercise of a reasonable standard of care; and
(c) that **Transpower** reasonably expects to persist for at least 5 years after the event or series of directly related events occurred or will occur

refurbishment investment means a **grid investment** that—
(a) is asset refurbishment as defined in the **Transpower Capex IM**; or
(b) would be asset refurbishment as defined in the **Transpower Capex IM** if an investment in a **transmission alternative** were an investment in the **grid**.
A **refurbishment investment** may also be a **compliance investment**

regional customer group means a **regional demand group** or **regional supply group**

regional demand group means a group of **customers** in a **modelled region** defined in, or determined by **Transpower** under—
(a) for a **BBI** under the **price-quantity method**, subclause 53(2), 56(3), 55(4) or 58(3) depending on the type of **regional NPB** being calculated; and
(b) for a **BBI** under the **resiliency method**, clause 61; and
(c) for a **BBI** under the **simple method**, clause 66

Commented [A15]: **Clarification:** Rather than defining "sustained" in general terms in former clause 8, we consider it is clearer to specify the relevant time period individually for each instance.

Commented [A16]: **Clarification**

regional NPB means **NPB** for a **regional customer group** calculated in accordance with, or assumed under, a **standard method** or the **simple method**

Commented [A17]: Typo

regional supply group means a group of **customers** in a **modelled region** defined in, or determined by **Transpower** under —
(d) for a **BBI** under the **price-quantity method**, subclause 53(2), 54(3), 55(4) or 56(3) depending on the type of **regional NPB** being calculated; and
(e) for a **BBI** under the **simple method**, clause 66

regulatory asset base or **RAB** means **Transpower's** record of **commissioned grid assets** and their values used to calculate **maximum revenue** under the **Transpower IMs**

regulatory control period or **RCP** means a regulatory period as defined in the **Transpower IPP**

related entity of a person means another person that controls, is controlled by, or is under common control with the first person, including a person that—
(a) is a related company of the first person as defined in section 2(3) of the Companies Act 1993; or
(b) would be a related company of the first person under that section if both the first person and the other person were companies registered under that Act

reliability BBI means a **post-2019 BBI** that is expected to reduce materially **curtailed energy** relative to the **post-2019 BBI's counterfactual** if there is an **outage** or other event or group of events affecting access to **transmission services**. A **reliability BBI** may also be a **market BBI** or **ancillary service BBI**, but cannot be a **resiliency BBI**

reliability regional NPB means **regional NPB** arising from changes in **curtailed energy**. **Reliability regional NPB** is calculated for **reliability BBIs**

replacement cost means, for a **grid asset** and subject to subclause 35(5), the cost of replacing the **grid asset**, either separately or as part of a group of **grid assets**, with a modern equivalent **grid asset** with the same service potential

replacement cost adjustment factor means, for a **grid asset** or group of **grid assets**, the **optimised replacement cost** for the **grid asset** or group of **grid assets** divided by the cost, as at (or about) 1 July 2006, of replacing the **grid asset** or group of **grid assets** with the then modern equivalent **grid asset** with the same service potential, as determined by **Transpower**

replacement investment means a **grid investment** that—
(a) is asset replacement as defined in the **Transpower Capex IM**; or
(b) would be asset replacement as defined in the **Transpower Capex IM** if an investment in a **transmission alternative** were an investment in the **grid**.
A **replacement investment** may also be a **compliance investment**

residual charge means a charge described in subclause 2(e) and calculated under clause 71 for a **load customer** and **pricing year**

residual charge adjustment event has the meaning in subclause 96(1)

residual charge adjustment factor or **RCAF** means the factor calculated under clause 74 for a **load customer** and **pricing year**

residual prudent discount recovery charge means a charge calculated under subclause 141(2), for a **prudent discount**, **customer** and **pricing year**

residual revenue means, for a **pricing year**, **recoverable revenue** for the **pricing year** less all **transmission charges** for the **pricing year** other than **residual charges**. The minimum value of **residual revenue** for a **pricing year** is 0

resiliency BBI means a **post-2019 BBI** for which the investment need is primarily attributable to mitigating a risk of cascade failure or a **HILP event**. A **resiliency BBI** cannot also be a **market BBI**, **ancillary service BBI** or **reliability BBI**

resiliency method means the method for calculating **NPB** for a **resiliency BBI** specified in clauses 59 to 61

reverse flow means **electricity** exiting the **grid** at a **GXP** and entering the **grid** at another **GXP** as a result of a **GXP tie**

scenario means a **market scenario** or **outage scenario**

Schedule 1 allocations means, for an **Appendix A BBI**, the allocations for the **Appendix A BBI** specified in Schedule 1 of the **2020 guidelines**

Schedule 1 beneficiary means, for an **Appendix A BBI**, a person specified in Schedule 1 of the **2020 guidelines** who has a positive **Schedule 1 allocation** for the **Appendix A BBI**

simple method means the method for calculating **NPB** for a **low-value post-2019 BBI** specified in clauses 62 to 67

simple method contribution has the meaning in clause 67(6)

simple method factor has the meaning in subclause 64(2)

simple method period has the meaning in clause 63

small regional loop has the meaning in paragraph 21(1)(c)

specified ancillary service means **instantaneous reserve**, **frequency keeping** or **voltage support**

stand-alone cost prudent discount means a discount of a **customer's transmission charges** provided under this **transmission pricing methodology** for the purpose in clause 136

standard method means the **price-quantity method** or **resiliency method**

standard method calculation period means, for a **BBI**, the period—
(a) starting on the **BBI's** expected **commissioning date**; and
(b) ending on the earlier of—
  (i) 20 years after the date the **BBI** is expected to be **fully commissioned**; and
  (ii) the end of the useful life of the **BBI**, as determined by **Transpower**

standard method rate means, for a **BBI**—
(c) if the **BBI** is a **tested investment**, the pre-tax, real discount rate used when the **BBI** was assessed under the **investment test**, excluding discount rates used only for sensitivity analysis; or
(d) otherwise—
  (i) the applicable rate in the **assumptions book**; or
  (ii) if there is no applicable rate in the **assumptions book**, the rate in clause D6(3)(a) of the **Transpower Capex IM**

start pricing year means—
(a) for a **connection investment**, the first **pricing year** that starts after the end of the **financial year** during which the **connection investment** was **commissioned**; or
~~(a)~~(b) for a **BBI**, the first **pricing year** that starts after the end of the **financial year** during which the **BBI** was **commissioned** (which, for an **Appendix A BBI**, is the **first pricing year**); or

Commented [A18]: **Clarification:** This is for completeness and is consistent with the way the components of connection charges are calculated (i.e. looking back to the previous financial year).

~~(b)~~(c) for a **SSCGU**, the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the date of the **SSCGU**; or

~~(c)~~(d) for a **reassignment**, the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **reassignment confirmation date**; or

~~(d)~~(e) for an **inefficient bypass prudent discount**, the first **pricing year** that starts—

(i) at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **prudent discount confirmation date**; and

(ii) on or after a date determined by **Transpower** based on the time that would be required for the **customer** to implement the relevant **alternative project**; or

~~(e)~~(f) for a **stand-alone cost prudent discount**, the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **prudent discount confirmation date**

station means a substation or switching station

substantial sustained increase means, for **large plant**, an increase in the **large plant's** expected annual **electricity** consumption or generation (as the case may be)—

(a) of at least 25% since the last time the relevant **customer's BBI customer allocations** for 1 or more **BBIs** were calculated, as assessed under subclause 84(4); and

(b) that is not attributable to a **large upgrade** of the **large plant**; and

(c) that **Transpower** reasonably expects to persist for at least 5 years after the start of the relevant **event pricing year**~~is sustained~~

substantial sustained change in grid use or **SSCGU** means an event or series of directly related events that result in a change in expected total annual **injection** or **offtake**—

(a) of at least 5% of average total annual **injection** or **offtake** (as the case may be) over **CMP F**; and

(b) that **Transpower** reasonably expects to persist for at least 5 years after the event or series of directly related events occurred~~is sustained~~

supplying load customer means, for a **connection location** and **trading period**, a **generator** who—

(a) owns or controls **generating plant** connected to the **grid** at the **connection location**; and

(b) has **embedded electricity** at the **connection location** of the type defined in paragraph 5(1)(d) during the **trading period**

system limit means a level of **supply**, **demand** or **electricity** flow at which the power system would not remain in a **satisfactory state** during and following an **outage scenario**, potentially requiring involuntary post-contingency generation or **demand** reduction

system limit model means a simplified model of the **grid** that—

(a) models a **reliability BBI's factual**, **counterfactual**, **system limits** and **market scenarios**; and

(b) applies the **reliability BBI's outage scenarios** to the **factual**, **counterfactual**, **system limits** and **market scenarios** to model the change in **curtailed energy** between the **reliability BBI's factual** and **counterfactual**

TA opex means operating costs ~~of the type described in clause 3.1.3(1)(c) of the **Transpower IMs**, being operating costs~~ for **transmission alternatives**, including of the type described in clause 3.1.3(1)(c) of the **Transpower IMs**

tested investment means a **connection investment** or **interconnection investment** that—

Commented [A19]: Clarification

Commented [A20]: Clarification

Commented [A21]: Change: Limiting this definition to clause 3.1.3(1)(c) of the Transpower IMs is not appropriate. Clause 3.1.3(1)(c) links to clause 3.1.3(3) which inappropriately (for the TPM) restricts the definition to operating expenditure approved under the Capex IM.

Commented [A22]: Typo

(a) was approved by the Electricity Commission under section III of Part F of the **rules**; or
~~(c)~~(b) was~~has been~~ individually approved by the **Commission** as a major capex project or listed project under the **Transpower Capex IM**; or
~~(d)~~(c) is a base capex project to which **Transpower** was required to apply a cost-benefit analysis under the **Transpower Capex IM**

total gross energy has the meaning in subclause 5(6)

transmission charges means the charges specified in clause 2

transmission services means the following services provided by a **grid owner**:
(a) electricity lines services, as defined in section 54C of the Commerce Act 1986, but excluding **system operator** services:
(b) the provision of **transmission alternatives**

Transpower Capex IM means the *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2

Transpower IMs means the *Transpower Input Methodologies Determination 2010* [2012] NZCC 17

Transpower IPP means the *Transpower Individual Price-Quality Path Determination* [2019] NZCC 19

Transpower operations facility means a facility that is used by **Transpower** only to operate the **grid** and is not a **station**

upgrade means, for an asset or **plant**, to alter the asset or **plant** physically so that the asset's or **plant's capacity** is permanently increased

unserved energy (measured in kWh or **MWh**) means an amount by which **offtake** at 1 or more **GXPs** is curtailed

unsupplied energy (measured in kWh or **MWh**) means an amount by which **injection** at 1 or more **GIPs** is curtailed

value of commissioned asset has the meaning in the **Transpower IMs**

value of lost load or **VOLL** means, for a **reliability BBI**—
(a) if the **reliability BBI** is a **tested investment**, the value of **unserved energy** used when the **reliability BBI** was assessed under the **investment test**, excluding values of **unserved energy** used only for sensitivity analysis; or
(b) otherwise—
  (i) the applicable value of **unserved energy** in the **assumptions book**; or
  (ii) if there is no applicable value of **unserved energy** in the **assumptions book**, the value of **unserved energy** referred to in subclause 4(1) of Schedule 12.2 of this Code

wholesale market model means a simplified model of prices and quantities in the **wholesale market** for **electricity** (and only in that **wholesale market**) that~~, subject to subclause 52(4)~~—
(a) models a **market BBI's factual**, **counterfactual** and **market scenarios**; and
(b) assumes suppliers offer prices based on their marginal variable costs of supply; and
(c) assumes perfectly inelastic demand up to 1 or more estimated costs of self-supply that are the same for all demand types; and
(d) applies least-cost dispatch to the **market BBI's factual**, **counterfactual** and **market scenarios**, under the assumptions in paragraphs (b) and (c), to model the change in prices and quantities in the **wholesale market** for **electricity** between the **market BBI's factual** and **counterfactual**~~.~~

Commented [A23]: Change: This is for completeness and to ensure the post-2019 CUWLP investment is captured as a tested investment.

Commented [A24]: Style

Commented [A25]: Typo: This definition does not need to be subject to clause 52(4) (or anything else in clause 52).

write-down means a reduction in an asset's value due to damage to, or destruction, stranding or decommissioning of, the asset before the end of its **economic life**.

Commented [A26]: **Clarification:** This definition has been introduced to clarify what we mean by "accelerated depreciation" below.

4 Benefit Factor

A **customer's benefit factor** for an **Appendix A BBI** (BF) is calculated as follows:

$$BF = \frac{CA}{E}$$

where

CA is the **customer's BBI customer allocation** for the **Appendix A BBI** (which may be 0)

E is—

(a) if the **customer** is a **Schedule 1 beneficiary**, the **customer's** average annual **offtake** or **injection** over **CMP D**, being the period the **Authority** used to calculate the **Schedule 1 allocations**; or

(b) otherwise, **Transpower's** estimate of the **customer's** annual **offtake** or **injection** when the **customer's assets** are fully operational, which must be the same as the value of variable E in paragraph 86(6)(a) if that paragraph was applied to the **customer** when the **customer** first connected to the **grid**,

subject, in each case, to any adjustments to those values under clauses 88 to 93 since they were first calculated or estimated.

5 Load Customers, Gross Energy and Maximum Gross Demand

(1) The different types of **load customer** are shown in figures 1, 2, 3 and 4. In figures 1, 2, ~~3,~~ and 4, "LN" means **local network**, "CP" means **consuming plant**, "GP" means **generating plant**, "NGN" means **non-grid network** and "POC" means a **grid point of connection**. This subclause (1) is subject to subclause (2):

(a) In figure 1, a **customer** owning or controlling LN, CP or GP is an **offtake customer** to the extent of the **offtake** for the relevant **trading period**:

(b) In figure 2, a **customer** owning or controlling LN or CP is a **direct supplied load customer** to the extent of the generated **electricity** net of any coincident **injection** through LN or CP for the relevant **trading period** (**embedded electricity**), provided that the minimum **embedded electricity** is 0. The **embedded electricity** is referred to as the **direct supplied load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**:

(c) In figure 3, a **customer** owning or controlling LN, **grid**-connected CP or **grid**-connected GP is an **indirect supplied load customer** to the extent of the generated **electricity** net of any coincident **injection** through LN or **grid**-connected CP for the relevant **trading period** (**embedded electricity**), provided that the minimum **embedded electricity** is 0. The **embedded electricity** is referred to as the **indirect supplied load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**:

(d) In figure 4, a **customer** owning or controlling GP is a **supplying load customer** to the extent of the **embedded electricity** for the relevant **trading period**. The **embedded electricity** is referred to as the **supplying load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period**.

Figure 1

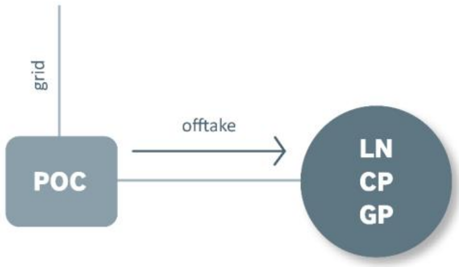


Figure 2

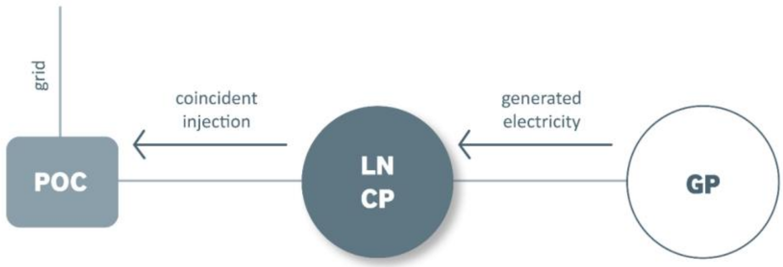
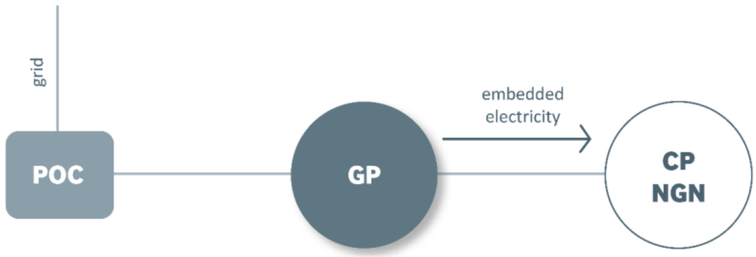


Figure 3

Figure 4



(2) If—

(a) GP in figure 2 is **battery storage**, the generated **electricity** referred to in paragraph (1)(b) is deemed to be 0; or

(b) **embedded** GP in figure 3 is **battery storage**, the generated **electricity** referred to in paragraph (1)(c) is deemed to be 0; or

(c) GP in figure 4 is **battery storage**, the **embedded electricity** referred to in paragraph (1)(d) is deemed to be 0.

(3) If a configuration of **consuming plant** and **generating plant** connected to the **grid** is such that the **customer** may be treated as either a **direct supplied load customer** or **supplying load customer**, the **customer's** status as a **direct supplied load customer** or **supplying load customer** must be determined by **Transpower**.

(4) **Gross energy** (measured in kWh or **MWh**) means, for a **load customer**, **connection location** or **grid point of connection**, and **trading period**—

(a) the **load customer's offtake** at the **connection location** or **grid point of connection** during the **trading period**; plus

(b) the **load customer's embedded electricity** at the **connection location** or **grid point of connection** during the **trading period**.

(5) **Maximum gross demand** (measured in kW or **MW**) means, for a **load customer**, **connection location** or **grid point of connection**, and period, the **load customer's** maximum per-**trading period gross energy** at the **connection location** or **grid point of connection** during the period multiplied by 2.

(6) **Total gross energy** (measured in kWh or **MWh**) for a **load customer** and period (TGE) is calculated as follows:

$$TGE = \left(\sum_{l}\sum_{t} GE_{tl}\right) - E_{battery}$$

where

~~GE_{tl} is the **load customer's gross energy** for **trading period** t at **connection location** l during the period.~~

~~$E_{battery}$ is total **injection** from all of the **load customer's grid**-connected **battery storage** over the period, if any.~~

GE_{tl} is the **load customer's gross energy** for **trading period** t at **connection location** l during the period

$E_{battery}$ is total **injection** from all of the **load customer's grid**-connected **battery storage** over the period, if any.

(7) Except as otherwise stated in this **transmission pricing methodology**, **Transpower** may use the following information to calculate **gross energy**, **maximum gross demand** and **total gross energy** and is not required to (but may) use any other information:

(a) **metering information**;

(b) information required to be provided by the **reconciliation manager** to **Transpower** under this Code, including under clause 28(b) of Schedule 15.4 of this Code;

(c) other **reconciled quantities** published or made available to **Transpower**;

Commented [A27]: Style

Commented [A28]: Style: These defined terms moved into the table format used elsewhere.

Commented [A29]: Change: This clause brings some certainty to the data sources Transpower may use to calculate gross load, and will insulate Transpower from potentially recurring disputes about the proper data sources to use. The first four listed data sources are either reconciled or derived from certified metering. The fifth is SCADA data, which we intend to use only as a "gap filler" where required (as it may be, particularly for historical gross load). We note this clause protects Transpower from disputes about data sources, not from disputes about errors in the calculation.

(d) **half-hour metering information** required to be provided by **generators** to **Transpower** under this Code, including under clauses 13.136, 13.137 and 13.137A of this Code:

(e) indications and measurements required to be provided by a **participant** to the **system operator** under this Code, including under Technical Code C of Schedule 8.3 of this Code, that are published or made available to **Transpower**.

6 Commissioning

(1) A **grid asset** is **commissioned** when it is first commissioned as defined in the **Transpower IMs**.

(2) A **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned** when the first **grid asset** or **transmission alternative** comprised in it is **commissioned** or started (as the case may be).

(3) A **connection investment** or **interconnection investment** (including a **BBI**) is **fully commissioned** when all **grid assets** and **transmission alternatives** comprised in it are **commissioned** or started (as the case may be).

(4) Subject to subclauses (1) to (3), the time a **grid asset**, **connection investment** or **interconnection investment** (including a **BBI**) is **commissioned** or **fully commissioned** is to be determined by **Transpower**.

7 Connection and Disconnection

In this **transmission pricing methodology**, unless the context otherwise requires—

(a) an asset becomes connected to a **network** at a **point of connection** at the time the **point of connection** is **commissioned**; and

(b) an asset becomes disconnected from a **network** at a **point of connection** at the time the **point of connection** is **decommissioned**; and

(c) subject to paragraphs (a) and (b), the time an asset becomes connected to or disconnected from a **network** or **plant** is to be determined by **Transpower**; and

(d) **plant** is **grid**-connected only if it is directly connected to the **grid**; and

(e) **embedded plant** is connected to a **local network** or **grid**-connected **plant** if the **embedded plant** is—

(i) directly connected to the **local network** or **grid**-connected **plant**; or

(ii) indirectly connected to the **local network** or **grid**-connected **plant** through other **plant** or a **non-grid network**.

~~**8 Sustained Change**~~

~~Where **Transpower** is required under this **transmission pricing methodology** to assess whether a change is sustained, the change must only be treated as sustained if **Transpower** reasonably expects the change to persist for at least 5 years after the relevant **transmission charges** inputs to their calculation are adjusted in response to the change.~~

~~9~~8 Large Plant

Where **Transpower** is required under this **transmission pricing methodology** to assess whether **plant**, or an **upgrade** or **de-rating** of **plant**, is **large**, **Transpower** may make that assessment by combining 2 or more units of **plant** that are—

(a) of the same type (**consuming plant** or **generating plant**); and

(b) owned by the same person or **related parties**,

if **Transpower** considers it is fair and reasonable in all the circumstances to do so.

Commented [A30]: **Clarification:** Replaced with individual definitions of "sustained".

~~10~~9 Interpretation

In this **transmission pricing methodology**, unless the context otherwise requires—

(a) all defined terms are shown in bold text; and

(b) a term in bold text not defined in this **transmission pricing methodology** has the meaning given to it in Part 1 of this Code; and

(c) any other grammatical form of a defined term has a corresponding meaning; and

(d) if there is any inconsistency between the text description of a calculation for which there is formula and the formula, the formula takes precedence; and

(e) if there is any inconsistency between an illustrative figure, table or associated commentary and the provisions of this **transmission pricing methodology** being illustrated by the figure, table or associated commentary, the provisions being illustrated take precedence; and

~~(e)~~(f) a reference to **Transpower** means **Transpower** in its capacity as a **grid owner**; and

Commented [A31]: Clarification

~~(f)~~(g) a reference—

(i) to the singular includes the plural and vice versa; and

(ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust or Crown entity; and

(iii) to a clause, subclause, paragraph, subparagraph or Part is to a clause, subclause, paragraph, subparagraph or Part of this **transmission pricing methodology**; and

(iv) to any legislation, including this Code, the **Transpower IPP**, the **Transpower IMs** and the **Transpower Capex IM**, includes that legislation as amended or replaced from time to time; and

~~(g)~~(h) the word "including" is to be read as "including, but not limited to", and the word "includes" is to be read as "includes, without limitation"; and

~~(h)~~(i) a reference to a preceding **financial year** is a reference to the first complete **financial year** that precedes the start of the **pricing year** in respect of which the relevant calculation is undertaken or assessment is made; and

~~(i)~~(j) a reference to a **plant** owner is a reference to the person who owns or controls the **plant**; and

~~(j)~~(k) a reference to a **customer's offtake**, **embedded electricity** or **injection** at a **connection location** is a reference to the **customer's offtake**, **embedded electricity** or **injection** at all **grid points of connection** at the **connection location** where the **customer offtakes electricity**, has **embedded electricity** or **injects electricity** (as the case may be); and

~~(k)~~(l) a reference to a **load customer's** (including an **offtake customer's**) or **injection customer's connection location**:

(i) is a reference to all **grid points of connection** at the **connection location** where the **load customer offtakes electricity** or has **embedded electricity** or where the **injection customer injects electricity** (as the case may be); and

(ii) does not include any **connection location** where the **load customer** does not **offtake electricity** or have **embedded electricity** or where the **injection customer** does not **inject electricity** (as the case may be).

Calculation of Transmission Charges

~~11~~10 Transmission Charges Calculated Separately

A **customer** may be both a **load customer** and an **injection customer** during the same **trading period**, including at the same **connection location** (but cannot be both an **offtake customer** and an **injection customer** during the same **trading period** in respect of the same **grid point of connection**). In this case, the **customer's transmission charges** are calculated separately for the **customer** as a **load customer** and an **injection customer**, except as otherwise stated in this **transmission pricing methodology**.

~~12~~11 **Calculations and Estimations**

(1) Except as otherwise stated in this **transmission pricing methodology**—

(a) any calculation (including of **transmission charges**) or estimation under this **transmission pricing methodology** is to be carried out by **Transpower**; and

(b) any input to a calculation or estimation under this **transmission pricing methodology** is to be determined by **Transpower**; and

(c) to the extent a calculation or estimation under this **transmission pricing methodology** requires modelling, **Transpower** may use the modelling tools it uses in its business from time to time, which may change over time.

Commented [A32]: Clarification

(2) To avoid doubt, **Transpower** is not required to maintain its access to a modelling tool it no longer uses in its business merely for the purpose of verifying previous calculations or estimations under this **transmission pricing methodology** that were made using the modelling tool.

Commented [A33]: Clarification: This clause is to remove any suggestion or implication we have to preserve access to superseded modelling tools for the life of the TPM (and incur the considerable cost of doing so).

(3) If this **transmission pricing methodology** specifies a source for an input to a calculation or estimation under this **transmission pricing methodology** but the source is not available or the input is not included in or provided by the source, the input is to be determined by **Transpower**.

(4) **Transpower** must calculate or estimate all values under this **transmission pricing methodology**—

(a) that are **connection customer allocations**, **BBI customer allocations** or other **transmission charge** allocators intended to sum to 1 or 100%, to at least 4 decimal places (if expressed as a decimal) or 2 decimal places (if expressed as a percentage), and **Transpower** is not obliged to calculate or estimate the values any more precisely than that; and

(b) that are in units of dollars, to 2 decimal places; and

(c) that are **supply** or **demand**, in whole kW; and

(d) that are **electricity**, in whole kWh.

(5) If—

(a) the **connection customer allocations** for a **connection asset**; or

(b) the **BBI customer allocations** for a **BBI**; or

(c) any other **transmission charge** allocators that are intended to sum to 1 or 100%,

do not sum to 1 or 100% due to rounding, **Transpower** must adjust all of the relevant **transmission charge** allocators on a pro rata basis to achieve a sum of 1 or 100%.

~~13~~12 **Determinations**

(1) Matters under this **transmission pricing methodology** determined by **Transpower** are determined in **Transpower's** sole discretion while acting—

(a) reasonably; and

(b) subject to subclause (2), in accordance with **GAAP**; and

(c) subject to subclause (3), with reference to—

(i) information made available to **Transpower** by or on behalf of **participants** and other persons with an interest in the determination; and

(ii) **Transpower's** and (where published) other persons' financial and regulatory records, registers and disclosures, including the **RAB**; and

(iii) other information relevant to the determination **Transpower** is reasonably able to obtain.

(2) If there is any inconsistency between the requirements of **GAAP** and the requirements of this **transmission pricing methodology**, this **transmission pricing methodology** takes precedence.

(3) **Transpower** is not required to give equal weight to the information referred to in paragraph (1)(c).

~~14~~13 **Reverse Flow**

(1) This clause 13 applies if all of the following conditions are satisfied:

(a) a **customer** has an agreement with the **system operator** under clause 6 of Technical Code A of Schedule 8.3 of this Code:

(b) the **customer** has notified **Transpower** in writing that there is **reverse flow** at a **connection location** as a result of a **GXP tie** authorised under the agreement referred to in paragraph (a):

(c) the **customer** notified **Transpower** under paragraph (b) within 20 **business days** of the **reverse flow** starting:

(d) **Transpower** is reasonably satisfied there is **reverse flow** at the **connection location** as a result of a **GXP tie** authorised under the agreement referred to in paragraph (a).

(2) Subject to subclause (3), **Transpower** must, despite anything else in this **transmission pricing methodology**—

(a) adjust the **customer's allocation data** for the **connection location** to mitigate or eliminate the impact of the **reverse flow**, as determined by **Transpower**; and

(b) use the adjusted **allocation data** to calculate future **transmission charges**.

(3) Subclause (2) does not apply to any **allocation data** used to calculate **regional NPB** for a **regional customer group** under the **simple method**.

~~(3)~~(4) **Transpower** must **publish** the details of any adjustment it makes under subclause (2) within 20 **business days** of making the adjustment.

~~15~~14 **Exceptional Operating Circumstances**

(1) Subject to subclause (2)~~If~~, if **Transpower** determines—

(a) a **Transpower** requirement ~~(as a **grid owner**) or a~~, **system operator** requirement, or planned or unplanned **outage** has caused exceptional operating circumstances in the power system; and

(b) those circumstances have resulted in a **customer's allocation data** not reflecting normal operating circumstances in the power system (a distortion),

Transpower may, despite anything else in this **transmission pricing methodology**—

(c) adjust the **allocation data** to mitigate or eliminate the distortion, as determined by **Transpower**; and

(d) use the adjusted **metering information** to calculate future **transmission charges**.

(2) Subclause (1) does not apply to any **allocation data** used to calculate **regional NPB** for a **regional customer group** under the **simple method**.

~~(2)~~(3) **Transpower** must **publish** the details of any adjustment it makes under subclause (1) within 20 **business days** of making the adjustment.

Commented [A34]: Clarification

Commented [A35]: Change: It is not appropriate to apply the reverse flow adjustment mechanism to the inputs to the regional NPB calculations for the simple method. Doing that would require re-assessing all of the branch flows that go into calculating those allocations, which would be a difficult task and would likely result in only very minor changes. This adjustment mechanism is intended to apply to individual allocation data only.

Commented [A36]: Change: The EOC mechanism should be extended to system operator requirements as well as grid owner ones. This is consistent with how the mechanism is applied under the current TPM.

Commented [A37]: Change: It is not appropriate to apply the EOC adjustment mechanism to the inputs to the regional NPB calculations for the simple method. Doing that would require re-assessing all of the branch flows that go into calculating those allocations, which would be a difficult task and would likely result in only very minor changes. This adjustment mechanism is intended to apply to individual allocation data only.

General

~~16~~15 Applications, Application Fees and Application Requirements

(1) **Transpower—**

(a) is not obliged to start assessing an **application**; and

(b) may suspend its assessment of, or reject, an **application**,

if—

(c) the **application fee** for the **application** has not been paid; or

(d) the **application** does not comply with the relevant **application requirements**; or

(e) the applicant otherwise does not comply, or has not complied, with this **transmission pricing methodology** in relation to the **application**.

(2) Subject to subclause (1), **Transpower** must—

(a) prioritise assessment of **applications** in the order they are received by **Transpower**; and

(b) complete its assessment of an **application** within a reasonable time of receiving it, having regard to the complexity of the **application** and the quality of the information provided by the applicant in support of it.

(3) **Application fees** must be reasonable having regard to **Transpower's** expected costs of assessing **applications** of the relevant type, and may be—

(a) fixed or based on actual costs; and

(b) capped or uncapped; and

(c) up-front or staged; and

(d) refundable or non-refundable.

(4) **Application requirements** must be reasonable having regard to the matters relevant to **Transpower's** assessment of **applications** of the relevant type.

~~17~~16 Consultation on Transmission Charges

(1) **Transpower** must consult on the following matters with at least the following **customers** before the relevant **transmission charges** or adjustments to them are finalised:

subject matter	minimum group to be consulted
Proposed **annual connection charges**	**Customers** who will pay the **connection charges**
Proposed material adjustment to **connection charges** during a **pricing year**	**Customers** who will pay the adjusted **connection charges**
Expected total **covered cost** for a **post-2019 BBI** expected to be **high-value** when **fully commissioned**	Public consultation
Proposed material adjustment to the expected total **covered cost** of a **post-2019 BBI** expected to be **high-value** immediately before or after the adjustment	Public consultation
Proposed starting **BBI customer allocations** for a **post-2019 BBI** expected to be **high-value** when **fully commissioned**	Public consultation
Proposed adjustment to the **BBI customer allocations** for a **post-2019 BBI** due to a **SSCGU**	Public consultation
Other proposed material adjustment to the **BBI customer allocations** for a **post-2019 BBI** expected to be **high-value** immediately before the adjustment	**Customers** who are or will be **beneficiaries** of the **post-2019 BBI**
Proposed allocation of **residual charges** for a **pricing year**	All **load customers**
Proposed material adjustment to the allocation of **residual charges** during a **pricing year**	All **load customers**

(2) **Transpower** must consult publicly on the proposed **modelled regions** and **regional NPBs** under the **simple method**, and proposed **simple method factors** and **demand adjustment factor**, for—

(a) the first **simple method period**, before the start of the **first pricing year**; and

(b) each subsequent **simple method period**, before the start of the **simple method period**,

provided that **Transpower** is not required to consult on the **demand adjustment factor** for the first **simple method period** (which is 1).

Commented [A38]: Typo

(3) Consultation under subclause (1) may occur as part of **Transpower** or **Commission** consultation required under the **Transpower Capex IM**, other parts of this Code, or **transmission agreements**, either before or after the start of the **first pricing year**.

(4) Consultation—

(a) under subclause (1) on the proposed starting **BBI customer allocations** for a **high-value post-2019 BBI** or a proposed material adjustment to the **BBI customer allocations** for a **high-value post-2019 BBI**; and

(b) under subclause (2),

must include consultation on any material departures from the assumptions and methodologies in the **assumptions book** and the reasons for those departures.

~~18~~17 Information about Transmission Charges

As part of **Transpower's** obligations under a **transmission agreement** to notify the relevant **customer** of **annual charges**, **monthly charges** and changes to them, **Transpower** must provide the **customer** with reasonable information that is sufficient for the **customer** to understand the basis on which the **customer's annual charges** and **monthly charges** have been calculated. For a **load customer**, this information must include, for the relevant **pricing year**—

(a) the amount of otherwise unallocated operating costs included in **residual revenue**; and

(b) **reassignment amounts** included in **residual revenue**.

Part B Grid Asset Classification

~~19~~18 Grid Assets and Land and Buildings

(1) **Grid assets** are **assets** and other works (including land, easements, leases and other interests in land, buildings, containment facilities and other structures) that—

(a) comprise or support the **grid**; and

(b) are—

(i) owned by or leased to **Transpower**, provided that if the **assets** or other works are leased by **Transpower** to another person then the **assets** or other works will only be **grid assets** if **Transpower** has expressly agreed in writing with that person that the **assets** or other works are to be treated as **grid assets** for the purposes of this **transmission pricing methodology**; or

(ii) owned by another person and not leased to **Transpower**, but only if **Transpower** has expressly agreed in writing with that person that the **assets** or other works are to be treated as **grid assets** for the purposes of this **transmission pricing methodology**.

(2) For the purposes of subparagraph (1)(b)(ii), **Transpower's** provision of, or agreement to provide, **grid assets** that facilitate the connection of other **assets** to the **grid** does not constitute **Transpower's** agreement to treat the other **assets** as **grid assets** for the purposes of this **transmission pricing methodology**.

(3) **Land and buildings** are **grid assets** that are land, easements, leases or other interests in land, buildings, oil containment facilities, or other structures that are not comprised in the **grid**.

(4) **Land and buildings** that support a part of the **grid** are referred to as being "part of" that part of the **grid**, together with the **grid assets** that comprise that part of the **grid**.

~~20~~19 Partial Funding of Grid Assets

Subject to other legal requirements and **GAAP**, a **grid asset** the capital cost of which is partially funded under an **investment agreement**—

(a) may be represented in **Transpower's** financial and regulatory records, registers and disclosures, including the **RAB**, as multiple **grid assets**; and

(b) those **grid assets** may be treated as separate **grid assets** for the purposes of calculating **transmission charges**,

as necessary or convenient to ensure **Transpower** does not under-recover the total cost of the **grid asset** through this **transmission pricing methodology** and the **investment agreement**. To avoid doubt, **Transpower** must not use its discretion under this clause to over-recover the total cost of a **grid asset**.

~~21~~20 Nodes and Links

(1) A **node** is any of the following:

(a) a **connection location**:

(b) a **station** that is not a **connection location**:

(c) a location in the **grid** where a circuit diverges or terminates (such as a "tee" point, or a deviation of a circuit within a **line** to connect to a **station** where the **line** does not terminate).

(2) For the purposes of paragraph (1)(c)—

(a) a circuit does not "diverge" at a location merely because it changes direction at the location, or transitions from overhead to underground or vice versa at the location; and
(b) adjacent towers, poles or other structures at which a circuit diverges may be treated as a single location.

(3) Subject to subclause (8), a **link** is either a single circuit or multiple parallel circuits (of the same voltage) that are **grid assets** and connect 2 **nodes** (and includes any **grid assets**, such as circuit breakers, that are required to connect the **link** at either **node**).

(4) To avoid doubt—
(a) a **Transpower operations facility** is not a **node**; and
(b) a circuit or multiple parallel circuits that are **grid assets** and connect—
(i) a **node**; and
(ii) a **Transpower operations facility** that is not connected to any other **node**,
is not a **link**.

(5) Figures 5 and 6 illustrate how **nodes** and **links** are identified under subclauses (1) to (4):
(a) Figure 5 shows a physical **grid** configuration. CL1, CL2 and CL3 are **connection locations**. TOF is a **Transpower operations facility**. T1, T2, T3 and T4 are towers. The lines are circuits between the **connection locations** or **Transpower operations facility** and the towers. All of the circuits are **grid assets** except the circuit between CL2 and CL3:
(b) Figure 6 shows the same **grid** configuration as figure 5 but in the form of **nodes** and **links**. **Nodes** N2, N4 and N5 correspond to **connection locations** CL1, CL2 and CL3 respectively. **Node** N1 corresponds to the divergence at tower T1. **Node** N3 corresponds to the divergence at towers T2 and T3, which are adjacent and treated as a single location. There is no **node** corresponding to tower T4 because the change of direction of the circuits at T4 is insufficient to constitute a divergence. There is no **node** corresponding to **Transpower operations facility** TOF because a **Transpower operations facility** is not a **node**. There is no **link** between N4 and N5 because the circuit between CL2 and CL3 is not a **grid asset**. There is no **link** between T3 and TOF because TOF is not a **node**.

Figure 5

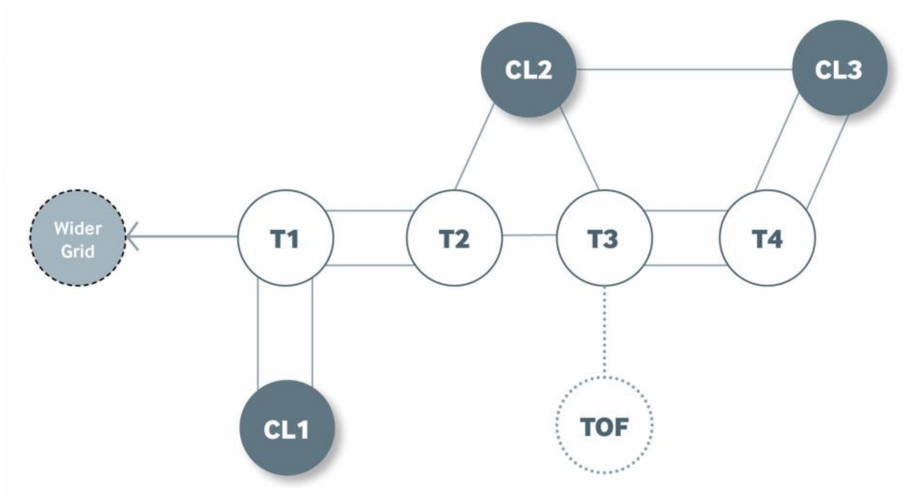
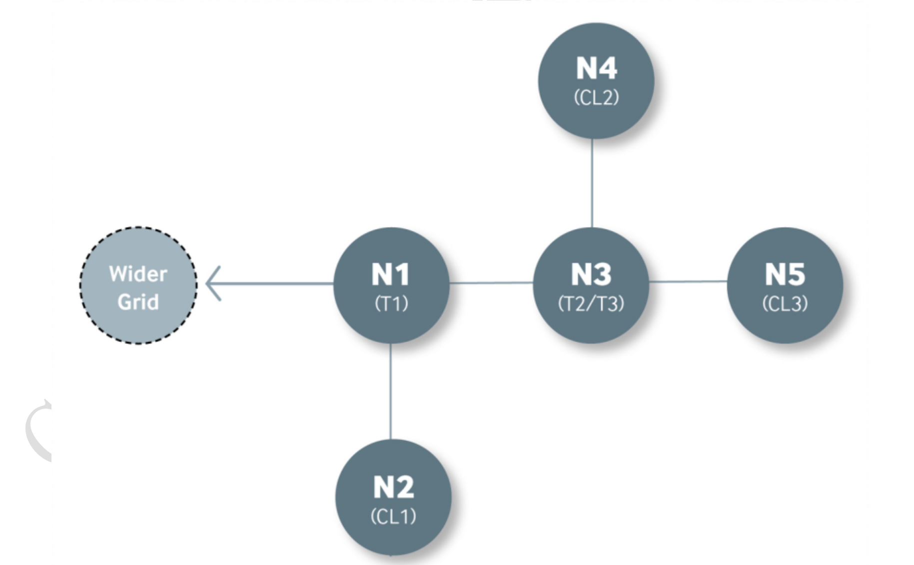


Figure 6



(6) Subclauses (1) to (3) must be applied to identify **nodes** and **links** contemporaneously and not prospectively or retrospectively. If a **grid asset** is expected to change from being a **node** or **link** to not being a **node** or **link**, or vice versa, once a future event occurs (such as the

commissioning or **decommissioning** of it or another **asset**), that does not affect the **node** or **link** status of the **grid asset** before the event occurs.

(7) Subject to subclause (8), if a **grid asset** was a **node** or **link** before this **transmission pricing methodology** came into effect or before an event occurred, that does not prevent the **grid asset** ceasing to be a **node** or **link** when this **transmission pricing methodology** came into effect or when the event occurred, or vice versa.

(8) A circuit or circuits that are not **grid assets** but, immediately before this **transmission pricing methodology** came into effect, comprised a “link” under the **previous transmission pricing methodology**—

- (a) will be treated as a **link** despite not being **grid assets**; but
- (b) will cease to be a **link** if the circuit or circuits otherwise cease to meet the requirements for comprising a **link** under this **transmission pricing methodology**.

~~22~~21 Connection and Interconnection Nodes and Links

(1) **Nodes** and **links** are identified as **connection nodes** or **connection links** or **interconnection nodes** or **interconnection links** according to the following rules:

- (a) an **interconnection node** is any **node** connected to 2 or more **nodes** in a **loop**, other than a **small regional loop**:
- (b) a **loop** is a continuous path of **nodes** and **links** with the same start and end **node**:
- (c) a **small regional loop** is a **loop** between any group of **nodes** (excluding the **nodes** at the Benmore and Haywards substations) with only a single **link** from the **loop** to a **node** outside the **loop** that—
  - (i) is part of another **loop**; or
  - (ii) ultimately links to another **loop**, either directly or indirectly through other **nodes**:
- (d) a **connection node** is any **node** that is not an **interconnection node**, including all **nodes** in a **small regional loop**:
- (e) a **connection link** is a **link** with a **connection node** at 1 or both of its ends:
- (f) an **interconnection link** is a **link** that connects 2 **interconnection nodes**.

(2) Figures 7, 8 and 9 illustrate how **small regional loops**, **interconnection nodes** and **links**, and **connection nodes** and **links** are identified under subclause (1):

- (a) In figures 7 and 8, **nodes** N2, N3 and N4 comprise a **small regional loop** because in each case there is only 1 **link** (from N4) to another **loop**. In figure 7, the **link** from N4 to the other **loop** is direct because **interconnection node** N6 is part of the other **loop**. In figure 8, the **link** from N4 to the other **loop** is indirect through **connection node** N5. In figures 6 and 7, N2, N3 and N4 are **connection nodes** and the **links** between and to them are **connection links**. In figure 8, the **link** from N5 to N6 is also a **connection link**:
- (b) In figure 9, **nodes** N2, N3 and N4 do not comprise a **small regional loop** because there is more than 1 **link** (from N3 and N4) to another **loop**. Even if the **link** from N4 to N6 did not exist, N2, N3 and N4 would still not comprise a **small regional loop** because there are 2 **links** to another **loop** from N3. In figure 9, N2, N3 and N4 are **interconnection nodes** and (apart from the **link** from **connection node** N1 to N2, which is a **connection link**) the **links** between and to them are **interconnection links**.

Figure 7

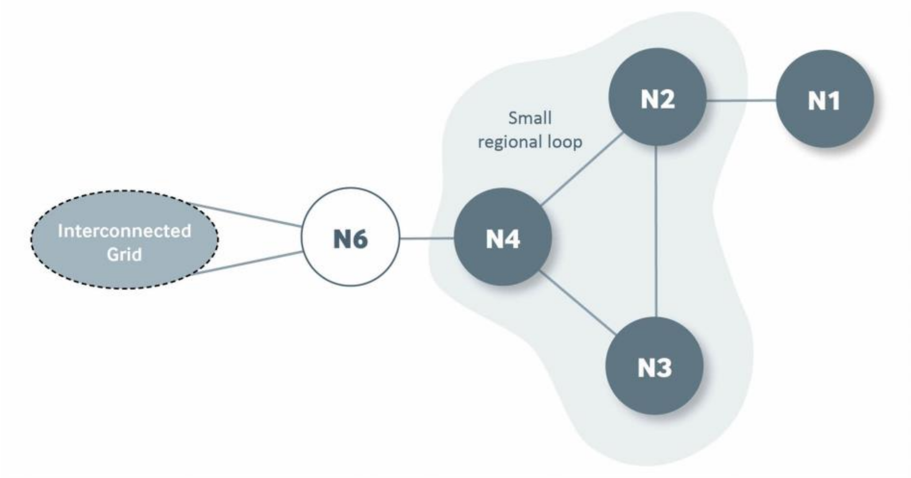


Figure 8

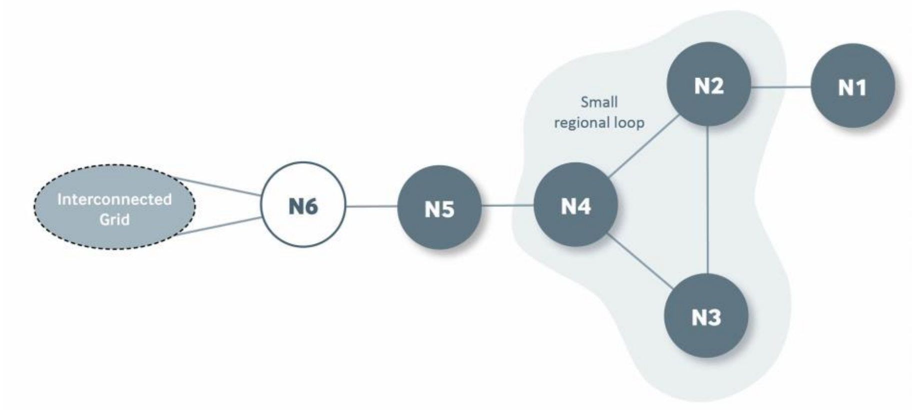
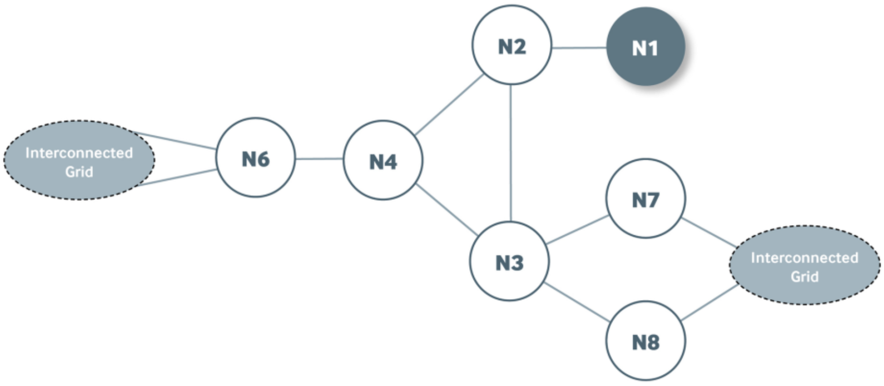


Figure 9



(3) Subject to subclause (4), subclause (1) must be applied to classify **nodes** and **links** contemporaneously and not prospectively or retrospectively. If a **node** or **link** is expected to change from a **connection node** or **link** to an **interconnection node** or **link**, or vice versa, once a future event occurs (such as the **commissioning** or **decommissioning** of it or another **asset**), that does not affect the classification of the **node** or **link** before the event occurs.

(4) If a group of **nodes** or **links** that are to be provided as part of the same project are **commissioned** in a staged manner, the **connection** or **interconnection** status of each **node** and **link** in the group must be determined prospectively based on all **nodes** and **links** in the group being **commissioned**. However—

- (a) if all the **nodes** and **links** have not been **commissioned** by the start of the **pricing year** that is at least 9 months after the first **node** or **link** is **commissioned**—
  - (i) subclause (3) will apply from the start of that **pricing year** and not this subclause (4) (so that the **nodes** and **links** will be classified contemporaneously from the start of that **pricing year**); and
  - (ii) once all the **nodes** and **links** are **commissioned**, subclause (3) will apply from the start of the first **pricing year** that starts after the last **node** or **link** is **commissioned** (so that the **nodes** and **links** will be classified contemporaneously from the start of that **pricing year**); and
- (b) this subclause (4) must not be applied to classify an **interconnection node** or **interconnection link** as a **connection node** or **connection link**.

(5) If a **node** or **link** was classified as a **connection node** or **link** before this **transmission pricing methodology** came into effect or before an event occurred, that does not prevent the **node** or **link** being re-classified as an **interconnection node** or **link** when this **transmission pricing methodology** came into effect or when the event occurred, or vice versa.

~~23~~22 Connection and Interconnection Assets

(1) A **connection asset** is any of the following that is not an **HVDC asset**:

- (a) a **grid asset** at a **connection node**, other than voltage support equipment that is not an **investment agreement asset**:
- (b) at an **interconnection node** that is a **connection location**—
  - (i) any **grid asset** that is used to connect a **customer's assets** to the **grid**. This may include:

(A) a supply transformer, feeder bay, or supply transformer high voltage or low voltage breaker:

(B) a low voltage breaker, low voltage bus section breaker, voltage transformer, revenue meter, or other equipment that is on the same bus as a feeder; and

(ii) a proportion of the **land and buildings** at the **connection location** (LB_{conn}) calculated as follows:

$$LB_{conn} = \frac{RC_{conn\ total}}{RC_{total}}$$

where

$RC_{conn\ total}$ is the total **replacement cost** of all **grid assets** described in subparagraph (i) at the **connection location** at the end of the preceding **financial year**

RC_{total} is the total **replacement cost** of all **grid assets** (excluding **land and buildings**) at the **connection location** at the end of the preceding **financial year**:

(c) a **grid asset** that is part of a **connection link**. If a **line** is included in a **connection link** and 1 or more other **links**, the part of the **line** ascribed to the **connection link** must be determined according to the length of the **line** included in the **connection link** relative to the total length of the **line**.

(2) An **interconnection asset** is any **grid asset** that is not a **connection asset**, and includes any **HVDC asset**.

~~24~~23 Associating Connection Assets with Connection Locations and Customers

(1) A **connection asset** that—

(a) is at a **connection location**; or

(b) if the **connection location** is a **connection node**, connects the **connection location** (directly or indirectly) to an **interconnection node**,

is referred to as a **connection asset** "for" the **connection location**, "that connects" (or other grammatical form of that phrase) the **customers** at the **connection location** and that those **customers** are "connected to" (or other grammatical form of that phrase).

(2) A **customer** who owns or controls **assets** connected at a **connection location** is referred to as a **customer** "at" the **connection location**.

(3) Subject to subclause (4), a **connection asset** for a **connection location** is referred to as "shared" between the **customers** at the **connection location**.

(4) A **connection asset** at a **connection location** that connects a specific **customer** only is not shared with any other **customer**.

(5) Figure 10 is the **node** and **link** configuration in figure 7 and illustrates how **connection assets** are associated with **connection locations** and **customers** under subclauses (1) to (3):

(a) N1, N3, N4 and N6 are **connection locations** at which **customers** A, B, C, D and E are connected. The smaller circles within N1, N3, N4 and N6 are **connection assets** at those **connection locations** that connect the specific **customers** shown only:

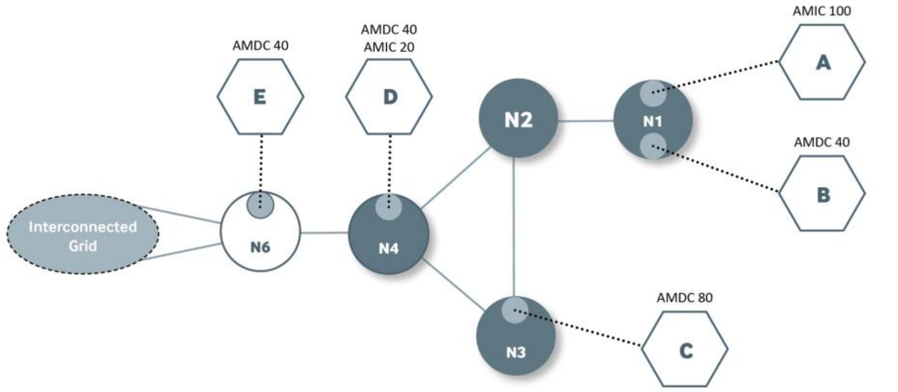
(b) The following table shows which **connection assets** are "for" the **connection locations** at N1, N3, N4 and N6. The **links** with an asterisk are "deep" **connection assets** for the relevant **connection location** because they are not located at, and do not directly connect to, the **connection location**:

connection assets	N1	N3	N4	N6
at **connection location**	Y	Y	Y	Y
in **link** N1-N2	Y	N	N	N
in **link** N2-N3	Y*	Y	N	N
in **link** N3-N4	Y*	Y	N	N
in **link** N2-N4	Y*	Y*	N	N
in **link** N4-N6	Y*	Y*	Y	N

(c) The following table shows how the **connection assets** at and between N1, N2, N3, N4 and N6 are "shared" between **customers** A, B, C, D and E:

connection assets	sharing
at N1	shared between A and B, apart from A- or B-specific **connection assets**
at N2	shared between A, B and C
at N3	shared between A, B and C, apart from C-specific **connection assets**
at N4	shared between A, B, C and D, apart from D-specific **connection assets**
at N6	shared between A, B, C, D and E, apart from E-specific **connection assets**
in **link** N1-N2	shared between A and B
in **link** N2-N3	shared between A, B and C
in **link** N3-N4	shared between A, B and C
in **link** N2-N4	shared between A, B and C
in **link** N4-N6	shared between A, B, C and D

Figure 10



~~25~~24 Discretion to Classify and Reclassify as Connection

(1) Despite anything else in this **transmission pricing methodology**, **Transpower** may classify or (subject to subclause (2)) reclassify any **grid asset** that would otherwise be an **interconnection asset** as a **connection asset** if—

- (a) the **grid asset** directly or indirectly connects 1 or more **customers** to the rest of the interconnected **grid**; and
- (b) the **grid asset** does not provide material **transmission services** to any other **customers**; and
- (c) **Transpower** considers it is fair and reasonable in all the circumstances to classify or reclassify the **interconnection asset** as a **connection asset**.

(2) **Transpower** must not reclassify a **grid asset** as a **connection asset** under subclause (1) retrospectively.

Part C Connection Charges

~~26~~25 Calculation of Connection Charges

(1) Only **customers** connected to **connection assets** pay **connection charges**.

(2) A **customer's annual connection charge** for a **connection asset**, **connection location** and **pricing year** (CC) is calculated as follows:

$$CC = \big((A + FA + M + O) \times CA\big) - RBT$$

where

A is the asset component for the **connection asset** and **pricing year** calculated under clause 27

FA is the **customer's funded asset** component for the **connection asset** and **pricing year** calculated under clause 28

M is the maintenance component for the **connection asset** and **pricing year** calculated under clause 31

O is the operating component for the **connection asset** and **pricing year** calculated under clause 32

CA is the **customer's connection customer allocation** for the **connection asset**, **connection location** and **pricing year**

RBT is the **customer's funded asset** rebate for the **connection asset**, **connection location** and **pricing year** calculated under clause 30.

(3) A **customer's annual connection charge** for a **connection location** and **pricing year** (ACC) is calculated as follows:

$$ACC = \sum_a CC_a$$

where CC_a is the **customer's annual connection charge** for **connection asset** a for the **connection location** and **pricing year**.

(4) A **customer's annual connection charge** for a **connection transmission alternative** and **pricing year** (TACC) is calculated as follows:

$$TACC = TAC \times \frac{\sum_l ACC_l}{\sum_l ACC_{l\,total}}$$

where

TAC is the **TA opex** for the **connection transmission alternative** and preceding **financial year**, less any contribution to the **TA opex** under **investment agreements**

Commented [A39]: Change: Investment agreements may extend to transmission alternatives, in which case there should not be double-recovery through connection charges.

ACC_l is the **customer's annual connection charge** for **connection location** l and the previous **pricing year**, where **connection location** l is a **connection location** that would be connected by a **connection asset** for which the **connection transmission alternative** is an alternative

$ACC_{l\ total}$ is the total of all **customers' annual connection charges** for **connection location** l and the previous **pricing year**.

(5) A **customer's monthly connection charge** for a **pricing year** (MCC) is calculated—

(a) for a **connection location**, as follows:

$$MCC = \frac{ACC}{12}$$

where ACC is the **customer's annual connection charge** for the **connection location** and **pricing year**; and

(b) for a **connection transmission alternative**, as follows:

$$MCC = \frac{TACC}{12}$$

where TACC is the **customer's annual connection charge** for the **connection transmission alternative** and **pricing year**.

(6) **Connection charges** are calculated for each **pricing year** before the start of the **pricing year**.

(7) A **connection charge** may be adjusted, including during a **pricing year**, under clauses 79 to 83 if there is a **connection charge adjustment event**.

26 Start of Connection Charges

Transpower must start the **connection charges** for a **connection investment** from the **connection investment's start pricing year**. To avoid doubt, this clause does not apply to charges under an **investment agreement**.

27 Asset Component

(1) The asset component of the **connection charge** for a **connection asset** and **pricing year** (A) allocates a portion of the capital cost of all **connection assets** to the **connection asset**, and is calculated as follows:

$$A = \cancel{(ARR \times RC)} ARR \times RC$$

where

ARR is the **connection asset** return rate for the **pricing year** calculated under subclause (2)

RC is—

(a) 0 if the **connection asset** is an **investment agreement asset**~~, 0~~; or

(b) otherwise, subject to subclause 28(1)~~27A(1)~~, the **replacement cost** of the **connection asset** at the end of the preceding **financial year**

.

Commented [A40]: **Clarification:** This is for completeness and is consistent with the way the components of connection charges are calculated (i.e. looking back to the previous financial year).

Commented [A41]: **Typo:** Unnecessary brackets removed.

Commented [A42]: **Style:** We have made this change throughout to match the Authority's change to clause 72.

Commented [A43]: **Style:** Clause numbering is conformed in this version.

Commented [A44]: **Typo**

(2) The **connection asset** return rate for a **pricing year** (ARR) is calculated as follows:

$$ARR = \cancel{\frac{(r \times (V_{total} - \Delta V_{total})) + (D_{total} - \Delta D_{total})}{RC_{total}}} \frac{(r \times V_{total}) + D_{total}}{RC_{total}}$$

where

r is **Transpower's PQ WACC** (pre-tax) for the **pricing year**

V_{total} is the total **closing RAB value** of all **connection assets** for the preceding **financial year**~~-~~

~~ΔV_{total} is **Transpower's** estimate of what the **closing RAB value** for the preceding **financial year** would have been for all **anticipatory capacity BBIs** if they had been included in the **RAB** as separate investments~~

D_{total} is total **depreciation** of all **connection assets** other than **investment agreement assets** for~~during~~ the preceding **financial year**, excluding **depreciation** due to **write-downs**

~~ΔD_{total} is an amount representing the notional **depreciation** of all **anticipatory capacity BBIs** during the preceding **financial year**, as determined by **Transpower**~~

RC_{total} is the total **replacement cost** of all **connection assets** other than **investment agreement assets** at the end of the preceding **financial year** ~~minus the value of any reductions made under subclause 27A(1) for the **pricing year**~~.

28 ~~27A~~ Anticipatory Capacity in Connection Assets

(1) Subject to subclause (3), **Transpower** may reduce the value of RC in subclause 27(1)~~27(1)~~ for a **connection asset** if the **connection asset**—

(a) was **commissioned** at or after the start of the **first pricing year**; and

(b) has **capacity** in addition to the **capacity** likely to be required during the relevant **pricing year** by the **customers** that the **connection asset** connects, as determined by **Transpower**.

(2) The size of the reduction in the value of RC under subclause (1) must be determined by **Transpower**—

(a) ~~determined by **Transpower**~~ having regard to the **capacity** in the **connection asset** the **customers** have agreed to fund under **investment agreements**; and

(b) to reflect the additional **replacement cost**~~proportionate to the amount~~ of the **connection asset** ~~additional **capacity** referred to in paragraph (1)(b)~~above the **replacement cost** of a **connection asset** with **capacity** sufficient to meet the requirements of the **customers** and reasonable **grid** contingencies during the relevant **pricing year**, but no more.

(3) **Transpower** must not reduce the value of RC under subclause (1) below any previously reduced value of RC for the **connection asset**.

Commented [A45]: Change: We consider this subclause should revert to our 30 June 2021 proposal.

In our view, the mechanism works better, and with the least disruption to current arrangements, if ARR is calculated in the normal way and the "work" of the discount is done through adjusting RC in subclause (1). The result is that the sum of the asset components calculated under subclause (1) will not recover the entire numerator of the ARR formula. The shortfall, being the aggregate asset component of all anticipatory capacity, will then fall to be recovered through benefit-based charges (not connection charges) under clause 29.

Our proposal has the benefit of removing any need to estimate notional RAB values or depreciation, consistent with the principle in clause 1(b)(iii) of the Guidelines. Our proposal also mitigates high charges for anticipatory capacity in the early years, which would result from the Authority's proposal to remove anticipatory capacity from the connection asset pool.

Commented [A46]: Style

Commented [A47]: Change: See section 4.3 of our submission.

Commented [A48]: Clarification: The application of paragraph (b) is also to be determined by Transpower.

Commented [A49]: Clarification: As previously drafted, this paragraph suggested an exactly proportionate relationship between the additional capacity and additional cost. Due to economies of scale, that is unlikely to be the case. This issue was raised during the Authority's consultation workshops.

(4) If **Transpower** reduces the value of RC under subclause (1), there is deemed to be a **commissioned BBI** (an **anticipatory capacity BBI**) for the **pricing year** only for the purposes of calculating **annual benefit-based charges** for these investments~~—~~
(a) that comprises the **connection asset**; and
(b) that has a **covered cost** for the **pricing year** (CC) calculated as follows:

$$CC \cancel{= (r \times V_i) + D_i} = \Delta RC \times ARR$$

where

~~r~~ ~~is **Transpower's PQ WACC** (pre-tax) for the **pricing year**~~

~~V_i~~ΔRC ~~is **Transpower's** estimate of what the **closing RAB value** for the preceding **financial year** would have been for the **anticipatory capacity BBI** if it had been included in the **RAB** as a separate investment~~is the absolute value of the reduction in the value of RC for the **pricing year**

~~D_i~~ARR is the **connection asset** return rate for the **pricing year** calculated under subclause 27(2)~~is an amount representing the notional **depreciation** of the **anticipatory capacity BBI** during the preceding **financial year**, as determined by **Transpower**~~; and

(c) for which the **start pricing year** is the **pricing year**; and
(d) for which a **customer's individual NPB** is calculated under the **simple method**, subject to the modifications in subclause (5) and even if—
(i) the absolute value of the reduction in the value of RC for the **pricing year**; or
(ii) the **anticipatory capacity BBI's** deemed **covered cost** for the **pricing year** under paragraph (b),
is more than the base capex threshold as defined in the **Capex IM**.

(5) The modifications referred to in paragraph (4)(d) are as follows:
(a) If **Transpower** determines the **anticipatory capacity BBI** is primarily to allow for a future increase in **offtake**, the **anticipatory capacity BBI's regional customer groups** are limited to **regional supply groups**:
(b) If **Transpower** determines the **anticipatory capacity BBI** is primarily to allow for a future increase in **injection**, the **anticipatory capacity BBI's regional customer groups** are limited to **regional demand groups**.

[Alternative drafting replacing clauses 27 and 28 above: Recovery of capital cost of anticipatory capacity through asset component of all connection charges]

29A Asset Component

(6) The asset component of the **connection charge** for a **connection asset** and **pricing year** (A) allocates a portion of the capital cost of all **connection assets** to the **connection asset**, and is calculated as follows:

$$A = (ARR \times RC) + (DARR \times RC')$$

where

ARR is the **connection asset** return rate for the **pricing year** calculated under subclause (2)

Commented [A50]: Change: We consider the drafting of this subclause from here should revert to our 30 June 2021 proposal, for the reasons above.

RC is—
(a) 0 if the **connection asset** is an **investment agreement asset**; or
(b) otherwise, subject to subclause (7), the **replacement cost** of the **connection asset** at the end of the preceding **financial year**

DARR is the discounted **connection asset** return rate for the **pricing year** calculated under subclause (11)

RC′ is the replacement cost of the **connection asset** at the end of the preceding **financial year** (even if **connection asset** a is an **investment agreement asset**) subject to any reduction made under subclause (7) for the **pricing year**.

(7) Subject to subclause (9), **Transpower** may reduce the value of RC in subclause (1) for a **connection asset** if the **connection asset**—
(a) was **commissioned** at or after the start of the **first pricing year**; and
(b) has **capacity** in addition to the **capacity** likely to be required during the relevant **pricing year** by the **customers** that the **connection asset** connects, as determined by **Transpower**.

(8) The size of the reduction in the value of RC under subclause (7) must be determined by **Transpower**—
(a) having regard to the **capacity** in the **connection asset** the **customers** have agreed to fund under **investment agreements**; and
(b) to reflect the additional **replacement cost** of the **connection asset** above the **replacement cost** of a **connection asset** with **capacity** sufficient to meet the requirements of the **customers** and reasonable **grid** contingencies during the relevant **pricing year**, but no more.

(9) **Transpower** must not reduce the value of RC under subclause (7) below any previously reduced value of RC for the **connection asset**.

(10) The **connection asset** return rate for a **pricing year** (ARR) is calculated as follows:

$$ARR = \frac{(r \times V_{total}) + D_{total}}{RC_{total}}$$

where

r is **Transpower's PQ WACC** (pre-tax) for the **pricing year**

V_{total} is the total **closing RAB value** of all **connection assets** for the preceding **financial year**

D_{total} is total **depreciation** of all **connection assets** other than **investment agreement assets** during the preceding **financial year,** excluding **depreciation** due to **write-downs**

RC_{total} is the total **replacement cost** of all **connection assets** other than **investment agreement assets** at the end of the preceding **financial year**.

(11) The discounted **connection asset** return rate for a **pricing year** (DARR) is calculated as follows:

$$DARR = \frac{ARR \times R_{total}}{RC'_{total}}$$

where

ARR is the **connection asset** return rate for the **pricing year** calculated under subclause (10)

R_{total} is the total of all reductions made under subclause (7) for the **pricing year**

RC'_{total} is the total **replacement cost** of all **connection assets** at the end of the preceding **financial year** (including **connection assets** that are **investment agreement assets**) less any reductions made under subclause (7) for the **pricing year**.

29 Funded Asset Component

(1) The **funded asset** component of the **connection charge** ensures that **non-contributing customers** pay part of the capital cost of **funded assets** through their **connection charges**.

(2) A **customer's funded asset** component for a **connection asset** is 0 unless—
(a) the **connection asset** is a **funded asset**; and
(b) the **customer** is, but for the **funded asset** component, a **non-contributing customer** for the **funded asset**.

(3) Subject to subclauses (4) and (5), a **non-contributing customer's funded asset** component for a **funded asset** and **pricing year** (FA) is calculated as follows:

$$FA = TF \times \frac{EL_{remain}}{EL_{total}} \times \frac{1}{10}$$

where

TF is the total amount paid, or expected to be paid, towards the capital cost of the **funded asset** under all **investment agreements**

EL_{remain} is the remaining **economic life** of the **funded asset** at the end of the **pricing year** during which the **non-contributing customer** connected to the **funded asset**

EL_{total} is the total **economic life** of the **funded asset**, including any part of it that has elapsed.

(4) The **non-contributing customer's funded asset** component for the **funded asset** applies for 10 consecutive **pricing years** only, starting with the **pricing year** after the **pricing year** during which the **non-contributing customer** connected to the **funded asset**.

(5) If the **non-contributing customer** agrees with 1 or more **prior contributing customers** to contribute towards the capital cost of a **funded asset**—
(a) subclause (3) applies to the **funded asset** subject to that agreement; and
(b) the agreement is deemed to be an **investment agreement** for the **funded asset** (even if **Transpower** is not a party to it).

30 Funded Asset Rebate

(1) A **non-contributing customer's funded asset** component for a **funded asset** and **pricing year** is rebated to each **prior contributing customer** for the **funded asset** in respect of the **non-contributing customer**.

(2) A **customer's funded asset** rebate for a **connection asset** and **pricing year** is 0 unless—

(a) the **connection asset** is a **funded asset**; and

(b) a **non-contributing customer** pays a **funded asset** component for the **funded asset** and **pricing year**; and

(c) the **customer** is a **prior contributing customer** for the **funded asset** in respect of the **non-contributing customer**.

(3) Subject to subclause (4), **prior contributing customer** c's **funded asset** rebate of **non-contributing customer** i's **funded asset** component for a **connection location** and **pricing year** (RBT_c) is calculated as follows:

$$RBT_c = FA_i \times CA_i \times \frac{AMDIC_c}{AMDIC_{total} - AMDIC_i}$$

where

FA_i is **non-contributing customer** i's **funded asset** component for the **funded asset** and **pricing year**

CA_i is **non-contributing customer** i's **connection customer allocation** for the **funded asset**, **connection location** and **pricing year**

$AMDIC_c$ is **prior contributing customer** c's **AMDC** or **AMIC** (as the case may be) for the **connection location** and **pricing year**

$AMDIC_{total}$ is the total of all **customers'** (including **prior contributing customer** c's and **non-contributing customer** i's) **AMDC** or **AMIC** (as the case may be) for the **connection location** and **pricing year**

$AMDIC_i$ is **non-contributing customer** i's **AMDC** or **AMIC** (as the case may be) for the **connection location** and **pricing year**.

(4) Subclause (3) applies subject to any agreement of the type referred to in subclause 29(5).

31 Maintenance Component

(1) The maintenance component of the **connection charge** for a **connection asset** and **pricing year** (M) allocates to the **connection asset** a portion of **Transpower's** total maintenance costs for all **connection assets**, and is calculated as follows:

$$M = MC \times (1 - ICR_{maint})$$

where

MC is the maintenance cost component for the **connection asset** and **pricing year** calculated under subclause (2)~~(1)~~

ICR_{maint} is the percentage of the maintenance cost for the **connection asset** and **pricing year** expected to be recovered by **Transpower** under **investment agreements**, expressed as a decimal and no more than 1.

(2) The maintenance cost component for the **connection asset** and **pricing year** (MC) is—
(a) if the **connection asset** is located at a **station**, the **station** maintenance cost component for the **pricing year** calculated under subclause (3); or
(b) if the **connection asset** is a **line**, the **line** maintenance cost component for the **pricing year** calculated under subclause (5).

(3) The **station** maintenance cost component for the **connection asset** and **pricing year** ($MC_{station}$) is calculated as follows:

$$MC_{station} = MRR_{station} \times RC$$

where

$MRR_{station}$ is the **station** maintenance recovery rate for the **pricing year** calculated under subclause (4)

RC is the **replacement cost** of the **connection asset** at the end of the preceding **financial year**.

(4) The **station** maintenance recovery rate for a **pricing year** ($MRR_{station}$) is calculated as follows:

$$MRR_{station} = \frac{AMC_{station\ total}}{RC_{station\ total}}$$

where

$AMC_{station\ total}$ is the average over the preceding 4 **financial years** of **Transpower's** maintenance costs for all **connection assets** located at **stations**

$RC_{station\ total}$ is the total **replacement cost** of all **connection assets** located at **stations** at the end of the preceding **financial year**.

(5) The **line** maintenance cost component is calculated using a **line** maintenance recovery rate that depends on the **line** type. The different **line** types (all AC) used are—
(a) 220kV or higher voltage tower **lines**; and
(b) other tower **lines**; and
(c) pole **lines**; and
(d) underground cable **lines**.

(6) The **line** maintenance cost component for the **connection asset** and **pricing year** (MC_{line}) is calculated as follows:

$$MC_{line} = MRR_{line\ t} \times L$$

where

$MRR_{line\ t}$ is the **line** maintenance recovery rate for the **connection asset's line** type t and the **pricing year** calculated under subclause (7)

L is the **line** length (in km) of the **connection asset** at the end of the preceding **financial year**.

(7) Subject to subclause (8), the **line** maintenance recovery rate for **lines** of type t and a **pricing year** ($MRR_{line\ t}$) is calculated as follows:

$$MRR_{line\ t} = \frac{AMC_{line\ t\ total}}{L_{t\ total}}$$

where

$AMC_{line\ t\ total}$ is the average over the preceding 4 **financial years** of **Transpower's** maintenance costs for all **connection assets** that are **lines** of type t

$L_{t\ total}$ is the total **line** length (in km) of all **connection assets** that are **lines** of type t at the end of the preceding **financial year**.

(8) **Transpower** may estimate the **line** maintenance recovery rate for underground cable **lines** if **Transpower** determines it has insufficient data to carry out the calculation in subclause (7) for underground cable **lines**.

32 Operating Component

(1) The operating component of the **connection charge** for a **connection asset** and **pricing year** (O) allocates to the **connection asset** a portion of **Transpower's** total operating costs for all **AC assets**, and is calculated as follows:

$$O = OC \times \left(1 - ICR_{op}\right)$$

where

OC is the operating cost component for the **connection asset** and **pricing year** calculated under subclause (2)

ICR_{op} is the percentage of the operating cost for the **connection asset** and **pricing year** expected to be recovered by **Transpower** under **investment agreements**, expressed as a decimal and no more than 1.

(2) The operating cost component for the **connection asset** and **pricing year** (OC) is calculated as follows:

$$OC = ORR \times \left(S - (0.1 \times S_{cust})\right)$$

where

ORR is the operating recovery rate for the **pricing year** calculated under subclause (3)

S is the number of switches that are part of the **connection asset** at the end of the preceding **financial year**

S_{cust} is the number of switches that are part of the **connection asset** and operated by a **customer** at the end of the preceding **financial year**.

(3) The operating recovery rate for the **pricing year** (ORR) is calculated as follows:

$$ORR = \frac{OC_{switch\ total}}{\left(S_{total} - (0.1 \times S_{cust\ total})\right)}$$

where

$OC_{switch\ total}$ is **Transpower's** total operating costs for all **AC switches** over the preceding **financial year**

S_{total} is the total number of **AC switches** at the end of the preceding **financial year**

$S_{cust\ total}$ is the total number of **AC switches** that are operated by a **customer** at the end of the preceding **financial year**.

33 Connection Customer Allocations

(1) Subject to subclause (5) and clause 34, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_1) is calculated as follows if the **connection asset** is—

(a) for 1 **connection location** only; and

(b) not a **mixed connection asset**:

$$CA_1 = \frac{AMDIC}{AMDIC_{total}}$$

where

AMDIC is the **customer's AMDC** or **AMIC** (as the case may be) at the **connection location** for the **pricing year**

$AMDIC_{total}$ is the total of all **customers' AMDCs** and **AMICs** at the **connection location** for the **pricing year**.

(2) Subject to subclause (5) and clause 34, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_{2+}) is calculated as follows if the **connection asset** is—

(a) for 2 or more **connection locations**, being the set of **connection locations** L; and

(b) not a **mixed connection asset**:

$$CA_{2+} = \frac{AMDIC}{AMDIC_{L\ total}}$$

where

AMDIC is the **customer's AMDC** or **AMIC** (as the case may be) at the **connection location** for the **pricing year**

$AMDIC_{L\ total}$ is the total of all **customers' AMDCs** and **AMICs** at all **connection locations** in the set of **connection locations** L for the **pricing year**.

(3) Subject to subclauses (4) and (5) and clause 34, a **customer's connection customer allocation** for a **connection asset**, **connection location** and **pricing year** (CA_{mixed}) is calculated as follows if the **connection asset** is a **mixed connection asset**:

$$CA_{mixed} = \frac{AMDIC}{C}$$

where

AMDIC is the **customer's AMDC** or **AMIC** (as the case may be) at the **connection location** for the **pricing year**

C is the **capacity** of the **connection asset** at the end of **CMP A** for the **pricing year**.

(4) If the sum of all **customers' connection customer allocations** for a **mixed connection asset** and **pricing year** is greater than 1, **Transpower** must scale down all of the **connection customer allocations** on a pro rata basis so that they sum to 1.

(5) If a **connection asset** is—

(a) an **investment agreement asset** provided under an **investment agreement** with a **customer**; and

(b) for more than 1 **connection location**, or for 1 **connection location** at which there is more than 1 **customer**,

then the calculation of the **connection customer allocations** for the **connection asset** for the **connection locations** is subject to any provisions in the **investment agreement** that alter the **customer's connection customer allocation** for the **connection asset** for the **connection locations**.

(6) The following table shows the **connection customer allocations** for the **connection assets** that are part of the **connection links** in figure 10 (based on the **AMDC** and **AMIC** quantities shown in figure 10):

<table>
<tr><th>link</th><th>connection location</th><th>customer</th><th>connection customer allocation</th></tr>
<tr><td rowspan="2">N1-N2</td><td rowspan="2">N1</td><td>A</td><td>$\frac{100}{140} = 0.7143$</td></tr>
<tr><td>B</td><td>$\frac{40}{140} = 0.2857$</td></tr>
<tr><td rowspan="3">N2-N3
N3-N4
N2-N4</td><td rowspan="2">N1</td><td>A</td><td>$\frac{100}{220} = 0.4545$</td></tr>
<tr><td>B</td><td>$\frac{40}{220} = 0.1818$</td></tr>
<tr><td>N3</td><td>C</td><td>$\frac{80}{220} = 0.3636$</td></tr>
<tr><td rowspan="5">N4-N6</td><td rowspan="2">N1</td><td>A</td><td>$\frac{100}{280} = 0.3571$</td></tr>
<tr><td>B</td><td>$\frac{40}{280} = 0.1429$</td></tr>
<tr><td>N3</td><td>C</td><td>$\frac{80}{280} = 0.2857$</td></tr>
<tr><td rowspan="2">N4</td><td>D (offtake)</td><td>$\frac{40}{280} = 0.1429$</td></tr>
<tr><td>D (injection)</td><td>$\frac{20}{280} = 0.0714$</td></tr>
</table>

34 De-rating

(1) This clause 34 applies if both of the following conditions are satisfied:

(a) a **customer** (the notifying **customer**) has notified **Transpower** in writing that the notifying **customer's assets** at a **connection location** have been **de-rated**:

(b) **Transpower** is reasonably satisfied the notifying **customer's assets** at the **connection location** have been **de-rated**.

(2) In this clause 34, a relevant **pricing year** is—

(a) the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the date the conditions in subclause (1) are first satisfied; and

(b) a subsequent **pricing year** if the date the conditions in subclause (1) are first satisfied is within **CMP A** for the **pricing year**.

(3) **Transpower** must, for each relevant **pricing year**, calculate **connection charges** for the **connection location** by—

(a) estimating the notifying **customer's** future **AMDC** and **AMIC** for the **connection location** taking into account—

(i) the new **capacity** of the connecting **customer's assets**; and

(ii) any available historical information about the notifying **customer's offtake** and **injection** at the **connection location**; and

(b) capping the notifying **customer's AMDC** and **AMIC** for the **connection location** and relevant **pricing year** at the notifying **customer's** estimated future **AMDC** and **AMIC** for the **connection location**.

35 Replacement Costs

(1) **Transpower** must review, including update as appropriate, the **replacement costs** it uses to calculate **connection charges** at intervals of no more than 5 years from the start of the **first pricing year**.

(2) **Transpower's** first review of **replacement costs** under subclause (1) may occur before the start of the **first pricing year**.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** who pay **connection charges** on any update to **replacement costs** under subclause (1) before updating the **replacement costs**.

(4) **Transpower** is not required to consult on an update to **replacement costs** under subclause (1) if **Transpower** determines—
   (a) the update is technical and non-controversial; or
   (b) there is widespread support for the update among **customers**; or
   (c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) Before **Transpower's** first review of **replacement costs** under subclause (1) is completed, the **replacement cost** of a **connection asset commissioned** before 1 July 2006 is calculated by multiplying the **connection asset's** unadjusted **replacement cost** by the **replacement cost adjustment factor**.

(6) If **Transpower** does not have a **replacement cost** for a **connection asset**, **Transpower** must use the **replacement cost** available to **Transpower** for the closest equivalent of the **connection asset**, as determined by **Transpower**, for the purposes of calculating **connection charges** for the **connection asset**.

Part D Benefit-based Charges

General

36 Calculation of Benefit-based Charges

(1) Subject to subclauses 87(7) and 88(6) and clause 92, only **beneficiaries** pay **benefit-based charges**, and only for the **BBIs** of which they are **beneficiaries**.

(2) A **beneficiary's annual benefit-based charge** for a **BBI** and **pricing year** (BBC) is calculated as follows:

$$BBC = CC \times CA$$

where

CC is the **BBI's covered cost** for the **pricing year**

CA is the **beneficiary's BBI customer allocation** for the **BBI**.

(3) A **beneficiary's monthly benefit-based charge** for a **BBI** and **pricing year** (MBBC) is calculated as follows:

$$MBBC = \frac{BBC}{12}$$

where BBC is the **beneficiary's annual benefit-based charge** for the **BBI** and **pricing year**.

(4) **Benefit-based charges** are calculated for each **pricing year** before the start of the **pricing year**.

(5) A **benefit-based charge** may be—
- (a) adjusted, including during a **pricing year**, under clauses 84 to 95 if there is a **benefit-based charge adjustment event**; and
- (b) adjusted under clause 101 if the relevant **BBI** is subject to **reassignment**.

37 Start of Benefit-based Charges

(1) Subject to subclause (2), **Transpower** must start the **benefit-based charges** for a **BBI** from the **BBI's start pricing year**. To avoid doubt, this subclause does not apply to charges under an **investment agreement**.

Commented [A51]: Clarification

(2) **Transpower** may delay the start of the **benefit-based charges** for a **low-value post-2019 BBI** under the **simple method** until the **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after **Transpower's** financial and regulatory records and registers contain all the locational information **Transpower** reasonably requires to calculate the **benefit-based charges** for the **BBI**.

38 Capital Expenditure on Existing BBIs

(1) Subject to subclause (4) and (5), **Transpower** must treat a **refurbishment investment** or **replacement investment** in respect of an existing **post-2019 BBI** as—

(a) part of the existing **post-2019 BBI**, in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**; or

(b) a separate **post-2019 BBI**; or

(c) part of an existing **post-2019 BBI** referred to in paragraph (b), in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**.

(2) Subject to subclause (4) and (5), **Transpower** must treat a **refurbishment investment** or **replacement investment** **commissioned** after 23 July 2019 in respect of an **Appendix A BBI** as—

(a) a separate **post-2019 BBI**; or

(b) part of an existing **post-2019 BBI** referred to in paragraph (a), in which case the **refurbishment investment** or **replacement investment** will increase the **covered cost** of the **post-2019 BBI** but will not change its **BBI customer allocations**.

(3) Subject to subclause (5), **Transpower** must treat an **enhancement investment** **commissioned** after 23 July 2019 in respect of an existing **BBI** as a separate **post-2019 BBI**.

(4) **Transpower** must not treat a **refurbishment investment** or **replacement investment** as part of an existing **post-2019 BBI** under subclause (1) or (2) if **Transpower** determines the **refurbishment investment** or **replacement investment** is likely to have—

(a) different **beneficiaries** than the existing **post-2019 BBI**; or

(b) a materially different distribution of **NPB** than the existing **post-2019 BBI**.

(5) If a **refurbishment investment**, **replacement investment** or **enhancement investment** referred to in subclause (1), (2) or (3) is an **exempt post-2019 investment**—

(a) **Transpower** must not treat the **refurbishment investment**, **replacement investment** or **enhancement investment** as, or as part of, a **post-2019 BBI**; and

(b) if the **refurbishment investment**, **replacement investment** or **enhancement investment** is in respect of an **Appendix A BBI**, **Transpower** must treat the **refurbishment investment**, **replacement investment** or **enhancement investment** as part of the **Appendix A BBI**, in which case the **refurbishment investment**, **replacement investment** or **enhancement investment** will increase the **covered cost** of the **Appendix A BBI** but will not change its **BBI customer allocations**.

39 Assumptions Book

(1) **Transpower** must **publish**, and may from time to time **publish** updates to, an **assumptions book**.

(2) The **assumptions book** must not contain any assumptions or methodologies that are inconsistent with this Code.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** on the **assumptions book** or any update to it before **publishing** the **assumptions book** or update.

Commented [A52]: Clarification

Commented [A53]: Clarification

Commented [A54]: **Change:** See section 4.2 of our submission.

This clause will result in the cost of the exempt post-2019 investment being recovered through residual charges, except if the investment relates to an Appendix A BBI in which case the cost will be added to the covered cost of the Appendix A BBI and recovered through its BBCs.

(4) **Transpower** is not required to consult on an update to the **assumptions book** if **Transpower** determines—
(a) the update is technical and non-controversial; or
(b) there is widespread support for the update among **customers**; or
(c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) Except as otherwise stated in this **transmission pricing methodology**, the **assumptions book** is not binding on **Transpower** or any **independent expert**.

(6) **Transpower** must review the content of the **assumptions book** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a review under clause 12.85 of this Code at intervals of no more than 7 years from the start of the **first pricing year**.

(7) The **assumptions book** may be part of the same document in which the **reassignment practice manual** or **prudent discount practice manual** is contained.

Covered Cost

40 Covered Cost

(1) A **BBI's covered cost** for a **pricing year** (CC) is calculated as follows:

$$CC = \sum_a (D_a + C_a + T_a) + AO$$

where

D_a is, subject to paragraph (6)(e), **depreciation** of **grid asset** a for the preceding **financial year**, where **grid asset** a is a **grid asset** comprised in the **BBI**, excluding **depreciation** due to a **write-down** of the **grid asset**~~accelerated **depreciation**~~

C_a is the **capital charge** for **grid asset** a and the preceding **financial year** calculated under subclause (2)

T_a is the sum of—
(a) **Transpower's** depreciation tax loss (positive value) or gain (negative value) for **grid asset** a and the preceding **financial year** calculated under subclause (3); and
(b) income tax on the **capital charge** for **grid asset** a and the preceding **financial year** calculated under subclause (5)

AO is the attributed opex component for the **BBI** and **pricing year** calculated under subclause 41(1).

(2) The **capital charge** for a **grid asset** and **financial year** (C) is calculated—
(a) if the **grid asset** had an **opening RAB value** for the **financial year**, as follows:

$$C = r \times V$$

where

Commented [A55]: **Clarification:** See also section 4.3 of our submission.

r is **Transpower's PQ WACC** (vanilla) at the start of the **financial year**

V is the **opening RAB value** for the **grid asset** and **financial year**; or

(b) if the **grid asset** was **commissioned** during the **financial year**, as follows:

$$C = V \times \frac{r \times (12.5 - m)}{12}$$

where

V is the **grid asset's value of commissioned asset**

r is **Transpower's PQ WACC** (vanilla) at the start of the **financial year**

m is the month of the **financial year** during which the **grid asset** was **commissioned** (for example, m = 3 for September).

(3) **Transpower's** depreciation tax loss or gain for a **grid asset** and **financial year** (T_{dep}) is calculated as follows:

$$T_{dep} = \frac{r \times (AD - TD - I)}{1 - r}$$

where

r is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the **financial year**;

AD is, subject to paragraph (6)(e), **depreciation** of the **grid asset** during the **financial year**, excluding **depreciation** due to a **write-down** of the **grid asset**

TD is, subject to paragraph (6)(e), tax depreciation of the **grid asset** during the **financial year**, excluding tax depreciation due to a **write-down** of the **grid asset**

I is notional interest for the **grid asset** and **financial year** calculated under subclause (4).

(4) Notional interest for a **grid asset** and **financial year** (I) is calculated as follows:

$$I = V \times L \times CD$$

where

V is the **opening RAB value** for the **grid asset** and **financial year** (if any)

L is leverage, as defined in the **Transpower IMs**, at the start of the **financial year**

CD is the estimated cost of debt used under the **Transpower IMs** to calculate **Transpower's PQ WACC** (vanilla) applicable at the start of the **financial year**.

(5) Income tax on the **capital charge** for a **grid asset** and **financial year** (T_{inc}) is calculated as follows:

Commented [A56]: Change: This is appropriate because write-downs are not otherwise part of covered cost (clauses 40(1) and 41(1)).

Commented [A57]: Change: This is appropriate because write-downs are not otherwise part of covered cost (clauses 40(1) and 41(1)).

$$T_{inc} = \frac{r \times C}{1 - r}$$

where

r is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the **financial year**;

C is the **capital charge** for the **grid asset** and **financial year** calculated under subclause (2).

(6) If a **grid asset** comprised in a **BBI** that is expected to be **high-value** when **fully commissioned**—
(a) was **commissioned** before or during a **pricing year's** preceding **financial year**; and
(b) does not have an asset type recorded in **Transpower's** fixed asset register at the time **Transpower** calculates the **BBI's covered cost** for the **pricing year**,

Transpower must—
(c) determine an interim asset type for the **grid asset** for **depreciation** and tax depreciation purposes; and
(d) use the interim asset type determined under paragraph (c) to calculate notional **depreciation** and notional tax depreciation for the **grid asset** and preceding **financial year**; and
(e) use the notional **depreciation** and notional tax depreciation calculated under paragraph (d) as the values for the variables D_a, AD and TD, as appropriate, in subclauses (1), (3) and 41(1) for the **grid asset** and **pricing year**; and
(f) make such adjustments to **depreciation** and depreciation tax loss or gain for the **BBI** and subsequent **financial years** as are necessary to ensure—
(i) there is no material over-recovery of **depreciation** for the **grid asset**; and
(ii) there is no material over or under-recovery of depreciation tax loss or gain for the **grid asset**.

41 Attributed Opex Component

(1) The attributed opex component for a **BBI** and **pricing year** (AO) is calculated as follows:

$$AO = \sum_{a} (D_a \times AOR) + HVDC + TA + MCP$$

where

D_a is, subject to subclause 40(6), **depreciation** of **grid asset** a for the preceding **financial year**, where **grid asset** a is a **grid asset** comprised in the **BBI**, excluding **depreciation** due to a **write-down** of the **grid asset** ~~accelerated depreciation~~

AOR is the attributed opex ratio for the **pricing year** calculated under subclause (3)

HVDC is—
(a) if the **BBI** comprises 1 or more **grid investments** in the **HVDC link**, an allocation of **HVDC opex** for the preceding **financial year** as determined by **Transpower** subject to subclause (2); or

Commented [A58]: Clarification

(b) otherwise, 0

TA is—
(a) if the **BBI** comprises 1 or more **grid investments** in **interconnection transmission alternatives**, **TA opex** for the **interconnection transmission alternatives** and preceding **financial year**, less any contribution to the **TA opex** under **investment agreements**; or
(b) otherwise, 0

MCP is **MCP opex** for the **BBI** and preceding **financial year**.

(2) **HVDC opex** for a **financial year** must be fully allocated to 1 or more **BBIs** that comprise a **grid investment** in the **HVDC link**, unless there are no such **BBIs**.

(3) The attributed opex ratio for a **pricing year** during an **RCP** (AOR) is calculated as follows:

$$AOR = \frac{OC + PC + RC - HVDC - TA - MCP - FD}{D}$$

where

OC is the **allowance** for operating costs, as defined in the **Transpower IMs**, for the **RCP**

PC is the **allowance** for pass-through costs, as defined in the **Transpower IMs**, for the **RCP**

RC is the **allowance** for recoverable costs, as defined in the **Transpower IMs**, for the **RCP**

HVDC is forecast **HVDC opex** for the **RCP**

TA is the **allowance** for **TA opex** for the **RCP**, to the extent any part of it is included in any of the above **allowances**

MCP is the **allowance** for **MCP opex** for the **RCP**, to the extent any part of it is included in any of the above **allowances**

FD is an amount of operating costs attributable to **Transpower** assets that are fully depreciated at the start of the **RCP**, as determined by **Transpower**

D is the **allowance** for **depreciation** for the **RCP**.

(4) The value of AOR in subclause (3) is—
(a) calculated for the whole of the **RCP**; and
(b) only re-calculated if any of the relevant **allowances** are reset by the **Commission** during the **RCP**.

42 Non-Grid Assets Comprised in Transmission Alternatives

For the purposes of calculating a **BBI's covered cost** for a **pricing year** under clauses 40 and 41, an asset that—
(a) is not a **grid asset** as defined in subclause 18(1); and
(b) is comprised in a **transmission alternative** that is comprised in the **BBI**; and

Commented [A59]: Change: Investment agreements may extend to transmission alternatives, in which case there should not be double-recovery through benefit-based charges.

Commented [A60]: Change: It is possible our RAB will contain assets comprised in post-2019 transmission alternatives that do not meet the definition of "grid asset". The capital components for these assets should be part of the covered cost of the relevant BBI.

(c) has an **opening RAB value** for the preceding **financial year**,
is treated as if it were a **grid asset**.

~~42~~43 ~~41A~~ Covered Cost of Anticipatory Capacity BBI
To avoid doubt, clauses 40 and 41 do not apply to an **anticipatory capacity BBI**, the deemed **covered cost** of which is as specified in paragraph 28(4)(b).

BBI Customer Allocations

~~43~~44 BBI Customer Allocations for Appendix A BBIs
(1) Subject to subclause (3), for each **Appendix A BBI**—
(a) the starting **beneficiaries** are the persons specified in Appendix A with a positive **BBI customer allocation** for the **Appendix A BBI**; and
(b) the starting **BBI customer allocations** are as specified in Appendix A.

(2) To avoid doubt, for each **Appendix A BBI**—
(a) the starting **beneficiaries** are based on the **Schedule 1 beneficiaries** of the **Appendix A BBI**; and
(b) the starting **BBI customer allocations** are based on the **Schedule 1 allocations** for the **Appendix A BBI**,
in each case adjusted as **Transpower** determines necessary to account for changes to **customers** before and after the **Authority** published the **2020 guidelines**.

(3) **Transpower** must adjust the starting **beneficiaries** and starting **BBI customer allocations** for the **Appendix A BBIs** under clauses 86 to 93 if there is a relevant **benefit-based charge adjustment event** before the **first pricing year**.

~~44~~45 BBI Customer Allocations for Post-2019 BBIs
(1) A **customer's BBI customer allocation** for a **post-2019 BBI** (CA) is calculated as follows:

$$CA = \frac{NPB}{NPB_{total}}$$

where

NPB is the **customer's individual NPB** for the **post-2019 BBI**

NPB_{total} is the total of all **customers' individual NPBs** for the **post-2019 BBI**.

(2) Subject to subclause (3), a **customer's individual NPB** for a **post-2019 BBI** is calculated under a **standard method** or the **simple method** as follows:

Commented [A61]: Typo

type	sub-type	method
post-2019 BBI expected to be **high-value** when **fully commissioned**	**resiliency BBI**	**resiliency method**
	otherwise	**price-quantity method**
post-2019 BBI expected to be **low-value** when **fully commissioned**		**simple method**

(3) For the purpose of calculating **customers' BBI customer allocations** for a **high-value intervening BBI** and its **start pricing year**, **Transpower** may apply the **simple method** if **Transpower** determines it is necessary to do so to ensure there is sufficient time for **Transpower** to complete a robust process for calculating the **BBI's BBI customer allocations** under the **standard method**, including consultation under clause 16.

(4) If **Transpower** applies the **simple method** under subclause (3) for a **high-value intervening BBI**, **Transpower** must carry out a wash-up of **transmission charges** in the **pricing year** after the **BBI's start pricing year** so that no **customer** is under or over-charged **benefit-based charges** for the **BBI** and **start pricing year** as a result of **Transpower** applying the **simple method** under subclause (3). The wash-up must include time value of money adjustments using **Transpower's ID WACC**.

(5) If a **post-2019 BBI** is a **tested investment**, the assumptions and other inputs (including the **factual**, **counterfactual**, **modelled constraints** and **scenarios**) **Transpower** uses in applying a **standard method** to the **post-2019 BBI** must be as consistent as reasonably practicable with the assumptions and other inputs used in applying the **investment test** to the **post-2019 BBI**, except—
- (a) as otherwise stated in this **transmission pricing methodology**; or
- (b) to the extent **Transpower** determines such alignment would not produce **BBI customer allocations** that are broadly proportionate to positive **NPB** from the **post-2019 BBI**, in which case **Transpower** may use assumptions and other inputs that applied up to, but not after, the **post-2019 BBI's final investment decision date**.

Commented [A62]: Change: This is added to eliminate any incentive a beneficiary may have to change its behaviour after a post-2019 BBI is committed with the aim of reducing its BBC allocation. In most cases we expect the allocations will already have been determined by the final investment decision date, but that may not be the case for the high-value intervening BBIs, for example.

Standard Method: Price-quantity Method

~~45~~46 Overview of Price-quantity Method

(1) Clauses 46 to 58 apply—
- (a) to the **price-quantity method** only; and
- (b) only to those **post-2019 BBIs** to which **Transpower** applies the **price-quantity method** in accordance with subclause 45(2).

(2) Under the **price-quantity method**—
- (a) **regional NPB** is calculated for a **regional customer group** as any of the following:
  - (i) **market regional NPB** under clauses 52 to 55:
  - (ii) **ancillary service regional NPB** under clause 56:
  - (iii) **reliability regional NPB** under clause 57:
  - (iv) **other regional NPB** under clause 58; and
- (b) **Transpower**—

(i) must calculate **market regional NPB** for a **market BBI**; and
(ii) may calculate **ancillary service regional NPB** for an **ancillary service BBI**; and
(iii) must calculate **reliability regional NPB** for a **reliability BBI**; and
(iv) subject to subclause 58(2), may calculate or estimate **other regional NPB** for a **market BBI**, **ancillary service BBI** or **reliability BBI**; and

(c) **individual NPB** is calculated for each **customer** in a **regional customer group** with positive **regional NPB**.

~~46~~47 Factual and Counterfactual

(1) **Transpower** must determine a **BBI's factual** and **counterfactual**.

(2) **Transpower** must apply the following principles to determine the **BBI's counterfactual** unless **Transpower** determines applying these principles does not produce a reasonably likely future **grid** state:

(a) if a **grid investment** comprised in the **BBI** is an **enhancement investment**, the **counterfactual** must include the **grid investment** not being made:
(b) if a **grid investment** comprised in the **BBI** is a **replacement investment** or **compliance investment**, the **counterfactual** must include the immediate decommissioning~~**decommissioning**~~ of the relevant **grid asset** or **transmission alternative** without replacement:
(c) if a **grid investment** comprised in the **BBI** is a **refurbishment investment**, the **counterfactual** must include leaving the relevant **grid asset** or **transmission alternative** in operation without refurbishment until it reaches replacement state and then immediately decommissioning~~**decommissioning**~~ it without replacement.

~~47~~48 Scenarios

(1) **Transpower** must determine a **BBI's scenarios** and probability weightings for the **scenarios**. The **BBI's market scenarios** must include variations in load growth, generation expansion and hydrology.

(2) **Transpower** must apply the same **scenarios** in a **BBI's factual** and **counterfactual**, unless the **BBI** is a **market BBI** that is expected to influence materially **generating plant** investment decisions, in which case **Transpower** may apply different generation development **market scenarios** in the **BBI's factual** and **counterfactual**.

(3) If a **market scenario** for a **BBI** includes a **customer** ceasing to be a **customer**, the **market scenario** must not be applied in the **BBI's factual or counterfactual** in respect of the **customer**. To avoid doubt, this means the present value of **regional NPB** for a **regional customer group** for the **BBI** of which the **customer** is a member may be different for the **customer** than for all other **customers** who are members of the **regional customer group**.

~~48~~49 Offtake and Injection at Same Connection Location

Despite clauses 50, 52~~,~~, 54, 55 and 68, in calculating—
(a) **market regional NPB** for a **regional customer group**; or
(b) a **customer's** share of **market regional NPB** for a **regional customer group**,

Transpower may set off market benefit and disbenefit arising in respect of a **customer** with **offtake** and **injection** at the same **connection location**.

~~49~~50 Individual NPB

A **customer's individual NPB** for a **BBI** (NPB) is calculated as follows:

Commented [A63]: **Typo:** For consistency with clause 58(2).

Commented [A64]: **Typo:** The defined term "decommissioning" in Part 1 of the Code does not extend to transmission alternatives.

Commented [A65]: **Typo**

Commented [A66]: **Typo**

$$NPB = \sum_{g} \left(PVRNPB_g \times \frac{IRA_g}{IRA_{g\,total}} \right)$$

where

$PVRNPB_g$ is the present value of **regional NPB** for **regional customer group** g calculated under clause 51, where **regional customer group** g is a **regional customer group** for the **BBI**—
(a) that has a positive present value of **regional NPB**; and
(b) of which the **customer** is a member

IRA_g is the value of the **customer's intra-regional allocator** for **regional customer group** g

$IRA_{g\,total}$ is the total of the values of all **customers' intra-regional allocators** for **regional customer group** g.

~~50~~51 Present Value of Regional NPB

(1) Subject to subclause (2), the present value of a **regional customer group's regional NPB** (PVRNPB) is calculated as follows:

$$PVRNPB = \sum_{n} \frac{RNPB_n}{(1+r)^n}$$

where

$RNPB_n$ is the **regional customer group's market regional NPB**, **ancillary service regional NPB**, **reliability regional NPB** or **other regional NPB** (as the case may be) for year n of the **BBI's standard method calculation period**

~~R~~r is the **BBI's standard method rate**.

Commented [A67]: Typo

(2) As an alternative to the calculation under subclause (1), **Transpower** may calculate a **regional customer group's market regional NPB**, **ancillary service regional NPB**, **reliability regional NPB** or **other regional NPB** (as the case may be) for each year of the **BBI's standard method calculation period** on a present value basis, provided that the method of calculating present value is consistent with the method in subclause (1).

~~51~~52 Modelling for Market Regional NPB

(1) This clause 52 applies to modelling for calculating **market regional NPB** for a **market BBI**.

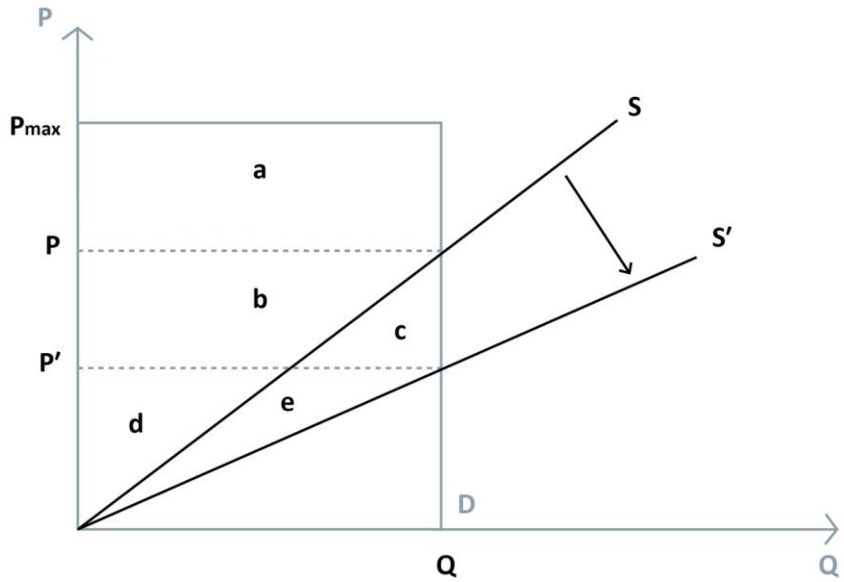
(2) **Transpower** must determine the **market BBI's investment grids**.

(3) **Transpower** must use a **wholesale market model** to model the prices, quantities and changes in prices and quantities in the **wholesale market** for **electricity** between the **market BBI's factual** and **counterfactual** under its **market scenarios** and based on its **investment grids**. The modelling must cover each year of the **market BBI's standard method calculation period**.

(4) The illustrative **wholesale market models** in figures 11 and 12 show alternative modelled prices, quantities and changes in prices and quantities for a notional **market BBI**, **market**

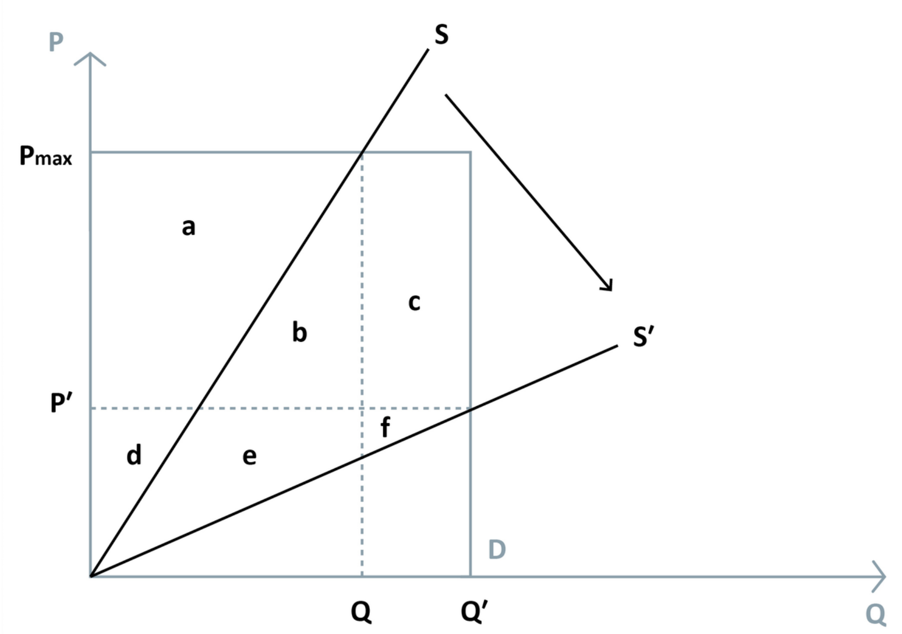
scenario and year of the **market BBI's standard method calculation period** (without ~~the application of~~applying subclause (5)). The effect of the **market BBI** is modelled as a change in the supply curve from S (**counterfactual**) to S′ (**factual**). P_{max} is **consumers'** estimated cost of self-supply for **electricity** or alternative energy.

Figure 11



Commented [A68]: Style

Figure 12



(5) **Transpower** may adjust prices in the modelling under this clause 52 if, and to the extent, **Transpower** determines it is appropriate to do so to moderate the sensitivity of modelled prices and changes in prices to modelling assumptions and other inputs, or otherwise with the objective of ensuring the **BBI customer allocations** for the **market BBI** are broadly proportionate to positive **NPB** from the **market BBI**.

~~52~~53 Modelled Regions and Regional Customer Groups

(1) **Transpower** must determine the **market BBI's modelled regions** as follows and based on the outcomes of the modelling under clause 52:

(a) a **modelled region** must be a set of either **GXPs** or **GIPs**:

(b) the modelled price or quantity changes, if any, at all **GXPs** or **GIPs** in a **modelled region** must be in the same direction:

(c) a region meeting the requirements of paragraphs (a) and (b) may comprise more than one **modelled region** if the market benefits or disbenefits accruing at different **GXPs** or **GIPs** in the region—

(i) are of a materially different magnitude; or

(ii) occur at different times, or are of a materially different magnitude, depending on whether there are binding **constraints**; or

(iii) occur under different **market scenarios**:

(d) **Transpower** must determine the **market BBI's modelled regions** with the objective of ensuring the **BBI customer allocations** for the **market BBI** are broadly proportionate to positive **NPB** from the **market BBI**.

(2) **Transpower** must determine the **market BBI's regional customer groups** as follows and based on the outcomes of the modelling under clause 52:

(a) Subject to paragraph (b), the **market BBI's regional customer groups** are as follows:

type of **regional customer group**	**regional customer group**
regional demand group	all **offtake customers** in a **modelled region** defined by a set of **GXPs**
regional supply group	all **injection customers** in a **modelled region** defined by a set of **GIPs**

(b) there may be more than 1 **regional demand group** or **regional supply group** for the same **modelled region**, each comprising different **offtake customers** or **injection customers** (as the case may be), if **Transpower** determines it is necessary to have more than 1 **regional demand group** or **regional supply group** for the **modelled region** to produce **BBI customer allocations** for the **market BBI** that are broadly proportionate to positive **NPB** from the **market BBI**, having regard to the attributes of the **offtake customers** or **injection customers** (including whether the **offtake customers** or **injection customers** currently exist in the **modelled region**).

(3) To avoid doubt—

(a) a **market BBI** may have 1 or more **future regional customer groups**, which may be **regional demand groups**, **regional supply groups** or a combination of both; and

(b) a **regional customer group** that is not a **future regional customer group** may, in future, include **offtake customers** or **injection customers** who do not currently exist in the relevant **modelled region**.

~~53~~54 Calculation of Market Regional NPB based on Quantity

(1) **Transpower** must calculate **market regional NPB** for a **market BBI** under this clause 54 if—

(a) **Transpower** determines, based on the outcomes of the modelling under clause 52 and taking into account the **market BBI's market scenarios** and their probability weightings determined by **Transpower** under clause 48(1), that most of the positive **market regional NPB** for the **market BBI's regional supply groups** relates to new **large generating plant** for which, at the time **Transpower** makes its determination under this paragraph, the proponent has not made its final decision to proceed with its investment in the **plant**; or

(b) subclause 55(1) does not apply.

(2) For each **regional customer group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit (positive value) or disbenefit (negative value) is calculated based on—

(a) ~~based on~~ the modelling under clause 52; and

(b) ~~for~~ the period or periods during which the **market BBI** is modelled to generate~~provide~~ its primary market benefits, as determined by **Transpower**,

as follows:

(c) for a **regional demand group**, quantities in the **counterfactual** are positive if prices decrease in the **factual** and negative if prices increase in the **factual**:

Commented [A69]: Clarification: There may only be one period of benefit and the manifestation of the benefit generated during a period (changes in prices and quantities versus the counterfactual) may manifest outside the period (but still within the relevant calculation period). In other words, there will be a causal relationship but not necessarily a temporal one.

(d) for a **regional supply group**, quantities in the **counterfactual** are positive if prices increase in the **factual** and negative if prices decrease in the **factual**:

(e) for a **regional demand group** or **regional supply group**, the positive or negative quantities under paragraph (c) or (d) (as appropriate) are summed with the changes in quantities between the **factual** and **counterfactual**, an increase being positive and a decrease being negative, the sum being the expected market benefit or disbenefit.

(3) To avoid doubt, the price and quantity increases and decreases referred to in paragraphs (2)(c) to (2)(e) may occur at times outside the period or periods referred to in paragraph (2)(b).

~~(3)~~(4) A **regional customer group's market regional NPB** for a year of the **market BBI's standard method calculation period** (MRNPB) is calculated as follows:

$$MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$$

where

$EMBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **market BBI**, but excluding any expected market benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 48(1).

~~(4)~~(5) To avoid doubt, subject to clause 49, expected market benefits and disbenefits are not summed between different **regional customer groups**.

~~(5)~~(6) If necessary for calculating the **BBI customer allocations** for the **market BBI**, **Transpower** must determine the dollar value of each **regional customer group's market regional NPB** for each year of the **market BBI's standard method calculation period**, taking into account total positive **market regional NPB** for the **market BBI** calculated under clause 55.

~~54~~55 Calculation of Market Regional NPB based on Price and Quantity

(1) **Transpower** must calculate **market regional NPB** for the **market BBI** under this clause 55 if—

(a) paragraph 54(1)(a) does not apply; and

(b) **Transpower** determines, based on the outcomes of the modelling under clause 52 and taking into account the **market BBI's market scenarios** and their probability weightings determined by **Transpower** under clause 48(1), that—

(i) most of the positive **market regional NPB** for the **market BBI's regional customer groups** derives from **consumers** avoiding having to pay their estimated cost of self-supply for **electricity** or alternative energy during peak **demand** periods; or

(ii) calculating **market regional NPB** for the **market BBI** under clause 54 would not produce **BBI customer allocations** that are broadly proportionate to positive **NPB** from the **market BBI**.

Commented [A70]: Clarification: See comment on clause 54(2).

(2) For a **regional demand group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit or disbenefit is equal to—

(a) the modelled change in consumer benefit for the **regional demand group** in the **wholesale market** for **electricity** (a positive change being a market benefit and a negative change being a market disbenefit); plus

(b) unless **Transpower** has adjusted modelled price outcomes under subclause 52(5), the modelled change in **loss and constraint excess** received by **customers** in the **regional demand group** as a result of the change in consumer benefit (a positive change being a market benefit and a negative change being a market disbenefit).

(3) For a **regional supply group**, **market scenario** and year of the **market BBI's standard method calculation period**, the expected market benefit or disbenefit arising is equal to—

(a) the modelled change in producer benefit for the **regional supply group** in the **wholesale market** for **electricity** (a positive change being a market benefit and a negative change being a market disbenefit); plus

(b) unless **Transpower** has adjusted modelled price outcomes under subclause 52(5), the modelled change in **loss and constraint excess** received by **customers** in the **regional demand group** as a result of the change in consumer benefit (a positive change being a market benefit and a negative change being a market disbenefit).

(4) In the illustrative **wholesale market model** in figure 11—

(a) the expected market benefit or disbenefit for the **regional demand group** is equal to the modelled change in consumer benefit, being:

factual	**counterfactual**	change in consumer benefit
a + b + c	a	b + c

(b) the expected market benefit or disbenefit for the **regional supply group** is equal to the modelled change in producer benefit, being:

factual	**counterfactual**	change in producer benefit
d + e	b + d	e - b

(5) In the illustrative **wholesale market model** in figure 12—

(a) the expected market benefit or disbenefit for the **regional demand group** is equal to the modelled change in consumer benefit, being:

factual	**counterfactual**	change in consumer benefit
a + b + c	0	a + b + c

(b) the expected market benefit or disbenefit for the **regional supply group** is equal to the modelled change in producer benefit, being:

factual	**counterfactual**	change in producer benefit
d + e + f	a + d	e + f - a

(6) A **regional customer group's market regional NPB** for a year of the **market BBI's standard method calculation period** (MRNPB) is calculated as follows:

$$MRNPB = \frac{1}{\sum_s W_s} \sum_s (EMBD_s \times W_s)$$

where

$EMBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **market BBI**, but excluding any expected market benefit or disbenefit attributable to a future **customer** or future **large plant** unless the **regional customer group** is a **future regional customer group**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 48(1).

(7) To avoid doubt, subject to clause 49, expected market benefits and disbenefits are not summed between different **regional customer groups**.

~~55~~56 **Ancillary Service Regional NPB**

(1) This clause 56 applies to calculating **ancillary service regional NPB** for an **ancillary service BBI** (if **Transpower** decides to calculate **ancillary service regional NPB** for the **ancillary service BBI**).

(2) **Transpower** must model changes in prices and quantities in the **wholesale market** for the relevant **specified ancillary service** between the **ancillary service BBI's factual** and **counterfactual** under its **market scenarios**. The modelling must cover each year of the **ancillary service BBI's standard method calculation period**.

(3) **Transpower** must determine the **ancillary service BBI's modelled regions** and **regional customer groups** as follows:

specified ancillary service	type of **regional customer group**	**modelled region**	**regional customer group**
instantaneous reserve (by **island**)	**regional demand group**	none	none
	regional supply group	**island**	all **grid-connected generators** in **modelled region**
frequency keeping	**regional demand group**	New Zealand	all **direct consumers** in **modelled region**

Commented [A71]: Style: We recommend the contents of all tables be changed to unjustified text because otherwise they can look peculiar (especially this table).

	regional supply group	none	none
voltage support (by **zone**)	**regional supply group**	none	none
	regional demand group	**zone**	all **connected asset owners** in **modelled region**

(4) For a **regional customer group**, **market scenario** and year of the **ancillary service BBI's standard method calculation period**, the expected market benefit or disbenefit is equal to the modelled change in the **allocable cost** of the **specified ancillary service** (a negative change being a market benefit and a positive change being a market disbenefit).

(5) A **regional customer group's ancillary service regional NPB** for a year of the **ancillary service BBI's standard method calculation period** (ASRNPB) is calculated as follows:

$$ASRNPB = \frac{1}{\sum_s W_s}\sum_s (EMBD_s \times W_s)$$

where

$EMBD_s$ is the expected market benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **ancillary service BBI**, but excluding any expected reliability benefit or disbenefit attributable to a future **customer** or future **large plant**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 48(1).

(6) To avoid doubt, subject to clause 49, expected market benefits and disbenefits are not summed between different **regional customer groups**.

~~56~~57 Reliability Regional NPB

(1) This clause 57 applies to calculating **reliability regional NPB** for a **reliability BBI**.

(2) **Transpower** must use a **system limit model** to model changes in expected **curtailed energy** between the **reliability BBI's factual** and **counterfactual** under its **outage scenarios**. The modelling must cover each year of the **reliability BBI's standard method calculation period**.

(3) The illustrative **system limit model** in figure 13 shows, for a notional **reliability BBI**, **outage scenario**, **market scenario** and year of the **reliability BBI's standard method calculation period**, the effect of the **reliability BBI**. The effect of the **reliability BBI** is modelled as a change in the **system limit** from S (**counterfactual**) to S′ (**factual**), which reduces the value of X (percentage of year t **supply**, **demand** or **active power** transfer is at or more than the **system limit**). The modelled change in expected **curtailed energy** for the year (ΔECE) is calculated as follows:

$$\Delta ECE = CE \times \Delta P$$

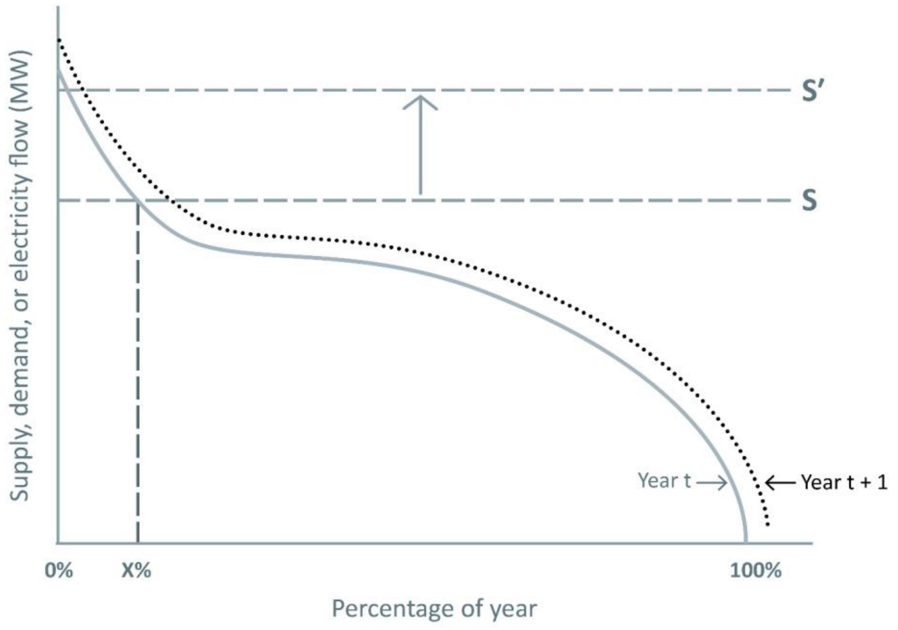
where

C~~U~~E is **Transpower's** estimate of **curtailed energy** caused by the **outage scenario** occurring in the **market scenario**

Commented [A72]: Typo

ΔP is the change in the value of X in figure 13 between the **counterfactual** and **factual**.

Figure 13



(4) **Transpower** must determine the **reliability BBI's modelled regions** and **regional customer groups** as follows and based on the outcomes of the modelling under subclause (2):

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a region defined by a set of **GXPs** at which there is expected to be a change in **unserved energy** in the same direction if an **outage scenario** for the **reliability BBI** occurs	all **offtake customers** in the **modelled region**
regional supply group	a region defined by a set of **GIPs** at which there is expected to be a change in **unsupplied energy** in the same direction if an **outage scenario** for the **reliability BBI** occurs	all **injection customers** in the **modelled region**

(5) For each **regional customer group**, **market scenario** and year of the **reliability BBI's standard method calculation period**, the expected reliability benefit or disbenefit (ERBD) is calculated as follows:

$$ERBD = -\sum_{z}(\Delta ECE_z \times VL)$$

where

ΔEUE_z is the modelled change in expected **curtailed energy** for the **regional customer group** and **outage scenario** z, where **outage scenario** z is an **outage scenario** for the **reliability BBI**, calculated under subclause (3)

VL is—

(a) if the **regional customer group** is a **regional demand group**, the **reliability BBI's VOLL**; or

(b) if the **regional customer group** is a **regional supply group**, a value of lost generation determined by **Transpower**.

(6) A **regional customer group's reliability regional NPB** for a year of the **reliability BBI's standard method calculation period** (RRNPB) is calculated as follows:

$$RRNPB = \frac{1}{\sum_s W_s}\sum_{s}(ERBD_s \times W_s)$$

where

$ERBD_s$ is the expected reliability benefit (positive value) or disbenefit (negative value) for the **regional customer group** and year for **market scenario** s, where **market scenario** s is a **market scenario** for the **reliability BBI**, but excluding any expected reliability benefit or disbenefit attributable to a future **customer** or future **large plant**

W_s is the probability weighting for **market scenario** s determined by **Transpower** under clause 48(1).

(7) To avoid doubt—
(a) expected reliability benefits and disbenefits are not summed between different **regional customer groups**; and
(b) all **regional demand groups**, and all members of a **regional demand group**, are assumed to have the same value of **unserved energy**, being the **reliability BBI's VOLL**; and
(c) all **regional supply groups**, and all members of a **regional supply group**, are assumed to have the same value of **unsupplied energy**, being the value of lost generation determined by **Transpower** under subclause (5).

~~57~~58 Other Regional NPB

(1) This clause 58 applies to calculating or estimating **other regional NPB** for a **market BBI**, **ancillary service BBI** or **reliability BBI**.

(2) **Transpower** must only calculate or estimate **other regional NPB** for a **BBI** if all of the following criteria are satisfied:
(a) **Transpower** reasonably expects positive **other regional NPB** for the **BBI** to be received—
(i) directly by 1 or more existing **customers**, whether in their capacities as **customers** or otherwise; or
(ii) by the majority of **embedded plant** owners connected to a **host customer's local network** or **grid**-connected **plant**, whether in their capacities as **embedded plant** owners or otherwise:
(b) **Transpower** determines the **other regional NPB** will be a material part of total positive **regional NPB** for the **BBI**:
(c) **Transpower** determines the dollar value of the **other regional NPB** can be calculated or estimated to a reasonable level of certainty without **Transpower** incurring disproportionate cost.

(3) **Transpower** must determine the **BBI's modelled regions** and **regional customer groups** as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a region in which **other regional NPB** is expected to arise from the **BBI**	all **offtake customers** in the **modelled region** expected to receive the **other regional NPB**
regional supply group		all **injection customers** in the **modelled region** expected to receive the **other regional NPB**

(4) To avoid doubt, the **BBI customer allocations** for a **BBI** are not adjusted merely because **other regional NPB** for the **BBI** arises or is discovered after the starting **BBI customer allocations** for the **BBI** have been calculated.

Standard Method: Resiliency Method

~~58~~59 Overview of Resiliency Method

(1) Clauses 59 to 61 apply—
- (a) to the **resiliency method** only; and
- (b) only to those **post-2019 BBIs** to which **Transpower** applies the **resiliency method** in accordance with subclause 45(2).

(2) Under the **resiliency method**—
- (a) there is 1 **modelled region** and 1 **regional customer group**; and
- (b) **regional NPB** for the **regional customer group** is assumed to be positive and is not calculated; and
- (c) **individual NPB** is calculated for each **customer** in the **regional customer group**.

~~59~~60 Individual NPB

Customer c's **individual NPB** for the **resiliency BBI** (NPB_c) is equal to the value of **customer** c's **intra-regional allocator** for the **regional customer group**.

~~60~~61 Modelled Region and Regional Customer Group

Transpower must determine a **resiliency BBI's modelled region** and **regional customer group** as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	the **island** in which the risk of cascade failure is mitigated	all **offtake customers** in the **modelled region**
	a region in which the risk of the **HILP event** is mitigated	
regional supply group	none	none

Simple Method

~~61~~62 Overview of Simple Method

(1) Clauses 62 to 67 apply—
- (a) to the **simple method** only; and
- (b) only to—
  - (i) those **low-value post-2019 BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 45(2); and
  - (ii) those **high –value intervening BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 45(3); and
  - ~~(ii)~~(iii) **anticipatory capacity BBIs**.

(2) Under the **simple method**—

Commented [A73]: **Clarification:** This clause should also capture the high-value intervening BBIs to which the simple method is temporarily applied.

(a) **regional NPB** is calculated for a **regional customer group** in respect of an **investment region** based on the extent to which the **regional customer group** is deemed to contribute to total **offtake** and **injection** in, or **electricity** flow to or from, the **investment region**, either as—
  (i) a **regional customer group** in the **investment region**; or
  (ii) a **regional demand group** in another **modelled region** that imports **electricity** from the **investment region** directly or indirectly; or
  (iii) a **regional supply group** in another **modelled region** that exports **electricity** to the **investment region** directly or indirectly; and

(b) **individual NPB** is calculated for each **customer** in a **regional customer group** with positive **regional NPB** in respect of the **investment region**.

(3) To avoid doubt, a **BBI** may have more than one **investment region** depending on where the **grid investments** comprised in the **BBI** are located.

~~62~~63 Simple Method Periods

(1) Subject to subclause (2), the **simple method periods** are—
  (a) the period starting on 24 July 2019 and ending at the end of the fourth **pricing year** after the **first pricing year**; and
  (b) each period of 5 **pricing years** immediately following the end of the previous **simple method period**.

(2) **Transpower** may start a new **simple method period** to coincide with the start of an **RCP**.

~~63~~64 Individual NPB

(1) A **customer's individual NPB** for a **BBI** in an **investment region** (NPB) is calculated as follows:

$$NPB = \sum_{g} (RNPB_g \times SMF_g)$$

where

$RNPB_g$ is **regional NPB** for **regional customer group** g, where **regional customer group** g is a **regional customer group** for the **BBI**—
  (a) that has positive **regional NPB** in respect of the **investment region**; and
  (b) of which the **customer** is a member

SMF_g is the **customer's simple method factor** for **regional customer group** g.

(2) A **customer's simple method factor** for a **simple method period** and **regional customer group** of which the **customer** is a member (SMF) is calculated as follows:

$$SMF = \frac{IRA}{IRA_{total}}$$

where

IRA is the value of the **customer's intra-regional allocator** for the **simple method period** and **regional customer group**

IRA$_{total}$ is the total of the values of all **customers' intra-regional allocators** for the **simple method period** and **regional customer group**.

(3) If a **benefit-based charge adjustment event** in any of paragraphs 84(1)(b) to 84(1)(k) occurs between the end of **CMP C** for a **simple method period** and the start of the **simple method period**, **Transpower** must apply subclause (6) to calculating all **customers' simple method factors** for the **simple method period** as if the **benefit-based charge adjustment event** occurred during the **simple method period**.

(4) The values of RNPB$_g$ and SMF$_g$ under subclause (1) are those that apply when the **BBI** is **commissioned**. To avoid doubt, the **BBI customer allocations** for the **BBI** do not change merely because—

(a) there are different values of **regional NPB** for a subsequent **simple method period**; or

(b) there are different **simple method factors** for a subsequent **simple method period**; or

(c) new **simple method factors** for a **simple method period** are published under paragraph (6)(b).

~~(3)~~(5) **Transpower** must—

(a) **publish** in the **assumptions book** the **simple method factors** for the first **simple method period** before the start of the **first pricing year**, which, subject to subclause (6), will apply to **BBIs commissioned** during the first **simple method period**; and

(b) **publish** in the **assumptions book** the **simple method factors** for each subsequent **simple method period** before the start of the subsequent **simple method period**, which, subject to subclause (6), will apply to **BBIs commissioned** during the subsequent **simple method period**.

~~(4)~~(6) If a **benefit-based charge adjustment event** in any of paragraphs 84(1)(b) to 84(1)(k) occurs, **Transpower** must—

(a) calculate or re-calculate (as the case may be) all **customers' simple method factors** for the current **simple method period** ~~under subclause (2)~~ using estimated values for the **customers' intra-regional allocators** to the extent necessary; and

(b) **publish** in the **assumptions book** the new **simple method factors**, which, subject to this subclause (6), will apply to **BBIs commissioned** during the **simple method period** after the new **simple method factors** are **published**.

~~64~~65 **Modelled Regions**

(1) The **modelled regions** are the **connection regions** and **HVDC link**.

(2) **Transpower** must—

(a) **publish** in the **assumptions book** the initial **modelled regions** before the start of the **first pricing year**; and

(b) **publish** in the **assumptions book** the **modelled regions** for each subsequent **simple method period** before the start of the subsequent **simple method period**.

(3) **Transpower** must review, including update as appropriate, the **modelled regions** (other than the **HVDC link**) for each **simple method period** before the start of the **simple method period**.

(4) **Transpower** must determine the **connection regions** for a **simple method period** by—

Commented [A74]: Change: This is added so that adjustment events that occur in te interregnum between CMP C and the start of a simple method period are not ignored when calculating simple method factors for that simple method period.

Commented [A75]: Clarification: This is the effect of subclauses (5) and (6) and clause 67(1), but we think it should be clearly stated.

Commented [A76]: Style: Redundant cross-reference.

(a) determining **high-voltage grid connection regions** on either side of the **HVDC link**; and

(b) isolating prevailing directional **electricity** flows on **interconnection branches** in the **high-voltage grid** (excluding the **HVDC link**) over **CMP C** for the **simple method period** and determining **high-voltage grid connection regions** on either side of the **interconnection branches** on which those **electricity** flows occur; and

(c) determining a **low-voltage grid connection region** on the **low-voltage grid** side of each **interconnection transformer branch** containing an **interconnecting transformer** connecting the **low-voltage grid** to a **high-voltage grid connection region**; and

(d) if a **low-voltage grid connection region** is connected to more than 1 **high-voltage grid connection region**, determining separate **low-voltage grid connection regions** on either side of the minimum transfer **interconnection branch** within the **low-voltage grid connection region**, so that each of the separate **low-voltage grid connection regions** is connected to only 1 **high-voltage grid connection region**; and

(e) for a **low-voltage connection region** connected to 1 **high-voltage connection region**, determining separate **low voltage grid connection regions** on either side of the minimum transfer **interconnection branch** within the **low-voltage grid connection region** if **electricity** flow on that **branch** is low relative to total **electricity** flows between **interconnecting transformers** in the **low-voltage grid connection region**; and

(f) incorporating—

(i) the **branches** referred to in paragraph (b) in both relevant **connection regions** in proportion to the **electricity** flows on those **branches** into each **connection region**; and

(ii) the **branches** referred to in paragraph (c), including the **interconnecting transformers**, in the relevant **low-voltage grid connection region**; and

(iii) the **branches** referred to in paragraphs (d) and (e) in both relevant **low-voltage connection regions** in half parts.

(5) **Transpower**—

(a) is not required to (but may) assess **electricity** flows over the entire **high-voltage grid** under paragraph (4)(b); and

(b) may amalgamate geographically adjacent **connection regions** for a **simple method period** if—

(i) the **connection regions** have the same voltage; and

(ii) 1 or more of the **connection regions** contains significantly fewer **market nodes** than the average number of **market nodes** contained in all **connection regions**.

~~65~~66 Regional Customer Groups

Subject to subclause 28(5)~~27A(7)~~, the **regional customer groups** are as follows:

type of **regional customer group**	**modelled region**	**regional customer group**
regional demand group	a **connection region**	all **offtake customers** in the **modelled region**
regional supply group		all **injection customers** in the **modelled region**

~~66~~67 **Regional NPB**

(1) **Transpower** must—

(a) **publish** in the **assumptions book** the **regional NPB** for each **regional customer group** in respect of each **investment region** for the first **simple method period** before the start of the **first pricing year**, which will apply to **BBIs commissioned** during the first **simple method period**; and

(b) **publish** in the **assumptions book** the **regional NPB** for each **regional customer group** in respect of each **investment region** for a subsequent **simple method period** before the start of the subsequent **simple method**, which will apply to **BBIs commissioned** during the subsequent **simple method period**.

(2) **Regional NPB** for a **regional customer group** in respect of an **investment region** for a **simple method period** (RNPB) is calculated as follows:

$$RNPB = \frac{1}{\sum_t W_t} \sum_t (SMC_t \times W_t) \times DAF$$

where

T is the number of **trading periods** for which SMC_t is calculated, which must be all **trading periods** during **CMP C** for the **simple method period** for which **Transpower** determines it has access to reliable values for the variables in subclause (6)

SMC_t is the **regional customer group's simple method contribution** in respect of the **investment region** for **trading period** t, where **trading period** t is a **trading period** during **CMP C** for the **simple method period**

W_t is a weighting for **trading period** t determined by **Transpower**

DAF is—

(a) if the **regional customer group** is a **regional demand group**, the **demand adjustment factor** for the **simple method period**; or

(b) if the **regional customer group** is a **regional supply group**, 1.

(3) **Transpower** must review, including update as appropriate, the **demand adjustment factor** for each **simple method period** after the first **simple method period**—

(a) taking into account the overall **BBI customer allocations** between **offtake customers** and **injection customers** across at least 10 **BBIs** under the **standard methods**; and

(b) with the objective of producing **BBI customer allocations** that are broadly proportionate to positive **NPB** from **BBIs commissioned** during the **simple method period**.

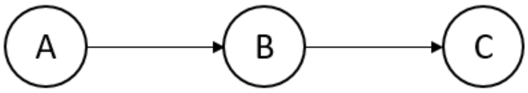
Transpower must publish the **demand adjustment factor** in the **assumptions book** before the start of the **simple method period**.

(4) Figure 14 illustrates how, given the generalised **electricity** flow state depicted (**connection region** A to B to C)—

(a) the **beneficiaries** of a **BBI** in one of the **connection regions** (being the **investment region**) are identified; and

(b) a **regional customer group's simple method contribution** in respect of the **investment region** is calculated for a **trading period** during which, on average, the **electricity** flow state prevailed.

Figure 14



		connection region A	**connection region** B	**connection region** C
simple method contribution	**regional supply group** A	$\frac{G_a}{(G_a + L_a + F_{a\_b})}$	$\frac{F_{a\_b}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{F_{a\_b}}{G_b + F_{a\_b}}\right)$
	regional supply group B	0	$\frac{G_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{F_{b\_c}}{(G_c + L_c + F_{b\_c})}\left(\frac{G_b}{G_b + F_{a\_b}}\right)$
	regional supply group C	0	0	$\frac{G_c}{(G_c + L_c + F_{b\_c})}$
	regional demand group A	$\frac{L_a}{(G_a + L_a + F_{a\_b})}$	0	0
	regional demand group B	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{L_b}{L_b + F_{b\_c}}\right)$	$\frac{L_b}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	0
	regional demand group C	$\frac{F_{a\_b}}{(G_a + L_a + F_{a\_b})}\left(\frac{F_{b\_c}}{L_b + F_{b\_c}}\right)$	$\frac{F_{b\_c}}{(G_b + L_b + F_{a\_b} + F_{b\_c})}$	$\frac{L_c}{(G_c + L_c + F_{b\_c})}$

(5) In figure 14—

(a) the **beneficiaries** of a **BBI** in **connection region** A (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** A; and

(ii) the **customers** in the **regional demand groups** in **connection regions** B and C, which import **electricity** from the **investment region** directly or indirectly; and

(b) the **beneficiaries** of a **BBI** in **connection region** B (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** B; and

(ii) the **customers** in the **regional supply group** in **connection region** A, which exports **electricity** to the **investment region** directly; and

(iii) the **customers** in the **regional demand group** in **connection region** C, which imports **electricity** from the **investment region** directly; and

(c) the **beneficiaries** of a **BBI** in **connection region** C (being the **investment region**) are deemed to be—

(i) the **customers** in the **regional demand group** and **regional supply group** in **connection region** C; and

(ii) the **customers** in the **regional supply groups** in **connection regions** A and B, which export **electricity** to the **investment region** directly or indirectly.

(6) In figure 14, a **regional customer group's simple method contribution** in respect of the **investment region** (being either **connection region** A, B or C) for a **trading period** is calculated in accordance with the relevant formula in figure 14, where:

G_x is total **injection** at all **GIPs** in **connection region** x during the **trading period**

L_x is total **offtake** at all **GXPs** in **connection region** x during the **trading period**

F_{x_y} is **electricity** flow from **connection region** x to **connection region** y during the **trading period**.

Intra-regional Allocators

~~67~~68 **Intra-regional Allocators**

(1) Subject to subclause (2), the **intra-regional allocator** for a **regional customer group** under the **price-quantity method** is as follows:

type of **BBI**	type of **regional customer group**	**intra-regional allocator**	subclause
peak BBI	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical **coincident peak offtake**	(7), (8)
non-**peak BBI**	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical annual **offtake**	(5)

(2) The **intra-regional allocator** for an **ancillary service regional customer group** under the **price-quantity method** is as follows:

Commented [A77]: Clarification: This new column helps with the navigation of this clause.

Commented [A78]: Style

specified ancillary service	type of ancillary service regional customer group	intra-regional allocator	subclause
instantaneous reserve	**regional supply group**	mean historical annual **injection**	(6)
frequency keeping	**regional demand group**	mean historical annual **offtake**	(5)
voltage support	**regional demand group**	mean peak kVar	(9)

Commented [A79]: Clarification

(3) The **intra-regional allocator** for the **regional customer group** under the **resiliency method** is mean historical annual **offtake** (subclause (5)).

Commented [A80]: Clarification

(4) The **intra-regional allocator** for a **regional customer group** under the **simple method** is as follows:

type of **regional customer group**	**intra-regional allocator**	subclause
regional supply group	mean historical annual **injection**	(11)
regional demand group	mean historical annual **offtake**	(10)

Commented [A81]: Clarification

(5) If a **regional customer group** for a **BBI** under a **standard method** has a mean historical annual **offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TO_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

TO_n is the **pre-existing customer's** total **offtake** at all **GXPs** in the **regional customer group's modelled region** during **capacity year** n of **CMP B** for the **BBI**.

(6) If a **regional customer group** for a **BBI** under a **standard method** has a mean historical annual **injection intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TI_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

TI_n is the **pre-existing customer's** total **injection** at all **GIPs** in the **regional customer group's modelled region** during **capacity year** n of **CMP B** for the **BBI**.

(7) If a **regional customer group** for a **BBI** under a **standard method** has a mean historical **coincident peak offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} CPO_n$$

where

N is the number of **capacity years** (rounded up to the nearest whole **capacity year**) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

CPO_n is the **pre-existing customer's coincident peak offtake** for the **regional customer group** and **capacity year** n of **CMP B** for the **BBI**.

(8) A **pre-existing customer's coincident peak offtake** for a **regional customer group** and **capacity year** is the **pre-existing customer's** total **offtake** at all **GXPs** in the **regional customer group's modelled region** during the **peak offtake trading period**, where:

(a) the **peak offtake trading period** is the **trading period** in the **peak offtake period** during which total **offtake** (across all **offtake customers**) at those **GXPs** was at its highest; and

(b) the **peak offtake period** is the part of the **capacity year** for which the **pre-existing customer** was a member of the **regional customer group** (which may be the whole **capacity year**).

(9) If a **regional customer group** for a **BBI** under a **standard method** has a mean peak kVar **intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} NPK_n$$

where

N is the number of **capacity years** (rounded up to the nearest whole **capacity year**) during **CMP B** for the relevant **BBI** for which the **pre-existing customer** was a member of the **regional customer group**

NPK_n is the **pre-existing customer's nominated peak kVar** for the **regional customer group's modelled region** and **capacity year** n of **CMP B** for the **BBI**.

(10) If a **regional customer group** for a **BBI** under the **simple method** has a mean historical annual **offtake intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TO_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP C** for the relevant **simple method period** for which the **pre-existing customer** was a member of the **regional customer group**

TO_n is the **pre-existing customer's** total **offtake** at all **GXPs** in the **regional customer group's modelled region** during **capacity year** n of **CMP C** for the **simple method period**.

(11) If a **regional customer group** for a **BBI** under the **simple method** has a mean historical annual **injection intra-regional allocator**, the value of a **pre-existing customer's intra-regional allocator** for the **regional customer group**, where the **pre-existing customer** is a member of the **regional customer group**, (IRA) is calculated as follows:

$$IRA = \frac{1}{N}\sum_{n} TI_n$$

where

N is the number of **capacity years** (including part **capacity years** expressed as a decimal) during **CMP C** for the relevant **simple method period** for which the **pre-existing customer** was a member of the **regional customer group**.

TI_n is the **pre-existing customer's** total **injection** at all **GIPs** in the **regional customer group's modelled region** during **capacity year** n of **CMP C** for the **simple method period**.

(a) calculate or re-calculate (as the case may be) all **customers' simple method factors** for the current **simple method period** under subclause 64(2) using estimated values for the **customers' intra-regional allocators** to the extent necessary; and

~~(a)~~(b) **publish** in the **assumptions book** the new **simple method factors**, which, subject to this subclause 64(6), will apply to **BBIs commissioned** during the **simple method period** after the new **simple method factors** are **published**.

~~68~~69 Recent Customers

The value of a **recent customer's intra-regional allocator** for a **regional customer group** is estimated under paragraph 86(3)(a) as if the **recent customer** were a new **customer** joining the **regional customer group**~~,~~ but also taking into account any available historical

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information about the **recent customer's** mean historical annual **injection**, mean historical annual **offtake** or mean historical **coincident peak offtake** (as the case may be).

~~69~~70 **Notional IRA Value**

If a **regional customer group** is a **future regional customer group**, **Transpower** must determine a value of the **intra-regional allocator** for a notional **pre-existing customer** who accounts for all of the **future regional customer group's market regional NPB**, being the **notional IRA value** for the **future regional customer group**.

Part E Residual Charges

~~70~~71 Calculation of Residual Charges

(1) Only **load customers** pay **residual charges**.

(2) A **load customer's annual residual charge** for a **pricing year** (ARC) is calculated as follows:

$$ARC = AMDR \times RCR$$

where

AMDR is the **load customer's AMDR** for the **pricing year**

RCR is the **residual charge** rate for the **pricing year** calculated under clause 77.

(3) A **load customer's monthly residual charge** for a **pricing year** (MRC) is calculated as follows:

$$MRC = \frac{ARC}{12}$$

where ARC is the **load customer's annual residual charge** for the **pricing year**.

(4) **Residual charges** are calculated for each **pricing year** before the start of the **pricing year**.

(5) A **residual charge** may be re-calculated, including during a **pricing year**, under clauses 96 to 100 if there is a **residual charge adjustment event**.

~~71~~72 Anytime Maximum Demand (Residual)

(1) A **load customer's AMDR** for **pricing year** n ($AMDR_n$) is—

(a) 0 if the **load customer** became a **customer** at or after the start of **financial year** n-4; or

(b) calculated as follows if the **load customer** became a **customer** before the start of **financial year** n-4 and at or after the start of **financial year** n-8:

$$AMDR_n = AMDR_{baseline} \times \left(\frac{n-m}{4} - 1\right)$$

where

m is the **financial year** during which the **load customer** became a **customer**

$AMDR_{baseline}$ is the **load customer's AMDR** baseline calculated or estimated under clause 73; or

(c) otherwise, calculated as follows:

$$AMDR_n = AMDR_{baseline} \times RCAF_n$$

where

$AMDR_{baseline}$	is the **load customer's AMDR** baseline calculated or estimated under clause 73
$RCAF_n$	is the **load customer's RCAF** for **pricing year** n.

[Alternative drafting replacing clause 72 above: Step adjustment for new customers and connection of new large consuming plant]

72A Anytime Maximum Demand (Residual)

A **load customer's AMDR** for a **pricing year** (AMDR) is calculated as follows:

$$AMDR = AMDR_{baseline} \times RCAF$$

where

$AMDR_{baseline}$	is the **load customer's AMDR** baseline calculated or estimated under clause 73
RCAF	is the **load customer's RCAF** for the **pricing year**.

~~72~~73 Anytime Maximum Demand (Residual) Baseline

(1) Subject to subclause 75(1), a **pre-existing load customer's AMDR** baseline ($AMDR_{baseline}$) is calculated as follows:

$$AMDR_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017}\sum_{l}\sum_{p} MGD_{pln}$$

where MGD_{pln} is the **pre-existing load customer's maximum gross demand** for **grid point of connection** p at **connection location** l and **financial year** n.

(2) A **recent load customer's AMDR** baseline—

(a) is estimated by **Transpower** assuming full operation of the **recent load customer's assets** from the start of **CMP D** and taking into account~~—~~:

(i) the type and **capacity** of the **recent load customer's assets**; and

(ii) the **AMDR** baselines for any other **load customers** with **assets** of the same or a similar type as the **recent load customer's assets**; and

(iii) any available information about the **recent load customer's maximum gross demand**,

~~To avoid doubt, the **recent load customer's** estimated **AMDR** baseline would not include~~but excluding any contribution to the **recent load customer's AMDR** from the charging or discharging of **large battery storage** other than the **battery storage's** energy losses~~of any **grid**-connected **battery storage**~~; and

(b) may be re-estimated by **Transpower** under clause 76.

~~73~~74 Residual Charge Adjustment Factor

(1) A **load customer's RCAF** for **pricing year** n ($RCAF_n$) is calculated as follows~~—~~:

$$RCAF_n = \frac{LATGE_n}{ATGE_{baseline}}$$

where

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Commented [A84]: **Change:** It is possible we will have to apply the exclusion proactively. It will not necessarily fall out of the calculation of MGD in all cases.

Commented [A85]: **Change:** If embedded battery losses are excluded, a new local network with only batteries connected would have an AMDR baseline of zero (noting that, technically, a "local network" can be any length of line connecting the battery). That would mean the distributor pays no residual charge even though the charging activity of the batteries sets the distributor's maximum gross demand, and may never pay a residual charge even if it connects non-battery load. Rather than make specific provision for that scenario, we consider the TPM should simply count battery losses towards the AMDR baseline of all recent load customers.

Also, although an embedded battery is likely to charge at times of low demand, it is likely to discharge at times of high demand and serve the customer's load at those times. In our view, when thought about from the perspective of the battery discharging, the rationale for ignoring the embedded battery's losses in estimating the customer's AMDR baseline is significantly weaker.

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$LATGE_n$ is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2)

$ATGE_{baseline}$ is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (3) or (4).

(2) A **load customer's** lagged average **total gross energy** for **pricing year** n ($LATGE_n$) is calculated as follows:

$$LATGE_n = \frac{1}{4}\sum_{m=n-8}^{n-5} TGE_m$$

where TGE_m is the **load customer's total gross energy** for **financial year** m.

(3) Subject to subclause 75(2), a **pre-existing load customer's** average **total gross energy** baseline ($ATGE_{baseline}$) is calculated as follows:

$$ATGE_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017} TGE_n$$

where TGE_n is the **pre-existing load customer's total gross energy** for **financial year** n.

(4) A **recent load customer's** average **total gross energy** baseline—

(a) is estimated assuming full operation of the **recent load customer's assets** from the start of **CMP D** and taking into account—

(i) the type and **capacity** of the **recent load customer's assets**; and

(ii) the **total gross energy** baselines for any other **load customers** with **assets** of the same or a similar type as the **recent load customer's assets**; and

(iii) any available information about the **recent load customer's total gross energy**; and

(b) may be re-estimated by **Transpower** under clause 76.

(5) To avoid doubt, a **load customer's RCAF** for a **pricing year** is only calculated if the **load customer's AMDR** for the **pricing year** is calculated under clause 72(1)(c).

[Alternative drafting replacing clause 74 above: Step adjustment for new customers and connection of new large consuming plant]

74A Residual Charge Adjustment Factor

(6) A **load customer's RCAF** for **pricing year** n ($RCAF_n$) is—

(a) 1 if the **load customer** became a **load customer** after the start of **financial year** n-8; or

(b) otherwise, calculated as follows:

$$RCAF_n = \frac{LATGE_n}{ATGE_{baseline}}$$

where

$LATGE_n$	is the **load customer's** lagged average **total gross energy** for **pricing year** n calculated under subclause (2)
$ATGE_{baseline}$	is the **load customer's** average **total gross energy** baseline calculated or estimated under subclause (3) or (4)

(7) A **load customer's** lagged average **total gross energy** for **pricing year** n ($LATGE_n$) is calculated as follows:

$$LATGE_n = \frac{1}{4}\sum_{m=n-8}^{n-5} TGE_m$$

where TGE_m is the **load customer's total gross energy** for **financial year** m.

(8) Subject to subclause 75(2), a **pre-existing load customer's** average **total gross energy** baseline ($ATGE_{baseline}$) is calculated as follows:

$$ATGE_{baseline} = \frac{1}{4}\sum_{n=2014}^{2017} TGE_n$$

where TGE_n is the **pre-existing load customer's total gross energy** for **financial year** n.

(9) A **recent load customer's** or new **load customer's** average **total gross energy** baseline is equal to the **load customer's** lagged average **total gross energy** for the first **pricing year** the **load customer's RCAF** is calculated under paragraph (6)(b). To avoid doubt, this means the **load customer's RCAF** for that **pricing year** will be 1.

~~74~~75 Reduction Events

(1) **Transpower** may reduce a **pre-existing load customer's AMDR** baseline by an amount determined by **Transpower**—

(a) if a **reduction event** for the **pre-existing load customer** has occurred or **Transpower** determines will occur; and

(b) to the extent the impact of the **reduction event** is not fully captured in the calculation of the **pre-existing load customer's AMDR** baseline under subclause 73(1).

(2) If **Transpower** reduces a **pre-existing load customer's AMDR** baseline under subclause (1), **Transpower** must also reduce the **pre-existing load customer's** average **total gross energy** baseline to the extent necessary to be consistent with the reduction in the **pre-existing customer's AMDR** baseline, as determined by **Transpower**.

~~75~~76 Re-estimating for Recent Load Customers

(1) **Transpower** may re-estimate either or both of a **recent load customer's AMDR** baseline and average **total gross energy** baseline when information is available about the **recent load customer's maximum gross demand** or **total gross energy** when the **recent load customer's assets** ~~is~~are fully operational, but may only re-estimate each of the~~a~~ **recent load customer's AMDR** baseline and average **total gross energy** baseline once.

(2) To avoid doubt, the purpose of a re-estimation under subclause (1) is to correct any material under- or over-estimation in **Transpower's** initial estimation of the~~a~~ **recent load customer's AMDR** baseline or average **total gross energy** baseline.

Commented [A87]: Clarification: For consistency with the definition of "reduction event", which allows for prospective reduction events (provided they are expected to happen before the start of the first pricing year).

Commented [A88]: Style

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Commented [A90]: Typo

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Commented [A92]: Style

[Alternative drafting replacing clause 76 above: Step adjustment for new customers and connection of new large consuming plant]

76A Re-estimating for Recent Load Customers

(3) **Transpower** may re-estimate a **recent load customer's AMDR** baseline when information is available about the **recent load customer's maximum gross demand** when the **recent load customer's assets** are fully operational, but may only re-estimate the **recent load customer's AMDR** baseline once.

(4) To avoid doubt, the purpose of a re-estimation under subclause (1) is to correct any material under- or over-estimation in **Transpower's** initial estimation of the **recent load customer's AMDR** baseline.

~~76~~77 Residual Charge Rate

The **residual charge** rate for a **pricing year** (RCR) is calculated as follows:

$$RCR = \frac{RR}{AMDR_{total}}$$

where

RR is **residual revenue** for the **pricing year**

$AMDR_{total}$ is the total of all **customers' AMDR** for the **pricing year**.

Part F Adjustments

General

~~77~~78 Adjustment Events

(1) An **adjustment event** is deemed to have occurred on the date **Transpower** has actual knowledge, and is reasonably satisfied, that the **adjustment event** has occurred, regardless of when the **adjustment event** actually occurred.

(2) Except as otherwise stated in this **transmission pricing methodology**, if an **adjustment event** occurs, **Transpower** must adjust relevant **transmission charges** from the date of the **adjustment event**, if necessary on a pro rata basis for the **event pricing year** depending on when the **adjustment event** occurred during the **event pricing year**.

(3) If **adjustment events** affecting the same **transmission charge** occur simultaneously, **Transpower** must determine an order in which the **adjustment events** will be deemed to have occurred for the purpose of adjusting the **transmission charge**.

Connection Charges

~~78~~79 Connection Charge Adjustment Events

(1) The following events are **connection charge adjustment events**:

(a) a **customer** (the connecting **customer**) connects at a **connection location** at which the **customer** is not already connected:

(b) a **customer** (the disconnecting **customer**) disconnects from a **connection location**:

(c) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **customer** at a **connection location** to another party (the purchaser):

(d) **Transpower** decides to voluntarily under-recover the **connection charges** for a **connection asset**, **connection location** or **connection transmission alternative**.

Commented [A93]: Change: See comment on clause 82.

(2) **Transpower** must not voluntarily under-recover the **connection charge** for a **connection asset**, **connection location** or **connection transmission alternative** if the effect of doing so would be to increase **residual revenue** for any **pricing year**.

(3) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **customer** at a **connection location** to a purchaser is treated as the **benefit-based charge adjustment event** in paragraph (1)(c) and not the **benefit-based adjustment event** in paragraph (1)(a) or (1)(b).

Commented [A94]: Clarification

~~79~~80 Connection Charge Adjustment Event: Connecting Customer

(1) This clause 80 applies in the case of the **connection charge adjustment event** in paragraph 79(1)(a).

(2) In this clause 80, a relevant **pricing year** is the **event pricing year** and the **pricing year** after the **event pricing year**.

(3) **Transpower** must, for each relevant **pricing year**—

(a) determine whether the connecting **customer** will be treated as an **offtake customer** or **injection customer** at the **connection location**; and

(b) estimate the connecting **customer's AMDC** or **AMIC** (as applicable depending on **Transpower's** determination under paragraph (a)) for the **connection location** taking into account—

(i) the type and **capacity** of the connecting **customer's assets**; and
(ii) **AMDC** or **AMIC** (as the case may be) for any other **customers** with **assets** of the same or a similar type as the new **customer's assets** connected at the **connection location**; and

(c) calculate or re-calculate (as the case may be) all **customers' connection customer allocations** for the **connection location** to account for the connecting **customer's AMDC** or **AMIC** estimated under paragraph (b); and
(d) calculate or re-calculate (as the case may be) all **customers' connection charges** for the **connection location** based on the **customers' connection customer allocations** calculated under paragraph (c); and
(e) calculate or re-calculate (as the case may be) all **customers' connection charges** for any relevant **connection transmission alternative**—
(i) to account for the connecting **customer's annual connection charge** for the **connection location** calculated under paragraph (d); and
(ii) assuming that **annual connection charge** applied for the previous **pricing year**.

(4) **Transpower** must start the connecting **customer's monthly connection charges** calculated under paragraph (3)(d) or (3)(e) as soon as reasonably practicable. The connecting **customer's monthly connection charges** may include an adjustment as necessary to ensure the connecting **customer** pays its full **connection charges** for the **connection location** or **connection transmission alternative** from the date the connecting **customer** connected at the **connection location**.

(5) **Transpower** is not required to (but may) start any other **customer's monthly connection charges** re-calculated under paragraph (3)(d) or (3)(e) during, or from the start of, an **exempt pricing year** for the **customer**. However, any over-recovery of **annual connection charges** for the **connection location** or **connection transmission alternative** and **exempt pricing year** resulting from the start of the connecting **customer's monthly connection charges** for the **connection location** or **connection transmission alternative** must be rebated, as appropriate, to the other **customers** by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~80~~81 Connection Charge Adjustment Event: Disconnecting Customer

(1) This clause 81 applies in the case of the **connection charge adjustment event** in paragraph 79(1)(b).

(2) **Transpower**—
(a) must make the disconnecting **customer's connection customer allocations** (and the inputs to their calculation) and **connection charges** for the **connection location** and any relevant **connection transmission alternative** 0; and
(b) must not increase—
(i) any other **customer's connection charges** for the **connection location** or **connection transmission alternative** and **event pricing year**; or
(ii) any other **transmission charges** for the **event pricing year**,

as a consequence of ~~the application of~~applying paragraph (a).

~~81~~82 Connection Charge Adjustment Event: ~~Partial~~ Sale of Business

(1) This clause 82 applies in the case of the **connection charge adjustment event** in paragraph 79(1)(c).

Commented [A95]: Style

Commented [A96]: **Change:** We have expanded this adjustment event to capture both partial and full sale of the relevant business. In the case of a full sale, the vendor's allocations and charges just need to be ported to the purchaser rather than following the full new customer process. This also applies to the equivalent BBC and residual charge adjustments below.

(2) In this clause 82, a relevant **pricing year** is the **event pricing year** and the **pricing year** after the **event pricing year**.

(3) **Transpower** must, for a sale of part of the vendor's business and for each relevant **pricing year**—
(a) determine an apportionment between the vendor and purchaser of the vendor's **connection customer allocations** (and the inputs to their calculation) for the **connection location** taking into account the size and nature of the transferred business; and
(b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **connection charges** for the **connection location** based on the apportionment of the vendor's **connection customer allocations** under paragraph (a); and
(c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **connection charges** for any relevant **connection transmission alternative**—
(i) to account for the vendor's and purchaser's **annual connection charges** for the **connection location** calculated under paragraph (b); and
(ii) assuming those **annual connection charges** applied for the previous **pricing year**.

(4) **Transpower** must, for a sale of all of the vendor's business—
(a) attribute all of the vendor's **connection customer allocation** (and the inputs to its calculation) for the **connection location** to the purchaser; and
(b) calculate or re-calculate (as the case may be) the purchaser's **connection charges** for the **connection location** based on the attribution of the vendor's **connection customer allocation** under paragraph (a); and
(c) calculate or re-calculate (as the case may be) the purchaser's **connection charge** for any relevant **connection transmission alternative**—
(i) to account for the purchaser's **annual connection charges** for the **connection location** calculated under paragraph (b); and
(ii) assuming those **annual connection charges** applied for the previous **pricing year**.

~~(4)~~(5) **Transpower** must start the purchaser's **monthly connection charges** calculated under paragraph (3)(b), ~~or~~ (3)(c), (4)(b) or (4)(c) as soon as reasonably practicable. The purchaser's **monthly connection charges** may include an adjustment as necessary to ensure the purchaser pays its full **connection charges** for the **connection location** or **connection transmission alternative** from the date of the transfer.

~~(5)~~(6) **Transpower** is not required to (but may) start the vendor's **monthly connection charges** calculated under paragraph (3)(b) or (3)(c) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of **annual connection charges** for the **connection location** or **connection transmission alternative** and **exempt pricing year** resulting from the start of the purchaser's **monthly connection charges** for the **connection location** or **connection transmission alternative** must be rebated to the vendor by way of an adjustment to its **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~82~~83 Connection Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 83 applies in the case of the **connection charge adjustment event** in paragraph 79(1)(d).

(2) In this clause 83, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover the **connection charges** for the **connection asset**, **connection location** or **connection transmission alternative**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **customers' connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** to account for the amount of the voluntary under-recovery of the **connection charges**.

(4) If **Transpower** decides to voluntarily under-recover the **connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** and a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **customers' monthly connection charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of **annual connection charges** for the **connection asset**, **connection location** or **connection transmission alternative** and relevant **pricing year** (accounting for the voluntary under-recovery) must be rebated, as appropriate, to the **customers** by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the relevant **pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

Benefit-based Charges

~~83~~84 Benefit-based Charge Adjustment Events

(1) The following events are **benefit-based charge adjustment events**:
(a) a **BBI** suffers **material damage**:
(b) a new **customer** connects to the **grid**:
(c) a **customer** (the exiting **customer**) ceases to be a **customer**:
(d) an existing **customer** (the connecting or disconnecting **customer**) connects **plant** to, or disconnects **plant** from, the **grid**:
(e) **large embedded plant** is connected to, or **large embedded plant** is disconnected from, a **host customer's** (the connecting or disconnecting **customer's**) **local network** or **grid**-connected **plant**:
(f) there is a **substantial sustained increase** by a **customer's** (the increasing **customer's**) existing **grid**-connected **plant**:
(g) there is a **substantial sustained increase** by existing **large embedded plant** connected to a **host customer's** (the increasing **customer's**) **local network** or **grid**-connected **plant**:
(h) a transformer at a **GXP** for a **distributor's** (the upgrading **distributor's**) **local network** is **upgraded**:
(i) a **distributor** (the connecting **distributor**) connects its **local network** at a **GXP** (new **GXP**) to which the connecting **distributor** was not connected immediately before connecting its **local network** at the new **GXP**:
(j) the **point of connection** for existing **large plant** changes:
(k) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **beneficiary** of a **BBI** to another party (the purchaser):
(l) **Transpower** decides to voluntarily under-recover a **BBI's covered cost**:
(m) there is a **SSCGU**.

(2) **Transpower** must not voluntarily under-recover a **BBI's covered cost** if the effect of doing so would be to increase **residual revenue** for any **pricing year**.

(3) For the purposes of paragraphs (1)(d) and (1)(e)—

Commented [A97]: Change

(a) a **large upgrade** of existing **plant** is treated as the connection of **large plant** equivalent in size to the **upgrade**; and

(b) a **large de-rating** of existing **plant** is treated as the disconnection of **large plant** equivalent in size to the **de-rating**; and

(c) a series of incremental **upgrades** or **de-ratings** of existing **plant** is treated as a **large upgrade** or **large de-rating** (as the case may be) if the incremental **upgrades** or **de-ratings** would constitute a **large upgrade** or **large de-rating** if undertaken at the same time.

(4) For the purposes of paragraphs (1)(f) and (1)(g), whether the increase in **electricity** consumed or generated by the **large plant** is a **substantial sustained increase** in respect of a **BBI** must be assessed against the average annual **electricity** consumption or generation by the **large plant** explicitly or implicitly included in the current value of the increasing **customer's intra-regional allocator** for its **regional customer group** and the **BBI**.

(5) To avoid doubt, the **benefit-based charge adjustment events** in paragraphs (1)(a) and (1)(l) do not result in any change to the relevant **BBI's BBI customer allocations**.

(6) The **benefit-based charge adjustment event** in paragraph (1)(j) is treated as the **benefit-based charge adjustment events** in 1 or both of paragraphs (1)(d) and (1)(e) (depending on the previous and new **point of connection**) occurring in respect of the same **large plant**, provided that clause 88 will not apply except as specified in clause 92.

~~(6)~~(7) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **beneficiary** of a **BBI** to a purchaser is treated as the **benefit-based charge adjustment event** in paragraph (1)(k) and not the **benefit-based adjustment event** in paragraph (1)(b) or (1)(c).

Commented [A98]: Clarification

~~(7)~~(8) Any of the **benefit-based charge adjustment events** in paragraphs (1)(b) to (1)(j) may also be a **SSCGU**, in which case both clause 95 and clause 86, 87, 88, 89, 90, 91 or 92 (as applicable depending on the **benefit-based charge adjustment event**) will apply. However, clause 86, 87, 88, 89, 90, 91 or 92 will only apply to a relevant **BBI** described in paragraph 95(2)(a) in respect of **pricing years** before the **SSCGU's start pricing year**.

~~84~~85 Benefit-based Charge Adjustment Event: Material Damage

(1) This clause 85 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(a).

(2) In this clause 85, a relevant **pricing year** is the **event pricing year** and the **pricing year** after the **event pricing year**.

(3) Subject to subclause (4), **Transpower** must, for each relevant **pricing year**—

(a) reduce the **BBI's covered cost** by an amount determined by **Transpower** to reflect the ~~reduction of the~~ **BBI's write-down** due~~value attributable~~ to the **material damage**, to the extent the **write-down**~~this reduction~~ is not already reflected in the relevant **RAB** values or **values of commissioned asset** used to calculate the **BBI's covered cost** for the relevant **pricing year**; and

(b) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **BBI** based on the reduction of the **BBI's covered cost** under paragraph (a).

Commented [A99]: Clarification: Making use of new definition of "write-down".

(4) If a **beneficiary** (the causing **beneficiary**) caused, or contributed to the cause of, the **material damage**, subclause (3) does not apply to the causing **beneficiary's benefit-based charge** for the **BBI**.

(5) **Transpower** is not required to (but may) start a **beneficiary's monthly benefit-based charge** calculated under paragraph (3)(b) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **BBI's covered cost** for the **exempt pricing year** (accounting for the **material damage**) must be rebated, as appropriate, to the **beneficiaries** (other than any causing **beneficiary**) by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

(6) **Transpower** must not increase any **transmission charges** for the **event pricing year** as a consequence of ~~the application of~~applying subclause (3).

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~~85~~86 Benefit-based Charge Adjustment Event: New Customer

(1) This clause 86 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(b).

(2) The new **customer**—
(a) is a **beneficiary** of each **post-2019 BBI** (a relevant **post-2019 BBI**) that has positive **regional NPB** for a **regional customer group** of which the new **customer** is expected to be a member (a relevant **regional customer group** for the relevant **post-2019 BBI**); and
(b) may be a **beneficiary** of 1 or more of the **Appendix A BBIs**.

(3) **Transpower** must, for each relevant **post-2019 BBI**—
(a) estimate the value of the new **customer's intra-regional allocator** for each relevant **regional customer group** assuming full operation of the new **customer's assets** and taking into account—
(i) the type and **capacity** of the new **customer's assets**; and
(ii) the values of the **intra-regional allocators** for any other **beneficiaries** of the relevant **post-2019 BBI** with **assets** of the same or a similar type as the new **customer's assets**; and
(b) subject to subclause (4), calculate the new **customer's individual NPB** for the relevant **post-2019 BBI**—
(i) under clause 50, 60 or 64 (as applicable depending on the method used to calculate **beneficiaries' BBI customer allocations** for the relevant **post-2019 BBI**); and
(ii) based on the value of the new **customer's intra-regional allocator** for each relevant **regional customer group** estimated under paragraph (a), but excluding the value of the new **customer's intra-regional allocator** from the denominator of the formula in clause 50 or subclause 64(2) (as applicable); and
(c) calculate the new **customer's BBI customer allocation** for the relevant **post-2019 BBI** based on the new **customer's individual NPB** for the relevant **post-2019 BBI** calculated under paragraph (b), but excluding the value of the new **customer's individual NPB** from the denominator of the formula in subclause 45(1); and
(d) scale down all **beneficiaries'** (including the new **customer's**) **BBI customer allocations** for the relevant **post-2019 BBI** by a factor (F) calculated as follows:

Commented [A101]: Typo

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the relevant **post-2019 BBI** calculated under paragraph (c); and

(e) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the relevant **post-2019 BBI** based on the **beneficiaries' BBI customer allocations** calculated under paragraph (d).

(4) If the new **customer** is in a **future regional customer group** for a relevant **BBI**, **Transpower** must calculate the new **customer's individual NPB** for the relevant **BBI** under paragraph (3)(b) in respect of the **future regional customer group** by using the **future regional customer group's notional IRA value** in the denominator of the formula in clause 50.

(5) The following tables illustrate the application of subclause (3) to a new **customer** (**customer** E) entering **regional customer group** Y for a **post-2019 BBI** where **regional customer group** Y is not a **future regional customer group** and the **post-2019 BBI** is not a **resiliency BBI**:

Before

r~~R~~egional customer group	**b~~B~~eneficiary**	**r~~R~~egional NPB**	**i~~I~~ntra-regional allocator**	**i~~I~~ndividual NPB**	**BBI customer allocation**
X	A	60	1	20	18.18%
	B		2	40	36.36%
Y	C	50	3	30	27.27%
	D		2	20	18.18%

Transition (paragraphs (3)(a) to (3)(c))

r~~R~~egional customer group	**b~~B~~eneficiary**	**r~~R~~egional NPB**	**i~~I~~ntra-regional allocator**	**i~~I~~ndividual NPB**	**BBI customer allocation**
X	A	60	1	20	18.18%
	B		2	40	36.36%
Y	C	50	3	30	27.27%
	D		2	20	18.18%
	E		1 (estimated)	1/5 × 50 = 10	10/110 = 9.09%

Commented [A102]: **Style:** Titles made all lower case and centred for consistency across the tables.

After (paragraph (3)(d))

r~~R~~egional customer group	**b~~B~~eneficiary**	**r~~R~~egional NPB**	**i~~I~~ntra-regional allocator**	**i~~I~~ndividual NPB**	**BBI customer allocation** (scaled by 1/1.0909)
X	A	60	1	20	16.67%
	B		2	40	33.33%
Y	C	50	3	30	25.00%
	D		2	20	16.67%
	E		1 (estimated)	10	8.33%

(6) **Transpower** must, for each **Appendix A BBI**—

(a) calculate the new **customer's BBI customer allocation** for the **Appendix A BBI** (CA) as follows:

$$CA = E \times \frac{1}{J}\sum_{j} BF_j$$

where

E is **Transpower's** estimate of the new **customer's** average annual **offtake** or **injection** at the new **customer's connection location** when the new **customer's assets** are fully operational

J is the number of incumbent **customers** of the same type as the new **customer** (**generator** or **connected asset owner**)—
(i) at the new **customer's connection location**; or
(ii) if there are no such incumbent **customers** at the new **customer's connection location**, at the **connection location** electrically closest to the new **customer's connection location** at which there is 1 or more such incumbent **customers**, as determined by **Transpower**,
each such incumbent **customer** being **customer** j

BF_j is **customer** j's **benefit factor** for the **Appendix A BBI**; and

(b) scale down all **beneficiaries'** (including the new **customer's**) **BBI customer allocations** for the **Appendix A BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 + CA}$$

where CA is the new **customer's BBI customer allocation** for the **Appendix A BBI** calculated under paragraph (a); and

(c) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **Appendix A BBI** based on the **beneficiaries' BBI customer allocations** calculated under paragraph (b).

(7) The following tables illustrate the application of subclause (6) to a new **customer** (**customer** E) for an **Appendix A BBI**, where the incumbent **beneficiaries** are all starting **beneficiaries** and the **benefit factors** for **beneficiaries** B and C are used in the calculation in subclause (6)(a):

Before

b~~B~~eneficiary	**benefit factor**	average annual **offtake/injection**	**BBI customer allocation**
A	0.1818	100	18.18%
B	0.1818	200	36.36%
C	0.0909	300	27.27%
D	0.0455	400	18.18%

Commented [A103]: Clarification

Transition (paragraph (6)(a))

b~~B~~eneficiary	**benefit factor**	average annual **offtake/injection**	**BBI customer allocation**
A	0.1818	100	18.18%
B	0.1818	200	36.36%
C	0.0909	300	27.27%
D	0.0455	400	18.18%
E	(0.1818 + 0.0909)/2 = 0.1364	250 (estimated)	0.1364 × 250 = 34.10%

Commented [A104]: Clarification

After (paragraph (6)(b))

b~~B~~eneficiary	**benefit factor**	annual **offtake/injection**	**BBI customer allocation** (scaled by 1/1.341)
A	0.1818	100	13.56%
B	0.1818	200	27.11%
C	0.0909	300	20.34%
D	0.0455	400	13.56%
E	0.1364	250 (estimated)	25.43%

(8) **Transpower** must start the new **customer's monthly benefit-based charges** calculated under paragraph (3)(e) or (6)(c) as soon as reasonably practicable. The new **customer's monthly benefit-based charges** may include an adjustment as necessary to ensure the new **customer** pays its full **benefit-based charge** for each **BBI** from the date the new **customer** connected to the **grid**.

(9) **Transpower** is not required to (but may) start any other **beneficiary's monthly benefit-based charges** re-calculated under paragraph (3)(e) or (6)(c) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **benefit-based charge** for a **BBI** and **exempt pricing year** resulting from the start of the new **customer's monthly benefit-based charge** for the **BBI** must be rebated, as appropriate, to the other **beneficiaries** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the **exempt pricing year**; or

(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~86~~87 Benefit-based Charge Adjustment Event: Exiting Customer

(1) This clause 87 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(c).

(2) The exiting **customer** ceases to be a **beneficiary** of each **BBI** (a relevant **BBI**) of which the exiting **customer** was a **beneficiary** immediately before ceasing to be a **customer**.

(3) Subject to subclause (7), **Transpower**—

(a) must, for each relevant **BBI**—

(i) make the exiting **customer's BBI customer allocation** and **benefit-based charge** for the relevant **BBI** 0; and

(ii) scale up all remaining **beneficiaries' BBI customer allocations** for the relevant **BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 - CA}$$

where CA is the exiting **customer's BBI customer allocation** for the relevant **BBI** immediately before it was set to 0 under subparagraph (i); and

(iii) re-calculate all remaining **beneficiaries' benefit-based charges** for the relevant **BBI** based on the remaining **beneficiaries' BBI customer allocations** calculated under subparagraph (ii); and

(b) must not increase—

(i) the remaining **beneficiaries' benefit-based charges** for the relevant **BBI** and **event pricing year**; or

(ii) any other **transmission charges** for the **event pricing year**,

as a consequence of ~~the application of~~applying subparagraph (a)(i).

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(4) The following tables illustrate the application of subclause (3) to a **customer** (**customer** D) exiting **regional customer group** Y for a **post-2019 BBI** that is not a **resiliency BBI**:

Before

r~~R~~egional customer group	**b~~B~~eneficiary**	**r~~R~~egional NPB**	**i~~I~~ntra-regional allocator**	**i~~I~~ndividual NPB**	**BBI customer allocation**
X	A	60	1	20	16.67%
	B		2	40	33.33%
Y	C	50	3	30	25.00%
	D		2	20	16.67%
	E		1	10	8.33%

After (subparagraphs (3)(a)(i) and (3)(a)(ii))

r~~R~~egional customer group	**b~~B~~eneficiary**	**r~~R~~egional NPB**	**i~~I~~ntra-regional allocator**	**i~~I~~ndividual NPB**	**BBI customer allocation** (scaled by 1/0.8333)
X	A	60	1	20	20.00%
	B		2	40	40.00%
Y	C	50	3	30	30.00%
	D		2	20	0%
	E		1	10	10.00%

(5) In subclauses (6) and (7), a **continuing BBI** is a **BBI**—

(a) of which the exiting **customer** was a **beneficiary** immediately before ceasing to be a **customer**; and

(b) **commissioned** less~~more recently~~ than 10 years before the date the exiting **customer** ceased to be a **customer**.

Commented [A106]: Style

(6) Subclause (7) applies to a **continuing BBI** until the start of the first **pricing year** that starts at least 10 years after the **continuing BBI's commissioning date**.

(7) If a **related entity** of the exiting **customer** is a **customer** after the exiting **customer** ceases to be a **customer**—

(a) subparagraphs (3)(a)(ii) and~~to~~ (3)(a)(iii) do not apply; and

Commented [A107]: Typo

(b) the exiting **customer's benefit-based charge** for the **continuing BBI** must be attributed (by way of increase) to the **related entity** in its capacity as a **customer**. If there is more than 1 **related entity**, this subclause applies to a **related entity** determined by **Transpower**; and

(c) **Transpower** must start the **related entity's monthly benefit-based charges** attributed under paragraph (b) as soon as reasonably practicable. The **related entity's monthly benefit-based charges** may include an adjustment as necessary to ensure the **related entity** pays its full attributed **benefit-based charge** for the **continuing BBI** from the date the exiting **customer** ceased to be a **customer**.

~~87~~88 Benefit-based Charge Adjustment Event: Large Plant Connected or Disconnected

(1) Subject to subclause 84(6), this clause 88 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(d) or 84(1)(e).

(2) **Transpower** must, for a connecting **customer**—

(a) comply with clause 86 as if the **large plant** had been connected to the **grid** by a separate new **customer** (the notional new **customer**) at—

(i) if the **large plant** is connected to the **grid**, the **connection location** where the **large plant** is connected; or

(ii) if the **large plant** is connected to the connecting **customer's local network**, the **connection location** electrically closest to the **large plant's** electrically closest **point of connection** to the **local network**, as determined by **Transpower**; or

(iii) if the **large plant** is connected to the connecting **customer's grid-**connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute (by way of increase) the notional new **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the connecting **customer**.

(3) Subject to subclause (6), **Transpower** must, for a disconnecting **customer**—

(a) comply with clause 87 (without regard to subclauses 87(5) to 87(7)) as if the **large plant** had been disconnected from the **grid** by a separate exiting **customer** (the notional exiting **customer**) at—

(i) if the **large plant** was connected to the **grid**, the **connection location** where the **large plant** was connected; or

(ii) if the **large plant** was connected to the disconnecting **customer's local network**, the **connection location** electrically closest to the **large plant's** electrically closest **point of connection** to the **local network** before the **large plant** was disconnected, as determined by **Transpower**; or

(iii) if the **large plant** was connected to the disconnecting **customer's grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute (by way of reduction) the notional exiting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **BBI** and **Appendix A BBI** to the disconnecting **customer**~~;~~, provided that the minimum value of the disconnecting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **BBI** and **Appendix A BBI** is 0.

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(4) In subclauses (5) and (6), a **continuing BBI** is a **BBI**—

(a) of which the notional exiting **customer** was a **beneficiary** immediately before the disconnection of the **large plant**; and

(b) **commissioned** less~~more recently~~ than 10 years before the date the **large plant** was disconnected.

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(5) Subclause (6) applies to a **continuing BBI** until the start of the first **pricing year** that starts at least 10 years after the **continuing BBI's commissioning date**.

(6) If the **large plant** owner or a **related entity** of the **large plant** owner (relevant person) is a **customer** after the disconnection of the **large plant**—

(a) subparagraphs 87(3)(a)(ii) to 87(3)(a)(iii) do not apply; and

(b) the notional exiting **customer's benefit-based charge** for the **continuing BBI** must be attributed (by way of increase) to the relevant person in its capacity as a **customer**. If there is more than 1 relevant person, this subclause applies to—

(i) the **large plant** owner; or

(ii) if the **large plant** owner is not a **customer** after the disconnection of the **large plant**, a **related entity** determined by **Transpower**; and

(c) **Transpower** must start the relevant person's **monthly benefit-based charges** attributed under paragraph (b) as soon as reasonably practicable. The relevant person's **monthly benefit-based charges** may include an adjustment as necessary to ensure the relevant person pays its full attributed **benefit-based charge** for the **continuing BBI** from the date the **large plant** was disconnected.

~~88~~89 Benefit-based Charge Adjustment Event: Substantial Sustained Increase

(1) This clause 89 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(f) or 84(1)(g).

(2) **Transpower** must—

(a) comply with clause 86 as if the **substantial sustained increase** were attributable to **plant** connected to the **grid** by a separate new **customer** (the notional new **customer**) at—

(i) if the **substantial sustained increase** is in **electricity** consumed or generated by **grid**-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; or

(ii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing **customer's local network**, the **connection location** electrically closest to the **large embedded plant's** electrically closest **point of connection** to the **local network**, as determined by **Transpower**; or

(iii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing

customer's grid-connected **plant**, the **connection location** where the **grid**-connected **plant** is connected; and

(b) attribute the notional new **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the increasing **customer**.

~~89~~90 Benefit-based Charge Adjustment Event: Distributor Transformer Upgrade

(1) This clause 90 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(h).

(2) **Transpower** must—

(a) comply with clause 86 as if a transformer equivalent in size to the **upgrade** had been connected at the **GXP** by a separate new **distributor** (the notional new **distributor**); and

(b) attribute the notional new **distributor's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the upgrading **distributor**.

~~90~~91 Benefit-based Charge Adjustment Event: Distributor Connection at GXP

(1) This clause 91 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(i).

(2) Subject to subclause (3), **Transpower** must—

(a) comply with clause 86 as if a **local network** had been connected at the new **GXP** by a separate new **distributor** (the notional new **distributor**), provided that the estimate of the notional new **distributor's intra-regional allocators** must take into account any expected reduction in the connecting **distributor's offtake** at other **GXPs** in the same **modelled region** as the new **GXP** as a result of the connection of the connecting **customer's local network** at the new **GXP**; and

(b) attribute the notional new **distributor's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the connecting **distributor**.

(3) Subclause (2) does not apply in respect of a **BBI** if—

(a) **Transpower** does not reasonably consider the connection of the connecting **customer's local network** at the new **GXP** to be associated with a sustained increase in the connecting **distributor's** expected total **offtake** at all **GXPs** in the same **modelled region** for the **BBI** as the new **GXP** (including the new **GXP**); or

(b) any sustained increase referred to in paragraph (a) is explicitly or implicitly included in the current value of the connecting **distributor's intra-regional allocator** for its **regional demand group** for the **modelled region** and **BBI**.

(4) An increase is sustained under subclause (3) only if **Transpower** reasonably expects the increase to persist for at least 5 years after the **benefit-based charge adjustment event** occurred.

Commented [A110]: Clarification

~~91~~92 Benefit-based Charge Adjustment Event: Changed Point of Connection

(1) This clause 92 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(j).

(2) **Transpower** must—

(a) apply subclauses 88(2) and 88(3) to calculate the notional new **customer's** and notional exiting **customer's BBI customer allocations**; and

(b) identify the **BBIs** of which both the notional new **customer** and notional exiting **customer** are **beneficiaries** (the relevant **BBIs**).

(3) If the notional new **customer's BBI customer allocation** for a relevant **BBI** is equal to or more than the notional exiting **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must—

(a) apply paragraph 88(2)(b) for the connecting c**ustomer** and relevant **BBI**; and

(b) apply paragraph 88(3)(b) for the disconnecting **customer** and relevant **BBI** (without regard to subclause 88(5)).

(4) If the notional exiting **customer's BBI customer allocation** for a relevant **BBI** is more than the notional new **customer's BBI customer allocation** for the relevant **BBI**, **Transpower** must—

(a) apply paragraph 88(2)(b) for the connecting **customer** and relevant **BBI**, but by attributing to the connecting **customer** the notional exiting **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for the relevant **BBI** instead of the notional new **customer's**; and

(b) apply paragraph 88(3)(b) for the disconnecting **customer** and relevant **BBI** (without regard to subclause 88(5)).

~~92~~93 **Benefit-based Charge Adjustment Event: ~~Partial~~ Sale of Business**

Commented [A111]: Change

(1) This clause 93 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(k).

(2) **Transpower** must, for a sale of part of the vendor's business—

(a) determine an apportionment between the vendor and purchaser of the vendor's **BBI customer allocation** (and the inputs to its calculation) for the **BBI** taking into account the size and nature of the transferred business; and

(b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **benefit-based charges** for the **BBI** based on the apportionment of the vendor's **BBI customer allocation** under paragraph (a); and

(c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—

(i) the vendor's and purchaser's **annual benefit-based charges** calculated under paragraph (b); and

(ii) any **annual residual charge** for the vendor or purchaser calculated under subclause 99(2) or 99(3) in respect of the same sale of business.

Commented [A112]: Change: If there is an apportionment of BBCs between vendor and purchaser there should also be an apportionment of the recovery charges.

(3) **Transpower** must, for a sale of all of the vendor's business—

(a) attribute the vendor's **BBI customer allocation** (and the inputs to its calculation) for the **BBI** to the purchaser; and

(b) calculate or re-calculate (as the case may be) the purchaser's **benefit-based charge** for the **BBI** based on the attribution of the vendor's **BBI customer allocation** under paragraph (a); and

(c) calculate or re-calculate (as the case may be) the purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—

(i) the purchaser's **annual benefit-based charge** calculated under paragraph (b); and

~~(i)~~(ii) any **annual residual charge** for the vendor or purchaser calculated under clause 99(2) or 99(3) in respect of the same sale of business.

~~(3)~~(4) **Transpower** must start the purchaser's **monthly benefit-based charge** calculated under paragraph (2)(b) or (3)(b) as soon as reasonably practicable. The purchaser's **monthly benefit-based charge** may include an adjustment as necessary to ensure the purchaser pays its full **benefit-based charge** for the **BBI** from the date of the transfer.

~~(4)~~(5) **Transpower** is not required to (but may) start the vendor's **monthly benefit-based charge** calculated under paragraph (2)(b) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of the **annual benefit-based charge** for the **BBI** and **exempt pricing year** resulting from the start of the purchaser's **monthly benefit-based charge** for the **BBI** must be rebated to the vendor by way of an adjustment to its **transmission charges**—

(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~93~~94 Benefit-based Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 94 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(l).

(2) In this clause 94, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover the **BBI's covered cost**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **BBI** to account for the amount of the voluntary under-recovery of the **BBI's covered cost**.

(4) If **Transpower** decides to voluntarily under-recover the **BBI's covered cost** for a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **beneficiaries' monthly benefit-based charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of the **BBI's covered cost** for the relevant **pricing year** (accounting for the voluntary under-recovery) must be rebated, as appropriate, to the **beneficiaries** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the relevant **pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~94~~95 Benefit-based Charge Adjustment Event: SSCGU

(1) This clause 95 applies in the case of the **benefit-based charge adjustment event** in paragraph 84(1)(m).

(2) **Transpower** must—

(a) determine which **post-2019 BBIs**, if any, satisfy all of the following conditions (the relevant **BBIs**):
   (i) the **post-2019 BBI** is expected to be **high-value** at the start of the **SSCGU's start pricing year**:
   (ii) the distribution of **regional NPB** for the **post-2019 BBI** is likely to have changed materially as a result of the **SSCGU**, compared to the distribution of **regional NPB** for the **post-2019 BBI** immediately before the **SSCGU**:
   (iii) the **SSCGU** was not a **market scenario** used to calculate the existing **BBI customer allocations** for the **post-2019 BBI**; and
(b) for each relevant **BBI**, re-calculate **beneficiaries' BBI customer allocations** as if the relevant **BBI** were a new **high-value post-2019 BBI** for which—

(i) the **standard method calculation period** starts on the date of the **SSCGU**; and
(ii) the **final investment decision date** is the date of the **SSCGU**.

(3) In carrying out the re-calculation under paragraph (2)(b), **Transpower** may use—
(a) a different **standard method** than was used to calculate the existing **BBI customer allocations** for the relevant **BBI**; or
(b) different **factual**, **counterfactual**, **investment grids**, **system limits**, **scenarios**, **modelled regions** and **regional customer groups** than were used to calculate the existing **BBI customer allocations** for the relevant **BBI**.

(4) From the **SSCGU's start pricing year**, **Transpower** must calculate **beneficiaries' benefit-based charges** for each relevant **BBI** based on the **beneficiaries' BBI customer allocations** for the relevant **BBI** re-calculated under paragraph (2)(b).

Residual Charges

~~95~~96 Residual Charge Adjustment Events

(1) The following events are **residual charge adjustment events**:

(a) a **customer** (the exiting **load customer**) ceases to be a **customer**:
(b) a **customer** (the disconnecting **load customer**) disconnects **consuming plant** from the **grid**:
(c) **large embedded consuming plant** is disconnected from a **host customer's** (the disconnecting **load customer's**) **local network** or **grid**-connected **plant**:
(d) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **load customer** to another party (the purchaser):
(e) **Transpower** decides to voluntarily under-recover **residual revenue**.

(2) **Transpower** must not voluntarily under-recover **residual revenue** for a **pricing year** if the effect of doing so would be to increase **residual revenue** for any other **pricing year**.

(3) For the purposes of paragraphs (1)(b) and (1)(c) a **large de-rating** of existing **consuming plant** is treated as the disconnection of **large consuming plant** equivalent in size to the **de-rating**.

(4) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **load customer** to a purchaser is treated as the **benefit-based charge adjustment event** in paragraph (1)(d) and not the **benefit-based adjustment event** in paragraph (1)(a), and the purchaser is not treated as a new **load customer**.

[Alternative drafting replacing clause 96 above: Step adjustment for new customers and connection of new large consuming plant]

96A Residual Charge Adjustment Events

(1) The following events are **residual charge adjustment events**:
(a) a new **customer** (the new **load customer**) connects to the **grid**:
(b) a **customer** (the exiting **load customer**) ceases to be a **customer**:
(c) an existing **customer** (the connecting or disconnecting **load customer**) connects **consuming plant** to, or disconnects **consuming plant** from, the **grid**:
(d) **large embedded consuming plant** is connected to, or **large embedded consuming plant** is disconnected from, a **host customer's** (the connecting or disconnecting **load customer's**) **local network** or **grid**-connected **plant**:

Commented [A113]: Change
Commented [A114]: Typo
Commented [A115]: Clarification

(e) a **customer** (the vendor) sells or otherwise transfers part of its business that constitutes it as a **load customer** to another party (the purchaser):

(f) **Transpower** decides to voluntarily under-recover **residual revenue**.

(2) **Transpower** must not voluntarily under-recover **residual revenue** for a **pricing year** if the effect of doing so would be to increase **residual revenue** for any other **pricing year**.

(3) For the purposes of paragraphs (1)(c) and (1)(d)—

(a) a **large upgrade** of existing **consuming plant** is treated as the connection of **large consuming plant** equivalent in size to the **upgrade**; and

(b) a **large de-rating** of existing **consuming plant** is treated as the disconnection of **large consuming plant** equivalent in size to the **de-rating**.

(4) To avoid doubt, a vendor's sale or other transfer of all or part of its business that constitutes it as a **load customer** to a purchaser is treated as the **benefit-based charge adjustment event** in paragraph (1)(e) and not the **benefit-based adjustment event** in paragraph (1)(a) or (1)(b).

96B Residual Charge Adjustment Event: New Load Customer

(1) This clause 96B applies in the case of the **residual charge adjustment event** in subclause 96A(1)(a).

(2) **Transpower** must—

(a) estimate the new **load customer's AMDR** baseline assuming full operation of the new **load customer's assets** from the start of **CMP D** and taking into account—

(i) the type and **capacity** of the new **load customer's assets**; and

(ii) the **AMDR** baselines for any other **load customers** with **assets** of the same or a similar type as the new **load customer's assets**,

but excluding any contribution to the new **load customer's AMDR** from the charging or discharging of **large battery storage** other than the **battery storage's** energy losses; and

(b) calculate or re-calculate (as the case may be) all **load customers' residual charges** to account for the new **load customer's AMDR** (but not any change in **residual revenue** that may have occurred during the **event pricing year**).

(3) **Transpower** must start the new **load customer's monthly residual charge** calculated under paragraph (2)(b) as soon as reasonably practicable. The new **load customer's monthly residual charge** may include an adjustment as necessary to ensure the new **load customer** pays its full **residual charge** from the date the new **load customer** connected to the **grid**.

(4) **Transpower** is not required to (but may) start any other **load customer's monthly residual charge** re-calculated under paragraph (2)(b) during, or from the start of, an **exempt pricing year** for the **load customer**. However, any over-recovery of **residual revenue** for the **exempt pricing year** resulting from the start of the new **load customer's monthly residual charge** must be rebated, as appropriate, to the other **load customers** by way of an adjustment to their **transmission charges**—

(a) if reasonably practicable, at the end of the **exempt pricing year**; or

(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

(5) To avoid doubt, **Transpower** may re-estimate the new **load customer's AMDR** baseline under clause 76A.

~~96~~97 Residual Charge Adjustment Event: Exiting Load Customer

(1) This clause 97 applies in the case of the **residual charge adjustment event** in paragraph 96(1)(a).

(2) **Transpower**—

(a) must make the exiting **load customer's AMDR** and **residual charge** 0; and

(b) must not increase—

(i) any other **load customer's residual charge** for the **event pricing year**; or

(ii) any other **transmission charges** for the **event pricing year**,

as a consequence of ~~the application of~~applying paragraph (a).

~~97~~98 Residual Charge Adjustment Event: Large Plant Disconnected

(1) This clause 98 applies in the case of the **residual charge adjustment event** in paragraph 96(1)(b) or 96(1)(c).

(2) **Transpower** must—

(a) comply with clause 97 as if the **large consuming plant** had been disconnected from the **grid** by a separate exiting **customer** (the notional exiting **load customer**); and

(b) subject to subclause (3), attribute (by way of reduction) the notional exiting **load customer's AMDR** and **residual charge** to the disconnecting **load customer**, provided that the minimum value of the disconnecting **load customer's AMDR** and **residual charge** is 0.

(3) To ensure the notional exiting **load customer's AMDR** is not double-counted through the disconnecting **load customer's RCAF**, the amount of the notional exiting **load customer's AMDR Transpower** must attribute to the disconnecting **load customer** under paragraph (2)(b) for **pricing year** m ($AMDR_{adj\ m}$) is calculated as follows:

(a) $AMDR_{adj\ m<n+5} = AMDR_{notional}$;

(b) $AMDR_{adj\ m=n+5} = 0.75 \times AMDR_{notional}$;

(c) $AMDR_{adj\ m=n+6} = 0.50 \times AMDR_{notional}$;

(d) $AMDR_{adj\ m=n+7} = 0.25 \times AMDR_{notional}$;

(e) $AMDR_{adj\ m>n+7} = 0$,

where

n is the **financial year** during which the **large consuming plant** was disconnected

$AMDR_{notional}$ is the notional exiting **load customer's AMDR**.

[Alternative drafting replacing clause 98 above: Step adjustment for new customers and connection of new large consuming plant]

98A Residual Charge Adjustment Event: Large Plant Connected or Disconnected

Commented [A116]: Style

Commented [A117]: **Change:** We consider subclause (3) from our 25 August 2021 proposal (with some changes for clarity) should be reinstated. Without subclause (3) there will be double-counting of the AMDR reduction when the reduction in total gross energy attributable to the existing large consuming plant comes through in the lagged adjustment factor (RCAF).

We note the proposed approach is not to reduce the customer's AMDR baseline but rather its AMDR (i.e. AMDR baseline adjusted for changes in total gross energy). If AMDR baseline were reduced this would introduce a risk of the baseline going to zero if the customer's total gross load had increased significantly between the time its AMDR baseline was set and the time the large consuming plant exited.

~~(3)~~(4) This clause 98A applies in the case of the **residual charge adjustment event** in paragraph 96A(1)(c) or 96A(1)(d).

~~(4)~~(5) **Transpower** must, for a connecting **load customer**—
(a) comply with clause 96B as if the **large consuming plant** had been connected to the **grid** by a separate new **customer** (the notional new **load customer**); and
(b) subject to subclause (7), attribute (by way of increase) the notional new **load customer's AMDR** and **residual charge** to the connecting **load customer**.

~~(5)~~(6) **Transpower** must, for a disconnecting **customer**—
(a) comply with clause 97 as if the **large consuming plant** had been disconnected from the **grid** by a separate exiting **customer** (the notional exiting **load customer**); and
(b) subject to subclause (7), attribute (by way of reduction) the notional exiting **load customer's AMDR** and **residual charge** to the disconnecting **load customer**, provided that the minimum value of the disconnecting **load customer's AMDR** and **residual charge** is 0.

~~(6)~~(7) To ensure the notional new or exiting **load customer's AMDR** is not double-counted through the connecting or disconnecting **load customer's RCAF**, the amount of the notional new or exiting **load customer's AMDR Transpower** must attribute to the connecting or disconnecting **load customer** under paragraph (2)(b) or (6)(b) for **pricing year** m ($AMDR_{adj\ m}$) is calculated as follows:

(a) $AMDR_{adj\ m < n+5} = AMDR_{notional}$;

(b) $AMDR_{adj\ m=n+5} = 0.75 \times AMDR_{notional}$;

(c) $AMDR_{adj\ m=n+6} = 0.50 \times AMDR_{notional}$;

(d) $AMDR_{adj\ m=n+7} = 0.25 \times AMDR_{notional}$;

(e) $AMDR_{adj\ m > n+7} = 0$,

where

n is the **financial year** during which the **large consuming plant** was connected or disconnected

$AMDR_{notional}$ is the notional new or exiting **load customer's AMDR**.

~~98~~99 Residual Charge Adjustment Event: ~~Partial~~ Sale of Business

(1) This clause 98 applies in the case of the **residual charge adjustment event** in paragraph 96(1)(d).

(2) **Transpower** must, for a sale of part of the vendor's business—
(a) determine an apportionment between the vendor and purchaser of the vendor's **AMDR** (and the inputs to its calculation) taking into account the size and nature of the transferred business; and
(b) calculate or re-calculate (as the case may be) the vendor's and purchaser's **residual charges** based on the apportionment of the vendor's **AMDR** under paragraph (a) (but not any change in **residual revenue** that may have occurred during the **event pricing year**); and

(c) calculate or re-calculate (as the case may be) the vendor's and purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—
(i) the vendor's and purchaser's **annual residual charges** calculated under paragraph (b); and
~~(i)~~(ii) any **annual benefit-based charges** for the vendor or purchaser calculated under subclause 93(2) or 93(3) in respect of the same sale of business.

(3) **Transpower** must, for a sale of all of the vendor's business—
(a) attribute the vendor's **AMDR** (and the inputs to its calculation) to the purchaser; and
(b) calculate or re-calculate (as the case may be) the purchaser's **residual charge** based on the attribution of the vendor's **AMDR** under paragraph (a); and
(c) calculate or re-calculate (as the case may be) the purchaser's **cap recovery charge** and **prudent discount recovery charges** for the **event pricing year** to account for—
(i) the purchaser's **annual residual charges** calculated under paragraph (b); and
(ii) any **annual benefit-based charges** for the vendor or purchaser calculated under subclause 93(2) or 93(3) in respect of the same sale of business.

~~(3)~~(4) **Transpower** must start the purchaser's **monthly residual charge** calculated under paragraph (2)(b) or (3)(b) as soon as reasonably practicable. The purchaser's **monthly residual charge** may include an adjustment as necessary to ensure the purchaser pays its full **residual charge** from the date of the transfer.

~~(4)~~(5) **Transpower** is not required to (but may) start the vendor's **monthly residual charge** calculated under paragraph (2)(b) during, or from the start of, an **exempt pricing year** for the vendor. However, any over-recovery of **residual revenue** for the **exempt pricing year** resulting from the start of the purchaser's **monthly residual charge** must be rebated to the vendor by way of an adjustment to its **transmission charges**—
(a) if reasonably practicable, at the end of the **exempt pricing year**; or
(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

~~99~~100 Residual Charge Adjustment Event: Voluntary Under-recovery

(1) This clause 100 applies in the case of the **residual charge adjustment event** in paragraph 96(1)(e).

(2) In this clause 100, a relevant **pricing year** is a **pricing year** for which **Transpower** decided to voluntarily under-recover **residual revenue**.

(3) **Transpower** must, for each relevant **pricing year**, calculate or re-calculate (as the case may be) all **load customers' residual charges** for the discounted **pricing year** to account for the amount of the voluntary under-recovery of **residual revenue**.

(4) If **Transpower** decides to voluntarily under-recover **residual revenue** for a relevant **pricing year** during, or within 1 month of the start of, the relevant **pricing year**, **Transpower** is not required to (but may) start **load customers' monthly residual charges** calculated under subclause (3) during, or from the start of, the relevant **pricing year**. However, any over-recovery of **residual revenue** for the relevant **pricing year** (accounting for the voluntary under-recovery) must be rebated, as appropriate, to **load customers** by way of an adjustment to their **transmission charges**—
(a) if reasonably practicable, at the end of the relevant **pricing year**; or

(b) otherwise, as soon as reasonably practicable during the next **pricing year**.

Part G Reassignment

~~100~~101 Effect of Reassignment

If an **eligible BBI** is **reassigned**, **Transpower** must, from the **reassignment's start pricing year**—

(a) reduce the **eligible BBI's covered cost** by the **eligible BBI's reassignment amount**; and

(b) calculate **beneficiaries' benefit-based charges** for the **eligible BBI** based on the reduction of the **eligible BBI's covered cost** under paragraph (a).

~~101~~102 Reassignment Amount

The **reassignment amount** for a **reassigned eligible BBI** (RA) is calculated as follows:

$$RA = CC \times (1 - RF)$$

where

CC is the **eligible BBI's covered cost**

RF is the **eligible BBI's reassignment factor**.

~~102~~103 Eligibility for Reassignment

(1) Before or as soon as reasonably practicable after the start of a **pricing year**, **Transpower** must **publish**—

(a) a list of **BBIs** that satisfy paragraph (a) of the definition of **eligible BBI** in clause 3 as at the start of the **pricing year**; and

(b) identify which of the listed **BBIs** are **post-2019 BBIs** that satisfy subparagraph (b)(i) of the definition of **eligible BBI** in clause 3 as at the start of the **pricing year**.

(2) The **reassignment threshold** is—

(a) $5m for the **first pricing year**; and

(b) calculated as follows for each **pricing year** after the **first pricing year**~~, calculated as follows~~:

$$RT = \$5m \times \frac{CPI}{CPI_{base}}$$

where

RT is the **reassignment threshold** for the **pricing year**

CPI is the average of the quarterly **CPIs** for the preceding **financial year**

CPI_{base} is the average of the quarterly **CPIs** for the most recent complete **financial year** before the start of the **first pricing year**.

(3) If there is a base adjustment to **CPI**, the calculation in paragraph (2)(b) is to include an equivalency adjustment to eliminate the impact of the base adjustment.

~~103~~104 Reassignment Application

(1) If an **eligible person** wishes for a **BBI** to be **reassigned**, the **eligible person** must submit to **Transpower** a written **application** for **reassignment** that meets the requirements of subclause (2).

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(2) An **application** for **reassignment** must—
(a) contain all of the information described in the relevant **application requirements**; and
(b) contain reasonable evidence that the conditions for **reassignment** are met; and
(c) be accompanied by an **independent verification** of the **application**.

(3) The **eligible person** must provide **Transpower** with any additional information **Transpower** determines is necessary to enable it to assess the **application**.

~~104~~105 Application Screening and Publication

(1) **Transpower** must reject an **application** for **reassignment** without assessing the **application** further if—
(a) the applicant is not an **eligible person**; or
(b) the **BBI** to which the **application** relates is not an **eligible BBI** when **Transpower** receives the **application**.

(2) **Transpower** may reject an **eligible person's application** for **reassignment** without assessing the **application** further—
(a) under subclause 15(1); or
(b) if an **eligible person** has previously applied for **reassignment** on substantially the same basis as the new **application** and **Transpower**—
(i) rejected the previous **application**; and
(ii) determines there has not been a change in circumstances since its decision on the previous **application** that materially increases the likelihood of the new **application** being approved.

(3) **Transpower** is not required to consult on any decision to reject an **application** under subclause (1), (2) or 15(1).

(4) Unless **Transpower** rejects an **application** under subclause (1), (2) or 15(1), and subject to clause 111, **Transpower** must **publish** the **application** and any information the **eligible person** provides to **Transpower** under subclause 104(3).

~~105~~106 Assessment

(1) In assessing an **eligible person's application** for **reassignment**, **Transpower** is not obliged to use the information the **eligible person** provided in or in support of the **application**.

(2) **Transpower** must approve the **application** if—
(a) **Transpower** determines that the **eligible BBI** to which the **application** relates has a **BBI reassignment factor** of less than 0.8; and
(b) **Transpower** reasonably expects the circumstances causing the **BBI reassignment factor** to be less than 0.8 to persist for at least 5 years after they occurred~~are sustained~~.

(3) Otherwise, **Transpower** must reject the **application**.

~~106~~107 Forecast Peak Loading and Reassignment Factors

(1) The **forecast loading period** for an **eligible BBI** the subject of a **reassignment** application is the period starting on the date **Transpower** receives the application and ending on the later of—
(a) 10 years after the date **Transpower** receives the application; and

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(b) if the **eligible BBI** is a **post-2019 BBI** to which subparagraph (b)(i) of the definition of **eligible BBI** in clause 3 does not apply, 20 years after the **eligible BBI's commissioning date**.

(2) **Forecast peak loading** for a **grid investment** comprised in the **eligible BBI** is the expected future peak electrical loading of the **grid investment** over the **eligible BBI's forecast loading period**, as determined by **Transpower**.

(3) The **investment reassignment factor** for a **grid investment** comprised in the **eligible BBI** is the proportion of the **grid investment's** total **replacement cost Transpower** determines it would incur to replace the **grid investment** with a **grid investment**—
(a) of the same type; and
(b) with a service potential sufficient to meet the **forecast peak loading** and reasonable **grid** contingencies, but no more.

(4) The **BBI reassignment factor** for the **eligible BBI** (BRF) is calculated as follows:

$$BRF = \frac{1}{CC_{total}}\sum_{i}(CC_i \times IRF_i)$$

where

CC_{total} is the **eligible BBI's covered cost** for the **pricing year** during which the application for **reassignment** was received

CC_i is the part of the **eligible BBI's covered cost** for the **pricing year** during which the application for **reassignment** was received attributable to **grid investment** i, where **grid investment** i is a **grid investment** comprised in the **eligible BBI**

IRF_i is **grid investment** i's **investment reassignment factor**.

(5) **Transpower** may **publish** in the **reassignment practice manual**, for 1 or more types of **grid investment** in, or in relation to, **interconnection assets**, information about the relationship between the **grid investment's forecast peak loading** and its **investment reassignment factor**, which may include 1 or more methods of calculating the **investment reassignment factor** as a function of **forecast peak loading**.

~~107~~108 Consultation on Draft Decision

(1) Subject to subclause 105(3), **Transpower** must consult with all **customers** on its draft decision to approve or reject an **eligible person's application** for **reassignment**.

(2) Subject to clause 111, **Transpower's** consultation under subclause (1) must include the information specified in paragraphs 110(a), 110(b) and 110(c) for the draft decision.

~~108~~109 Decision and Independent Review

(1) If **Transpower** approves an **eligible person's application** for **reassignment**, **Transpower** may approve a different **BBI reassignment factor** than sought in the **application**.

(2) **Transpower** must notify the **eligible person** whether **Transpower** approves or rejects the **application**. **Transpower's** notice must include the information specified in paragraphs 110(a), 110(b) and 110(c).

(3) The **eligible person** may, within 60 days of **Transpower** notifying the **eligible person** of **Transpower's** decision on the **application**, refer any aspect of **Transpower's** decision to an **independent expert** for review.

(4) The **independent expert's** decision will be binding on **Transpower** and the **eligible person**, and will have effect as if **Transpower** had made the decision itself, except that the **eligible person** may not refer the decision to an **independent expert** again.

(5) The costs of the **independent expert** must be met by the **eligible person** unless the **independent expert** decides an aspect of **Transpower's** decision under review was unreasonable, in which case **Transpower** may be required to meet all or some of the costs of the **independent expert**, as determined by the **independent expert**.

~~109~~110 Decision to be Published

Subject to clause 111, as soon as reasonably practicable after the **reassignment confirmation date**, **Transpower** must **publish**—

(a) its decision to approve or reject the **eligible person's application** for **reassignment**; and

(b) if **Transpower** approves the **application**, the **eligible BBI** and its **BBI reassignment factor**; and

(c) **Transpower's** analysis supporting its decision, including any material departures from the assumptions and methodologies in the **reassignment practice manual** and the reasons for those departures; and

(d) any report prepared by an **independent expert** relating to the **reassignment**.

~~110~~111 Commercially Sensitive Information

(1) Subject to subclause (2), **Transpower** is not obliged to **publish** or otherwise disclose any information under subclause 105(4) or 108(2) or clause 110 if—

(a) the **eligible person** identifies the information as commercially sensitive; and

(b) **Transpower** determines the disclosure of the information would be likely to commercially disadvantage the **eligible person** or any other person, in a material manner.

(2) **Transpower** must always **publish** under subclause 108(2) and clause 110 at least—

(a) its draft decision or decision (as the case may be) to approve or reject the **eligible person's application** for **reassignment**; and

(b) if the **application** is approved, the **eligible BBI** and its **BBI reassignment factor**.

~~111~~112 Reversal

(1) **Transpower** must fully or partially reverse a **reassignment** if—

(a) **Transpower** determines that the **forecast peak loading** of 1 or more of the **grid investments** comprised in the relevant **BBI** have increased such that the **BBI's BBI reassignment factor** has increased; and

(b) **Transpower** reasonably expects the circumstances causing the **BBI reassignment factor** to have increased to persist for at least 5 years after they occurred~~are sustained~~; and

(c) at the time of the reversal, the total **closing RAB value** of all **grid assets** comprised in the **BBI** for the most recent complete **financial year** is at least the **reassignment threshold**.

(2) If **Transpower** proposes to fully or partially reverse the **reassignment**—

(a) clause 108 applies as if that clause applied to **Transpower's** draft decision to reverse the **reassignment**;

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(b) **Transpower** must **publish** its decision on the reversal, including—
   (i) the **BBI's** new **BBI adjustment factor**; and
   (ii) **Transpower's** analysis supporting its decision, including any material departures from the assumptions and methodologies in the **reassignment practice manual** and the reasons for those departures; and

(c) an **eligible person** for the **BBI** may, within 60 days of **Transpower** publishing its decision on the reversal, refer any aspect of **Transpower's** decision to an **independent expert** for review, in which cases subclauses 109(4) and 109(5) will apply; and

(d) clauses 110 and 111 apply as if those clauses applied to Transpower's decision on the reversal and the **eligible person** referred to in paragraph 111(1)(a) were any **eligible person** who referred **Transpower's** decision to an **independent expert** under paragraph (c).

(3) If **Transpower** determines that the **BBI's BBI reassignment factor** is 0.8 or more, **Transpower** must fully reverse the **reassignment**.

(4) To avoid doubt, all references to the **BBI's BBI reassignment factor** in this clause 112 refer to the **BBI reassignment factor** calculated by reference to the **replacement costs** of the **grid investments** comprised in the **BBI** without any adjustment for their **investment reassignment factors** for the current **reassignment** of the **BBI**.

(5) A full or partial reversal of **reassignment** will have effect from the first **pricing year** that starts at least 6 months (or such shorter period as **Transpower** may determine is practicable) after the **reassignment confirmation date**.

~~112~~113 Reassignment Practice Manual

(1) **Transpower** may from time to time **publish**, and **publish** updates to, a **reassignment practice manual**.

(2) The **reassignment practice manual** must not contain any assumptions or methodologies that are inconsistent with this Code.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** on the **reassignment practice manual** or any update to it before **publishing** the **reassignment practice manual** or update.

(4) **Transpower** is not required to consult on an update to the **reassignment practice manual** if **Transpower** determines—
   (a) the update is technical and non-controversial; or
   (b) there is widespread support for the update among **customers**; or
   (c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) The **reassignment practice manual** is not binding on **Transpower** or any **independent expert**.

(6) **Transpower** must review the content of the **reassignment practice manual** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a review under clause 12.85 of this Code no later than 7 years after its date of **publication** and, after that, at intervals of no more than 7 years~~ from the start of the **first pricing year**~~.

Commented [A121]: **Clarification:** The previous drafting implicitly assumed there will be a reassignment practice manual within seven years of the first pricing year, which does not have to be the case. This new wording matches section 52Y of the Commerce Act 1986 (relating to input methodologies).

(7) The **reassignment practice manual** may be part of the same document in which the **assumptions book** or **prudent discount practice manual** is contained.

Part H Transitional Price Cap

~~113~~114 Cap and Cap Condition

(1) Despite anything else in this **transmission pricing methodology**, a **capped customer's transmission charges** for each **pricing year** preceding **pricing year** 2038 are reduced by the minimum amount necessary (if any) to ensure the **cap condition** is satisfied for the **capped customer** and **pricing year**.

(2) The **cap condition** for a **pricing year** is:

$$CC - IC_{19} - HVDC_{19} \leq DC$$

where

CC is a **capped customer's capped charges** for the **pricing year**

IC_{19} is the **capped customer's** annual interconnection charge for **pricing year** 2019 under the **previous transmission pricing methodology**

$HVDC_{19}$ is the **capped customer's** annual HVDC charge for **pricing year** 2019 under the **previous transmission pricing methodology**

DC is the **capped customer's difference cap** for the **pricing year**.

(3) To avoid doubt, the values of IC_{19} and $HVDC_{19}$ in subclause (2) include the impact on the **capped customer's** charges for **pricing year** 2019 of any—

(a) prudent discount provided under the **previous transmission pricing methodology**; or

(b) **input connection contract**, **new investment agreement contract** or **notional embedding contract**.

~~(3)~~(4) A **capped customer's capped charges** include the **capped customer's** annual **cap recovery charge**. It is therefore possible the **cap condition** will not be satisfied for the **capped customer** when a **cap recovery charge** is allocated to the **capped customer**. Accordingly, for each **pricing year**, subclause (1) is applied iteratively until the **cap condition** does not result in a reduction in any **capped customer's capped charges** for the **pricing year**. The annual **cap recovery charge** component of **capped charges** is 0 for the first iteration.

~~(4)~~(5) The **cap condition** applies at the start of a **pricing year** only. The **cap condition** is not applied again, and **difference caps** and **cap recovery charges** are not re-calculated, if there is an adjustment to **transmission charges** during the **pricing year**.

~~(5)~~(6) The **cap condition** is applied, and the **difference cap** is calculated, subject to any applicable prudent discount agreement entered into under this **transmission pricing methodology** or the **previous transmission pricing methodology**, provided that the prudent discount agreement applies or applied at the relevant time.

~~(6)~~(7) Despite anything else in this clause 114, the **cap condition** must not result in **Transpower** recovering less than **recoverable revenue** for a **pricing year**. If **Transpower** determines it is necessary to do so, **Transpower** may reduce all **capped customers' cap reductions** for a **pricing year** on a pro rata basis to ensure **Transpower** recovers **recoverable revenue** for the **pricing year** (but not more than **recoverable revenue** for the **pricing year**).

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~~114~~115 Difference Cap

(1) A **capped customer's difference cap** for **pricing year** n (DC_n) is calculated as follows:

$$DC_n = NEB_{19} \times (0.035 + (0.02 \times N) + \Delta CPI_n + \Delta TGE_n)$$

where

NEB_{19} is the **capped customer's** notional **electricity** bill for **pricing year** 2019 calculated under subclause (2)

N is—

(a) 0 if the **capped customer** is a **distributor**~~, 0~~; or

(b) the greater of 0 and n-2024 if the **capped customer** is a **direct consumer**~~, the greater of 0 and n-2024~~

ΔCPI_n is the proportionate change in **CPI** for **pricing year** n calculated under subclause (3)

ΔTGE_n is the proportionate increase (if any) in the **capped customer's total gross energy** for **pricing year** n calculated under subclause (5).

(2) A **capped customer's** notional **electricity** bill for **pricing year** 2019 (NEB_{19}) is calculated as follows:

$$NEB_{19} = LC_{19} + (P_{19} \times TGE_{19})$$

where

LC_{19} is—

(a) if the **capped customer** is a **distributor**, the **capped customer's** "total line charge revenue" for **pricing year** 2019, as disclosed in the **capped customer's** Report on Billed Quantities and Line Charge Revenues (Schedule 8) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or

(b) if the **capped customer** is a **direct consumer**, the **capped customer's** total annual transmission charges for **pricing year** 2019 under the **previous transmission pricing methodology**

P_{19} is the volume weighted average of **final prices** at the **capped customer's connection locations** during **CMP G**, using **gross energy** per **trading period** for weighting

TGE_{19} is the **capped customer's total gross energy** for **pricing year** 2019, being—

(a) if the **capped customer** is a **distributor**, the **capped customer's** "electricity entering system for supply to consumers' connection points" for **pricing year** 2019, as disclosed in the **capped customer's** Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or

(b) if the **capped customer** is a **direct consumer**, as determined by **Transpower**.

(3) Subject to subclause (4), the proportionate change in **CPI** for **pricing year** n (ΔCPI_n) is calculated as follows:

$$\Delta CPI_n = \frac{CPI_{n-2}}{CPI_{19}} - 1$$

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where

CPI is the average of the quarterly **CPIs** for **pricing year** n-2

CPI_{19} is 1041.75, being the average of the quarterly **CPIs** for **pricing year** 2019.

(4) If there is a base adjustment to **CPI**, the calculation in subclause (3) is to include an equivalency adjustment to eliminate the impact of the base adjustment.

(5) The proportionate increase (if any) in a **capped customer's total gross energy** for **pricing year** n (ΔTGE_n) is calculated as follows:

$$\Delta TGE_n = \frac{TGE_{n-2}}{TGE_{19}} - 1$$

where

TGE_n is the **capped customer's total gross energy** for **pricing year** n-2, being—

(a) if the **capped customer** is a **distributor**, the **capped customer's** "electricity entering system for supply to consumers' connection points" for **pricing year** n-2, as disclosed in the **capped customer's** Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March of year n-1; or

(b) if the **capped customer** is a **direct consumer**, as determined by **Transpower**.

TGE_{19} is as defined in subclause (2) for the **capped customer**.

~~115~~116 Cap Recovery Charge

(1) A **customer's annual cap recovery charge** for a **pricing year** (ACRC) is calculated as follows:

$$ACRC = CR_{total} \times \frac{CRRC}{CRRC_{total}}$$

where

CR_{total} is the total of all **customers' cap reductions** for the **pricing year**

CRRC is the **customer's cap recovery-relevant charges** for the **pricing year**

$CRRC_{total}$ is the total of all **customers' cap recovery-relevant charges** for the **pricing year**.

(2) A **customer's monthly cap recovery charge** for a **pricing year** (MCRC) is calculated as follows:

$$MCRC = \frac{ACRC}{12}$$

where ACRC is the **customer's annual cap recovery charge** for the **pricing year**.

Part I Prudent Discount Policy

General

~~116~~117 Effect of Prudent Discount Agreements

(1) Despite anything else in this **transmission pricing methodology**, a **prudent discount recipient's transmission charges** are subject to its **prudent discount** agreement.

(2) Except as otherwise stated in this **transmission pricing methodology**, allocations of **transmission charges** (other than **cap recovery charges** and **prudent discount recovery charges**) and adjustments to those allocations are calculated without regard to the impact of any **prudent discount** agreement on the effective allocations of **transmission charges**.

~~117~~118 Prudent Discount Applications

(1) If a **customer** wishes to receive a **prudent discount**, the **customer** must submit to **Transpower** a written **application** for the **prudent discount** that meets the requirements of subclause (2).

(2) The **application** must—
(a) contain all of the information described in the relevant **application requirements**; and
(b) contain reasonable evidence that the conditions for obtaining the **prudent discount** are met; and
(c) include at least the level of detail a prudent board of directors of a company would reasonably expect when assessing an investment proposal for the **alternative project** proposed in the **application**; and
(d) be accompanied by an **independent verification** of the **application**.

(3) The **customer** must provide **Transpower** with any additional information **Transpower** determines is necessary to enable it to assess the **application**.

~~118~~119 Application Screening and Publication

(1) **Transpower** must reject an **application** for a **prudent discount** without assessing the **application** further if the applicant is not a **customer**.

(2) **Transpower** may reject a **customer's application** for a **prudent discount** without assessing the **application** further—
(a) under subclause 15(1); or
(b) if a **customer** has previously applied for a **prudent discount** on substantially the same basis as the new **application** and **Transpower**—
(i) rejected the previous **application**; and
(ii) determines there has not been a change in circumstances since its decision on the previous **application** that materially increases the likelihood of the new **application** being approved.

(3) **Transpower** is not required to consult on any decision to reject an **application** under subclause (1), (2) or 15(1).

(4) Unless **Transpower** rejects an **application** under subclause (1), (2) or 15(1), and subject to clause 128, **Transpower** must **publish** the **application** and any information the **customer** provides to **Transpower** under subclause 118(3).

~~119~~120 Assessment

(1) In assessing a **customer's application** for a **prudent discount**, **Transpower** is not obliged to use the information the **customer** provided in or in support of the **application**, but must not assess an **alternative project** that is not the **alternative project** proposed in the **application**.

(2) In assessing whether the **alternative project** would provide the same or a substantially similar level of service to the **customer** as the **transmission services** it currently receives, **Transpower** must consider—

(a) access to **electricity**; and
(b) quality of supplied **electricity**; and
(c) reliability and security of supply of **electricity**; and
(d) any other measure of quality for **transmission services** **Transpower** determines is relevant.

~~120~~121 Calculation of Alternative Project Costs

(1) The **alternative project costs** for an **alternative project** are the capital, operating, maintenance and overhead costs of the **alternative project**, as would be incurred by:

(a) the **customer**, in the case of an **inefficient bypass prudent discount**; or
(b) an efficient **transmission services** provider, in the case of a **stand-alone cost prudent discount**.

(2) For the purposes of calculating the **alternative project costs**, the value of any increase or decrease in **electrical** losses that would result from the **alternative project** must be included as an operating cost of the **alternative project** (with a decrease being treated as a negative cost).

(3) The **alternative project costs** must be calculated accounting for the impact of the relevant capital, operating, maintenance and overhead costs on the **customer's** or efficient **transmission services** provider's tax liability.

~~121~~122 Assessment of Commercial Viability

(1) The **alternative project** proposed in a **customer's application** for a **prudent discount** is only commercially viable if it is reasonably likely that:

$$\frac{PVATC - PVAPC}{PVAPC} > 0.1$$

where

PVAPC is the present value of the **alternative project costs** for the **alternative project** calculated under subclause (2)

PVATC is the present value of the **customer's avoided transmission charges** calculated under subclause (2).

(2) In carrying out the present value calculations under subclause (1), **Transpower** must use the formula:

$$PV = \sum_{n} \frac{A_n}{(1+r)^n}$$

where

PV is the present value being calculated

A_n are the **alternative project costs** or **avoided transmission charges** (as the case may be) for year n of the relevant **prudent discount calculation period**

r is the relevant **prudent discount rate**.

~~122~~123 Consultation on Draft Decision

(1) Subject to subclause 119(3), **Transpower** must consult with all **customers** on its draft decision to approve or reject a **customer's application** for a **prudent discount**.

(2) Subject to clause 128, **Transpower's** consultation under subclause (1) must include—
(a) the information specified in paragraphs 127(a) and 127(c) and subparagraph 127(b)(i) for the draft decision; and
(b) if **Transpower** proposes to approve the **application**, the terms of the proposed **prudent discount** agreement specified in subparagraphs 128(2)(b)(ii), 128(2)(b)(iii) and 128(2)(b)(iv).

~~123~~124 Decision and Independent Review

(1) If **Transpower** approves a **customer's application** for a **prudent discount**, **Transpower** may—
(a) approve different terms of the **prudent discount** than sought in the **application**, including a different amount of the **prudent discount**; and
(b) approve the **application** subject to reasonable conditions.

(2) **Transpower** must notify the **customer** whether **Transpower** approves or rejects the **application**. **Transpower's** notice must include—
(a) the information specified in paragraphs 127(a) and 127(c) and subparagraph 127(b)(i); and
(b) if **Transpower** approves the **application**, the terms of the proposed **prudent discount** agreement specified in subparagraphs 128(2)(b)(ii), 128(2)(b)(iii) and 128(2)(b)(iv).

(3) The **customer** may, within 60 days of **Transpower** notifying the **customer** of **Transpower's** decision on the **application**, refer any aspect of **Transpower's** decision to an **independent expert** for review.

(4) The **independent expert's** decision will be binding on **Transpower** and the **customer**, and will have effect as if **Transpower** had made the decision itself, except that the **customer** may not refer the decision to an **independent expert** again.

(5) The costs of the **independent expert** must be met by the **customer** unless the **independent expert** decides an aspect of **Transpower's** decision under review was unreasonable, in which case **Transpower** may be required to meet all or some of the costs of the **independent expert**, as determined by the **independent expert**.

~~124~~125 Prudent Discount Agreement

(1) If **Transpower** approves a **customer's application** for a **prudent discount**, **Transpower** must promptly offer a **prudent discount** agreement to the **customer**.

(2) A **prudent discount** agreement must provide for—

(a) the **customer** to pay **Transpower** an annuity, calculated under clause 126, in monthly instalments; and

(b) **Transpower** to calculate the **customer's transmission charges** in accordance with clause 135 or 140, as applicable; and

(c) **Transpower** to have the right to terminate the **prudent discount** agreement immediately if any of the conditions of **Transpower's** approval is not, or ceases to be, satisfied; and

(d) if the **prudent discount** agreement is for a **stand-alone cost prudent discount**, the **customer** to have the right to terminate the **prudent discount** agreement at the start of a **pricing year** by notifying **Transpower** at least 6 months before the start of the **pricing year**.

(3) The term of the **prudent discount** agreement must be the same as the relevant **prudent discount calculation period**, subject to earlier termination in accordance with the terms of the **prudent discount** agreement. To avoid doubt the term of the **prudent discount** agreement must start on the **prudent discount's start pricing year**.

(4) For the purposes of the **EDB IMs**, the annuity under a **prudent discount** agreement payable by a **distributor** is deemed to be a charge payable to **Transpower** under this **transmission pricing methodology** for **transmission services** provided to the **distributor**.

~~125~~126 Calculation of Annuity

The annuity under a **prudent discount** agreement (AN) is levelised and calculated as follows:

$$AN = \frac{APC}{\sum_{n=1}^{N} \frac{1}{(1+r)^n}}$$

where

N is the number of years in the relevant **prudent discount calculation period**, with each such year being year n

APC is the present value of the **alternative project costs** for the relevant **alternative project** calculated under subclause 122(2)

r is the relevant **prudent discount rate**.

~~126~~127 Decision to be Published

Subject to clause 128, as soon as reasonably practicable after the **prudent discount confirmation date**, **Transpower** must **publish**—

(a) its decision to approve or reject the **customer's application** for the **prudent discount**; and

(b) if **Transpower** approves the **application**—
  (i) any conditions of its approval; and
  (ii) a copy of the relevant **prudent discount** agreement; and

(c) its analysis supporting its decision, including any material departures from the assumptions and methodologies in the **prudent discount practice manual** and the reasons for those departures; and

(d) any report prepared by an **independent expert** relating to the **prudent discount**.

~~127~~128 Commercially Sensitive Information

(1) Subject to subclause (2), **Transpower** is not obliged to **publish** any information under subclause 119(4) or 123(2) or clause 127 if—

(a) the **customer** identifies the information as commercially sensitive; and

(b) **Transpower** determines the disclosure of the information would be likely to commercially disadvantage the **customer** or any other person, in a material manner.

(2) **Transpower** must always **publish** under subclause 123(2) and clause 127 at least—

(a) its draft decision or decision (as the case may be) to approve or reject the **customer's application** for the **prudent discount**; and

(b) if **Transpower** approves the application—

(i) details of the **alternative project** and **alternative project costs**; and

(ii) the annuity under the **prudent discount** agreement and details of how it was calculated; and

(iii) details of how the **prudent discount recipient's transmission charges** will be calculated under the **prudent discount** agreement; and

(iv) the term of the **prudent discount** agreement.

~~128~~129 Prudent Discount Practice Manual

(1) **Transpower** may from time to time **publish**, and **publish** updates to, a **prudent discount practice manual**.

(2) The **prudent discount practice manual** must not contain any assumptions or methodologies that are inconsistent with this Code.

(3) Subject to subclause (4), **Transpower** must consult with all **customers** on the **prudent discount practice manual** or any update to it before **publishing** the **prudent discount practice manual** or update.

(4) **Transpower** is not required to consult on an update to the **prudent discount practice manual** if **Transpower** determines—

(a) the update is technical and non-controversial; or

(b) there is widespread support for the update among **customers**; or

(c) there has been adequate prior consultation on the update so that all relevant views of **customers** have been considered.

(5) The **prudent discount practice manual** is not binding on **Transpower** or any **independent expert**.

(6) **Transpower** must review the content of the **prudent discount practice manual** and consider whether any of the content is appropriate for incorporation in this **transmission pricing methodology** by way of a review under clause 12.85 of this Code no later than 7 years after its date of **publication** and, after that, at intervals of no more than 7 years ~~from the start of the **first pricing year**~~.

(7) The **prudent discount practice manual** may be part of the same document in which the **assumptions book** or **reassignment practice manual** is contained.

Commented [A127]: **Clarification:** The previous drafting implicitly assumed there will be a prudent discount practice manual within seven years of the first pricing year, which does not have to be the case. This new wording matches section 52Y of the Commerce Act 1986 (relating to input methodologies).

Inefficient Bypass Prudent Discount

~~129~~130 Purpose of Inefficient Bypass Prudent Discount

The purpose of an **inefficient bypass prudent discount** is to help ensure this **transmission pricing methodology** does not provide incentives for a **customer** to invest in an **alternative project** that would allow a **customer** to reduce its own **transmission charges**, by bypassing existing **grid assets**, while increasing total economic costs.

~~130~~131 Multiple Benefitting Customers

If there is more than 1 **benefitting customer** for an **application** for an **inefficient bypass prudent discount**—

(a) all references to the applicant **customer** or **prudent discount recipient** in clauses 117 to 135 and 141 are deemed to include every **benefitting customer**; and

(b) without limiting paragraph (a)—

(i) the commercial viability test in clause 122 must be applied using the total **avoided transmission charges** of all **benefitting customers**; and

(ii) the inefficiency test in subclause 133(2) must be applied using **Transpower's** costs of providing **transmission services** to all **benefitting customers**; and

(c) the highest **prudent discount rate** across the **benefitting customers** applies to the **application**.

~~131~~132 Assessment of Equivalence, Feasibility and Commercial Viability

Transpower must assess whether the **alternative project** for an **inefficient bypass prudent discount**—

(a) would provide the **customer** with the same or a substantially similar level of service as the **transmission services** provided by the **grid assets** the **alternative project** would bypass; and

(b) is technically feasible using present day technology and construction methods, including that it is feasible for the **customer** to obtain the necessary resource consents and property rights for the **alternative project**; and

(c) is operationally feasible, including that the **alternative project** is compliant with applicable **asset owner performance obligations**, **technical codes** and any other requirements in Part 8 of this Code; and

(d) is otherwise consistent with **GEIP**; and

(e) is commercially viable under subclause 122(1).

~~132~~133 Assessment whether the Alternative Project is Inefficient

(1) If **Transpower** determines the **alternative project** for an **inefficient bypass prudent discount** satisfies all of the criteria in clause 132, **Transpower** must assess whether the **alternative project** is inefficient under subclause (2).

(2) The **alternative project** is only inefficient if it is reasonably likely that—

$$PVAPC > (PVTC_{no\ ap} - PVTC_{ap})$$

where

PVAPC is the present value of the capital, operating, maintenance and overhead costs of the **alternative project**, including, but not limited to, the **alternative project costs**

$PVTC_{no\ ap}$ is the present value of **Transpower's** capital, operating, maintenance and overhead costs of providing **transmission services** to the **customer** at the required service levels, including the cost of future **grid investments**, without the **alternative project** calculated under subclause (3)

$PVTC_{ap}$ is the present value of **Transpower's** capital, operating, maintenance and overhead costs of providing **transmission services** to the **customer** at the required service levels, including the cost of future **grid investments**, with the **alternative project** calculated under subclause (3).

(3) In carrying out the present value calculations under subclause (2), **Transpower** must use the formula:

$$PV = \sum_{n} \frac{C_n}{(1+r)^n}$$

where

PV is the present value being calculated

C_n is the relevant costs for year n of the relevant **prudent discount calculation period**

r is the relevant **prudent discount rate**.

~~133~~134 Approval or Rejection of Inefficient Bypass Prudent Discount Application

(1) **Transpower** must approve a **customer's application** for an **inefficient bypass prudent discount** if **Transpower** determines—

(a) the **alternative project** for the **application** satisfies all of the criteria in clause 132; and

(b) the **alternative project** is inefficient under subclause 133(2).

(2) Otherwise, **Transpower** must reject the **application**.

~~134~~135 Impact on Transmission Charges

A **prudent discount** agreement for an **inefficient bypass prudent discount** must provide for **Transpower** to calculate the **prudent discount recipient's transmission charges** during the term of the **prudent discount** agreement as if the relevant **alternative project** had been implemented, assuming none of its **alternative project costs** would be recovered through **transmission charges**.

Stand-alone Cost Prudent Discount

~~135~~136 Purpose of Stand-alone Cost Prudent Discount

The purpose of a **stand-alone cost prudent discount** is to help ensure this **transmission pricing methodology** does not result in a **customer** paying **transmission charges** that exceed the efficient stand-alone cost of the **transmission services** the **customer** receives from **interconnection investments**. A **stand-alone cost prudent discount** achieves this by replacing the **prudent discount recipient's benefit-based charges** and **residual charge** with an annuity under a **prudent discount agreement** equal to the **alternative project costs** of an **efficient stand-alone investment**.

~~136~~137 Assessment of Equivalence, Feasibility and Commercial Viability

(1) **Transpower** must assess whether the **alternative project** for a **stand-alone cost prudent discount**—

(a) is an **efficient stand-alone investment** that would provide the **customer** with the same or a substantially similar level of service as the **transmission services** the **customer** currently receives; and
(b) subject to subclause (2), is technically feasible using present day technology and construction methods; and
(c) is operationally feasible, including that the **alternative project** is compliant with applicable **asset owner performance obligations**, **technical codes** and any other requirements in Part 8 of this Code; and
(d) is otherwise consistent with **GEIP**; and
(e) is commercially viable under clause 122.

(2) The **alternative project** is technically feasible even if it is not feasible to obtain any or all of the necessary resource consents and property rights for the **alternative project**, provided that the **alternative project** is technically feasible in all other respects. In calculating the **alternative project costs**, **Transpower** must use estimates of the likely cost of obtaining any resource consents and property rights that are not feasible to obtain based on the cost of obtaining broadly equivalent resource consents and property rights for feasible activities in feasible locations.

~~137~~138 Assessment of Efficient Stand-alone Investment
(1) An **efficient stand-alone investment** is an investment in the **grid** or a **transmission alternative** an efficient **transmission services** provider would make to supply **transmission services** solely to the **customer** who has applied for a **stand-alone cost prudent discount**, assessed by—
(a) using the existing **grid** and the **customer's** existing **grid points of connection** as a starting point; and
(b) holding **connection assets** constant; and
(c) applying optimisation tests to **interconnection assets** to identify, in the single-**customer** hypothetical, stranded **interconnection assets**, excess **capacity** in **interconnection assets** and other **interconnection asset** over-engineering.

(2) An **efficient stand-alone investment** does not need to be in the same location or follow the same route as the existing **grid**.

~~138~~139 Approval or Rejection of Stand-alone Cost Prudent Discount Application
(1) **Transpower** must approve a **customer's application** for a **stand-alone cost prudent discount** if **Transpower** determines the **alternative project** for the **application** satisfies all of the criteria in subclause 137(1).

(2) Otherwise, **Transpower** must reject the **application**.

~~139~~140 Impact on Transmission Charges
A **prudent discount** agreement for a **stand-alone cost prudent discount**—
(a) must provide for the **prudent discount recipient's benefit-based charges** and **residual charge** to be 0 during the term of the **prudent discount** agreement; and
(b) must not provide for a change to any other **transmission charge**.

Prudent Discount Recovery

~~140~~141 Prudent Discount Recovery Charges
(1) Subject to subclause (3), **customer** c's **BBI prudent discount recovery charge** for **discounted BBI** b and a **pricing year** ($BPDS_{cb}$), where **customer** c is a **beneficiary** of **discounted BBI** b and not the **prudent discount recipient**, is calculated as follows:

$$BPDS_{cb} = (PD - A) \times \frac{BBC_{recipient\ b}}{\sum_k BBC_{recipient\ k} + RC_{recipient}} \times \frac{BBC_{cb}}{\sum_j BBC_{jb}}$$

where

PD is the amount of the relevant **prudent discount** for the **pricing year**

A is the annuity payable by the **prudent discount recipient** for the **prudent discount** and **pricing year**

$BBC_{recipient\ b}$ is the **prudent discount recipient's** **annual** **benefit-based charge** for **discounted BBI** b and the **pricing year** without the **prudent discount**

Commented [A128]: Clarification

$BBC_{recipient\ k}$ is the **prudent discount recipient's** **annual** **benefit-based charge** for **discounted BBI** k for the **pricing year** without the **prudent discount**, where **discounted BBI** k is a **discounted BBI** for the **prudent discount** (including **discounted BBI** b)

Commented [A129]: Clarification

$RC_{recipient}$ is—

(a) if the **prudent discount** includes any discount to the **prudent discount recipient's residual charge** or **connection charges**, the **prudent discount recipient's** **annual** **residual charge** for the **pricing year** without the **prudent discount**; or

(b) otherwise, 0

Commented [A130]: Clarification

BBC_{cb} is **customer** c's **annual** **benefit-based charge** for **discounted BBI** b and the **pricing year**

Commented [A131]: Clarification

BBC_{jb} is **customer** j's **annual** **benefit-based charge** for **discounted BBI** b and the **pricing year**, where **customer** j is a **beneficiary** of **discounted BBI** b and not the **prudent discount recipient** (including **customer** c).

Commented [A132]: Clarification

(2) Subject to subclause (3), **customer** c's **residual prudent discount recovery charge** for a **prudent discount** and **pricing year** ($RPDS_c$), where **customer** c is a **load customer** and not the **prudent discount recipient**, is calculated as follows:

$$RPDS_c = (PD - A - BPDS) \times \frac{RC_c}{\sum_j RC_j}$$

where

PD is the amount of the **prudent discount** for the **pricing year**

A is the annuity payable by the **prudent discount recipient** for the **prudent discount** and **pricing year**

BPDS is the total amount of the **prudent discount** to be recovered through **BBI prudent discount recovery charges** for the **pricing year**

RC_c is **customer** c's **annual** **residual charge** for the **pricing year**

Commented [A133]: Clarification

RC_j is **customer** j's **annual** **residual charge** for the **pricing year**, where **customer** j is not the **prudent discount recipient** (including **customer** c).

Commented [A134]: Clarification

(3) The minimum value of a **BBI prudent discount recovery charge** or **residual prudent discount recovery charge** is 0.

(4) A **customer's annual prudent discount recovery charge** for a **pricing year** (APDRC) is the sum of the **customer's BBI prudent discount recovery charges** and **residual prudent discount recovery charges** for the **pricing year**.

(5) A **customer's monthly prudent discount recovery charge** for a **pricing year** (MPDRC) is calculated as follows:

$$MPDRC = \frac{APDRC}{12}$$

where APDRC is the **customer's annual prudent discount recovery charge** for the **pricing year**.

(6) **Prudent discount recovery charges** are calculated at the start of a **pricing year** only. **Prudent discount recovery charges** are not re-calculated if there is an adjustment to **transmission charges** during the **pricing year**.

Appendix A – Appendix A BBIs and Starting BBI Customer Allocations

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Alpine Energy Ltd	3.07%	0.85%	1.50%	2.99%	0.30%	0.30%	0.24%
Aurora Energy Ltd	5.64%	1.57%	0.90%	4.49%	0.30%	0.30%	0.27%
Beach Energy Resources NZ (Holdings) Ltd	0.03%	0.07%	0.10%	0.08%	0.03%	0.03%	0.04%
Buller Electricity Ltd	0.26%	0.08%	0.08%	0.19%	0.01%	0.01%	0.01%
Centralines Ltd	0.07%	0.21%	0.24%	0.17%	0.05%	0.05%	0.01%
Contact Energy Ltd	2.08%	12.56%	24.07%	0.09%	5.90%	5.90%	21.39%
Counties Power Ltd	0.31%	1.06%	1.08%	0.85%	2.60%	2.60%	1.42%
Daiken Southland Ltd	0.27%	0.09%	1.39%	0.28%	0.02%	0.02%	0.02%
EA Networks	1.68%	0.51%	0.76%	1.71%	0.26%	0.26%	0.15%
Eastland Network Ltd	0.17%	0.35%	0.57%	0.41%	0.05%	0.05%	0.00%
Electra Ltd	2.71%	0.79%	0.95%	0.67%	0.34%	0.34%	0.15%
Genesis Energy Ltd	1.20%	3.23%	0.00%	0.03%	3.63%	3.63%	7.69%
GTL Energy New Zealand Ltd	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Horizon Energy Distribution Ltd	0.23%	0.24%	0.37%	0.43%	0.04%	0.04%	0.00%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
KiwiRail Holdings Ltd	0.03%	0.07%	0.11%	0.08%	0.20%	0.20%	0.12%
Mainpower New Zealand Ltd	3.17%	0.88%	1.28%	2.95%	0.24%	0.24%	0.20%
Marlborough Lines Ltd	2.01%	0.45%	0.87%	1.88%	0.15%	0.15%	0.13%
MEL (Te Apiti) Ltd	0.11%	0.01%	0.00%	0.00%	0.09%	0.09%	0.00%
MEL (West Wind) Ltd	0.00%	0.08%	0.00%	0.00%	0.20%	0.20%	0.00%
Mercury NZ Ltd	0.69%	0.06%	0.08%	0.07%	6.76%	6.76%	10.73%
Mercury SPV Ltd	0.45%	0.01%	0.00%	0.00%	0.28%	0.28%	0.00%
Meridian Energy Ltd	0.12%	33.65%	1.10%	0.05%	7.01%	7.01%	0.00%
Methanex New Zealand Ltd	0.03%	0.06%	0.09%	0.07%	0.03%	0.03%	0.04%
Nelson Electricity Ltd	0.28%	0.06%	0.12%	0.23%	0.02%	0.02%	0.02%
Network Tasman Ltd	3.02%	0.71%	1.34%	2.57%	0.20%	0.20%	0.17%
Network Waitaki Ltd	1.12%	0.36%	0.52%	2.17%	0.13%	0.13%	0.08%
New Zealand Steel Ltd	0.30%	0.50%	0.96%	0.85%	2.45%	2.45%	1.34%
Nga Awa Purua Joint Venture	0.00%	0.00%	0.00%	0.00%	0.97%	0.97%	8.06%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Ngatamariki Geothermal Ltd	0.01%	0.00%	0.00%	0.00%	0.58%	0.58%	4.89%
Norske Skog Tasman Ltd	0.00%	0.00%	0.00%	0.00%	0.18%	0.18%	2.48%
Northpower Ltd	0.66%	1.13%	2.17%	1.79%	5.94%	5.94%	2.92%
Nova Energy Ltd	0.04%	0.00%	0.00%	0.00%	0.03%	0.03%	0.00%
NZ Aluminium Smelters Ltd	21.77%	7.26%	2.13%	23.65%	1.59%	1.59%	1.62%
OMV New Zealand Production Ltd	0.34%	0.01%	0.00%	0.00%	0.21%	0.21%	0.00%
Orion New Zealand Ltd	18.00%	4.89%	7.19%	14.73%	1.14%	1.14%	1.00%
Pan Pac Forest Product Ltd	0.34%	0.47%	0.77%	0.69%	0.10%	0.10%	0.00%
Powerco Ltd	3.97%	6.26%	8.59%	6.71%	1.90%	1.90%	3.61%
Powernet Ltd	5.31%	1.38%	10.58%	6.34%	0.38%	0.38%	0.35%
Scanpower Ltd	0.04%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Southdown Cogeneration Ltd	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%
Southern Generation GP Ltd	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southpark Utilities Ltd	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Customer	Bunnythorpe Haywards	HVDC	LSI Reliability	LSI Renewables	NIGU	UNIDRS	Wairakei Ring
Tararua Wind Power	0.26%	0.01%	0.00%	0.00%	0.16%	0.16%	0.00%
The Lines Company Ltd	0.16%	0.36%	0.47%	0.37%	0.18%	0.18%	0.49%
Todd Generation Taranaki Ltd	0.49%	0.18%	0.00%	0.03%	0.52%	0.52%	0.00%
Top Energy Ltd	0.00%	0.24%	0.00%	0.00%	1.08%	1.08%	0.52%
Trustpower Ltd	0.09%	0.66%	0.02%	0.17%	0.16%	0.16%	1.15%
Unison Networks Ltd	0.63%	1.34%	2.20%	1.60%	0.16%	0.16%	0.00%
Vector Ltd	5.44%	10.77%	19.03%	14.41%	50.86%	50.86%	24.57%
Waipa Networks Ltd	0.25%	0.59%	0.81%	0.64%	0.33%	0.33%	1.02%
Waverley Wind Farm	0.27%	0.01%	0.00%	0.00%	0.17%	0.17%	0.00%
WEL Networks Ltd	0.51%	1.13%	1.82%	1.41%	1.12%	1.12%	2.38%
Wellington Electricity Lines Ltd	11.69%	4.24%	4.92%	3.22%	0.82%	0.82%	0.66%
Westpower Ltd	0.39%	0.09%	0.18%	0.45%	0.04%	0.04%	0.03%
Whareroa Cogeneration Ltd	0.10%	0.03%	0.00%	0.00%	0.02%	0.02%	0.00%
Winstone Pulp International	0.16%	0.29%	0.43%	0.36%	0.07%	0.07%	0.00%